

Numerical Simulation of Progressive CO₂ Injection for Improved Coalbed Methane Extraction and Carbon Sequestration

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Abstract: A numerical simulation-based comparative analysis was conducted to investigate the displacement and extraction performance of coalbed methane (CH₄) under two CO₂ injection strategies: direct injection and progressive staged injection. Results show that direct CO₂ injection rapidly generates high-pressure zones, elevates reservoir pressure, and reduces permeability, leading to limited methane depletion and strong spatial heterogeneity in the extraction zone. In contrast, progressive CO₂ injection integrates staged pressurization with pressure-relief extraction, effectively lowering reservoir pressure, maintaining higher permeability, and significantly expanding the CH₄ extraction range. For both strategies, CH₄ recovery and CO₂ sequestration increased continuously with time; however, the progressive scheme achieved smoother and more efficient CH₄ production while sustaining sequestration effectiveness. After 300 days of injection and extraction, the average CH₄ content declined from 17.09 m³/t to 10.31 m³/t, yielding 1.69×10^5 m³ of recovered CH₄ and 2.97×10^5 m³ of sequestered CO₂. These findings demonstrate that progressive CO₂ injection can simultaneously enhance coalbed methane recovery and CO₂ geological storage, offering technical insights for efficient CBM development and mine gas control.

Keywords: Numerical Simulation; Progressive CO₂ Injection; Enhanced Coalbed Methane Recovery; CO₂-CH₄ Displacement; Carbon Capture and Storage.

1. Introduction

Coalbed methane (CBM) is an important unconventional natural gas resource, and its efficient development plays a significant role in reducing environmental pollution and improving energy utilisation [1]. However, high in-situ methane content is a major factor contributing to coal and gas outburst (CGO) hazards. In China, more than 60% of coal seams characterised by high gas content and low permeability are classified as outburst-prone, posing serious risks to mine safety [2]. Therefore, enhancing coal seam permeability and improving CBM extraction efficiency remain key scientific and engineering challenges in both gas control and CBM exploitation.

Conventional techniques such as pressure-relief extraction, hydraulic fracturing, and thermal stimulation have been widely explored, yet they often suffer from limitations including low extraction efficiency, reservoir damage, and high operational cost [3,4]. In contrast, gas-displacement-based enhanced CBM recovery (ECBM), especially CO₂-ECBM, has attracted increasing interest due to its combined benefits of methane extraction and CO₂ geological sequestration [5,6]. CO₂ exhibits 2-4 times stronger adsorption affinity than CH₄ under comparable temperature and pressure conditions [9,10], enabling effective displacement of adsorbed methane through competitive adsorption mechanisms [7,8]. However, the preferential adsorption of CO₂ induces coal matrix swelling, reduces permeability, and inhibits methane desorption and migration [11]. Numerical simulations and theoretical studies show that reservoir permeability and porosity are highly sensitive to reservoir stress and adsorption-induced deformation. In zones invaded by CO₂, these parameters often decline sharply,

resulting in abrupt permeability reduction and localized overpressure [12,13].

To mitigate these limitations, this study proposes a progressive CO₂ injection strategy aimed at enhancing CH₄ recovery while reducing permeability loss caused by coal matrix swelling. The strategy combines pre-drainage depressurisation with staged CO₂ injection from central to peripheral boreholes, enabling gradual pressure release, sustained desorption, and preservation of higher permeability. A multi-field coupled model incorporating multi-component diffusion-seepage, coal deformation, and thermal effects is developed to simulate the process systematically. Analyses of CH₄ distribution, permeability evolution, effective drainage zones, and CO₂ sequestration characteristics reveal the synergistic enhancement mechanisms between reservoir depressurisation and CO₂ injection, providing theoretical foundations for efficient CO₂-ECBM field implementation and its role in low-carbon CBM development.

2. Multiphysics Coupling Model

The CO₂-enhanced coalbed methane (ECBM) process involves several simplifying assumptions: (i) CH₄ is uniformly distributed within matrix pores and microfractures, and the coal reservoir is treated as an isotropic elastic medium; (ii) Water migration occurs only within the fracture network, while dissolved gas transport and matrix permeability are neglected; (iii) CH₄ and CO₂ adsorption follows a modified non-isothermal Langmuir competitive adsorption model; (iv) Gas diffusion obeys Fick's law, fluid flow follows Darcy's law, and Newtonian laminar flow is assumed within fractures. Figure 1 presents the coupled gas-water transport processes during CO₂-ECBM.

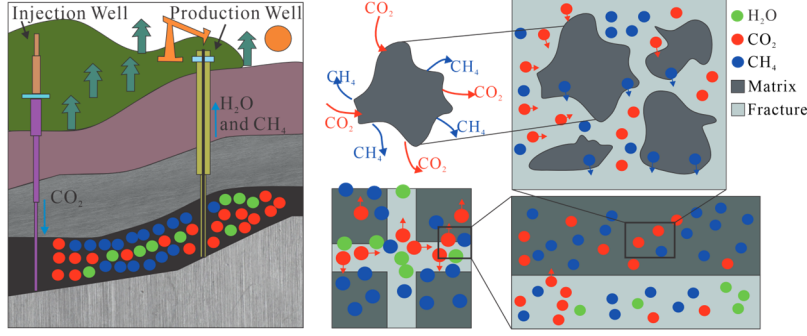


Fig 1. Schematic Diagram of CO2-ECBM Injection Process [14]

2.1. Diffusion-flow Field

1) Gas diffusion in the coal matrix

Adsorbed gas diffuses from the microporous matrix to the fracture system following Fick's law. The mass conservation equation for CH₄ and CO₂ diffusion is:

$$\frac{\partial \rho_{gi}}{\partial t} + \nabla \cdot (-D_i \nabla C_i) = Q_i \quad (1)$$

The mass exchange term Q_i describes transfer between adsorbed and free states, kg/(m³ · s). Before production, CH₄ in coal is in dynamic equilibrium; CO₂ injection and pressure depletion disturb this balance and drive mass exchange. Q_i is expressed as:

$$Q_i = (\rho_{gi} - \rho_{pgi})\tau \quad (2)$$

where, τ is the desorption-diffusion coefficient, m²/s; ρ_{pgi} is the adsorbed concentration under the hypothetical equilibrium pressure p_i . Based on the extended Langmuir model:

$$\rho_{pgi} = \rho_{ia} \rho_c \frac{a_i b_i p_i}{1 + b_i p_i + b_2 p_2} \quad (3)$$

where ρ_{ia} is the gas density at standard conditions, kg/m³; ρ_c is coal density, kg/m³; a_i and b_i are Langmuir parameters, m³/kg; p_1 and p_2 are CH₄ and CO₂ partial pressures, MPa.

2) Gas-water flow in fractures

Fractures contain a two-phase gas-water system driven by reservoir pressure. The matrix acts as a gas source through desorption and diffusion, while water mainly resides in fractures and follows Darcy flow. The mass balance in the fracture system is:

$$\begin{cases} \frac{\partial \rho S_g \phi \rho_{gi}}{\partial t} + \nabla \cdot (\rho_{gi} u_{gi}) = (1-\phi) Q_i \\ \frac{\partial \rho S_w \phi \rho_w}{\partial t} + \nabla \cdot (\rho_w u_w) = 0 \end{cases} \quad (4)$$

where ϕ is fracture porosity; S_g and S_w are gas and water saturations, $S_w + S_g = 1$; ρ_w is water density, kg/m³; u_{gi} and u_w are gas and water velocities, m/s.

Water density varies with temperature:

$$\rho_w = c(T - T_s) + \rho_{ws} \quad (5)$$

Where: c is the temperature coefficient of water, kg/(m³ · K); T is the coal reservoir temperature, K; T_s is the temperature under standard conditions, K; ρ_{ws} is the water density under standard conditions, kg/m³.

Capillary effects link phase pressures as:

$$\begin{cases} p_w = p_g - p_c \\ p_c = p_e \left(\frac{S_w - S_{wr}}{1 - S_{gr} - S_{wr}} \right)^{-1/2} \end{cases} \quad (6)$$

Where p_w is the water-phase pressure in the fracture, MPa; p_g is the total gas pressure of CH₄ and CO₂ in the fracture, MPa; p_c is the capillary pressure, MPa; p_e is the entry (displacement) pressure, MPa; S_{wr} and S_{gr} are the irreducible water saturation and residual gas saturation in the fracture, respectively.

Based on Darcy's law and incorporating the Klinkenberg correction, the phase velocities are:

$$\begin{cases} u_{gi} = -\frac{k_{rg} k}{\mu_{gi}} \left(1 + \frac{b}{p_g} \right) \nabla p_g \\ u_w = -\frac{k_{rw} k}{\mu_w} \nabla p_w \end{cases} \quad (7)$$

Where: u_{gi} is the flow velocity of the individual gas component in the fracture, m/s; u_w is the water-phase flow velocity in the fracture, m/s; k_{rg} and k_{rw} are the relative permeabilities of the gas phase and water phase, m²; k is the absolute permeability of the coal reservoir, m²; μ_{gi} is the dynamic viscosity of the gas phase, MPa · s; μ_w is the dynamic viscosity of the water phase, MPa · s; b is the Klinkenberg factor, MPa.

2.2. Stress Field

Coal deformation is controlled by in-situ stress, pore pressure, gas adsorption/desorption, and temperature. Based on poroelasticity, the stress-strain relationship is:

$$\sigma_{kl} = 2G\varepsilon_{kl} + \frac{2G\nu}{1-2\nu} \varepsilon_{cc} \delta_{kl} - a p_f \delta_{kl} - K a_T T \delta_{kl} - K \varepsilon_s \delta_{kl} \quad (8)$$

$$\begin{cases} p_f = S_w p_w + \sum_{i=1}^2 S_g p_{gi} \\ \varepsilon_s = \sum_{i=1}^2 a_{si} V_i \end{cases} \quad (9)$$

where σ_{kl} and ε_{kl} are stress and strain, MPa; ν is Poisson's ratio; a is the Biot coefficient; ε_s is adsorption-induced strain; a_{si} is the adsorption strain coefficient, kg/m³; V_i is gas adsorption amount, m³/kg; a_T is the thermal expansion coefficient, K⁻¹.

2.3. Temperature Field

Temperature changes arise from adsorption/desorption heat, elastic deformation, conduction, and convection. The energy conservation equation of the coal-fluid system is:

$$\frac{\partial [(\rho C_p)_{eff} T]}{\partial t} + \eta_{eff} \nabla T - \nabla \cdot (\lambda_{eff} \nabla T) + K a_T T \frac{\partial \varepsilon_s}{\partial t} +$$

$$\sum_{i=1}^2 q_{sti} \frac{\rho_c \rho_{gi}}{M_{gi}} \frac{\partial V_i}{\partial t} = 0 \quad (10)$$

where $(\rho C_p)_{eff}$ is the effective heat capacity, J/(m³·K); η_{eff} is the effective convective coefficient, J/(m²·K); λ_{eff} is the effective thermal conductivity, W/(m·K); and q_{sti} is

adsorption heat, J/mol.

2.4. Multiphysics Coupling

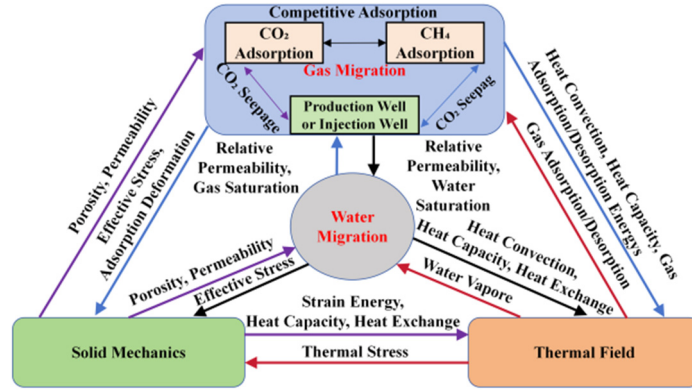


Fig 2. Multiphysics coupling diagram [14]

Coal porosity and permeability evolve with adsorption/desorption, stress changes, and temperature variations (Fig. 2). Fracture porosity is:

$$\phi = 1 - \frac{1-\phi_0}{1+\epsilon_s} \left[1 - \frac{a}{K_s} \Delta \left(\sum_{i=1}^2 p_{gi} + p_w \right) + a_T \Delta T + \Delta \epsilon_s \right] \quad (11)$$

where ϕ_0 is initial fracture porosity and $\Delta \epsilon_s$ is adsorption-induced volumetric strain.

Permeability follows the cubic law:

$$k = k_0 \left(\frac{\phi}{\phi_0} \right)^3 \quad (12)$$

where k_0 is the initial permeability.

3. Geological Models and Numerical Simulation Schemes

3.1. Geological Model

The No. 5 coal seam beneath the 17246 working face of the

No. 6 seam in Zhangji Coal Mine (Huainan, China) was selected as the study area. Drilling sites were arranged in both the intake and return roadways, where CO₂ was injected into the lower adjacent seam through downward cross-layer boreholes to enhance methane extraction. Each roadway contained five drilling sites (ten in total), with 25 boreholes per site in a 5 × 5 layout spaced at 10 m. Based on a five-spot configuration, each CO₂ injection borehole was surrounded by four extraction boreholes, forming nine injection and sixteen extraction boreholes within each site.

For numerical simulation and parameter analysis, a two-dimensional 60 m × 60 m rectangular domain is constructed to represent Seam No. 5, with a 5 × 5 layout of drilling sites. A monitoring line (Line A) crossing boreholes (1,1), (2,2), and (3,3) was defined to track reservoir pressure and permeability during CO₂ injection. The model layout is shown in Fig. 3.

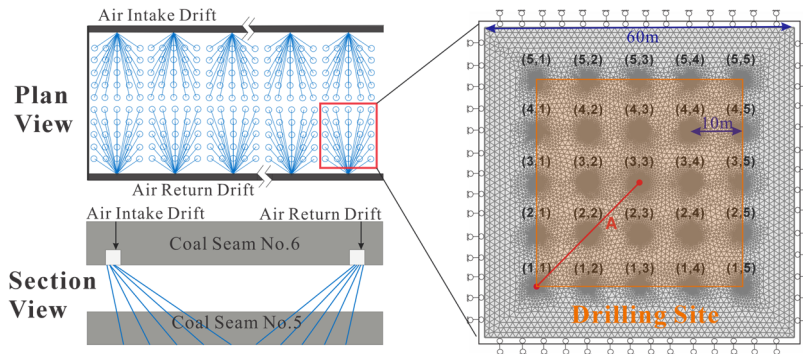


Fig 3. Schematic Geological Model

3.2. Numerical Parameter

The No. 5 coal seam in Zhangji Coal Mine lies at a depth of 537.5–648.3 m (corresponding to an in-situ temperature of 28–31 °C), with an average thickness of 5.2 m, a permeability of approximately 0.35 mD, and an initial CH₄ pressure of 1.50 MPa [15,16]. Additional simulation parameters were obtained from coal seam development data in the Huainan-HuaiBei Basin, laboratory tests, and relevant literature [17,18]. The key parameters used in the numerical model are summarised in Table 1.

3.3. Numerical Scheme

To evaluate coalbed methane recovery under different CO₂ injection approaches, two injection-production schemes were designed.

1) Direct CO₂ injection: CO₂ is injected through 9 injection boreholes while methane is extracted from 16 production boreholes simultaneously, with an injection pressure of 2 MPa.

2) Progressive CO₂ injection: CO₂ is injected in staged intervals, and the corresponding extraction schedule is summarised in Table 2.

Table 1. Key parameters for numerical simulation

Parameter	Value	Parameter	Value
Klinkenberg factor(MPa)	0.76	Coal density(kg·m ⁻³)	1.38×10^3
Langmuir pressure(MPa)	1.74	Initial porosity(%)	2.94
Langmuir volume(m ³ ·kg ⁻¹)	0.012	CH ₄ desorption time(d)	0.38
Permeability(mD)	0.35	Water density at standard Conditions(kg·m ⁻³)	1×10^3
Capillary pressure(MPa)	0.05	Thermal conductivity of CH ₄ (W·(m·K) ⁻¹)	3.01×10^{-2}
Elastic modulus of coal(GPa)	3.0	Thermal conductivity of CO ₂ (W·(m·K) ⁻¹)	1.37×10^{-2}
Adsorption-induced strain Coefficient of coal(kg·m ⁻³)	0.10	Thermal conductivity of water(W·(m·K) ⁻¹)	5.99×10^{-2}
Thermal expansion coefficient of coal(K ⁻¹)	2.4×10^{-5}	Thermal conductivity of coal(W·(m·K) ⁻¹)	0.19
Viscosity of CH ₄ (Pa·s)	1.34×10^{-5}	Initial water saturation(%)	0.30
Water viscosity(Pa·s)	1×10^{-3}	Poisson's ratio	0.37
Viscosity of CO ₂ (Pa·s)	1.84×10^{-5}	CH ₄ density at standard conditions(kg·m ⁻³)	0.717
Initial temperature(K)	323.15	CO ₂ density at standard conditions(kg·m ⁻³)	1.977

Table 2. Progressive CO₂ injection scheme

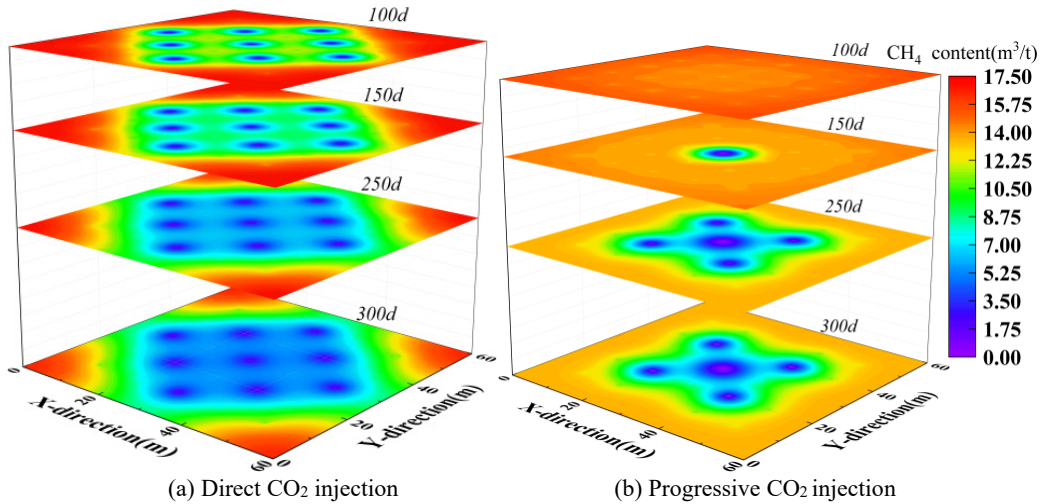
Stage	Time(d)	Location of CO ₂ injection wells	CO ₂ injection pressure
First	0-100	Production stage (no CO ₂ injection wells active)	0
Second	100-150	(3,3)	2
Third	150-250	(2,2);(2,4);(3,3);(4,2);(4,4)	1.5
Forth	250-300	(1,3);(2,2);(2,4);(3,1);(3,3);(3,5);(4,2);(4,4);(5,3)	1.3

4. Results and Analysis

4.1. Analysis of Injection Effects

Fig. 4 presents the spatial evolution of CH₄ content under the two injection-production schemes. Under the direct CO₂ injection scheme (Fig. 4a), CH₄ content near the injection

boreholes gradually decreases with time. By 200 days, the influence zones of the nine CO₂ injection boreholes have merged to form a rectangular low-CH₄ zone; by 300 days, CH₄ content inside this zone has fallen from the initial 17.09 m³/t to below 11.36 m³/t. In contrast, areas outside the drilling field show only minor reductions, with some zones remaining above 15 m³/t, indicating strong spatial heterogeneity.

**Fig 4.** CH₄ content variation under different schemes

Under the progressive CO₂ injection scheme (Fig. 4b), a more pronounced enhancement effect is observed. After 100 days of pressure-relief extraction, CH₄ content has generally dropped below 13.57 m³/t. During the subsequent CO₂ displacement stage, the low-CH₄ zone expands outward from the centre. By 300 days, a stable zone with CH₄ content below 11.93 m³/t is established, and methane around the borehole

periphery is effectively extracted, with CH₄ content still remaining below 13.57 m³/t. These results demonstrate that the progressive scheme significantly enlarges the displacement range and improves extraction uniformity.

Figure 5a compares CH₄ extraction under the two schemes. In the direct CO₂ injection case, the extraction rate peaks at 1382.6 m³/d on day 15 and then declines rapidly, resulting in

a cumulative production of $2.07 \times 10^5 \text{ m}^3$ at 300 days. Under the progressive injection scheme, extraction remains more stable, with slight increases near days 100, 150, 250, and 300 that correspond to staged CO_2 injection. This strategy enhances CH_4 displacement and yields a cumulative production of $1.69 \times 10^5 \text{ m}^3$ at 300 days.

Figure 5b shows the CO_2 sequestration results. For direct injection, the sequestration rate reaches $4486.3 \text{ m}^3/\text{d}$ on day

13 before decreasing sharply, giving a cumulative total of $6.49 \times 10^5 \text{ m}^3$ by day 300. The progressive scheme shows a stepwise increase aligned with the injection stages, reaching $2.97 \times 10^5 \text{ m}^3$ at 300 days.

Overall, direct injection achieves higher short-term displacement efficiency, while the progressive scheme maintains a more stable and controlled extraction-sequestration process.

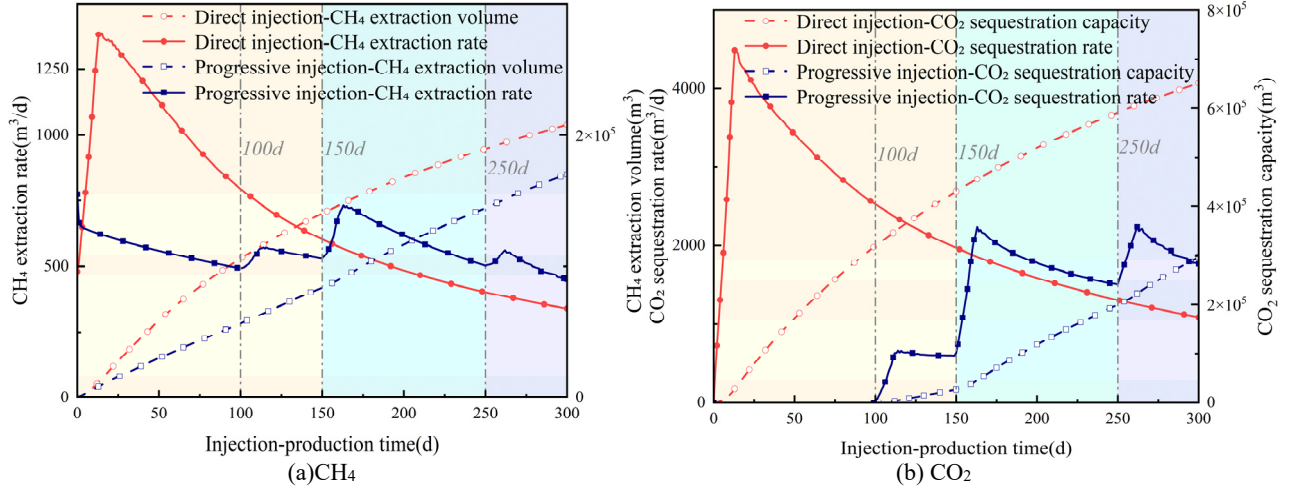


Fig 5. Extraction and sequestration performance under different schemes

To evaluate the overall performance of the two injection-production schemes, three indicators were selected within the $60 \text{ m} \times 60 \text{ m}$ two-dimensional model: (i) Average CH_4 content, reflecting the overall gas reduction in the coal seam; (ii) Coefficient of variation of CH_4 content, indicating spatial uniformity, with higher values representing stronger heterogeneity; (iii) Injection-to-production ratio (CH_4 extracted / CO_2 sequestered), used to assess efficiency, where a higher ratio indicates greater CH_4 output for the same or lower CO_2 injection. Definitions of relevant parameters are listed in Table 3.

Table 3. Evaluation of injection-production performance

Scheme	Average CH_4 content (m^3/t)	Coefficient of variation of CH_4 content	Injection-production ratio
Direct CO_2 injection	8.79	0.42	0.32
progressive CO_2 injection	10.31	0.31	0.57

In summary, although the progressive CO_2 injection scheme yields slightly lower early gas production and sequestration volumes than direct injection, it provides better reservoir stability and more sustained production gains over the 300-day cycle. It effectively reduces CH_4 content, enlarges the extraction zone, and enables coordinated optimization of CO_2 sequestration and CBM recovery, making it more suitable for long-term CBM development and integrated mine-gas management.

4.2. Analysis of Coal Reservoir Changes

Figure 6 presents the pressure distribution under the two injection-production schemes. In the direct CO_2 injection case (Fig. 6a), pressures around the injection holes continuously rise. By day 300, the reservoir pressure reaches 1.68 MPa and a rectangular high-pressure zone develops around the nine injection wells, with local pressures exceeding 1.85 MPa —roughly 0.35 MPa above the initial value. Such persistent high-pressure input restricts gas migration, leading to local pressure buildup that suppresses CH_4 desorption and flow.

Under direct CO_2 injection, the average CH_4 content decreases to $8.79 \text{ m}^3/\text{t}$ after 300 days, with a coefficient of variation of 0.42 and an injection-to-production ratio of 0.32 . Under the progressive injection scheme, the average CH_4 content reaches $10.31 \text{ m}^3/\text{t}$, while the coefficient of variation drops to 0.31 , and the injection-to-production ratio increases to 0.57 . These results indicate that although the progressive scheme yields slightly lower total CH_4 recovery at 300 days, it significantly improves the spatial uniformity of CH_4 reduction and achieves higher injection-production efficiency.

In contrast, the progressive injection scheme (Fig. 6b) allows substantial early pressure relief, with mean reservoir pressure reduced to $1.03\text{--}1.27 \text{ MPa}$ at day 100. As CO_2 is injected stepwise, pressures near injection points gradually increase but remain within $1.03\text{--}1.51 \text{ MPa}$. This indicates that a stable pressure gradient and favorable pressure-relief conditions are maintained throughout the injection-production cycle.

Fig. 7 presents the pressure evolution along Monitoring Line A at 100, 150, 250, and 300 days. The pressure near the extraction hole (1,1) remains consistently lower than that near the injection holes (2,2) and (3,3), forming a clear gradient from the injection to the extraction side. Under direct CO_2 injection, reservoir pressure continues to rise and effective depressurization is not achieved. In contrast, the progressive-injection scheme lowers the pressure across most of the reservoir except in the vicinity of the injection holes, establishing a stable pressure-gradient pathway that supports gas migration.

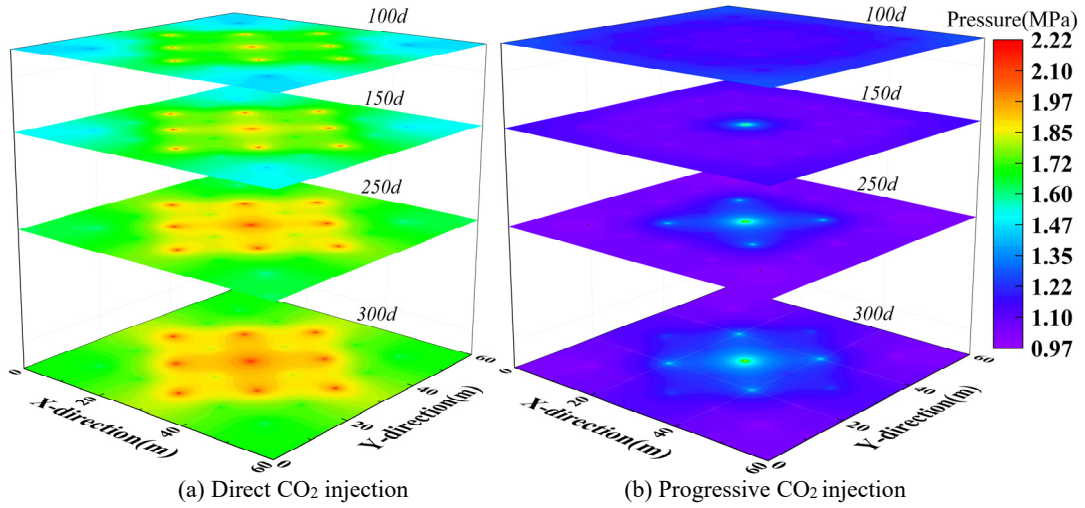


Fig 6. Reservoir pressure evolution under different schemes

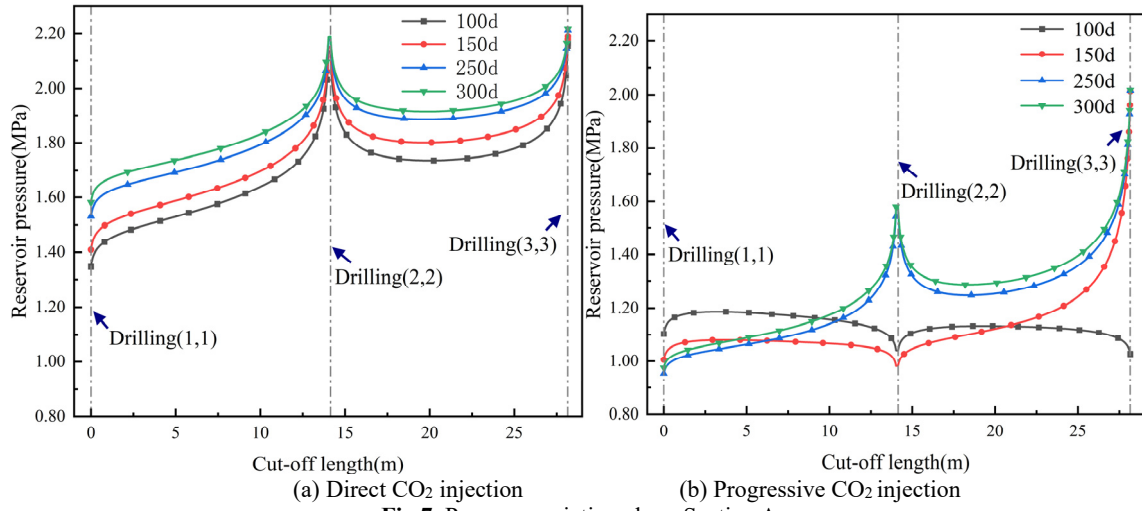


Fig 7. Pressure variation along Section A

Table 4 further confirms this trend. With direct injection, the average reservoir pressure increases to 1.79 MPa at 300 days. Under progressive injection, the pressure drops to 1.19 MPa at 100 days-0.31 MPa below the initial value, and slightly rebounds after 250 days due to additional active

injection points, ultimately stabilizing at 1.14 MPa. Overall, progressive injection alleviates localized pressure buildup caused by CO₂-induced matrix swelling and enables staged pressure release and stable pressure control, which favors continuous CH₄ desorption and efficient transport.

Table 4. Average reservoir pressure at each stage under different schemes

Injection-production time(d)		100d	150d	250d	300d
Average reservoir pressure(MPa)	Direct CO ₂ injection	1.60	1.65	1.75	1.79
	Progressive CO ₂ injection	1.19	1.10	1.09	1.14

Fig. 8 compares the spatial permeability distribution under the two schemes. As shown in Fig. 8a, direct CO₂ injection causes substantial permeability reduction around the injection holes, with an 8.5%-50.6% decline by 300 days. The affected zones coalesce into a rectangular low-permeability belt where permeability generally decreases by more than 40%. This reflects pronounced adsorption-induced swelling and pore-structure compaction under sustained high-pressure injection.

In contrast, Fig. 8b shows that the progressive-injection scheme increases reservoir permeability by about 10% during the initial 100-day depressurization stage. Subsequent CO₂ injection produces only minor permeability reduction near the injection holes, while the surrounding coal seam maintains relatively high permeability. This indicates that progressive injection effectively limits cumulative swelling and preserves favorable flow channels.

Fig. 9 shows the permeability evolution along Monitoring Line A. Permeability near the extraction hole (1,1) is consistently lower than that near injection holes (2,2) and (3,3), with both schemes exhibiting a decreasing trend toward the extraction side. In the direct-injection case, permeability declines markedly over time. Under progressive injection, permeability increases significantly at 100 days due to depressurization and, although it declines slightly afterward, the reduction is confined to areas close to the injection holes, while most regions retain relatively high permeability.

As presented in Table 5, the average permeability under direct injection decreases from 0.35 mD to 0.23 mD within 300 days, a 34.3% reduction. Under progressive injection, permeability slightly exceeds the initial value at 150 days and declines only modestly thereafter, remaining at 0.31 mD by 300 days. Overall, the progressive CO₂-injection strategy not

only enhances methane recovery but also mitigates permeability loss associated with CO₂-induced swelling,

thereby maintaining long-term reservoir flow capacity and supporting stable CO₂-ECBM development.

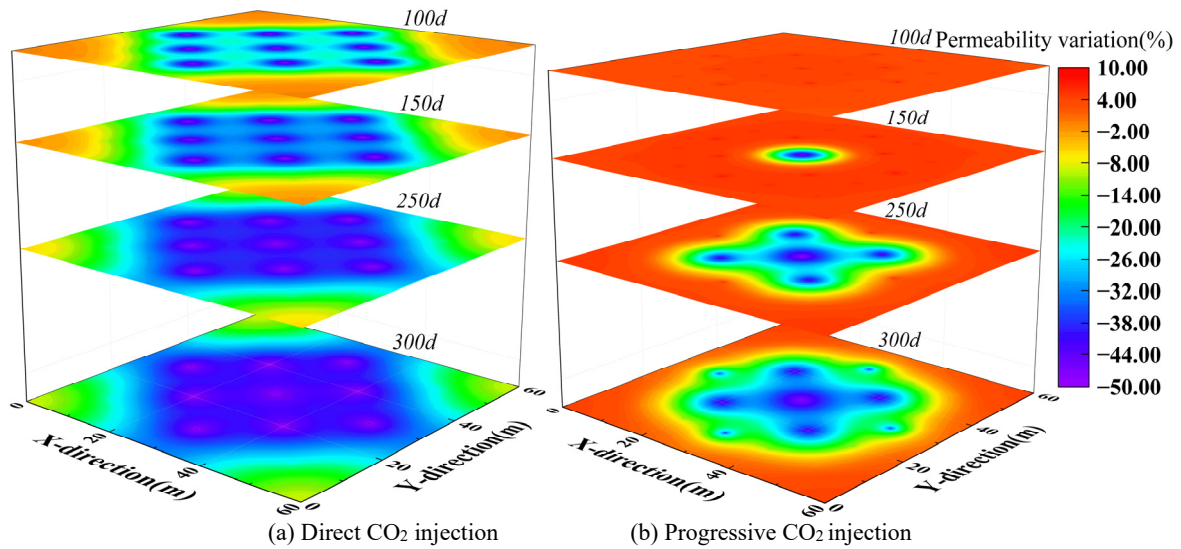


Fig 8. Reservoir permeability evolution under different schemes

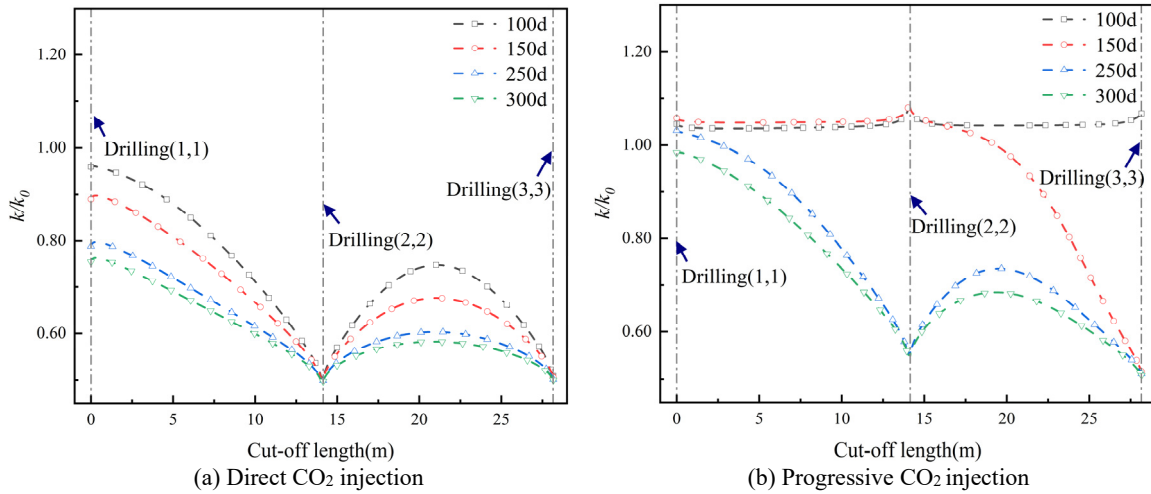


Fig 9. Permeability variation along Section A

Table 5. Average reservoir permeability at each stage under different schemes

Injection-production time(d)		100d	150d	250d	300d
Average reservoir permeability(mD)	Direct CO ₂ injection	0.29	0.27	0.24	0.23
	Progressive CO ₂ injection	0.36	0.35	0.33	0.31

4.3. Potential Applications

The progressive CO₂ injection model developed in this study provides a practical reference for gas control and CBM development in coal mines. The simulations show that regulating the CO₂ injection sequence and injection-production intensity can expand the CH₄ extraction range while maintaining effective pressure relief and reservoir permeability, thereby improving extraction efficiency and long-term stability. This approach is well suited for high-gas, low-permeability coal seams and offers a feasible pathway for mine gas management, CBM productivity enhancement, and mine-scale carbon-emission reduction. The model may be further applied to structurally complex or multi-seam settings to enable large-scale, low-disturbance CO₂-CH₄ displacement.

It should also be noted that the model assumes an idealized borehole layout and homogeneous seams, while CO₂ injection safety remains a key concern in real underground operations. Potential leakage may occur in fracture zones or insufficiently sealed boreholes, creating locally CO₂-rich environments and

associated safety risks. Therefore, field applications should combine improved borehole sealing, enhanced roadway ventilation, and controlled injection pressure with a multi-level CO₂ monitoring and early-warning system to ensure effective sequestration and prevent CO₂ migration into active workings. Future field experiments are required to validate CO₂ migration, sequestration safety, and long-term stability, and to further refine the integrated CO₂ sequestration-extraction framework.

5. Conclusion

1) The simulation results show that within the 300-day injection-production cycle, progressive injection yields a more uniform CH₄ distribution, with the coefficient of variation decreasing from 0.42 to 0.31. Its average CH₄ content reaches 10.31 m³/t, slightly higher than 8.79 m³/t under direct injection, but the progressive scheme establishes a more stable extraction zone. At the same time, the injection-production ratio increases from 0.32 to 0.57, indicating higher

CH₄ recovery efficiency with a smaller CO₂ injection volume.

2) Under direct injection, the rapid influx of CO₂ leads to continuous pressure buildup and the formation of a large permeability-attenuation zone. In contrast, the progressive scheme first reduces the reservoir pressure to 1.19 MPa during the pre-injection pressure-relief stage and then maintains a more stable permeability structure during injection. By 300 days, the average permeability reaches 0.31 mD (compared with 0.23 mD for direct injection), indicating that progressive injection effectively mitigates permeability reduction caused by CO₂ adsorption and swelling, thereby maintaining long-term gas-flow capacity.

3) Progressive CO₂ injection enhances CH₄ extraction efficiency while improving reservoir stability, providing a feasible approach for mine gas control and integrated CO₂-ECBM development. However, fractured roadway surrounding rock and complex underground ventilation conditions may allow CO₂ migration along fractures, posing potential leakage risks. Therefore, practical engineering application should incorporate borehole sealing and reinforcement, pressure monitoring, CO₂ concentration early-warning systems, and ventilation regulation to ensure the safety and long-term effectiveness of CO₂ sequestration.

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