

Article

Research on the Extraction Efficiency of Tight Oil in Porous Media Under Varying CO₂ Injection Pressures

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Abstract

Developing complex fault-block low-permeability reservoirs faces great challenges in constructing efficient injection-production flow pathways, which often leads to unsatisfactory waterflooding development performance. To improve the recovery efficiency of this type of reservoir, this study first carried out laboratory extraction experiments and then conducted CO₂ extraction numerical simulations on low-permeability porous media via ANSYS to validate the experimental results. Based on investigations targeting the target reservoir, the key findings are summarized as follows: Supercritical CO₂ preferentially extracts light hydrocarbon components lighter than C₁₀, which accounts for more than 60% of the total extracted components; when the pressure exceeds 20 MPa, a small amount of heavy components C₁₅₊ can also be extracted. Under the experimental conditions adopted in this study, the optimal CO₂ reinjection pressure range is determined as 12–20 MPa. Within this range, the extraction efficiency increases by 2.0–2.5% per 1 MPa increment of pressure, and this pressure condition can effectively dissolve medium hydrocarbon components and promote the formation of uniform plug flow. However, when the reinjection pressure continues to rise beyond 20 MPa, the CO₂ extraction efficiency will gradually decrease. The numerically simulated CO₂ extraction efficiency of crude oil shows high consistency with the experimental measurements. This study confirms that CO₂ huff-n-puff can be effectively applied for crude oil extraction in the peripheral areas of tight reservoirs and fault-block reservoir units. Nevertheless, in field application, it is imperative to optimize the reinjection pressure design: accurately customizing injection pressure parameters according to different reservoir types and their specific development requirements is a core measure to improve CO₂ extraction efficiency.

Keywords: tight oil reservoir; low permeability; CO₂ injection and extraction; Ansys simulation

Academic Editor: Youguo Yan

Received: 30 June 2026

Revised: 21 July 2026

Accepted: 29 July 2026

Published: 31 July 2026

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1. Introduction

Complex fault-block reservoirs in China constitute a significant portion of the country's crude oil reserves. With the escalating energy demand and advancements in exploration and development technologies, their proportion in both proven and producing reserves continues to rise, highlighting their growing importance in development initiatives [1,2]. This type of reservoir is characterized by well-developed fault barriers and abundant secondary internal faults. The oil-bearing area of a single fault block is generally 0.3–0.5 km², with strong reservoir sealing and limited natural energy. After long-term waterflooding development, such reservoirs generally face a series of prominent problems: short anhydrous production period, strong interlayer heterogeneity, complex water distribution, scattered

remaining oil, poor effect of production stimulation measures, rapid production decline and sharp growth of water cut [3–5]. Although subsequent development interventions such as well pattern adjustment and layered development have been implemented, it is still difficult to effectively improve oil recovery [6,7]. In particular, low-permeability complex fault-block reservoirs with a small oil-bearing area are the most challenging type for efficient development [4]. Low-permeability reservoirs naturally have poor water absorption capacity. Coupled with insufficient reservoir understanding and strong reservoir sensitivity, the connectivity of the injection-production well pattern is poor, making it difficult to establish an effective displacement system [8,9]. Traditional development methods cannot meet the development demand, so it is urgent to explore innovative high-efficiency development strategies.

Aiming at the demand of enhanced oil recovery EOR in low-permeability reservoirs, CO₂ flooding and CO₂ huff-and-puff technology have attracted extensive research attention in recent years due to their great production-increase potential. Laboratory experiments including long-core displacement and microscopic visualization have clarified the mechanisms of viscosity reduction, miscibility and crude oil extraction by CO₂. Numerical simulation studies based on compositional models have completed extensive optimization of development schemes, laying a solid foundation for the application of CO₂-based development technology. In the current EOR research field, innovative technologies and methods are emerging continuously: nanoparticle-assisted EOR technology can further improve displacement efficiency and sweep efficiency in tight formations by reducing interfacial tension and optimizing fluid distribution, opening up a new approach for reservoir development [10]. Composite computational fluid dynamics CFD modeling can accurately characterize multi-phase and multi-component flow in porous media, overcoming the limitation of traditional numerical simulation in accurately describing interfacial interactions, and provides methodological support for fine simulation of CO₂ huff-and-puff processes [11]. Although existing studies have formed a preliminary theoretical framework for CO₂ development of low-permeability reservoirs, most of them focus on conventional homogeneous low-permeability reservoirs. For complex fault-block reservoirs characterized by a small oil-bearing area, strong sealing and poor well pattern connectivity, targeted feasibility verification of CO₂ huff-and-puff development is still insufficient. Different from existing research, this paper targets the unique development challenges of such reservoirs, verifies the effectiveness of CO₂ huff-and-puff development technology, provides new support for the development of these hard-to-recover reserves, and fills the research gap in this field. The same-well injection-production huff-and-puff mode can effectively avoid the problem of insufficient well pattern connectivity and has been widely applied in the development of hard-to-recover reserves in the oilfield periphery [12–14]. Supercritical CO₂ has the characteristics of high permeability, strong diffusivity and good solubility. After injection, it can quickly diffuse into the reservoir matrix to extract crude oil and transport it to the surface through the wellbore, which effectively solves the difficulty of establishing effective displacement in low-permeability complex fault-block reservoirs with a small oil-bearing area. Meanwhile, this technology can also realize CO₂ sequestration and emission reduction, with comprehensive environmental, economic and social benefits [15].

However, current research still lacks quantitative investigation on reasonable CO₂ reinjection pressure for field engineering practice, which has become a prominent bottleneck restricting the large-scale application of CO₂ enhanced oil recovery and storage in Xinjiang's tight oil reservoirs [16,17]. With the rapid development of Carbon Capture, Utilization and Storage (CCUS) demonstration projects in Xinjiang, it has been verified that formation pressure varies dynamically across the whole life cycle of CO₂ reinjection. Especially for pure CO₂ geological storage projects, reinjection pressure will keep rising

with the growth of cumulative reinjection volume, bringing great uncertainty to pressure regulation and control [18]. Existing studies mostly focus on the measurement of minimum miscible pressure of CO₂-crude oil systems but fail to quantitatively characterize the reasonable reinjection pressure interval under different formation pressure conditions, reservoir heterogeneity and development stages [19]. Up to now, the quantitative coupling relationship between reinjection pressure, CO₂ extraction efficiency and long-term storage security has not been fully clarified [20]. This knowledge gap leads to a series of practical problems including poor working condition adaptability, high energy consumption and severe gas channeling in field engineering, which greatly reduces the synergistic benefit of oil recovery improvement and carbon sequestration [21,22].

Therefore, targeted quantitative research on CO₂ reinjection pressure for tight oil reservoirs is urgently needed to clarify the quantitative characterization method and optimization strategy of reasonable reinjection pressure, so as to provide solid theoretical and engineering support for the efficient and large-scale development of CCUS projects in Xinjiang's tight oil resources.

2. Research Conditions and Methods

The study utilizes wells located in the marginal zone of the XX tight oil reservoir as case examples. Initially, it is ascertained that the porosity of the rocks within this block spans from 10% to 20%, with permeability values approximately ranging between 0.5 and 5 mD. On this basis, porous media models with three distinct permeability values—0.95, 2.23, and 3.03—were established, with experimental cores being directly sampled for the purpose (refer to Table 1). Subsequently, a comprehensive component analysis of the crude oil sampled directly from the site was carried out (see Table 2), and the critical characteristic parameters of the pseudo-components were fitted for subsequent numerical simulation (see Table 3). Ultimately, both experimental investigations and numerical simulations were conducted under uniform research conditions to assess the extraction efficiency of tight oil through CO₂ injection at varying pressures, thereby offering valuable insights to support the advancement of CO₂ injection technology aimed at enhancing oil recovery in tight oil reservoirs.

Table 1. Physical parameters of experimental rock cores.

Number	Length (cm)	Cross-Sectional Area (cm ²)	Porosity (%)	Permeability (mD)	Weight (g)
1#	4.31	5.0074	11.02	2.15	40.44
2#	4.26	5.0029	10.39	1.93	39.68
3#	4.11	5.0242	12.18	2.33	39.01
4#	4.05	4.8997	11.08	3.21	38.28
5#	4.01	4.9757	12.21	3.54	37.34

Table 2. Composition of crude oil samples.

Component	C ₅	C ₆	C ₇	C ₈	C ₉	C ₁₀	C ₁₁
Molar composition	1.284	4.208	6.79	9.054	8.928	2.031	3.159
Component	C ₁₂	C ₁₃	C ₁₄	C ₁₅	C ₁₆	C ₁₇	C ₁₈
Molar composition	1.029	4.361	3.642	1.036	2.041	2.031	1.451
Component	C ₁₉	C ₂₀	C ₂₁	C ₂₂	C ₂₃	C ₂₄	C ₂₅
Molar composition	3.291	2.341	5.601	1.281	2.807	2.458	3.142

Table 2. Cont.

Component	C ₂₆	C ₂₇	C ₂₈	C ₂₉	C ₃₀	C ₃₀₊
Molar composition	2.351	2.842	2.428	3.147	3.522	13.744
Remark	C ₂₅₊ properties: Relative density = 0.838; Molecular weight = 218					

Table 3. Characteristic parameters of proposed components of formation fluids.

Component	Molecular Weight	Critical Pressure (MPa)	Temperature (°C)	Ω_a	Ω_b	Deviation Factor	Specific Volume
CO ₂	44.01	7.39	31.55	0.43	0.09	0.23	78.00
C ₅₊	16.04	4.60	−82.55	0.43	0.09	0.01	77.00
C ₁₀₊	36.32	4.60	60.98	0.43	0.09	0.12	126.86
C ₁₅₊	58.12	3.73	144.31	0.43	0.09	0.19	186.10
C ₂₀₊	75.82	3.27	204.98	0.43	0.09	0.26	241.47
C ₂₅₊	133.63	2.54	343.49	0.43	0.09	0.43	389.78
C ₃₀₊	325.00	1.04	566.69	0.43	0.09	1.04	828.33

2.1. Research Subjects and Conditions

(1) Experimental core: The relevant core parameters are shown in Table 1.

(2) Crude oil composition: The composition and content of the crude oil are shown in Table 2.

In numerical simulation computations, when the number of components attains a specific threshold, a further increase in the component count does not substantially enhance simulation accuracy; instead, it escalates the computational workload. By employing the heavy fraction splitting methodology, the heavy components of the target crude oil were fractionated according to the principles of hydrocarbon property similarity [23,24]. Subsequently, the split constituents were recombined into six pseudo-components: C₅₊, C₁₀₊, C₁₅₊, C₂₀₊, C₂₅₊, and C₃₀₊. This splitting approach simplifies the phase equilibrium calculations within the model, thereby reducing its computational workload. Analysis of the fitting results from the CO₂ swelling test data confirms that the regressed fluid critical parameters accurately depict the characteristics of the formation fluid, meeting the criteria for simulation accuracy. Specific parameter values are recorded in Table 3.

(3) Experimental apparatus: Comprising an extraction vessel, separation vessel, desiccation unit, electric heating system, refrigeration system, CO₂ booster pump, chemical additive injection pump, pressure regulation valve control cabinet, and electrical control cabinet. Schematic illustrations of the extraction experimental procedure are shown in Figure 1.

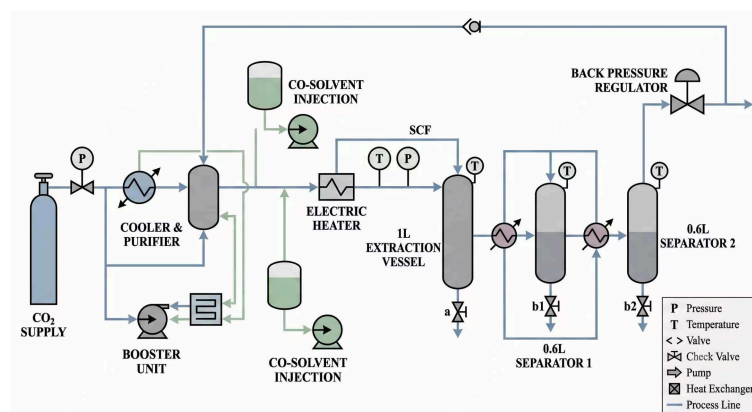


Figure 1. Schematic illustration of the extraction experimental procedure.

2.2. Physical Experiments

Experimental Methodology for Single-Round CO₂ Extraction and Compositional Analysis [25–27]: ① establish connections along the flow pathway and confirm system integrity, followed by an initial heating and drying phase for 10 min; ② evacuate the system to attain water saturation, subsequently inject crude oil into the core at a constant flow rate of 0.05 mL/min until pressure stabilization is achieved (pressure should remain stable for at least 2 pore volumes (PVs)) with no water production detected. Weigh the core to ascertain the mass of the saturated oil; ③ liquefy the CO₂ feedstock; ④ place the beaker containing the core within the supercritical CO₂ reactor, secure the lid and valves, set the apparatus temperature to 72 °C, adjust the ambient pressure, and perform the experiment by injecting at a constant pressure as specified by the design pressure outlined in Table 4; ⑤ execute the extraction protocol: elevate the temperature/pressure to the predetermined conditions, maintain for 1 h, remove the core, and store it wrapped in plastic film; ⑥ remove any residual moisture from the surface of the extracted core using filter paper, and measure its mass (m_3) using a precision electronic balance; ⑦ conduct a compositional analysis of the crude oil using gas chromatography (Thermo Fisher, Waltham, MA, USA, single quadrupole ISQ model, mass range: 1.2 to 1100 amu).

Table 4. Core experiment parameters.

Simulation Number	Injection Pressure (MPa)	Core Weight (g)	Saturated Oil Mass (g)
1	10	40.44	1.60
2	12	39.68	1.65
3	15	39.01	1.73
4	20	34.78	1.80
5	25	37.21	1.88

2.3. Numerical Simulation

(1) Physical model establishment

Fully numerical simulation of the Navier–Stokes equations for two-phase fluid flow in porous media with real structures or particles is extremely challenging due to the extensive numerical computations required. Therefore, this paper only considers a finite number of identical particles as the porous medium. Per Xu et al. [28,29], the simple cubic SC packing arrangement is validated for computational fluid dynamics CFD simulations using ANSYS Fluent (version R15.0). Consequently, the porous media's internal structure was modeled using SC packing, incorporating a finite set of identical uniform particles to minimize microscale heterogeneity effects on extraction analysis. This approach yielded the homogeneous pore model depicted in Figure 2. Macroscopic dimensions are annotated in Figure 2 right: axial length $Z = 2$ m, with cross-sectional dimensions in the X–Y plane representing a cylindrical domain of diameter 0.9928 m.

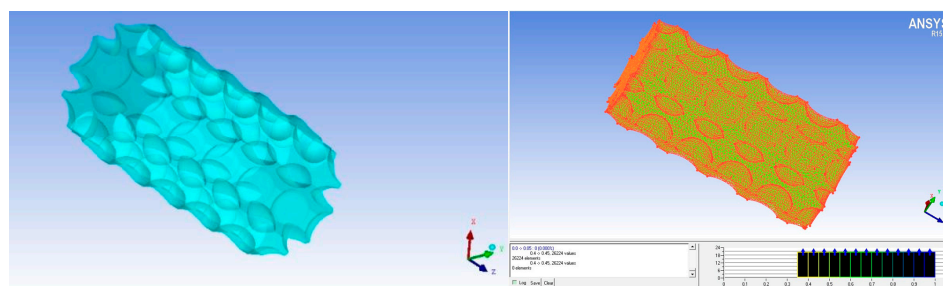


Figure 2. Three-dimensional diagram of the model and its network partitioning.

To facilitate comparative analysis, simulation results were primarily analyzed along the X–Z plane at $y = -41$ m Figure 2 [30,31].

(2) Mathematical equation

The porous medium model involves defining a porous medium region and setting its porosity, as well as the flow resistance and inertial resistance coefficients of the fluid (see Equation (1)). According to the literature [32], the numerical simulation methods for complex flow fields used in engineering are still primarily based on turbulence simulation methods that rely on solving the Reynolds correlation quantity transport equation and the time-averaged equation. Solving the time-averaged Reynolds equation not only avoids the problem of excessive computational effort in the DNS method but also achieves excellent results for practical engineering applications. Therefore, the Reynolds averaging method is adopted to construct the mathematical equations.

1. Momentum equation model

The porous media model accounts for flow impedance within the computational domain by introducing a momentum sink term into the governing equations [33,34]. This sink term comprises two components: a viscous resistance term (Darcy drag) and an inertial resistance term.

$$S_j = - \left(\sum_{j=1}^3 D_{ij} \mu v_j + \sum_{j=1}^3 C_{ij} \frac{1}{2} \rho |v| v_j \right) \quad (i = x, y, z) \quad (1)$$

Here, D_{ij} and C_{ij} represent the viscous resistance and inertial resistance coefficient tensors, respectively. This momentum sink term induces a pressure gradient across the porous medium. In all governing transport and continuity equations, the transient term adopts the form $\frac{\partial}{\partial t}(\gamma \rho \phi)$, where γ denotes porosity. The fluid viscosity μ is expressed in mPa·s, velocity v in m/s, while i and j denote Cartesian unit vectors.

2. Component change model

For multicomponent systems, the conservation of mass and momentum governs fluid behavior. Subsequently, during mixing processes, the mass conservation equation is expressed as Equation (2), where fluid phase composition is determined by volume percentage, defined in Equation (3). The momentum conservation equation is given by Equation (4).

$$\frac{\partial \rho_m}{\partial t} + \frac{\partial}{\partial x_j} (\rho_m u_j) = 0 \quad (2)$$

$$\rho_m = \rho_p \alpha_p + \rho_g \alpha_g \quad (3)$$

$$\frac{\partial}{\partial t} (\rho_m u_i) + \frac{\partial}{\partial x_j} (\rho_m u_i u_j) = - \frac{\partial p}{\partial x_i} + \rho_m g_i + \frac{\partial \tau_{ij}}{\partial x_j} \quad (4)$$

Among them, τ_{ij} shear stress, MPa; see Equation (5).

$$\tau_{ij} = \mu_m \left(\frac{\partial u_i}{\partial x_j} + \frac{\partial u_j}{\partial x_i} - \frac{2}{3} \delta_{ij} \frac{\partial u_k}{\partial x_k} \right) \quad (5)$$

Within the governing equations, the variables are defined as follows: u_j —velocity component m/s; T —time s; ρ_m —mixture density kg/m³; ρ_p —oil phase density kg/m³; ρ_g —gas phase density kg/m³; α_p —oil phase volume fraction dimensionless; α_g —gas phase volume fraction dimensionless; μ_m —mixture dynamic viscosity, mPa·s; p —pressure, MPa; u_j, u_i, u_k —velocity components in Cartesian directions m/s; x_i, x_j, x_k —Cartesian coordinates m; g_i —gravitational acceleration component m/s².

3. Turbulence model

The numerical simulation employs the finite volume method with second-order up-wind discretization for governing equations. The Renormalization Group RNG k - ε turbulence model is implemented, featuring modified constants derived from renormalization group theory and additional terms in its transport equations. The turbulent kinetic energy (k) and dissipation rate (ε) equations retain structural similarity to the standard k - ε formulation.

$$\rho \frac{dk}{dt} = \frac{\partial}{\partial x_i} \left[\left(\alpha_k \mu_{eff} \right) \frac{\partial k}{\partial x_i} \right] + G_k + G_b - \rho \varepsilon - Y_M + S_k \quad (6)$$

$$\rho \frac{d\varepsilon}{dt} = \frac{\partial}{\partial x_i} \left[\left(\alpha_\varepsilon \mu_{eff} \right) \frac{\partial \varepsilon}{\partial x_i} \right] + G_{1\varepsilon} \frac{\varepsilon}{k} (G_k + C_{3\varepsilon} G_b) - C_{2\varepsilon} \rho \frac{\varepsilon^2}{k} - R_\varepsilon + S_\varepsilon \quad (7)$$

In the governing equations, the terms are defined as follows: G_k denotes the turbulence kinetic energy production term originating from mean velocity gradients; G_b signifies the turbulence kinetic energy production due to buoyancy forces; Y_M represents the dilatation dissipation contribution from compressible turbulence fluctuations; α_k corresponds to the inverse effective turbulent Prandtl number for turbulence kinetic energy k ; α_ε designates the inverse effective turbulent Prandtl number for dissipation rate ε ; S_k indicates the user-defined source term for turbulence kinetic energy; S_ε describes the user-defined source term for turbulence dissipation rate.

The turbulent viscosity coefficient is computed as:

$$d \left(\frac{\rho^2 k}{\sqrt{\varepsilon \mu}} \right) = 1.72 \frac{\tilde{v}}{\sqrt{\tilde{v}^3 - 1 - C_v}} d\tilde{v} \tilde{v} = \tilde{\mu}_{eff} / \mu, C_v = 100. \quad (8)$$

(3) Simulation design content

The boundary conditions and simulation design details are provided in Table 5.

Table 5. Simulation schemes under different pressures.

Simulation Number	Temperature (°C)	Initial Pressure (MPa)	Injection Pressure (MPa)	Porosity (%)	Permeability (mD)
1	72	0	10.00	10	0.95
2	72	0	12.00	15	2.23
3	72	0	15.00	15	2.23
4	72	0	20.00	20	3.03
5	72	0	25.00	20	3.03

3. Results and Analysis

3.1. Analysis of Crude Oil Extraction Efficiency Under Different Pressures

The results of crude oil extraction rates under different CO₂ reinjection pressures, obtained through numerical simulation and indoor experiments, are shown in Figure 3.

As evidenced in Figure 3, the crude oil extraction rate demonstrates a monotonic increase with rising CO₂ reinjection pressure within the 10–25 MPa range. Numerical simulations consistently exceed laboratory measurements by <5%, indicating strong experimental-numerical agreement. The extraction rate profile exhibits two distinct phases: Low-growth phase (10–12 MPa): Differential extraction increase averages 1.2% per MPa, corresponding to a low-gradient curve; High-growth phase (12–20 MPa): Extraction rate rises by 2.2% per MPa, characterized by a steeper slope.

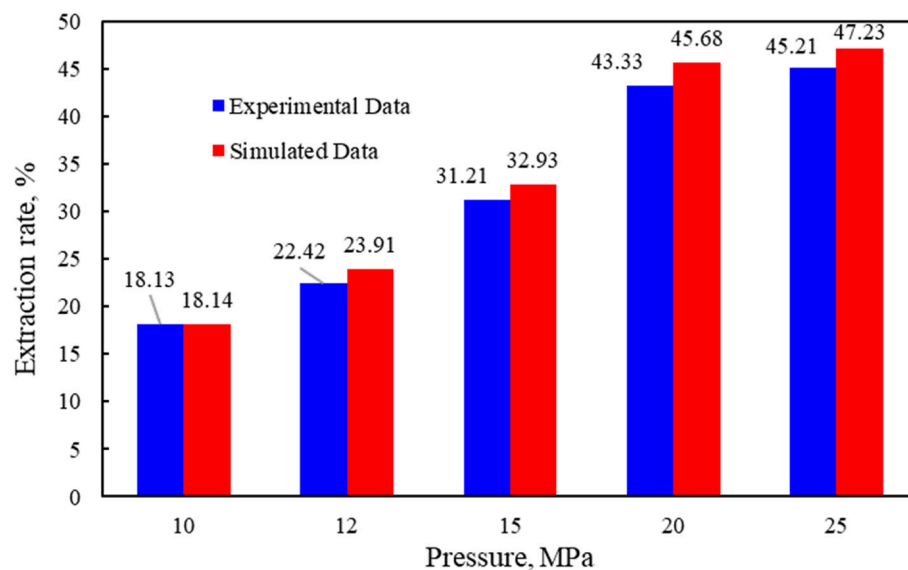


Figure 3. Diagram of extraction rate changes under different pressures.

Given CO₂'s critical pressure (7.38 MPa), reinjection pressures beyond this threshold induce supercritical fluid (Supercritical carbon dioxide SC-CO₂) conditions. Per supercritical solubility theory (Chrastil model): During the low-growth phase, SC-CO₂ density increases markedly with sharp molecular compaction, enhancing solvation power. This elevates the solubility coefficient K of light hydrocarbons (C₁–C₁₂; e.g., n-heptane, toluene), driving rapid extraction rate escalation; in the high-growth phase, density growth decelerates but SC-CO₂ attains liquid alkane-like solvent strength, enabling extraction of medium fractions (C₁₂–C₂₀; e.g., diesel distillates). Concurrently, the CO₂ diffusion coefficient (D) in crude oil increases under elevated pressure, intensifying mass transfer efficiency. Furthermore, pressure elevation approaches the minimum miscibility pressure (MMP), substantially reducing interfacial tension and improving displacement efficiency.

3.2. The Impact of Extraction Under Different Reinjection Pressures on Crude Oil Components

Through simulation analysis, the mass fractions of each component of the remaining oil in the core after throughput extraction can be obtained, as shown in Figure 4.

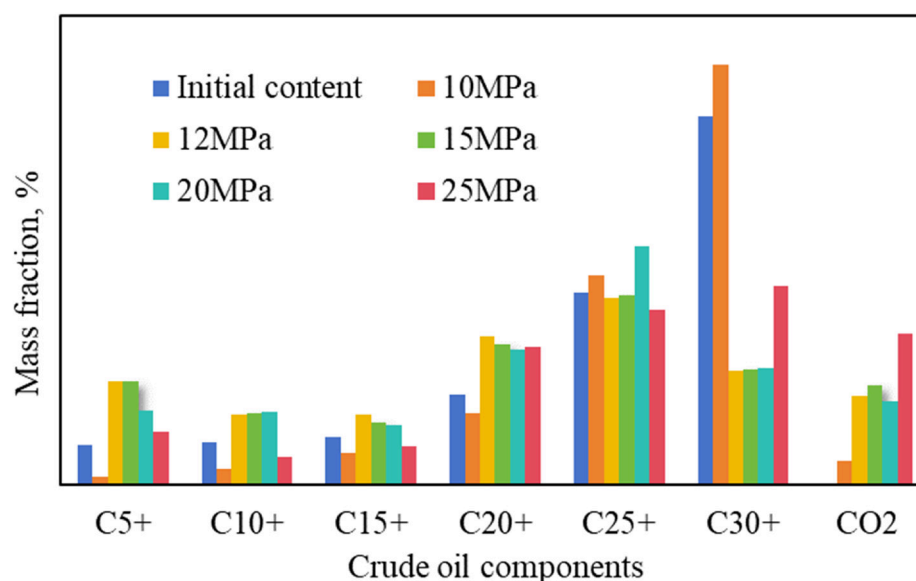


Figure 4. Mass fraction of remaining oil components in the core.

Figure 4 reveals three distinct pressure-dependent extraction regimes: At 10.00 MPa, slightly above the CO₂ critical pressure of 7.38 MPa, limited solubility results in preferential extraction of light fractions C₅–C₉ and concomitant relative enrichment of heavy components C₂₅–C₃₀+. The residual oil exhibits increased mass fraction of heavy constituents due to light-end stripping. Within the 12–15 MPa range, elevated pressure enhances both miscibility and solubility, as evidenced by 11.28. These synergistic effects improve the extraction efficiency of heavy hydrocarbons. Maximum heavy-component extraction occurs at 20 MPa, where CO₂ solubility saturates. Further pressure increase to 25 MPa induces heavy-component re-enrichment. Analysis suggests that under conventional medium and low pressures (<20 MPa), CO₂, due to its small molecular size and weak polarity, preferentially extracts the light components from crude oil. However, at 25 MPa, CO₂ is in a high-density supercritical state, and its intermolecular forces and polarity greatly match those of the heavy components (C₂₅–C₃₀) of crude oil, reversing the priority and initiating the extensive dissolution of heavy components. The light components originally dissolved in the supercritical phase of CO₂ will condense out of the CO₂ phase and return to the crude oil phase in the core pores due to the excessively high density of CO₂ and the system pressure exceeding the “reverse condensation pressure threshold” of the phase envelope (See Figure 5) [35–37]. Meanwhile, a large amount of CO₂ itself (19.35%) remains, directly occupying the flow channels. These precipitated light components cannot migrate with the fluid to the production end and ultimately remain trapped in the core.

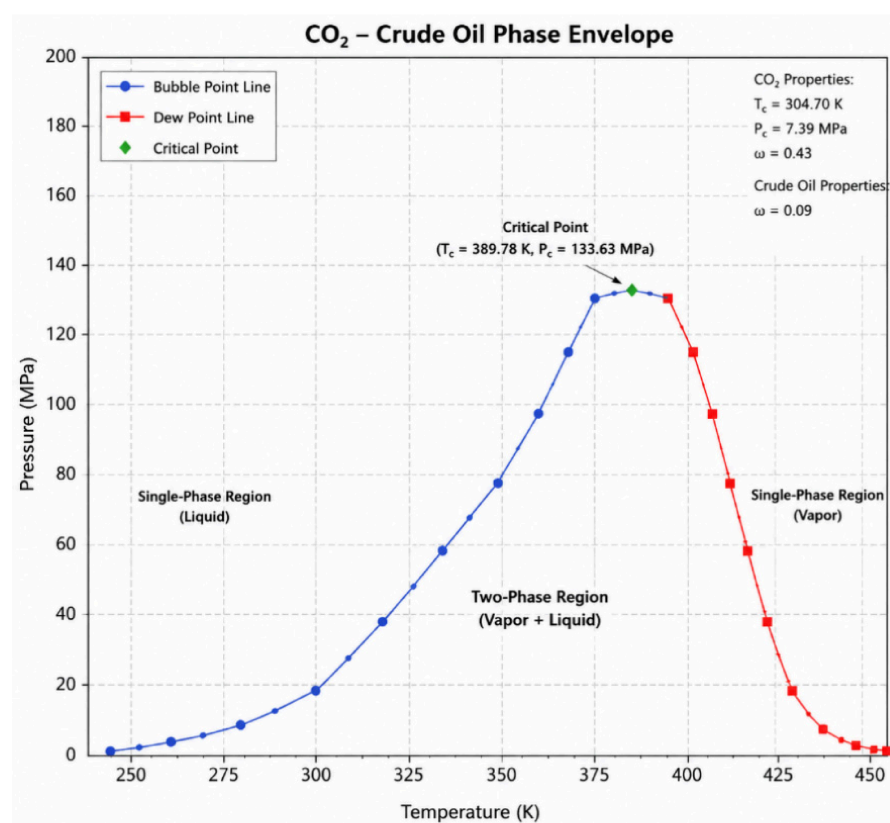


Figure 5. CO₂-Crude oil phase envelope.

Additionally, simulation analysis reveals that as pressure increases, more components of CO₂ tend to remain trapped in porous media. Under low-pressure conditions, the amount of CO₂ retention is limited, but it increases significantly at 25 MPa. Therefore, during the extraction of tight oil using CO₂, a moderate amount of CO₂ can be sequestered, and the higher the pressure, the greater the amount of CO₂ sequestered.

The fluid extracted from the indoor experiment was subjected to component analysis using a chromatograph, and the content of each component is presented in Table 6.

Table 6. Table of extracted oil samples.

Back Pressure		Component Content (%)				
Component	10 MPa	12 MPa	15 MPa	20 MPa	25 MPa	
C ₅	48.4921	53.5216	58.7815	61.2506	69.1125	
C ₆	19.7412	17.2697	16.0749	15.0601	12.2446	
C ₇	7.3407	7.8924	8.1472	6.0249	4.5449	
C ₈	4.6618	3.9856	2.304	4.3346	2.066	
C ₉	2.3195	2.6361	4.0062	3.3026	1.0409	
C ₁₀	3.2631	1.6723	1.0511	1.2541	1.3569	
C ₁₁	2.0231	2.5941	1.7456	1.842	1.3917	
C ₁₂	1.9461	2.1027	1.2541	1.451	1.751	
C ₁₃	1.8354	1.781	1.1561	1.0231	1.0351	
C ₁₄	1.7026	1.4121	1.0245	1.0114	1.0024	
C ₁₅	1.7261	1.0271	1.034	1.003	1.0354	
C ₁₆	1.0561	1.267	1.001	0.752	0.9513	
C ₁₇	1.0252	0.354	0.781	0.813	0.1562	
C ₁₈	0.9512	0.7548	0.4621	0.259	0.714	
C ₁₉	0.4514	0.5471	0.5102	0.136	0.0159	
C ₂₀	0.8561	0.2147	0.314	0.0081	0.1234	
C ₂₁	0.4782	0.4672	0.211	0.0045	0.2851	
C ₂₂	0.0231	0.3351	0.0321	0.0047	0.5103	
C ₂₃	0.1004	0.0721	0.0261	0.002	0.0154	
C ₂₄	0.0054	0.0813	0.081	0.0123	0.631	
C ₂₅₊	0.0012	0.012	0.0023	0.451	0.016	

Table 6 demonstrates that increasing pressure enhances CO₂ solubility and induces monotonic growth in the absolute extraction yield of C₅ hydrocarbons. Consequently, the C₅ fraction in extracts rises from 48.49% to 69.11%. At 20 MPa, the substantial increase in absolute C₅ extraction (constituting 62.25% of extracts) reduces the relative proportion of C₆–C₁₀ fractions despite their rising absolute yields. This inverse relationship stems from the solvation selectivity of supercritical CO₂: Low-to-medium pressures preferentially extract low-carbon-number components (lower boiling points, reduced polarity), while high-density CO₂ (≥ 20 MPa) is required to dissolve higher-carbon-number, higher-boiling-point constituents.

Thus, supercritical CO₂ primarily extracts light hydrocarbons ($\leq C_{10}$), with minimal extraction of heavy components ($\geq C_{15}$). Experimental and simulation results exhibit strong agreement, validating numerical modeling as a robust methodology for studying supercritical CO₂ extraction in tight oil systems.

3.3. Analysis of Non-Equilibrium Pressure Characteristics During the Injection-Production Process

When CO₂ is injected into the system, it enters a pressurization mode. The equilibrium pressure characteristics of different core profiles can be obtained through simulation, as shown in Figure 6 below.

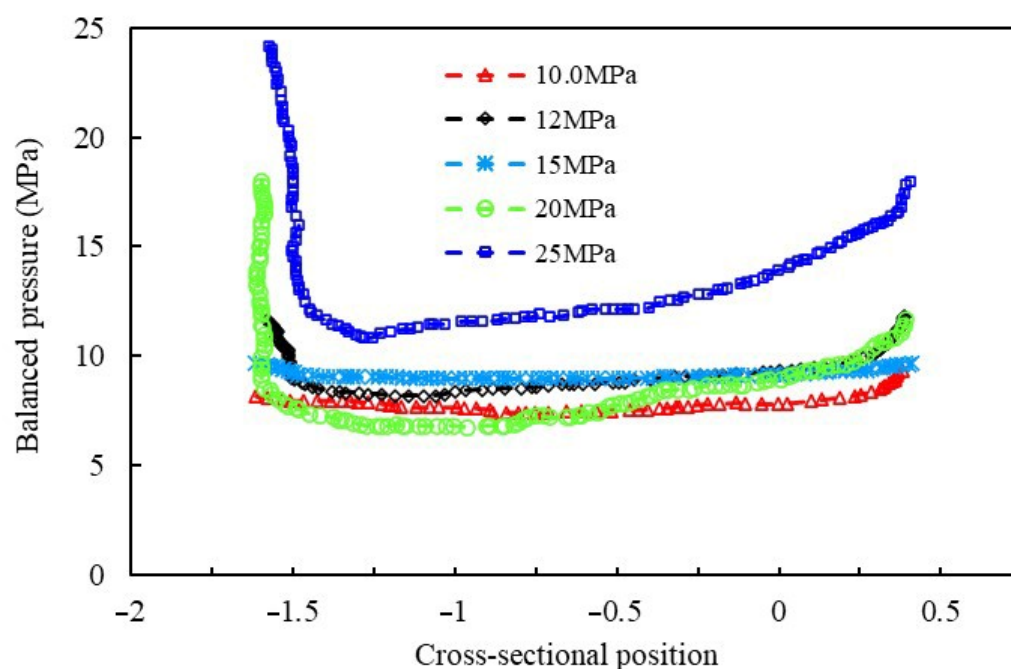


Figure 6. Pressure change at the cross-section of CO₂ injection.

Figure 6 demonstrates consistent system pressure evolution during CO₂ injection across all tested pressures: an initial sharp decline, followed by gradual recovery, and ultimate stabilization at the injection pressure. However, at injection pressures of 20.00 MPa and 25.00 MPa, the distal pressure right most model boundary remains significantly lower than the inlet pressure. Analysis suggests that the strong non-Darcy resistance brought about by high injection flow rate, coupled with the deteriorated flow capacity of CO₂ after mixing with crude oil in the intermediate region, jointly leads to a rapid pressure drop starting from the injection end and reaching its lowest point in the intermediate region. After crude oil dissolves CO₂, its viscosity decreases significantly, significantly improving the flow capacity in the production end region, causing the pressure to start rising from the lowest point in the middle. Although an increase in flow rate near the outlet brings some non-Darcy resistance, the upward trend remains unchanged, ultimately resulting in a state where the pressure at the production end is higher than that in the intermediate region.

Post-injection simulations with outlet pressure fixed at 8.00 MPa reveal persistent pressure differentials within the system. This disequilibrium drives CO₂-mediated elution of crude oil constituents during depressurization, confirming system-wide pressure depletion. Subsequent simulation results characterize this process.

The data presented in Figure 7 demonstrate that different initial pressure conditions yield a consistent pattern of system pressure evolution, characterized by a distinct parabolic pressure distribution: elevated pressures at the two boundaries of the flow system and reduced pressure in the central region. This indicates that the initial pressure condition has negligible influence on the subsequent depressurization dynamics of the system. This unique pressure evolution phenomenon originates from the non-equilibrium state of the flow system: The inertial effect preserves the forward momentum of the injected CO₂; The abrupt drop in inlet pressure forms a reverse pressure gradient along the flow direction, which generates a counter-flow driving force [38].

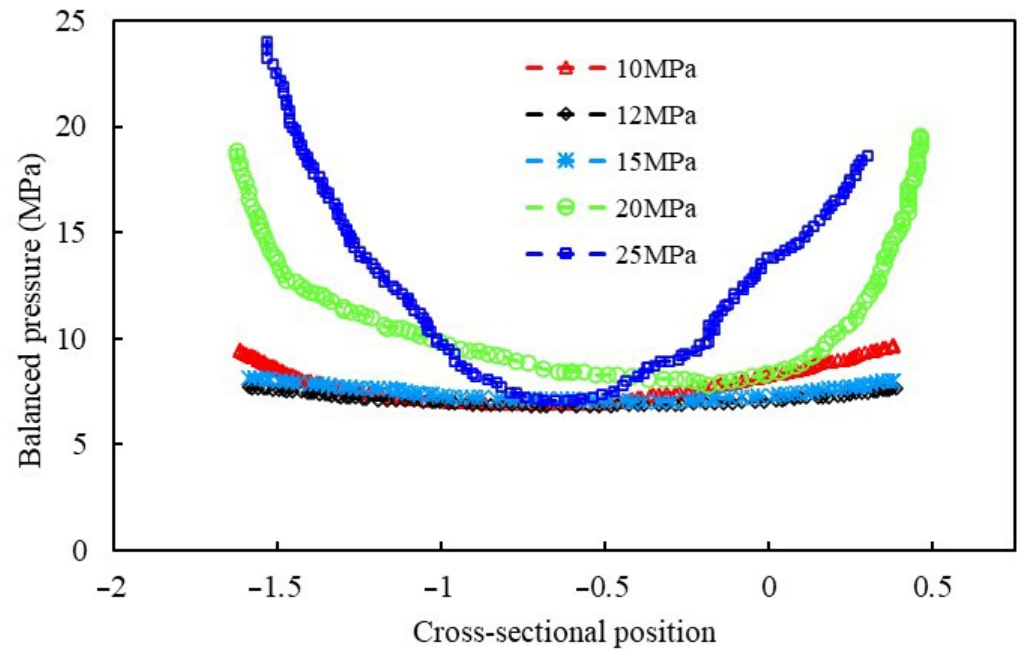


Figure 7. Comparison of pressure at the cross-section of CO₂ release.

3.4. Flow State During the Extraction Process

The pressure distribution and velocity vectors during the simulated pressure relief process are shown in Figure 8 (the unit of the pressure contour map is MPa, and the unit of the velocity map is m/s).

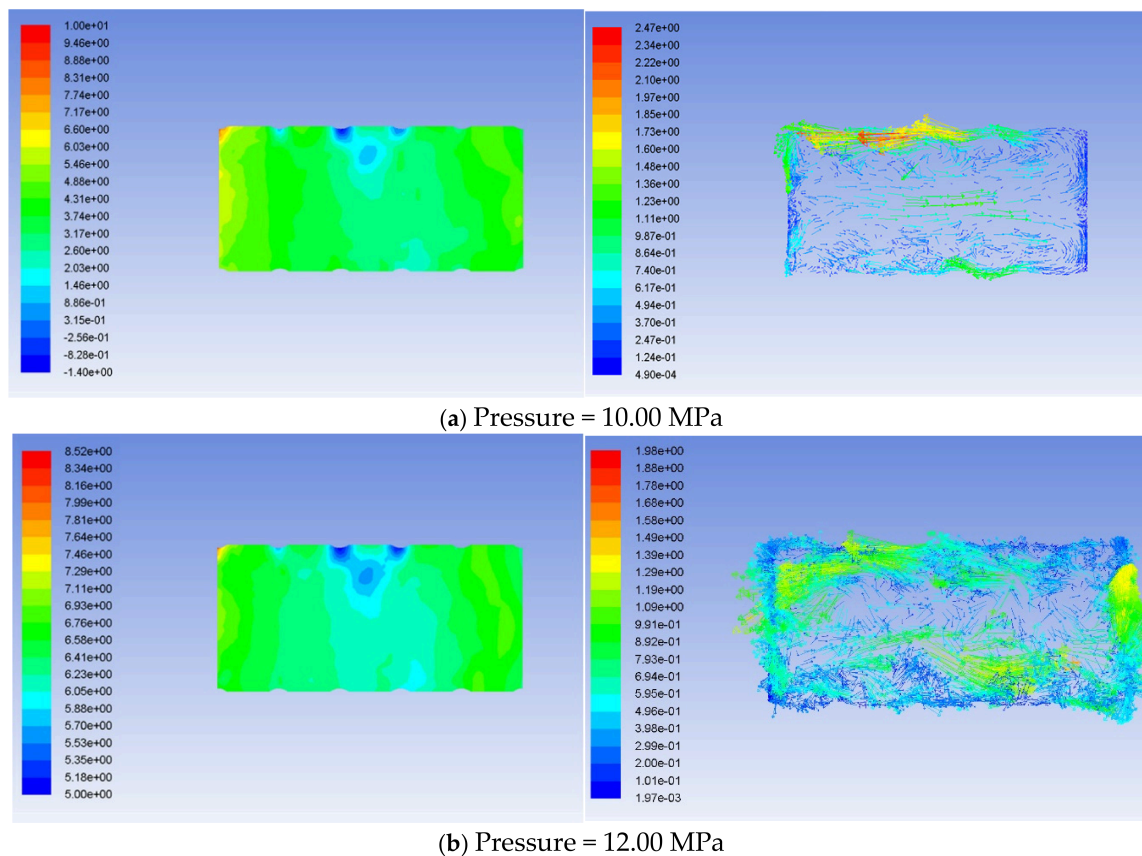


Figure 8. Cont.

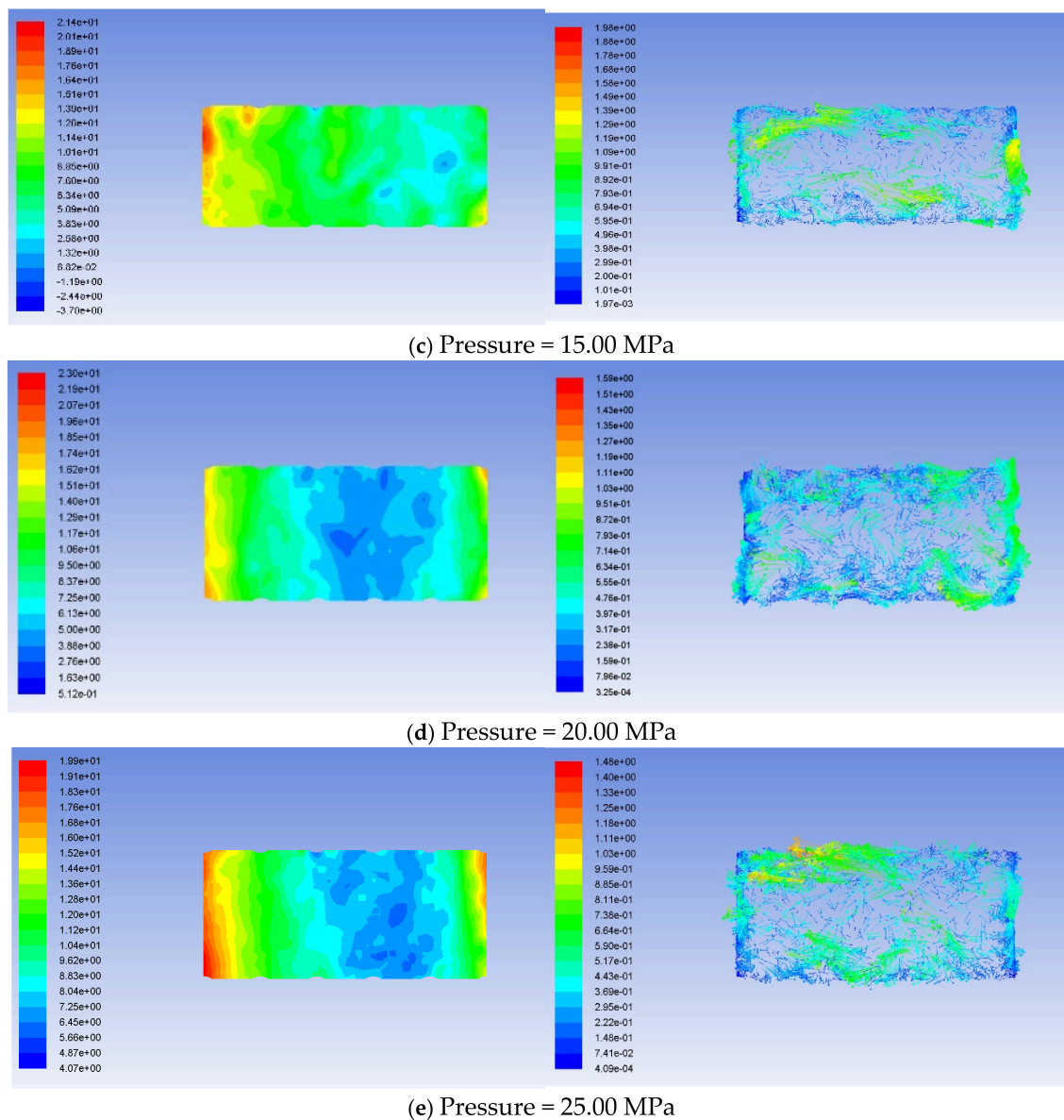


Figure 8. Cloud chart of pressure distribution and velocity vector diagram at the cross-section during CO₂ release.

As depicted in Figure 8, the flow state undergoes a transition from “weak drive → confined flow (a → b)” to “strong drive-uniform flow (b → c, d)”, and subsequently to “overdrive-channeling flow (d → e)”. The fundamental disparities arise from the pressure dependency of CO₂ solubility, the extent of crude oil viscosity modification, and flow control mechanisms. (1) The overall pressure distribution in Figure 8a is relatively uniform, characterized by low pressure transfer efficiency and sluggish energy dissipation; the velocity vector arrows are short and dispersed, lacking a discernible directional consistency, and “dead oil zones” are present at the core edges or within localized areas of low-permeability pores, resulting in a low overall flow velocity. (2) Figure 8b exhibits a pronounced pressure gradient along the seepage direction, significantly larger than that in Figure 8a, indicating effective pressure transmission and the formation of a driving gradient; the length of velocity vector arrows increases, their direction tends to align, the area of “dead oil zones” diminishes, and the flow range extends to over 70% of the core area, with minor velocity concentration in localized high-permeability channels. (3) In Figure 8c, the overall pressure gradient is relatively gentle, displaying a uniform color transition from dark blue to light

green and then to yellow-orange. There are no pressure anomaly regions characterized by abrupt local color changes, indicating uniform pressure transmission within the core and the absence of localized “pressure islands”. The velocity vector distribution is uniform, with minimal variations in arrow length and highly consistent directions. There are almost no “dead oil zones” with stagnant flow velocities, and the overall flow pattern exhibits typical characteristics of “piston-like displacement”. (4) In Figure 8d, abrupt color changes from dark blue (indicating low pressure) to blue-green are observed in certain localized areas, forming a “pressure concentration zone”. The overall pressure gradient distribution is non-uniform, reflecting localized variations in pressure transmission within the core. The differences in arrow lengths representing velocity vectors increase significantly, with flow velocities notably elevated in the local yellow-green regions and arrow directions deviating from the main flow direction. In low-permeability zones, the arrows are short, and flow velocities are low, demonstrating the “fingering phenomenon” in fluid displacement. (5) The pressure distribution in Figure 8e exhibits characteristics of “single-channel breakthrough”, with only a localized area on the left side displaying an orange-red high-pressure zone, while the majority of the remaining area is blue-green, with pressures close to the original formation pressure. Under these conditions, the pressure gradient is at its maximum, yet the pressure influence range is minimal. Over 90% of the velocity vectors are concentrated within the “low-pressure breakthrough zone” on the left, with arrow lengths reaching 0.8 to 1.0 m/s and directions pointing directly towards the outlet along the breakthrough path. Velocity vectors outside the breakthrough zone are nearly negligible, presenting a flow pattern predominantly characterized by “channeling”.

In summary, the flow state of CO₂-displaced crude oil evolves in a “three-stage” manner with increasing injection pressure: at the low-pressure stage (<12.0 MPa), insufficient CO₂ dissolution leads to limited reduction in crude oil viscosity, with flow resistance predominating and resulting in confined flow (inefficient); at the medium-pressure stage (12~20 MPa), near-miscible dissolution of CO₂ occurs, leading to the lowest crude oil viscosity and a flow ratio ≈ 1 , resulting in uniform plug flow (efficient); at the high-pressure stage (20.0~25.0 MPa), excessive CO₂ dissolution combined with an imbalance in the flow ratio leads to gravitational differentiation and channeling, resulting in non-uniform/channeling flow (inefficient). The flow state during pressure release and oil extraction after CO₂ injection into the core for crude oil extraction is essentially determined by the phase interaction between CO₂ and crude oil, the dissolution-extraction effect, and the hydrodynamic characteristics of fluids in porous media.

4. Conclusions

- (1) The crude oil extraction efficiency of CO₂ increases monotonically with pressure, and its growth shows a clear staged characteristic. In the pressure range of 8–15 MPa, the growth rate of extraction efficiency is relatively low with a small slope on the efficiency-pressure correlation curve, and the incremental amplitude of extraction efficiency is approximately 1.5–2.0. In the pressure range of 15–28 MPa, the growth rate is significantly higher with a larger slope, and the incremental amplitude of extraction efficiency reaches approximately 2.0–2.5. The numerical simulation results obtained in this study are consistent with the measured experimental trend.
- (2) Pressure can effectively regulate the selectivity of CO₂ component extraction, but excessively high pressure will eventually lead to a reduction in overall extraction efficiency. Under the experimental conditions of this work, extraction efficiency presents a clear three-stage evolution law with changing pressure. At low pressures <12 MPa, the flow capacity of CO₂ in the porous medium of tight reservoirs is limited, so extraction efficiency is generally maintained at a moderate level. In the medium

- pressure range of 12–20 MPa, relatively uniform plug flow of CO₂ is formed, resulting in significantly higher extraction efficiency. However, when pressure enters the high range >20 MPa, obvious CO₂ channeling occurs in the porous medium, which deteriorates sweep efficiency and ultimately reduces the overall extraction efficiency.
- (3) In the process of CO₂ extraction development for tight oil, a non-negligible amount of injected CO₂ can be effectively sequestered in the reservoir, and the total amount of CO₂ sequestration increases with the increase in operating pressure.

Author Contributions: Conceptualization, C.D.; methodology, C.D. and X.J.; software, X.P.; formal analysis, S.Z.; investigation, C.D.; resources, X.P.; data curation, X.J. and X.P.; writing—original draft, C.D. and S.Z.; writing—review and editing, S.Z.; project administration, X.J. and X.P.; funding acquisition, S.Z. All authors have read and agreed to the published version of the manuscript.

Funding: This project was funded by the China Postdoctoral Science Foundation (2023M744278) and Science and Technology Research Project of Chongqing Education Commission (KJQN202301518).

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

Acknowledgments: Thank Li Tao for his assistance and guidance in numerical simulation.

Conflicts of Interest: Authors Chunyu Du, Xingrui Jia and Xuanwei Pang were employed by Songyuan Gas Production Plant of Jilin Oilfield. The remaining author declares 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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