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Comeplex Fracture Network Fracturing Coupled with CO_2-WAG Technology Improves Recovery and Storage Efficiency in Ultra-low Permeability Reservoirs

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ABSTRACT

This paper addresses the challenges of high injection pressures, difficulty in establishing displacement systems, and low recovery rates in ultra-low permeability reservoirs by proposing an integrated development strategy that combines large-scale complex fracture network fracturing with a CO_2 cooperative injection-production process based on the "injection – shut-in – production" cycle. The approach aims to enhance both oil recovery and CO_2 sequestration potential through reservoir modification and crude oil property regulation. A non-intrusive embedded discrete fracture model (EDFM) is used to accurately represent the complex fracture network in three-dimensional space, overcoming the limitations of traditional methods in multi-scale fracture handling. The paper compares the effects of three development methods: conventional water injection, CO_2 huff-and-puff, and CO_2-water alternating injection (CO_2-WAG). Key parameters such as injection timing, total CO_2 volume, injection rate, and shut-in time are optimized, with carbon sequestration efficiency introduced as a core evaluation index. Simulation results show that cyclic CO_2-WAG can increase recovery by 8.9% compared to conventional water injection. Key mechanisms include: CO_2 reducing oil viscosity and expanding its volume during the shut-in phase, water injection controlling CO_2 flow and expanding sweep volume, and periodic injection – shutdown operations restoring fracture conductivity and maintaining reservoir pressure. This method improves fluid exchange between fractured and unfractured zones, reducing recovery discrepancies. Optimized injection gas rates and timing can delay production decline and reduce fracture closure risks. From a carbon sequestration perspective, the optimized CO_2-WAG scheme improves both oil recovery and CO_2 sequestration efficiency, achieving synergistic optimization. This study offers an integrated method for ultra-low permeability tight oil reservoirs, providing a reliable pathway for green and efficient development.

Keywords: CO_2-WAG Injection, Complex Fracture Network, Enhanced Oil Recovery, Carbon Sequestration, Ultra-low Permeability Reservoirs

1. INTRODUCTION

Unconventional ultra-low permeability reservoirs, as a crucial replacement for global oil and gas resources, present both significant resource potential and extremely complex development challenges. These reservoirs typically have nanoscale pore throats, poor pore connectivity, and very low fluid mobility, resulting in high injection pressures, difficulty in establishing effective displacement systems, prominent injection-production conflicts, and generally low recovery rates (often below 15%) under conventional waterflooding development[1,2]. Although traditional hydraulic fracturing technology can create main fractures in the reservoir to improve near-wellbore flow capacity, the simple or single fracture network systems formed are insufficient for fully and effectively utilizing the ultra-low permeability matrix areas. Moreover, as production progresses, fracture conductivity often rapidly declines due to stress sensitivity, resulting in unsatisfactory development outcomes[3,4].

To overcome these challenges, large-scale complex fracture network fracturing technology has emerged. This technology aims to "break" the reservoir, creating a complex fracture system consisting of main fractures, branch fractures, and natural microfractures, which greatly increases the stimulated reservoir volume (SRV) and oil drainage area[5,6]. However, relying solely on physical modification is insufficient for efficient reservoir development; it must be coupled with high-efficiency

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displacement fluids and cyclic injection-production processes. CO_2, due to its unique physicochemical properties, is regarded as an ideal medium to improve recovery in ultra-low permeability reservoirs[7]. Its high solubility in crude oil significantly reduces oil viscosity, causes oil volume expansion, and can achieve near-miscible or miscible states under suitable pressures, drastically reducing oil-water interfacial tension and enhancing microscopic oil displacement efficiency[8,9]. Specifically, the CO_2 huff-and-puff technology based on the "injection–shut-in–production" cycle has shown potential for increasing oil recovery at single well points. However, conventional CO_2 huff-and-puff has inherent flaws such as limited action radius, early gas breakthrough, and small sweep volume[10].

By combining CO_2 huff-and-puff with the water-alternating-gas (WAG) concept, a cyclic CO_2-WAG technology based on the huff-and-puff mechanism is proposed. This method theoretically combines the advantages of both approaches: on one hand, CO_2 injection and shut-in processes achieve full extraction and miscible displacement of crude oil in the complex fracture network and adjacent matrix; on the other hand, subsequent water injection effectively controls CO_2 mobility, suppresses gas coning, expands the sweep volume, and promotes fluid exchange between fractures and matrix through periodic pressure disturbance and capillary suction[11,12]. More importantly, in the context of global efforts to achieve "carbon neutrality," integrating CO_2 geological sequestration with enhanced oil recovery (CCUS-EOR) has become a key path for the green transformation of the oil and gas industry. Ultra-low permeability reservoirs typically have good sealing properties, making them ideal for CO_2 sequestration[13,14]. Therefore, exploring an integrated development model that simultaneously improves both oil recovery and carbon sequestration efficiency holds significant scientific and engineering value.

Currently, research into the mechanisms of this composite technology system faces several challenges. First, the multiphase fluid exchange mechanism between complex fracture networks and porous matrix is extremely complicated, involving physical and chemical processes such as fracture dynamic opening and closing under stress sensitivity, non-Darcy flow, and CO_2 diffusion and dissolution in crude oil[15,16]. Second, the dynamic operation of cyclic injection–shut-in–production involves the interaction of several key parameters, and its optimization design lacks systematic theoretical guidance. Existing numerical simulation methods often face bottlenecks in balancing computational efficiency and accuracy when dealing with large-scale, multi-scale discrete fracture networks and multi-field coupling issues.

To address these challenges, this paper proposes an integrated development strategy that combines large-scale complex fracture network fracturing with cyclic CO_2-WAG injection. This study aims to construct a coupled geological mechanics and multiphase flow numerical model to thoroughly reveal the oil recovery and sequestration mechanisms of this technology in the new fracture network environment. The research will systematically compare the effects of conventional water injection, CO_2 huff-and-puff, and cyclic CO_2-WAG development methods, with a focus on optimizing key parameters throughout the entire CO_2-WAG process. The ultimate goal is to develop a set of green and efficient development methods and optimization processes that integrate "reservoir modification, efficient oil recovery, and carbon sequestration" for ultra-low permeability tight oil reservoirs, providing solid technical support and decision-making basis for the effective development of similar reservoirs.

2. METHODOLOGY

2.1 Embedded Discrete Fracture Model (EDFM) Method

The Embedded Discrete Fracture Model (EDFM) was introduced by J. A. Rojas and G. F. P. Stokes[17]. This method is a numerical technique designed to directly embed fracture structures into the computational grid. In this method, the positions and shapes of fractures are explicitly defined within the grid. The core advantage of EDFM is its ability to explicitly incorporate the influence of fractures on fluid flow. By embedding fractures within the grid, EDFM allows for more precise simulation of fracture effects, particularly when dealing with complex fracture networks.

Figure 1 illustrates the process of constructing fracture units in EDFM. Using a simplified model that includes three matrix cells and two fractures (Fracture 1 and Fracture 2), the basic principles of EDFM are explained: when a fracture intersects a matrix cell, an independent fracture segment is generated in the intersection area, which connects non-adjacently to the corresponding matrix cell; when multiple fractures intersect, connections are also made between the fracture segments. In Figure 2, Matrix Cells 1, 2, and 3 represent the original grid. Fracture 1 does not intersect with Cell 1, so no new connection is created. However, it intersects Cells 2 and 3, generating Fracture Cells 5 and 6. Fracture 2 intersects all three matrix cells, creating Fracture Cells 7, 8, and 9. Each fracture cell independently computes its volume based on its aperture and spatial distribution characteristics, and the corresponding conductivity is calculated based on different types of connections.

This method discretizes complex fracture networks into multiple fracture segments, accurately representing the flow exchange between these segments and matrix cells. It provides an effective solution for modeling multi-scale fracture systems and lays a solid numerical foundation for subsequent flow simulations.

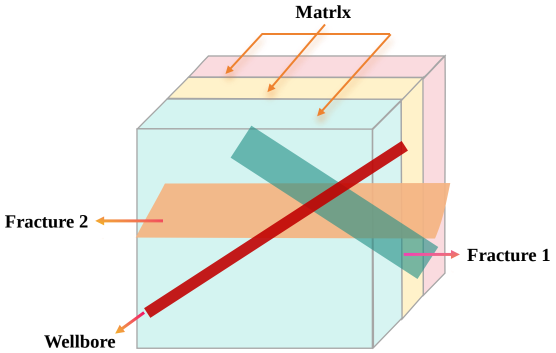

Fig. 1 Schematic diagram of the physical domain model of the structured matrix unit

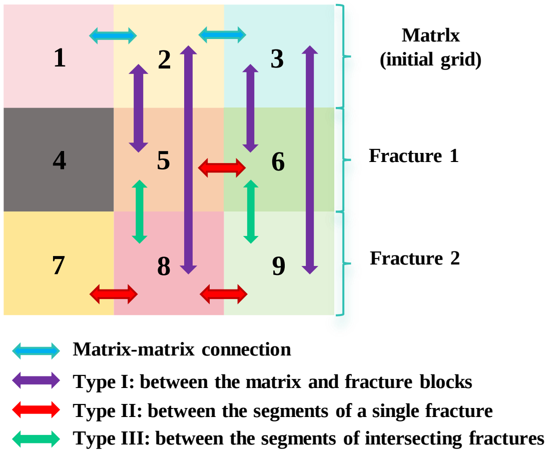

Fig. 2 Schematic diagram of the matrix unit Computational domain

In the fracture-matrix system, conductivity is a key parameter used to measure the ability of fluid to flow between different connection types. The method of calculating conductivity varies depending on the type of fracture. There are three main connection types (Type I, Type II, and Type III), and the calculation of their conductivity is based on permeability, contact area, and the distance between fracture segments and matrix blocks or other fracture segments.

The conductivity (T_I) between the matrix and fracture blocks is defined by the following equation:

$$T_I = \frac{2Ak\cos(\theta)}{d} \tag{1}$$

where: A is the area of intersection between the fracture and the matrix block, k is the permeability of the matrix material, θ is the angle between the fracture normal vector and the direction of matrix permeability, d represents the average normal distance between the fracture plane and the matrix block.

The conductivity (T_{II}) between the segments of a single fracture is defined by the following equation:

$$T_{II} = \frac{\boldsymbol{k}_f A_c}{d_{seg}} \tag{2}$$

where: k_f is the permeability of the fracture segment, A_c is the area of the common face between the two fracture segments, d_{seg} is the distance from the center of mass of each segment to the contact line of the two segments.

The conductivity (T_{III}) between segments of intersecting fractures is determined by:

$$T_{III} = \frac{k_f wL}{d_f} \tag{3}$$

where: k_f is the permeability of the fracture material, w is the width of the fracture segment, L is the length of the intersection line between the two fracture segments, d_f is the average distance from the centroid of each segment to the intersection line.

2.2 Model Description

The M reservoir block was put into production in 2006-2007, using a rectangular well pattern for water injection development. During the early stages of development, single well production was low and declined rapidly. By 2022, a large-scale fracturing production was carried out on 27 vertical wells and 3 horizontal wells in the M reservoir. As of 2022, the recovery factor during the waterflooding phase was only 5.64%, with water cut exceeding 70%, marking the transition into a high-water-cut development stage.

The M reservoir is a typical low-porosity, ultra-low permeability reservoir, with significant heterogeneity and complex pore-throat structures. It average porosity is 12.86%, and the average permeability is $1.35\times10^{-3}\mu m^2$, resulting in poor fluid mobility within the reservoir. The original formation conditions of the reservoir are as follows: temperature 92.5°C, pressure 21 MPa, crude oil viscosity 5.8 mPa·s, density 0.848 g/cm³, gas-to-oil ratio (GOR) 18.14 m³/m³, and saturation pressure 3.95 MPa.

In this study, the equation of state (EOS) was used to characterize the crude oil system, and the model was accurately fitted using experimental data. The established fluid model contains six fitted components, with their molar fractions listed in Table 1. Additionally, field studies indicate that under the formation temperature of the M reservoir (92.5°C) and the expected injection pressure range (19-26 MPa), CO_2 cannot achieve miscibility with the crude oil system, and the displacement process follows a non-miscible mechanism.

Table 1 Compositions of reservoir fluid and injected gas

Compositions	Mole fractions of reservoir fluid(%)	Mole fractions of injected gas(%)
N_2	0.22	0.1
CO_2	1.21	99.9
C_1	56.31	0
C_2-C_6	7.35	0
C_7-C_{10}	6.25	0
C_{11+}	28.66	0

2.3 Modelling Schemes and General Workflow

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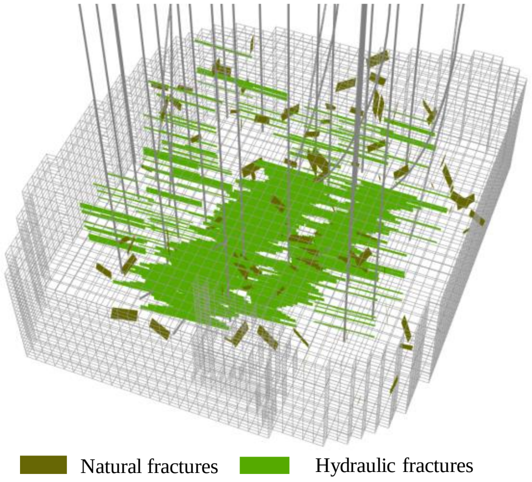


Fig. 3 Distribution of fractures in the model

Table 2 Parameters of hydraulic/natural fractures, and grid in the numerical model

Parameters	Results	Unit
Grid size	20×20×5	m
Number of grids	42000	-
Matrix porosity	8%～15%	-
Matrix Permeability	0.2～2.1	$10^{-3}\mu m^2$
Horizontal well length	868	m
Depth	2726	m
Number of hydraulic fractures	592	-
Half-length of hydraulic fractures	125～200	m
Hydraulic fracture spacing	15	m
Hydraulic fracture height	8～14	m
Average hydraulic fracture permeability	83	$10^{-3}\mu m^2$
Number of natural fractures	100	-
Natural fracture height	0.1-6	m
Average natural fracture permeability	7～40	$10^{-3}\mu m^2$

First, based on the reservoir fluid characteristics system representation and in conjunction with the Embedded Discrete Fracture Model (EDFM), a high-precision numerical simulation model for the M ultra-low permeability reservoir was constructed through history matching of reservoir production dynamics. The model has a grid size of 20m×20m×5m, and includes 3 fractured horizontal production wells (MFHW), 21 vertical production wells, and 6 injection/recovery wells. After complex fracture network fracturing of 30 wells, the reservoir block is developed using the "injection–shut-in–production" huff-and-puff process. The fracture system consists of 592 artificial hydraulic fractures and

100 natural fractures (Figure 3), revealing the complex flow network of the reservoir. The parameters for the reservoir, fractures, and grid are summarized in Table 2.

Based on the history matching of the M reservoir model, a systematic evaluation was conducted to assess the recovery performance over the next 10 years under three development modes: conventional water injection, CO_2 huff-and-puff, and cyclic CO_2-WAG. After evaluation, CO_2-WAG was selected as the optimal development mode, and its key parameters were finely optimized, including injection timing, total CO_2 injection volume, injection rate, and shut-in time. Based on this, an optimal integrated development and sequestration plan for the M reservoir was proposed.

Table 3 Injection-production parameters of the CO_2-EOR numerical model

Parameters	Results	Unit
Production method	Conventional water injection, CO_2 huff and puff, Cyclic CO_2-Water alternating gas (CO_2-WAG)	-
Injection timing	0,3,6,9,12,15	month
CO_2 injection volume	3000,6000,9000,12000,15000,18000,21000	m^3
Injection rate	150,200,250,300,350	m^3/d
Soaking time	15,30,45,60	d

The numerical simulation considered a 10-year production cycle, with an annual oil production rate of 2% (i.e., 26.56 m^3 per day) and a minimum bottom-hole pressure (BHP) constraint of 5 MPa. The specific injection and production parameters for CO_2-EOR are detailed in Table 3.

3. RESULTS AND DISCUSSIONS

3.1 Optimal Production Method

After completing the history matching of the M reservoir and establishing the production baseline, a systematic evaluation was conducted to assess the comprehensive effects of three development methods over a ten-year production period following large-scale fracturing: conventional water injection, CO_2 huff-and-puff, and cyclic CO_2-WAG. The numerical simulation results indicate that cyclic CO_2-WAG has a significant advantage in enhancing oil recovery.

According to the recovery comparison data shown in Figure 4, the final recovery rate for the cyclic CO_2-WAG scheme is 5.44 percentage points higher than that for conventional water injection, highlighting the development potential of this process in ultra-low permeability fractured reservoirs. To further reveal its production enhancement mechanism, this study compared the spatial distribution evolution of oil saturation under different development modes (Figure 5). The results show that after CO_2 huff-and-puff, the oil saturation decreases significantly, primarily due to CO_2's low density, high diffusivity, and its effects of viscosity

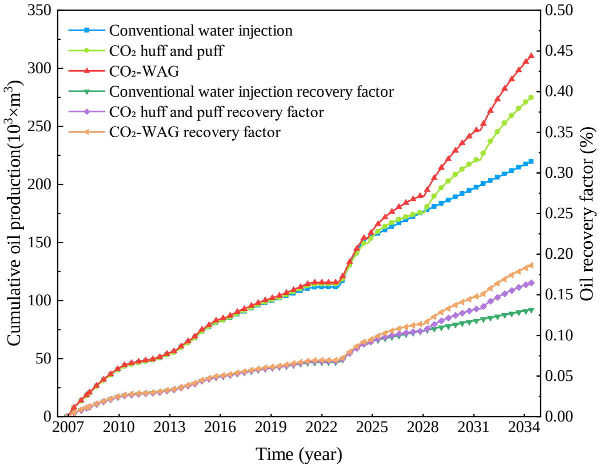


Fig. 4 Comparison of cumulative oil production and oil recovery factor under different development methods

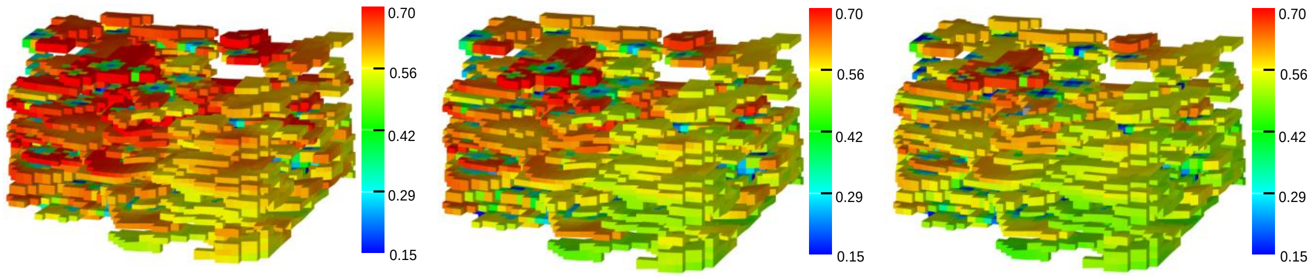
reduction and oil expansion. These properties enable CO_2 to quickly replenish formation pressure and enhance oil mobility.

In the cyclic CO_2-WAG mode, the oil saturation decreases most significantly, and its spatial distribution is more uniform. The core advantage of this mode lies in the synergistic effect of "CO_2 extraction—water phase controlled flow": during the CO_2 injection and shut-in phase, CO_2 achieves full diffusion and near-miscible displacement in the complex fracture network and matrix; subsequently, water phase injection effectively controls gas mobility, suppresses gas coning, and enhances fluid exchange between fractures and matrix through periodic pressure adjustment. This mechanism collectively promotes the simultaneous improvement of sweep volume and oil displacement efficiency, providing the physical basis for the significant increase in recovery rate through the cyclic CO_2-WAG technology.

metric to comprehensively assess the efficiency of CO_2 utilization and the economic benefits.

Figure 6 shows the predicted cumulative oil increment and oil replacement ratio for the six schemes. When CO_2-WAG is initiated 12 months after fracturing (corresponding to a reservoir pressure coefficient of 0.68, as shown in Figure 7), the best production enhancement and high oil replacement ratio are achieved. Conversely, if the energy supplementation is delayed beyond 12 months, the cumulative oil increment and oil replacement ratio significantly decrease due to excessive reservoir energy depletion.

In conclusion, this study recommends initiating CO_2-WAG energy supplementation 12 months after fracturing as the optimal operational window. This strategy maximizes crude oil production while ensuring efficient CO_2 utilization and optimizing the project's economic benefits.



Conventional water injection *CO_2 huff and puff* *CO_2-WAG*

Fig. 5 Comparison of remaining oil distribution under different development methods

3.2 Injection Timing

To determine the optimal timing for initiating CO_2-WAG energy supplementation after fracturing, this study designed six development schemes with different injection start times and systematically evaluated the impact of injection timing on production dynamics. The oil replacement ratio was introduced as a key evaluation

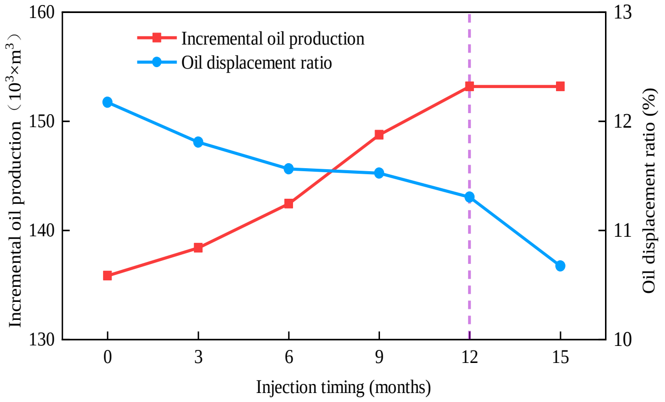


Fig. 6 Comparison of incremental oil production and oil displacement ratio at different injection timings

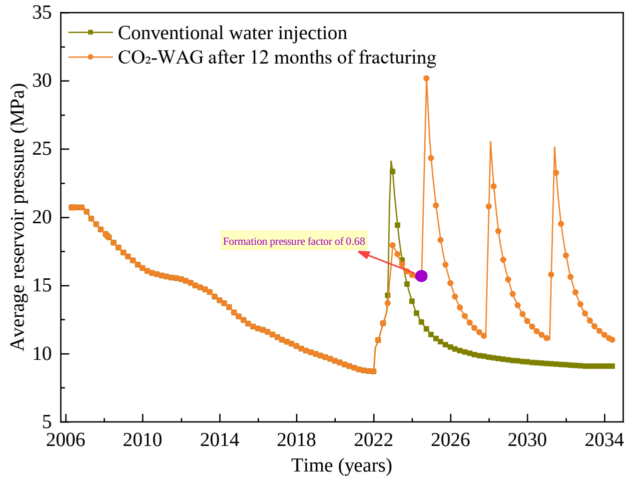


Fig. 7 Changes in formation pressure at the optimal injection timing

3.3 CO_2 Injection Volume

To determine the optimal single-cycle CO_2 injection volume, Figure 8 systematically analyzes the development performance under six different injection volume schemes. By comparing the cumulative oil increment and the oil replacement ratio (i.e., the amount of crude oil increment per unit of CO_2 injected), it was found that when the single-well single-cycle CO_2 injection volume reaches 15,000 m³, the system's oil replacement ratio peaks, indicating that CO_2 utilization efficiency is highest at this point.

Although further increases in injection volume continue to yield some additional oil production, the growth trend in cumulative oil increment slows significantly, suggesting diminishing marginal benefits in the development process. Therefore, considering the dual objectives of improving recovery efficiency and maximizing CO_2 geological sequestration, the optimal single-well single-cycle CO_2 injection volume is determined to be 15,000 m³. This injection volume ensures effective production enhancement while guaranteeing the economic and efficient utilization and sequestration of CO_2 resources.

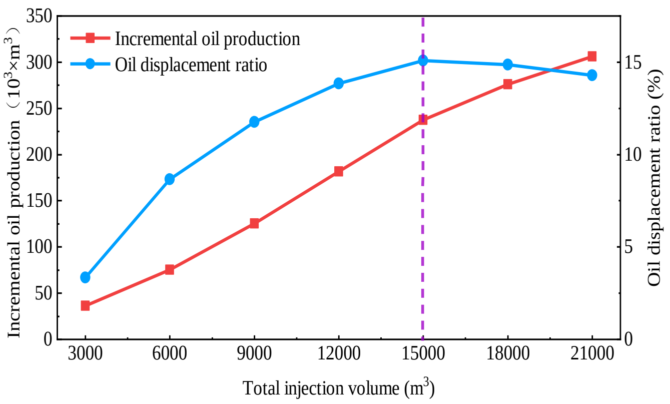


Fig. 8 Comparison of incremental oil production and oil displacement ratio at different CO_2 injection volume

3.4 Injection Rate

To systematically evaluate the impact of CO_2 injection rate on development dynamics, five different injection rate schemes were set up, with a focus on analyzing their effects on daily oil production, cumulative oil increment, and oil replacement ratio. Figures 9 and 10 show that when the injection rate is 200 m³/d, daily oil production, cumulative oil increment, and oil replacement ratio all reach their peak values, indicating that under this condition, the CO_2 migration and displacement processes in the reservoir are most coordinated. Once the injection rate exceeds this critical value, both cumulative oil increment and oil replacement ratio decline, reflecting a breakdown in the dynamic balance between gas injection and crude oil seepage. This phenomenon may be related to the intensified gas fingering, reduced effective sweep volume, or fracture conductivity damage caused by rapid fluctuations in reservoir pressure.

Based on the above observations, it is recommended to set 200 m³/d as the optimal CO_2 injection rate for this project. This rate ensures effective displacement efficiency while balancing gas utilization economics and maintaining reservoir geological integrity.

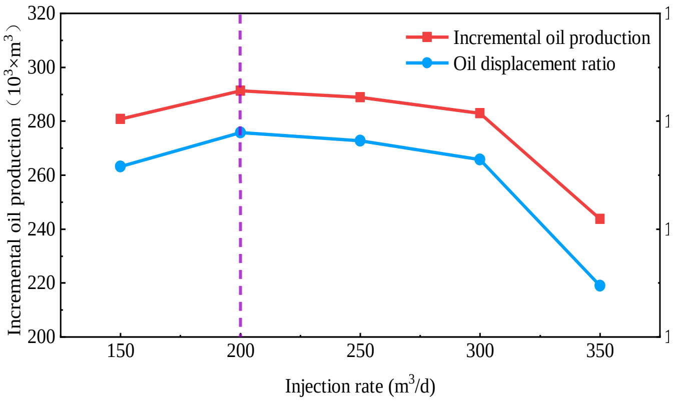


Fig. 9 Comparison of incremental oil production and oil displacement ratio at different CO_2 injection rate

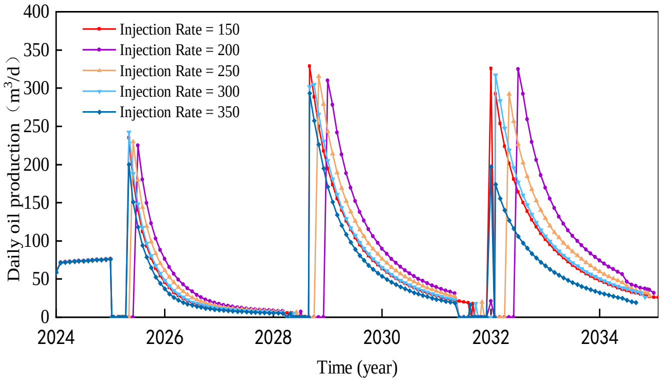


Fig. 10 Comparison of daily oil production at different CO_2 injection rate

3.5 Soaking Time

As shown in Figure 11, the evaluation of four shut-in time schemes indicates that a single-cycle shut-in time of 45 days yields the best development results, with peak values for both cumulative oil increment and oil replacement ratio. This period provides the necessary conditions for CO_2 to achieve full mass transfer within the fracture network and matrix system: CO_2 continuously dissolves and extracts light hydrocarbons from the crude oil, significantly reducing interfacial tension and bringing the system closer to a near-miscible state. This process not only reduces crude oil viscosity and promotes its expansion but also further enhances microscopic oil displacement efficiency.

Figure 12 results show that if the shut-in time is too short, the reduction in interfacial tension is insufficient, which negatively impacts recovery efficiency. Conversely, if the shut-in time is too long, the economic efficiency decreases, and the effect of interfacial tension improvement weakens over time. Overall analysis suggests that a 45-day shut-in time achieves the optimal balance between interfacial tension control, improvement in crude oil properties, and economic feasibility. This is the recommended parameter under the conditions of this study.

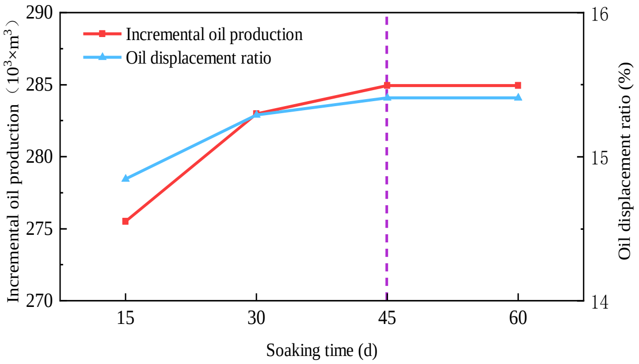
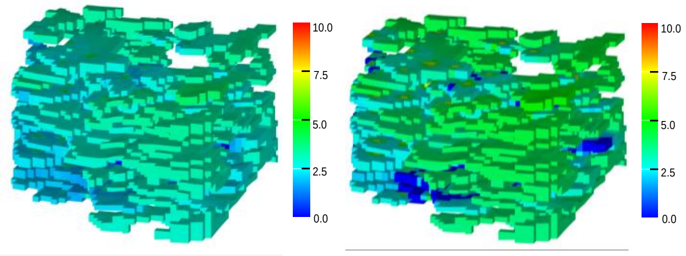
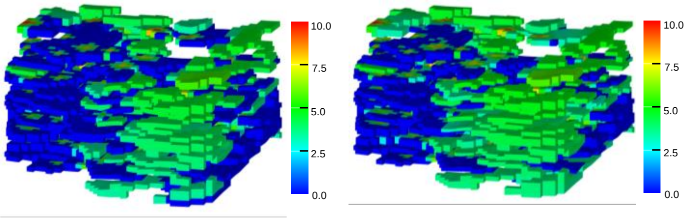


Fig. 11 Comparison of incremental oil production and oil



Shut-in for 15 days *Shut-in for 30 days*



Shut-in for 45 days *Shut-in for 60 days*

Fig. 12 Comparison of reservoir interfacial tension at four soaking times

3.6 Optimal CO_2 EOR Scheme

Based on the optimization results of the key parameters, this study has determined the recommended CO_2 supplementation and production enhancement scheme for the M reservoir block. Using this optimized scheme, the production dynamics for the next 10 years were predicted. The results shown in Figure 13 indicate that under conventional water injection development, the cumulative oil production would be 151,100 tons. In contrast, with the optimized CO_2 production enhancement scheme, the cumulative oil production could reach 255,700 tons, with an increase of 104,600 tons, resulting in an 8.98% improvement in recovery. Furthermore, this scheme achieves significant production enhancement while injecting a total of 36×10^4 m^3 of CO_2, with a cumulative CO_2 gas production of 23.69×10^4 m^3, resulting in a 34.19% macro CO_2 sequestration efficiency.

This demonstrates the dual benefits of enhancing crude oil recovery and promoting carbon sequestration, providing a technical reference for the green and efficient development of similar ultra-low permeability reservoirs.

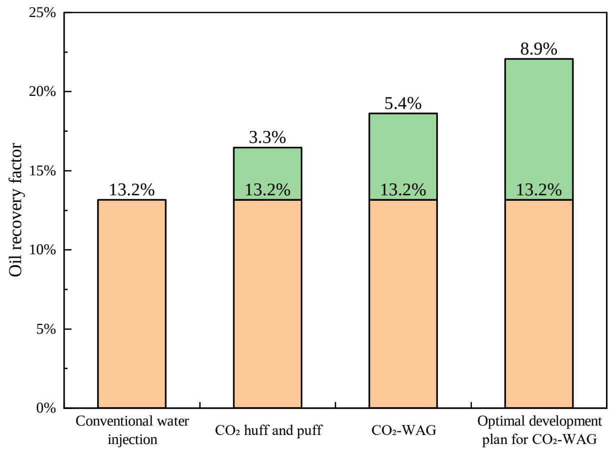


Fig. 13 Comparison of oil recovery factor of the best development plans

4. CONCLUSIONS

Based on the integrated numerical simulation study of complex fracture network fracturing and cyclic CO_2-WAG injection in ultra-low permeability reservoirs, the following key conclusions were drawn:

(1) The development effect of cyclic CO_2-WAG technology is significantly superior to conventional water injection. Over a 10-year forecast period, it can increase the final recovery rate by 8.98%, with a cumulative oil increment of 104,600 tons. This advantage is due to the full diffusion of CO_2 during the shut-in phase and its viscosity reduction and oil expansion effects, as well as the synergistic mechanism of subsequent water phase injection, which effectively controls gas mobility and expands the sweep volume.

(2) Systematic optimization of CO_2-WAG process parameters is crucial to achieving the best development results. The optimal operational strategy determined in this study is: initiating CO_2-WAG 12 months after fracturing, with a single-well single-cycle CO_2 injection volume of 15,000 m^3, an injection rate of 200 m^3/d, and a shut-in time of 45 days. This configuration ensures efficient oil displacement while balancing the economic utilization of CO_2.

(3) The optimized CO_2-WAG scheme achieves the dual objectives of improving crude oil recovery and promoting carbon sequestration. Under the optimal scheme, a CO_2 macro sequestration efficiency of 34.19% was achieved, demonstrating that this integrated "fracturing–gas injection–sequestration" development strategy can serve as a feasible technical path for the green and efficient development of similar ultra-low permeability reservoirs.

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