

Article

Optimization of CO₂ Flooding Strategies for an Undeveloped Chang 8 Tight Oil Reservoir in the Ordos Basin, China

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Abstract

The Chang 8 tight oil reservoir in the Xifeng area of the Ordos Basin is characterized by poor reservoir properties, making conventional water flooding ineffective for efficient reservoir development. CO₂ flooding is therefore considered an important approach for enhancing oil recovery in tight reservoirs. However, suitable development strategies for direct CO₂ injection in undeveloped reservoir areas remain insufficiently understood. In this study, compositional numerical simulation combined with a single-factor sensitivity analysis was employed to investigate the effects of key parameters, including well pattern configuration, fracturing parameters, injection–production strategy, and gas injection modes. The results indicate that an inverted nine-spot well pattern with vertical well injection and vertical well production, a well spacing of 500 m, and a row spacing of 200 m can achieve relatively favorable areal and vertical sweep performance. A fracture half-length of 80 m, fracture widths of 0.003–0.005 m, and fracturing treatment before initial production help balance early-stage productivity and gas channeling control. Maintaining an injection rate of 0.03–0.04 PV/a, an oil production rate of 2–3 m³/d, and a bottomhole flowing pressure of 13–14 MPa is beneficial for maintaining reservoir energy and stabilizing displacement-front propagation. Based on neighboring field development experience, switching from continuous CO₂ injection to water–alternating–gas (WAG) injection during the mid-development stage can improve mobility control and enlarge the CO₂ swept volume. Under the current geological model and simulation conditions, the recommended development strategy predicts a recovery factor of 35.43% over a 30-year production period. The results provide reasonable parameter ranges and an engineering reference for direct CO₂ flooding development in the Chang 8 tight oil reservoir and similar reservoirs.



Academic Editor: Mofazzal Hossain

Received: 25 April 2026

Revised: 27 May 2026

Accepted: 10 June 2026

Published: 13 June 2026

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Keywords: tight oil reservoir; CO₂ flooding; direct injection; numerical simulation; parameter optimization; recovery factor prediction

1. Introduction

The Ordos Basin is a major oil and gas production base in China, where low-grade petroleum resources, such as low-permeability and tight reservoirs, are increasingly becoming crucial for safeguarding national energy security and sustaining stable oil and gas output [1]. However, these reservoirs are characterized by low porosity, low permeability,

and strong heterogeneity, with well-developed natural and induced fractures [2]. Such reservoirs exhibit a recovery factor of merely 5–10% under natural energy development, while conventional water flooding still encounters issues including high injection pressure, limited sweep efficiency, and marginal improvement in oil recovery [3]. A significant amount of residual oil remains unrecovered in the reservoir and cannot be effectively produced. Consequently, it is necessary to explore efficient enhanced oil recovery (EOR) techniques that are better suited to the characteristics of tight oil reservoirs.

CO₂ is characterized by low viscosity, strong diffusivity, and favorable injectivity, enabling it to readily penetrate the micropore throats of low-permeability and tight reservoirs. It can also reduce crude oil viscosity, improve the mobility ratio, and supplement reservoir energy [4,5]. Under reservoir temperature and pressure conditions, CO₂ can readily develop near-miscible or miscible displacement with crude oil, thereby enhancing microscopic oil displacement efficiency [6]. In recent years, extensive studies have been conducted worldwide on the mechanisms, displacement characteristics, and development modes of CO₂ flooding in tight oil reservoirs [7–9]. However, most existing studies have focused on CO₂ injection implemented during the middle and late stages of waterflooding development [10–12], while relatively limited attention has been paid to the direct application of CO₂ flooding in undeveloped tight oil reservoirs. In particular, studies on the optimization of development parameters under original reservoir conditions in undeveloped areas remain insufficient.

Compared with CO₂ flooding implemented after waterflooding in mature oilfields, the direct application of CO₂ flooding in undeveloped reservoirs offers several advantages. On the one hand, the original formation pressure, intact reservoir energy, and undisturbed fluid distribution are conducive to establishing a stable displacement pressure field during the initial stage of development, while avoiding common issues associated with CO₂ injection following the middle and late stages of waterflooding, such as aggravated reservoir heterogeneity, fragmented residual oil distribution, and reservoir energy depletion. On the other hand, the absence of fixed well pattern deployment and reservoir stimulation schemes provides greater flexibility for optimizing CO₂ flooding development parameters. However, CO₂ flooding development is highly sensitive to parameters such as well pattern deployment, fracturing scale, injection–production strategy, and gas injection mode, all of which collectively influence displacement front stability, sweep efficiency, and gas channeling behavior [13–15]. Owing to the lack of production performance data in undeveloped reservoirs, the optimization of development parameters is considerably more challenging than that in adjustment reservoirs with a prior waterflooding history.

At present, studies on the direct implementation of CO₂ flooding in undeveloped tight oil reservoirs still lack parameter analysis of key engineering parameters, particularly regarding the coupled effects of well pattern deployment, fracturing parameters, injection–production strategy, and gas injection mode. Unlike conventional research approaches focused on CO₂ injection following waterflooding, this study is based on the original formation energy, native seepage conditions, and undeveloped well pattern configuration of undeveloped tight oil reservoirs. Focusing on the optimization of development parameters for direct CO₂ flooding in undeveloped areas, the effects of well pattern configuration and well spacing, fracturing parameters, injection–production strategy, and gas injection mode on recovery factor, formation pressure maintenance, and gas channeling behavior are investigated in detail, aiming to address the current lack of research on CO₂ flooding development parameters in undeveloped tight oil reservoirs.

Based on this, an undeveloped area of the Chang 8 tight oil reservoir in the Xifeng Oilfield, Ordos Basin, was selected as the study target. A three-dimensional compositional numerical simulation model was established, and a single-factor control variable method

was employed to optimize well pattern configuration and well spacing, fracturing parameters, and injection–production strategy, as well as to compare different gas injection modes. On this basis, recommended ranges of development parameters suitable for the direct implementation of CO₂ flooding in the study area were proposed. The research results can provide technical references for CO₂ flooding development in similar undeveloped tight oil reservoirs.

2. Geological Model and Numerical Simulation Methods

2.1. Geological Model Construction

The target reservoir is the Chang 8₁ reservoir located in an oilfield in the western part of the Ordos Basin. The main sand body of the pay zone extends in a northeast–southwest direction, and the overall structure dips westward. The average burial depth is 2095 m, with an average drilled thickness of 9.3 m. The original formation pressure is 18.5 MPa, and the reservoir temperature is 71.4 °C. The reservoir is relatively well developed and stable in the eastern part, with a thickness of approximately 15 m, while it thins to about 7.5 m in the western part. The geological profile is shown in Figure 1. Exploration wells have been completed in this reservoir, and no development activities have yet been carried out.

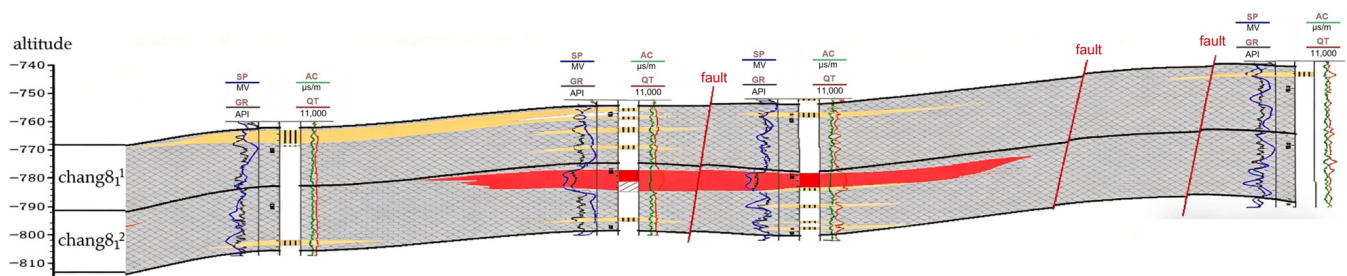


Figure 1. Geological profile of the study area.

To optimize the CO₂ flooding development strategy for the undeveloped area, a three-dimensional geological model of a typical well group was established using CMG (version 2024.20) based on logging data from exploration wells and relevant geological parameters, aiming to accurately characterize the geological features of the study block. The model adopts a Cartesian grid system, with the principal grid orientation set to NE 67.5° according to the dominant direction of natural fractures. The horizontal grid size is 25 m × 25 m, and the vertical grid resolution is 0.5 m. The typical well-group model contains 53 × 45 × 11 grids (approximately 2.6 × 10⁴ cells), including about 2.3 × 10⁴ active grid cells (Figure 2).

The Chang 8₁ reservoir can be subdivided into two sublayers, namely Chang 8₁¹ and Chang 8₁². In the model, the porosity of Chang 8₁¹ ranges from 1.1% to 16.2%, with an average of 8.6%, while the permeability ranges from 0.01 to 2.65 mD. For Chang 8₁², the porosity ranges from 2.9% to 12.0%, with an average of 8.1%, and the permeability ranges from 0.01 to 1.34 mD. The overall average permeability of the model is 0.43 mD, with an average porosity of 8.3% and an effective thickness ranging from 8 to 15 m.

Considering that the fracture width is much smaller than the grid size of the model, a macroscopic equivalent method based on permeability multiplication was adopted to characterize hydraulic fractures. The enhanced conductivity of the fractured reservoir was represented by equivalently increasing the permeability of grids within fracture-developed regions.

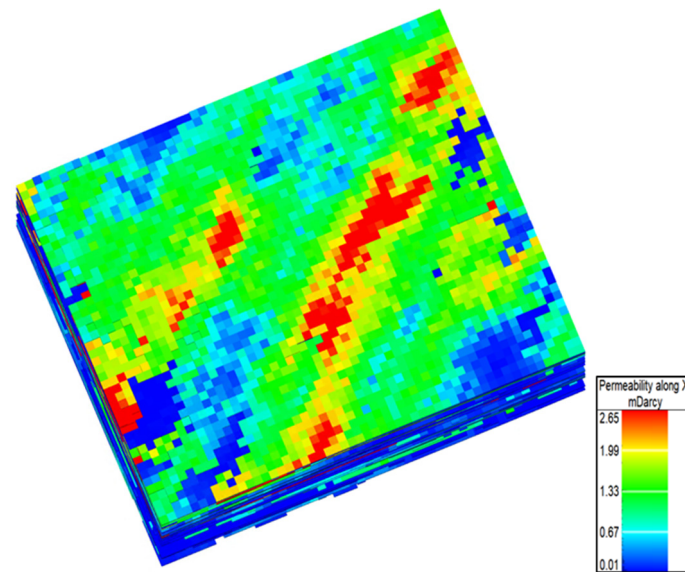


Figure 2. Three-dimensional permeability field of the typical well pattern model.

2.2. Fluid Model Construction

Referring to the crude oil PVT properties, CO₂ swelling experiments, and slim-tube test results from adjacent reservoirs, the saturation pressure of the formation crude oil is 12.14 MPa, the crude oil density under reservoir conditions is 0.7494 g/cm³, the original gas–oil ratio is 89 m³/m³, the crude oil viscosity is 1.05 mPa·s, and the minimum miscibility pressure (MMP) is 18.87 MPa [16]. Fluid phase behavior was characterized using the Peng–Robinson equation of state (EOS), and pseudo-component lumping, EOS parameter regression, and phase behavior matching were conducted using the WinProp module in CMG.

Considering both computational efficiency and phase behavior characterization accuracy, the reservoir fluid was lumped into seven pseudo-components: CO₂, C₁, C_{2–4}, C_{5–7}, C_{8–12}, C_{13–20}, and C₂₁₊. Previous studies on similar tight oil reservoirs have demonstrated that the content of resins and asphaltenes in heavy fractions significantly affects the swelling behavior and miscibility characteristics of the CO₂–crude oil system, and inappropriate lumping of heavy fractions may lead to deviations in phase behavior prediction [17]. Therefore, rather than relying solely on theoretical lumping methods, this study calibrated the EOS model using laboratory PVT experimental data.

In WinProp, the EOS model was comprehensively tuned by adjusting the critical properties, acentric factors, and binary interaction coefficients of the pseudo-components. The calibration was based on flash tests, constant composition expansion tests, differential liberation tests, and gas injection swelling tests. In addition, the MMP value (18.87 MPa) determined from slim-tube experiments was used to constrain the miscibility behavior. The final calibrated model can reasonably characterize the phase behavior of the CO₂–crude oil system under reservoir conditions.

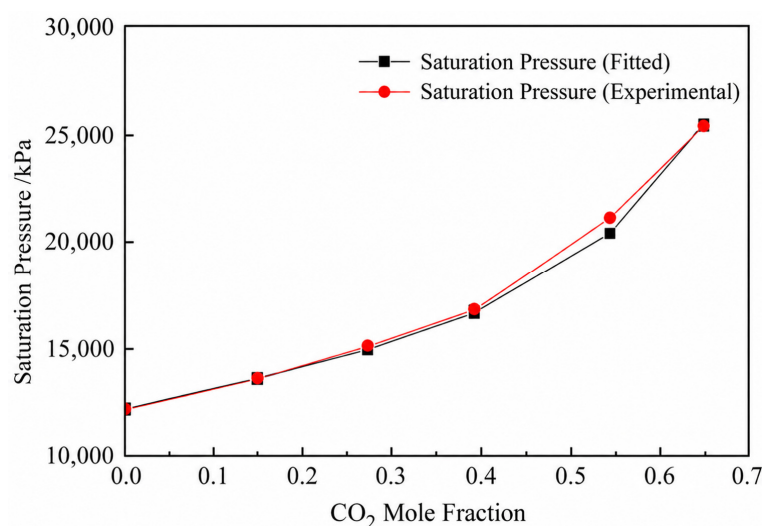
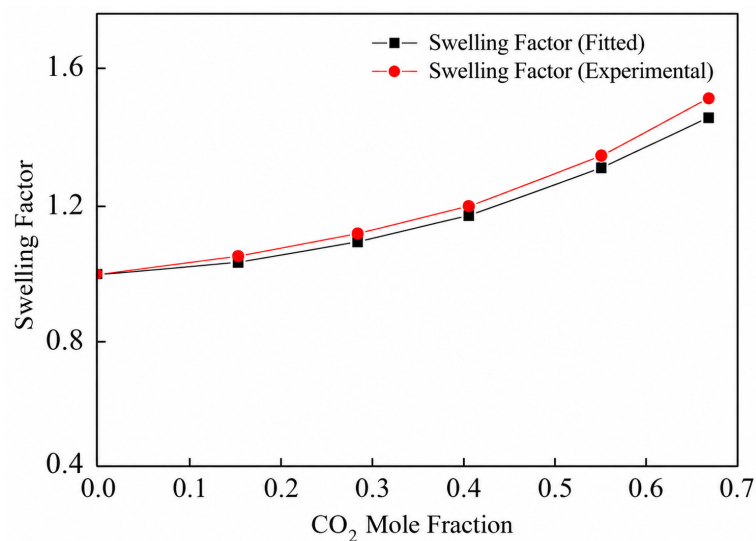
The final matching results are presented in Tables 1 and 2, while the fitting results of the CO₂ swelling factor, saturation pressure, and slim-tube MMP tests are shown in Figures 3 and 4. The simulation errors of key PVT parameters were controlled within 3.5%, indicating that the adopted pseudo-component lumping strategy and EOS parameterization method can satisfy the requirements of subsequent compositional numerical simulation studies.

Table 1. Properties of reservoir oil after history matching.

Density (kg/m ³)	Viscosity (mPa·s)	Saturation Pressure (MPa)	GOR (m ³ /m ³)	Cricondentherm (°C)	Cricondenbar (MPa)	Critical Temperature (°C)	Critical Pressure (MPa)
749.4	1.07	12.06	92	483.35	19.22	423.21	14.22

Table 2. Fitting results of pseudo-component characteristic parameters of reservoir fluids.

Component	Mole Fraction	Molar Mass	Critical Pressure (atm)	Critical Temperature (K)	Acentric Factor	OmegaA	OmegaB
CO ₂	0.00	44.01	72.8	304.2	0.2250	0.4448	0.0650
C ₁	0.3999	16.04	45.4	190.6	0.0080	0.4572	0.0779
C ₂₋₄	0.1127	44.47	42.26	272.10	0.1490	0.4572	0.0777
C ₅₋₇	0.1201	86.34	30.06	403.02	0.2820	0.4602	0.0776
C ₈₋₁₂	0.1927	101.09	27.44	738.05	0.4120	0.6083	0.1030
C ₁₃₋₂₀	0.1328	208.86	24.57	776.51	0.5510	0.4389	0.0699
C ₂₁₊	0.0416	910.50	20.91	1196.66	0.9350	0.2926	0.0943

**Figure 3.** CO₂ injection saturation pressure fitting.**Figure 4.** CO₂ swelling factor fitting.

The oil–water and gas–oil relative permeability curves utilized in the model are shown in Figures 5 and 6. The data were obtained from laboratory relative permeability experiments conducted on core samples from the target block, reflecting the typical seepage characteristics of the ultra-low permeability reservoir in the study area.

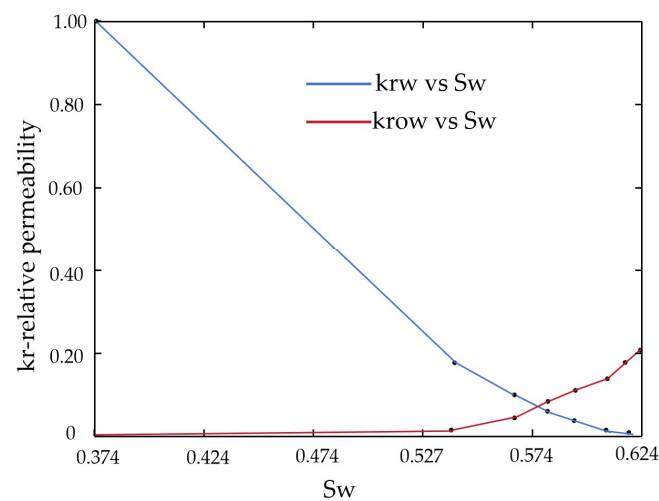


Figure 5. Oil–water relative permeability curves.

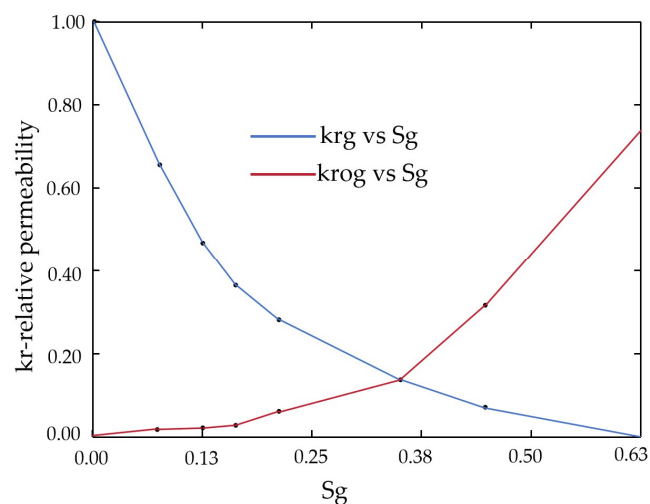


Figure 6. Gas–oil relative permeability curves.

The oil–water relative permeability curves indicate that the irreducible water saturation reaches 37.4%, suggesting that effective oil displacement by water injection requires relatively high injection volumes. The two-phase flow region is relatively narrow, and the oil relative permeability (k_{row}) decreases rapidly with increasing water saturation, whereas the water relative permeability (k_{rw}) increases slowly and exhibits a relatively low endpoint value. Overall, these characteristics indicate weak oil–water co-flow capacity and highlight the inherent limitations of waterflooding development in ultra-low permeability reservoirs.

In contrast, the gas–oil relative permeability curves exhibit a significantly broader two-phase flow region and a higher endpoint gas relative permeability (k_{rg}), while the decline in oil relative permeability (k_{rog}) is comparatively more gradual. These characteristics indicate a wider oil–gas co-flow interval and stronger gas-phase seepage capacity under gas flooding conditions, directly demonstrating that gas injection development has greater advantages than waterflooding in improving displacement efficiency.

2.3. Numerical Experiment Design

To investigate the effects of key engineering parameters, such as well pattern deployment, fracturing parameters, injection–production parameters, and gas injection modes, on the performance of CO₂ flooding, a series of numerical experiments were performed based on the base model using the single-factor control variable method. The parameter ranges were primarily determined according to the actual geological conditions of the study area, development experience from similar tight oil reservoirs in the Ordos Basin, and previous research results, and were further adjusted considering engineering feasibility. While keeping all other factors constant, sensitivity analyses were conducted by varying one parameter at a time to quantify the influence of each factor on development performance. All experimental variables and comparative schemes are summarized in Table 3.

Table 3. Design of numerical simulation cases for CO₂ flooding.

Case No.	Category	Optimization Variable	Cases
1	well pattern deployment	Well pattern type	Inverted 5-spot, 7-spot, and 9-spot patterns under vertical-well injection with vertical-well production; inverted 5-spot, 7-spot, and 9-spot patterns under vertical-well injection with horizontal-well production
2		Well spacing and row spacing (m)	300-150, 300-200, 400-150, 400-200, 500-150, 500-200
3	Fracturing parameters	Fracture half-length (m)	50, 80, 100, 120
4		Fracture width (m)	0.001, 0.003, 0.005, 0.007
5		Fracturing timing (months)	0, 3, 6, 9, 12
6	Injection–production parameters	Single-well injection rate (PV/year)	0.02, 0.03, 0.04
7		Single-well oil production rate (m ³ /d)	2, 3, 4, 5
8		bottomhole flowing pressure (MPa)	12, 13, 14, 15
9		Perforation placement	Top injection–bottom production; commingled injection–production; bottom injection–top production
10	Gas injection modes		Continuous gas injection; intermittent gas injection; WAG injection

3. Results and Discussion

3.1. Well Type and Well Pattern Optimization

3.1.1. Well Pattern

To determine the reasonable well pattern, this study compared three patterns, namely inverted 5-spot, inverted 7-spot, and inverted 9-spot well patterns, under two development modes: vertical well injection with vertical well production and vertical well injection–horizontal well production. The results of Case 1 (Figure 7) indicate that the inverted 9-spot well pattern with vertical well injection and vertical well production is more favorable for overall development performance. It maintains a relatively high daily oil rate during the early production stage and exhibits superior reservoir pressure maintenance, the slowest increase in gas–oil ratio, the latest CO₂ breakthrough time, and the highest ultimate recovery factor over the long term. This advantage results from improved vertical and areal sweep efficiency. Vertically, vertical wells penetrate multiple layers, effectively overcoming the

strong vertical heterogeneity caused by interlayers in the study area [18], thereby providing a geological basis for efficient vertical sweep. Laterally, the inverted nine-spot well pattern, characterized by a larger drainage area and a greater number of producing wells, effectively distributes injected gas and mitigates channeling, thus maximizing the sweep volume. In contrast, although the vertical well injection–horizontal well production mode yields higher initial production due to the larger contact area of horizontal wellbores, the injected CO₂ is severely restricted by interlayers in the vertical direction [19], making it difficult to effectively displace oil beyond the interval penetrated by the horizontal well. This results in accelerated gas channeling, poorer pressure maintenance, and lower recovery factor in the later stage. Considering reservoir adaptability and the stability of development performance, the inverted 9-spot well pattern with vertical well injection–vertical well production is identified as the reasonable well pattern for CO₂ flooding in the study area.

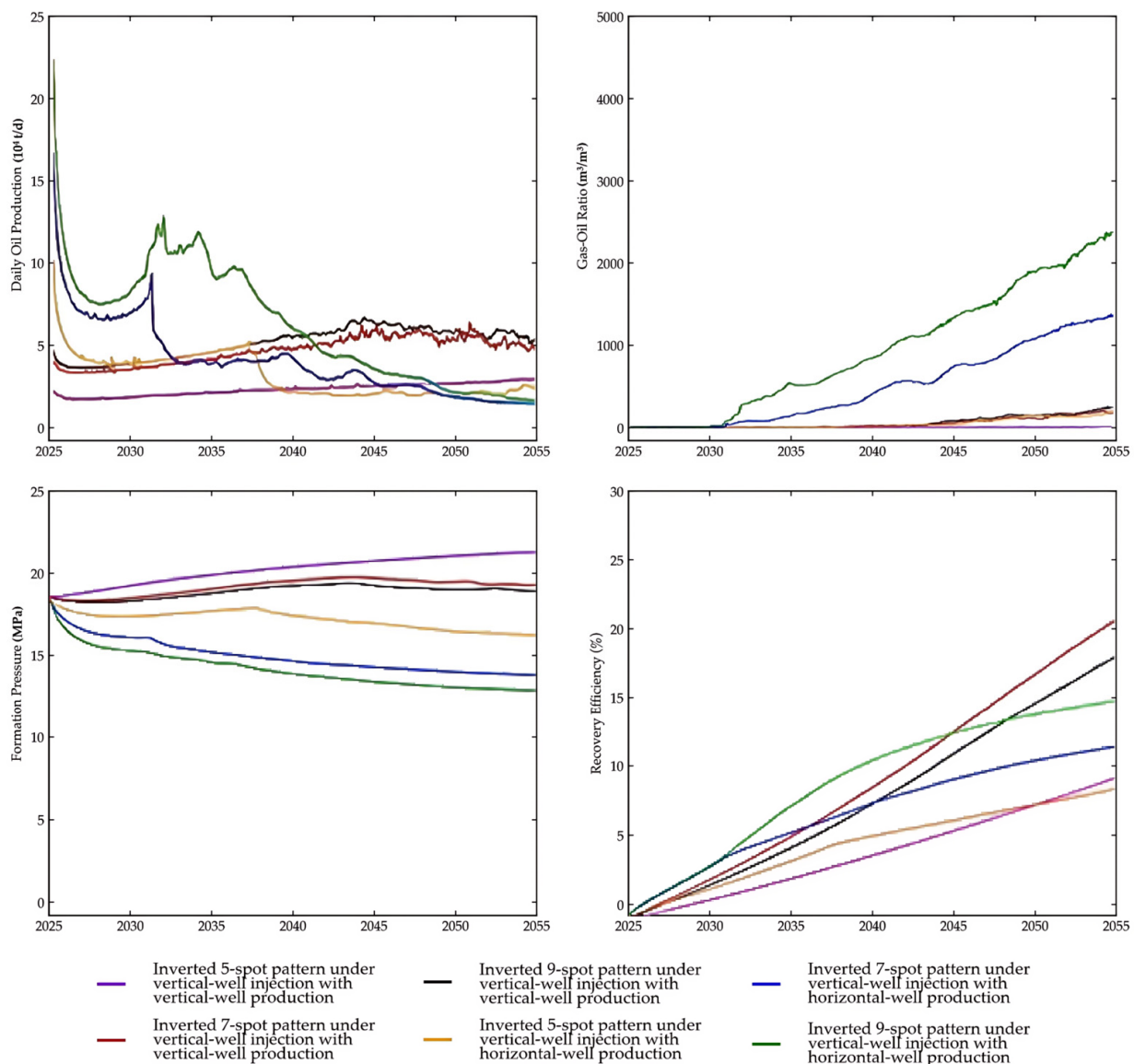


Figure 7. Comparison of development performance under different well patterns within a 30-year development.

3.1.2. Well Spacing and Row Spacing

Based on the inverted nine-spot well pattern with vertical well injection–vertical well production, Case 2 evaluated six combinations of well spacing and row spacing

(Figure 8). The results indicate that smaller spacing combinations can achieve a rapid increase in initial oil production due to shorter displacement distances; however, they also lead to early CO₂ breakthrough and a sharp rise in the gas–oil ratio, resulting in rapid reservoir pressure depletion and a shortened stable production period, ultimately limiting the recovery factor [20]. In contrast, larger spacing combinations exhibit a slower increase in initial production, but the extended injection–production distance enlarges the sweep volume within the controlled area, reduces the displacement pressure gradient, and prolongs the contact and mass transfer time between CO₂ and crude oil. This effectively delays gas channeling [21], resulting in a smoother gas–oil ratio curve and improved reservoir pressure maintenance, thereby achieving a longer stable production period and higher ultimate recovery factor. Therefore, a well spacing of 500 m and a row spacing of 200 m are recommended for the study area.

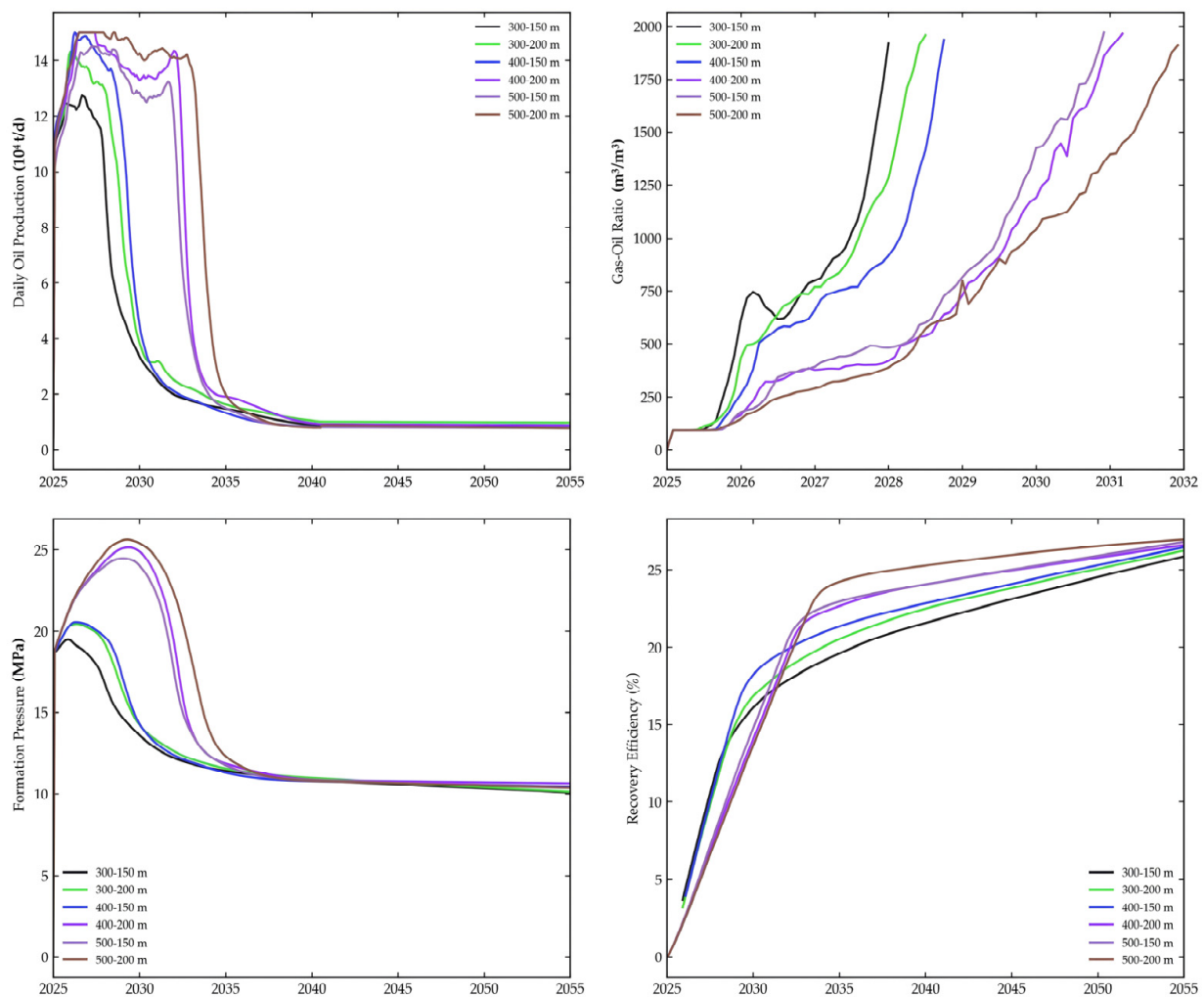


Figure 8. Comparison of development performance under different well and row spacing combinations.

3.2. Fracturing Parameter Optimization

3.2.1. Fracture Half-Length

After determining the well pattern and spacing, optimization of fracturing parameters was carried out. Simulations were conducted with varying fracture half-lengths. The results of Case 3 (Figure 9) indicate that excessively long fractures significantly enhance early oil production; however, they also increase the risk of early CO₂ channeling along high-conductivity pathways. This leads to premature gas channeling, a rapid rise in the gas–

oil ratio, accelerated reservoir pressure depletion, and ultimately a reduction in recovery factor [22]. When the fracture half-length is 50 m, reservoir pressure is best maintained and the gas–oil ratio increases most slowly; however, the contribution to initial productivity is limited. In contrast, the 80 m case achieves a favorable balance, maintaining relatively high initial oil production while exhibiting a gradual increase in gas–oil ratio and a slower decline in reservoir pressure, resulting in a higher ultimate recovery factor. Therefore, a fracture half-length of 80 m is recommended to achieve a balance between productivity enhancement and gas channeling control.

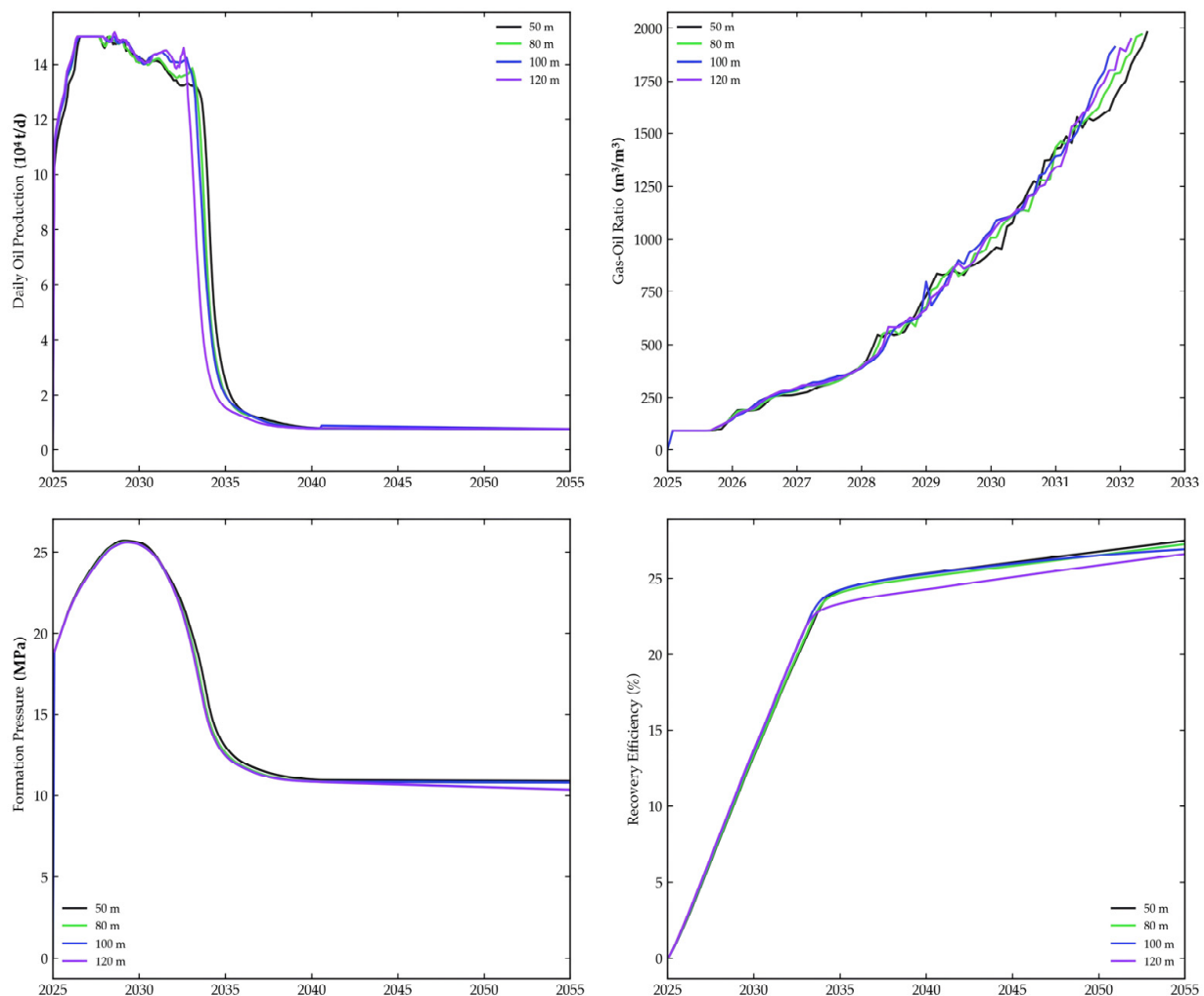


Figure 9. Development performance under different fracture half-lengths.

3.2.2. Fracture Width

Regarding fracture width, Case 4 (Figure 10) shows that an excessively large fracture width (0.007 m), despite providing extremely high fracture conductivity, leads to rapid reservoir depletion and poor pressure maintenance, ultimately resulting in lower recovery factor. Conversely, a very small fracture width (0.001 m) enhances reservoir pressure maintenance during the early stage but restricts fluid flow [23], making the system more prone to gas channeling in the middle and late stages, thereby negatively affecting development performance. Results show that fracture widths of 0.003 m and 0.005 m yield nearly identical development indicators and exhibit the most favorable production behavior. They ensure relatively high initial productivity and a prolonged stable production period, while effectively maintaining a reasonable pressure level and moderating the increase in gas–oil

ratio, ultimately achieving the highest recovery factor. To balance early productivity and long-term energy sustainability, fracture widths of 0.003–0.005 m are recommended.

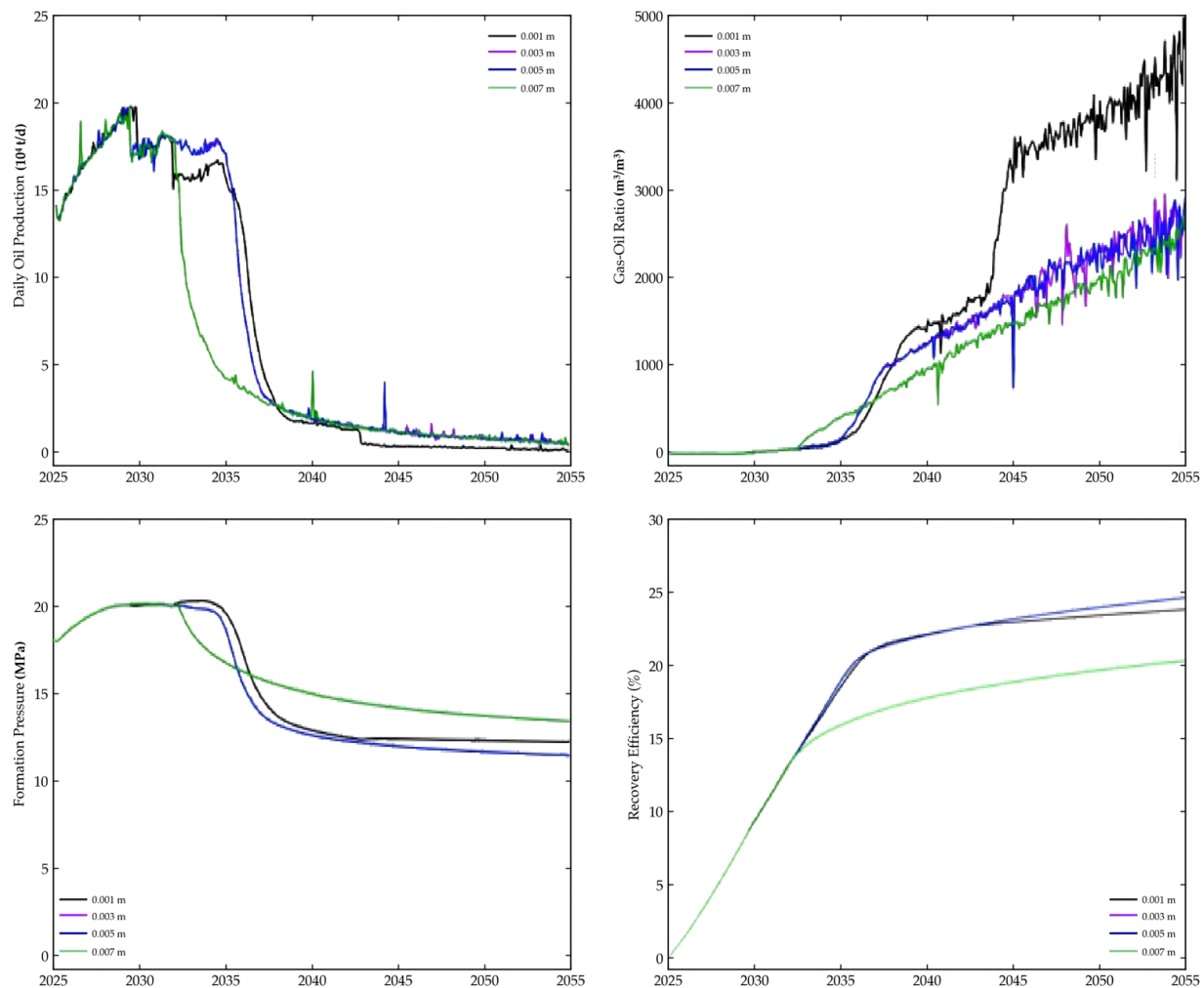


Figure 10. Development performance under different fracture widths.

3.2.3. Fracturing Timing

Based on the numerical simulations of Case 5 concerning fracturing timing, the effects of implementing fracturing at different time points after production initiation on CO₂ flooding performance were analyzed (Figure 11). The results indicate that earlier fracturing leads to better overall performance. When fracturing is conducted immediately upon production start (0 month), the abundant initial reservoir energy facilitates the formation of a complex fracture network with a large stimulated reservoir volume [24]. This highly effective fracture system significantly increases the contact volume between CO₂ and crude oil and promotes more uniform displacement. As a result, production performance exhibits better reservoir pressure maintenance, a noticeable delay in gas channeling, and consistently low gas–oil ratios throughout the production cycle, ultimately yielding the highest cumulative recovery factor. In contrast, delaying the timing of fracturing leads to inferior performance. Due to prior depletion of reservoir energy and the resulting changes in effective stress, fracture propagation becomes increasingly constrained, resulting in a significant reduction in the effective stimulated reservoir volume. The inability to establish a stable displacement flow field under low-pressure conditions makes the system more susceptible to CO₂ channeling. This is reflected in rapid reservoir pressure depletion and an uncontrolled rise in gas–oil ratio, which severely limits the ultimate development performance.

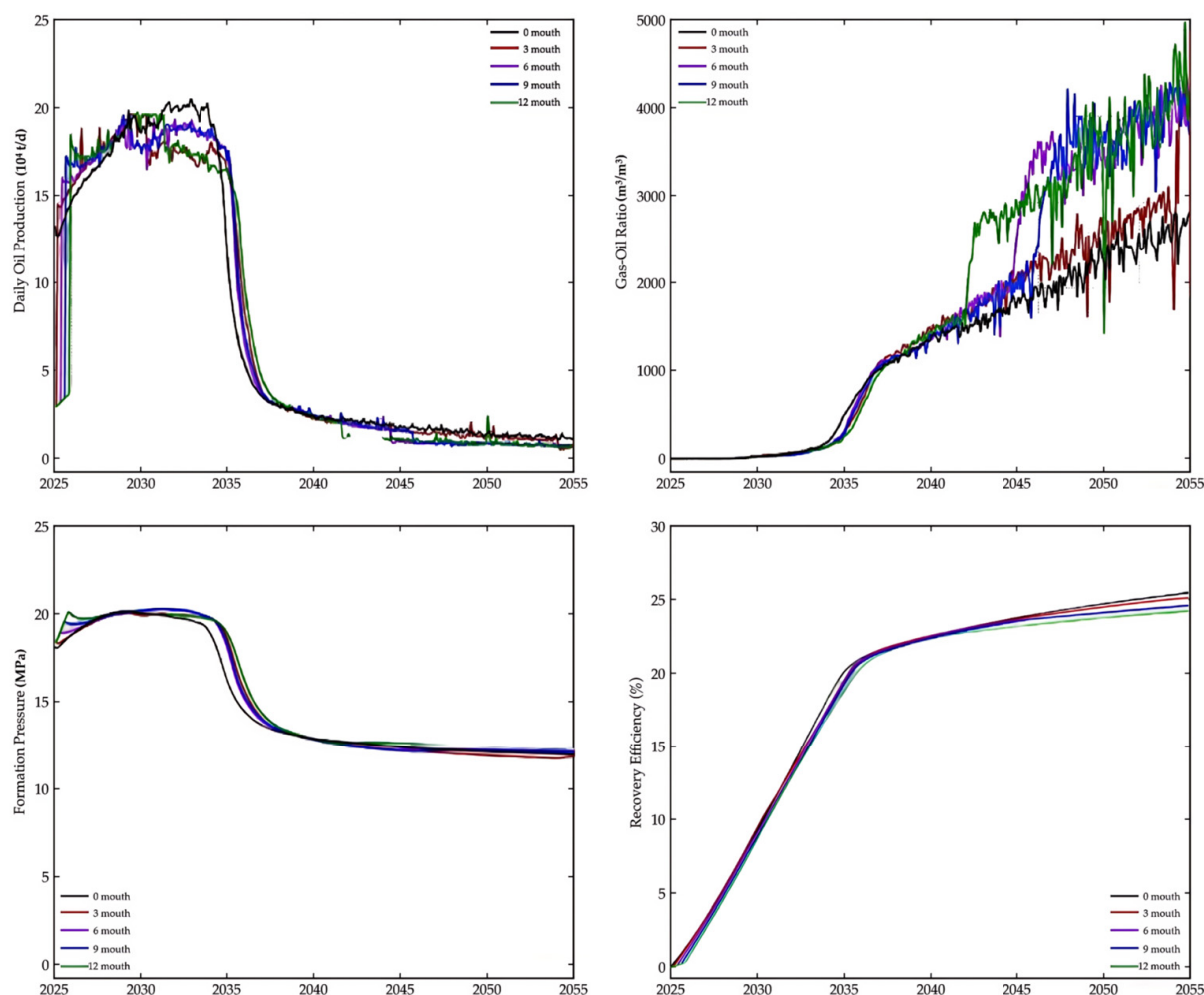


Figure 11. Effect of fracturing timing on development performance.

3.3. Dynamic Optimization of Injection–Production Parameters

3.3.1. Injection Rate Optimization

Injection rate is a key parameter that controls both the rate of reservoir energy replenishment and the displacement driving force during CO₂ flooding. The results of Case 6 indicate that higher injection rates lead to a more rapid increase in initial daily oil production and better reservoir pressure maintenance (Figure 12). When the injection rate exceeds 0.03 PV/year, the stable production period is further extended. The underlying mechanism is that a higher injection rate can promptly supplement reservoir energy [25]. Meanwhile, sufficient energy support enhances the maintenance of a reasonable pressure differential at production wells, thereby sustaining higher oil production rates and enhancing production stability. However, excessively high injection rates may intensify viscous fingering and gravity override of CO₂ [26], which could increase the risk of earlier gas channeling in the long term. Considering injection practices in other oilfields together with the simulation results, it is recommended that the single-well CO₂ injection rate in the Xifeng area be controlled at 20–30 t/d, corresponding to an injection rate of 0.03–0.04 PV/year.

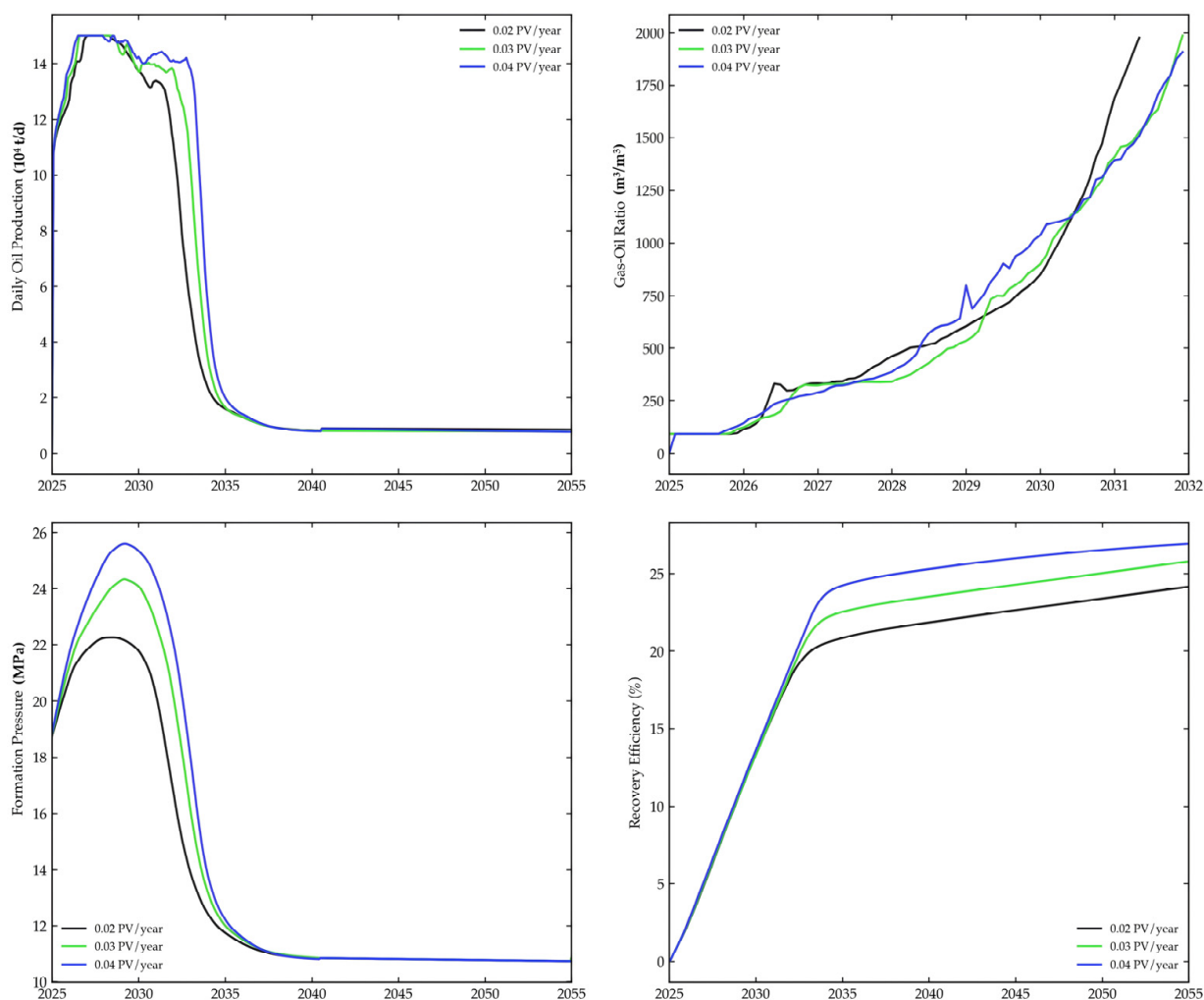


Figure 12. Development performance under different CO₂ injection rates.

3.3.2. Oil Production Rate Optimization

The oil production rate controls the rate of reservoir energy depletion and plays a critical role in determining the duration of the stable production period and the production decline trend. Case 7 compares different single-well oil production rates, showing that higher oil production rates lead to a shorter stable production period, a faster decline rate, and a lower recovery factor. The results indicate that excessively high oil production rates (Figure 13) cause the fluid withdrawal rate to exceed the energy replenished by CO₂ injection, resulting in rapid reservoir energy depletion. This, in turn, shortens the stable production period and reduces recovery factor [27]. In contrast, lower oil production rates allow more sufficient contact between CO₂ and crude oil, enlarging the sweep volume and delaying production decline [28]. An oil production rate in the range of 2–3 m³/d is recommended, as it helps maintain relatively high initial production while avoiding excessive reservoir energy depletion, thereby extending the stable production period and improving overall recovery.

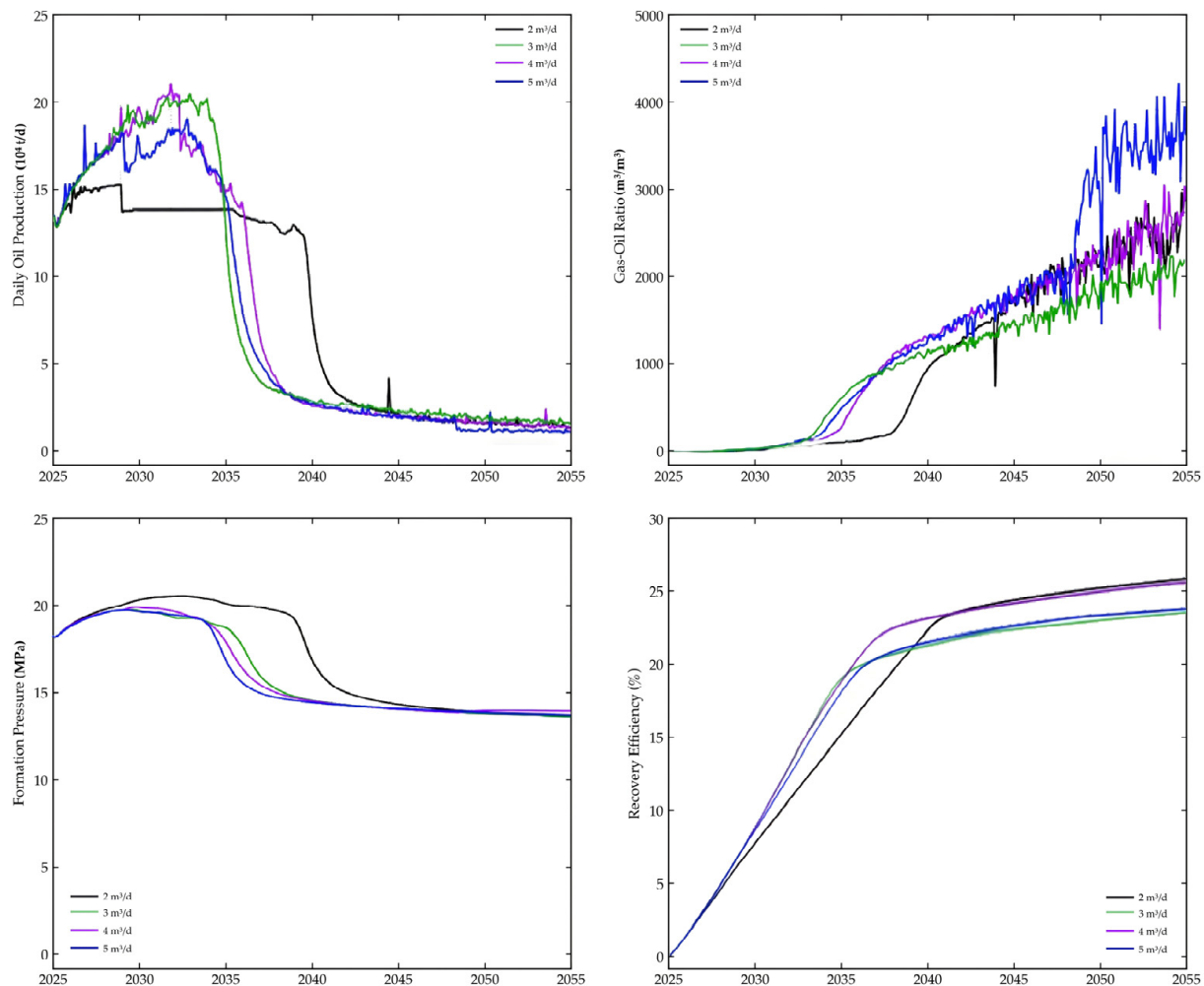


Figure 13. Development performance under different production rates.

3.3.3. Bottomhole Flowing Pressure Control

Case 8 investigated the development performance under different bottomhole flowing pressures set at 0, 1, 2, and 3 MPa above the saturation pressure (corresponding to absolute pressures of 12, 13, 14, and 15 MPa, respectively). The results (Figure 14) show that higher bottomhole flowing pressure leads to lower initial oil production but a slower decline rate in the later stage, better reservoir pressure maintenance, delayed gas channeling, and a significantly higher ultimate recovery factor. This behavior can be explained by the fact that a low bottomhole flowing pressure provides the largest production pressure differential at the early stage, resulting in the highest initial oil production rate. However, it also causes rapid depletion of reservoir energy, leading to a sharp decline in reservoir pressure. Moreover, the pressure near the wellbore can easily drop below the saturation pressure, which triggers substantial CO₂ exsolution and the formation of free gas, which may cause gas blockage near the wellbore and block flow channels [29]. In contrast, higher bottomhole flowing pressure, although yielding lower initial production, enhances reservoir pressure maintenance stability. The smaller pressure differential ensures a more stable displacement front and significantly delays gas channeling, thereby maximizing ultimate recovery factor. Considering the balance among production build-up period, stable production duration, and recovery factor, it is recommended to operate at a bottomhole flowing pressure of 13–14 MPa.

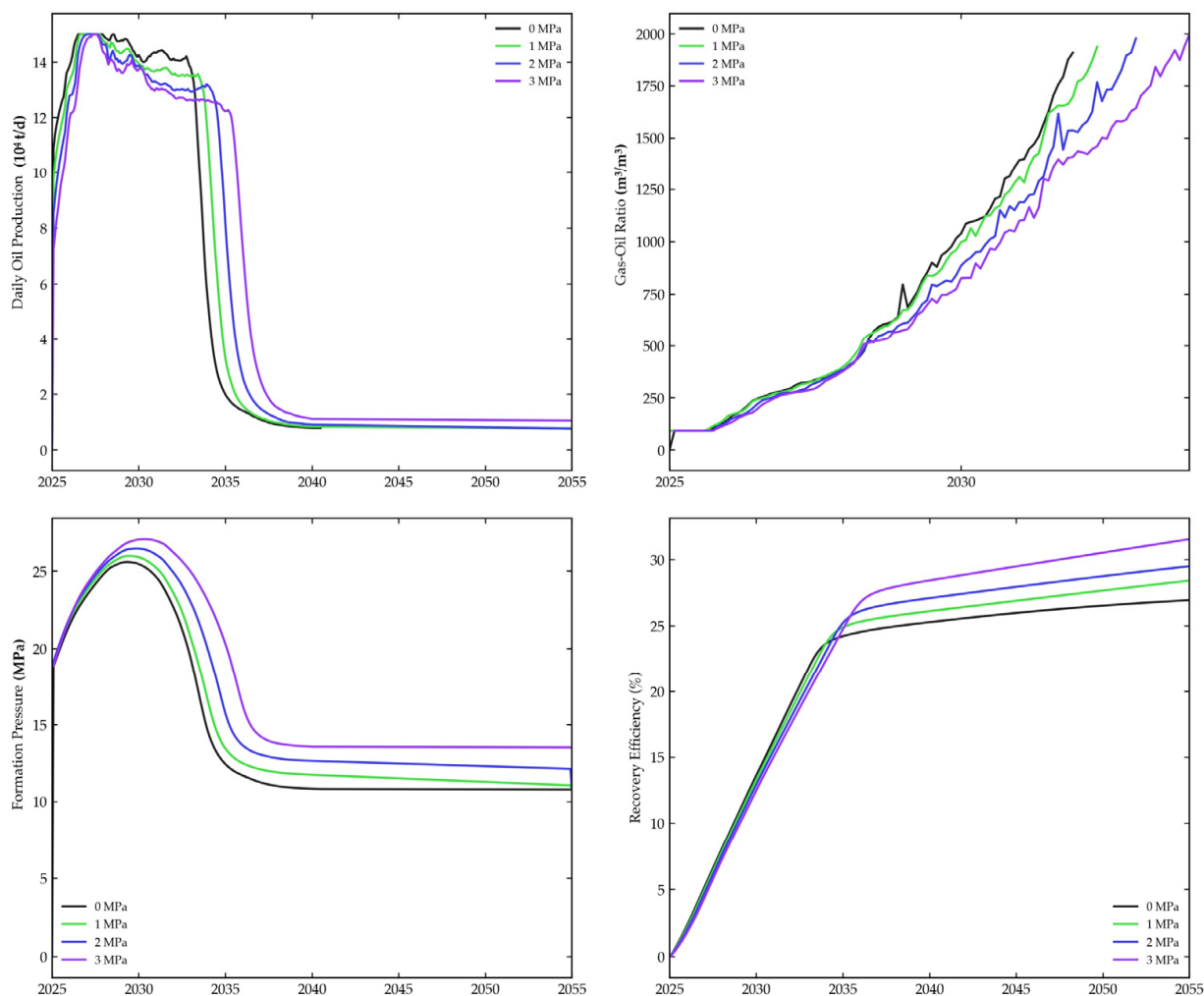


Figure 14. Development performance under different bottomhole pressures.

3.3.4. Perforation Placement Optimization

To optimize the CO_2 displacement pathway, Experiment 9 comparatively investigated three perforation schemes: bottom injection–top production, commingled injection–production, and top injection–bottom production. The simulation results (Figure 15) indicate that the commingled injection–production scheme achieves the best development performance, characterized by a high and stable production profile, a relatively gentle decline rate, the highest ultimate recovery factor, the latest gas breakthrough time, and the most favorable reservoir pressure maintenance. The top injection–bottom production scheme exhibits outstanding early-stage productivity, with the highest daily oil production, the slowest increase in gas–oil ratio, and relatively good reservoir pressure maintenance; however, its ultimate recovery factor is slightly lower than that of the commingled scheme. In contrast, the bottom injection–top production scheme shows the poorest performance across all development indicators.

The oil saturation profiles (Figures 16–18) further compare the sweep characteristics of the three perforation schemes in different reservoir intervals. Under the bottom injection–top production scheme, only the lower reservoir section is effectively swept, whereas the top injection–bottom production scheme mainly mobilizes crude oil in the upper section. In both cases, vertically unswept zones remain due to the sealing effect of interlayers and barriers. By contrast, the commingled injection–production scheme employs perforation across the entire well interval, allowing CO_2 to bypass the constraints imposed by interlayers and effectively sweep the upper, middle, and lower reservoir sections simultaneously, thereby

achieving the most balanced reservoir utilization. These results reveal the fundamental mechanism underlying the superior performance of the commingled injection–production scheme: full-interval perforation is the key to maximizing vertical sweep volume.

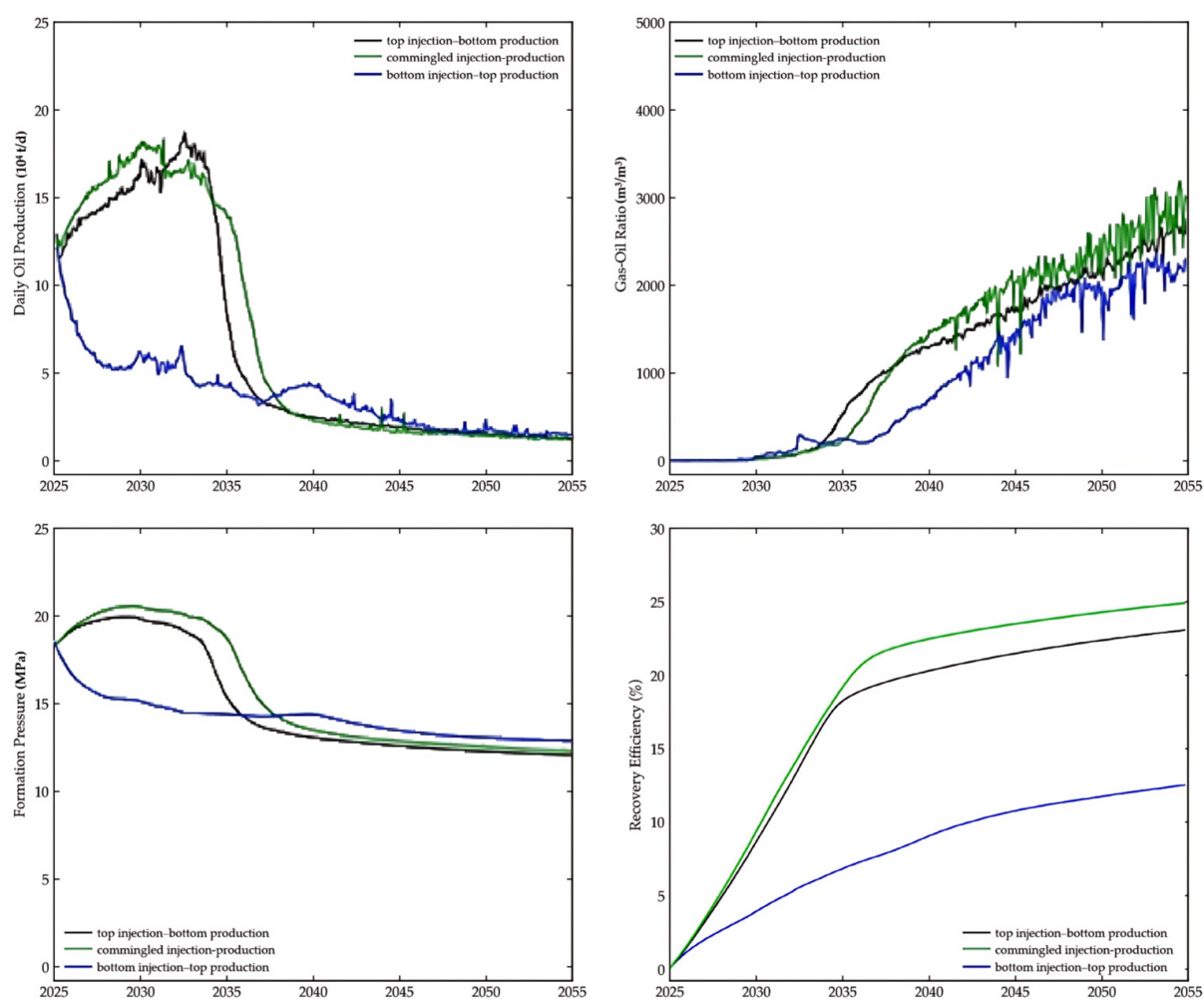


Figure 15. Comparison of development performance under different perforation schemes.

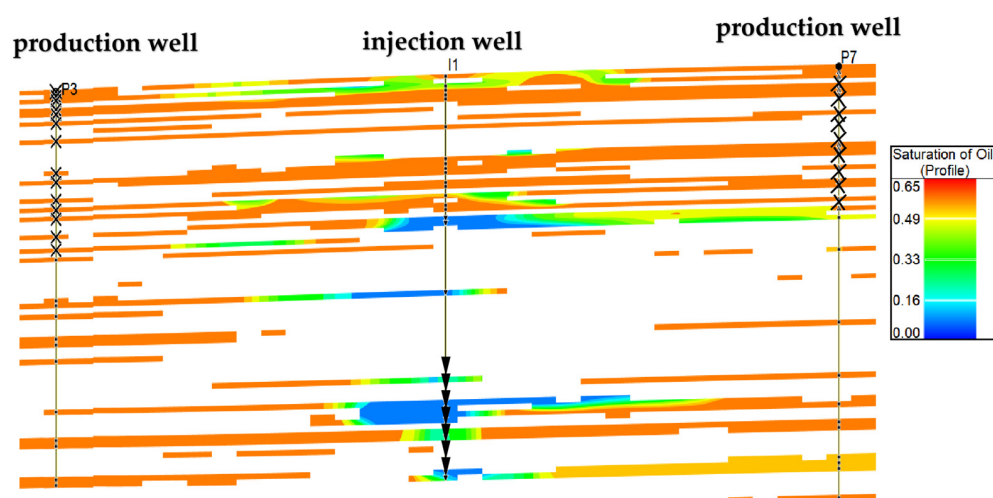


Figure 16. Bottom injection-top production final oil saturation profile.

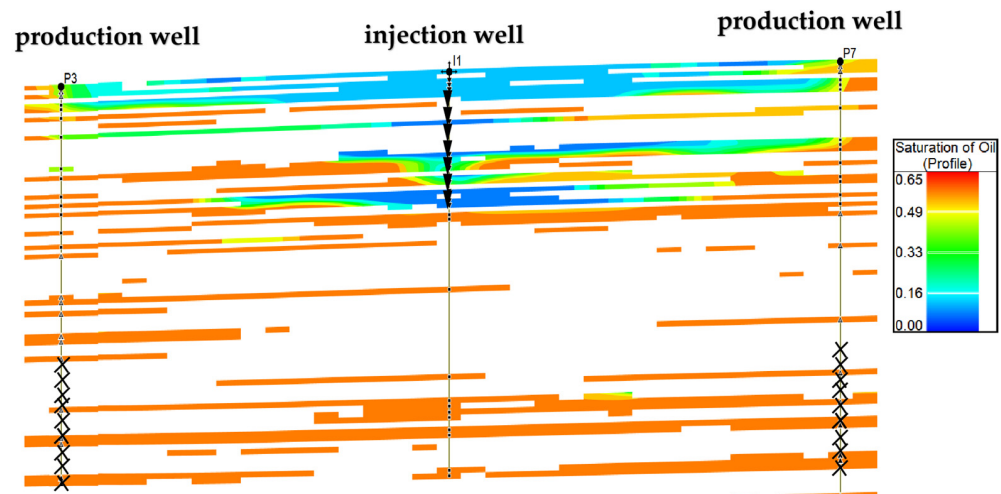


Figure 17. Top injection–bottom production final oil saturation profile.

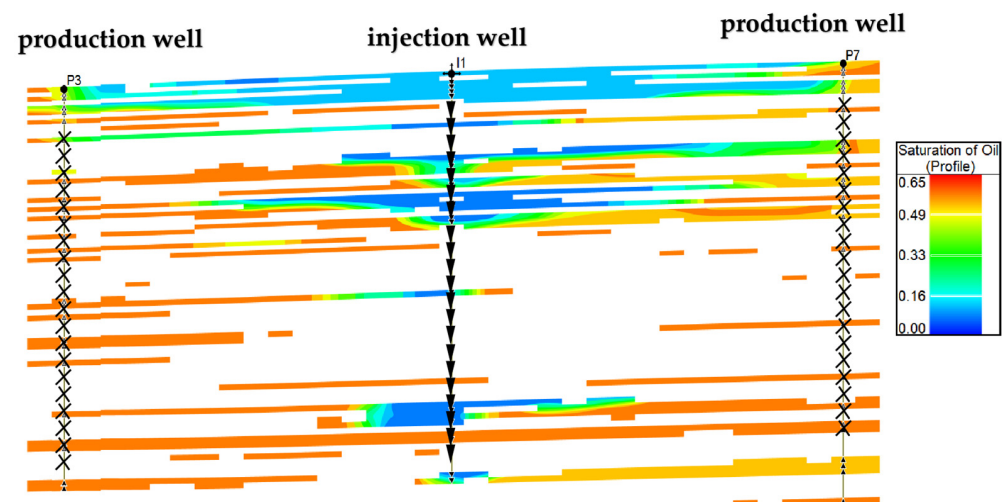


Figure 18. Commingled injection–production final oil saturation profile.

These findings indicate that, although commingled injection–production represents the theoretically optimal static scheme for CO₂ flooding in strongly heterogeneous reservoirs, engineering practice necessitates a comprehensive balance between economic returns and risk mitigation. Given the inherent uncertainty regarding subsurface conditions in undeveloped reservoirs, a dynamic development strategy entailing initial top injection–bottom production followed by subsequent conversion to commingled injection–production is recommended to circumvent development risks. During the initial development phase, top injection–bottom production is employed to achieve rapid production build-up and stable displacement of the top oil layers through gravity segregation at a relatively low cost. Upon the emergence of a distinct inflection point in the gas–oil ratio during the middle to late production stages, timely conversion to commingled injection–production is implemented to overcome interlayer barriers and mobilize oil in the middle and lower intervals, thereby substantially enhancing the vertical sweep efficiency and ultimate economic returns.

3.4. Gas Injection Mode Optimization

The Case 10 experimental scheme was designed to compare three injection modes: continuous gas injection, intermittent gas injection, and WAG injection. Based on neighboring field experience from CO₂ flooding projects, continuous CO₂ injection was applied during the early development stage to rapidly establish the displacement front and supplement formation energy. Beginning in 2028, the development scheme was converted to WAG

injection and intermittent gas injection for comparative analysis. To mitigate the mobility contrast between gas and water phases and suppress preferential CO₂ channeling in low-permeability reservoirs, a small-slug WAG scheme was adopted, with a water–gas ratio of 1:1 and a slug size of 0.01 PV for comparative evaluation of different injection methods [30]. The results (Figure 19) show that, compared with continuous gas injection and intermittent gas injection, the WAG scheme exhibits relatively lower daily oil production during the early stage. However, it can effectively reduce the gas–oil ratio and replenish formation energy, thereby maintaining reservoir pressure at a relatively high level. Consequently, the production decline rate is slower in the later stage, and the final recovery factor is superior to those of the continuous and intermittent gas injection schemes.

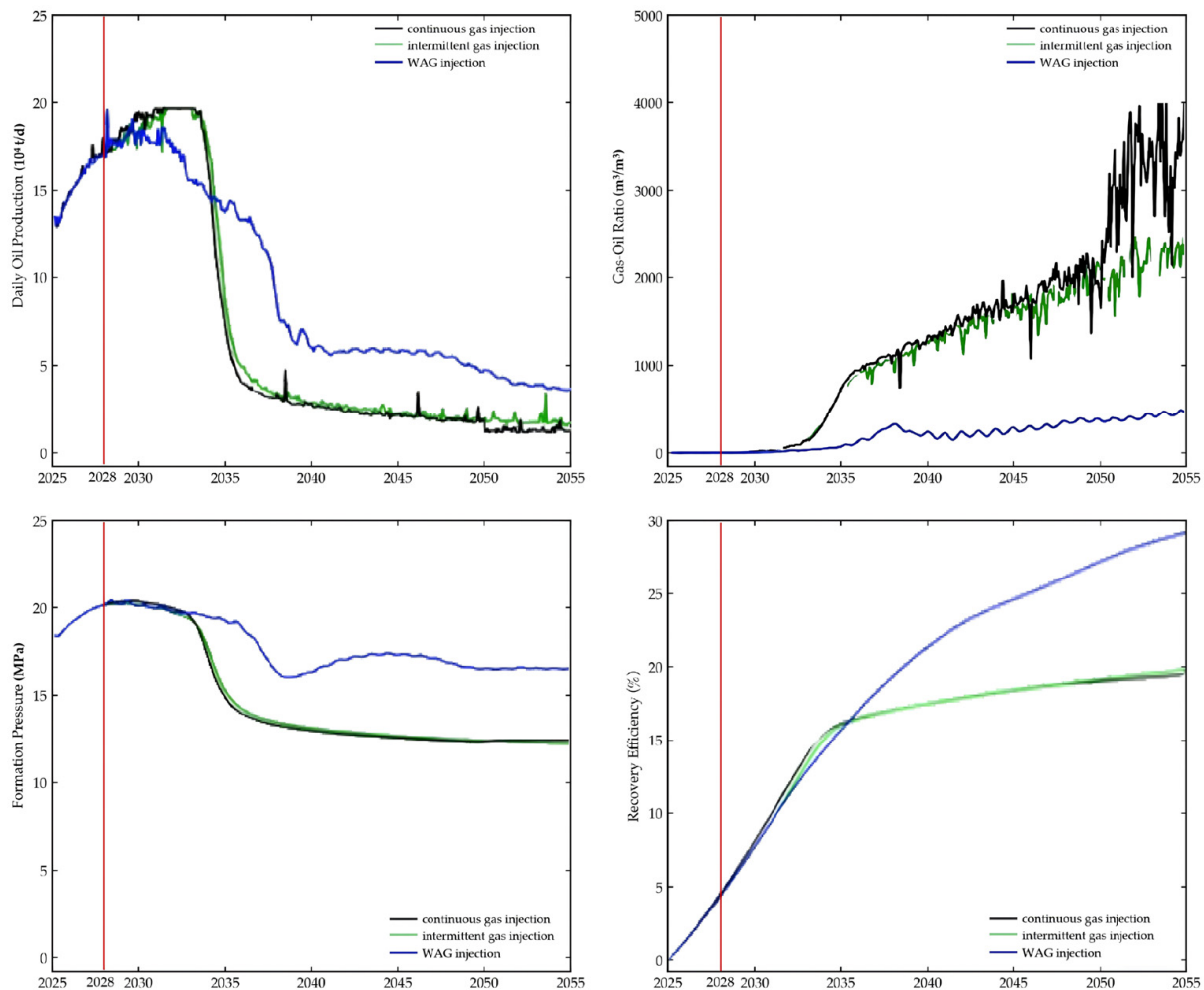


Figure 19. Development performance under different gas injection schemes.

After switching to the WAG development mode, alternating injection of water and CO₂ helps improve the gas–water mobility ratio and mitigate preferential CO₂ flow through high-permeability channels, thereby enlarging the CO₂ sweep volume and slowing the increase in gas–oil ratio [31]. In addition, periodic water injection effectively supplements formation energy and maintains reservoir pressure at a relatively high level [32], which is beneficial for improving displacement efficiency and extending the stable production period. Compared with continuous gas injection, WAG injection can alleviate gas channeling in low-permeability reservoirs to a certain extent and improve reservoir utilization during the later development stage. However, when reservoir properties are poor and water injectivity is insufficient to sustain stable WAG operation, intermittent gas injection is recommended

instead. Considering the overall development performance, WAG injection is preferentially recommended when water injection conditions are favorable.

3.5. Performance Prediction of Optimized Development Scenarios

Based on the optimized development strategy, the predicted development performance for the undeveloped Chang 8 reservoir in the Xifeng Oilfield, Ordos Basin, is as follows: the peak daily oil production of the well group is equivalent to an annual oil production rate of approximately 4.6×10^3 t, with a stable production period of about 7 years. By the end of the 30th production year, both reservoir pressure and gas–oil ratio remain within reasonable ranges. Under the current geological model and fluid parameter conditions, the central estimate of the recovery factor is 35.43% (Figures 20 and 21).

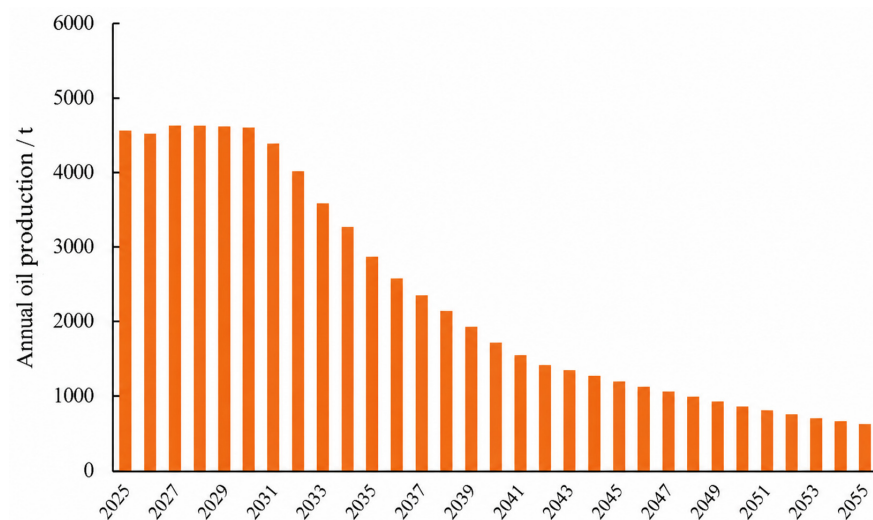


Figure 20. Predicted annual oil production under the optimized scheme.

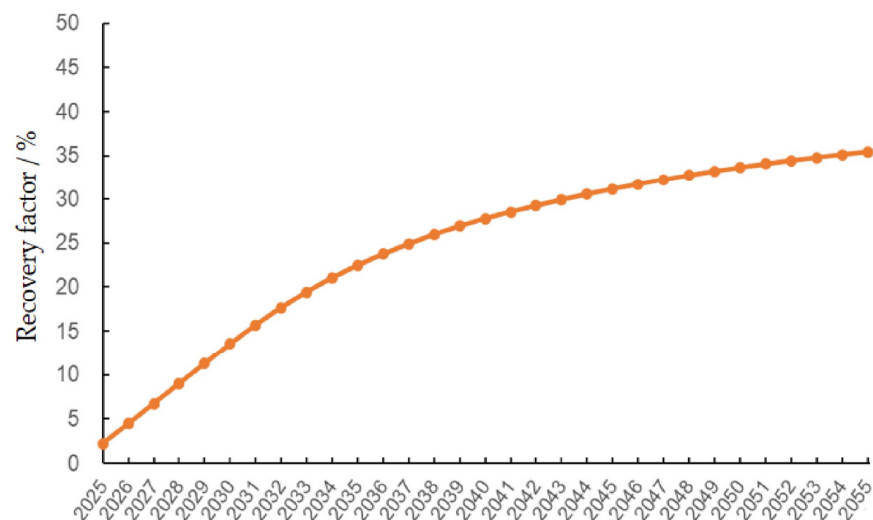


Figure 21. Predicted recovery factor under the optimized scheme.

Although a relatively comprehensive evaluation of key parameters has been conducted through single-factor sensitivity analysis, this study is primarily based on the single-factor control variable method and does not further consider the coupled effects among parameters such as well spacing, fracture parameters, and injection–production strategy. Therefore, the results are more suitable for analyzing general development patterns and providing engineering references. Prior to field-scale application, it is recommended to perform multi-parameter integrated uncertainty analyses based on multiple geological

models to quantify the probabilistic distribution of recovery performance under geological uncertainty conditions. During actual field development, the simulation model should be continuously updated based on dynamic monitoring data, with close tracking of gas–oil ratio and reservoir pressure variations, while corresponding gas channeling risk control measures should be formulated in advance.

4. Conclusions

This study focuses on the undeveloped tight oil reservoir of the Chang 8 formation in the Xifeng area of the Ordos Basin. Based on numerical simulation methods, the effects of different CO₂ flooding development strategies were investigated, leading to the following main conclusions:

- (1) Both well pattern and fracturing parameters exhibit reasonable ranges. The inverted 9-spot well pattern with vertical well injection–vertical well production is considered a relatively suitable well pattern, with a recommended well spacing of 500 m and row spacing of 200 m. A reasonable fracture half-length of 80 m is recommended, while fracture widths of 0.003–0.005 m are considered appropriate. These parameters not only ensure sufficient initial productivity but also help delay the formation of preferential flow channels, thereby providing favorable conditions for enhancing both areal and vertical sweep efficiency.
- (2) Injection–production parameters and injection strategies are critical for controlling displacement stability. An injection rate of 0.03–0.04 PV/year achieves a balance between reservoir energy replenishment and gas channeling control, while an oil production rate of 2–3 m³/d is considered appropriate. Maintaining the bottomhole flowing pressure at 13–14 MPa stabilizes the displacement front. Switching from continuous CO₂ injection to WAG injection during the mid-development stage can improve mobility control and expand the sweep volume. Together, these parameters determine the reasonable operational boundaries for CO₂ flooding development in the study area. In cases where reservoir water injectivity is poor and stable WAG injection cannot be achieved, intermittent gas injection is recommended as an alternative.
- (3) Based on the comprehensive analysis of well pattern, fracturing design, and injection–production schemes, an effective development strategy for directly implementing CO₂ flooding in undeveloped areas has been proposed. The prediction results indicate that the recommended scheme can achieve a prolonged stable production period and maintain favorable reservoir pressure conditions, with a predicted recovery factor of 35.43% after 30 years of production under the current geological model and simulation conditions. The results indicate that appropriate parameter combinations can help delay gas channeling and improve sweep efficiency, providing valuable technical guidance for CO₂ flooding development in similar low-permeability tight reservoirs.

Author Contributions: Conceptualization, J.W. and W.W.; methodology, W.W.; software, L.L.; validation, P.X., W.W. and L.S.; formal analysis, Q.L.; investigation, Y.F.; resources, J.W.; data curation, P.X.; writing—original draft preparation, P.X.; writing—review and editing, W.W. and Q.Z.; visualization, P.X. and L.L.; supervision, W.W.; project administration, J.W.; funding acquisition, J.W. All authors have read and agreed to the published version of the manuscript.

Funding: This research was funded by the National Major Science and Technology Projects of China grant number 2025ZD1408301.

Data Availability Statement: The data supporting the findings of this study are available from the corresponding author upon reasonable request.

Acknowledgments: The authors extend their gratitude to the Research Institute of Exploration and Development, Changqing Oilfield Company, PetroChina and the Postgraduate Innovation Project of Northwest University (2025–2026) for funding this study.

Conflicts of Interest: Authors Jiwei Wang, Yongjian Feng, Qiang Liu and Luming Shi were employed by Research Institute of Exploration and Development, Changqing Oilfield Company, PetroChina. Author Long Liu was employed by the Petroleum Development Center, Shengli Oilfield Company, SINOPEC. The remaining authors declare that the research was conducted in the absence of any commercial or financial relationships that could be construed as a potential conflict of interest.

Abbreviations

The following abbreviations are used in this manuscript:

CO ₂	Carbon Dioxide
EOR	Enhanced Oil Recovery
WAG	Water–Alternating–Gas
PV	Pore Volume
GOR	Gas–Oil Ratio
MMP	Minimum Miscibility Pressure

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