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Pore-Scale Numerical Investigation of Surfactant-Assisted CO₂ Injection Strategies for Heavy-Oil Recovery in Two-Dimensional Porous Media

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Abstract

Understanding pore-scale interactions among CO₂, the aqueous phase, and heavy oil is crucial for optimizing surfactant-assisted CO₂-enhanced oil recovery. In this study, a three-phase volume-of-fluid (VOF) framework is established in OpenFOAM to simulate immiscible displacement in two-dimensional porous media composed of circular solid grains. Two pore geometries are considered: a relatively uniform geometry and a preferential-channel geometry designed to promote early breakthrough. Sixteen injection schemes are compared, including pure CO₂ flooding, ordinary-water flooding, surfactant–water flooding, aqueous-phase preflush followed by CO₂ injection, and cyclic aqueous-phase/CO₂ injection with different aqueous-slug durations and switching frequencies. The effects of pore geometry, injection strategy, capillary number, viscosity ratio, interfacial tension, and wettability are evaluated using pore-volume-normalized oil recovery, breakthrough PV (the ratio of injected volume to pore volume), cumulative injected CO₂ PV at breakthrough, and phase-distribution indicators. The results show that pore geometry strongly affects macroscopic sweep and breakthrough behavior. In the preferential-channel geometry, pure CO₂ flooding and continuous ordinary-water flooding suffer from early breakthrough and poor sweep, whereas continuous surfactant–water flooding maintains high recovery because reduced oil–water interfacial tension and a more water-wet wall condition promote oil-film detachment and residual-oil mobilization. At 2.5 injected PV, the high-frequency short-slug and 1 s surfactant–water cyclic schemes give the highest or near-highest recovery in the relatively uniform geometry, while continuous surfactant–water flooding remains the highest-recovery scheme in the preferential-channel geometry. Considering the higher chemical demand of continuous surfactant injection and the carbon-utilization objective of CO₂-EOR, the combined surfactant–water/CO₂ schemes are evaluated to clarify the coupling between surfactant-induced oil mobilization and CO₂ displacement. Surfactant–water preflush followed by CO₂ injection becomes more effective as the preflush duration increases, and its recovery advantage over ordinary-water preflush is especially large in the preferential-channel geometry. However, the increase in CO₂ breakthrough PV in this geometry is limited compared with the recovery increment, indicating that the main benefit of surfactant–water is not only delayed gas breakthrough but also enhanced microscopic oil mobilization in poorly swept regions. Increasing the switching frequency slightly improves the cyclic response in the relatively uniform geometry under the tested schedules, whereas all cyclic schemes remain strongly constrained by reconnection with the dominant gas pathway in the preferential-channel geometry. Within the present idealized immiscible VOF model, these comparisons provide a controlled pore-scale comparison for distinguishing surfactant-induced residual-oil mobilization from CO₂ gas-channeling effects in heavy-oil porous media.



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1. Introduction

Carbon dioxide (CO₂) capture, utilization, and storage (CCUS) has received increasing attention because of its potential to reduce greenhouse-gas emissions while supporting subsurface energy development [1–3]. Among different CCUS pathways, CO₂-enhanced oil recovery (CO₂-EOR) is considered an important utilization technology because it can improve oil production and simultaneously contribute to geological CO₂ storage [4–7]. Desch et al. [8] conducted a CO₂ miscible displacement study in the Little Knife field and demonstrated the field-scale potential of CO₂-EOR. Xiao et al. [9] compared water flooding and CO₂ injection in extra-/ultra-low-permeability reservoirs and reported higher recovery under CO₂ flooding. Feng et al. [10] evaluated miscibility effects in low-permeability reservoirs, while Ding et al. [11] investigated the influence of fracture density, miscibility, and production scheme on CO₂-EOR in fractured reservoirs. Gao and Pu [12] examined supercritical CO₂ huff-and-puff in tight conglomerate reservoirs, and Li et al. [13,14] further discussed CO₂-assisted recovery mechanisms in shale and tight sandstone reservoirs. Depending on whether the injection pressure reaches the minimum miscibility pressure, CO₂ flooding can be classified into miscible, near-miscible, and immiscible displacement. In miscible or near-miscible conditions, CO₂ can dissolve into crude oil, induce oil swelling, reduce oil viscosity and density, extract light components, and decrease the CO₂–oil interfacial tension, thereby improving oil mobility and displacement efficiency [15–17].

However, in immiscible or weakly miscible conditions, especially in heterogeneous porous media, the low viscosity and high mobility of CO₂ can induce viscous fingering, preferential flow channels, early gas breakthrough, and limited sweep efficiency. Zhang et al. [18] numerically simulated liquid CO₂ displacement of water in dual-permeability pore-network micromodels and showed that flow behavior depended strongly on injection rate and pore structure. Liu et al. [19] used a two-phase lattice Boltzmann model to simulate pore-scale liquid CO₂ displacement of water and analyzed preferential flow paths in dual-permeability systems. Zhu et al. [20] used the phase-field method to investigate pore-scale CO₂–oil displacement and observed pressure reduction in the CO₂ main channel and oil reflow after gas breakthrough. Ma et al. [21] studied CO₂/oil flow in heterogeneous porous media under immiscible and near-miscible conditions and found that near-miscible flooding could enlarge the CO₂ swept area but still left oil trapped in small pore throats. Song et al. [22] carried out a multiple-parameter phase-field analysis and showed that capillary number, viscosity ratio, wettability, density ratio, interfacial tension, gravity, and permeability all affect CO₂ distribution and oil recovery at the pore scale. These studies indicate that CO₂ displacement is controlled not only by bulk fluid properties but also by local pore-throat geometry, interface deformation, gas-channel evolution, and residual-oil morphology.

Surfactant flooding is another important enhanced oil recovery technique, particularly for reservoirs where oil is strongly trapped by capillary forces and unfavorable wettability. Massarweh and Abushaikh [23] reviewed recent advances in surfactant-assisted EOR and summarized the roles of interfacial-tension reduction, wettability alteration, emulsification, and mobility control. Classical and recent surfactant-EOR studies have also emphasized that surfactant formulation, salinity, adsorption, and ultralow interfacial tension are key factors controlling chemical flooding performance [24,25]. Yang et al. [26] reviewed micromodel studies of surfactant flooding and emphasized that pore-scale visualization can

reveal oil-bank formation, snap-off, oil-film detachment, and trapped-oil mobilization. Ratanpara et al. [27] focused on wettability alteration by surfactants and nanofluids and showed that shifting rock surfaces from oil-wet toward water-wet conditions can substantially improve microscopic displacement. When the oil–water interfacial tension is reduced, the capillary pressure resisting oil displacement decreases, and trapped oil can pass through narrow pore throats more easily. Meanwhile, wettability alteration weakens the adhesion of oil films on solid surfaces and allows the aqueous phase to invade pore-wall regions that are difficult to sweep during conventional water flooding. For heavy-oil systems, these mechanisms are particularly important because high oil viscosity and strong oil–solid adhesion usually lead to severe residual-oil trapping and low waterflooding efficiency.

Although continuous surfactant–water flooding can provide strong microscopic oil mobilization, it is not necessarily the only preferred strategy for practical CO₂-EOR applications. From an engineering perspective, continuous surfactant injection usually requires a relatively large amount of chemical agent, which may increase operational cost. In addition, one important motivation of CO₂-EOR is to utilize CO₂ while improving oil recovery, thereby contributing to carbon utilization and low-carbon energy development. Therefore, combining surfactant–water with CO₂ injection is attractive because it may integrate the microscopic oil-mobilization ability of surfactants with the utilization value of CO₂. The key issue is not simply whether continuous surfactant–water flooding can give the highest recovery under a given numerical condition, but how surfactant–water preflush or alternating injection interacts with subsequent CO₂ invasion, breakthrough, and gas-channeling behavior.

Water-alternating-gas (WAG) injection can reduce gas mobility and improve sweep efficiency compared with continuous gas injection. Afzali et al. [28] reviewed WAG injection and pointed out that the combination of water and gas injection can reduce viscous fingering and improve displacement stability. Kumar and Mandal [29] reviewed chemically enhanced water-alternating-gas/CO₂ (CEWAG) injection and summarized the synergistic roles of chemical agents and CO₂ in improving both microscopic and macroscopic recovery. Chowdhury et al. [30] directly investigated three-phase pore-scale interactions during water- and surfactant-alternating-gas injection using CO₂, providing an important reference for WAG/SAG processes in geo-sequestration and enhanced oil recovery. Phukan and Saha [31] further investigated low-salinity surfactant-alternating-gas/CO₂ flooding in sandstone reservoirs and showed that surfactant-assisted alternating injection can be affected by salinity, adsorption, interfacial-tension reduction, and foam stability. Ma et al. [32] reviewed foam-flow modeling techniques in porous media and showed that foam can reduce gas mobility through apparent-viscosity increase and gas relative-permeability reduction. Nevertheless, the effectiveness of surfactant-assisted CO₂ flooding depends on whether surfactant-induced interfacial effects, wettability alteration, gas-mobility control, and CO₂–oil interactions are sufficiently developed. If these mechanisms are not fully activated, CO₂ may still preferentially flow through high-permeability channels after surfactant–water preflush, resulting in early breakthrough and limited post-breakthrough oil recovery.

At the pore scale, oil–water–CO₂ displacement is a three-phase flow process involving moving contact lines, interface deformation, droplet breakup, gas fingering, oil-film detachment, and residual-oil trapping. Al-Bayati et al. [15] used micro-CT imaging to evaluate the influence of permeability heterogeneity on CO₂ miscible flooding efficiency in sandstone reservoirs. Pu et al. [16] analyzed the microscopic CO₂ displacement mechanism in low-permeability heterogeneous glutenite reservoirs, while Wei et al. [17] visualized CO₂–oil interactions from swelling to miscibility. Alhosani et al. [33] used high-resolution X-ray imaging to examine oil–water–CO₂ configurations in oilfields and showed that pore-scale

CO₂ distribution can be strongly influenced by wettability order and three-phase occupancy. These experimental visualization techniques provide valuable observations, but they are often expensive, time-consuming, and difficult to repeat under identical pore structures and fluid properties. Therefore, pore-scale numerical simulation is an effective complementary approach for isolating the effects of pore geometry, fluid properties, interfacial tension, wettability, and injection strategy. Existing numerical methods for pore-scale multiphase flow include the lattice Boltzmann method [19,34], phase-field method [20,21,35–39], front-tracking method [40], and volume-of-fluid (VOF) method [41]. Among these methods, VOF is suitable for immiscible multiphase displacement because it tracks phase volume fractions and provides good mass conservation, which is useful for calculating oil recovery, outlet phase flow rates, pressure drop, breakthrough time, and residual oil volume.

Although there have been numerous studies on the CO₂–oil two-phase flooding, surfactant–water flooding, or WAG/SAG processes separately, systematic pore-scale comparisons among continuous single-phase flooding, aqueous-phase preflush followed by CO₂ injection, and cyclic aqueous-phase/CO₂ injection remain limited. In particular, the relative contributions of surfactant-induced residual-oil mobilization, CO₂ gas displacement, delayed CO₂ breakthrough, and alternating-injection-induced sweep improvement are still unclear. The influence of aqueous-slug duration and switching frequency is also insufficiently resolved, especially when a persistent preferential pathway is present. This distinction is important because surfactant–water mainly improves microscopic displacement by reducing oil–water capillary resistance and altering wettability, whereas CO₂ mainly affects gas invasion, gas-channel formation, breakthrough behavior, and possible oil displacement after preflush. A direct comparison between continuous surfactant–water flooding and surfactant–water/CO₂ combined injection is also necessary for evaluating whether the recovery loss caused by replacing part of the surfactant–water injection with CO₂ can be understood in terms of CO₂ utilization and coupled displacement mechanisms.

In this study, an immiscible three-phase VOF numerical model is established in OpenFOAM to compare surfactant-assisted CO₂ injection strategies in two-dimensional heavy-oil porous media. Two controlled pore-scale geometries are used: a relatively uniform geometry and a preferential-channel geometry designed to produce early breakthrough. The intended contribution is not the discovery of a new surfactant or CO₂-EOR mechanism, but a systematic comparison of selected injection schedules under a consistent numerical framework. Specifically, the work provides: (i) a controlled parametric screening of pure flooding, aqueous-phase preflush, and cyclic aqueous-phase/CO₂ injection schedules in two geometries with different breakthrough tendencies; (ii) a comparison of recovery, breakthrough PV, cumulative injected CO₂ PV at breakthrough, and phase distributions to separate prescribed IFT/wettability effects from CO₂ gas-channeling behavior; and (iii) a geometry-dependent assessment of whether replacing part of continuous surfactant–water injection by CO₂ mainly preserves surfactant-induced oil mobilization or is limited by reconnection with a preferential gas pathway. Sixteen cases are designed to compare pure CO₂ flooding, continuous ordinary-water flooding, continuous surfactant–water flooding, ordinary-water preflush followed by CO₂ injection, surfactant–water preflush followed by CO₂ injection, and cyclic aqueous-phase/CO₂ injection. The effects of capillary number, viscosity ratio, pore geometry, injection strategy, interfacial tension, and wettability are evaluated using pore-volume-normalized oil recovery, breakthrough PV, cumulative injected CO₂ PV at breakthrough, and phase-distribution characteristics. The objective is to clarify, within the simplified numerical assumptions, how prescribed surfactant-induced interfacial and wettability effects interact with CO₂ invasion and gas-channeling behavior.

2. Theory and Mathematical Model

2.1. Governing Equations for Incompressible Multiphase Flow

The pore-scale displacement of oil by CO₂, ordinary water, and surfactant–water is treated as an incompressible immiscible multiphase flow process. Following the common formulation used in pore-scale multiphase-flow simulations [40,41], the velocity and pressure fields are governed by the continuity and momentum equations:

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

$$\frac{\partial \rho \mathbf{U}}{\partial t} + \nabla \cdot (\rho \mathbf{U} \mathbf{U}) = -\nabla p + \nabla \cdot \left[\mu (\nabla \mathbf{U} + \nabla \mathbf{U}^T) \right] + \mathbf{F}_\sigma, \quad (2)$$

where $\mathbf{U}$ is the velocity vector, p is pressure, ρ is the mixture density, μ is the mixture dynamic viscosity, and $\mathbf{F}_\sigma$ is the interfacial-tension force.

In the three-phase system, the local phase composition is described by the volume fractions of oil, aqueous phase, and CO₂, denoted as α_o , α_w , and α_c , respectively. These phase fractions satisfy

$$\alpha_o + \alpha_w + \alpha_c = 1. \quad (3)$$

The mixture density and dynamic viscosity are calculated by volume-fraction-weighted averaging:

$$\rho = \alpha_o \rho_o + \alpha_w \rho_w + \alpha_c \rho_c, \quad (4)$$

$$\mu = \alpha_o \mu_o + \alpha_w \mu_w + \alpha_c \mu_c, \quad (5)$$

where the subscripts o , w , and c represent oil, the aqueous phase, and CO₂, respectively. In the surfactant–water cases, the aqueous phase represents surfactant–water, and its influence is reflected mainly through reduced oil–water interfacial tension and modified wall wettability. The present model is therefore an isothermal, incompressible and immiscible VOF baseline model. The volume-fraction-weighted mixture properties in Equations (4) and (5) are used for the numerical comparison, while surfactant transport, adsorption, dynamic interfacial tension and CO₂ mass transfer are not solved explicitly.

2.2. VOF Interface-Capturing Method

The interfaces among oil, the aqueous phase, and CO₂ are captured using the volume-of-fluid (VOF) method. The VOF method directly transports phase volume fractions and is suitable for immiscible multiphase flow with strong interface deformation, coalescence, and breakup. Peng et al. [41] compared VOF, level-set, and VOSET approaches for pore-scale immiscible displacement and showed that the interface-capturing strategy can significantly affect pore-scale phase distribution and displacement prediction.

For each phase, the volume-fraction transport equation can be expressed in a representative algebraic VOF form as

$$\frac{\partial \alpha_i}{\partial t} + \nabla \cdot (\alpha_i \mathbf{U}) + \nabla \cdot [\alpha_i (1 - \alpha_i) \mathbf{U}_{r,i}] = 0, \quad (6)$$

where α_i is the volume fraction of phase (i), and $\mathbf{U}_{r,i}$ denotes a numerical compression velocity associated with the algebraic VOF interface-compression term. This term is introduced to reduce numerical diffusion of the phase interface and maintain a relatively sharp interface. It should not be interpreted as a physical relative velocity between phases. In OpenFOAM, the magnitude of this artificial compression is controlled by the dimensionless interface-compression coefficient, denoted here as c_α . A larger c_α sharpens the numerical interface but may also affect curvature and contact-line behavior, so it is treated as a numerical setting rather than a physical parameter. The sensitivity to c_α is examined in Section 3.4. For a three-phase calculation, the volume fractions are solved under the

constraint of Equation (3) so that the sum of the local phase volume fractions remains equal to unity, and each computational cell is occupied by oil, the aqueous phase, CO₂, or their numerically resolved interfaces.

2.3. Interfacial Tension and Wall Wettability

The interfacial tension force is introduced through the continuum surface force (CSF) formulation. In the VOF framework, the interfacial force is distributed over the numerically resolved interface region and is related to the interfacial tension coefficient, local interface curvature, and phase-fraction gradient. For an interface between phase i and phase j , the CSF-type force can be expressed in a representative form as

$$\mathbf{F}_{\sigma,ij} = \sigma_{ij}\kappa_{ij}\nabla\alpha_i, \quad (7)$$

where $\mathbf{F}_{\sigma,ij}$ is the interfacial tension force between phases i and j , σ_{ij} is the corresponding interfacial tension coefficient, κ_{ij} is the local interface curvature, and $\nabla\alpha_i$ is used to localize the capillary force near the interface. For the present three-phase system, the total interfacial tension force is obtained from the contributions of the oil–water, oil–CO₂, and water–CO₂ interfaces:

$$\mathbf{F}_\sigma = \mathbf{F}_{\sigma,ow} + \mathbf{F}_{\sigma,oCO_2} + \mathbf{F}_{\sigma,wCO_2}. \quad (8)$$

Different interfacial tension coefficients are assigned to the oil–water, oil–CO₂, and water–CO₂ interfaces. The ordinary-water cases use the baseline oil–water interfacial tension, whereas the surfactant–water cases use a reduced oil–water interfacial tension to represent the prescribed effect of surfactant addition. Previous studies have shown that surfactants can improve oil mobilization by reducing oil–water interfacial tension and altering rock wettability [23,26,27]. In the present model, surfactant–water is therefore treated as an idealized aqueous phase with prescribed oil–water interfacial tension and contact angle; surfactant concentration transport, adsorption, dynamic interfacial-tension evolution, emulsification, and foam generation are not explicitly solved.

The present simulations also treat CO₂ and the aqueous phase as immiscible fluids with fixed water–CO₂ interfacial properties. Under reservoir pressure and temperature conditions, CO₂ can dissolve into the aqueous phase and modify the local CO₂ inventory, aqueous-phase properties, and three-phase occupancy. In surfactant–water preflush and cyclic aqueous-phase/CO₂ injection, repeated contact between CO₂ and water could influence gas breakthrough, local saturation redistribution, and the apparent mobility of the gas phase. These effects may change the quantitative breakthrough and recovery response, but they are outside the present immiscible VOF formulation. Therefore, the results should be interpreted as a baseline comparison that isolates capillary-force reduction, wettability alteration, and geometrically controlled gas channeling, rather than as a full description of CO₂–water mass transfer in reservoir conditions [30,31,33].

Wall wettability is specified by prescribing contact angles at solid boundaries. The contact angle controls the interface orientation near the pore wall and therefore affects capillary pressure, snap-off behavior, and residual oil distribution. In the OpenFOAM implementation, the prescribed contact angle modifies the near-wall interface normal used in the surface-tension calculation, thereby imposing the desired wetting condition at solid surfaces. For the surfactant–water cases, a more water-wet condition is used to represent the wettability-alteration effect of the surfactant–water. For CO₂-involved cases, the oil–CO₂ and water–CO₂ interfacial properties are kept consistent with the corresponding injection scenario. Similar pore-scale studies have shown that wettability can strongly influence the displacement path, remaining-oil morphology, and final recovery [22,30].

2.4. Injection Schemes and Dimensionless Parameters

Different injection schemes are designed to compare pure CO₂ flooding, continuous ordinary-water flooding, continuous surfactant–water flooding, sequential aqueous-phase/CO₂ injection, and cyclic injection with different aqueous-slug durations and switching frequencies. The same injection schedule is applied to the two pore geometries. Because the two geometries have different pore areas and pore volumes, direct comparison based on physical time may introduce bias. Therefore, the injected pore volume is used as the normalized injection coordinate:

$$N_{PV}(t) = \frac{\int_0^t Q_{in}(\tau) d\tau}{V_p}, \quad (9)$$

where Q_{in} is the total inlet flow rate and V_p is the initial pore volume of the corresponding geometry. In this study, Geometry A and Geometry B are normalized by their own pore volumes when comparing recovery, saturation, pressure drop, and breakthrough behavior.

For phase-specific analysis, the injected CO₂ pore volume and water pore volume are calculated as

$$N_{CO_2PV}(t) = \frac{\int_0^t Q_{CO_2,in}(\tau) d\tau}{V_p}, \quad (10)$$

$$N_{WPV}(t) = \frac{\int_0^t Q_{w,in}(\tau) d\tau}{V_p}, \quad (11)$$

where $Q_{CO_2,in}$ and $Q_{w,in}$ are the inlet flow rates of CO₂ and the aqueous phase, respectively. The breakthrough of CO₂ or the aqueous phase is identified when the corresponding outlet area-averaged phase fraction exceeds a prescribed threshold.

The capillary number and viscosity ratio are used to characterize the competition between viscous force, capillary force, and mobility contrast. Following the definitions commonly used in pore-scale immiscible displacement and CO₂ flooding studies [21,22,42,43], they are written as

$$Ca = \frac{u_{inj}\mu_d}{\sigma_{do}}, \quad (12)$$

$$M = \frac{\mu_d}{\mu_o}, \quad (13)$$

where u_{inj} is the injection velocity, μ_d is the dynamic viscosity of the displacing phase, μ_o is the oil viscosity, and σ_{do} is the interfacial tension between the displacing phase and oil. For CO₂ flooding, the displacing phase is CO₂; for ordinary-water and surfactant–water flooding, the displacing phase is the aqueous phase. Thus, the study does not introduce a single unified three-phase capillary number. Instead, Ca is defined for each displacement mode using the corresponding displacing-phase viscosity and displacing-phase/oil interfacial tension. Comparisons of Ca between CO₂, ordinary-water and surfactant–water cases should therefore be interpreted as regime-level comparisons within the selected parameterization, rather than as a direct one-to-one comparison of a single physical control variable. The oil recovery based on the residual oil volume is calculated as

$$R_o(t) = 1 - \frac{V_o(t)}{V_{o,0}}, \quad (14)$$

where $V_{o,0}$ is the initial oil volume and $V_o(t)$ is the remaining oil volume in the computational domain. This residual-oil-volume-based recovery is used as the primary recovery indicator because it is less affected by local outlet backflow than outlet-flow integration [20].

3. Computational Domain and Simulation Setup

3.1. Pore-Scale Geometries and Mesh Generation

Two two-dimensional porous-media geometries are constructed to investigate the influence of pore-structure arrangement on multiphase displacement. Both geometries have the same external domain size of 60 mm $\times$ 20 mm, but they differ in the arrangement and size distribution of circular solid grains. The left boundary is defined as a velocity inlet, the right boundary as a pressure outlet, and the upper, lower, and grain-surface boundaries are treated as no-slip walls.

Geometry A represents a relatively uniform pore network. The circular solid grains in Geometry A have a diameter of 4 mm, and the gap between adjacent circular grains is 1 mm. The grains are arranged in a regular staggered pattern, and the pore throats are relatively evenly distributed. Therefore, the injected phase is expected to advance through multiple connected flow paths rather than through a single dominant channel. As shown in Figure 1, the local mesh enlargement indicates that the pore-throat region and the near-wall region around the circular grains are well resolved. The geometry inset further shows the regular circular-grain arrangement and the characteristic pore-throat spacing.

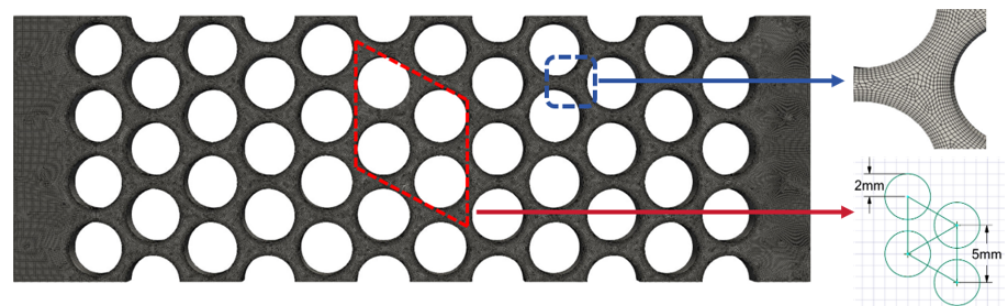


Figure 1. Geometry A and its mesh structure. Geometry A represents a relatively uniform pore structure. The local mesh enlargement shows the mesh resolution near the pore throat and circular grain surfaces, while the geometry inset illustrates the circular-grain arrangement and characteristic pore-throat spacing.

Geometry B is intentionally designed as a heterogeneous pore structure with preferential flow paths, as shown in Figure 2. In Geometry B, large circular grains with a diameter of 4 mm are arranged in the central region, with a gap of 1 mm between adjacent large grains. Smaller circular grains with a diameter of 2 mm are distributed near the upper and lower regions, with a gap of 0.5 mm between adjacent small grains. This arrangement creates clear pore-throat contrasts between the central and near-wall regions. The larger central pore throats provide lower flow resistance, whereas the smaller near-wall pore throats increase local capillary resistance. As a result, Geometry B is expected to promote preferential flow and earlier breakthrough of the injected aqueous phase or CO₂.

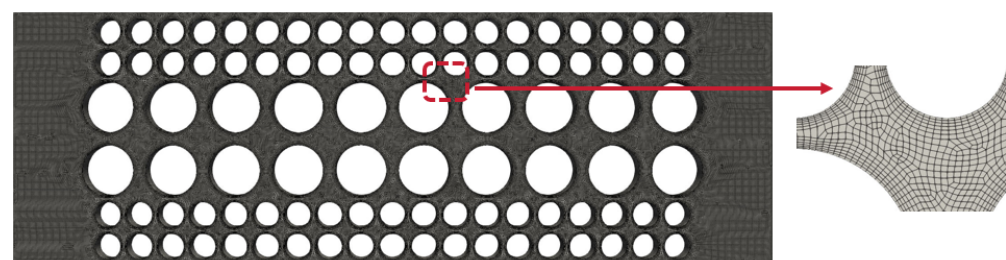


Figure 2. Geometry B and its mesh structure. Geometry B is designed as a preferential-channel pore structure. The local mesh enlargement shows the mesh resolution in the narrow pore-throat region between circular grains.

The use of these two circular-grain geometries is motivated by controlled mechanism separation rather than by direct reproduction or optimization of a specific reservoir rock. Geometry A provides a relatively uniform reference in which the injected phase can advance through several comparable pore pathways, whereas Geometry B deliberately introduces a dominant central pathway and smaller near-wall throats to create bypassed regions and stronger residual-oil trapping. This design is not intended to generate turbulence; it is used to test whether reduced oil–water interfacial tension and a more water-wet wall condition can mobilize oil left in capillary-controlled or poorly swept regions. The strong trapping tendency is therefore part of the controlled comparison, not a claim that the geometry is an optimal industrial pore structure. Extension to micro-CT-based or stochastic three-dimensional pore networks is needed for reservoir-specific prediction.

The same mesh-generation strategy is applied to both geometries. The medium mesh used in the main simulations has a global mesh size of 0.1 mm, and the edge size along the circular grain surfaces is also set to 0.1 mm. Boundary-layer meshes are generated near the no-slip walls and grain surfaces to better resolve near-wall velocity gradients, contact-line motion, and interface evolution. The first boundary-layer height is 0.04 mm, the maximum number of boundary layers is 6, and the growth rate is 1.15. These settings are used to maintain sufficient near-wall resolution while keeping the computational cost acceptable, and the sensitivity of the main indicators to time step and mesh resolution is examined below.

The main geometric and mesh information of the two computational domains is summarized in Table 1. Although the two geometries have the same external domain size and mesh-generation settings, their pore structures, mesh cell numbers, and effective pore volumes are different. Therefore, all subsequent displacement results are normalized by the pore volume of the corresponding geometry.

Table 1. Geometric, mesh, and pore-volume information for Geometry A and Geometry B.

Geometry	Pore Structure	Number of Cells	V_p/m^3	$V_p/\mu\text{L}$
Geometry A	Uniform	74,187	7.5523×10^{-7}	755.23
Geometry B	Preferential-channel	91,172	8.9861×10^{-7}	898.61

As listed in Table 1, the effective pore volume of Geometry B is larger than that of Geometry A. Specifically, $V_{p,A} = 7.5523 \times 10^{-7} \text{ m}^3$, whereas $V_{p,B} = 8.9861 \times 10^{-7} \text{ m}^3$. These pore volumes are used for calculating the total injected PV, phase-specific injected PV, and breakthrough PV in the following analysis. Therefore, the comparison between Geometry A and Geometry B is based on pore-volume-normalized displacement behavior rather than physical injection time.

3.2. Fluid Properties and Interfacial Parameters

The fluids considered in this study include heavy oil, CO_2 , ordinary water, and surfactant–water. For the present pore-scale immiscible VOF simulations, all phases are treated as incompressible Newtonian fluids. The density and dynamic viscosity values used in the main injection-scheme simulations are listed in Table 2. The main comparison cases used a heavy-oil density of 900 kg/m^3 and a dynamic viscosity of $0.1 \text{ Pa}\cdot\text{s}$. Ordinary water and surfactant–water are assigned the same density and dynamic viscosity so that the effect of surfactant addition is represented through interfacial-tension reduction and wettability alteration rather than through a change in bulk aqueous-phase viscosity. The CO_2 phase is represented by the selected compressed- CO_2 density and viscosity listed in Table 2.

Table 2. Density and dynamic viscosity of fluids used in the main simulation cases.

Phase	Density/kg·m ^{−3}	Dynamic Viscosity/Pa·s
CO ₂	140.65	1.65×10^{-5}
Heavy oil	900	1.00×10^{-1}
Ordinary water	1000	1.05×10^{-3}
Surfactant–water	1000	1.05×10^{-3}

The interfacial parameters used in different injection scenarios are summarized in Table 3. In the phase-pair notation used in this study, the phase before the dash is defined as the primary phase, and the phase after the dash is defined as the secondary phase. The listed contact angle is the contact angle of the primary phase on the solid wall in the presence of the secondary phase.

Table 3. Interfacial tension coefficients and primary-phase contact angles used in the simulations. The phase pair is written as “primary phase–secondary phase”, and the contact angle is measured through the primary phase.

Phase Pair	Interfacial Tension/N·m ^{−1}	Primary-Phase Contact Angle/°
Ordinary water–CO ₂	0.035	70
Ordinary water–oil	0.045	120
Surfactant–water–CO ₂	0.030	70
Surfactant–water–oil	0.005	60
CO ₂ –oil	0.010	90

As illustrated in Figure 3, the blue region denotes the primary phase and the yellow region denotes the secondary phase. The contact angle is measured through the primary phase. According to this convention, when the primary-phase contact angle is smaller than 90°, the solid wall is considered preferentially wet by the primary phase. When the primary-phase contact angle is larger than 90°, the primary phase has weak wettability on the wall, and the wall is relatively more favorable to the secondary phase. A contact angle close to 90° represents an approximately neutral wetting condition.

**Figure 3.** Definition of the primary-phase contact angle used in the simulations: (a) large primary-phase contact angle; (b) small primary-phase contact angle. The blue region denotes the primary phase, the yellow region denotes the secondary phase, and the contact angle is measured through the primary phase.

Table 3 lists the interfacial tension coefficients and primary-phase contact angles used for the different phase pairs. The ordinary-water–oil and surfactant–water–oil entries are used to distinguish the baseline water–oil condition from the surfactant-modified water–oil condition. Compared with ordinary water, surfactant–water is assigned a lower oil–water

interfacial tension and a smaller primary-phase contact angle, representing interfacial-tension reduction and wettability alteration toward stronger aqueous-phase wetting.

These interfacial-tension coefficients and contact angles are used in the continuum surface force calculation and wall contact-angle boundary condition in OpenFOAM. The ordinary-water cases use a relatively high oil–water interfacial tension and a larger primary-phase contact angle, corresponding to a less favorable wetting condition for aqueous-phase displacement of oil. In contrast, the surfactant–water cases use a much lower oil–water interfacial tension and a smaller surfactant–water–oil contact angle, representing capillary-force reduction and wettability alteration. These two effects are expected to reduce oil adhesion on solid surfaces, promote oil-film detachment, and enhance residual-oil mobilization during surfactant–water flooding and surfactant–water/CO₂ injection.

3.3. Injection Schemes and Case Design

The initial pore space is fully saturated with heavy oil. During injection, the left boundary is used as the inlet and the right boundary is used as the pressure outlet. The inlet velocity is fixed at 0.01 m/s for the main injection-scheme comparison. The injected phase is controlled by assigning time-dependent inlet phase fractions for CO₂, ordinary water, and surfactant–water. Sixteen injection schemes are designed for each geometry, giving 32 primary displacement simulations across the two pore structures. The schemes include pure CO₂ flooding, continuous ordinary-water flooding, continuous surfactant–water flooding, ordinary-water or surfactant–water preflush followed by CO₂ injection, and cyclic aqueous-phase/CO₂ injection. The same injection schedules are applied to Geometry A and Geometry B so that the effect of pore structure can be evaluated under identical injection conditions. The sixteen injection schemes are summarized in Table 4.

Table 4. Injection schemes used in the simulation design. The same injection schedules are applied to Geometry A and Geometry B.

Case No.	Injection Type	Injection Schedule
1	Pure CO ₂ flooding	0–10 s: CO ₂ only
2	Surfactant-water preflush + CO ₂	0–1 s: surfactant water; 1–10 s: CO ₂
3	Surfactant-water preflush + CO ₂	0–2 s: surfactant water; 2–11 s: CO ₂
4	Surfactant-water preflush + CO ₂	0–3 s: surfactant water; 3–12 s: CO ₂
5	Surfactant-water preflush + CO ₂	0–4 s: surfactant water; 4–13 s: CO ₂
6	High-frequency short-slug surfactant-water/CO ₂ injection	0.25 s surfactant water + 1 s CO ₂ , repeated ten times
7	Cyclic surfactant-water/CO ₂ injection	0.5 s surfactant water + 2 s CO ₂ , repeated five times
8	Cyclic surfactant-water/CO ₂ injection	1 s surfactant water + 2 s CO ₂ , repeated five times
9	Continuous surfactant-water flooding	0–10 s: surfactant water only
10	Ordinary-water preflush + CO ₂	0–1 s: ordinary water; 1–10 s: CO ₂
11	Ordinary-water preflush + CO ₂	0–2 s: ordinary water; 2–11 s: CO ₂
12	Ordinary-water preflush + CO ₂	0–3 s: ordinary water; 3–12 s: CO ₂
13	Ordinary-water preflush + CO ₂	0–4 s: ordinary water; 4–13 s: CO ₂
14	Cyclic ordinary-water/CO ₂ injection	0.5 s ordinary water + 2 s CO ₂ , repeated five times
15	Cyclic ordinary-water/CO ₂ injection	1 s ordinary water + 2 s CO ₂ , repeated five times
16	Continuous ordinary-water flooding	0–10 s: ordinary water only

The main purpose of this case design is to separate the effects of surfactant-induced oil mobilization, aqueous-phase preflush, CO₂ gas displacement, and cyclic injection. The

pure CO₂ case is used as a reference for gas-channeling behavior. The continuous ordinary-water and surfactant–water cases are used to compare the effects of interfacial-tension reduction and wettability alteration. The sequential injection cases are used to evaluate whether an aqueous slug before CO₂ injection can delay gas breakthrough and improve sweep efficiency. Cases 6 and 7 have the same total surfactant–water and CO₂ injection durations (2.5 and 10 s, respectively) but different switching frequencies, so they are used to evaluate the schedule response to finer phase alternation. Cases 7 and 14, and Cases 8 and 15, use matched 0.5 s and 1 s aqueous slugs, respectively, allowing the influence of aqueous-phase type to be isolated at the same cyclic schedule. Case 8 contains a larger total surfactant–water dose than Cases 6 and 7 and is therefore interpreted separately from the equal-dose switching-frequency comparison.

3.4. Pore-Volume Normalization and Data Extraction

Because Geometry A and Geometry B have different pore areas and effective pore volumes, direct comparison based on physical injection time may lead to biased interpretation. Under the same inlet velocity and injection duration, the same physical time does not necessarily correspond to the same fraction of pore space being swept in different geometries. Therefore, the injected pore volume (PV), defined as the ratio of cumulative injected volume to the effective pore volume of the corresponding geometry, is used as the normalized injection coordinate. This normalization allows oil recovery, phase saturation, pressure response, outlet phase flow rate, and breakthrough behavior to be compared at equivalent injection stages rather than at the same physical time.

For sequential and cyclic injection cases, the total injected volume may contain both the aqueous phase and CO₂. Therefore, in addition to the total injected PV, the cumulative injected CO₂ volume and aqueous-phase volume are recorded during post-processing. For CO₂-involved cases, the CO₂ breakthrough is expressed by the CO₂-injected PV at breakthrough, denoted as $N_{\text{CO}_2, \text{bt}}$:

$$N_{\text{CO}_2, \text{bt}} = \frac{\int_0^{t_{\text{bt}}} Q_{\text{CO}_2, \text{in}}(t) dt}{V_p}, \quad (15)$$

where t_{bt} is the CO₂ breakthrough time, $Q_{\text{CO}_2, \text{in}}(t)$ is the inlet CO₂ flow rate, and V_p is the pore volume of the corresponding geometry. When the inlet total flow rate is constant, this quantity can also be written as

$$N_{\text{CO}_2, \text{bt}} = \frac{Q_{\text{in}}}{V_p} \int_0^{t_{\text{bt}}} \alpha_{\text{CO}_2, \text{in}}(t) dt, \quad (16)$$

where $\alpha_{\text{CO}_2, \text{in}}(t)$ is the inlet volume fraction of CO₂. Thus, the aqueous-phase preflush period is not counted in $N_{\text{CO}_2, \text{bt}}$, and for cyclic injection, only the cumulative CO₂ injection stages before breakthrough are included. This phase-specific indicator allows CO₂ breakthrough behavior to be compared based on the actual amount of CO₂ injected rather than on the total injected volume.

The oil recovery is evaluated from the remaining oil volume in the computational domain. This residual-oil-volume-based recovery is used as the primary recovery indicator because it is less affected by local outlet backflow than outlet-flow integration [20]. The outlet-based cumulative oil production is also calculated as an auxiliary indicator, but the domain-based recovery is used for the main comparison among different injection schemes. The main quantities extracted from each simulation include oil recovery, average phase saturation, pressure drop between inlet and outlet, outlet phase flow rates, and breakthrough PV. The pressure drop is obtained from the difference between

the area-averaged inlet and outlet pressures. The breakthrough of CO₂ or the aqueous phase is identified when the corresponding outlet area-averaged phase fraction exceeds a prescribed threshold.

To compare different cases at equivalent injection stages, the main flow variables are extracted at selected injected pore volumes of 0.3 PV, 0.5 PV, 1.0 PV, 1.5 PV, 2.0 PV, 2.5 PV, and 3.0 PV. When a target PV does not coincide exactly with a saved simulation time, the corresponding value is obtained by linear interpolation between the two nearest output time steps. If a given target PV is not reached, the value at that PV is excluded from the quantitative comparison. For Cases 6 and 7, the 2.5 PV comparison represents the response of the two schedules at the same total injected volume; because the schedules can be at different positions within their cycles at that instant, the result is interpreted as a switching-frequency response rather than as a strict comparison at identical cumulative phase exposure.

Numerical sensitivity to time-step size, mesh resolution and VOF interface-compression coefficient.

The sensitivity of the main numerical indicators was checked using the representative surfactant–water preflush followed by CO₂ case (Case 5) in both geometries. A baseline interface-compression coefficient of $c_\alpha = 0.7$ was used for the time-step and mesh-sensitivity tests. Table 5 shows that, when the number of cells is fixed, changing the time step from 2.5×10^{-6} s to 1.0×10^{-5} s changes the 2.5 PV oil recovery by 0.58 percentage points in Geometry A and 0.97 percentage points in Geometry B. The corresponding variation in CO₂ breakthrough PV is 0.0035 in Geometry A and 0.0040 in Geometry B.

Table 5. Time-step sensitivity results for Case 5.

Geometry	Time Step/s	Cell Number	R_0 at 2.5 PV/%	$N_{\text{CO}_2, \text{bt}}$
A	2.5×10^{-6}	74,187	73.13	0.5098
A	5.0×10^{-6}	74,187	73.54	0.5079
A	1.0×10^{-5}	74,187	73.71	0.5063
B	2.5×10^{-6}	91,172	69.38	0.3701
B	5.0×10^{-6}	91,172	69.89	0.3729
B	1.0×10^{-5}	91,172	70.35	0.3741

Table 6 compares three mesh levels for the same case. From the medium mesh to the fine mesh, the 2.5 PV recovery changes by 0.56 percentage points in Geometry A and 0.88 percentage points in Geometry B, while $N_{\text{CO}_2, \text{bt}}$ changes by 0.0049 and 0.0046, respectively. These variations are small compared with the recovery differences among the injection strategies discussed below. The medium mesh and the time step of 1.0×10^{-5} s are therefore used for the main simulations as a balance between numerical resolution and computational cost.

Table 6. Mesh-resolution sensitivity of the representative surfactant–water preflush followed by CO₂ case (Case 5).

Geometry	Mesh Level	Cell Number	R_0 at 2.5 PV/%	$N_{\text{CO}_2, \text{bt}}$
A	Coarse	37,640	74.55	0.5196
A	Medium	74,187	73.71	0.5063
A	Fine	111,171	73.15	0.5014
B	Coarse	49,012	72.74	0.3798
B	Medium	91,172	70.35	0.3741
B	Fine	131,138	69.47	0.3695

Additional tests were performed to check the sensitivity to the VOF interface-compression coefficient c_α . When c_α was changed from 0.5 to 1.0 for the same representative case, the 2.5 PV oil recovery changed from 74.42% to 73.49% in Geometry A, corresponding to a difference of 0.93 percentage points, and from 69.33% to 70.99% in Geometry B, corresponding to a difference of 1.66 percentage points. The corresponding $N_{\text{CO}_2, \text{bt}}$ changed from 0.5158 to 0.4990 in Geometry A and from 0.3770 to 0.3713 in Geometry B. These results indicate that the interface-compression setting affects the quantitative recovery and breakthrough values to some extent, but the observed recovery variations remain within a few percentage points for this representative case. Therefore, the following discussion focuses on trends and relative differences among injection strategies rather than on single-case numerical values.

4. Results and Discussion

4.1. Dimensionless Analysis of Capillary Number and Viscosity Ratio

Before comparing the different injection schemes for Geometry A and Geometry B, a dimensionless parameter analysis is conducted to examine the effects of capillary number and viscosity ratio on pore-scale oil displacement. This analysis is performed using Geometry A as the representative pore structure so that the effects of injection velocity and oil viscosity could be examined without introducing additional geometric variability. The capillary number and viscosity ratio are calculated according to the definitions given in Section 2.4. In this analysis, the injection velocity is varied between 0.01 and 0.1 m/s, and the oil viscosity is varied from 0.01 to 1.0 Pa·s. For each flooding mode, $\log Ca$ is calculated using the viscosity of the corresponding displacing phase and the interfacial tension between the displacing phase and oil. Accordingly, the CO₂ flooding cases correspond to $\log Ca = -4.78$ and -3.78 , whereas the surfactant–water flooding cases correspond to $\log Ca = -2.68$ and -1.68 . The viscosity ratio $\log M$ is obtained by varying the oil viscosity while keeping the displacing-phase viscosity fixed. Following the fixed-pore-volume comparison strategy used in pore-scale CO₂ flooding studies [21,22], the remaining-oil-volume-based recovery at 2 injected PV is used to evaluate the effects of $\log Ca$ and $\log M$. In addition, the breakthrough PV of the displacing phase is used as an auxiliary indicator to interpret the recovery trends.

The recovery at 2 injected PV is selected for the dimensionless analysis to provide a fixed injected-volume basis for cases with different injection velocities and oil viscosities. This avoids the bias that high-velocity cases would inject more fluid if physical time is used as the comparison coordinate. At 2 injected PV, the displacement has passed the early invasion stage and can reflect the combined effects of viscous force, mobility contrast, capillary resistance, and breakthrough behavior. Therefore, 2 PV is used as a representative comparison point for the $\log Ca$ – $\log M$ analysis.

4.1.1. Effect of $\log Ca$ and $\log M$ on Oil Recovery and Breakthrough PV During CO₂ Flooding

Figure 4 shows the influence of $\log Ca$ and $\log M$ on oil recovery during CO₂ flooding at 2 injected PV. Overall, the oil recovery increases with increasing $\log Ca$, indicating that a stronger viscous driving force helps CO₂ to invade the pore space and displace oil. The influence of $\log M$ is also evident. At $\log Ca = -4.78$, the recovery increases from 0.572 to 0.670 as $\log M$ increases from -4.78 to -2.78 . At $\log Ca = -3.78$, the highest recovery reaches 0.872 when $\log M = -2.78$. This trend suggests that a more favorable viscosity ratio can improve CO₂ displacement efficiency by reducing the mobility contrast between CO₂ and heavy oil.

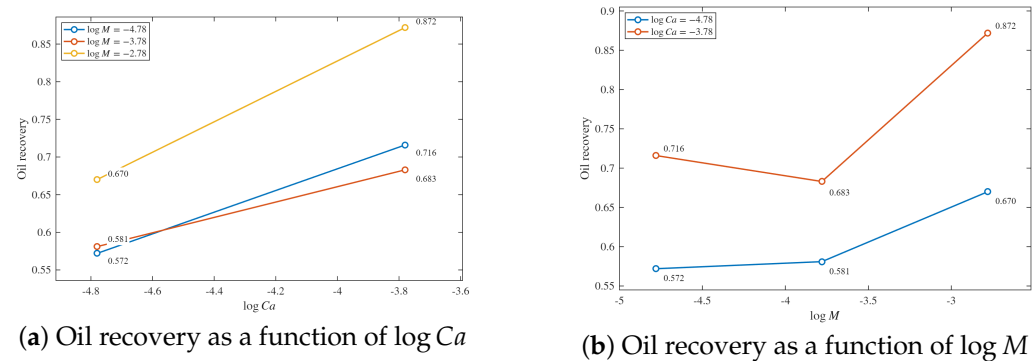


Figure 4. Effect of capillary number and viscosity ratio on oil recovery during CO₂ flooding at 2 injected PV: (a) oil recovery as a function of log Ca; (b) oil recovery as a function of log M.

However, the CO₂ flooding results are not strictly monotonic under all parameter combinations. At log Ca = −3.78, the recovery at log M = −3.78 is slightly lower than that at log M = −4.78. This indicates that CO₂ displacement is not controlled only by viscous force and viscosity ratio. Because CO₂ has low viscosity and high mobility, it can rapidly form preferential flow channels after breakthrough. Once a connected CO₂ pathway is established, subsequent CO₂ tends to flow through the existing low-resistance channel, and the post-breakthrough recovery increment becomes limited. Therefore, the recovery at a fixed injected PV should be interpreted together with CO₂ breakthrough behavior.

The CO₂ breakthrough PV values listed in Table 7 provide a normalized basis for interpreting the recovery trends in Figure 4. Unlike breakthrough time, breakthrough PV removes the direct influence of injection velocity and indicates how much pore volume has been injected before CO₂ first reaches the outlet. At log Ca = −4.78, the CO₂ breakthrough PV increases from 0.456 to 0.657 as log M increases from −4.78 to −2.78. This trend is consistent with the recovery increase shown in Figure 4, indicating that a more favorable viscosity ratio allows CO₂ to sweep more pore space before breakthrough.

Table 7. Breakthrough PV of CO₂ under different log Ca and log M conditions.

log M	log Ca = −4.78	log Ca = −3.78
−4.78	0.456	0.402
−3.78	0.502	0.464
−2.78	0.657	0.469

At the higher-log Ca condition, the breakthrough PV remains relatively low, ranging from 0.402 to 0.469. This suggests that stronger viscous driving can accelerate the formation of a connected CO₂ pathway. Therefore, although increasing log Ca may enhance the initial displacement ability of CO₂, it may also promote early gas channeling. For CO₂ flooding, a high recovery at 2 PV should therefore be evaluated together with breakthrough PV, because early breakthrough can significantly reduce the effectiveness of continued CO₂ injection.

4.1.2. Effect of log Ca and log M on Oil Recovery and Breakthrough PV During Surfactant–Water Flooding

Figure 5 presents the corresponding results for surfactant–water flooding. Compared with CO₂ flooding, surfactant–water flooding gives a higher overall recovery under the same oil-viscosity range. The influence of log M is particularly clear. At log Ca = −2.68, the recovery increases from 0.711 to 0.897 as log M increases from −2.98 to −0.98. This

indicates that improving the mobility condition between the injected surfactant–water and heavy oil promotes oil displacement and reduces residual oil.

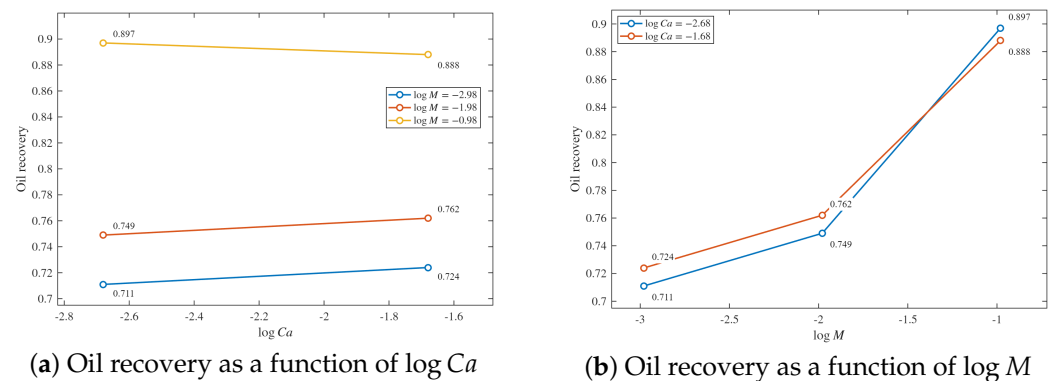


Figure 5. Effects of capillary number and viscosity ratio on oil recovery during surfactant–water flooding at 2 injected PV: (a) oil recovery as a function of log Ca; (b) oil recovery as a function of log M.

In contrast, the influence of log Ca on surfactant–water flooding is relatively weak. At the same log M, increasing log Ca from -2.68 to -1.68 causes only a small change in recovery. For example, when log M = -1.98 , the recovery increases slightly from 0.749 to 0.762. When log M = -0.98 , the recovery decreases slightly from 0.897 to 0.888. This weak or non-monotonic log Ca response indicates that, after the oil–water interfacial tension is reduced and the wall wettability is shifted toward a more water-wet condition, simply increasing injection velocity does not necessarily produce a proportional increase in oil recovery. A higher injection velocity may shorten the contact time between the surfactant–water and residual oil or enhance local preferential flow.

The surfactant–water breakthrough PV values in Table 8 further explain the recovery behavior shown in Figure 5. At log Ca = -2.68 , the breakthrough PV increases from 0.462 to 0.750 as log M increases from -2.98 to -0.98 , which corresponds to the significant increase in oil recovery. This indicates that a more favorable viscosity ratio delays the formation of a connected aqueous-phase pathway and allows the surfactant–water to contact and mobilize more oil before breakthrough.

Table 8. Breakthrough PV of surfactant–water under different log Ca and log M conditions.

log M	log Ca = -2.68	log Ca = -1.68
-2.98	0.462	0.466
-1.98	0.516	0.469
-0.98	0.750	0.536

At the higher-log Ca condition, the breakthrough PV is lower and varies within a narrower range. This suggests that increasing injection velocity can promote a faster connection between inlet and outlet, while the improvement in recovery becomes less sensitive to log Ca. Unlike CO₂ flooding, surfactant–water flooding is not only governed by viscous displacement. The reduced oil–water interfacial tension lowers the capillary resistance against oil mobilization, and the more water-wet surface condition weakens the adhesion of oil films on solid walls. Therefore, surfactant–water flooding can maintain a relatively high recovery even when the effect of log Ca is limited.

4.1.3. Comparative Analysis of CO₂ Flooding and Surfactant–Water Flooding Mechanisms

To further interpret the breakthrough PV trends listed in Tables 7 and 8, representative phase-distribution contours near breakthrough are compared in Figure 6.

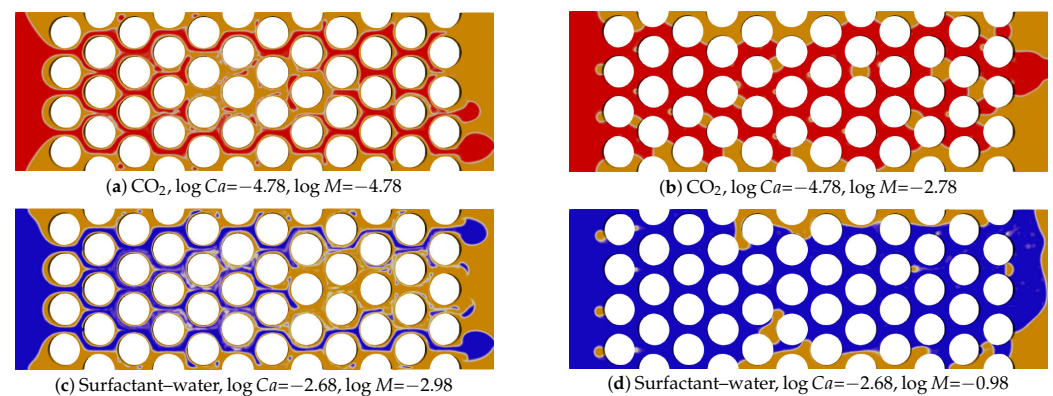


Figure 6. Representative phase-distribution contours of CO₂ flooding and surfactant–water flooding near breakthrough under selected log Ca and log M conditions: (a,b) CO₂ flooding under low- and high-log M conditions; (c,d) surfactant–water flooding under low- and high-log M conditions. Red: CO₂; blue: aqueous phase; yellow: oil; white: solid grains.

As shown in Figure 6, CO₂ flooding is characterized by the formation of a connected gas pathway near breakthrough. A more favorable log M enlarges the swept region before breakthrough, but the displacement remains strongly affected by gas-channel formation. In contrast, surfactant–water flooding shows more effective aqueous-phase invasion and residual-oil mobilization, especially under the higher-log M condition. This supports the interpretation that CO₂ flooding is mainly limited by preferential gas flow, whereas surfactant–water flooding benefits from capillary-force reduction and wettability alteration.

Overall, the combined analysis of oil recovery, breakthrough PV, and phase distribution indicates that recovery at a fixed injected PV should not be evaluated alone. For gas injection, a high recovery at 2 PV may still be accompanied by early breakthrough and strong post-breakthrough channeling. For surfactant–water injection, delayed breakthrough is generally associated with improved sweep and enhanced residual-oil mobilization. Therefore, oil recovery, log Ca , log M , breakthrough PV, and phase-distribution contours should be considered together to distinguish viscous-force enhancement, capillary-force reduction, wettability alteration, and gas-channeling effects in pore-scale heavy-oil displacement.

4.2. Overall Oil Recovery Comparison at 2.5 Injected PV

Because a large number of injection schemes are considered in this study, plotting all recovery curves as a function of injected PV would make the comparison difficult to interpret. Therefore, the oil recovery at 2.5 injected PV is selected as a representative comparison point for the main injection-scheme comparison. This injected volume is reached by all valid cases in both geometries, allowing for a consistent comparison among different injection schemes and between the two pore geometries. Figure 7 compares the oil recovery calculated from the remaining oil volume in the computational domain.

Figure 7 shows a clear geometry-dependent ranking. In Geometry A, Case 8 (1 s surfactant–water + 2 s CO₂) gives the highest recovery, approximately 77.69%, followed closely by Case 6 (high-frequency short slugs, 77.47%) and Case 9 (continuous surfactant–water flooding, 77.0%). Case 7, the 0.5 s surfactant–water cyclic schedule, gives 75.85%. In Geometry B, continuous surfactant–water flooding remains the highest-recovery scheme at approximately 75.9%, while Cases 6–8 give only 40.62%, 41.20%, and 41.57%, respectively. Surfactant–water preflush followed by CO₂ injection also improves steadily with preflush

duration: the recovery increases from approximately 63.3% to 73.7% in Geometry A and from 35.9% to 70.3% in Geometry B as the preflush duration increases from 1 to 4 s. These results show that cyclic surfactant–water/CO₂ injection can approach the continuous-surfactant reference in the relatively uniform geometry, but repeated CO₂ injection remains strongly constrained by the preferential pathway in Geometry B.

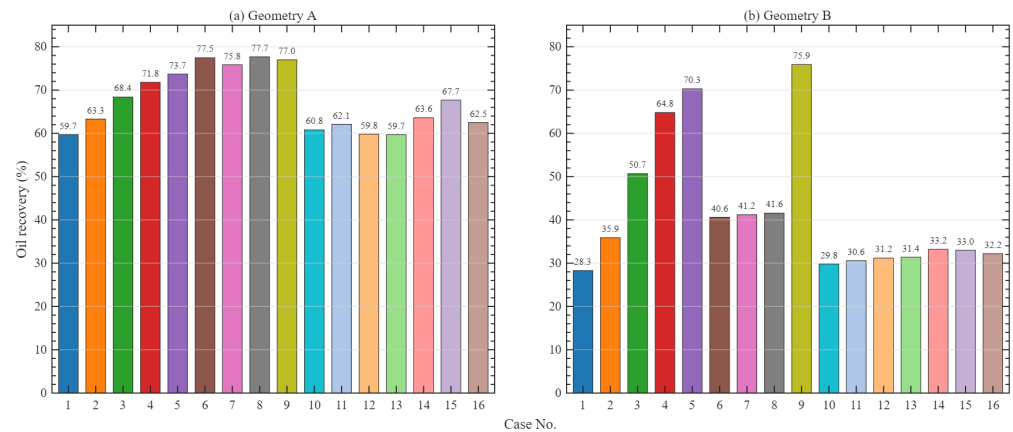


Figure 7. Oil recovery at 2.5 injected PV under different injection schemes: (a) Geometry A; (b) Geometry B.

Overall, the 2.5 PV comparison provides a general ranking of the injection schemes. Continuous surfactant–water flooding remains the upper recovery reference in Geometry B and a near-upper reference in Geometry A, where the two newly included cyclic schedules give comparable or slightly higher recovery. The surfactant–water/CO₂ and cyclic cases are therefore analyzed below to clarify whether their performance is associated with aqueous-phase type, switching frequency, CO₂ breakthrough, or preferential gas channeling.

Although continuous surfactant–water flooding provides the highest or near-highest recovery, it should not be interpreted as the only preferred strategy for practical application. From an engineering perspective, continuous surfactant–water injection requires a larger chemical input, which may increase operational cost. In addition, one important motivation of CO₂-EOR is to utilize CO₂ while improving oil recovery, thereby contributing to carbon utilization and low-carbon energy development. Therefore, continuous surfactant–water flooding serves as a reference for strong surfactant-induced oil mobilization, whereas the surfactant–water/CO₂ and cyclic cases are used to examine how interfacial and wettability effects interact with CO₂ invasion, breakthrough, and gas-channeling behavior.

4.3. Effect of Pore Geometry on Continuous Single-Phase Flooding

To isolate the influence of pore geometry on displacement behavior, only the continuous single-phase flooding cases are compared in this section, including Case 1 (pure CO₂ flooding), Case 9 (continuous surfactant–water flooding), and Case 16 (continuous ordinary-water flooding). The sequential and cyclic injection cases are not included in this comparison because, at the same total injected PV, they may contain different proportions of the aqueous phase and CO₂. Therefore, the continuous single-phase flooding cases provide a clearer basis for evaluating how Geometry A and Geometry B influence breakthrough behavior and oil recovery.

Figure 8 shows the oil recovery curves of the three continuous single-phase flooding cases in Geometry A and Geometry B. The selected PV points are 0, 0.3, 1.0, 1.5, 2.0, and 2.5 PV. The vertical dashed lines indicate the breakthrough PV of the corresponding injected phase. The detailed breakthrough PV values are listed in Table 9.

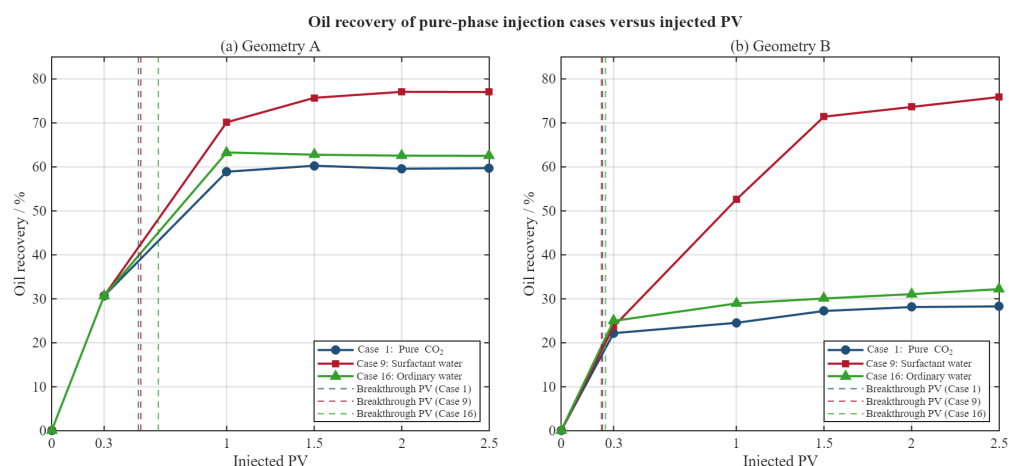


Figure 8. Oil recovery of continuous single-phase flooding cases versus injected PV: (a) Geometry A; (b) Geometry B. Vertical dashed lines indicate the breakthrough PV of the corresponding injected phase.

Table 9. Breakthrough PV of continuous single-phase flooding cases in Geometry A and Geometry B.

Case No.	Injection Type	Geometry A	Geometry B
1	Pure CO ₂	0.496	0.236
9	Continuous surfactant–water	0.509	0.231
16	Continuous ordinary–water	0.610	0.253

As shown in Table 9, all three injected phases break through much earlier in Geometry B than in Geometry A. The breakthrough PV decreases from 0.496 to 0.236 for CO₂, from 0.509 to 0.231 for surfactant–water, and from 0.610 to 0.253 for ordinary water, corresponding to reductions of 52.4%, 54.6%, and 58.5%, respectively. This confirms that Geometry B promotes preferential flow and allows the injected phase to reach the outlet with a smaller injected pore volume.

Figure 9 provides visual evidence for the different displacement behaviors in the two pore geometries. In Geometry B, pure CO₂ flooding and continuous ordinary–water flooding show more concentrated preferential pathways, leaving substantial residual oil away from the main flow channel. In contrast, continuous surfactant–water flooding leaves less residual oil in both geometries, indicating that surfactant-induced interfacial-tension reduction and wettability alteration partly compensate for the unfavorable preferential-flow effect.

The effect of pore geometry is most pronounced for pure CO₂ flooding. In Geometry A, the oil recovery increases rapidly before 1.0 PV and then approaches a plateau of approximately 59.7% at 2.5 PV. In Geometry B, however, the recovery reaches only approximately 28.3% at 2.5 PV, a decrease of 31.4 percentage points. This large difference indicates that CO₂ flooding is highly sensitive to preferential flow paths. Because CO₂ has low viscosity and high mobility, it can rapidly form a connected gas channel in Geometry B. After breakthrough, subsequent CO₂ mainly flows through the established low-resistance pathway, so the additional recovery becomes limited and a large amount of oil remains in poorly swept regions.

A similar geometric effect can also be observed for continuous ordinary–water flooding. The recovery at 2.5 PV decreases from approximately 62.5% in Geometry A to 32.2% in Geometry B, a decrease of 30.3 percentage points. Although ordinary water has a higher viscosity than CO₂, the preferential-channel structure still promotes early breakthrough

and reduces the swept area. In contrast, continuous surfactant–water flooding shows much weaker sensitivity to the change in pore geometry. Its recovery remains high in both geometries, reaching approximately 77.0% in Geometry A and 75.9% in Geometry B at 2.5 PV, with only a 1.1 percentage-point decrease. This indicates that surfactant–water can still mobilize residual oil effectively even in the preferential-channel geometry through reduced oil–water interfacial tension and a more water-wet wall condition.

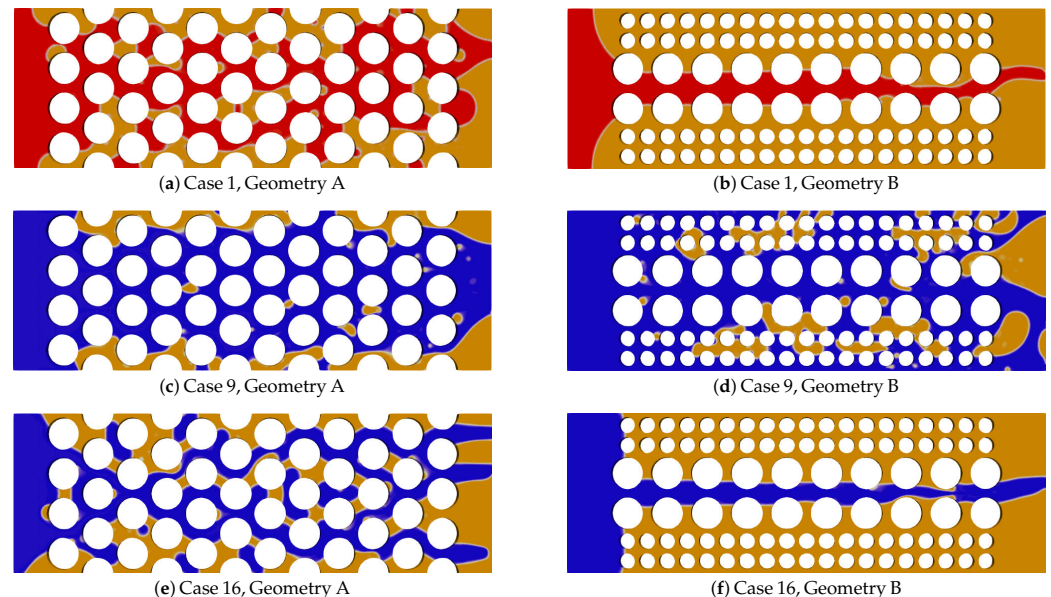


Figure 9. Phase-distribution contours of continuous single-phase flooding cases in Geometry A and Geometry B at 2.5 injected PV: (a,b) Case 1, pure CO₂ flooding; (c,d) Case 9, continuous surfactant–water flooding; (e,f) Case 16, continuous ordinary-water flooding. Red: CO₂; blue: aqueous phase; yellow: oil; white: solid grains.

Overall, Geometry B successfully represents a pore structure that is prone to preferential channeling, as reflected by the much lower breakthrough PV values for all injected phases. This geometric feature significantly reduces the recovery of pure CO₂ flooding and continuous ordinary-water flooding, but it has a relatively small influence on continuous surfactant–water flooding. Therefore, the comparison indicates that pore geometry mainly controls breakthrough behavior and macroscopic sweep efficiency, whereas surfactant–water improves microscopic displacement efficiency through interfacial-tension reduction and wettability alteration.

4.4. Effect of Injection Strategy on Oil Recovery and CO₂ Breakthrough

After clarifying the influence of pore geometry, this section further compares the effects of different injection strategies on oil recovery and CO₂ breakthrough. The comparison focuses on two aspects. First, the recovery increment of surfactant–water cases relative to the corresponding ordinary-water cases is evaluated at 2.5 injected PV. Second, the CO₂ breakthrough behavior is compared using the CO₂-injected PV at breakthrough, $N_{\text{CO}_2, \text{bt}}$, defined in Section 3.4. This combined comparison is necessary because oil recovery is controlled not only by macroscopic sweep and gas breakthrough but also by microscopic oil mobilization associated with interfacial-tension reduction and wettability alteration [23,26,27].

The recovery increment is defined as the difference between the oil recovery of a surfactant–water case and that of the corresponding ordinary-water case:

$$\Delta R_o = R_{o, \text{SW}} - R_{o, \text{OW}}, \quad (17)$$

where $R_{o,SW}$ and $R_{o,OW}$ are the oil recoveries of the surfactant–water and ordinary–water cases at 2.5 injected PV, respectively. The unit of ΔR_o is percentage points.

Figure 10 compares the recovery increment of surfactant–water cases relative to the corresponding ordinary–water cases at 2.5 injected PV. The comparison includes 1–4 s aqueous-phase preflush, the matched 0.5 s and 1 s cyclic water/CO₂ schedules, and 10 s continuous aqueous-phase flooding. The corresponding case pairs are Cases 2/10, 3/11, 4/12, 5/13, 7/14, 8/15, and 9/16.

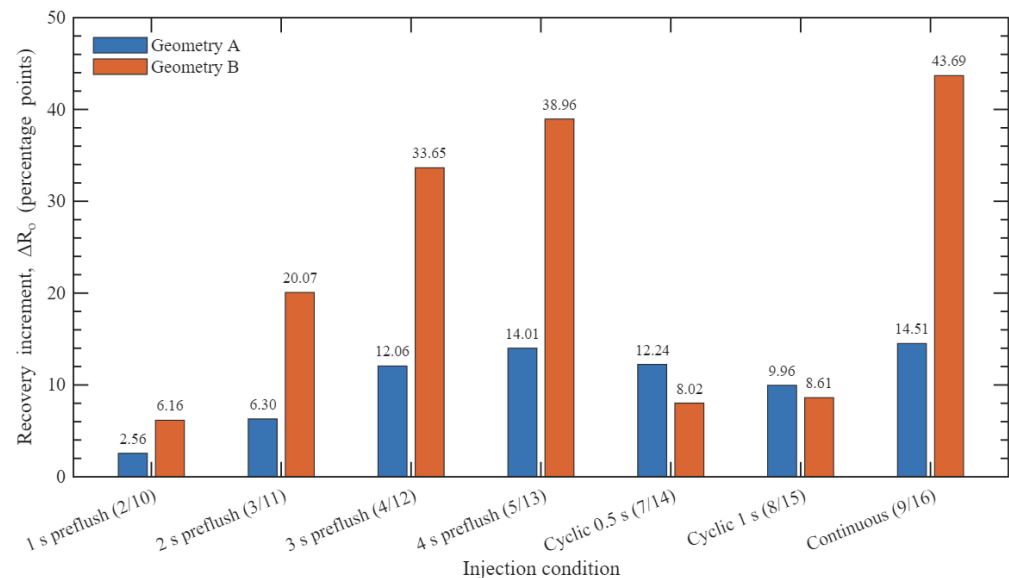


Figure 10. Recovery increment of surfactant–water cases relative to ordinary–water cases at 2.5 injected PV. The labels on the horizontal axis indicate the corresponding case pairs. The increment is expressed in percentage points.

As shown in Figure 10, surfactant–water provides a positive recovery increment under all comparable injection conditions in both geometries. For the preflush cases, the recovery increment increases with increasing surfactant–water preflush duration. In Geometry A, the increment increases from 2.56 percentage points for the 1 s preflush to 14.01 percentage points for the 4 s preflush. In Geometry B, the corresponding increment increases more significantly from 6.16 to 38.96 percentage points. For cyclic injection, the 0.5 s surfactant–water schedule exceeds the corresponding ordinary–water schedule by 12.24 percentage points in Geometry A and 8.02 percentage points in Geometry B. The 1 s cyclic pair gives increments of approximately 9.96 and 8.61 percentage points, respectively. Thus, replacing ordinary water with surfactant–water improves both cyclic schedules, although the absolute recovery of the cyclic cases remains limited in the preferential-channel geometry.

Figure 11 further illustrates the phase-distribution difference between surfactant–water and ordinary–water preflush in Geometry B. Under the same 4 s aqueous-phase preflush followed by CO₂ injection, the ordinary–water case shows a more pronounced CO₂ preferential pathway, and a large amount of oil remains in regions away from the main flow channel. In contrast, the surfactant–water case shows more dispersed aqueous-phase invasion and less residual oil in the pore space. This indicates that the recovery increment of surfactant–water is not only caused by delayed CO₂ breakthrough, but is also associated with reduced oil–water interfacial tension, improved aqueous-phase wettability, and enhanced microscopic residual-oil mobilization.

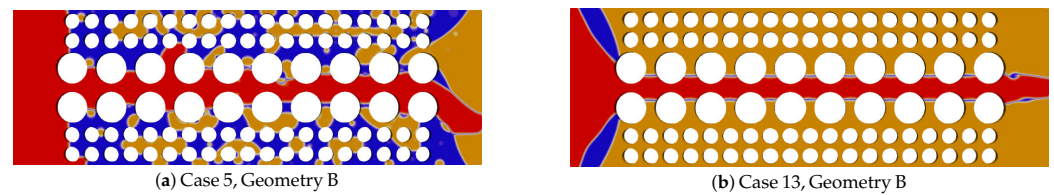


Figure 11. Phase-distribution contours comparing surfactant–water preflush and ordinary–water preflush followed by CO₂ injection in Geometry B at 2.5 injected PV: (a) Case 5, 4 s surfactant–water preflush followed by CO₂ injection; (b) Case 13, 4 s ordinary–water preflush followed by CO₂ injection. Red: CO₂; blue: aqueous phase; yellow: oil; white: solid grains.

The 10 s continuous flooding comparison gives the largest increment in Geometry B, reaching 43.69 percentage points, whereas the corresponding increment in Geometry A is 14.51 percentage points. This means that surfactant–water has a much stronger advantage over ordinary water in Geometry B. Since Geometry B is more prone to preferential flow, ordinary water mainly follows the dominant flow channels and leaves a large amount of oil unswept. In contrast, surfactant–water can reduce oil–water interfacial tension and shift the wall condition toward a more water-wet state, which weakens oil adhesion on solid surfaces and promotes residual-oil mobilization [23,26,27].

Figure 12 compares the CO₂ breakthrough behavior under different preflush and cyclic-injection conditions. The breakthrough is expressed by $N_{CO_2, bt}$, so the aqueous-phase preflush period is excluded and only the cumulative injected CO₂ volume before breakthrough is counted.

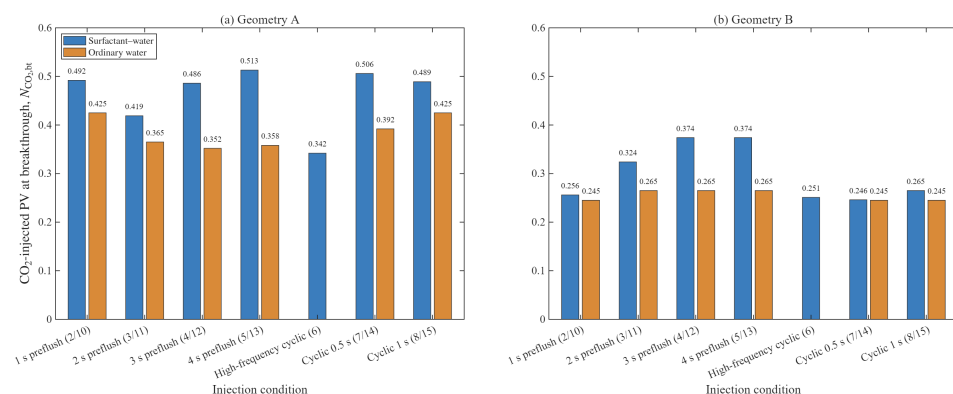


Figure 12. Effect of injection condition on CO₂ breakthrough expressed by CO₂-injected PV at breakthrough: (a) Geometry A; (b) Geometry B. The comparison includes the paired preflush and cyclic schedules and the high-frequency short-slug surfactant–water Case 6 as an additional unpaired condition.

The CO₂ breakthrough results show that surfactant–water preflush generally increases $N_{CO_2, bt}$ compared with ordinary–water preflush. In Geometry A, $N_{CO_2, bt}$ for the surfactant–water preflush cases ranges from 0.419 to 0.513, whereas that for the ordinary–water preflush cases ranges from 0.352 to 0.425. This suggests that, in the relatively uniform geometry, surfactant–water preflush can delay the formation of a connected CO₂ pathway more effectively than ordinary–water preflush.

In Geometry B, $N_{CO_2, bt}$ for the surfactant–water preflush cases increases from 0.256 for the 1 s preflush to approximately 0.374 for the 3–4 s preflush, while the ordinary–water preflush cases remain nearly constant at approximately 0.245–0.265. Although this indicates a certain delay in CO₂ breakthrough for longer surfactant–water preflushes, the increase in $N_{CO_2, bt}$ is much smaller than the corresponding recovery increment shown in Figure 10. Therefore, the large recovery improvement in Geometry B cannot be explained solely by delayed CO₂ breakthrough. Instead, it is mainly associated with the surfactant–

induced reduction in capillary trapping and the mobilization of oil in regions that are not efficiently swept by the main gas channel.

The cyclic-injection cases provide additional comparisons of alternating aqueous-phase/CO₂ injection. Cases 7 and 14 have the same schedule of 0.5 s aqueous phase + 2 s CO₂ repeated five times. For this pair, $N_{\text{CO}_2, \text{bt}}$ is 0.506 and 0.392 in Geometry A for surfactant–water and ordinary water, respectively, whereas both values are approximately 0.245 in Geometry B. Cases 8 and 15 use the matched 1 s aqueous phase + 2 s CO₂ schedule; the corresponding surfactant–water values are approximately 0.489 in Geometry A and 0.265 in Geometry B, compared with approximately 0.425 and 0.245 for ordinary water. The high-frequency Case 6 gives $N_{\text{CO}_2, \text{bt}} \approx 0.342$ in Geometry A and 0.251 in Geometry B. These results show that surfactant–water can delay breakthrough under the two matched cyclic schedules in Geometry A, while the effect remains small in Geometry B. The lower $N_{\text{CO}_2, \text{bt}}$ of Case 6 in Geometry A also indicates that its relatively high recovery is not primarily caused by delayed breakthrough.

Figure 13 explains the geometry dependence of the baseline Case 7. In Geometry A, the CO₂ phase forms a relatively tortuous invasion pattern, and the aqueous phase remains distributed in several pore regions, indicating that the surfactant–water slug can partially disturb the CO₂ flow path before breakthrough. In Geometry B, however, CO₂ rapidly reconnects with the central preferential channel and reaches the outlet through a more concentrated pathway. This behavior is consistent with the low recoveries of all three surfactant–water cyclic schedules in Geometry B. Since the present VOF model does not explicitly include foam generation or gas-mobility reduction, the cyclic surfactant–water/CO₂ injection cannot fully represent the gas-blocking effect that may occur in foam-assisted or chemically enhanced WAG processes [29,30,32].

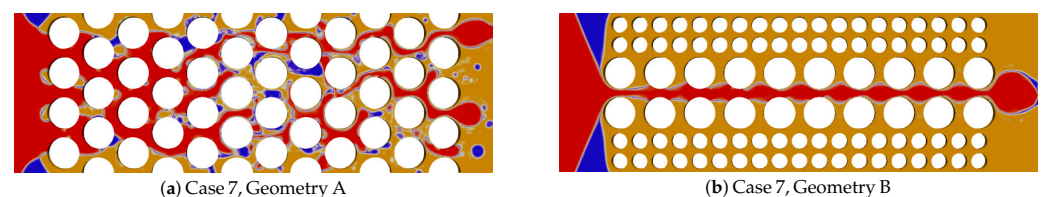


Figure 13. Phase-distribution contours of Case 7 near CO₂ breakthrough: (a) Geometry A; (b) Geometry B. Red: CO₂; blue: aqueous phase; yellow: oil; white: solid grains.

The newly included cyclic schedules clarify two separate effects. First, Cases 6 and 7 have identical total program durations and the same total surfactant–water and CO₂ injection times, but Case 6 uses twice the switching frequency. At 2.5 injected PV, Case 6 gives 77.47% recovery in Geometry A, compared with 75.85% for Case 7, whereas the corresponding values in Geometry B are 40.62% and 41.20%. Thus, finer alternation provides a modest benefit in the relatively uniform geometry but does not improve the preferential-channel geometry. Second, Case 8 can be compared with the matched ordinary-water Case 15. Case 8 gives 77.69% and 41.57% recovery in Geometries A and B, respectively, exceeding Case 15 by approximately 9.96 and 8.61 percentage points. This confirms a positive surfactant effect at the 1 s cyclic schedule, but the small absolute recovery in Geometry B shows that increasing the aqueous-slug duration and surfactant dose is still insufficient to overcome repeated reconnection with the dominant gas pathway.

Overall, Figures 10, 12 and 13 show that surfactant–water improves oil recovery through both delayed CO₂ breakthrough and enhanced microscopic oil mobilization. The latter effect is especially important in Geometry B, where the recovery increment is much larger than the increase in $N_{\text{CO}_2, \text{bt}}$. The comparison between Cases 6 and 7 further shows that increasing the switching frequency produces only a geometry-dependent and relatively modest change, while the matched Cases 8 and 15 confirm that the surfactant advantage

persists for a 1 s cyclic water slug. Alternating injection is therefore effective only when the aqueous slugs can disturb the preferential CO₂ pathway; otherwise, CO₂ rapidly reconnects with the dominant channel and the benefit of cyclic injection remains limited.

5. Conclusions

In this study, a pore-scale three-phase VOF model is established in OpenFOAM to investigate immiscible displacement of heavy oil by CO₂, ordinary water, and surfactant–water in two two-dimensional porous media. The effects of capillary number, viscosity ratio, pore geometry, injection strategy, aqueous-phase type, and CO₂ breakthrough behavior are analyzed using oil recovery, breakthrough PV, cumulative injected CO₂ PV at breakthrough, and phase-distribution characteristics. The main conclusions are as follows:

1. The dimensionless analysis shows that CO₂ flooding and surfactant–water flooding are governed by different displacement mechanisms. For CO₂ flooding, increasing the capillary number and improving the viscosity ratio can enhance oil recovery, but the recovery response is strongly affected by early gas-channel formation and post-breakthrough flow through preferential pathways. For surfactant–water flooding, the influence of viscosity ratio is more stable, whereas the influence of capillary number becomes weaker after the oil–water interfacial tension is reduced and the wall wettability is shifted toward a more water-wet condition.
2. The overall comparison at 2.5 injected PV indicates that the 1 s surfactant–water cyclic case and the high-frequency short-slug case give the highest or near-highest recovery in the relatively uniform geometry, whereas continuous surfactant–water flooding remains the highest-recovery scheme in the preferential-channel geometry. Surfactant–water preflush followed by CO₂ injection becomes more effective as the preflush duration increases. Pure CO₂ flooding and ordinary-water cases show lower recovery, especially in the preferential-channel geometry. Although continuous surfactant–water flooding provides the strongest and most geometry-robust reference response, the combined surfactant–water/CO₂ schemes remain important because they reduce reliance on continuous chemical injection and allow for CO₂ utilization while retaining part of the surfactant-induced oil-mobilization effect.
3. Pore geometry strongly affects breakthrough behavior and macroscopic sweep efficiency. In the preferential-channel geometry, all injected phases break through at much lower injected PV than in the relatively uniform geometry. Pure CO₂ flooding is the most sensitive to this geometric effect because the low viscosity and high mobility of CO₂ promote rapid gas-channel formation. Ordinary-water flooding is also weakened by preferential flow, whereas surfactant–water flooding maintains high recovery in both geometries because it can mobilize residual oil that is not efficiently swept by the main flow channel.
4. The injection-strategy comparison shows that surfactant–water consistently improves oil recovery relative to ordinary water. The recovery increment increases with surfactant–water preflush duration and is much larger in the preferential-channel geometry. However, the corresponding increase in CO₂-injected PV at breakthrough is limited in this geometry. Therefore, the large recovery improvement caused by surfactant–water cannot be explained solely by delayed CO₂ breakthrough. It is mainly attributed to microscopic residual-oil mobilization caused by reduced oil–water interfacial tension, weakened oil adhesion on solid walls, and improved water-wetness.
5. Cyclic surfactant–water/CO₂ injection exhibits a strong geometry dependence. Under the two tested equal-total-dose schedules, increasing the switching frequency from the 0.5 s/2 s schedule to the 0.25 s/1 s schedule produces a modest recovery increase

in the relatively uniform geometry but no improvement in the preferential-channel geometry. The matched 0.5 s and 1 s cyclic comparisons both show positive recovery increments for surfactant–water relative to ordinary water, yet their absolute performance remains limited in Geometry B because repeated CO₂ injection reconnects with the dominant gas pathway. Since foam generation, CO₂–oil mass transfer, oil swelling, viscosity reduction, and gas-mobility control are not explicitly included in the present immiscible VOF model, the simulated alternating-injection effect should be interpreted mainly as an interfacial-tension and wettability effect rather than as a full representation of foam-assisted or miscible CO₂-EOR mechanisms.

Overall, within the present idealized two-dimensional immiscible VOF model, the pore-scale simulations indicate that surfactant-assisted displacement improves heavy-oil recovery mainly by enhancing microscopic oil mobilization, while CO₂ displacement is strongly affected by preferential gas channeling. The results support a trend-level distinction among the roles of pore geometry, prescribed surfactant-induced capillary-force reduction, wettability alteration, and CO₂ breakthrough in surfactant-assisted CO₂ flooding. Future work should incorporate CO₂–water and CO₂–oil mass transfer, foam or gas-mobility-control models, and micro-CT-based or stochastic three-dimensional pore structures to further evaluate the applicability of surfactant-assisted CO₂ EOR under more realistic reservoir conditions.

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