

Article

Investigation of Waterflooding Model Considering Dynamic Fracture Propagation in Ultra-Low Permeability Reservoirs with High-Angle Fractures

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Abstract

High-angle fractures are widely developed in ultra-low permeability reservoirs in the Ordos Basin, and their propagation has a significant influence on waterflooding performance. However, few studies have focused on the identification of high-angle fractures, let alone the impact of their propagation on waterflooding performance. Therefore, a waterflooding model considering dynamic fracture propagation was developed to evaluate the impact of fracture propagation on waterflooding performance in this study. Firstly, based on the logging response characteristics of high-angle fracture intervals, the high-angle fracture identification model was established by the fuzzy comprehensive evaluation method, and a comprehensive index was proposed to identify high-angle fracture intervals. A threshold of approximately 70 effectively distinguishes high-angle fracture intervals from non-high-angle fracture intervals. After that, the waterflooding model considering dynamic fracture propagation was established to investigate the effect of its parameters on waterflooding performance. A smaller initial leak-off coefficient and a faster decline rate reduce fluid loss, promote fracture propagation, and ultimately improve oil recovery. Higher injection rates promote dynamic fracture propagation, accelerate water cut rise, mitigate production decline, and enhance cumulative oil production, while improving the waterflooding response of wells along the fracture direction. Optimal well group performance is achieved at a fracture orientation of 45°, beyond which production declines. Increasing well spacing reduces the water cut rise rate and the production decline rate, thereby improving cumulative oil production. However, it leads to a faster production decline in the early development stage. This work could provide theoretical guidance for waterflooding in ultra-low permeability reservoirs.

Keywords: ultra-low permeability reservoir; high-angle fracture; fracture identification; waterflooding model; dynamic fracture propagation



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1. Introduction

There are abundant reserves of low-permeability oil reservoirs in China, with proven geological reserves exceeding 140×10^8 t, accounting for more than 48% of the total oil reserves [1,2]. These reservoirs are mainly distributed in the Songliao, Bohai Bay, Tarim, Ordos, and Junggar basins. The ultra-low permeability reservoir of the Yanchang Formation in the Ordos Basin is typical of low-permeability reservoirs in China, characterized by poor reservoir properties and well-developed high-angle fractures [3,4]. Waterflooding is currently a widely used method for low-permeability reservoirs in China. However, poor reservoir properties and developed natural high-angle fractures could easily lead to pressure build-up in the near-well area of injection wells during waterflooding. When the bottomhole pressure exceeds the fracture propagation pressure, fractures will propagate toward the production wells, ultimately resulting in water breakthrough [5,6]. Therefore, the identification of high-angle fractures and the impact of fracture propagation on waterflooding performance are crucial for waterflooding development in ultra-low permeability reservoirs in the Ordos Basin.

Currently, commonly used methods for identifying natural fractures include direct core observation, imaging logging, and conventional logging interpretation [7–9]. Direct core observation and imaging logging are the most intuitive and reliable approaches for identifying natural fractures. However, limited data availability and high cost are the main challenges of these two methods [10,11]. In contrast, conventional logging interpretation has been widely studied due to the abundance of available data [12,13]. Previous studies have shown that fracture-developed intervals exhibit corresponding response characteristics on conventional logging curves, and different logging curves show varying sensitivity to fractures. The dual laterolog resistivity (LLD and LLS) in such intervals is generally lower than that in the surrounding rock, accompanied by an increase in the dual laterolog resistivity difference (LLD–LLS). Specifically, high-angle fracture intervals are characterized by positive separation (LLD > LLS), whereas low-angle fracture intervals display negative separation (LLD < LLS) or no significant separation. Meanwhile, fracture-developed intervals typically exhibit an increase in acoustic time difference, with the acoustic transit time curve showing cycle-skipping and short, serrated patterns. Additionally, density logging, neutron logging, and natural gamma-ray logging can also indicate natural fractures to some extent. Generally, the fracture-developed intervals are characterized by low density, high neutron porosity, and low natural gamma-ray values. Accordingly, natural fractures can be identified based on the response characteristics of various logging curves. However, due to the strong heterogeneity of ultra-low permeability fractured reservoirs, it is difficult to accurately identify natural fractures solely by a single logging curve. In recent years, advances in applied mathematics and geostatistics have promoted the integration of mathematical methods with logging data for fracture identification. Methods such as multivariate statistical analysis, BP neural networks, clustering algorithms, and grey system theory have been applied and have improved identification accuracy [14–17]. These new attempts provide a new approach for the identification of high-angle fractures.

During waterflooding, when the bottomhole pressure of injection wells exceeds the formation fracture pressure or the fracture propagation pressure, the formation may be fractured or the existing natural fractures may be activated, resulting in the generation of dynamic fractures. This phenomenon is consistent with the concept of “water injection-induced fractures” described in international literature [5,18–21]. These dynamic fractures serve as a double-edged sword in the waterflooding development of low-permeability reservoirs. Although they can significantly enhance reservoir permeability and injectivity, they simultaneously intensify reservoir heterogeneity and adversely affect waterflooding efficiency. Field monitoring investigations have demonstrated that water injection

can induce fracture activation and dynamic propagation in low-permeability reservoirs. For example, previous studies based on field measurements and inversion methods have identified the initiation and propagation characteristics of injection-induced fractures, confirming their significant influence on reservoir pressure distribution and fluid flow behavior [22–24]. Nevertheless, the limited monitoring range and difficulty in continuously tracking fracture propagation under long-term waterflooding conditions make it challenging to quantitatively evaluate the impact of dynamic fracture propagation on waterflooding performance. Currently, studies on the impact of dynamic fractures on waterflooding performance in ultra-low permeability reservoirs are mostly conducted using numerical simulation methods. However, these studies often neglect the propagation characteristics of dynamic fractures in the simulation process, simplifying them into time-independent fractures with specific orientations and fixed lengths. Unlike hydraulic fractures, dynamic fractures induced during waterflooding propagate slowly over a long period and are accompanied by significant fluid loss. Numerous classical fracture propagation models, including PKN, KGD, radial, pseudo-3D, and full 3D models, have incorporated fluid leak-off effects [25–30]. However, these models generally employ the Carter leak-off model, which is primarily developed for short-term hydraulic fracturing processes and may underestimate long-term fluid loss during dynamic fracture propagation, thereby overestimating fracture propagation length. Consequently, these classical models may not fully capture the time-dependent propagation behavior of dynamic fractures during long-term waterflooding. As a result, existing classical fracture propagation models fail to accurately describe the complex dynamic fracture propagation process during waterflooding. To address this issue, researchers have conducted extensive studies on dynamic fracture propagation models in recent years, achieving simulations of dynamic fracture propagation during waterflooding [31–35]. However, solving these models requires complex numerical methods, such as fracture initiation criteria, fluid-solid coupling algorithms, and adaptive mesh refinement, leading to intricate computational procedures and high computational cost. These limitations severely restrict the wide application of these models. To overcome these limitations, a half-length increment model for dynamic fracture propagation based on Griffith's energy balance principle has been proposed [36,37]. By avoiding complex remeshing procedures and explicit simulation of fracture propagation processes, this approach provides an efficient alternative for evaluating the impact of dynamic fracture propagation on waterflooding performance. Moreover, existing studies have predominantly focused on fracture propagation models, whereas the impact of dynamic fracture propagation on waterflooding performance remains insufficiently understood. Therefore, a waterflooding model considering dynamic fracture propagation is essential for evaluating waterflooding performance in low-permeability reservoirs.

In this paper, taking the ultra-low permeability reservoir with high-angle fractures in the WB Block of the Ordos Basin as an example, a waterflooding model considering dynamic fracture propagation was developed to evaluate the impact of fracture propagation on waterflooding performance in this study. Firstly, based on the logging response characteristics of high-angle fracture intervals identified through the integration of the imaging logging and conventional logging data, the high-angle fracture identification model was established by the fuzzy comprehensive evaluation method and validated using core observation data. Then, the waterflooding model considering dynamic fracture propagation was developed by coupling the oil–water two-phase flow model, the embedded discrete fracture model, and the dynamic fracture propagation model. Finally, the effects of injection rate, fracture orientation, and well spacing on the waterflooding performance considering dynamic fracture propagation were analyzed. This work could provide

theoretical guidance for improving waterflooding performance in ultra-low permeability fractured reservoirs.

2. Methodology

2.1. High-Angle Fracture Identification Model

Imaging logging, which can provide intuitive image information of wellbore profile, has become one of the predominant methods for identifying fractures in formations. However, imaging logging data is relatively limited due to the high cost and time-consuming nature of imaging logging. In contrast, conventional logging data are widely available in oil and gas wells and can effectively characterize variations in petrophysical parameters, including lithology, porosity, bulk density, and acoustic transit time. Abnormal responses of these parameters are closely associated with fracture development. Therefore, they provide reliable indirect indicators for identifying high-angle fracture intervals. Therefore, conventional logging interpretation is a more practical and widely used approach for high-angle fracture identification. In this section, the logging response characteristics of high-angle fracture intervals were first determined by integrating imaging and conventional logging data. Subsequently, the high-angle fracture identification model was established based on the fuzzy comprehensive evaluation method. Finally, the model was validated using core observation data.

2.1.1. Logging Response Characteristics of High-Angle Fracture Intervals

Imaging logging can effectively characterize structural features of the wellbore profile, providing a reliable basis for fracture identification and reservoir evaluation. On imaging logs, color intensity represents formation resistivity, where lighter colors indicate high resistivity and darker colors represent low resistivity. Fracture-developed intervals typically exhibit low resistivity due to mud invasion and thus appear as dark features on the imaging logs. When a fracture has high-angle or near-vertical dip, it manifests as a high-amplitude sinusoidal curve on the imaging logs, as shown in Figure 1.

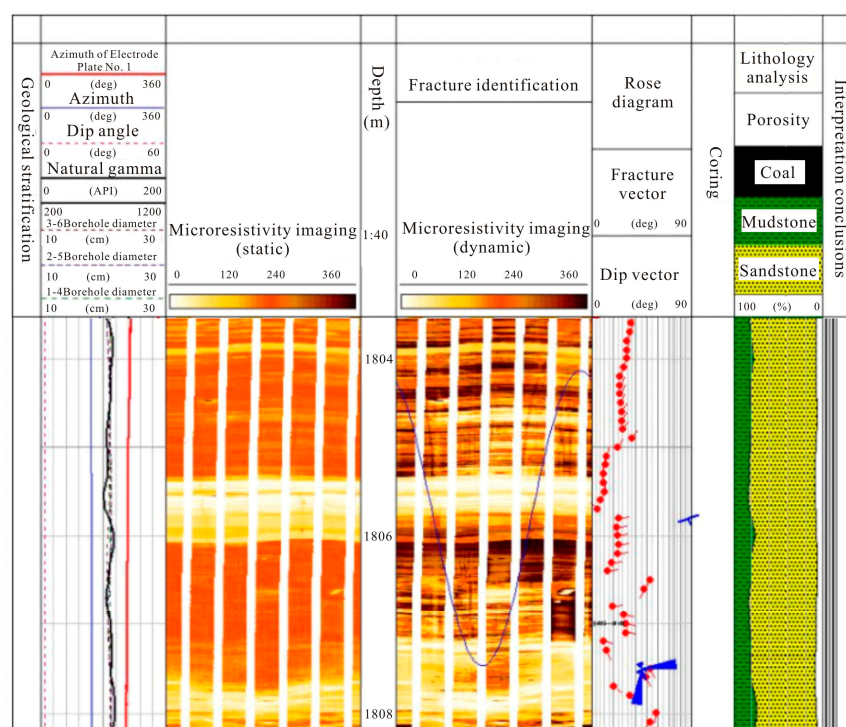


Figure 1. Characteristics of high-angle fracture intervals on imaging logs.

After identifying high-angle fracture intervals using imaging logs, the corresponding conventional logging responses were further analyzed, as illustrated in Figure 2. The spontaneous potential curve shows little variation in high-angle fracture intervals. In contrast, natural gamma-ray, acoustic transit time, and compensated neutron logging values increase significantly, whereas the density log shows relatively low values. Moreover, the deep and shallow laterolog resistivity curves exhibit distinct separation in high-angle fracture intervals, indicating significant differences between the two responses.

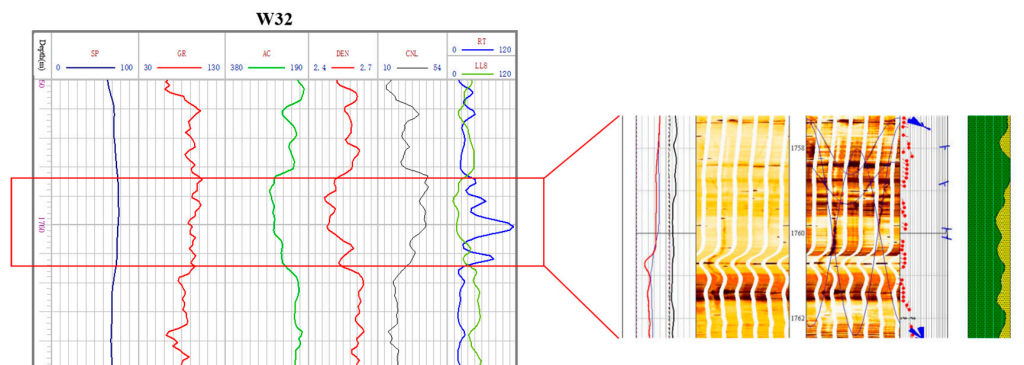


Figure 2. Conventional logging response characteristics of high-angle fracture intervals.

2.1.2. Establishment of the High-Angle Fracture Identification Model

To overcome the limitations of identifying high-angle fractures using a single logging curve, a high-angle fracture identification model was established based on the fuzzy comprehensive evaluation method by integrating multiple logging responses. According to the analysis in Section 2.1.1, natural gamma-ray, spontaneous potential, acoustic transit time, bulk density, and the difference between the deep and shallow laterolog resistivities were selected as the conventional logging evaluation parameters for high-angle fractures. The workflow for establishing the high-angle fracture identification model is illustrated in Figure 3.

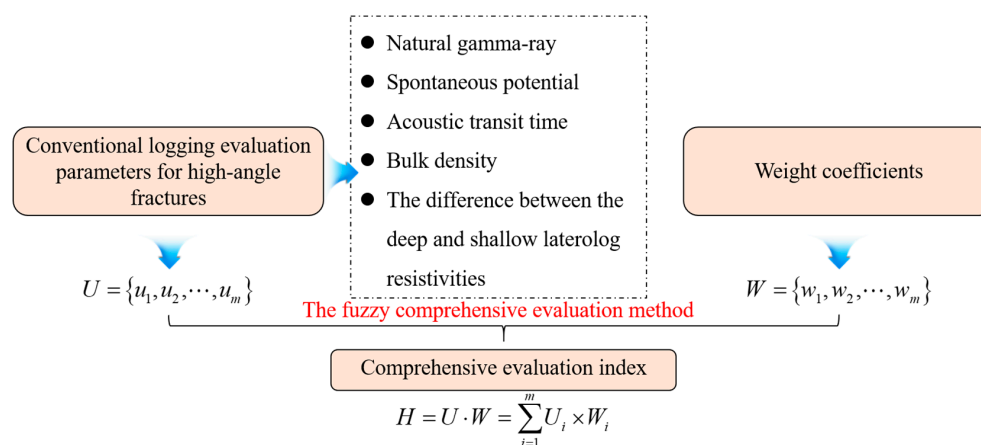


Figure 3. The workflow for establishing the high-angle fracture identification model.

First, based on imaging logging data from nine wells in the WB Block, response characteristics of natural gamma-ray, spontaneous potential, acoustic transit time, bulk density, and the difference between the deep and shallow laterolog resistivities were obtained for both high-angle fracture and non-high-angle fracture intervals. Subsequently, weight coefficients of these conventional logging evaluation parameters were determined via the analytic hierarchy process. Based on imaging logging calibration, a pairwise comparison matrix was constructed using the 1–9 Saaty scale, as shown in Table 1. The eigenvector

corresponding to $\lambda_{\max} = 5.12$ yields $\omega_{\text{GR}} = 0.3$, $\omega_{\text{SP}} = 0.05$, $\omega_{\text{AC}} = 0.15$, $\omega_{\text{DEN}} = 0.1$, and $\omega_{\text{LLD-LLS}} = 0.4$. The consistency ratio is $\text{CR} = 0.027$ (< 0.10), confirming the reliability of the derived weights.

Table 1. The comparison matrix.

	GR	SP	AC	DEN	LLD-LLS
GR	1	6	2	3	1/2
SP	1/6	1	1/3	1/2	1/8
AC	1/2	3	1	3/2	1/3
DEN	1/3	2	2/3	1	1/4
LLD-LLS	2	8	3	4	1

After that, the comprehensive evaluation index was calculated using the fuzzy comprehensive evaluation method. Finally, the comprehensive evaluation indices of high-angle fracture and non-fracture intervals were plotted in a scatter plot, as shown in Figure 4. Figure 4 shows that 69 data points were collected, including 14 non-fracture intervals and 55 high-angle fracture intervals. The two groups can be approximately separated by a comprehensive evaluation index of 70. To justify the selection of the threshold value, the identification accuracy for high-angle fracture and non-fracture intervals under different thresholds was calculated, and the corresponding accuracy curves were plotted (Figure 5). As the threshold increases, the identification accuracy of non-fracture intervals gradually increases, while that of high-angle fracture intervals gradually decreases. At a threshold of 70, the average of the identification accuracies for high-angle fracture and non-fracture intervals reaches its maximum value of 88.3%. Therefore, a comprehensive evaluation index of 70 is selected as the threshold to distinguish high-angle fracture intervals from non-fracture intervals.

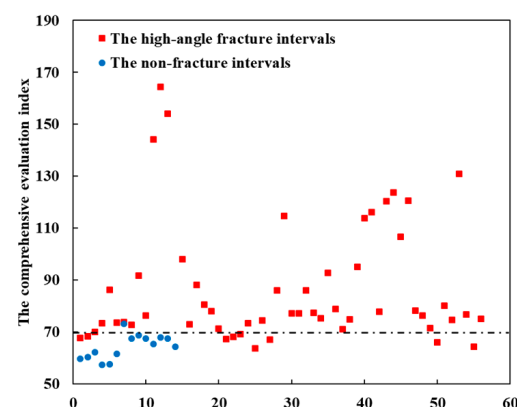


Figure 4. Scatter plot of the comprehensive evaluation index for high-angle fracture and non-fracture intervals.

Additionally, bootstrap resampling (10,000 iterations) was performed to estimate the 95% confidence interval (CI) of the classification accuracy. The resampling procedure yielded a mean classification accuracy of 86.96% (60/69), with a 95% CI ranging from 79.0% to 94.9% for the threshold value of 70. Although the lower bound of the CI was close to the majority-class baseline accuracy (79.7%), the observed accuracy remained substantially higher than the expected performance under chance conditions. Moreover, the binomial test demonstrated that the classification performance was statistically significant ($p < 0.001$), suggesting that the observed accuracy was unlikely to result from random variation. The CI width of approximately 15.9 percentage points is relatively narrow given the moderate sample size ($n = 69$), suggesting well-constrained sampling error and stable threshold

behavior. Accordingly, intervals with a comprehensive evaluation index greater than 70 are identified as high-angle fracture intervals, whereas those with values below 70 are considered non-fracture intervals.

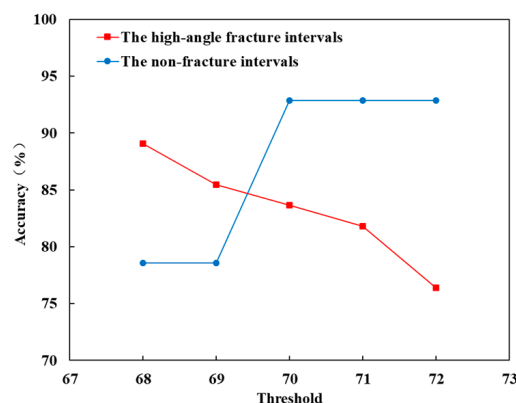


Figure 5. Identification accuracy for high-angle fracture and non-fracture intervals under different thresholds.

2.1.3. Model Validation

After establishing the high-angle fracture identification model, core observation data were used to validate its accuracy. The locations of high-angle fractures were identified through core observation, as shown in Figure 6. Subsequently, the corresponding conventional logging response values were extracted from conventional logging data.



Figure 6. Locations of high-angle fractures in core samples.

Based on the conventional logging response values at the identified high-angle fracture locations, the corresponding comprehensive evaluation index was further calculated using the high-angle fracture identification model, as shown in Table 2. It can be observed that the comprehensive evaluation index for high-angle fracture locations identified from core samples consistently exceeds 70, while that for non-fracture locations is generally below 70. This indicates that the proposed model has reliable results and sufficient accuracy to identify high-angle fractures in the WB Block.

Table 2. The comprehensive evaluation index for high-angle fracture and non-fracture locations.

Well	Depth/m	Fracture Dip/°	LLD-LLS	DEN	AC	SP	GR	Comprehensive Evaluation Index
W103	1778.7	82	13.9	2.6	225.9	78.6	131.6	83.1
W102	1804.0	83	−114.3	2.5	209.2	75.4	68.3	101.6
W55	1745.5	72	72.6	2.6	224.2	16.2	92.6	91.5
W55	1851.3	No fracture	10.7	2.6	213.9	33.7	94.3	66.6
W55	2181.0	No fracture	−8.4	2.5	222.5	68.9	76.2	63.3
W38	1963.3	62	28.7	2.5	228.2	53.9	75.9	71.4
W38	1968.5	No fracture	27.1	2.5	219.5	54.4	75.0	69.2

Table 2. Cont.

Well	Depth/m	Fracture Dip/°	LLD-LLS	DEN	AC	SP	GR	Comprehensive Evaluation Index
W107	1660.3	70	86.0	2.6	241.9	99.5	129.1	114.6
W107	1657.0	75	100.4	1.9	307.6	94.6	114.8	125.6
W107	1655.0	90	−73.1	2.2	274.7	92.6	117.1	110.4
W107	1655.2	86	54.8	2.6	222.7	93.0	108.9	92.9
W107	1648.2	90	78.5	2.6	217.5	99.2	97.0	98.3
W107	1695.0	No fracture	48.3	24.4	213.3	50.7	79.0	68.0
W107	1699.0	No fracture	44.1	15.8	244.3	44.7	73.0	67.1
W296	1738.1	82	21.3	2.6	233.5	58.3	100.3	76.8
W296	1740.0	No fracture	6.6	2.5	227.3	46.6	100.3	69.4
W296	1767.5	No fracture	−12.9	2.6	216.4	60.7	88.1	67.3
W07-311	1702.3	70	30.9	2.4	274.1	77.9	138.2	99.1

2.2. Waterflooding Model Considering Dynamic Fracture Propagation

2.2.1. Mathematical Model of Oil–Water Two-Phase Flow Based on Embedded Discrete Fractures

Oil–water two-phase black oil model is adopted, and the continuity equations for the oil–water two-phase system are given as follows.

$$\nabla \left(\frac{k_o k_{ro}}{\mu_o B_o} \nabla p_o \right)_{\beta} + q_o = \frac{\partial}{\partial t} \left(\frac{\phi S_o}{B_o} \right)_{\beta}, \quad (1)$$

$$\nabla \left(\frac{k_w k_{rw}}{\mu_w B_w} \nabla p_w \right)_{\beta} + q_w = \frac{\partial}{\partial t} \left(\frac{\phi S_w}{B_w} \right)_{\beta}, \quad (2)$$

where subscripts w and o are the water phase and oil phase, respectively; subscripts β is the fracture or matrix; k is the absolute permeability, m^2 ; k_r is the relative permeability, dimensionless; ∇p is the pressure gradient, Pa/m ; q is the source or sink term, m^3/s ; ϕ is the porosity, dimensionless; S_w and S_o are the oil and water saturation, dimensionless; B_w and B_o are the water and oil volume factor, dimensionless; t is the time, s .

Additional equation.

$$S_o + S_w = 1, \quad (3)$$

$$p_w = p_o - p_{cow}, \quad (4)$$

where p_w and p_o are the water pressure and oil pressure, Pa ; p_{cow} is the capillary force, Pa .

Considering the advantages of the embedded discrete fracture model (EDFM) in handling complex fracture networks, the EDFM was selected to simulate the effect of fracture on the waterflooding performance. In the EDFM, fractures are cut by matrix grid boundaries, forming three types of non-neighboring connections. As shown in Figure 7, three connection types are the connection between the fracture segment and the matrix cell it penetrates (NNC type I), the connection between fracture segments in an individual fracture (NNC type II), and the connection between intersecting fracture segments (NNC type III).

The transmissibility factor between non-neighboring connections is proposed to calculate the transfer flux between non-neighboring connections. The transfer flux of phase l can be calculated using the following equation.

$$q = \lambda_l T_{NNC} \Delta P_{NNC}, \quad (5)$$

where λ_l is the relative mobility of phase l , $\text{Pa}^{-1} \cdot \text{s}^{-1}$; T_{NNC} is the transmissibility between two neighboring cells, $\text{m}^3 \cdot \text{Pa}^{-1} \cdot \text{s}^{-1}$; ΔP_{NNC} is the pressure difference between two neighboring cells, Pa.

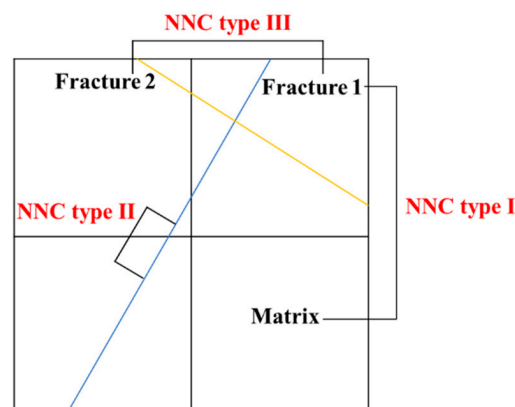


Figure 7. A brief sketch of EDFM.

The transmissibility factor between non-neighboring connections can be calculated as:

$$T_{NNC} = \frac{k_{NNC} A_{NNC}}{d_{NNC}}, \quad (6)$$

where k_{NNC} is the permeability between two neighboring cells, m^2 ; A_{NNC} is the contact area between two neighboring cells, m^2 ; d_{NNC} is the average normal distance between two neighboring cells, m.

In addition to defining these non-neighboring connections, the connection between the fracture and the well is introduced in the EDFM. The well-fracture index WI is defined as:

$$WI = \frac{2\pi k_f w_f}{\ln(r_e/r_w)}, \quad (7)$$

$$r_e = 0.14 \sqrt{L^2 + W^2}, \quad (8)$$

where k_f is the fracture permeability, m^2 ; w_f is the fracture aperture, m; L and W are the length and height of the fracture segment, m; r_w is the wellbore radius, m.

The oil well produces at a constant bottomhole flowing pressure, and its production rate can be calculated using the following equation.

$$\begin{cases} q_o = -\rho_o PI_o (p_o - p_{wf}) \\ q_w = -\rho_w PI_w (p_w - p_{wf}) \end{cases}, \quad (9)$$

$$\begin{cases} PI_o = \frac{kk_{ro}}{\mu_o B_o \ln\left(\frac{0.208 \sqrt{\Delta x \Delta y}}{r_w} + S\right)} \\ PI_w = \frac{kk_{rw}}{\mu_w B_w \ln\left(\frac{0.208 \sqrt{\Delta x \Delta y}}{r_w} + S\right)} \end{cases}, \quad (10)$$

where p_{wf} is the constant bottomhole flowing pressure, Pa; PI is the productivity index, $\text{m}^3 \cdot \text{Pa}^{-1} \cdot \text{s}^{-1}$; S is the skin factor, dimensionless.

2.2.2. Dynamic Fracture Propagation Model

According to Griffith's energy balance principle, the energy supplied by the injection system during hydraulic fracturing is partly converted into elastic energy stored in the formation and fluid system (reversible energy) and partly into the energy required to

fracture the rock (irreversible energy). The energy balance equation for the entire system over a unit time step can be expressed as:

$$E_{inj} = E_{fl} + E_{loss} + E_{fs} + E_s, \quad (11)$$

where E_{inj} is the energy supplied by the injection system over a unit time step, J; E_{fl} is the elastic energy stored in the fluid within the newly created fracture over a unit time step, J; E_{loss} is the energy consumed by fluid leak-off into the formation over a unit time step, J; E_{fs} is the elastic energy stored in the formation over a unit time step, J; E_s is the energy absorbed to create new fractures over a unit time step, J.

It is assumed that, during fracture propagation, the fluid pressure within the fracture is uniform and equal to the fracture propagation pressure. Additionally, only Mode I (opening-type) fracture occurs during the propagation. These assumptions provide a simplified description of dynamic fracture propagation and are adopted to capture the fracture behavior while maintaining computational efficiency. The assumption of uniform fracture pressure neglects pressure variation along the fracture, which may result in an overestimation of fracture propagation length and propagation rate, because the net pressure at the fracture tip may be lower under actual conditions. Moreover, the consideration of only Mode I fracture propagation may not fully represent complex fracture behaviors, including shear deformation, fracture branching, and interactions with natural fracture networks. Nevertheless, these assumptions are reasonable for evaluating the overall impact of dynamic fracture propagation on waterflooding performance and are consistent with previous studies in low-permeability reservoirs. According to Irwin's theory and the fracture tip propagation criterion, the fracture propagation pressure can be calculated using the following equation.

$$p_{fp} = p_{foc} + \frac{K_{Icr}}{\sqrt{\pi L_f}}, \quad (12)$$

where p_{fp} is the fracture propagation pressure, Pa; p_{foc} is the fracture opening pressure, Pa; K_{Icr} is the critical stress intensity factor, Pa m^{1/2}; L_f is the fracture half-length, m.

Initially, the fracture opening pressure can be expressed as:

$$p_{foc} = \sigma_h, \quad (13)$$

where σ_h is the minimum horizontal principal stress of the formation, Pa.

Assuming a constant injection rate (Q_{inj}), the energy supplied by the injection system over a unit time step (E_{inj}) is given by:

$$E_{inj} = P_{inj} Q_{inj}, \quad (14)$$

where P_{inj} is the injection pressure, Pa; Q_{inj} is the injection rate, m³/s.

The other energy terms in Equation (11) can be determined by the following equation.

$$E_{fl} = P_{fp} w l_i h, \quad (15)$$

$$E_{loss} = 2 P_{fp} L_{f,i} h \int_{t_i}^{t_{i+1}} \frac{C}{\sqrt{t}} dt, \quad (16)$$

$$E_{fs} = \frac{\pi \sigma_h^2 A_i^2}{16 E h}, \quad (17)$$

$$E_s = 2 \gamma h l_i, \quad (18)$$

where p_{fp} is the fracture propagation pressure, Pa; w is the fracture aperture, m; l_i is the fracture propagation length at the i -th time step, m; h is the fracture height, m; $L_{f,i}$ is the fracture half-length before the fracture propagation at the i -th time step, m; C is the leak-off coefficient, $\text{m s}^{-1/2}$; t is time, s; σ_h is the minimum horizontal principal stress of the formation, Pa; A_i is the fracture surface area of the newly propagated fracture at the i -th time step, m^2 ; E is the elastic modulus of the rock, Pa; γ is the specific surface energy, J/m^2 .

Therefore, the energy-balance equation for the entire system over a unit time step during dynamic fracture propagation can be obtained as:

$$\frac{P_{inj}Q_{inj}}{2} = P_{fp}wl_ih + 2P_{fp}L_{f,i}h \int_{t_i}^{t_{i+1}} \frac{C}{\sqrt{t}} dt + \frac{\pi\sigma_h^2 A_i^2}{16Eh} + 2\gamma hl_i, \quad (19)$$

2.2.3. Model Solution

The waterflooding model considering dynamic fracture propagation was established by coupling the mathematical model of oil–water two-phase flow based on the embedded discrete fracture model with the dynamic fracture propagation model. The model was solved using the finite difference method, and the detailed solution workflow is shown in Figure 8. Given a specified injection rate, at each time step, the dynamic fracture propagation model is first used to determine whether the dynamic fracture will propagate. If the propagation condition is not met, the injection time and injection rate are directly substituted into the EDFM-based oil–water two-phase flow model, and the model is solved using the finite difference method. If the propagation condition is met, the fracture propagation length is first calculated using the dynamic fracture propagation model, and the fracture mesh is updated accordingly. Then, the EDFM-based oil–water two-phase flow model is solved again using the finite difference method.

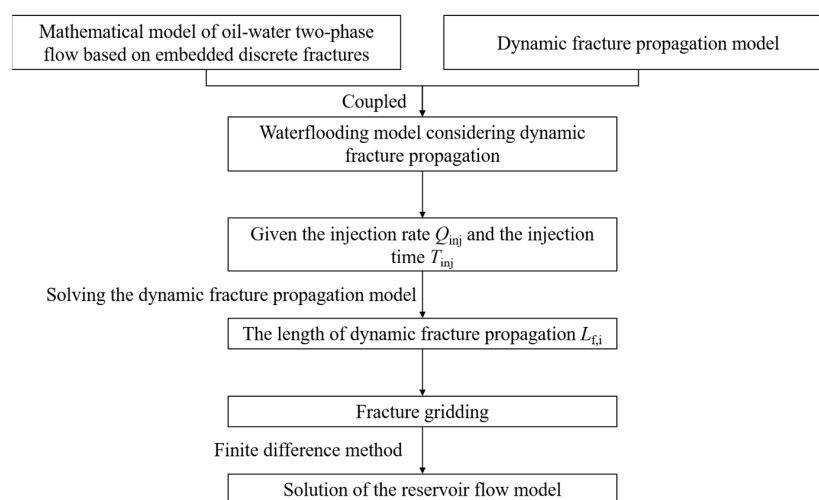


Figure 8. Detailed solution workflow of the waterflooding model considering dynamic fracture propagation.

3. Results and Discussion

3.1. Model Verification

To investigate the effect of various process parameters on waterflooding performance considering dynamic fracture propagation, a well group model for S017-371 was established, as shown in Figure 9. The model dimensions are $660 \text{ m} \times 660 \text{ m} \times 20 \text{ m}$, with a grid size of $20 \text{ m} \times 20 \text{ m} \times 20 \text{ m}$. Moreover, it adopts a square inverted five-spot well pattern, with a well spacing of approximately 140 m. To minimize the interference of uncertainties in the surrounding reservoir on dynamic fracture propagation and well production performance

within the well group, a closed boundary condition was adopted in this study to more accurately characterize the evolution of fractures during water injection and its impact on waterflooding performance.

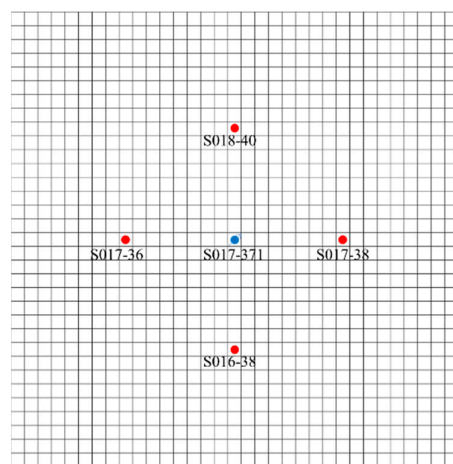


Figure 9. Well group model for S017-371.

The reservoir parameters obtained from the Chang 4 + 5 member in the WB Block are shown in Table 3, and the capillary pressure curve and the relative permeability curve are presented in Figure 10. Moreover, the direction of fracture propagation coincides with that of the maximum principal stress, both trending in the north direction.

Table 3. Basic parameters of the reservoir.

Reservoir Parameters	Value	Reservoir Parameters	Value
Matrix porosity	0.13	Initial oil saturation in matrix	0.55
Oil viscosity (mPa·s)	5	Water viscosity (mPa·s)	1
Matrix coefficient of compressibility (MPa ⁻¹)	8.6×10^{-4}	Fracture coefficient of compressibility (MPa ⁻¹)	1×10^{-4}
Oil coefficient of compressibility (MPa ⁻¹)	1×10^{-3}	Water coefficient of compressibility (MPa ⁻¹)	5×10^{-4}
Initial reservoir pressure (MPa)	12.8	Matrix permeability (mD)	4.1
Formation fracture pressure (MPa)	38.5	Initial fracture half length (m)	1
Minimum horizontal principal stress (MPa)	28.2	Elastic modulus (GPa)	30.2
Specific surface energy (J·m ⁻²)	5×10^5	Fracture height (m)	17.1

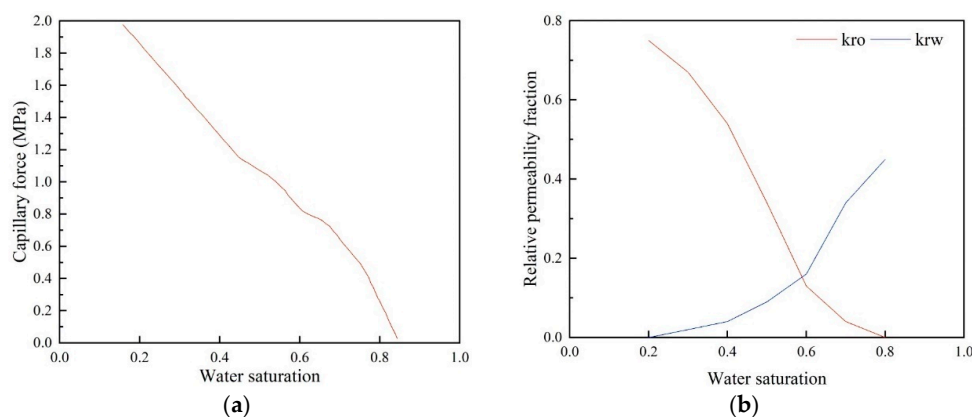


Figure 10. Capillary pressure and relative permeability curves: (a) capillary pressure curve; (b) relative permeability curve.

The high-angle fracture intervals of Well S017-371 were identified using the proposed high-angle fracture identification model. Figure 11 illustrates the identification results for Well S017-371. Figure 11 shows that two high-angle fracture intervals are identified in the

Chang 4 + 5 member for Well S017-371, located at 1851.9–1855.6 m and 1865.5–1878.9 m, respectively. The cumulative height of high-angle fracture intervals for Well S017-371 in the Chang 4 + 5 member reaches 17.1 m, accounting for 29.5% of the formation thickness. These intervals are highly likely to propagate during waterflooding.

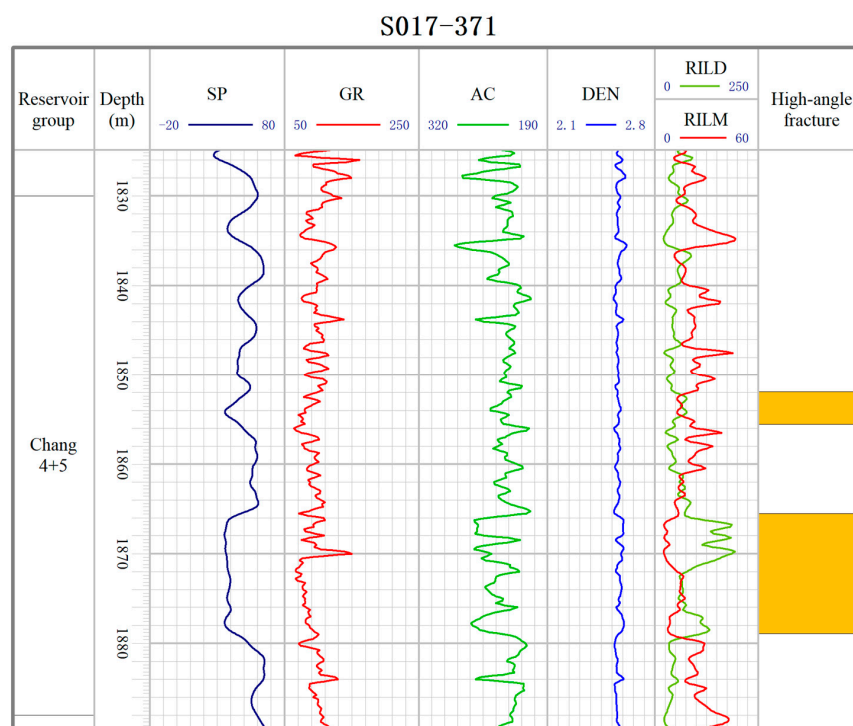


Figure 11. High-angle fracture identification results for Well S017-371.

To validate the high-angle fracture identification results for Well S017-371, the injectivity index of this well during waterflooding and the production performance of its corresponding oil wells were analyzed. Figure 12 presents the injectivity index of Well S017-371 at different injection times. As shown in Figure 12, the injectivity index exhibits multiple cycles of abrupt increases followed by gradual declines during water injection, which is consistent with the occurrence of dynamic fracture propagation. The dynamic fracture propagation reduces flow resistance, resulting in a sudden increase in the injectivity index. Subsequently, as formation pressure gradually equilibrates during water injection, fractures tend to close, leading to a reduction in flow capacity and a gradual decline in the injectivity index. In addition, two oil wells corresponding to Well S017-371 (S018-40 and S016-38) successively experienced water breakthrough after only three years of waterflooding, with water cuts abruptly increasing from 35.02% and 41.35% to 90.14% and 94%, respectively. This behavior may be attributed to the fact that the injection-production orientation between these two oil wells and Well S017-371 aligns with the direction of maximum principal stress, which is consistent with the dominant orientation of natural fractures in the WB Block. Therefore, dynamic fracture propagation during waterflooding leads to a rapid increase in water cut in S018-40 and S016-38. The above analysis indicates that high-angle fracture intervals are developed in Well S017-371, and their propagation during water injection significantly influences the production performance of the corresponding oil wells, which indirectly validates the reliability of the proposed model.

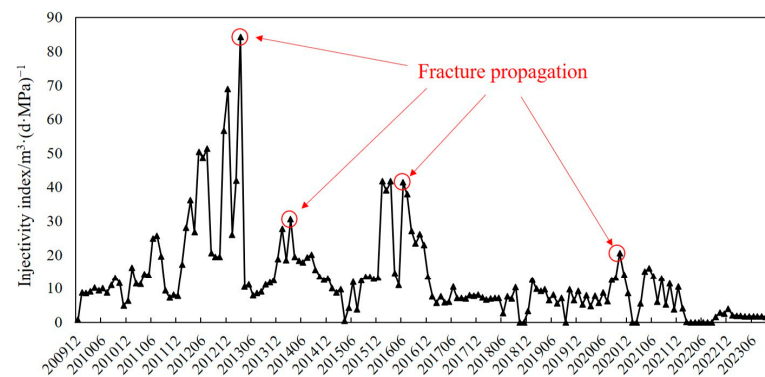


Figure 12. Injectivity index of Well S017-371 at different injection times.

The liquid and oil production history matching for the waterflooding model with and without considering dynamic fracture propagation are shown in Figure 13. The liquid production history matching accuracies for both models are higher than 95%, and the oil production history matching accuracies are 95.2% and 88.4%, respectively. It can be seen that the waterflooding model considering dynamic fracture propagation has reliable simulation results and sufficient accuracy to analyze the waterflooding process in ultra-low permeability reservoirs. Although a systematic uncertainty analysis was not performed, the reliability of the numerical results was further supported by the stable simulation behavior. During the simulation period, the pressure and saturation fields evolved smoothly without non-physical oscillations, and the numerical solver achieved convergence at each time step.

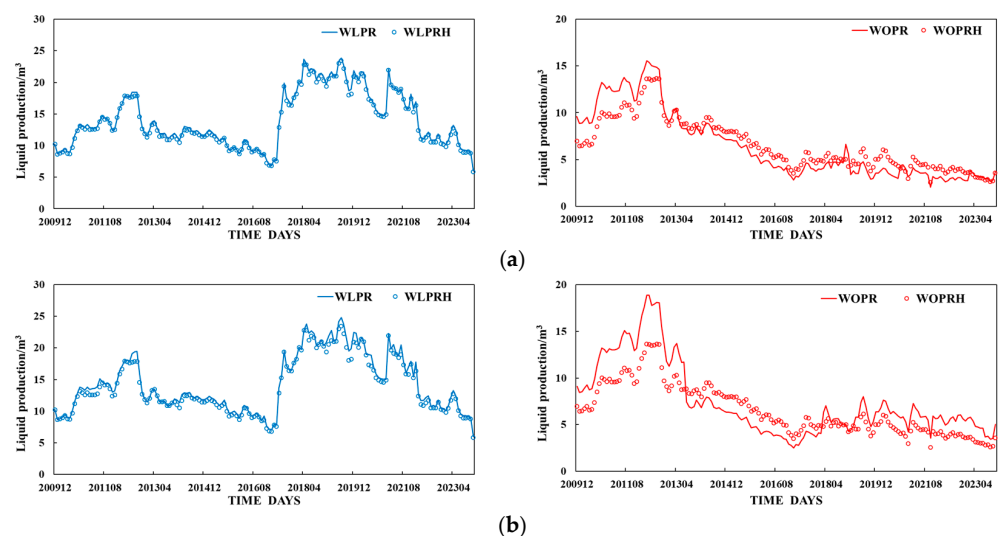


Figure 13. Liquid and oil production history matching: (a) the waterflooding model considering dynamic fracture propagation; (b) the waterflooding model without considering dynamic fracture propagation.

3.2. Results of Simulation

3.2.1. Effect of Leak-Off Coefficient on Waterflooding Performance Considering Dynamic Fracture Propagation

To investigate the effect of leak-off coefficient on waterflooding performance that considers dynamic fracture propagation, a series of schemes with different leak-off coefficients were simulated. The time-dependent variations in the leak-off coefficient in these schemes are $C(t) = -0.045t + 0.3$, $C(t) = -0.045t + 0.5$, and $C(t) = -0.055t + 0.3$, respectively, all of which follow the form $C(t) = -at + b$, where a is the leak-off coefficient decline rate and b is the initial leak-off coefficient. The simulations were conducted under a constant

bottomhole flowing pressure of 7 MPa for production and an injection rate of $30 \text{ m}^3/\text{d}$, with a production period of 10 years. The results are presented in Figures 14 and 15.

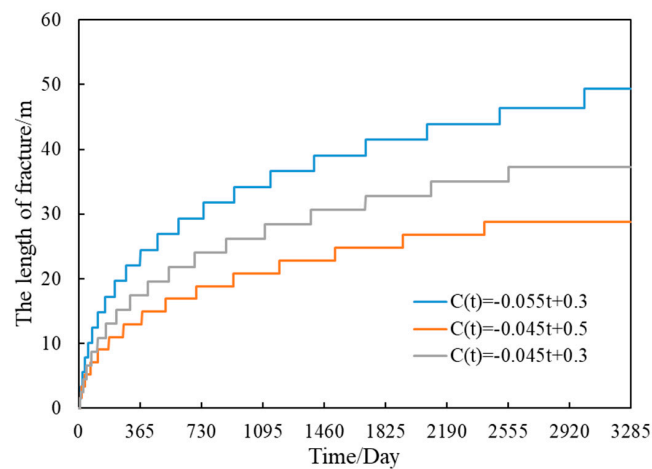


Figure 14. The dynamic fracture length at different leak-off coefficients.

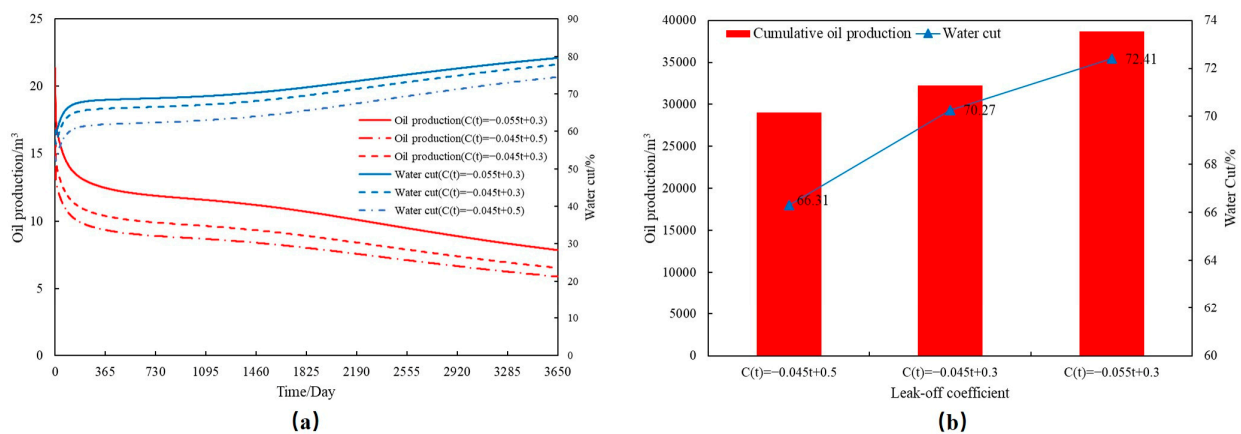


Figure 15. Comparison of production performance for well group S017-371 at different leak-off coefficients: (a) production performance; (b) cumulative oil production and water cut.

Figure 14 shows the dynamic fracture length at different leak-off coefficients. The smaller the initial leak-off coefficient and the faster the leak-off coefficient decline rate, the easier the fracture propagates, and the longer the fracture propagation length within the same time interval. This is because a smaller initial leak-off coefficient and a faster leak-off decline rate both reduce fluid leak-off, facilitating a more rapid increase in fluid pressure inside the fracture near the wellbore, thereby promoting fracture propagation and increasing the fracture propagation length over the same period. The observed trend is qualitatively consistent with the findings of Han et al. [37], who reported similar fracture propagation behavior under varying leak-off conditions. However, the impact of leak-off coefficient on waterflooding performance considering dynamic fracture propagation was not further investigated in their study. Figure 15a presents the production performance of well group S017-371 at different leak-off coefficients. It can be observed that the trends of water cut and oil production for well group S017-371 at different leak-off coefficients are consistent. As the initial leak-off coefficient increases, the water cut rise rate of the well group decreases, while the production decline rate increases. Conversely, as the leak-off decline rate increases, the water cut rise rate of the well group increases, while the production decline rate decreases. It can be seen from Figure 15b that the cumulative oil production of the well group over 10 years decreases from $32,239 \text{ m}^3$ to $29,027 \text{ m}^3$ when the initial leak-off coefficient increases from $0.3 \text{ m} \cdot \text{d}^{-1/2}$ to $0.5 \text{ m} \cdot \text{d}^{-1/2}$, and it increases from

32,239 m³ to 38,706 m³ when the leak-off decline rate increases from 0.045 to 0.055. The larger the initial leak-off coefficient, the greater the early fluid leak-off, which slows down the increase in fracture net pressure, inhibits fracture propagation, and consequently leads to a lower water cut rise rate, a higher production decline rate, and a decrease in cumulative oil production. The faster the leak-off coefficient decline rate, the less the late-stage fluid leak-off, thereby promoting fracture propagation. This results in a higher water cut rise rate, a slower oil production decline rate, and an increase in cumulative oil production. Therefore, a smaller initial leak-off coefficient and a faster decline rate can enhance oil recovery performance.

3.2.2. Effect of Injection Rate on Waterflooding Performance Considering Dynamic Fracture Propagation

To investigate the effect of injection rate on waterflooding performance considering dynamic fracture propagation, a series of schemes with injection rates of 20 m³/d, 30 m³/d, and 50 m³/d were simulated. The simulations were conducted under a constant bottomhole flowing pressure of 7 MPa for production, with a production period of 10 years. The results are presented in Figures 16 and 17.

Figure 16 shows the dynamic fracture length at different injection rates. A higher injection rate facilitates dynamic fracture propagation, resulting in a longer propagation length within the same time interval. This is because a higher injection rate supplies more energy to the formation over a given time interval, promoting fracture initiation and increasing the dynamic fracture propagation length. Additionally, as the number of propagation cycles increases, both the time required for a single dynamic fracture propagation and the corresponding propagation length increase. This is attributed to the fact that longer fractures require more energy for further propagation. The increased energy demand prolongs the time required for each propagation cycle during water injection, allowing more energy to accumulate within the fracture. Consequently, a larger increment in fracture length is observed in subsequent propagation cycles. The positive correlation between injection rate and fracture propagation length observed in this study agrees with the general trend reported by Han et al. [37], who also found that higher injection rates promote more rapid fracture propagation. However, the impact of injection rate on waterflooding performance considering dynamic fracture propagation was not further investigated in their study.

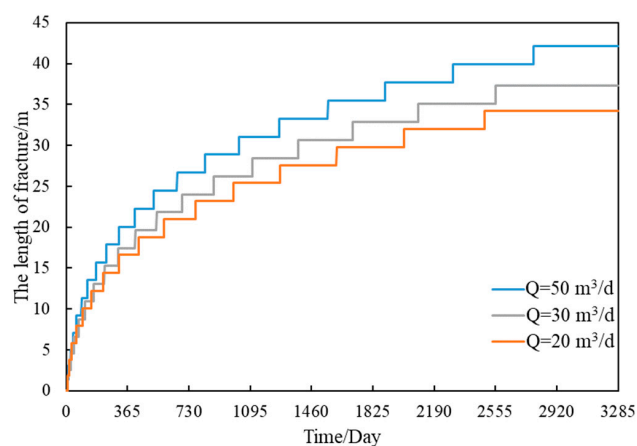


Figure 16. The length of dynamic fracture at different injection rates.

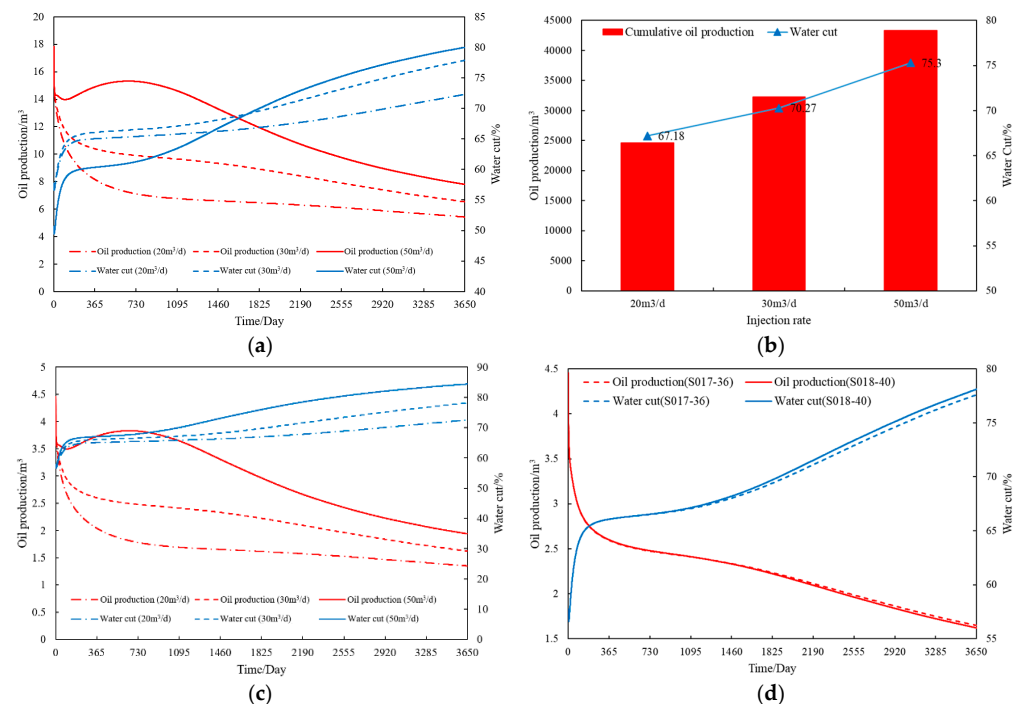


Figure 17. Comparison of production performance for well group S017-371 at different injection rates: (a) production performance; (b) cumulative oil production and water cut; (c) production performance of Well S018-40; (d) production performance of wells S017-36 and S018-40 at 30 m³/d.

Figure 17a presents the production performance of well group S017-371 at different injection rates. As the injection rate increases, the water cut rise rate of the well group increases, while the production decline rate decreases. Notably, at an injection rate of 50 m³/d, the well group even exhibits an increase in oil production during the early development stage. It can be seen from Figure 17b that the cumulative oil production of the well group over 10 years increases from 24,654 m³ to 43,346 m³ as the injection rate increases from 20 m³/d to 50 m³/d. The results indicate that a higher injection rate leads to higher cumulative oil production. As shown in Figure 17c, both the oil production and the water cut of Well S018-40, which is located along the direction of dynamic fracture propagation, increase with increasing injection rate. Meanwhile, the water breakthrough time is significantly advanced. At an injection rate of 50 m³/d, the water cut of Well S018-40 reaches 70% within 1096 days, compared with 2908 days at 20 m³/d, representing a time reduction of nearly two-thirds. The reason for the above results can be analyzed from Figure 18 as follows. A higher injection rate not only supplies formation energy in time and delays formation pressure decline, but also increases the dynamic fracture propagation length within the same time interval and accelerates the waterflooding response for oil wells located along the fracture propagation direction, thereby improving oil production and slowing down the production decline rate. However, the increased propagation length of dynamic fracture also accelerates the water breakthrough time of those wells, increasing their water cut rise rate.

Figure 17d shows the production performance of wells S017-36 and S018-40 at an injection rate of 30 m³/d. The two wells exhibit similar overall trends in water-cut evolution and oil production. These wells are located along and perpendicular to the direction of dynamic fracture propagation, respectively. However, compared to Well S017-36, Well S018-40 exhibits a faster increase in water cut and lower oil production. Nevertheless, the differences in oil production and water cut between the two wells remain small during the production period. From Figure 18, oil wells located along the direction of dynamic

fracture propagation exhibit a stronger waterflooding response, whereas those oriented perpendicular to this direction show a weaker response. This explains the faster water cut rise and lower oil production of Well S018-40. Moreover, slow dynamic fracture propagation and low formation permeability weaken the advantage of high-permeability fractures, resulting in only minor differences in oil production and water cut between the two wells during the production period.

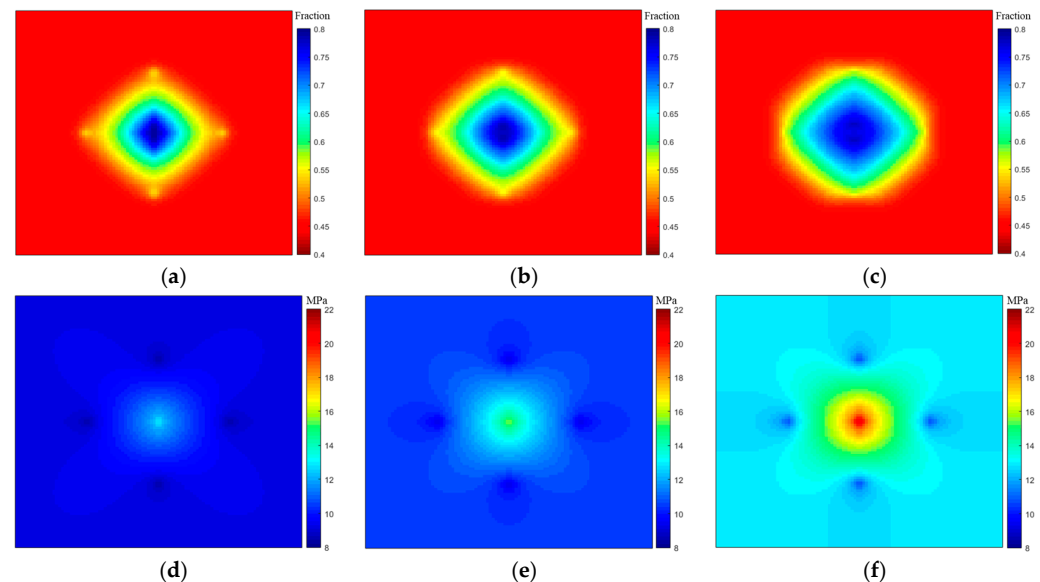


Figure 18. Water saturation and pressure distribution after 10 years of waterflooding at different injection rates: (a) water saturation distribution at $20 \text{ m}^3/\text{d}$; (b) water saturation distribution at $30 \text{ m}^3/\text{d}$; (c) water saturation distribution at $50 \text{ m}^3/\text{d}$; (d) pressure distribution at $20 \text{ m}^3/\text{d}$; (e) pressure distribution at $30 \text{ m}^3/\text{d}$; (f) pressure distribution at $50 \text{ m}^3/\text{d}$.

3.2.3. Effect of Fracture Orientation on Waterflooding Performance Considering Dynamic Fracture Propagation

To investigate the effect of fracture orientation on waterflooding performance considering dynamic fracture propagation, a series of schemes with fracture orientations of 0° , 30° , 45° , and 60° were simulated. The fracture orientation was defined as the angle between the line connecting injection well S017-371 and production well S017-80 and the fracture propagation direction. The simulations were conducted under a constant bottom-hole flowing pressure of 7 MPa for production and an injection rate of $30 \text{ m}^3/\text{d}$, with a production period of 10 years.

Figure 19a presents the production performance of well group S017-371 at different fracture orientations. As the fracture orientation increases from 0° to 45° , both the water cut rise rate and the production decline rate decrease with increasing fracture orientation. However, when the fracture orientation exceeds 45° , both rates increase with increasing fracture orientation. Moreover, the well group S017-371 exhibits similar production performance at fracture orientations of 45° and 60° due to the same distribution of wells and fractures. At a fracture orientation of 0° , the time required for the water cut of the well group S017-371 to reach 70% is 1919 days, whereas at 45° , this time is delayed by 564 days. Specifically, for Well S018-40, which is located along the direction of dynamic fracture propagation, the time required to reach a water cut of 70% increases from 1885 days at 0° to 2484 days at 45° . Moreover, at a fracture orientation of 45° , the water cut rise rate of the well group S017-371 becomes slower and more uniform. As shown in Figure 19b, the cumulative oil production of the well group increases from $32,240 \text{ m}^3$ to $33,801 \text{ m}^3$ as the fracture orientation increases from 0° to 45° .

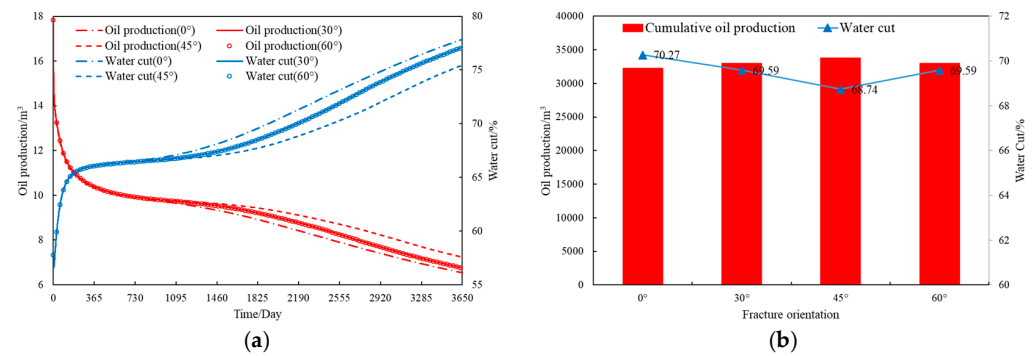


Figure 19. Comparison of production performance for well group S017-371 at different fracture orientations: (a) Production performance; (b) cumulative oil production and water cut.

As illustrated in Figure 20, increasing fracture orientation reduces the rate of water saturation increase near oil wells located along the direction of dynamic fracture propagation, resulting in a more uniform water saturation distribution within the well group. Simultaneously, it more effectively supplies formation energy, leading to a significant rise in formation pressure, which in turn decreases the water cut rise rate of the well group and increases cumulative oil production. In summary, a fracture orientation of 45° effectively delays water breakthrough in oil wells located along the direction of dynamic fracture propagation, thereby reducing the water cut rise rate of the well group and ultimately improving cumulative oil production. The observed influence of fracture orientation on waterflooding performance considering dynamic fracture propagation is qualitatively consistent with previous studies [38]. However, previous studies primarily focused on the ultimate oil recovery, whereas the present work further investigates detailed production responses, including the evolution of water cut, water saturation distribution, and pressure distribution, providing a more comprehensive understanding of waterflooding performance considering dynamic fracture propagation.

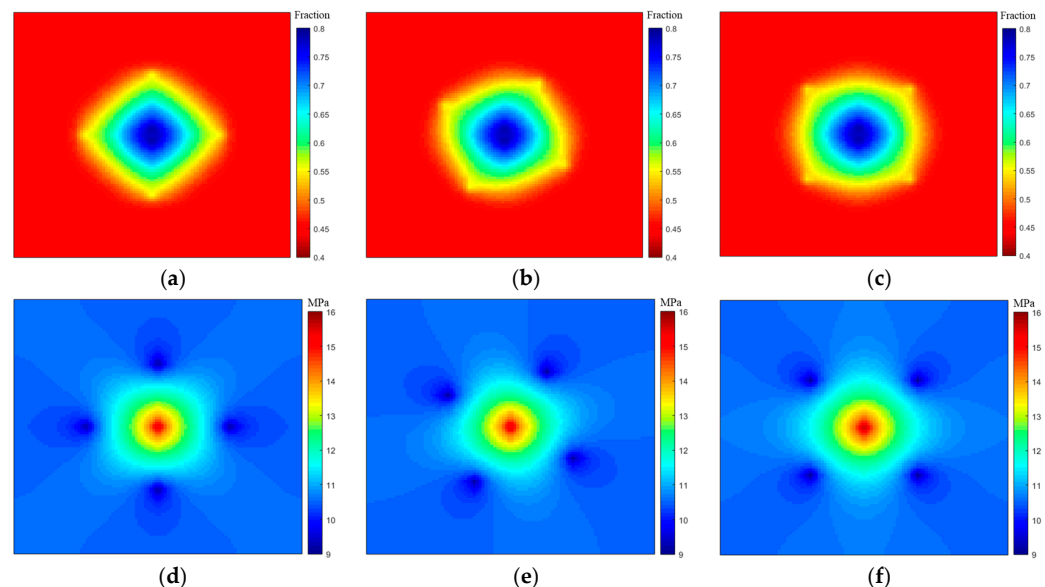


Figure 20. Water saturation and pressure distribution after 10 years of waterflooding at different fracture orientations: (a) water saturation at 0°; (b) water saturation at 30°; (c) water saturation at 45°; (d) pressure distribution at 0°; (e) pressure distribution at 30°; (f) pressure distribution at 45°.

3.2.4. Effect of Well Spacing on Waterflooding Performance Considering Dynamic Fracture Propagation

To investigate the effect of well spacing on waterflooding performance considering dynamic fracture propagation, a series of schemes with well spacings of 80 m, 140 m, and 200 m were simulated. The simulations were conducted under a constant bottom-hole flowing pressure of 7 MPa for production and an injection rate of 30 m³/d, with a production period of 10 years. The results are shown in Figures 21 and 22.

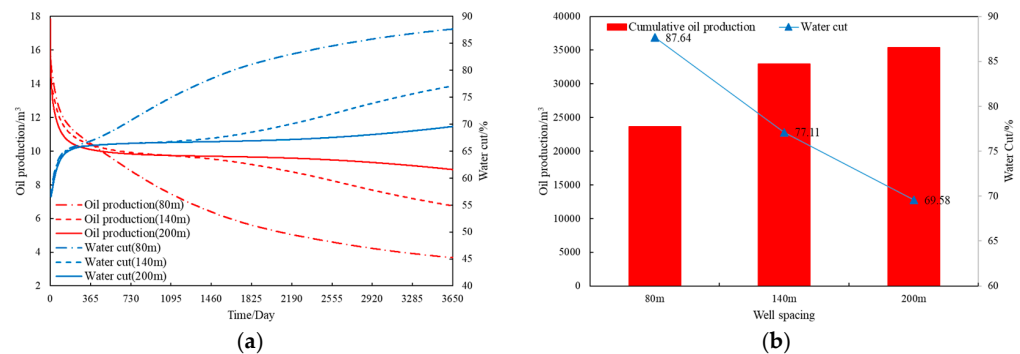


Figure 21. Comparison of production performance for well group S017-371 at different well spacings: (a) production performance; (b) cumulative oil production and water cut.

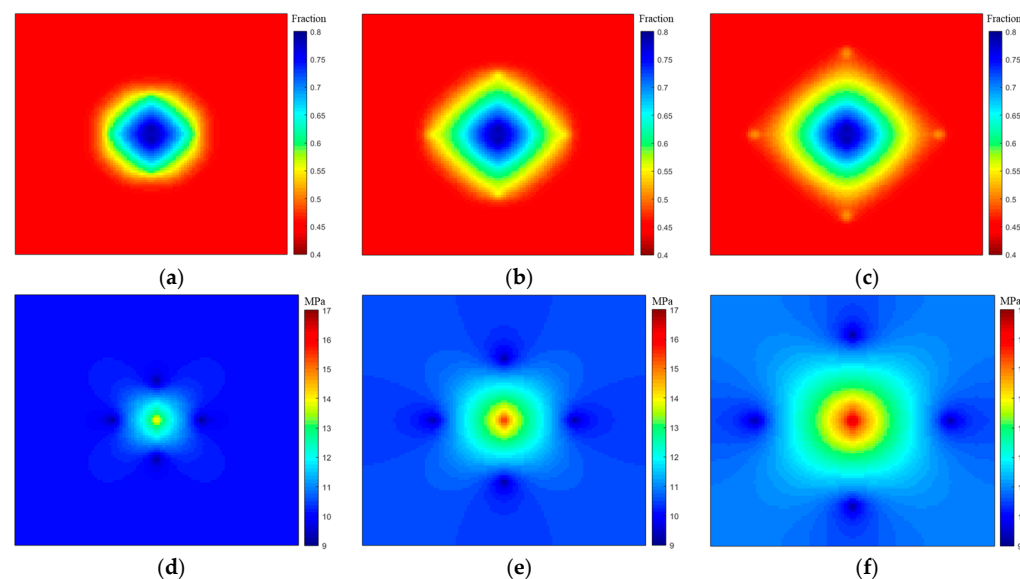


Figure 22. Water saturation and pressure distribution after 10 years of waterflooding at different well spacings: (a) water saturation at 80 m; (b) water saturation at 140 m; (c) water saturation at 200 m; (d) pressure distribution at 80 m; (e) pressure distribution at 140 m; (f) pressure distribution at 200 m.

Figure 21a illustrates the production performance of well group S017-371 at different well spacings. As the well spacing increases, both the water cut rise rate and the production decline rate of the well group decrease. Notably, at a well spacing of 200 m, the water cut of well group increases more slowly and uniformly. Meanwhile, larger well spacing also leads to a weaker waterflooding response and a more rapid production decline in the early development stage. For example, at a well spacing of 80 m, the water cut of the well group reaches 70% in 671 days, whereas at 200 m, it does not reach 70% even after 10 years of production. For Well S018-40, which is located along the direction of dynamic fracture propagation, the water cut reaches 70% after 693 days at 80 m, whereas it reaches only 69.5% after 10 years at 200 m. These results indicate that increasing well spacing effectively delays the water breakthrough in oil wells, particularly for wells located along

the direction of dynamic fracture propagation. As shown in Figure 21b, the cumulative oil production of the well group over 10 years increases from 23,671 m³ to 35,359 m³ as the well spacing increases from 80 m to 200 m. As illustrated in Figure 22, increasing well spacing delays the waterflooding response in oil wells, resulting in a significant decline in formation pressure near oil wells in the early development period and a rapid decline in oil production. Nevertheless, it also reduces the rate of water saturation increase near the oil wells and more effectively supplies formation energy, thereby slowing the water cut rise rate and significantly increasing oil production. The observed influence of well spacing on waterflooding performance considering dynamic fracture propagation is broadly consistent with previous studies [38]. However, previous studies mainly focused on the ultimate oil recovery without systematically analyzing the detailed production responses, such as the evolution of water cut, water saturation distribution, and pressure distribution. In contrast, the present study further investigates the impact of well spacing on waterflooding performance considering dynamic fracture propagation by quantitatively evaluating these responses, thereby providing practical guidance for optimizing well spacing to enhance waterflooding performance in ultra-low permeability fractured reservoirs.

3.2.5. Parameter Analysis of Multi-Factor Orthogonal Experiments

Based on the above single-factor analysis, an orthogonal experimental design was further conducted, and the experimental schemes and simulation results are presented in Table 4. The results of each scheme were analyzed using range analysis based on the data in Table 4, and the detailed results are summarized in Table 5. As shown in Table 5, the influence of different parameters on waterflooding performance considering dynamic fracture propagation follows the order of injection rate > well spacing > fracture orientation. Among the investigated conditions, a fracture orientation of 45° consistently provides the best performance under different combinations of injection rates and well spacing. The theoretical optimal combination is an injection rate of 50 m³/d, a fracture orientation of 45°, and a well spacing of 200 m, corresponding to Scheme 9, with a predicted cumulative oil production of 46,045 m³. This finding could provide theoretical guidance for improving waterflooding performance in ultra-low permeability fractured reservoirs in the WB Block of the Ordos Basin.

Table 4. Orthogonal experimental design and results.

Scheme	Injection Rate (m ³ /d)	Fracture Orientation (°)	Well Spacing (m)	Cumulative Oil Production (m ³)
1	20	0	80	24,552
2	20	30	140	26,942
3	20	45	200	28,745
4	30	0	140	32,250
5	30	30	200	35,053
6	30	45	80	30,853
7	50	0	200	44,973
8	50	30	80	41,776
9	50	45	140	46,045

Table 5. Range analysis and optimal level combination for the orthogonal experiment.

Level	Injection Rate (m ³ /d)	Fracture Orientation (°)	Well Spacing (m)
K1	26,746	33,925	32,394
K2	32,719	34,590	35,079
K3	44,265	35,214	36,257
Range	17,519	1289	3863
Factor ranking	1	3	2
Optimal level	50 m ³ /d	45°	200 m

4. Conclusions

In this study, a waterflooding model considering dynamic fracture propagation was developed to investigate the impact of fracture propagation on waterflooding performance in ultra-low permeability reservoirs with high-angle fractures. The main conclusions are as follows.

1. A high-angle fracture identification model was established using the fuzzy comprehensive evaluation method, with a threshold of 70 selected to distinguish fracture from non-fracture intervals. At this threshold, the identification accuracy averaged 88.3%, with a bootstrap-estimated 95% CI ranging from 79.0% to 94.9% ($p < 0.001$), confirming the criterion's reliability and applicability in the study block.
2. A waterflooding model considering dynamic fracture propagation was developed by coupling the oil–water two-phase flow mathematical model, the embedded discrete fracture model, and the dynamic fracture propagation model to realize the simulation of the waterflooding process considering the fracture propagation. History matching against field production data yielded an oil production fitting accuracy of 95.2% for the model considering dynamic fracture propagation, which is substantially higher than the 88.4% accuracy for the model without this consideration, demonstrating the necessity of incorporating fracture propagation for accurate performance prediction in ultra-low permeability reservoirs.
3. A lower initial leak-off coefficient and a faster decline rate of the leak-off coefficient reduce fluid loss from the fracture, accelerate the buildup of fracture net pressure, and promote dynamic fracture propagation, thereby improving oil recovery performance. In the studied case, increasing the initial leak-off coefficient from 0.3 to 0.5 $\text{m}\cdot\text{d}^{-1/2}$ reduced the cumulative oil production by approximately 10.0%, whereas increasing the leak-off coefficient decline rate from 0.045 $\text{m}\cdot\text{d}^{-1}$ to 0.055 $\text{m}\cdot\text{d}^{-1}$ increased cumulative oil production by approximately 20%.
4. Higher injection rates supply more energy to the formation over a given time interval, promoting dynamic fracture propagation and increasing fracture length. When the injection rate is increased from 20 to 50 m^3/d , the fracture length increases by 23%, accompanied by a 75.8% increase in cumulative oil production. However, as the number of propagation cycles increases, the energy required for fracture propagation increases, resulting in longer propagation time and larger incremental fracture growth. Increasing injection rate raises the water cut rise rate of the well group while slowing its production decline rate and increasing cumulative oil production. Nevertheless, a higher injection rate also promotes earlier water breakthrough in production wells located along the fracture propagation direction.
5. Fracture orientation and well spacing significantly affect waterflooding performance. Among the orientations, 45° yields the highest cumulative oil production of 33,801 m^3 , which is 4.8% higher than 0° and 2.6% higher than 30° , primarily by delaying water breakthrough and reducing the water cut rise rate. Increasing well spacing from 80 m to 200 m improves cumulative oil production from 23,671 m^3 to 35,359 m^3 , an increase of 44.6%, but accelerates early-stage production decline.
6. This work provides a practical framework for identifying high-angle fractures and evaluating waterflooding performance considering dynamic fracture propagation. The proposed fracture identification model was developed based on data from the WB Block, and its applicability to other reservoirs with different geological conditions requires further validation. In addition, the waterflooding model considering dynamic fracture propagation was developed under the assumptions of homogeneous reservoir properties and uniform well spacing. The model does not fully consider the coupled effects of complex natural fracture networks, large-scale reservoir heterogeneity, or

dynamic geomechanical stress changes, which should be further investigated in future studies.

Author Contributions: Conceptualization: S.K. and F.H.; Methodology: S.K. and T.Z.; Investigation: S.K. and Y.Y.; Formal analysis: Y.G. and D.L.; Writing—original draft: S.K.; Writing—review and editing: Y.Y.; Visualization: R.D.; Supervision: S.K. and F.H.; Funding acquisition: S.K. and F.H. All authors have read and agreed to the published version of the manuscript.

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Data Availability Statement: The original contributions presented in this study are included in the article. Further inquiries can be directed to the corresponding author.

Conflicts of Interest: Author Tong Zhang was employed by Yan'an Zhongshida Oil and Gas Engineering Technology Service Co., Ltd. Author Yanru Gao and Dongbin Liang were employed by PetroChina Changqing Oilfield Company. 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.

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