

Article

Enhancing Recovery of Low-Productivity Coalbed Methane Wells in Medium-Shallow Reservoirs by CO₂ Huff-and-Puff

Chenlong Yang ^{1,2}, Zhiming Fang ^{1,2,*} , Shaicheng Shen ^{1,2}  and Haibin Wang ^{1,2}¹ State Key Laboratory of Geomechanics and Geotechnical Engineering Safety, Institute of Rock and Soil Mechanics, Chinese Academy of Sciences, Wuhan 430071, China² University of Chinese Academy of Sciences, Beijing 100049, China

* Correspondence: zmfang@whrsm.ac.cn

Abstract

Coalbed methane (CBM) is a vital clean energy resource, yet its extraction efficiency is often hindered by rapid production decline and low production rates in medium-shallow reservoirs. This study investigates the potential of CO₂ huff-and-puff technology to enhance CBM recovery and achieve CO₂ storage in low-productivity wells. A comprehensive model, constructed based on the geological conditions of the Qinshui Basin, was developed. Numerical simulations revealed that CO₂ huff-and-puff significantly improves CH₄ production by displacing adsorbed CH₄ and maintaining reservoir pressure. Key findings indicate that higher CO₂ injection volumes yield substantial increases in both peak CH₄ production and cumulative production compared with conventional extraction. Optimal soaking times balance recovery efficiency and operational costs. Sensitivity analysis identified gas diffusion coefficients, initial permeability, and Langmuir volume constants as critical geological parameters influencing the performance. This study preliminarily demonstrates the feasibility of large-scale CO₂ huff-and-puff for enhancing production in low-productivity CBM wells and provides theoretical insights for revitalizing China's underperforming CBM wells while advancing carbon neutrality goals, although further experimental validation is still required.



Academic Editor: Haishen Jiang

Received: 26 September 2025

Revised: 4 November 2025

Accepted: 9 November 2025

Published: 11 November 2025

Citation: Yang, C.; Fang, Z.; Shen, S.; Wang, H. Enhancing Recovery of Low-Productivity Coalbed Methane Wells in Medium-Shallow Reservoirs by CO₂ Huff-and-Puff. *Separations* **2025**, *12*, 314. <https://doi.org/10.3390/separations12110314>

Copyright: © 2025 by the authors. Licensee MDPI, Basel, Switzerland. This article is an open access article distributed under the terms and conditions of the Creative Commons Attribution (CC BY) license (<https://creativecommons.org/licenses/by/4.0/>).

Keywords: coalbed methane; low-productivity well; medium-shallow reservoirs; CO₂ huff-and-puff; ECBM

1. Introduction

Coalbed methane (CBM), a significant clean and efficient energy source, plays a dual role in addressing energy shortages and enhancing environmental sustainability. Its large-scale development not only supplements natural gas supplies and mitigates coal mine hazards (e.g., gas outbursts) but also contributes to greenhouse gas reduction [1–3]. China possesses the world's third-largest CBM reserves, with two major production bases established in the Qinshui Basin and the eastern Ordos Basin [4,5]. Distinct from other tight gas reservoirs (e.g., shale gas), medium- to shallow-depth CBM primarily exists in an adsorbed state within coal seams [6–8]. However, conventional extraction methods face a critical limitation: rapid production decline due to reservoir pressure depletion, coupled with slow desorption of adsorbed CBM, which hinders efficient recovery [9]. Globally, the CBM industry has experienced divergent developmental trajectories. Since 2008, the development of CBM in the United States has entered a period of decline, characterized by a continuous decrease in annual production and a drop in single-well productivity [10–12].

This situation highlights the urgent need for technological innovations to revitalize the CBM industry. In the Powder River Basin, approximately 8000 wells have already been shut down or abandoned [13]. In the southern part of the Cooper Basin in Australia, although coal seams exhibit relatively high permeability, their low gas content necessitates stimulation and productivity enhancement measures to achieve commercial viability [14]. In countries such as England, France, and Turkey, large-scale CBM development has not been realized, primarily due to low permeability, which results in poor well productivity [13]. China's annual CBM production has demonstrated sustained growth since 2005. However, since 2012, this growth has markedly slowed, accompanied by a decline in newly drilled wells (as shown in Figure 1). The slowdown in production growth is primarily attributed to the prevalence of low-productivity CBM wells, resulting from multiple engineering challenges: reservoir damage during drilling and completion, improper drainage strategies, and natural pressure depletion following prolonged production. By the end of 2020, only ~60% (12,880 wells) of the 21,217 drilled nationwide were operational [15]. Analysis of 4200 CBM wells (Table 1) reveals that more than 50% are low-productivity wells across most blocks, with some regions exceeding 90%. Additionally, certain blocks exhibit average daily production as low as a few hundred cubic meters per well, highlighting severe inefficiencies. Given the ubiquitous distribution and high proportion of underperforming wells, low productivity has emerged as a critical bottleneck in China's CBM development. Consequently, enhancing recovery in existing wells has become an urgent priority for the industry.

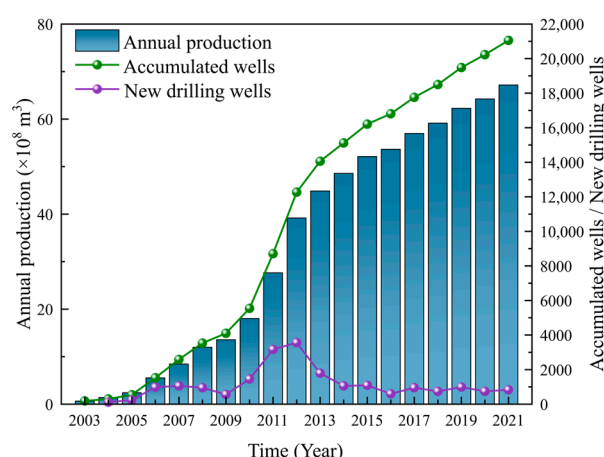


Figure 1. Annual CBM production and well development statistics (accumulated and newly drilled wells) in China from 2003 to 2021 [16], Copyright 2023 Coal Geology & Exploration.

In recent years, various stimulation measures have been implemented in several regions to enhance production from low-productivity CBM wells. Reservoir stimulation has become a critical technical approach for improving CBM productivity, primarily through re-fracturing techniques including conventional hydraulic fracturing, acid fracturing, indirect roof fracturing, and nitrogen fracturing [25]. To address well shutdowns caused by sand or coal fines during drainage operations, a pilot project was conducted in the Zhengzhuang Block of the Qinshui Basin, where oriented sand-controlled hydra-jet fracturing was applied in two L-shaped horizontal wells. Following stimulation, these wells achieved stable daily gas production rates of $1.01 \times 10^4 \text{ m}^3/\text{d}$ and $1.60 \times 10^4 \text{ m}^3/\text{d}$ respectively [26]. Furthermore, to tackle the challenges of low pressure, low permeability, and low saturation, a field trial was conducted in the Pingdingshan mining area using liquid nitrogen injection-assisted fracturing technology. After the treatment, the wells achieved stable and sustained gas production, with a cumulative gas production of $6.2 \times 10^5 \text{ m}^3$ [27]. While these technologies have demonstrated promising results in field applications, their broader

implementation requires further validation. Notably, secondary hydraulic fracturing may cause reservoir damage and environmental contamination [28], and is often ineffective for wells experiencing production declines due to natural depletion or inherently low gas content [29].

Table 1. CBM production data for partial regions of China.

	Region	Period	Number of Wells	Production Status
Qinshui Basin	Shizhuangnan Block [17]	by the end of 2019	950+	278 (29.3%) non-producing wells, 536 (56.4%) have an average production below 500 m ³ /d, only 38 wells (4%) maintain an average production exceeding 1000 m ³ /d with an overall average production <300 m ³ /d, nearly 90% of wells (89.31%) produce below 500 m ³ /d
	Xishan Block [18]	2011–2021	700+	463 wells (32%) demonstrate average production rates below 500 m ³ /d
	Fanzhuang Block [19]	2006–2020	1426 vertical wells	42.8% of wells (121) remain productive, maintaining an average output of 124 m ³ /d
	Zhaozhuang Block [20]	2006–2018	283	22 wells (25.9%) are non-productive, with an additional 40 wells (47.1%) producing at average rates less than 200 m ³ /d
	Yangquan Block [21]	-	85	
Ordos Basin	Liulin County	by the end of 2019	570	46.7% of wells (266) maintain production at an average rate of 1052 m ³ /d, whereas the unfractured wells (304, 53.3%) remain non-productive
	Linfen Block [22]	2013–2015	164	79.3% of active wells exhibited sustained production rates below 500 m ³ /d
Henan	Pingdingshan Block [23]	2011–2013	5	overall average production rate of 157.6 m ³ /d, with a maximum peak production reaching 586 m ³ /d
Yunnan	Enhong Block [24]	2005–2018	4	overall average production rate of 302 m ³ /d, with a maximum peak production reaching 750.31 m ³ /d
	Laochang Block [24]	2011–2018	11	overall average production rate of 682 m ³ /d, with a maximum peak production reaching 1864 m ³ /d

It is widely recognized that CO₂-enhanced coalbed methane (CO₂-ECBM) recovery is an effective method for improving CBM production [30–35]. This technology enhances CBM recovery through CO₂ injection into coal seams while simultaneously enabling CO₂ geological storage, thereby contributing to carbon emission reduction and supporting the “dual carbon” strategy [36–38]. Numerous studies on CO₂-ECBM have elucidated the mechanisms underlying CH₄ production enhancement, CO₂ sequestration, and changes in the physical properties of coal reservoirs during the process. Li et al. [39] based on a coupled numerical model and employing the influence factor method, analyzed the effects of CO₂ and CH₄ on coal deformation in CO₂-ECBM. Their results indicated that, in the early stage of injection, coal deformation is primarily governed by CH₄ desorption, whereas in the later stage it gradually shifts to being dominated by CO₂ adsorption. Wang et al. [40] using molecular dynamics simulations, investigated the CO₂ injection process as well as the displacement of CH₄ by CO₂ after injection cessation, and revealed that the CO₂–CH₄ displacement rate is relatively high in the initial stage of gas injection, while isobaric diffusion effects dominate once gas pressure equilibrium is reached. Ye et al. [41] developed a classification-based model to examine the dynamic evolution of the fracture network within coal seams during CO₂ injection, and found that the injection altered the original stress equilibrium of the coal seam, thereby inducing corresponding deformation and thermal expansion. As a practical application of CO₂-ECBM, CO₂ huff-and-puff involves direct CO₂ injection into low-productivity wells to enhance CH₄ output. As illustrated in Figure 2, the CO₂ huff-and-puff process for enhancing CBM comprises three distinct phases: gas injection, soaking, and production. Among its operational strategies, the CO₂ huff-and-puff approach is particularly suited for stimulating low-productivity CBM wells. In this process, CO₂ is injected into a target well, allowed to soak and displace adsorbed CH₄, and subsequently produced together with mobilized CH₄. After CO₂ is separated from the mixed gas produced during the third stage of CO₂ huff-and-puff, it can be re-injected into the coal seam for a new huff-and-puff, which is analogous to the injection

of dry gas into hydrocarbon reservoirs to enhance condensate recovery [42]. Compared with conventional displacement methods, CO₂ huff-and-puff requires no auxiliary injection wells, consumes less CO₂, and can be implemented using existing well infrastructure, thus lowering operational costs and cycle time. Owing to its simplicity, cost-effectiveness, and effectiveness in enhancing CH₄ production while ensuring CO₂ storage, this technology can serve as a practical solution for revitalizing underperforming CBM wells, especially in regions like China where numerous such wells exist. Two early-stage micro-pilot tests conducted in the Qinshui Basin in 2004 [43] and 2010 [44], injected 192.3 t and 233.6 t of CO₂, respectively. Post-soak production data confirmed enhanced CH₄ production upon wells reopening, demonstrating the technique's preliminary feasibility. However, due to the limited injection volumes and small scale, the stimulation mechanisms and the scalability for commercial deployment remain insufficiently understood and require further systematic investigation. While most research on CO₂ huff-and-puff has focused on shale gas, findings exhibit significant discrepancies. For instance, one numerical simulation reported a 55% CO₂ storage efficiency and increased gas production after injecting $\sim 3.8 \times 10^4$ t CO₂ over 12 cycles in two years [45]. Similarly, Fathi and Akkutlu [46] observed a 30% recovery increase with over 90% CO₂ storage after five years of continuous CO₂ injection. Conversely, Eshkalak et al. [47] documented merely 4% recovery enhancement after five years of injection and five years of soaking, with most CO₂ being re-extracted. These contradictory results may be related to variations in operational huff-and-puff strategies and reservoir-specific factors. Furthermore, the technique proves less effective in low-permeability formations or those with high CO₂ Langmuir volume constant [48]. Currently, no studies have been conducted on large-scale CO₂ huff-and-puff for enhancing production in low-productivity CBM wells in medium-shallow coal seams. Despite these shale gas studies, existing results are inconsistent regarding both methane recovery and CO₂ storage efficiency. Critically, coal reservoirs differ fundamentally from shale in permeability, adsorption behavior, and geomechanical properties, necessitating targeted investigations. Thus, a comprehensive evaluation of CO₂ huff-and-puff's feasibility and mechanistic effects in coal seams—particularly for revitalizing low-productivity CBM wells is imperative to bridge this knowledge gap.

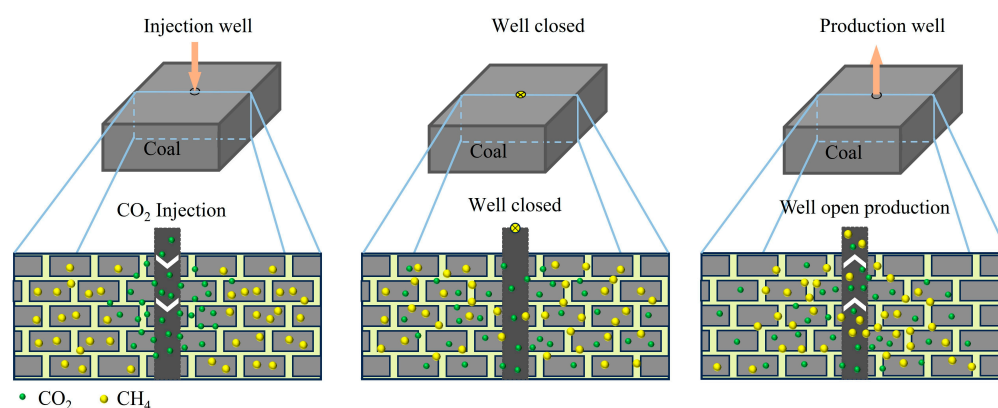


Figure 2. Schematic diagram of CO₂ huff-and-puff.

Numerous researchers have developed mathematical models to simulate the CO₂-ECBM process, facilitating in-depth investigations of CO₂ injection and CH₄ extraction through numerical simulations. Typically, coal seams are conceptualized as dual-porosity system consisting of fractures and matrix blocks. Upon CO₂ injection into the coal seam, multiple complex mechanisms come into play, including CO₂-CH₄ binary gas interactions, gas adsorption and desorption, gas-water two-phase flow within fractures, mass exchange between fractures and the matrix, and dynamic variations in porosity and

permeability [49–51]. For instance, Liu et al. [52] incorporated these complex processes into a fully coupled model to evaluate CH₄ recovery under a scenario involving one CO₂ injection well and eight production wells. Similarly, Fan et al. [53] developed a numerical model to optimize the composition scheme for CO₂/N₂ mixed-gas displacement. Yang et al. [54] established a numerical model based on the Qinshui Basin to examine the impact of different CO₂ injection rates on the CO₂-ECBM process. Based on the aforementioned mechanisms, Hou et al. [55] further incorporated thermodynamic effects to investigate the influence of CO₂ injection temperature and pressure on CO₂-ECBM. While these models provide a relatively comprehensive description of the CO₂-ECBM process, most studies have predominantly focus on CO₂ displacement, with significantly less attention given to CO₂ huff-and-puff technologies.

In summary, existing research on CO₂ huff-and-puff for enhancing production in low-productivity CBM wells within shallow to medium-shallow coal reservoirs remains limited. The fundamental mechanisms governing gas migration during CO₂ huff-and-puff operations, along with their dual effects of CH₄ production enhancement and CO₂ storage potential, are not yet fully understood. To address these knowledge gaps, we develop a comprehensive numerical model employed to simulate CO₂ huff-and-puff applications, evaluating both its technical feasibility for enhancing recovery of low-productivity CBM wells in medium-shallow reservoirs and its associated CO₂ storage potential. Finally, through extensive parametric studies, we identify and analyze the key geological parameters that significantly influence the production enhancement efficacy of CO₂ huff-and-puff operations.

2. Derivation of Mathematical Model for CO₂ Huff-and-Puff Technology

In the following, a set of field governing equations are defined to govern the fluid transport, gas adsorption, coal deformation and porosity-permeability evolution. Based on these equations, a corresponding numerical model is developed to investigate its feasibility for both CBM production enhancement and CO₂ storage, as well as the actual enhancement effect and influencing factors. This model aims to systematically simulate the interactions between CH₄ and CO₂ in coal seams and can be applied to evaluate the performance of CO₂ huff-and-puff operations in low-production CBM wells in medium-shallow reservoirs, with simulation results potentially informing field development strategies.

2.1. Basic Assumptions

The migration of CH₄, CO₂, and water within coal seams involves complex multi-physical processes, including gas adsorption/desorption, matrix swelling/shrinkage, and fluid flow/diffusion. The following model is developed based on the following assumptions [56–60]: (1) The coal seam is modeled as a homogeneous and isotropic dual-porosity medium, consisting of a matrix system and a fracture system. The matrix serves as the primary storage site for gas adsorption, while the fracture provides the main pathways for fluid flow; (2) The fluids in the coal seam comprise both gas and water phases, with gas solubility in the aqueous phase assumed negligible; (3) Gas flow obeys Darcy's law, and competitive adsorption of CH₄ and CO₂ is described by the extended Langmuir equation; and (4) All gaseous components in the coal seam are treated as ideal gases and obey the ideal gas law.

2.2. Governing Equations of Fluid Transport

The gas in the matrix exists in two states: free gas in micropores and adsorbed gas on the micropore surfaces. The gas adsorption behavior follows the extended Langmuir

adsorption equation. Therefore, the governing equation for fluid transport in coal matrix can be derived by applying the mass conservation principle, expressed as follows [61–64]:

$$\frac{\partial}{\partial t} \left(\phi_m \rho_{mgi} + \rho_c \rho_{gsi} \frac{V_{Li} b_i p_{mgi}}{1 + \sum_{i=1}^2 b_i p_{mgi}} \right) = Q_i \quad (1)$$

where the subscript i denotes the gas component ($i = 1$ for CH_4 , $i = 2$ for CO_2); ϕ_m is the porosity of the matrix; ρ_{mgi} is the free gas density of component i in the matrix, kg/m^3 ; ρ_c is coal density, kg/m^3 ; ρ_{gsi} is the standard density of gas component i , kg/m^3 ; V_{Li} represents the Langmuir volume constant of gas component i , m^3/kg ; b_i is defined as the reciprocal of the Langmuir pressure constant ($b_i = 1/p_{Li}$, where p_{Li} is the Langmuir pressure constant of component i , Pa); p_{mgi} denotes the partial pressure of gas component i in the matrix pore space, Pa; and Q_i represents the source-sink term for gas component i , $\text{kg}/(\text{m}^3 \cdot \text{s})$.

Based on the ideal gas law, the free gas density is given by [65]:

$$\rho_{gi} = \frac{M_{gi}}{RT} p_{gi} \quad (2)$$

where ρ_{gi} is the density of the free gas component i , kg/m^3 ; M_{gi} is the molar mass of gas component i , kg/mol ; R is the universal gas constant, $\text{J}/(\text{mol} \cdot \text{K})$; T is the temperature, K; and p_{gi} is the partial pressure of gas component i , Pa.

The gas exchange between matrix and fractures is governed by the following mass transfer equation derived from Fick's law [66]:

$$Q_i = \xi \cdot D_i \cdot S_g \cdot \frac{M_{gi}}{RT} (p_{fgi} - p_{mgi}) \quad (3)$$

where ξ is the shape factor related to the matrix block size, m^{-2} ; D_i is the diffusion coefficient of gas component i , m^2/s ; S_g is the gas saturation; and p_{fgi} denotes the partial pressure of gas component i in the fractures, Pa.

By substituting Equations (2) and (3) into Equation (1), the governing equations for CH_4 and CO_2 transport in the coal matrix can be expressed as:

$$\frac{\partial}{\partial t} \left(\phi_m \frac{M_{gi}}{RT} p_{mgi} + \frac{V_{Li} b_i p_{mgi}}{1 + \sum_{i=1}^2 b_i p_{mgi}} \rho_c \rho_{gsi} \right) = \xi D_{si} S_g \frac{M_{gi}}{RT} (p_{fgi} - p_{mgi}) \quad (4)$$

The fracture system contains a mixture of CH_4 , CO_2 , and water, resulting in gas-water two-phase flow. The mass conservation equations for the water phase and gas phase in the fracture system can be expressed as [54]:

$$\begin{cases} \frac{\partial (s_g \phi_f p_{fgi})}{\partial t} + \nabla \cdot \left(-p_{fgi} \frac{k k_{rg}}{\mu_{gi}} \nabla p_{fgi} \right) = -\xi D_{si} S_g (p_{fgi} - p_{mgi}) \\ \frac{\partial (s_w \phi_f \rho_w)}{\partial t} + \nabla \cdot \left(-\rho_w \frac{k k_{rw}}{\mu_w} \nabla p_{fw} \right) = 0 \end{cases} \quad (5)$$

where s_g and s_w represent the gas saturation and water saturation, respectively, satisfying $s_w + s_g = 1$; ϕ_f denotes fracture porosity; k is the permeability of the coal fracture, m^2 ; k_{rg} and k_{rw} represent the relative permeability of gas and water, respectively; μ_{gi} and μ_w denote the dynamic viscosities of gas component i and water, respectively, Pa·s; ρ_w indicates water density in the fractures, kg/m^3 ; and p_{fw} are the pressures of water in the fractures, Pa; and related by $p_{fw} = p_{fg} - p_{cgw}$, where p_{cgw} is the gas-water capillary pressure, Pa.

2.3. Governing Equation of the Mechanical Field

Coal seams are characterized as homogeneous porous media comprising both matrix and fracture systems, with their deformation governed by multiple factors, including stress conditions, gas adsorption/desorption effects, and mechanical interactions with adjacent coal seams. Based on poroelastic theory, the stress field in coal reservoirs can be described by the following governing equation [52,67]:

$$\sigma_{ij} = 2G\varepsilon_{ij} + \frac{2G\nu}{1-2\nu}\varepsilon_{kk}\delta_{ij} - \alpha p_f \delta_{ij} - K\delta_{ij} \frac{\varepsilon_{Li} y_i \frac{p_{mg}}{p_{Li}}}{1 + \sum_{k=1}^2 y_k \frac{p_{mg}}{p_{Lk}}} \quad (6)$$

where σ_{ij} represents the stress tensor component, Pa; G denotes the shear modulus of coal, Pa; ε_{ij} is the strain tensor component; ν is Poisson's ratio; α is the Biot coefficient; p_f is the mean pore pressure, satisfying $p_f = p_{ws} + (p_{fg1} + p_{fg2})s_g$, Pa; $K = E/3(1 - 2\nu)$ is bulk modulus, Pa; E is Young's modulus, Pa; ε_{Li} denotes the maximum swelling strain of gas component i ; p_{mg} is the total matrix pore pressure, Pa; y_i is the mole fraction of gas component i ; and δ_{ij} is the Kronecker delta.

The strain–displacement relation equations and stress equilibrium equation in coal seam can be defined as [68,69]:

$$\begin{cases} \varepsilon_{ij} = \frac{1}{2}(u_{i,j} + u_{j,i}) \\ \sigma_{ij,j} + F_i = 0 \end{cases} \quad (7)$$

where u_i is the displacement component in the i -th direction, m; and F_i is the body force component in the i -th direction, N.

Substituting Equation (6) into Equation (7) yields the governing equation for the mechanical field in coal reservoirs:

$$Gu_{i,jj} + \frac{G}{1-2\nu}u_{j,ji} + F_i = \alpha \left(s_w p_{w,i} + \sum_{n=1}^2 s_g p_{fgn,i} \right) + K \left(\sum_{i=1}^2 \varepsilon_{si} \right)_{,i} \quad (8)$$

2.4. Dynamic Porosity-Permeability Model for Coal Seam Fractures

Permeability and porosity are key factors influencing CO₂-ECBM. During CBM extraction, the boundary conditions of the coal reservoir can be regarded as uniaxial strain conditions. Under these conditions, the fracture compressibility follows the Palmer and Mansoori [70]. By integrating the multi-component adsorption model with the Palmer-Mansoori porosity-pressure relationship, the following governing equation can be obtained:

$$\frac{\phi_f}{\phi_{f0}} = \exp \left[c_f (p_{fg} - p_{fg0}) \right] + \frac{1}{\phi_{f0}} \left(1 - \frac{K}{M} \right) \left(\sum_{i=1}^2 \frac{\varepsilon_{Li} y_{0i} \frac{p_{mg0}}{p_{Li}}}{1 + \sum_{k=1}^2 y_{0k} \frac{p_{mg0}}{p_{Lk}}} - \sum_{i=1}^2 \frac{\varepsilon_{Li} y_i \frac{p_{mg}}{p_{Li}}}{1 + \sum_{k=1}^2 y_k \frac{p_{mg}}{p_{Lk}}} \right) \quad (9)$$

where ϕ_{f0} represents the initial fracture porosity; c_f denotes the fracture compressibility, 1/Pa; p_{fg0} is the initial total gas pressure in fracture, Pa; $M = E(1 - \nu)/[(1 + \nu)(1 - 2\nu)]$ defines the constrained axial modulus, Pa; p_{mg0} indicates the initial total matrix pore pressure, Pa; and y_{0i} corresponds to the initial mole fraction of gas component i .

Based on the cubic law [71,72], the dynamic evolution model of permeability can be expressed as:

$$\frac{k}{k_0} = \left(\frac{\phi_f}{\phi_{f0}} \right)^3 \quad (10)$$

where k_0 is the initial permeability of fracture, m².

Equations (4), (5) and (8)–(10) collectively constitute the CO₂ huff-and-puff mathematical model, which can be validated by previous studies [66,73], as this work adopts a similar modeling approach to those earlier publications.

3. Numerical Simulation of CO₂ Huff-and-Puff Technology

3.1. Geological Model

The Qinshui Basin, one of China’s earliest CBM development regions, holds significant commercial potential with estimated CBM reserves of $3.95 \times 10^{12} \text{ m}^3$ [74]. In 2019, CBM production in Qinshui Basin accounted for 71% of China’s total output [75], underscoring its pivotal role in the domestic CBM industry. The southern Qinshui Basin includes multiple blocks such as Mabi, Zhengzhuang, Panzhuang, and Fanzhuang, which primarily host medium-shallow CBM reservoirs. Prior to 2015, vertical wells and small-scale hydraulic fracturing were the primary extraction methods; however, sustained single-well production rarely exceeded 10^4 m^3 [76]. A significant proportion of CBM wells exhibited low productivity, with an overall production capacity fulfillment rate of merely 59.4%. Notably, 56% of these wells had daily production below 500 m^3 [15], indicating widespread under-performance. To address these challenges, numerical simulations of CO₂ huff-and-puff ECBM recovery could provide valuable insights into optimizing extraction techniques and improving production efficiency in the Qinshui Basin.

The numerical model for CO₂ huff-and-puff ECBM recovery was developed based on the geological conditions of the southern Qinshui Basin in Shanxi Province. The model adopts a well spacing of 200 m, with the production/injection well positioned at the center and perforations evenly distributed along the vertical axis. The coal seam dimensions are $200 \text{ m} \times 200 \text{ m} \times 5 \text{ m}$, discretized into grid blocks of $4 \text{ m} \times 4 \text{ m} \times 1 \text{ m}$. A schematic diagram of the coal seam model is presented in Figure 3, where points A (0, 100, 2.5) and B (200, 100, 2.5) denote key monitoring locations, respectively. The top surface of the coal seam is situated at a burial depth of 500 m. Initial reservoir conditions include a permeability of 10 mD, a gas pressure of 2200 kPa, and a coal seam saturated solely with CH₄. The key physical parameters used in the simulation, summarized in Table 2, were derived from field-measured data and laboratory test results.

Table 2. Parameters used in the numerical simulation.

Parameters	Value	Refs
Initial porosity of matrix (φ_{m0})	0.05	[77]
Initial porosity of fracture (φ_{f0})	0.02	[77]
Initial fracture permeability (k_0 , mD)	10	[78]
Coal density (ρ_c , kg/m ³)	1400	[79]
Temperature (T , K)	298.15	[66]
Fracture compressibility (c_f , 1/kPa)	2.4×10^{-4}	[66]
Poisson’s ratio (ν)	0.35	[74]
CH ₄ Langmuir pressure constant (p_{L1} , MPa)	3.5	[80]
CH ₄ Langmuir volume constant (V_{L1} , m ³ /kg)	0.0112	[80]
CO ₂ Langmuir pressure constant (p_{L2} , MPa)	1.38	[74]
CO ₂ Langmuir volume constant (V_{L2} , m ³ /kg)	0.04771	[74]
CH ₄ Langmuir strain constant (ε_{L1})	0.0128	[74]
CO ₂ Langmuir strain constant (ε_{L2})	0.0237	[74]
CH ₄ Diffusion coefficient (D_1 , cm ² /s)	1.1×10^{-8}	[81]
CO ₂ Diffusion coefficient (D_2 , cm ² /s)	1.4×10^{-8}	[81]

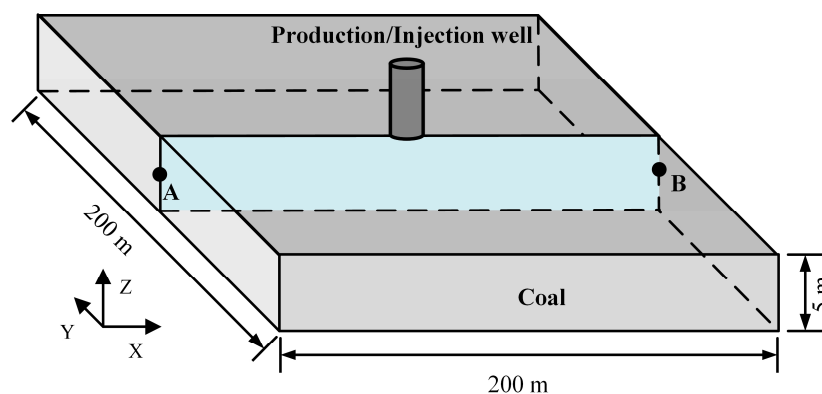


Figure 3. Geological model of numerical simulation.

3.2. Simulation Schemes

The CO₂ huff-and-puff ECBM recovery process is simulated in two phases:

(1) Conventional extraction phase: The initial stage involves direct CBM production without CO₂ injection. When the CH₄ production rate declines below 500 m³/d, the well is considered to have reached a low-production state. Production is stopped, and the well is shut in to facilitate the transition to the subsequent operational phase.

(2) CO₂ huff-and-puff phase: CO₂ is injected into the coal seam at a constant rate of 50 t/d. After injection, the well is shut in for a soaking period to allow gas adsorption and pressure equilibration. The well is then reopened for CBM production. Once the CH₄ production rate again falls below 500 m³/d, production ceases, and the recovery and storage efficiency are calculated and summarized.

Table 3 presents the numerical simulation schemes, which evaluate varying CO₂ injection volumes and soaking durations to assess CO₂ huff-and-puff performance. These schemes are designed to investigate CH₄ production enhancement under different CO₂ huff-and-puff conditions and evaluate CO₂ storage efficiency and its influencing factors. Subsequently, the impact of key geological parameters on process performance is analyzed to provide further insights.

Table 3. Numerical simulation schemes.

Injection Volume (t)	Soaking Time (d)
1000	5, 30, 60, 90, 120
1500	
2000	
2500	
3000	

To systematically evaluate the impact of geological parameters on CO₂ huff-and-puff performance, we designed numerical simulation scenarios incorporating diverse combinations of key geological parameters and performed extensive simulations. The results demonstrate that three key geological factors exert the most pronounced effects on CO₂ huff-and-puff performance: (1) gas diffusion coefficient, (2) initial fracture permeability, and (3) Langmuir volume constant. Based on these findings, we focused our subsequent sensitivity analysis on these three key factors. Using a baseline scheme of 2000 t CO₂ injection with a 60-day soaking time, we performed sensitivity analysis by independently varying individual each of these key parameters by 20%, while maintaining constant total injection volume and soaking time. This approach allowed us to isolate and quantify the impact of each geological factor on production enhancement. Table 4 details the specific

numerical simulation scenarios and corresponding parameter settings employed to analyze the influence of these key geological factors.

Table 4. Numerical schemes for key geological parameters analysis.

Key Geological Parameters	Value Setting
CH ₄ Diffusion coefficient ($D_1 \times 10^8$, cm ² /s)	0.88, 1.1, 1.32
Initial fracture permeability (k_0 , mD)	8, 10, 12
CH ₄ Langmuir volume constant ($V_{L1} \times 10^3$, m ³ /kg)	8.96, 11.2, 13.44
CO ₂ Langmuir volume constant ($V_{L2} \times 10^3$, m ³ /kg)	38.08, 47.71, 57.34

4. Results and Discussion

4.1. Mechanisms of CO₂ Huff-and-Puff ECBM Recovery

To gain an in-depth understanding of the intrinsic mechanisms underlying CBM enhancement during CO₂ huff-and-puff operations, this section comprehensively examines simulation results through multiple perspectives. These include the spatiotemporal evolution of CH₄ and CO₂ distribution, temporal variations of adsorbed and free gas mole fraction, and compositional evolution in production wells. Special attention is devoted to investigating the transport behavior of CH₄ and CO₂, as well as competitive adsorption/desorption processes throughout the injection-soaking-production phases. The integrated analysis aims to reveal the multi-physical processes governing CO₂ huff-and-puff ECBM recovery.

4.1.1. Transformation Between Adsorbed and Free Gas During CO₂ Huff-and-Puff

Figure 4 presents the spatiotemporal evolution of free CH₄ and CO₂ distribution within horizontal cross-section fracture network under varying CO₂ injection volumes of 1000 t, 2000 t, and 3000 t, respectively. It reveals three distinct migration patterns during different operational phases:

- (1) During the gas injection phase, the free CH₄ content within fractures demonstrates progressive accumulation, with CH₄ near the wellbore experiences displacement by injected CO₂, migrating toward peripheral regions. Simultaneously, significant CO₂ accumulation occurs near the wellbore, with the high-concentration zone expanding proportionally with injection volume.
- (2) During the soaking phase, free CH₄ exhibits concentration gradient-driven back-migration toward the wellbore. Continuous CO₂ diffusion from fractures into the coal matrix occurs, accompanied by adsorption phenomena. This dual process leads to continuous reduction in free CO₂ content, diminution of the wellbore-proximal high-CO₂-concentration zone, and progressive expansion of the CO₂-CH₄ mixing zone. Notably, the extent of the mixed zone increases significantly with higher CO₂ injection volumes. This is due to the higher injection volume leading to an increase in coal seam pore pressure, resulting in an increase in concentration gradients in the coal seam, thus accelerating the diffusion and mixing of CO₂ and CH₄ molecules.
- (3) During the production phase, after reopening the well, rapid co-extraction of the mixed CH₄ and CO₂ occurs, causing a rapid decline in the content of both CH₄ and CO₂ within the fracture system. Meanwhile, CH₄ located farther from the wellbore migrates toward the wellbore. Due to the relatively limited shut-in duration, some of the injected CO₂ has not been fully adsorbed by the coal matrix, resulting in partial CO₂ being re-extracted after reopening the well.

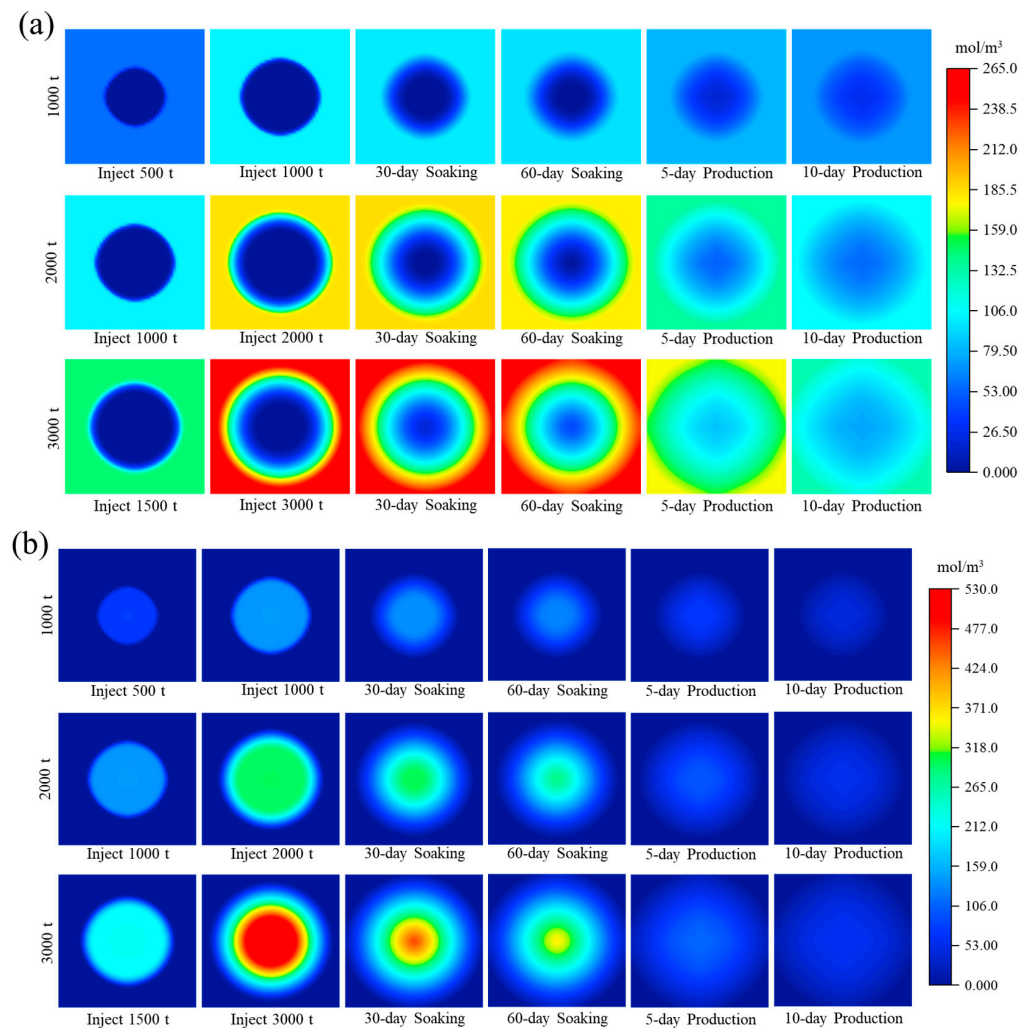


Figure 4. Spatiotemporal evolution of free gas content in the coal reservoir during the CO₂ huff-and-puff process under different CO₂ injection volumes: (a) CH₄ and (b) CO₂.

Figure 5 presents the spatiotemporal evolution of adsorbed CH₄ and CO₂ distribution within horizontal cross-section under varying CO₂ injection volumes of 1000 t, 2000 t, and 3000 t, respectively. The analysis reveals three distinct migration patterns during different operational phases:

- (1) During the CO₂ injection phase, competitive adsorption between CO₂ and CH₄ induces rapid desorption of CH₄ near the wellbore. Additionally, free CH₄ in fractures is displaced to regions farther from the wellbore, leading to a reduction in CH₄ partial pressure in the near-wellbore region. According to the Langmuir equation, this decrease in partial pressure results in a reduction of CH₄ adsorption capacity.
- (2) During the soaking phase, CO₂ adsorption continues to increase, forming a high-concentration CO₂ adsorption zone near the wellbore. After 60 days of soaking, the spatial extent of this CO₂-rich zone expands with higher injection volumes.
- (3) During the production phase, extraction of free CO₂ from fractures slightly reduces adsorbed CO₂ content. Meanwhile, as CH₄ migrates toward the wellbore, a portion of CH₄ is re-adsorbed by the coal matrix during this flow process, leading to a localized increase in CH₄ adsorption near the wellbore. Overall, after CO₂ huff-and-puff, the adsorbed CH₄ content around the wellbore remains significantly lower than the initial state, confirming effective displacement. Moreover, substantial CO₂ storage is

achieved, with both the storage capacity and spatial distribution of CO₂ increasing proportionally with injection volume.

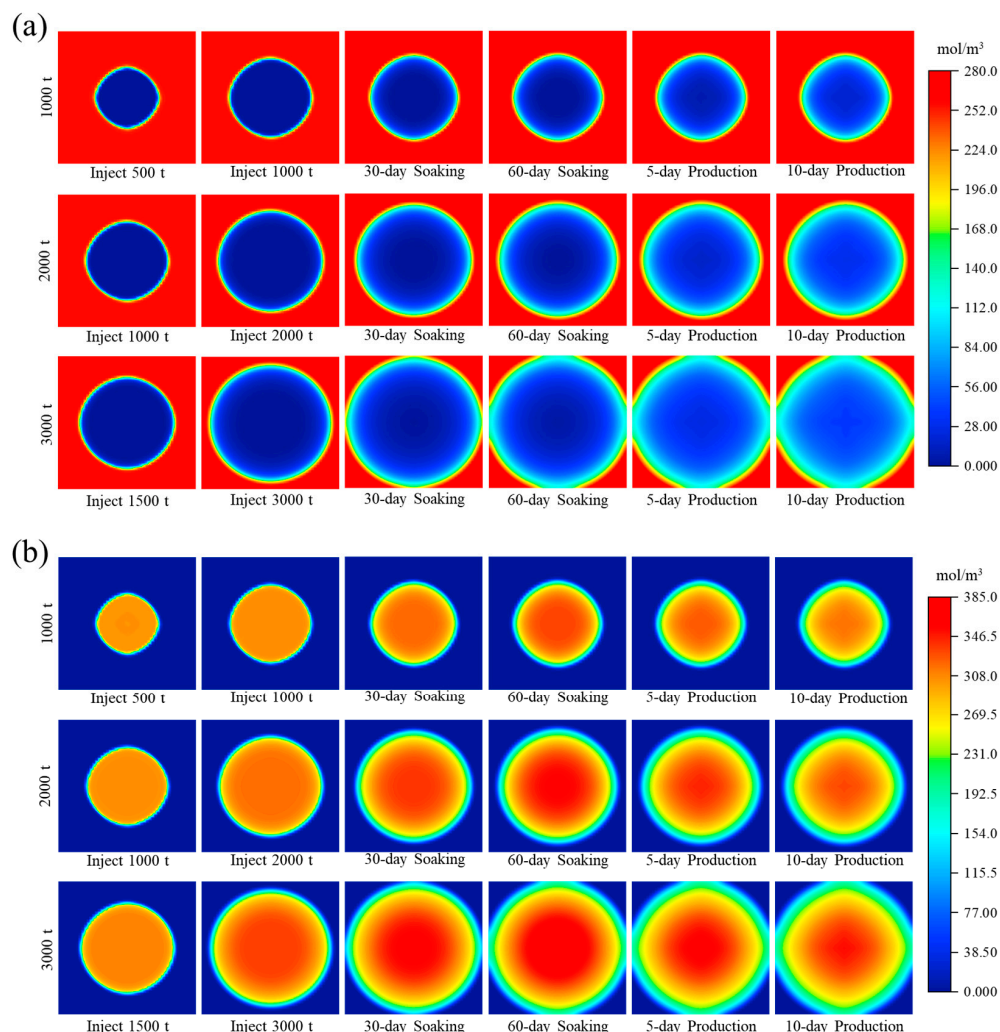


Figure 5. Spatiotemporal evolution of adsorbed content in the coal reservoir during the CO₂ huff-and-puff process under different CO₂ injection volumes: (a) CH₄ and (b) CO₂.

Figure 6 presents the variation of adsorbed and free gas mole fraction in coal seam during the CO₂ huff-and-puff process. The process can be distinctly divided into four phases: conventional extraction, injection, soaking, and production.

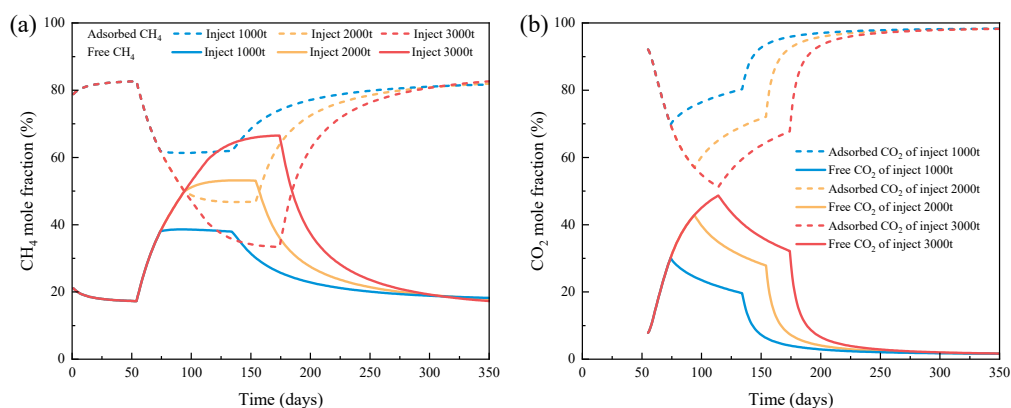


Figure 6. Variation of adsorbed and free gas mole fraction in coal seam: (a) CH₄ and (b) CO₂.

The conventional extraction phase demonstrates limited effectiveness in extracting adsorbed CH_4 from the coal seam, as it relies exclusively on pressure depletion to recover a limited amount of free methane. Consequently, the free CH_4 mole fraction shows a marginal decline while the adsorbed CH_4 mole fraction increases accordingly. After the conventional extraction, the adsorbed and free CH_4 molar fractions are 82.69% and 17.31%, respectively.

The initiation of CO_2 injection marks a significant transition. Given the initial absence of CO_2 in the coal seam, the injected CO_2 rapidly diffuses through the coal matrix, achieving extensive adsorption. Following the first day of injection, the majority of the injected CO_2 has been adsorbed by the coal matrix, resulting in an adsorbed CO_2 mole fraction of 92.15%. As the CO_2 injection rate outpaces the adsorption rate by the coal matrix, the adsorbed CO_2 mole fraction continuously declines with ongoing injection. The competitive adsorption of CO_2 and CH_4 , as well as the reduction in CH_4 partial pressure induced by CO_2 injection promotes substantial CH_4 desorption. Consequently, the free CH_4 mole fraction rises significantly. When the injection amount of CO_2 reaches 2000 t, the adsorbed and free CH_4 mole fraction in the coal seam become equal, each accounting for 50%. Furthermore, higher CO_2 injection volumes result in greater CO_2 adsorption within the coal seam, inducing more extensive desorption of adsorbed CH_4 . When the injection volume reaches 3000 t, the free CH_4 content in the coal seam increases markedly, even surpassing the adsorbed CH_4 content, reaching 66.56% after soaking.

The subsequent soaking phase shows continued but diminished displacement activity. While free CO_2 persists in displacing adsorbed CH_4 , the rate of change for both adsorbed and free CH_4 contents decreases significantly compared to the injection phase, stabilizing in later soaking periods. This temporal pattern indicates that the majority of CO_2 - CH_4 adsorption-displacement behavior occurs during the injection phase. Notably, considerable CH_4 desorption continues during early soaking, particularly under high CO_2 injection volumes. During the soaking phase, continuous conversion of adsorbed CO_2 to the free state occurs, leading to a progressive increase in the adsorbed CO_2 mole fraction and a corresponding decrease in the free CO_2 mole fraction. Moreover, higher injection volumes intensify the mutual transformation between adsorbed and free CO_2 during this phase. Over the entire injection and soaking process, adsorbed CO_2 consistently dominates over free CO_2 , demonstrating that most of the injected CO_2 remains in the adsorbed state within the coal seam. Quantitative analysis reveals that by the end of soaking, adsorbed CH_4 mole fraction decreases by 24.87%, 43.30%, and 59.55% for CO_2 injection volumes of 1000 t, 2000 t, and 3000 t, respectively, compared to pre-injection levels. The observed CO_2 - CH_4 adsorption-displacement ratio ranges between 1.41 and 1.49, suggesting that approximately 1.45 CO_2 molecules are required to displace each CH_4 molecule.

Gas extraction following well reopening is identical to conventional extraction and does not induce significant changes in the total adsorbed gas content within the coal seam. However, the total free gas content decreases rapidly due to drainage, resulting in a corresponding decline in its fraction. The adsorbed and free CH_4 mole fractions become equal again at day 4 for an injection volume of 2000 t and at day 12 for an injection volume of 3000 t after reopening. Changes in the adsorbed and free CO_2 mole fractions occur predominantly during the initial phase of well reopening. As drainage progresses, these fractions gradually stabilize.

Post-extraction analysis reveals that the adsorbed CH_4 and CO_2 mole fractions stabilize at approximately 82% and 98%, respectively. Compared to free CO_2 , adsorbed CO_2 exhibits stable and secure attachment to the micropore surfaces of the coal matrix with minimal migration potential. These characteristics establish CO_2 huff-and-puff as an effective method for both enhanced coalbed methane recovery and long-term CO_2 storage.

4.1.2. Evolution of Gas Volume Fraction in Production Well

Following CO₂ injection and the soaking period, the production phase yields a mixture of CO₂ and CH₄ from the extraction well. Figure 7 illustrates the variations in the CH₄ and CO₂ volume fraction in production well under three CO₂ injection schemes (1000 t, 2000 t, and 3000 t) with a fixed 60-day soaking time.

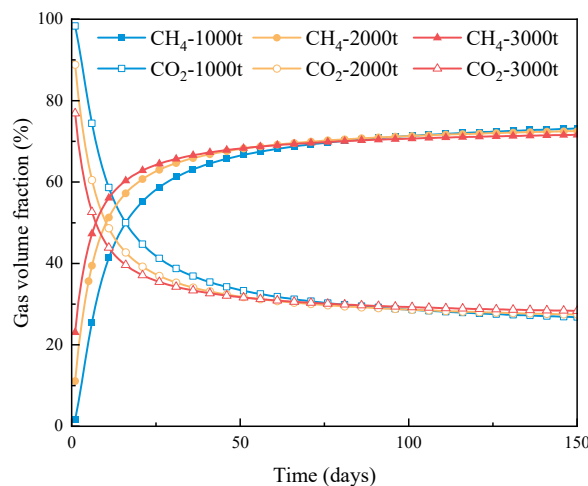


Figure 7. Variation of CH₄ and CO₂ volume fraction in the production well after reopening.

During the initial production phase, the CO₂ volume fraction is relatively high due to the accumulation of undiffused CO₂ near the wellbore. On the first production day, CO₂ accounts for over 75% of the produced gas across all injection volumes, peaking at 98.3% for the 1000 t case—indicating near-pure CO₂ production initially.

As extraction progresses, CH₄ migration toward the well gradually alters the composition. The crossover point (50% CH₄/50% CO₂) occurs at day 16, 10, and 7 for injection volumes of 1000 t, 2000 t, and 3000 t, respectively. Beyond this parity point, the CH₄ volume fraction continues to rise but at a diminishing rate. By approximately day 80, the produced gas becomes predominantly CH₄ in all cases, with CH₄ volume fractions exceeding 70%, demonstrating effective recovery of the native CBM.

4.1.3. Evolution of Coal Seam Permeability

Permeability is a critical factor influencing CH₄ production, with its variation governed by both effective stress and coal matrix swelling/shrinkage induced by gas adsorption/desorption. To illustrate this, we analyze the scheme involving CO₂ injection volume of 2000 t followed by a 60-day soaking time. Figure 8 presents the temporal evolution of coal seam permeability at varying distances from the wellbore along cross-section A–B. The analysis reveals three patterns during different operational phases:

- (1) During the initial phase of conventional extraction, the abrupt pressure drops near the wellbore after well opening causes a rapid increase in effective stress, resulting in a sharp decline in permeability. In contrast, regions farther from the wellbore exhibit a moderate permeability increase primarily due to coal matrix shrinkage caused by CH₄ desorption. As extraction progresses, the sustained reduction in coal seam gas pressure elevates effective stress, inducing compressive deformation and an overall downward permeability trend. By the end of conventional extraction, the permeability reaches a minimum of 3.42 mD.
- (2) During the injection phase, CO₂ injection increases fracture pressure, which reduces effective stress and consequently enhances permeability. During the subsequent soaking phase, permeability initially increases before declining. This transient increase

occurs because CO₂ continues displacing adsorbed CH₄ early in the soaking period, thereby improving flow pathways. However, as displacement weakens, ongoing CO₂ diffusion and adsorption reduce free gas in fractures, lowering pore pressure and permeability. A notably permeability reduction is observed at 80 m from the wellbore during soaking. This phenomenon occurs because permeability in this region, where pore pressure remains relatively stable, is predominantly governed by matrix adsorption characteristics. Situated within the CH₄–CO₂ transition zone, the coal matrix exists in a mixed-gas adsorption state. According to the extended Langmuir strain model, matrix swelling under mixed-gas adsorption exceeds that under single-component adsorption. This leads to a greater pore structure contraction and thus lower permeability compared to adjacent zones under pure adsorption states.

- (3) Following well reopening, continuous reservoir pressure depletion leads to a sustained permeability decline, causing the production to drop rapidly after reaching its peak. By the 97th day of extraction, the coal seam permeability reverts to its initial value of 10 mD. Continued extraction further reduces the minimum permeability to 8.51 mD by the end of production—below the initial permeability level.

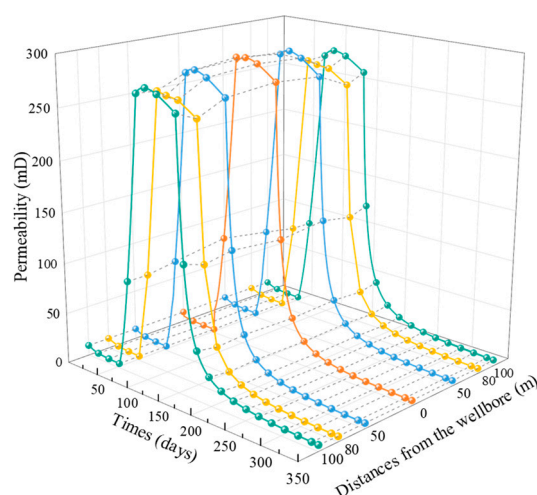


Figure 8. Variation in coal seam permeability with time at distances of 0, 50, 80, and 100 m from the wellbore along cross-section A–B.

4.2. Effects of CO₂ Injection Volume and Soaking Time on CH₄ Enhancement and CO₂ Storage Performance

4.2.1. Variation of CH₄ Production

CH₄ production is a key indicator for evaluating the engineering feasibility and stimulation potential of CO₂ huff-and-puff technology, reflecting its practical effectiveness in ECBM recovery. Figure 9 presents the CH₄ production rate and cumulative production under different CO₂ injection volumes and soaking times.

During the conventional extraction phase (without CO₂ injection), CBM is produced directly from the coal seam. Initial production peaks rapidly at 7804.53 m³/d but declines sharply thereafter. By day 53, CH₄ production rate drops to 500 m³/d, yielding a cumulative output of only 8.61×10^4 m³—a recovery of just 5.33%. This limited recovery occurs because the extracted CH₄ primarily derives from free CH₄ in the coal seam, while adsorbed CH₄ cannot effectively replenish fractures through desorption and diffusion. Additionally, declining pore pressure increases effective stress, reducing coal permeability and further accelerating CH₄ production decline. Given that most CBM exists in an adsorbed state, conventional extraction methods result in extremely low efficiency. Therefore, stimulation measures are necessary to improve production in low-productivity wells.

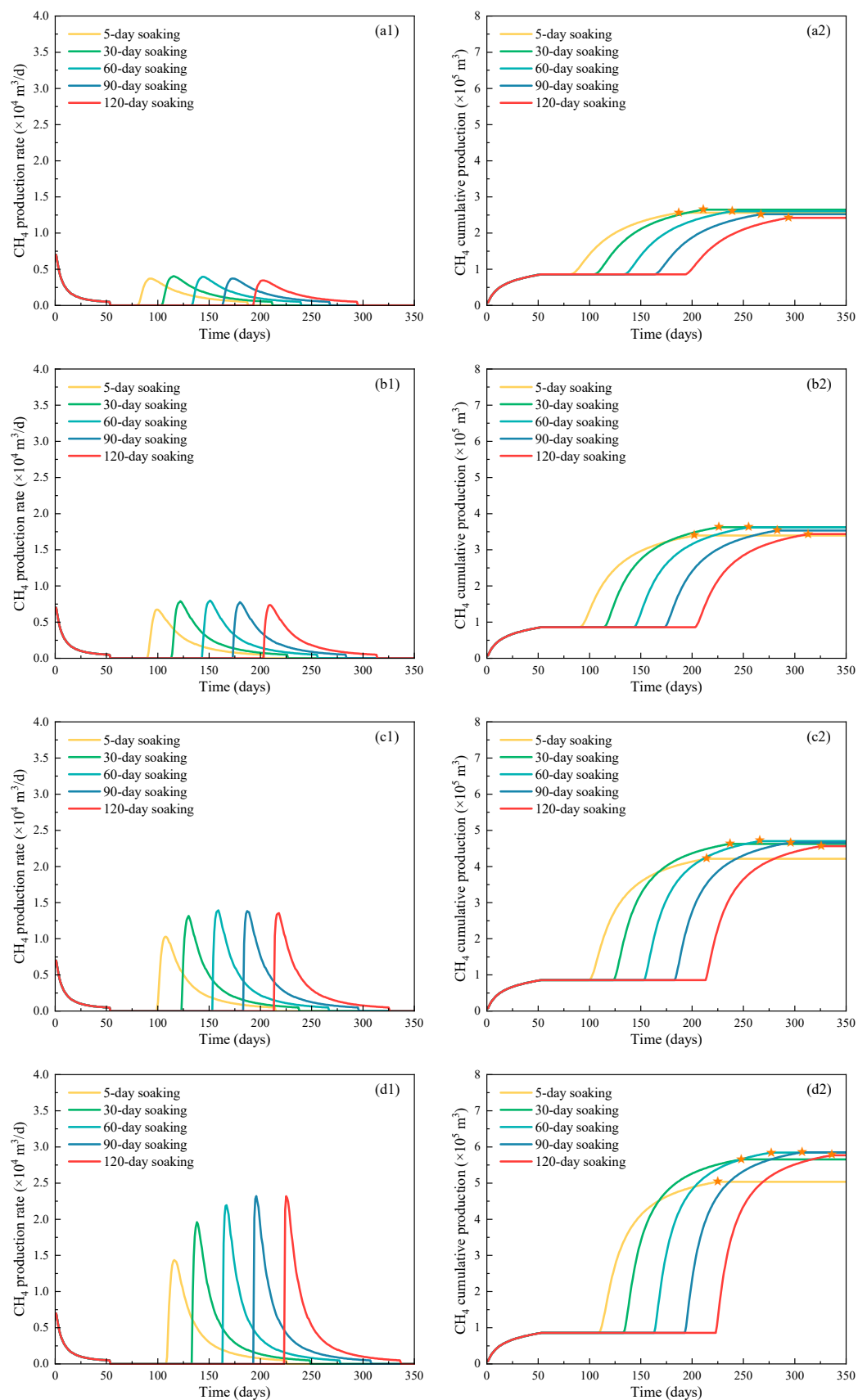


Figure 9. Cont.

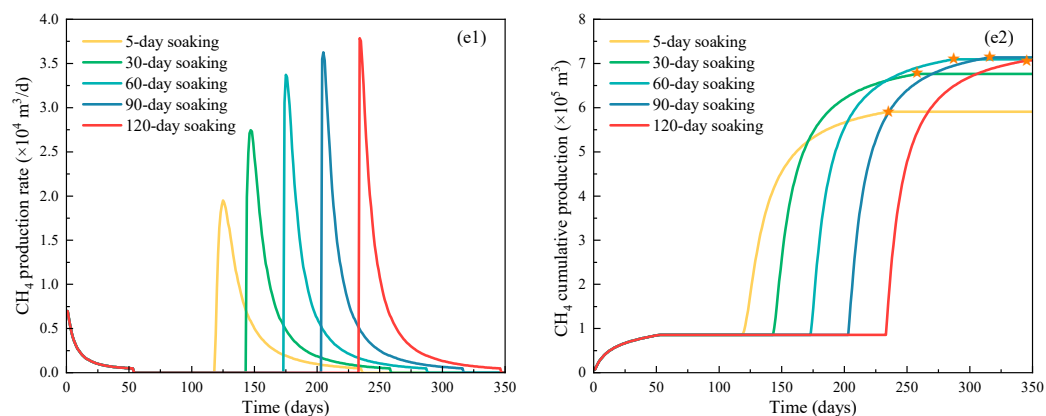


Figure 9. CH₄ production rate and cumulative production under different operating schemes. ((a–e) represents CO₂ injection volumes of 1000 t, 1500 t, 2000 t, 2500 t, and 3000 t, respectively, and numbers 1 and 2 represent CH₄ production rate and cumulative production, respectively. The pentagram symbol represents the shut-in operation of the production well).

Following conventional extraction, CO₂ is injected into the coal seam, followed by a soaking period. During this phase, the production well is converted into an injection well, and production is temporarily suspended, resulting in no CH₄ output and constant cumulative production. The injected CO₂ reduces the partial pressure of CH₄ and competes for adsorption sites, promoting extensive CH₄ desorption from the coal matrix.

Upon well reopening, CH₄ production rapidly rises to a new peak, with magnitude strongly dependent on CO₂ injection volumes. At 1000 t injection, peak production rate reaches 4051.43 m³/d, still below the conventional extraction peak. At 3000 t injection, peak production rises to 37,867.95 m³/d—3.85 times higher than conventional extraction, demonstrating a substantial improvement. Notably, higher CO₂ injection volumes lead to earlier peak production but also faster subsequent decline rates. Additionally, at low CO₂ injection volumes, peak production initially increases with soaking time before declining. In contrast, at high injection volumes, peak production improves continuously with extended soaking. Under all simulation schemes, CH₄ production eventually falls below 500 m³/d by approximately 112 days of operation, prompting well shut in.

Overall, CO₂ huff-and-puff significantly enhances cumulative CH₄ production compared to conventional extraction under all simulation schemes. Particularly, with 3000 t injection volume and 90 days soaking, maximum cumulative CH₄ production reaches $7.14 \times 10^5 \text{ m}^3$, 7.29 times higher than conventional extraction. When the soaking time is short, cumulative CH₄ production increases with longer soaking times. This occurs because CO₂ continuously displaces adsorbed CH₄ while free CO₂ is adsorbed, enriching CH₄ in fractures. Additionally, driven by concentration gradients, free CH₄ displaced by injected CO₂ diffuses back toward the wellbore. Thus, extended soaking enhances post-reopening CH₄ production. However, as soaking time increases, excessive soaking reduces cumulative CH₄ production due to gas diffusion into micropores, depleting reservoir energy. This suggests an optimal soaking window for maximizing recovery, consistent with findings in nitrogen huff-and-puff studies [82].

Compared to soaking time, CO₂ injection volume has a more pronounced impact on CH₄ production. Higher injection volumes consistently yield greater cumulative CH₄ production. For instance, at 60 days soaking time, increasing CO₂ injection from 1000 t to 3000 t raises cumulative CH₄ production from $2.60 \times 10^5 \text{ m}^3$ to $7.09 \times 10^5 \text{ m}^3$, a 172.69% increase. Larger CO₂ injection volumes enhance CH₄ displacement efficiency and maintain high reservoir pressure, further improving production, analogous to the principle of dry

gas injection in hydrocarbon reservoirs for sustaining pressure and boosting condensate recovery [42].

In summary, CO₂ huff-and-puff effectively revitalizes low-productivity CBM wells, substantially boosting both CH₄ production rates and cumulative CH₄ output in a short timeframe. Optimization of injection volume and soaking duration is critical to maximizing economic returns while avoiding diminishing recovery effects from excessive soaking.

Figure 10 presents the relationship between total CH₄ recovery and soaking time under different CO₂ injection volumes after CO₂ huff-and-puff operations. The simulation results demonstrate significantly enhanced CH₄ recovery across all simulation schemes compared to conventional extraction. Specifically, with a 3000 t injection volume and 90-day soaking time, the maximum CH₄ recovery reaches 44.19%. Our analysis indicates that CH₄ recovery is particularly sensitive to CO₂ injection volume, exhibiting a positive correlation where larger injection volumes correspond to higher recovery rates.

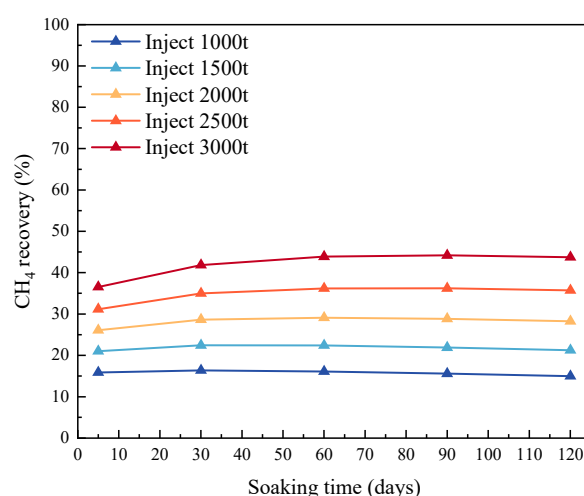


Figure 10. Variation in total CH₄ recovery with soaking time under different CO₂ injection volumes after CO₂ huff-and-puff operations.

The data show a consistent pattern where CH₄ recovery initially increases, then decreases with prolonged soaking time, although the soaking duration exhibits weaker influence than injection volume. This trend becomes especially evident at lower injection quantities. For instance, at an injection volume of 1000 t, CH₄ recovery remains relatively stable (15.01–16.38%) regardless of soaking times. This phenomenon suggests that at lower injection volumes, the majority of CO₂–CH₄ displacement occurs during the injection phase itself, rendering prolonged soaking times unnecessary for optimal recovery.

These findings highlight the importance of tailoring soaking duration to both coal seam properties and injection scale in practical applications. Such optimization can maximize production gains while maintaining operational efficiency, providing valuable guidance for field implementation of CO₂ huff-and-puff techniques.

4.2.2. CO₂ Storage Efficiency

To evaluate the CO₂ storage capacity of coal seams, we define CO₂ storage efficiency as the ratio of stored CO₂ to injected CO₂. Figure 11 indicates the variation in storage efficiency during CO₂ huff-and-puff operations under different injection volumes and soaking times after conventional extraction. Initially, before well reopening, the stored CO₂ equals the injected amount, maintaining a 100% storage efficiency. However, when production resumes after the soaking period, partial CO₂ is re-extracted, causing a rapid decline in storage efficiency. Across all simulation schemes, the storage efficiency stabilizes approximately 50 days after production restart, suggesting equilibrium in CO₂ retention within

the coal seam. This stabilization coincides with reservoir pressure depletion, characterized by an initial production peak followed by gradual decline. Simultaneously, wellhead gas composition transitions from CO₂-dominated to CH₄-rich as production continues.

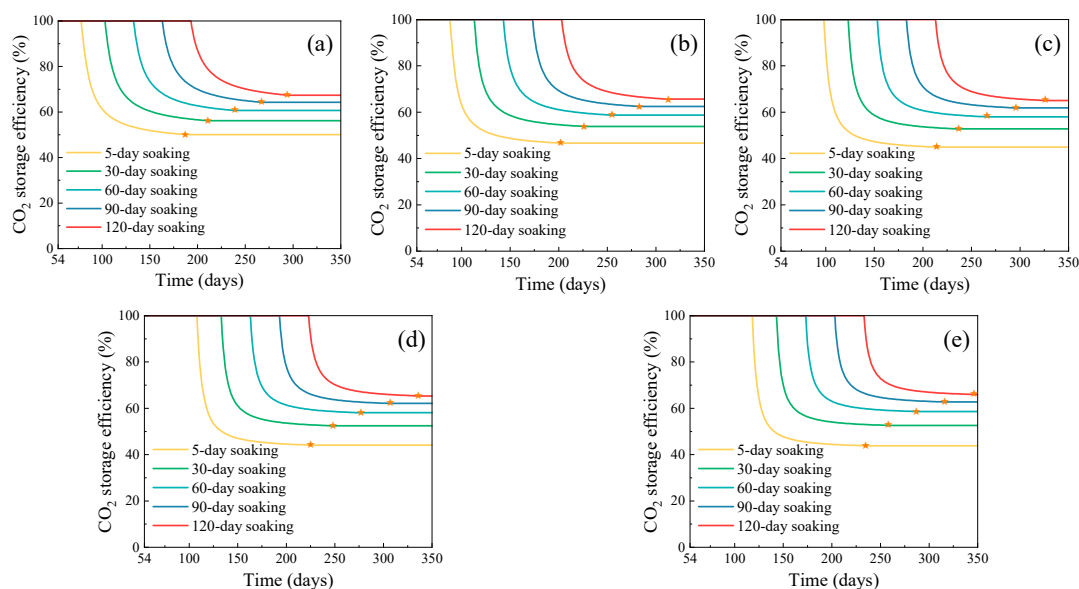


Figure 11. Variation of CO₂ storage efficiency during CO₂ huff-and-puff under different simulation schemes after conventional extraction. ((a–e) represent CO₂ injection volumes of 1000 t, 1500 t, 2000 t, 2500 t, and 3000 t, respectively. The pentagram symbol represents the shut-in operation of the production well).

Figure 12 presents the ultimate storage efficiencies at well closure, showing significant impacts from soaking time. For 2000 t injection, increasing the soaking period from 5 to 120 days enhances storage efficiency from 44.94% to 65.09%. This represents a 44.84% increase in storage efficiency, with an additional 402.58 t of CO₂ storage. Comparatively, injection volume demonstrates more modest influence, with storage efficiencies ranging narrowly between 58.02% and 60.69% for different CO₂ injection volumes at a fixed 60-day soaking time.

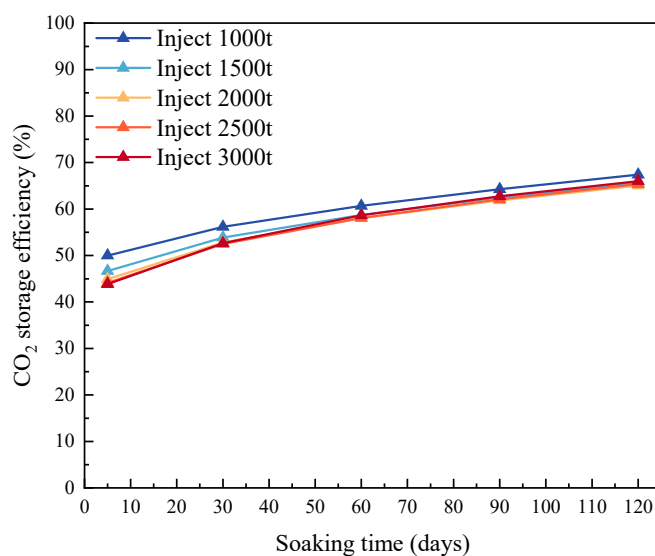


Figure 12. Variation of CO₂ storage efficiency with soaking time after CO₂ huff-and-puff under different CO₂ injection volumes.

4.2.3. Displacement Efficiency

Displacement efficiency is defined as the ratio of cumulative CH_4 production to injected CO_2 volume, reflecting the amount of CH_4 recovered per unit of CO_2 injected and serving as a key indicator for evaluating CO_2 huff-and-puff performance.

Figure 13 presents the CO_2 displacement efficiency during huff-and-puff operations under different CO_2 injection volumes and soaking times following conventional extraction. The variation pattern of displacement efficiency closely follows that of cumulative CH_4 production. During injection and soaking phases, when no CH_4 is produced, the efficiency remains at zero. Upon well reopening, efficiency increases steadily but at a declining rate as CH_4 production rate declines, eventually stabilizing.

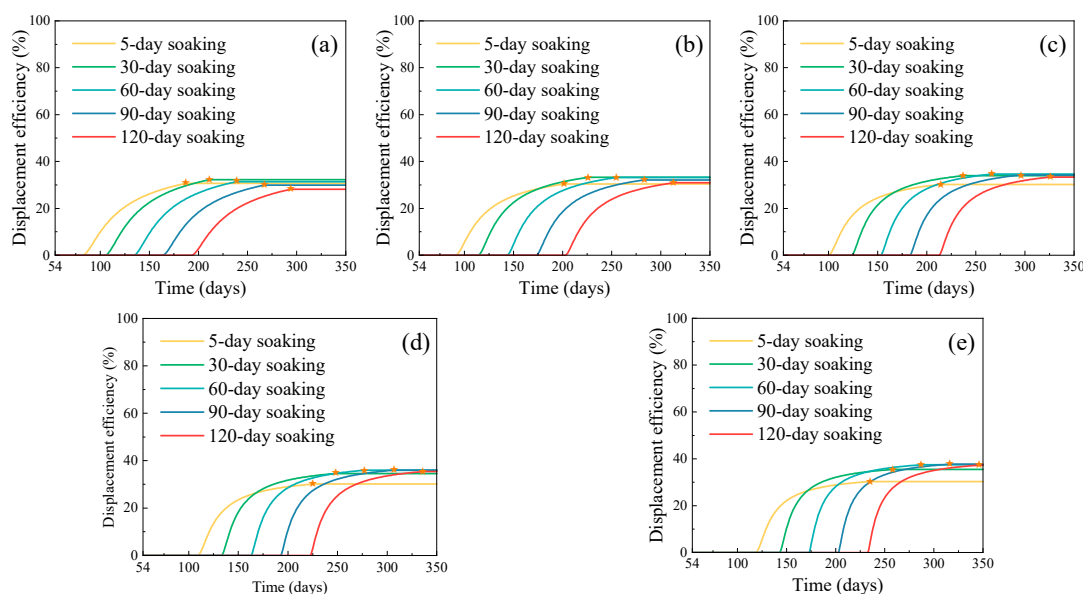


Figure 13. Variation in displacement efficiency during CO_2 huff-and-puff under different simulation schemes after conventional extraction. ((a–e) represent CO_2 injection volumes of 1000 t, 1500 t, 2000 t, 2500 t, and 3000 t, respectively. The pentagram symbol represents the shut-in operation of the production well).

Figure 14 further presents the variation in final displacement efficiency at well closure under different simulation schemes. At constant injection volumes, the efficiency first increases but then decreases with prolonged soaking. With a 5-day soaking period, all injection volumes yield similar efficiencies around 30%. As the soaking time increases, the difference in displacement efficiency between different injection volumes becomes more pronounced. Moreover, larger CO_2 injection volumes generally lead to higher displacement efficiencies.

Across all simulation schemes, the CO_2 displacement efficiency ranges between 28% and 38%, demonstrating the effectiveness of huff-and-puff in enhancing CH_4 recovery. Previous simulation studies on CO_2 and N_2 displacement in CBM recovery reveal that the displacement efficiency of CO_2 under varying injection pressures ranges merely from 6.0% to 8.7%, whereas N_2 achieves a significantly higher efficiency of 23–32% [66]. Notably, the CO_2 huff-and-puff technique not only outperforms continuous CO_2 flooding but also slightly exceeds N_2 displacement efficiency, confirming its significant advantage in enhancing CH_4 recovery.

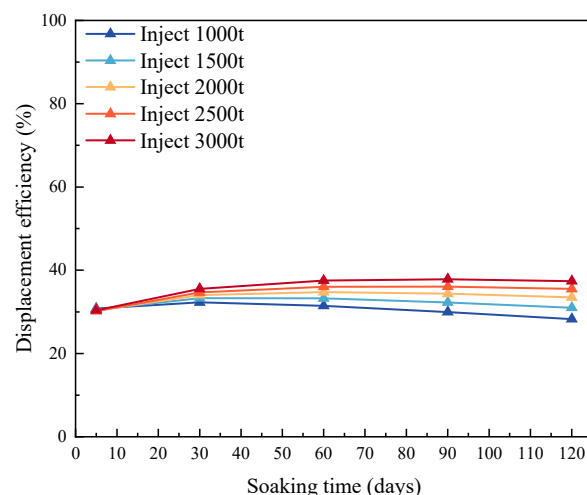


Figure 14. Variation in displacement efficiency with soaking time after CO₂ huff-and-puff under different CO₂ injection volumes.

4.3. Effects of Key Geological Parameters on CO₂ Huff-and-Puff Performance

Existing studies indicate that the effectiveness of CO₂ huff-and-puff technology for ECBM varies significantly across different reservoirs due to heterogeneous geological conditions. To systematically investigate the key geological parameters influencing CO₂ huff-and-puff performance, we conducted extensive numerical simulations under various schemes. It was found that three key geological factors predominantly influence CO₂ huff-and-puff performance: (1) gas diffusion coefficient, (2) initial fracture permeability, and (3) Langmuir volume constant.

Using a baseline scheme of 2000 t CO₂ injection with a 60-day soaking time, we performed sensitivity analysis by independently varying individual parameters by 20%, while maintaining constant total injection volume and soaking time. This approach allowed us to isolate and quantify the impact of each geological factor on production enhancement.

4.3.1. Effects of Key Geological Parameters on CH₄ Production

In coal seams, CH₄ primarily exists in an adsorbed state within the coal matrix. For CH₄ to migrate to the wellbore for extraction, it must undergo a three-stage process: (1) desorption from the coal matrix into a free state, (2) diffusion through the matrix to the fracture network, and (3) flow through the fractures to the wellbore. This process is commonly described as the “desorption–diffusion–flow” mechanism.

In most coal seams, desorption and diffusion are the rate-limiting steps that govern CH₄ migration and ultimately determine well productivity. The diffusion coefficient, which controls the rate of gas transfer between the matrix and fractures, plays a critical role in both CO₂ adsorption and CH₄ desorption efficiency within the coal matrix. Figure 15 compares CH₄ production rates and cumulative production for diffusion coefficients of $0.88 \times 10^{-8} \text{ cm}^2/\text{s}$ and $1.32 \times 10^{-8} \text{ cm}^2/\text{s}$. The results demonstrate that reducing the CH₄ diffusion coefficient leads to higher CH₄ production rates and greater cumulative production. This occurs because a lower diffusion coefficient inhibits the re-adsorption of free CH₄ displaced by CO₂. Consequently, more free CH₄ accumulates in the fractures, enhancing CH₄ production when the well is reopened.

Coal seam permeability is a key parameter controlling gas flow capacity in reservoirs, directly determining gas migration velocity and ultimate production. Low permeability is a primary factor contributing to low-productivity wells, as it restricts gas flow rates. This limitation not only reduces CH₄ recovery efficiency but also diminishes the effectiveness of CO₂ huff-and-puff ECBM. Figure 16 compares CH₄ production rates and cumulative

production for initial fracture permeability of 8 mD and 12 mD. The results demonstrate the significant impact of permeability on CH₄ production. At 12 mD, the peak CH₄ production rate is 1.93 times that at 8 mD, accompanied by a 13.6% increase in cumulative production. These findings underscore that higher permeability substantially enhances the performance of CO₂ huff-and-puff ECBM.

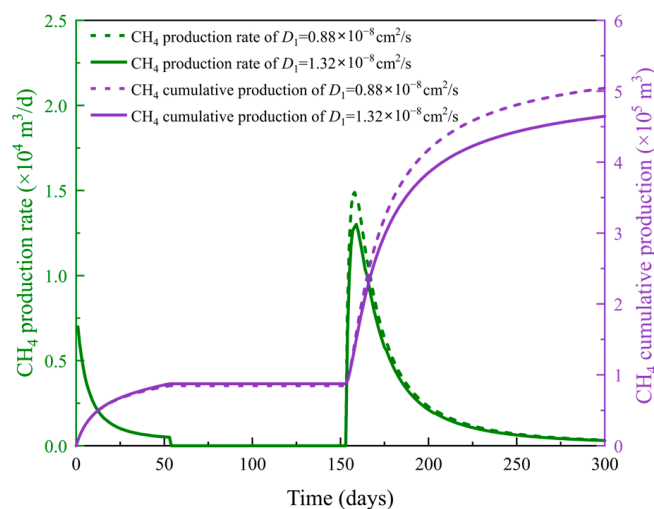


Figure 15. Effects of different gas diffusion coefficients on CH₄ production rate and cumulative production.

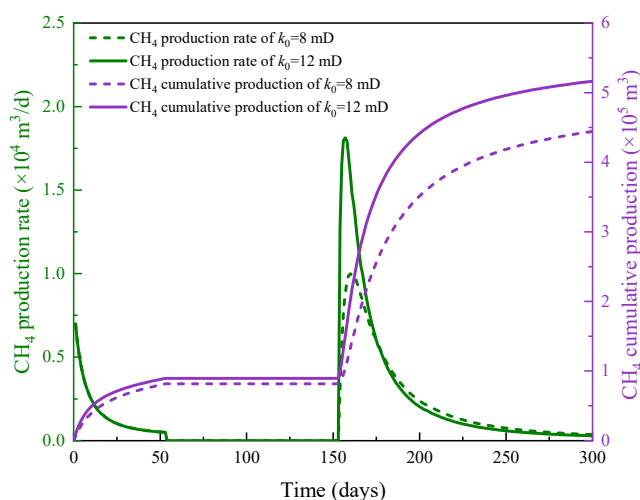


Figure 16. Effects of different initial fracture permeability on CH₄ production rate and cumulative production.

The Langmuir volume constant is a critical parameter for evaluating gas adsorption capacity in coal seams, as it directly determines gas adsorption quantity and influences the gas storage capability of the coal matrix. Figure 17 presents the CH₄ production rate and cumulative production under different Langmuir volume constants for CH₄ (V_{L1}) and CO₂ (V_{L2}). The results indicate that variations in V_{L1} have a limited impact on cumulative CH₄ production, with fluctuations remaining within 5%. However, V_{L1} significantly influences initial CH₄ reserves in coal seams, consequently affecting recovery efficiency. In contrast, cumulative CH₄ production shows a positive correlation with V_{L2} . A higher V_{L2} indicates greater CO₂ adsorption capacity in the coal seams, which enhances the desorption of adsorbed CH₄ and consequently improves CH₄ production after well reopening.

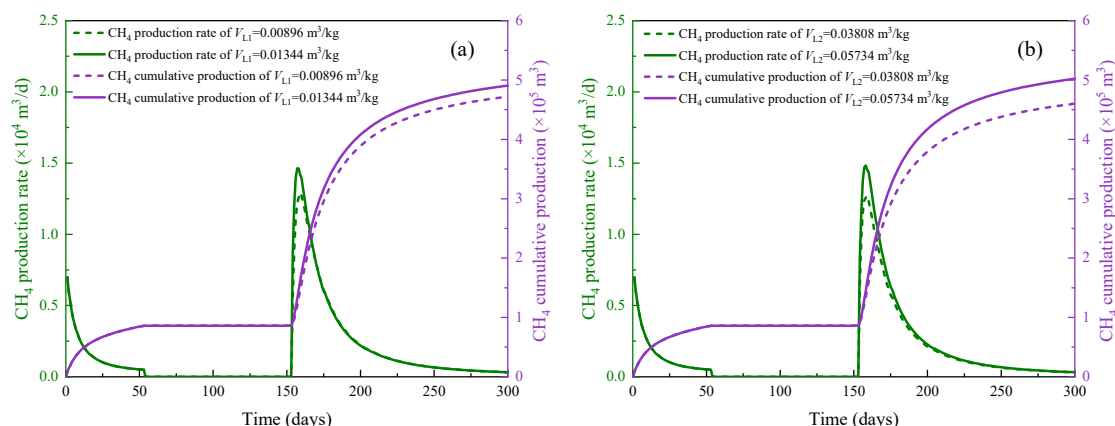


Figure 17. Effects of different gas Langmuir volume constants on CH₄ production rate and cumulative production: (a) CH₄ Langmuir volume constant V_{L1} and (b) CO₂ Langmuir volume constant V_{L2} .

Figure 18 presents the CH₄ recovery performance after CO₂ huff-and-puff operations under different geological parameters. Specifically, when V_{L1} values are 0.00896 and 0.01344 m³/kg, the corresponding CH₄ recovery is 33.71% and 25.53%, representing a 15.72% increase and 12.36% decrease, respectively, compared to the baseline scheme. This inverse relationship demonstrates that higher V_{L1} values lead to lower CH₄ recovery, indicating that coal seams with lower initial CH₄ reserves exhibit more significant production enhancement during CO₂ huff-and-puff operations.

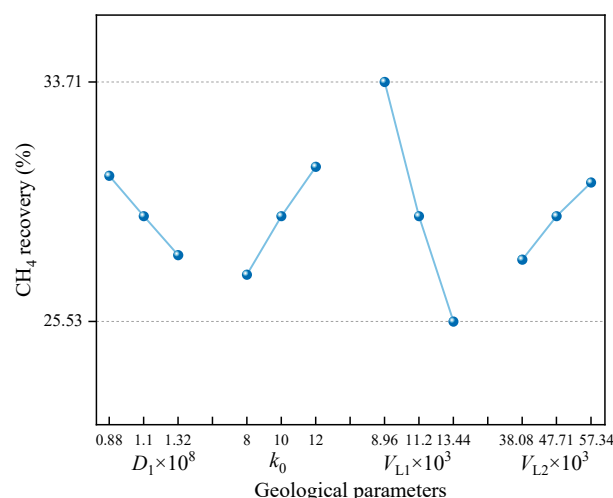


Figure 18. Effects of different geological parameters on CH₄ recovery.

Overall, the results demonstrate that the CH₄ Langmuir volume constant (V_{L1}) has the most significant influence on recovery efficiency, followed by initial fracture permeability and the diffusion coefficient, while the CO₂ Langmuir volume constant (V_{L2}) shows the least impact. Therefore, in practical CO₂ huff-and-puff projects, priority should be given to characterizing V_{L1} , permeability, and diffusion coefficient to achieve higher recovery.

4.3.2. Effects of Key Geological Parameters on CO₂ Storage

Figure 19 presents CO₂ storage efficiency under different geological parameters. Contrary to the trend observed for CH₄ recovery, V_{L2} emerges as the primary controlling factor for CO₂ storage, with coal seam permeability and diffusion coefficient playing secondary roles. However, the absolute variation in CO₂ storage efficiency across all parameter schemes remains relatively modest, with deviations within 5% compared to the baseline scheme.

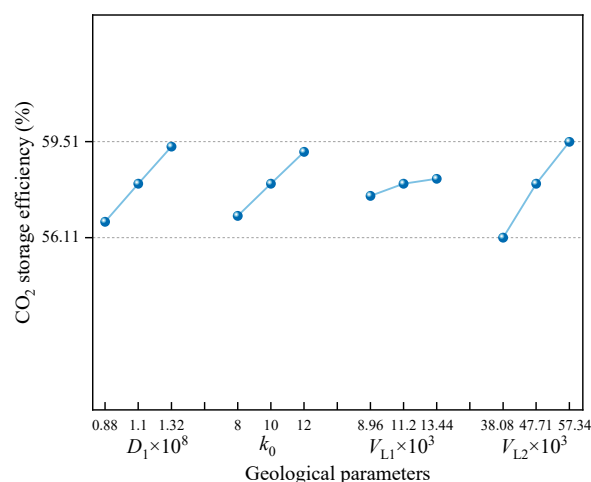


Figure 19. Effects of different geological parameters on CO₂ storage efficiency.

Figure 20 presents the displacement efficiency under different geological parameters. It can be observed that, compared to the CO₂ storage efficiency, the displacement efficiency exhibits greater sensitivity to variations in these geological parameters. Permeability exerts the most significant influence on displacement efficiency. Specifically, at permeability values of 8 and 12 mD, the corresponding displacement efficiencies are 31.8% and 37.2%, representing a decrease of 8.62% and an increase of 6.90% relative to the baseline scheme. Consequently, CO₂ huff-and-puff achieves greater CH₄ displacement in high-permeability reservoirs. Consistent with the trend observed for CO₂ storage efficiency, the Langmuir volume constant of CH₄ has the least pronounced effect on displacement efficiency.

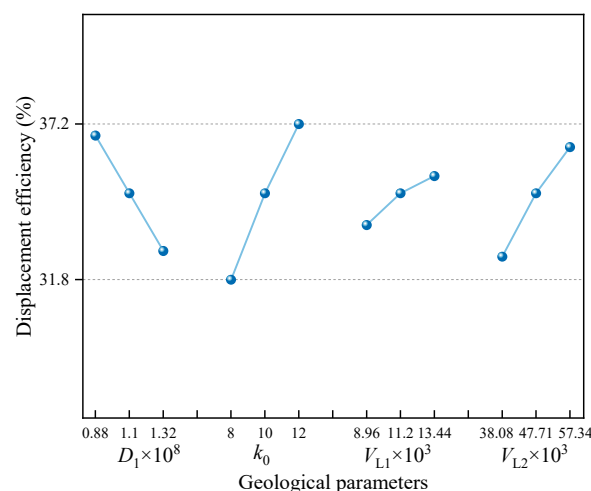


Figure 20. Effects of different geological parameters on displacement efficiency.

4.4. Effects of Coal Seam Anisotropy

In actual coal seams, strong heterogeneity and anisotropy often develop due to tectonic deformation and diagenetic processes, which can significantly influence the distribution and migration of gases within the reservoir. Using a baseline scheme of 2000 t CO₂ injection with a 60-day soaking time, the CO₂ huff-and-puff performance considering anisotropy was analyzed by maintaining a constant horizontal permeability while varying the vertical permeability of the coal seam. Figure 21 presents the CH₄ production rate and cumulative production when the ratio of vertical to horizontal permeability is 0.1, 0.3 and 0.6, respectively. The results indicate that when the ratios are 0.1, 0.3 and 0.6, the peak CH₄ production rates are 13,687.74 m³/d, 13,289.00 m³/d and 12,518.16 m³/d, representing

reductions of 2.92%, 5.75% and 11.22% compared with isotropic conditions. Coal seam anisotropy decreases both the daily and cumulative CH₄ production, and the greater the anisotropy, the more pronounced the reduction in CH₄ yield. This is because the reduction in vertical permeability hinders gas flow in the vertical direction and to some extent slows the migration of CH₄ toward the well.

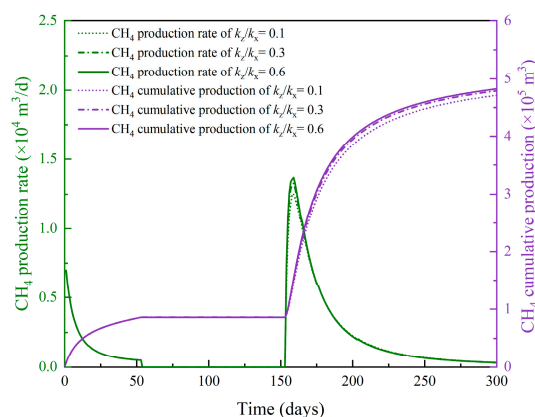


Figure 21. Effects of different ratios of vertical to horizontal permeability on CH₄ production rate and cumulative production.

Figure 22 presents the variations in CH₄ recovery, CO₂ storage efficiency, and displacement efficiency with respect to the ratio of vertical to horizontal permeability. The results show that when the ratio is 0.1, the CH₄ recovery, CO₂ storage efficiency, and displacement efficiency are 28.39%, 57.78%, and 33.70%, respectively, which are 2.31%, 0.42%, and 3.07% lower than those under isotropic conditions. After considering anisotropy, CH₄ recovery, CO₂ storage efficiency, and displacement efficiency all decrease slightly, although the overall influence remains limited. This is because perforations are distributed across different coal seam layers, and gas mainly migrates horizontally through perforations at the same depth toward the wellbore. As a result, vertical gas flow between coal seams at different heights has a limited effect on the overall CH₄ recovery and CO₂ storage performance.

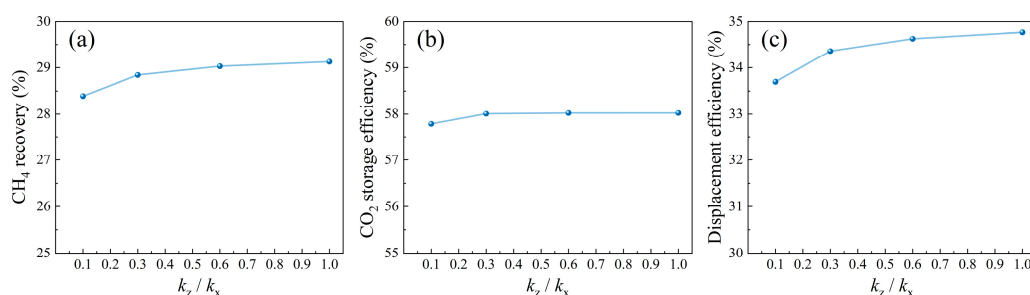


Figure 22. Effects of different ratios of vertical to horizontal permeability: (a) CH₄ recovery, (b) CO₂ storage efficiency and (c) displacement efficiency.

5. Conclusions

This study investigates the theoretical principles and advantages of CO₂ huff-and-puff ECBM for low-productivity wells in medium-shallow reservoirs. A comprehensive numerical model reflecting the geological conditions of the Qinshui Basin was established to assess CH₄ production enhancement and CO₂ storage potential in medium-shallow coal seams via CO₂ huff-and-puff. Key findings include:

1. CO₂ huff-and-puff enhances CH₄ recovery through competitive adsorption, where CO₂ displaces CH₄ from the coal matrix, and reservoir pressure maintenance. The

process involves three phases— injection, soaking, and production, wherein soaking time critically influences CH₄ desorption and CO₂ storage.

2. Higher CO₂ injection volumes (e.g., 2000–3000 t) significantly enhance CH₄ production. Soaking times of 30–90 days maximize economic returns, while excessive soaking diminishes gains due to energy depletion.
3. CH₄ recovery is most sensitive to the CH₄ Langmuir volume constant and initial fracture permeability, whereas CO₂ storage efficiency is primarily controlled by the CO₂ Langmuir constant. Lower diffusion coefficients enhance CH₄ retention in fractures.
4. This study preliminarily demonstrates the feasibility of large-scale CO₂ huff-and-puff for enhancing production in low-productivity CBM wells. However, further research under field-world conditions is essential for large-scale deployment. CO₂ huff-and-puff offers a sustainable solution for CBM extraction and carbon storage, aligning with China's "dual carbon" strategy. The integration of this technology with carbon capture, utilization, and storage (CCUS) promises a sustainable pathway for energy production and emission reduction.
5. In this study, the coal seam is assumed to be a homogeneous and isotropic medium. The results presented above are based on idealized homogeneous coal properties and must be calibrated against field pilot tests before practical implementation. Key uncertainties, including the neglect of thermal effects, simplified boundary conditions, coal heterogeneity, permeability anisotropy, and the long-term security of CO₂ storage, will be addressed in future research.

Author Contributions: Conceptualization, C.Y.; funding acquisition, Z.F.; investigation, C.Y.; methodology, C.Y.; project administration, Z.F.; supervision, Z.F.; validation, S.S.; visualization, H.W.; writing—original draft preparation, C.Y.; writing—review and editing, Z.F., S.S. and H.W. All authors have read and agreed to the published version of the manuscript.

Funding: This study was partly supported by the Hubei Provincial Technological Innovation Program (Grant No. 2025BCB042) and the 181 Major R&D projects of Metallurgical Corporation of China Ltd., project number (212024YH611225).

Data Availability Statement: Data is contained within the article.

Conflicts of Interest: The authors declare no conflicts of interest. The authors declare that this study received funding from the Metallurgical Corporation of China Ltd. The funder was not involved in the study design, collection, analysis, interpretation of data, the writing of this article or the decision to submit it for publication.

References

1. Bai, G.; Su, J.; Zhang, Z.; Lan, A.; Zhou, X.; Gao, F.; Zhou, J. Effect of CO₂ injection on CH₄ desorption rate in poor permeability coal seams: An experimental study. *Energy* **2022**, *238*, 121674. [[CrossRef](#)]
2. Lin, J.; Ren, T.; Wang, G.; Booth, P.; Nemcik, J. Experimental investigation of N₂ injection to enhance gas drainage in CO₂-rich low permeable seam. *Fuel* **2018**, *215*, 665–674. [[CrossRef](#)]
3. Zhang, C.; Wang, E.; Li, B.; Kong, X.; Xu, J.; Peng, S.; Chen, Y. Laboratory experiments of CO₂-enhanced coalbed methane recovery considering CO₂ sequestration in a coal seam. *Energy* **2023**, *262*, 125473. [[CrossRef](#)]
4. Tu, Z.; Li, L.; Wang, F.; Zhang, Y. Review on separation of coalbed methane by hydrate method. *Fuel* **2024**, *358*, 130224. [[CrossRef](#)]
5. Xu, F.; Hou, W.; Xiong, X.; Xu, B.; Wu, P.; Wang, H.; Feng, K.; Yun, J.; Li, S.; Zhang, L.; et al. The status and development strategy of coalbed methane industry in China. *Pet. Explor. Dev.* **2023**, *50*, 765–783. [[CrossRef](#)]
6. Heng, X.; Li, H.; Li, Q.; Fu, J.; Yao, C.; Ye, P.; Zhang, S.; Niu, Y. Investigation of an adsorption model of wet coal that considers coal seam gas pressure and temperature effects. *ACS Omega* **2025**, *10*, 5634–5644. [[CrossRef](#)]
7. Tang, X.; Wang, Z.; Ripepi, N.; Kang, B.; Yue, G. Adsorption affinity of different types of coal: Mean isosteric heat of adsorption. *Energy Fuels* **2015**, *29*, 3609–3615. [[CrossRef](#)]
8. Zhu, Q.; Du, X.; Zhang, T.; Yu, H.; Liu, X. Investigation into the variation characteristics and influencing factors of coalbed methane gas content in deep coal seams. *Sci. Rep.* **2024**, *14*, 18813. [[CrossRef](#)]

9. Yin, G.; Deng, B.; Li, M.; Zhang, D.; Wang, W.; Li, W.; Shang, D. Impact of injection pressure on CO₂-enhanced coalbed methane recovery considering mass transfer between coal fracture and matrix. *Fuel* **2017**, *196*, 288–297. [\[CrossRef\]](#)
10. Gao, L.; Mastalerz, M.; Schimmelmann, A. The origin of coalbed methane. In *Coal Bed Methane*; Elsevier: Amsterdam, The Netherlands, 2020; pp. 3–34.
11. Li, D.; Gao, X.; Liu, Z.; Zan, X.; Zheng, Z.; Jia, J.; Wu, J. Comparison and revelation of coalbed methane resources distribution characteristics and development status between China and America. *Coal Sci. Technol.* **2018**, *46*, 252–261.
12. Ma, T.; Liu, J.; Fu, J.; Wu, B. Drilling and completion technologies of coalbed methane exploitation: An overview. *Int. J. Coal Sci. Technol.* **2022**, *9*, 68. [\[CrossRef\]](#)
13. Palmer, I. Coalbed methane completions: A world view. *Int. J. Coal Geol.* **2010**, *82*, 184–195. [\[CrossRef\]](#)
14. Salmachi, A.; Rajabi, M.; Wainman, C.; Mackie, S.; McCabe, P.; Camac, B.; Clarkson, C. History, Geology, In Situ Stress Pattern, Gas Content and Permeability of Coal Seam Gas Basins in Australia: A Review. *Energies* **2021**, *14*, 2651. [\[CrossRef\]](#)
15. Xu, F.; Wang, B.; Zhao, X.; Yun, J.; Zhang, S.; Wang, H.; Yang, Y. Thoughts and suggestions on promoting high quality development of China's CBM business under the goal of "double carbon". *China Pet. Explor.* **2021**, *26*, 9–18.
16. Sang, S.; Liu, S.; Han, S.; Zheng, S.; Liu, T.; Zhou, X.; Wang, R.; Wang, M. Coal methane control and its emission reduction potential in China. *Coal Geol. Explor.* **2023**, *51*, 159–175.
17. Yi, Y. Research on the Production Characteristics and Drainage Control of CBM Wells in the Shizhuangnan Block of Qinshui Basin. Master's Thesis, China University of Geosciences, Beijing, China, 2020.
18. Feng, Y. Analysis on the Low-yield Genesis of Coalbed Methane Stripper Wells and Key Stimulation Technologies. Master's Thesis, Henan Polytechnic University, Jiaozuo, China, 2021.
19. Wang, T. Key Factors of Low Production of Coalbed Methane Vertical Well in Fanzhuang Block and Its Secondary Fracturing Reconstruction. Master's Thesis, China University of Mining and Technology, Beijing, China, 2020.
20. Dong, K. Study on Geological Conditions Affected to Production of Coalbed Methane Well of Broken Soft Coal Reservoir. Ph.D. Thesis, China Coal Research Institute, Beijing, China, 2019.
21. Zhao, L. Research on the genesis Mechanism and Development Technology of Low Temperature and Low Pressure Coalbed Methane Reservoirs in Yangquan Mining Area. Ph.D. Thesis, Henan Polytechnic University, Jiaozuo, China, 2023.
22. Wang, D. The Research of Affective Facts of Production and Enrichment of CBM in Linfen Block. Ph.D. Thesis, China University of Geosciences, Beijing, China, 2015.
23. Wang, W. Analysis on effect of gas production and influence factors of CBM separate layer pressure control and multi-layer drainage in tectonic coal mining area. *Coal Sci. Technol.* **2019**, *47*, 120–124.
24. Zhang, Z. Controlling Factors of Productivity Difference of Coalbed Methane Wells in Eastern Yunnan and Western Guizhou. Ph.D. Thesis, China University of Mining and Technology, Beijing, China, 2022.
25. Sun, H. Development status and prospect of CBM fracturing technology in China. *China Offshore Oil Gas* **2021**, *33*, 120–128.
26. Huang, Z.; Li, Z.; Li, G.; Yang, R.; Mei, Y.; Niu, J.; Li, Z.; Wu, C.; Wen, H.; Cong, R. Oriented and sand control hydra-jet fracturing in coalbed methane horizontal wells and field applications. *J. China Coal Soc.* **2022**, *47*, 2687–2697.
27. Zhang, W.; Si, L.; Guo, Q.; Tian, K.; Zhang, R. Study on mechanism and application of liquid nitrogen injection combined with fracturing to enhance permeability in CBM wells. *Coal Sci. Technol.* **2019**, *47*, 97–102.
28. Qin, L.; Li, S.; Zhai, C.; Lin, H.; Zhao, P.; Shi, Y.; Bai, Y. Changes in the pore structure of lignite after repeated cycles of liquid nitrogen freezing as determined by nitrogen adsorption and mercury intrusion. *Fuel* **2020**, *267*, 117214. [\[CrossRef\]](#)
29. Cao, Y.; Shi, B.; Zhou, D.; Wu, H.; Liu, T.; Tian, L.; Cao, Y.; Jia, M. Study and application of stimulation technology for low production CBM well through high pressure N₂ Injection-soak. *J. China Coal Soc.* **2019**, *44*, 2556–2565.
30. Lin, X.; Liu, Z.; Zhu, W.; Si, L.; Qu, B.; Liu, S.; Zhang, Y. Mechanism of matrix–fracture equilibrium time lag property inducing coal sub-matrix mass transfer behavior and its effect on the coal seepage characteristics in CO₂ sequestration. *Phys. Fluids* **2025**, *37*, 016601. [\[CrossRef\]](#)
31. Wang, Z.; Fu, X.; Pan, J.; Deng, Z. Effect of N₂/CO₂ injection and alternate injection on volume swelling/shrinkage strain of coal. *Energy* **2023**, *275*, 127377. [\[CrossRef\]](#)
32. Zhou, F.; Hussain, F.; Cinar, Y. Injecting pure N₂ and CO₂ to coal for enhanced coalbed methane: Experimental observations and numerical simulation. *Int. J. Coal Geol.* **2013**, *116–117*, 53–62. [\[CrossRef\]](#)
33. Fang, Z.; Yang, C.; Wang, R. Monitoring technologies for CO₂ storage in coal seams and enhanced coalbed methane recovery: A review of field applications. *Fuel Process. Technol.* **2025**, *276*, 108274. [\[CrossRef\]](#)
34. Shen, S.C.; Fang, Z.M.; Li, X.C.; Jiang, Q.; Shen, H.M.; Shi, L. Enhanced coalbed methane recovery from lignite using CO₂ and N₂. *Energy Fuels* **2025**, *39*, 10394–10409. [\[CrossRef\]](#)
35. Lin, K.; Jing, T.; Wei, N.; Chen, Q.; Zhao, W.; Zhou, J.; Ali, M.; Wang, W.; Li, X. A Comprehensive Analysis of the Mutual Feedback Mechanisms between CO₂ Geological Storage and Underground Coal Mining in the Ordos Basin. *Energy Fuels* **2025**, *39*, 5802–5817. [\[CrossRef\]](#)

36. Fang, H.; Sang, S.; Wang, Z.; Guo, J.; Liu, H.; Xu, H.; Chen, R. Numerical analysis of temperature effect on CO₂ storage capacity and CH₄ production capacity during the CO₂-ECBM process. *Energy* **2024**, *289*, 130022. [\[CrossRef\]](#)
37. Zhang, S.; Sang, S.; Wu, J.; Zhou, X.; Zhang, B.; Yang, R.; Guo, J.; Liu, X.; Zhang, W.; Li, Y. Progress and application of key technologies for CO₂ enhancing coalbed methane. *J. China Coal Soc.* **2022**, *47*, 3952–3964.
38. Lin, K.; Wei, N.; Jiang, D.; Zhang, Y. Progress and perspectives in source-sink matching for CCUS: A critical review. *Renew. Sustain. Energy Rev.* **2026**, *226*, 116313. [\[CrossRef\]](#)
39. Li, Z.; Ni, G.; Wen, Y.; Jiang, H.; Liu, Y.; Huang, Q.; Huang, W. Analysis of permeability evolution mechanism during CO₂ enhanced coalbed methane recovery based on impact factor method. *Fuel* **2021**, *304*, 121389. [\[CrossRef\]](#)
40. Wang, L.; Hu, L.; Guo, H.; Wang, Z.; Xiao, Y.; Zhang, Z. Differences in CH₄ Displacement Efficiency by CO₂/N₂ Injection in Anthracite under Isobaric and High Pressures: Molecular Dynamics Insights. *Energy Fuels* **2025**, *39*, 1959–1970. [\[CrossRef\]](#)
41. Ye, D.; Liu, G.; Gao, F.; Wang, X.; Wei, M.; Liu, Z.; Li, D. A novel interdisciplinary model for optimizing coalbed methane recovery and carbon dioxide sequestration: Fracture dynamics, gas mechanics, and its application. *Phys. Fluids* **2024**, *36*, 076607. [\[CrossRef\]](#)
42. Matkivskyi, S. Optimization of gas recycling technique in development of gas-condensate fields. *Min. Miner. Deposits* **2023**, *17*, 101–107. [\[CrossRef\]](#)
43. Wong, S.; Law, D.; Deng, X.H.; Robinson, J.; Kadatz, B.; Gunter, W.D.; Ye, J.P.; Feng, S.L.; Fan, Z.Q. Enhanced coalbed methane and CO₂ storage in anthracitic coals-Micro-pilot test at South Qinshui, Shanxi, China. *Int. J. Greenh. Gas Control* **2007**, *1*, 215–222. [\[CrossRef\]](#)
44. Liu, S.; Huang, F.; Du, R.; Chen, S.; Guan, Y.; Liu, Y.; Wang, T. Progress and typical case analysis of demonstration projects of the geological sequestration and utilization of CO₂. *Coal Geol. Explor.* **2023**, *51*, 158–174. [\[CrossRef\]](#)
45. Lee, J.H.; Cho, J.; Lee, K.S. Effects of aqueous solubility and geochemistry on CO₂ injection for shale gas reservoirs. *Sci. Rep.* **2020**, *10*, 2071. [\[CrossRef\]](#) [\[PubMed\]](#)
46. Fathi, E.; Akkutlu, I.Y. Multi-component gas transport and adsorption effects during CO₂ injection and enhanced shale gas recovery. *Int. J. Coal Geol.* **2014**, *123*, 52–61. [\[CrossRef\]](#)
47. Eshkalak, M.O.; Al-Shalabi, E.W.; Sanaei, A.; Aybar, U.; Sepehrnoori, K. Simulation study on the CO₂-driven enhanced gas recovery with sequestration versus the re-fracturing treatment of horizontal wells in the U.S. nonconventional shale reservoirs. *J. Nat. Gas Sci. Eng.* **2014**, *21*, 1015–1024. [\[CrossRef\]](#)
48. Kim, T.H.; Cho, J.; Lee, K.S. Evaluation of CO₂ injection in shale gas reservoirs with multi-component transport and geomechanical effects. *Appl. Energy* **2017**, *190*, 1195–1206. [\[CrossRef\]](#)
49. Su, E.; Zhu, X.; Chen, X.; Su, W.; Wang, L.; Ye, X.; Wang, T. Gas transport behavior of tectonic and intact coal reservoirs during CO₂-enhanced coalbed methane recovery. *Phys. Fluids* **2025**, *37*, 076652. [\[CrossRef\]](#)
50. Fang, H.; Ye, K.; Yu, S.; Wang, Y.; Wang, Z. Determining the Starting Time of CO₂ Injection and Its Implications for the CO₂-ECBM Process. *ACS Omega* **2024**, *10*, 1591–1609. [\[CrossRef\]](#) [\[PubMed\]](#)
51. Ma, T.; Rutqvist, J.; Oldenburg, C.M.; Liu, W. Coupled thermal-hydrological-mechanical modeling of CO₂-enhanced coalbed methane recovery. *Int. J. Coal Geol.* **2017**, *179*, 81–91. [\[CrossRef\]](#)
52. Liu, X.; Sang, S.; Zhou, X.; Wang, Z. Coupled adsorption-hydro-thermo-mechanical-chemical modeling for CO₂ sequestration and well production during CO₂-ECBM. *Energy* **2023**, *262*, 125306. [\[CrossRef\]](#)
53. Fan, C.; Elsworth, D.; Li, S.; Chen, Z.; Luo, M.; Song, Y.; Zhang, H. Modelling and optimization of enhanced coalbed methane recovery using CO₂/N₂ mixtures. *Fuel* **2019**, *253*, 1114–1129. [\[CrossRef\]](#)
54. Yang, L.; Fan, C.-J.; Luo, M.-K.; Wen, H.-O.; Sun, H.; Zhou, L.-J.; Cheng, Z.-H.; Zhang, Z.-P. Geological parameters and gas mixture composition on enhanced coalbed methane recovery: A THM modeling approach. *Pet. Sci.* **2025**, *22*, 2078–2095. [\[CrossRef\]](#)
55. Hou, Y.; Huang, S.; Han, J.; Liu, X.; Han, L.; Fu, C. Numerical Simulation of the Effect of Injected CO₂ Temperature and Pressure on CO₂-Enhanced Coalbed Methane. *Appl. Sci.* **2020**, *10*, 1385. [\[CrossRef\]](#)
56. Fan, N.; Wang, J.; Deng, C.; Fan, Y.; Mu, Y.; Wang, T. Numerical study on enhancing coalbed methane recovery by injecting N₂/CO₂ mixtures and its geological significance. *Energy Sci. Eng.* **2019**, *8*, 1104–1119. [\[CrossRef\]](#)
57. Fan, Y.P.; Deng, C.B.; Zhang, X.; Li, F.Q.; Wang, X.Y.; Qiao, L. Numerical study of CO₂-enhanced coalbed methane recovery. *Int. J. Greenh. Gas Control* **2018**, *76*, 12–23. [\[CrossRef\]](#)
58. Fang, H.-H.; Sang, S.-X.; Liu, S.-Q. Numerical simulation of enhancing coalbed methane recovery by injecting CO₂ with heat injection. *Pet. Sci.* **2019**, *16*, 32–43. [\[CrossRef\]](#)
59. Liu, S.; Fang, H.; Sang, S.; Ashutosh, T.; Wu, J.; Zhang, S.; Zhang, B. CO₂ injectability and CH₄ recovery of the engineering test in qinshui Basin, China based on numerical simulation. *Int. J. Greenh. Gas Control* **2020**, *95*, 102980. [\[CrossRef\]](#)
60. Wei, X.R.; Wang, G.X.; Massarotto, P.; Golding, S.D.; Rudolph, V. Numerical simulation of multicomponent gas diffusion and flow in coals for CO₂ enhanced coalbed methane recovery. *Chem. Eng. Sci.* **2007**, *62*, 4193–4203. [\[CrossRef\]](#)
61. Lin, J.; Ren, T.; Wang, G.; Nemcik, J. Simulation investigation of N₂-injection enhanced gas drainage: Model development and identification of critical parameters. *J. Nat. Gas Sci. Eng.* **2018**, *55*, 30–41. [\[CrossRef\]](#)

62. Kumar, H.; Elsworth, D.; Mathews, J.P.; Liu, J.; Pone, D. Effect of CO₂ injection on heterogeneously permeable coalbed reservoirs. *Fuel* **2014**, *135*, 509–521. [[CrossRef](#)]
63. Mu, Y.; Fan, Y.; Wang, J.; Fan, N. Numerical study on injection of flue gas as a heat carrier into coal reservoir to enhance CBM recovery. *J. Nat. Gas Sci. Eng.* **2019**, *72*, 103017. [[CrossRef](#)]
64. Fang, H.; Sang, S.; Liu, S. The coupling mechanism of the thermal-hydraulic-mechanical fields in CH₄-bearing coal and its application in the CO₂-enhanced coalbed methane recovery. *J. Pet. Sci. Eng.* **2019**, *181*, 106177. [[CrossRef](#)]
65. Liu, T.; Lin, B.; Yang, W.; Zhai, C.; Liu, T. Coal permeability evolution and gas migration under non-equilibrium state. *Transp. Porous Media* **2017**, *118*, 393–416. [[CrossRef](#)]
66. Shen, S. Study on Gas Displacement of Coalbed Methane in Low-Rank Coal Seams in Jiergalangtu Area, Inner Mongolia. Ph.D. Thesis, Institute of Rock and Soil Mechanics, Chinese Academy of Sciences, Beijing, China, 2024.
67. Huo, B.; Jing, X.; Fan, C.; Han, Y. Numerical investigation of flue gas injection enhanced underground coal seam gas drainage. *Energy Sci. Eng.* **2019**, *7*, 3204–3219. [[CrossRef](#)]
68. Zhou, L.; Zhou, X.; Fan, C.; Bai, G.; Yang, L.; Wang, Y. Modelling of flue gas injection promoted coal seam gas extraction incorporating heat-fluid-solid interactions. *Energy* **2023**, *268*, 126664. [[CrossRef](#)]
69. Zhou, L.; Zhou, X.; Fan, C.; Bai, G. Coal permeability evolution triggered by variable injection parameters during gas mixture enhanced methane recovery. *Energy* **2022**, *252*, 124065. [[CrossRef](#)]
70. Palmer, I.; Mansoori, J. How permeability depends on stress and pore pressure in coalbeds: A new model. *SPE Reserv. Eval. Eng.* **1998**, *1*, 539–544. [[CrossRef](#)]
71. Wu, Y.; Liu, J.; Elsworth, D.; Miao, X.; Mao, X. Development of anisotropic permeability during coalbed methane production. *J. Nat. Gas Sci. Eng.* **2010**, *2*, 197–210. [[CrossRef](#)]
72. Cui, X.; Bustin, R.M. Volumetric strain associated with methane desorption and its impact on coalbed gas production from deep coal seams. *AAPG Bull.* **2005**, *89*, 1181–1202. [[CrossRef](#)]
73. Fang, Z.; Shen, S. Optimizing enhanced coalbed methane recovery in thick lignite formations: An integrated technical and economic evaluation. *Results Eng.* **2025**, *27*, 106733. [[CrossRef](#)]
74. Fan, C.; Elsworth, D.; Li, S.; Zhou, L.; Yang, Z.; Song, Y. Thermo-hydro-mechanical-chemical couplings controlling CH₄ production and CO₂ sequestration in enhanced coalbed methane recovery. *Energy* **2019**, *173*, 1054–1077. [[CrossRef](#)]
75. Ye, J.; Hou, S.; Zhang, S. Progress of coalbed methane exploration and development in China during the 13th Five-Year Plan period and the next exploration direction. *Coal Geol. Explor.* **2022**, *50*, 15–22.
76. Gao, Y.; Zhang, C.; Zhao, L.; Jia, H.; Qin, M.; Zhang, W.; Ji, Y.; Yuan, S. Application of drainage technology for L-shaped coalbed methane horizontal well in Southern Qinshui Basin. *Coal Sci. Technol.* **2025**, *53*, 304–314. [[CrossRef](#)]
77. Li, S.; Fan, C.; Han, J.; Luo, M.; Yang, Z.; Bi, H. A fully coupled thermal-hydraulic-mechanical model with two-phase flow for coalbed methane extraction. *J. Nat. Gas Sci. Eng.* **2016**, *33*, 324–336. [[CrossRef](#)]
78. Wu, Y.; Liu, J.; Chen, Z.; Elsworth, D.; Pone, D. A dual poroelastic model for CO₂-enhanced coalbed methane recovery. *Int. J. Coal Geol.* **2011**, *86*, 177–189. [[CrossRef](#)]
79. Fang, Z.; Li, X.; Li, H.; Chen, H. Feasibility study of gas mixture enhanced coalbed methane recovery technology. *Rock Soil Mech.* **2010**, *31*, 3223–3229.
80. Hou, X. Study on Gas Controlling Mechanism and Coupled Accumulation of Deep Coal Measure Gases in Qinshui Basin. Ph.D. Thesis, China University of Mining and Technology, Beijing, China, 2020.
81. Hu, B. Methane Adsorption Behavior Characteristics of Multi-scale Pore Structure in Coal and Its Microscopic Influencing Mechanism. Ph.D. Thesis, China University of Mining and Technology, Beijing, China, 2022.
82. Gao, Y. Study on Nitrogen Injection and Production Increasing Technology in Coalbed Methane Wells. Master's Thesis, China University of Petroleum, Beijing, China, 2018.

Disclaimer/Publisher's Note: The statements, opinions and data contained in all publications are solely those of the individual author(s) and contributor(s) and not of MDPI and/or the editor(s). MDPI and/or the editor(s) disclaim responsibility for any injury to people or property resulting from any ideas, methods, instructions or products referred to in the content.