

Article

Seepage and Heat Transfer Characteristics of CO₂ Plume Geothermal Systems Under Different Injection Conditions

Yuhao Zhu ^{1,2}, Meilong Fu ^{1,2,*}, Yuxia Zhou ³, Guojun Li ^{1,2} and Jianqiang Lu ⁴¹ State Key Laboratory of Low-Carbon Catalysis and CO₂ Utilization, Yangtze University, Wuhan 430100, China² Hubei Key Laboratory of Oil and Gas Drilling and Production Engineering, Yangtze University, Wuhan 430100, China³ CNOOC (China) Co., Ltd. Hainan Branch, Haikou 570100, China⁴ Gas Field Company, Shaanxi Yanchang Petroleum (Group) Co., Ltd., Xi'an 710065, China

* Correspondence: fmlytze@163.com

Abstract

CO₂ plume geothermal systems (CPGS) hold significant potential for geothermal energy extraction due to their dual benefits of carbon sequestration and efficient heat transfer. Existing studies primarily focus on macroscopic models of geothermal systems, with limited evaluation of real thermal reservoir cores in terms of CP GS heat extraction performance. This study investigates the seepage and heat transfer characteristics of CO₂ under various injection conditions through a combination of experiments and numerical simulations. Experimental results indicate that under the tested conditions, CO₂ exhibits 20–50% higher heat transfer capacity compared to distilled water. The heat transfer capacity increases with injection flow rate, while injection temperature shows a relatively limited influence under high-velocity seepage conditions. Specifically, at low injection flow rates, lower injection temperatures result in higher heat transfer capacity due to the increased thermal driving force between CO₂ and the reservoir rock. Microscale seepage-heat transfer simulations reveal that an increase in injection flow rate enhances CO₂ flow velocity within the pore network, expands the swept volume, and consequently strengthens convective heat transfer and increases the effective heat exchange area. Additionally, higher thermal reservoir temperatures establish a greater temperature gradient between the working fluid and rock, thereby enhancing heat transfer between CO₂ and the reservoir rock. The findings of this study provide valuable insights for optimizing CP GS design, particularly in understanding the impact of injection conditions on heat transfer capacity, with both practical engineering and theoretical implications.

Keywords: CO₂ plume geothermal system; specific enthalpy difference; microscale seepage-heat transfer model



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1. Introduction

With the increasing global demand for clean energy, geothermal energy has gained significant attention as a green and sustainable energy source. Among various geothermal extraction technologies, the CO₂ plume geothermal system (CPGS) has demonstrated considerable potential [1–3]. CP GS, first proposed by Randolph at the University of Minnesota in 2011, utilizes the excellent flowability and heat transfer capacity of CO₂. In this system, supercritical CO₂ is injected into geothermal reservoirs, forming a plume effect that facilitates geothermal energy extraction for power generation or other energy applications while simultaneously achieving CO₂ geological sequestration [4,5].

Building upon Randolph's theoretical framework, Shi et al. [6,7] conducted simulations comparing geothermal systems using CO₂ and water. Their results indicated that in sandstone reservoirs, CO₂ exhibited a 200% higher heat extraction rate than water. However, they also highlighted that complex geological conditions and specific temperature-pressure combinations could limit CO₂ heat transfer efficiency and the long-term stability of sequestration. Garapati [8] investigated the effects of well spacing and reservoir permeability on CPGS thermal extraction rates, showing that increasing well spacing reduces the rate of thermal depletion and extends reservoir lifespan, while lower permeability restricts plume expansion, thus affecting heat exchange efficiency. Cui et al. [9], based on thermodynamic and geochemical reaction principles, examined the influence of formation water reflux and rock-fluid interactions on heat extraction capacity. Their findings suggested that formation water reflux accelerates geochemical reactions between CO₂, formation water, and reservoir rock, leading to a reduction in CO₂ seepage velocity and ultimately affecting heat extraction efficiency. Xu et al. [10] developed a three-dimensional well-reservoir coupling model to simulate CO₂ flow and heat transfer under the geological and geothermal conditions of the Qingshankou Formation in the Songliao Basin, China. Their study focused on the fluid and thermal dynamics of CPGS in heterogeneous reservoirs, providing valuable insights for the future design of CO₂-based geothermal extraction systems.

Existing studies primarily focus on macroscopic models of geothermal systems [11–16], with limited evaluation of real geothermal reservoir cores in terms of CPGS heat extraction performance. Comparative studies on the seepage and heat transfer characteristics of CO₂ and conventional working fluids (e.g., distilled water) in porous media can provide valuable references and scientific foundations for future geothermal resource research and development.

This study investigates the seepage and heat transfer behavior of CO₂ and distilled water in geothermal reservoir rocks through experiments and numerical simulations. Core-scale heat transfer experiments were conducted to compare the heat extraction capacity of CO₂ and distilled water in geothermal reservoir rocks. Both constant flow rate and constant pressure injection methods were employed to examine the effects of injection temperature and flow rate on CO₂ heat transfer under steady-state and high-velocity seepage conditions. Additionally, the microstructure of the rock was reconstructed based on CT scanning, and the lattice Boltzmann method (LBM) was used to simulate CO₂ seepage and heat transfer characteristics under varying injection flow rates and reservoir temperatures. The primary contribution of this study lies in the quantitative characterization of CO₂ heat transfer capacity under different conditions, providing a clear understanding of how injection parameters influence heat extraction efficiency. The findings offer theoretical and practical insights for the further development and optimization of CPGS.

2. Experimental Methods

2.1. Experimental Materials and Equipment

Experimental Materials: CO₂ gas cylinder; Artificial homogeneous sandstone core ($\varnothing 25 \times 300$ mm); Core samples from the Dongfang 13-2 gas field in the Yingqiong Basin; Distilled water.

Experimental Equipment: Supercritical CO₂ heat transfer and seepage displacement simulation system (Figure 1); V|Tome|X S 180 & 240 micro/nano dual X-ray tube core CT scanning system.

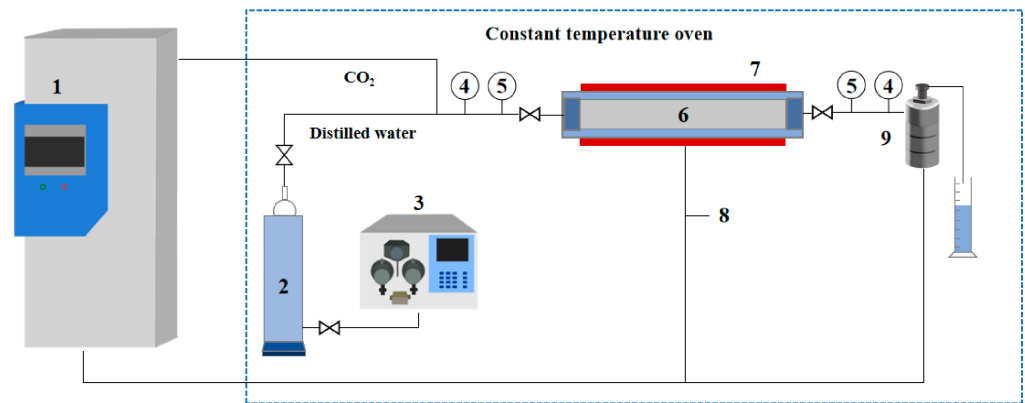


Figure 1. Supercritical CO₂ Heat Transfer and Seepage Displacement Simulation System. 1—CO₂ constant flow displacement pump; 2—Intermediate container; 3—Peristaltic pump; 4—Pressure sensor; 5—Temperature sensor; 6—Core; 7—Heating and insulation system; 8—Back pressure device; 9—Back pressure valve.

The experimental cores used in this work were collected from the Dongfang 13-2 gas field. Artificial homogeneous sandstone cores were only adopted for the preliminary calibration of the experimental system, while all heat transfer tests in this study were performed on natural sandstone cores. The average physical and thermal parameters of the natural core samples are as follows: density of 2600 kg/m³, specific heat capacity of 900 J/(kg·°C), thermal conductivity of 2.5 W/(m·°C), average porosity of 15.5%, and average permeability of 45.5 mD.

2.2. Heat Transfer Experiment of CO₂ in Geothermal Reservoirs

The CO₂ heat transfer experiment in geothermal reservoirs consists of constant flow rate and constant pressure injection experiments. The constant flow rate experiment aims to compare the heat transfer performance of CO₂ and distilled water under steady-state seepage conditions, analyzing the effects of injection temperature and flow rate on heat transfer efficiency, with variables including working fluids (CO₂ and distilled water), injection temperature (24 °C, 35 °C), and flow rates (0.1, 0.5, 1.0 g/min). The constant pressure experiment examines the impact of injection temperature and flow rate on CO₂ heat transfer under high-velocity seepage conditions, with the displacement pressure difference (10, 15, 20 MPa) as the experimental variable, focusing on heat extraction efficiency under high flow rates. The experiment is based on the geothermal development of the depleted gas reservoir in the Dongfang 13-2 gas field in the Yingqiong Basin, with a reservoir temperature of 150 °C, a core permeability of 40 mD, and a back pressure of 10 MPa.

2.2.1. Experimental Procedure

- (1) After drying, the core is placed in the core holder and connected to the experimental apparatus. The core is then heated to 150 °C.
- (2) The confining pressure and back pressure are applied. Water flooding is performed to saturate the core, and CO₂ flooding is conducted to establish residual water saturation. The core was first fully saturated with distilled water. CO₂ was then injected until no additional water was produced at the outlet, indicating that the irreducible (residual) water saturation had been established. Residual water saturation is not required for the distilled water heat transfer experiments.
- (3) Heat transfer experiments using distilled water and CO₂ are conducted under different conditions. The inlet and outlet temperatures and pressures of the working fluid are recorded in real time. The experiment was continued for at least 600 s after the outlet

temperature reached its maximum value. During this period, no sustained increase in outlet temperature was observed. The selected steady-state interval used for enthalpy calculation was determined according to the stability of the outlet temperature rather than the total experimental duration.

2.2.2. Data Processing Method

Since the thermophysical properties of CO₂ vary significantly with temperature and pressure, the specific enthalpy difference was used to quantify the heat extraction capacity of the working fluid. The specific enthalpy difference was calculated as:

$$\Delta h = h_{out}(T_{out}, P_{out}) - h_{in}(T_{in}, P_{in})$$

where h_{in} and h_{out} represent the specific enthalpy of the injected and produced fluids, respectively (kJ/kg); T_{in} , T_{out} , P_{in} , and P_{out} are the corresponding inlet and outlet temperatures and pressures.

The enthalpy values were calculated using the CoolProp (6.4.3) thermophysical property library in Python (3.9). The calculation procedure was implemented in PyCharm (2025.1), and the real-time temperature and pressure data recorded during the experiments were imported to obtain the instantaneous enthalpy difference. In this study, the enthalpy of CO₂ was obtained from the thermodynamic property model implemented in the CoolProp database based on the measured temperature and pressure conditions. No polynomial fitting or empirical correlation was applied. The specific enthalpy difference was calculated as the difference between the outlet and inlet specific enthalpy values. The temperature and pressure measured during the experiments were directly used as inputs for the thermodynamic property calculation.

For CO₂ injection experiments, residual water saturation was considered by treating the porous medium as a CO₂–water two-phase system after the establishment of irreducible water saturation. The calculated enthalpy difference represents the thermal energy carried by the flowing CO₂ phase, while the influence of residual water is incorporated through its effect on CO₂ transport pathways and effective heat-transfer area rather than being directly included in the enthalpy calculation.

2.2.3. Uncertainty Analysis

In the homogeneous core experiments, uncertainties mainly originate from the measurement errors of outlet temperature and core dimensions. The temperature differences used in the heat transfer calculation are defined as:

$$T_{out} - T_{in} = \Delta T_1$$

$$2T_w - T_{out} - T_{in} = \Delta T_2$$

The uncertainty of ΔT_1 is calculated as:

$$U(\Delta T_1) = \pm \left[\left(\frac{\partial \Delta T_1}{\partial T_{in}} U T_{in} \right)^2 + \left(\frac{\partial \Delta T_1}{\partial T_{out}} U T_{out} \right)^2 \right]^{1/2}$$

The uncertainty of ΔT_2 is calculated as:

$$U(\Delta T_2) = \pm \left[\left(\frac{\partial \Delta T_2}{\partial T_w} U T_w \right)^2 + \left(\frac{\partial \Delta T_2}{\partial T_{out}} U T_{out} \right)^2 + \left(\frac{\partial \Delta T_2}{\partial T_{in}} U T_{in} \right)^2 \right]^{1/2}$$

Since the inlet and outlet temperature measurements are independent and do not affect each other, the uncertainty of the heat transfer coefficient h for the homogeneous core experiments is expressed as:

$$U(h) = \pm \left[\left(\frac{\partial h}{\partial T_1} U\Delta T_1 \right)^2 + \left(\frac{\partial h}{\partial T_2} U\Delta T_2 \right)^2 + \left(\frac{\partial h}{\partial R} UR \right)^2 + \left(\frac{\partial h}{\partial L} UL \right)^2 \right]^{1/2}$$

The partial derivatives are expressed as:

$$\frac{\partial h}{\partial R} = \frac{c_i \rho_i q (T_{out} - T_{in})}{LR^2 (T_{in} + T_{out} - 2T_w)}$$

$$\frac{\partial h}{\partial L} = \frac{c_i \rho_i q (T_{out} - T_{in})}{L^2 R (T_{in} + T_{out} - 2T_w)}$$

$$\frac{\partial h}{\partial \Delta T_1} = \frac{c_i \rho_i q}{LR \Delta T_2} = \frac{c_i \rho_i q}{LR (2T_w - T_{in} - T_{out})}$$

$$\frac{\partial h}{\partial \Delta T_2} = \frac{c_i \rho_i q \Delta T_1}{LR \Delta T_2^2} = \frac{c_i \rho_i q (T_{in} - T_{out})}{LR (T_{in} + T_{out} - 2T_w)^2}$$

The temperature display accuracy of the experimental system is 0.1 °C, and the dimensional measurement accuracy is 0.01 cm. Therefore, the uncertainties of $U(\Delta T_1)$ and $U(\Delta T_2)$ are 0.1414 and 0.1732, respectively, while the uncertainties of UR and UL are both 0.01.

For each experimental condition with different design parameters, the average outlet temperature and average core temperature during the 5 min period before reaching the maximum outlet temperature were used in the calculation. The specific heat capacity and density were obtained based on the average pressure and temperature values during this 5 min period. The flow rate used in the calculation corresponds to the inlet flow rate.

2.3. Seepage-Heat Transfer Simulation of CPGS

The seepage-heat transfer simulation of the CO₂ plume geothermal system (CPGS) is based on in situ core samples collected from the Dongfang 13-2 gas field in the Yingqiong Basin. Utilizing CT scanning technology and a 3D microscale reconstruction method, a microscale rock model was established to investigate CO₂ flow and heat transfer mechanisms in deep geothermal reservoirs under high-temperature and high-pressure conditions. This study employs digital rock physics to explore CO₂ seepage and heat transfer at the microscale level, aiming to reveal the fundamental heat transfer mechanisms of supercritical CO₂ in geothermal reservoir rocks.

2.3.1. Experimental and Simulation Methods

- (1) CT cross-sectional scanning was performed on $\varnothing 5 \times 24$ mm cores to obtain the internal structure of each layer.
- (2) A 3D microscale rock reconstruction was conducted using digital rock technology to construct a deep geothermal rock microscale model.
- (3) The simulation conditions were set as follows:
 - Injection temperature: 40 °C.
 - Injection pressure: 10 MPa.
 - Confining pressure: 35 MPa.
 - Simulation variables: Flow rate: 0.1, 0.5, and 2 mL/min; Reservoir temperature: 150, 180, and 200 °C.
 - The Lattice Boltzmann Method (LBM) was employed for numerical calculations.

2.3.2. Data Processing Methods

(1) Microscale Rock Model Construction

CT scan data were processed using image processing algorithms to reconstruct a microscale digital rock model. The representative elementary volume (REV) of the core was extracted, and a $0.49\text{ cm} \times 0.49\text{ cm} \times 0.49\text{ cm}$ 3D microscale rock model was established (Figure 2).

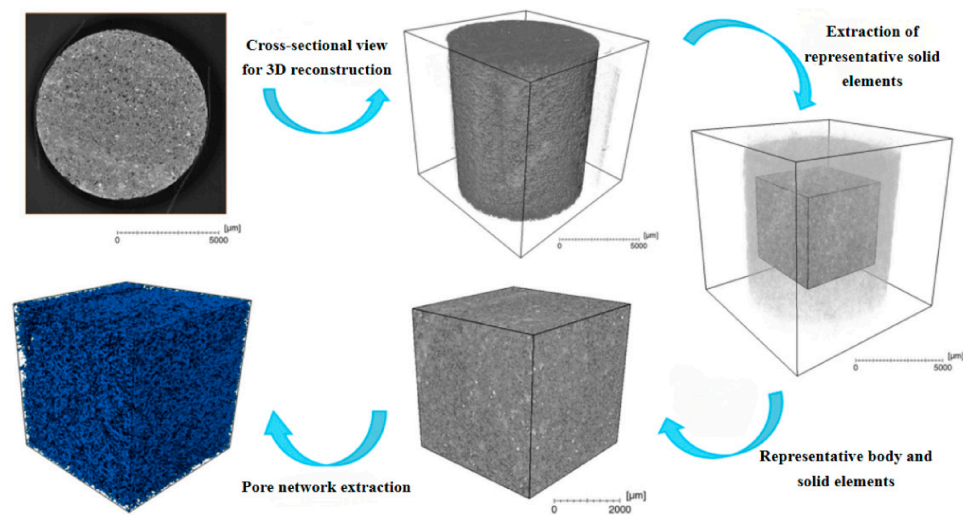


Figure 2. 3D Reconstruction of Rock Microscale Model for Flow Simulation.

(2) Microscale Fluid Seepage-Heat Transfer Computation

The Lattice Boltzmann Method (LBM) was employed to simulate fluid seepage and heat transfer. As a mesoscopic-scale modeling technique, LBM is capable of accurately capturing fluid flow and thermal conduction in porous media [17]. The simulation incorporated multiple-relaxation-time (MRT) models and dual-distribution function (DDF) models to simulate the seepage and heat transfer of supercritical CO_2 within the rock core.

To ensure consistency with the experimental conditions, dimensionless unit conversion was applied, as follows:

- Length: 1 lattice unit represents $0.3 \times 10^{-4}\text{ m}$.
- Time: 1 time step represents $1.26 \times 10^{-4}\text{ s}$.
- Mass conversion factor: $3 \times 10^{-10}\text{ kg}$.
- Temperature: Processed using characteristic temperature normalization.

By leveraging the LBM numerical simulation, the LBM simulation was used to analyze the pore-scale flow behavior and heat transfer characteristics, providing detailed microscale data support for subsequent seepage-heat transfer analysis.

3. Experimental Results and Discussion

3.1. Heat Transfer Experiment of CO_2 in Geothermal Reservoirs

3.1.1. Heat Transfer Experiment of Distilled Water

To clarify the difference in heat transfer performance between CO_2 and distilled water in geothermal reservoirs, a series of heat transfer experiments were conducted, examining the effects of injection temperature and flow rate on the specific enthalpy difference (Δh). The results indicate that at injection flow rates of 0.1, 0.5, and 1.0 g/min, the Δh values for distilled water injected at $24\text{ }^\circ\text{C}$ were 57.27, 70.33, and 84.53 kJ/kg, respectively, while those for $35\text{ }^\circ\text{C}$ injection were 54.11, 69.99, and 83.98 kJ/kg, respectively. Overall, the specific enthalpy difference under $35\text{ }^\circ\text{C}$ injection was slightly lower than that under $24\text{ }^\circ\text{C}$ injection.

(1) Influence of Injection Temperature on Heat Transfer Performance

The results show that under the same flow rate conditions, the Δh values for 24 °C injection were slightly higher than those for 35 °C injection. This is mainly due to the reduction in water viscosity at higher temperatures, which enhances fluid mobility and improves convective heat transfer within the core. However, a higher injection temperature also reduces the temperature gradient between the working fluid and the rock, weakening conductive heat transfer. As a result, although conductive heat transfer efficiency decreases at 35 °C, the enhancement of convective heat transfer partially offsets this effect, allowing the overall heat transfer efficiency to remain at a high level without a significant decrease in Δh .

(2) Influence of Injection Flow Rate on Heat Transfer Performance

As the injection flow rate increases, the residence time of the working fluid in the core decreases, shortening the window for conductive heat transfer. However, higher flow rates also enhance fluid-wall interactions, increasing convective heat transfer intensity. Additionally, the expansion of the swept volume further improves overall heat transfer efficiency. Therefore, under high-flow injection conditions, although the reduction in residence time may negatively impact conductive heat transfer, the significant enhancement of convective heat transfer leads to an overall improvement in heat transfer efficiency, as shown in Table 1 and Figure 3.

Table 1. Heat Transfer Experiment Results for Distilled Water.

Working Fluid	Injection Temperature (°C)	Flow Rate (g/min)	Avg. Heat Extraction Temperature (°C)	Specific Enthalpy Diff. (kJ/kg)	Heat Transfer Parameters W/(K·m ²)	Re	Uncertainty Values (%)
Distilled Water	24	1.0	44.34	84.53	1.8196	0.934	0.0104
		0.5	41.82	70.33	0.7698	0.467	0.0048
		0.1	37.99	57.27	0.1488	0.093	0.0846
	35	1.0	55.72	83.98	2.1042	1.179	1.1650
		0.5	52.42	69.99	0.8840	0.590	0.5221
		0.1	49.72	54.11	0.1433	0.118	0.0955

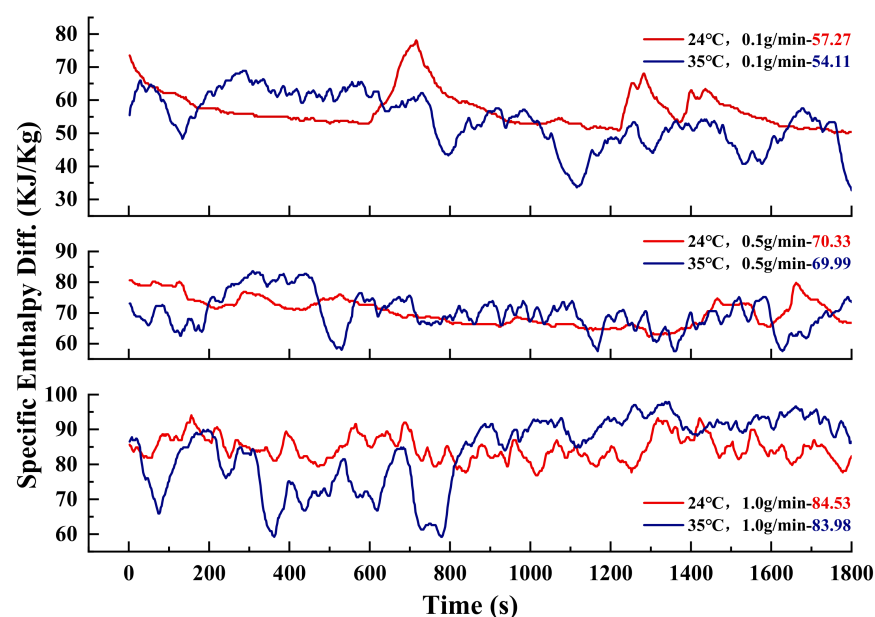


Figure 3. Heat transfer curves of distilled water.

In addition, the high-amplitude fluctuations also originate from the transient thermal equilibrium process and pressure oscillations of the displacement pump.

3.1.2. Constant Flow Rate Heat Transfer Experiment of CO₂

The experimental results, as shown in Table 2 and Figure 4, indicate that CO₂ exhibits significantly higher heat transfer performance than distilled water. At 24 °C and a flow rate of 1.0 g/min, the specific enthalpy difference (Δh) of CO₂ reached 128.01 kJ/kg, which is 51.44% higher than that of distilled water. Under 35 °C and 1.0 g/min conditions, Δh was 118.03 kJ/kg, showing a 40.55% increase. The superior heat transfer capability of CO₂ is mainly attributed to its low viscosity, high compressibility, and strong convective heat transfer characteristics. Compared to distilled water, CO₂ is more prone to forming high-velocity seepage within the core, allowing for large-scale convective heat transfer, thereby significantly enhancing heat transfer efficiency.

Table 2. Constant Flow Rate Heat Transfer Experiment Results for CO₂.

Working Fluid	Injection Temperature (°C)	Flow Rate (g/min)	Avg. Heat Extraction Temperature (°C)	Specific Enthalpy Diff. (kJ/kg)	Increase in Specific Enthalpy Compared to Water	Heat Transfer Parameters W/(K·m ²)	Re	Uncertainty Values (%)
CO ₂	24	1.0	50.70	128.01	51.44%	2.5546	11.120	0.0177
		0.5	46.15	97.89	39.19%	0.9903	5.560	0.0095
		0.1	42.45	72.60	26.77%	0.1535	1.112	0.0016
	35	1.0	55.89	118.03	40.55%	2.7974	14.637	0.0119
		0.5	49.58	90.02	28.61%	0.9615	7.319	0.0071
		0.1	46.27	66.38	22.68%	0.1491	1.464	0.0011

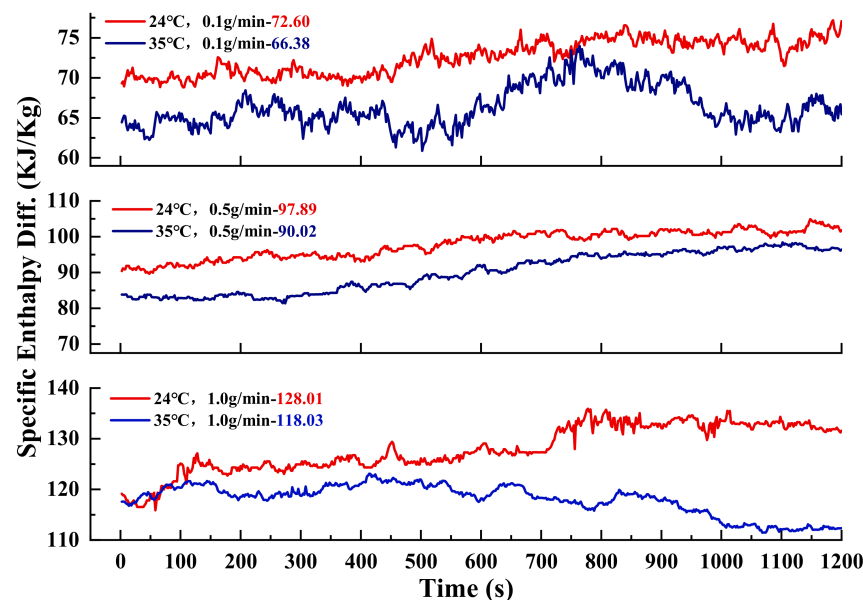


Figure 4. Constant Flow Rate Heat Transfer Experiment Curves for CO₂.

(1) Influence of Flow Rate on Heat Transfer Performance

The heat transfer performance of CO₂ increases with increasing flow rate, similar to that of distilled water. However, owing to its lower viscosity and higher mobility, CO₂ achieves higher seepage velocities under identical injection conditions, resulting in a larger swept volume within the porous medium. The increased seepage velocity enhances convective heat transfer between the fluid and the rock matrix, thereby improving the

overall heat extraction performance. For example, at an injection temperature of 24 °C, the specific enthalpy difference increased from 72.60 kJ/kg at 0.1 g/min to 128.01 kJ/kg at 1.0 g/min, representing an increase of approximately 76%. Although increasing the flow rate reduces the residence time of the working fluid within the core, the enhanced convective heat transfer resulting from the higher seepage velocity outweighs this effect, leading to a significant improvement in the overall heat transfer performance.

(2) Influence of Injection Temperature on Heat Transfer Performance

The effect of injection temperature on CO₂ heat transfer differs from that of distilled water. The experimental results show that Δh at 24 °C is consistently higher than at 35 °C, whereas distilled water exhibits relatively small variations in Δh across different temperatures. This phenomenon is primarily governed by the thermophysical properties and heat transfer mechanisms of CO₂.

First, CO₂ has a lower specific heat capacity at lower temperatures, allowing it to absorb heat more rapidly upon entering the core, thereby increasing heat transfer efficiency. Second, compared with distilled water, supercritical CO₂ exhibits a significantly lower dynamic viscosity under the experimental conditions (150 °C and 10 MPa), resulting in a mobility approximately 7–8 times higher when mobility is characterized as the inverse of dynamic viscosity. This enhanced mobility facilitates more efficient transport through the pore network and contributes to improved convective heat transfer. Due to CO₂'s high mobility, an increase in injection temperature has a limited effect on further enhancing its flowability, unlike distilled water, which compensates for the reduction in temperature gradient through improved mobility. Additionally, at lower temperatures, CO₂ benefits from a greater heat transfer driving force (temperature gradient), and its rapid heat absorption rate further enhances heat transfer capacity. Consequently, at higher injection temperatures, the improvement in flowability is insufficient to counteract the reduction in conductive heat transfer caused by the lower temperature gradient, leading to higher Δh values under lower injection temperature conditions.

The fluctuations in Figure 4 arise partly because the specific enthalpy difference is not measured directly but is calculated from the instantaneous inlet and outlet temperatures and pressures. Small oscillations in the displacement pump and back-pressure regulator, together with the measurement uncertainty of the temperature and pressure sensors, are therefore propagated into the calculated enthalpy difference. This effect is particularly noticeable for CO₂ because its thermophysical properties are sensitive to variations in temperature and pressure under the investigated conditions. In addition, transient redistribution of CO₂ and residual water within the heterogeneous pore network may contribute to short-term variations in the outlet temperature.

At a flow rate of 1 mL/min, increasing the injection temperature from 24 to 35 °C increased the inlet specific enthalpy and reduced the temperature difference between the injected fluid and the heated core. Meanwhile, the higher flow rate shortened the residence time of CO₂ within the core, limiting the amount of heat transferred to each unit mass of fluid. Consequently, the increase in outlet enthalpy was insufficient to compensate for the higher inlet enthalpy, resulting in a decrease in the specific enthalpy difference. It should be emphasized that this decrease represents a reduction in the heat absorbed per unit mass and does not necessarily indicate a reduction in the total heat extraction rate.

3.1.3. Constant Pressure Difference Heat Transfer Experiment of CO₂

The heat transfer experiment under constant flow mode investigated the heat transfer capacity of CO₂ under steady-state seepage conditions and analyzed the influence of various factors. In contrast, this experiment adopts constant pressure-difference displacement to simulate heat transfer behavior under relatively high-velocity seepage conditions, aim-

ing to explore the impact of flow regime on CO₂ heat transfer capacity. The experimental results, as shown in Table 3 and Figure 5, indicate that increasing the displacement pressure difference significantly enhances CO₂ heat transfer capacity, while injection temperature has a relatively minor effect.

Table 3. Heat Transfer Experiment Results for CO₂ with Constant Pressure Injection.

Working Fluid	Injection Temperature (°C)	Flow Rate (cm ³ /s)	Injection Pressure Diff. (MPa)	Avg. Heat Extraction Temperature (°C)	Specific Enthalpy Diff. (kJ/kg)	Re
CO ₂	24	210.06	20 MPa	71.71	211.33	136.12
		109.46	15 MPa	66.14	195.44	70.93
		91.98	10 MPa	60.48	178.57	59.60
	35	215.50	20 MPa	81.01	210.29	134.47
		155.76	15 MPa	73.8	194.31	97.20
		96.08	10 MPa	71.62	178.49	59.96

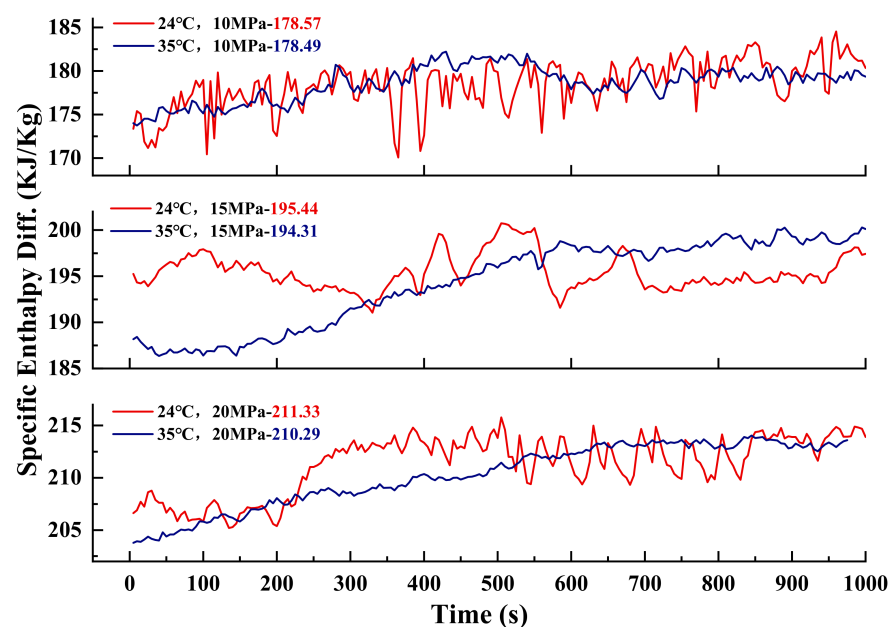


Figure 5. Heat Transfer Experiment Curves for CO₂ with Constant Pressure Injection.

(1) Effect of Displacement Pressure Difference on CO₂ Heat Transfer Capacity

As the displacement pressure difference increases, CO₂ heat transfer capacity improves significantly. A higher pressure difference enhances CO₂ seepage characteristics within the core, increasing flow velocity and seepage intensity, which in turn expands the heat transfer interface between CO₂ and the rock surface, significantly strengthening convective heat transfer efficiency. Additionally, increasing the pressure difference increases the driving force for CO₂ transport through the porous medium, resulting in higher seepage velocity and enhanced convective heat transfer. However, the effect of pressure difference on the spatial uniformity of fluid distribution was not quantitatively evaluated in this study due to the lack of direct flow visualization measurements.

(2) Effect of Injection Temperature on CO₂ Heat Transfer Capacity

Under constant pressure difference conditions, CO₂ heat transfer capacity is primarily governed by high-velocity seepage heat transfer, and the impact of injection temperature is relatively minor. This is because CO₂ naturally exhibits high mobility, meaning that

even with changes in injection temperature, its flow behavior remains largely unchanged. Furthermore, at higher flow velocities, heat transfer is primarily dominated by convective mechanisms, where CO₂ heat transfer efficiency depends mainly on flow regime and heat transfer interface, rather than conductive heat transfer driven by temperature gradients. As a result, temperature variation has a limited effect on overall CO₂ heat transfer performance.

3.1.4. Dominant Factors Controlling CO₂ Heat Transfer Capacity

Based on the experimental results, CO₂ heat transfer capacity is influenced by different dominant factors depending on the flow regime:

- At lower injection flow rates, CO₂ heat transfer is affected by both injection flow rate and injection temperature:
 - Injection temperature affects CO₂ mobility and the temperature gradient between the working fluid and the rock, thereby influencing heat transfer efficiency.
 - Injection flow rate determines CO₂ seepage characteristics within the core, controlling the mode of heat transfer.
- At higher injection flow rates, CO₂ mobility is primarily controlled by pressure difference:
 - High-velocity seepage heat transfer dominates the process, with strong convective effects.
 - Temperature variation has a negligible impact on flow behavior and heat transfer efficiency, making it a less significant factor.

In conclusion, the heat transfer capacity of CO₂ varies with the flow regime and is influenced by different dominant factors. Under steady-state seepage conditions, the heat transfer capacity is mainly controlled by both injection temperature and flow rate, whereas under high-velocity seepage conditions, the pressure difference primarily governs the seepage velocity and convective heat transfer, making the influence of injection temperature relatively minor.

3.2. CPGS Seepage and Heat Transfer Simulation

3.2.1. Effect of Fluid Injection Velocity on Seepage

Based on CT scan-reconstructed digital core models, the porosity of the Yingqiong Basin gas field core was determined to be 0.37. Porosity is a critical parameter influencing fluid seepage characteristics, as a higher porosity provides a larger accessible space for fluid flow, thereby affecting CO₂ movement within the rock pore medium. To investigate the seepage characteristics of CO₂ under different injection flow rates, seepage simulations were conducted on the reconstructed core model, and the results are presented in Figure 6.

(1) Influence of Flow Rate on Seepage Velocity

As the injection flow rate increases, the seepage velocity of CO₂ within the rock pore medium significantly improves. Figure 6 illustrates the distribution of seepage velocity under different injection flow rates, showing the following trends:

- At 0.1 mL/min, CO₂ mainly concentrates in high-permeability pore channels, with a relatively low overall seepage velocity and limited flow regions.
- At 0.5 mL/min, the fluid velocity increases, and CO₂ distributes more uniformly across a broader pore network, expanding the overall seepage region.
- At 2.0 mL/min, CO₂ penetrates deeper into the core, with an extended flow pathway, achieving the highest overall seepage velocity and the most uniform fluid distribution.

(2) Seepage Distribution Characteristics

The simulation results indicate that CO₂ exhibits distinct seepage characteristics at different flow rates:

- At low flow rates (0.1 mL/min), CO₂ primarily flows through high-permeability pathways, while localized regions with lower permeability experience limited fluid penetration, leading to uneven seepage distribution.
- At moderate flow rates (0.5 mL/min), CO₂ follows an increased number of flow pathways, improving fluid distribution uniformity and enhancing connectivity across the seepage network.
- At high flow rates (2.0 mL/min), CO₂ nearly saturates the entire pore network, demonstrating a more widespread and continuous flow pattern, with optimal seepage uniformity throughout the core.

In summary, as the injection flow rate increases, CO₂ seepage velocity improves, flow distribution becomes more uniform, and lower-permeability regions receive greater fluid coverage. Although a uniform velocity boundary condition was imposed at the inlet, the heterogeneous pore geometry immediately redistributed the flow, resulting in spatially non-uniform velocity fields near the inlet. These results provide a fundamental basis for further analysis of how seepage characteristics influence heat transfer efficiency.

3.2.2. Effect of Fluid Injection Velocity on Heat Transfer

As shown in Figure 7, the temperature distribution within the core at 180 °C under different injection flow rates exhibits significant differences. During low-temperature (40 °C) fluid injection, the fluid storage space and surface temperature of the rock matrix decrease, indicating that the injected low-temperature fluid effectively removes heat from the high-temperature reservoir as follows:

- At low flow rate (0.1 mL/min), the temperature decrease is limited to the surface near the fluid injection, with heat being primarily extracted from the core's outer layer.
- At high flow rate (2.0 mL/min), the temperature reduction area significantly expands, allowing the fluid to more uniformly extract heat from the reservoir.

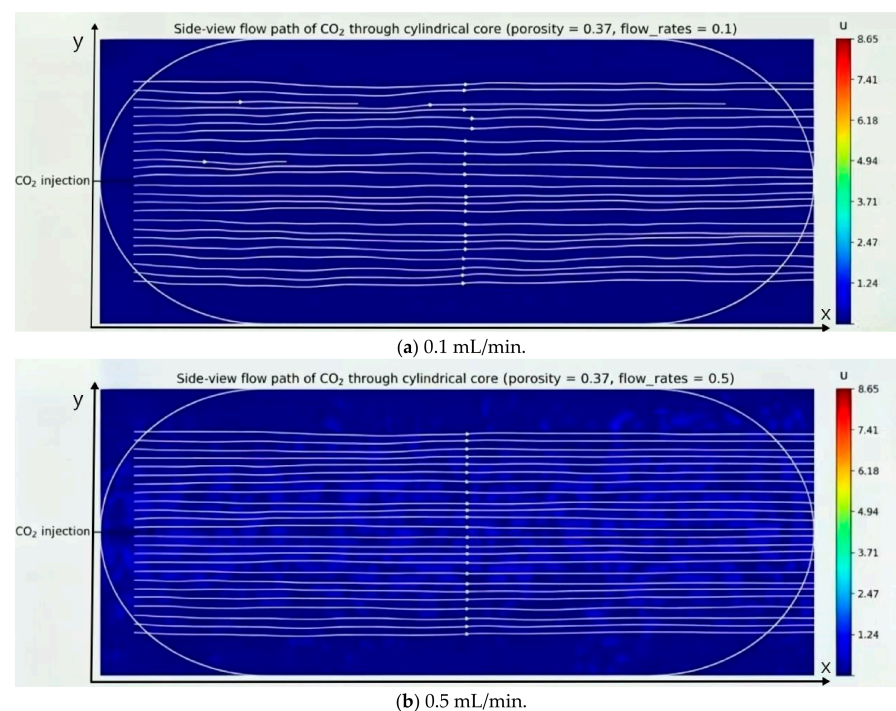


Figure 6. Cont.

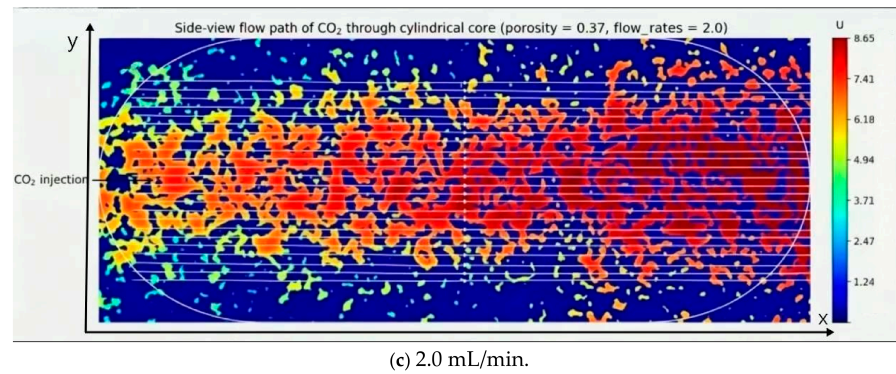


Figure 6. Seepage Velocity Distribution of Core at 180 °C under Different Injection Flow Rates.

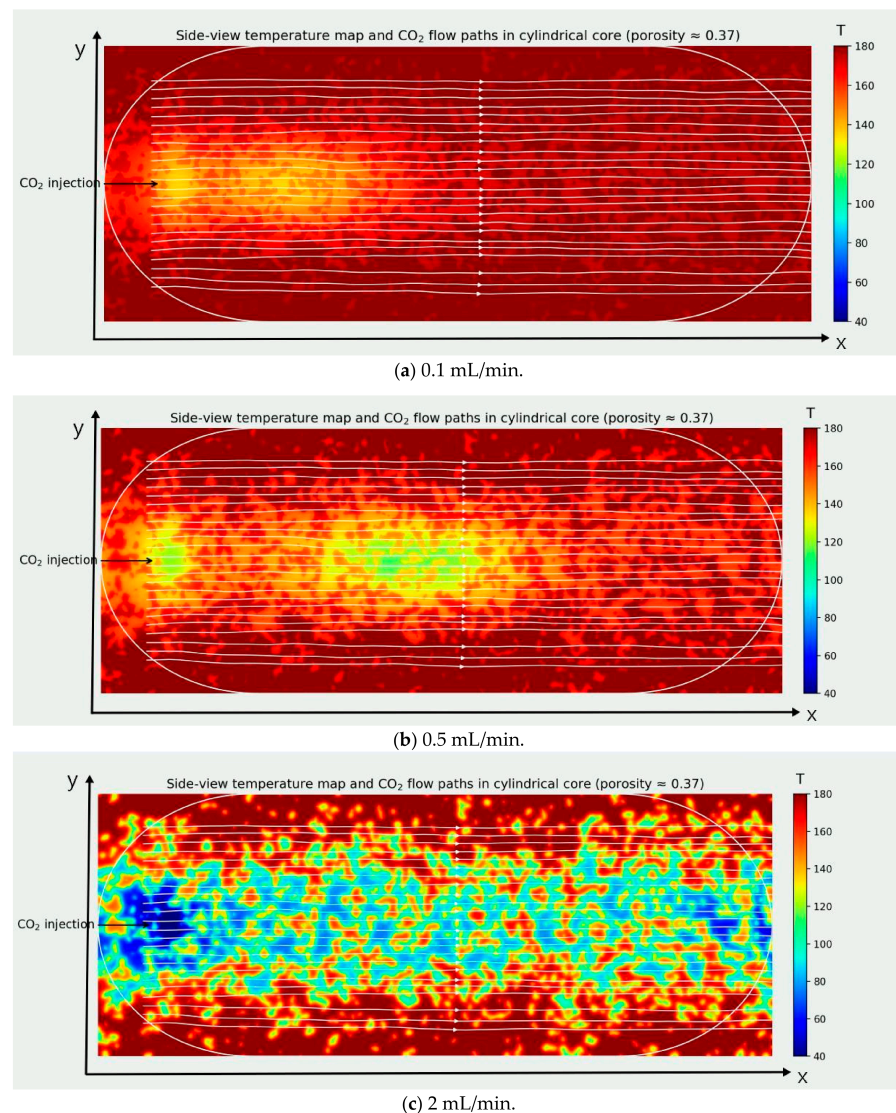


Figure 7. Temperature Distribution in Core at 180 °C under Different Injection Flow Rates.

As the injection flow rate increases, the fluid seepage velocity and coverage area also increase, resulting in a lower temperature distribution across the rock's microchannels, and more heat is extracted by the fluid. Specifically, we have the following:

- Under higher flow rates, the flow pathways for the fluid expand significantly, increasing the area where the temperature drops. The contact area between fluid and rock increases, which effectively enhances convective heat transfer efficiency.

- As a result, more heat is extracted by the fluid, reducing the temperature within the core and improving overall heat transfer capacity.

In summary, increased flow rate not only enhances CO₂ seepage velocity but also significantly boosts convective heat transfer by increasing the contact area between fluid and rock, leading to a more uniform temperature distribution and increased heat extraction efficiency.

3.2.3. Effect of Reservoir Rock Temperature on Heat Transfer

As shown in Figure 8, the temperature distribution exhibits significant differences under varying reservoir temperature conditions. At an injection rate of 0.5 mL/min, enhanced fluid flow leads to a more pronounced temperature contrast between the rock pores and the matrix. As the matrix temperature increases from 150 °C to 200 °C, the CO₂ cooling front is clearly constrained, and its propagation distance decreases. Meanwhile, the cooling region gradually shifts from relatively uniform diffusion to being concentrated along high-permeability channels. This indicates that under high-temperature conditions, the heat transfer mechanism transitions from convection–diffusion coupling dominance to channel-controlled dominance.

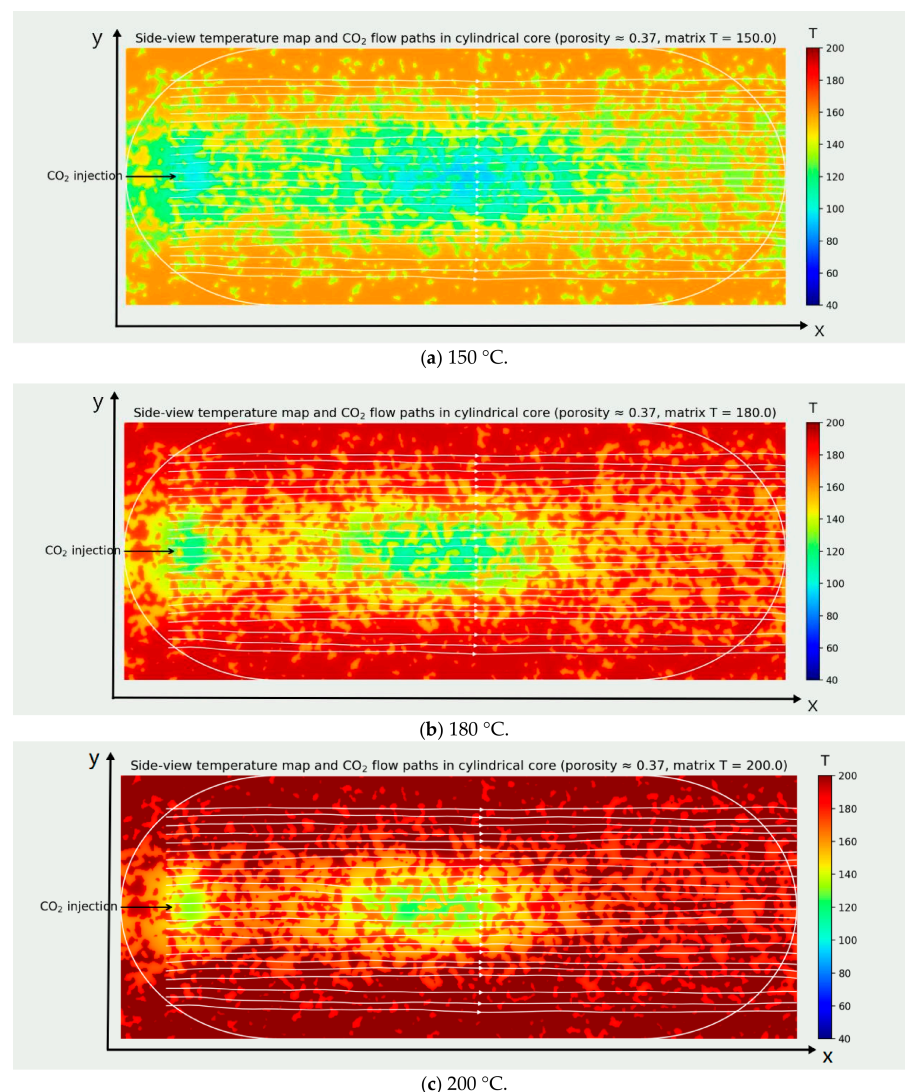


Figure 8. Temperature Distribution in Core after Seepage at Different Thermal Reservoir Temperatures.

4. Conclusions

This study compared the heat transfer performance of CO₂ and distilled water through core displacement experiments and investigated the effects of injection flow rate and temperature on CO₂ heat transfer performance under different flow regimes. Using CT scanning technology, the microstructure of the rock was reconstructed, and the lattice Boltzmann method was employed to simulate the seepage and heat transfer characteristics of CO₂ under various injection flow rates and reservoir temperatures. Based on the experimental results, the following conclusions were drawn:

- (1) CO₂ has significantly better heat transfer performance than distilled water. At injection flow rates of 0.1, 0.5, and 1.0 g/min, and an injection temperature of 24 °C, the enthalpy differences in CO₂ were 26.77%, 39.19%, and 51.44% higher than those of distilled water, respectively. At an injection temperature of 35 °C, these values were 22.68%, 28.61%, and 40.55% higher than those of distilled water, respectively.
- (2) The impact of injection conditions on the heat transfer performance of CO₂ and distilled water differs. In laminar flow conditions, the heat transfer capacity of distilled water is primarily controlled by the flow rate, with its heat transfer ability increasing as the flow rate increases. In contrast, CO₂'s heat transfer capacity is influenced by both flow rate and injection temperature. As the flow rate increases, its heat transfer ability improves. However, as the injection temperature increases, the heat transfer ability of CO₂ decreases. This is because the contribution of increased flowability to heat transfer diminishes, while for distilled water, the enhanced flowability compensates for the negative impact of reduced temperature differences, resulting in little change in heat transfer performance.
- (3) Convective heat transfer dominates in CO₂ high-velocity seepage. At injection pressure differentials of 10, 15, and 20 MPa, with an injection temperature of 24 °C, the enthalpy differences in CO₂ were 178.57, 195.44, and 211.33 kJ/kg, respectively. At an injection temperature of 35 °C, these values were 178.49, 194.31, and 210.29 kJ/kg, respectively. Under constant pressure differential conditions, CO₂ flows at high speeds, and the contribution of temperature to fluid mobility is significantly reduced. Moreover, the high-velocity seepage state weakens the impact of the temperature difference between the working fluid and the rock matrix, resulting in an increase in heat transfer capacity with increasing injection pressure differential, with minimal effect from temperature changes.
- (4) The simulation results of seepage and heat transfer based on the core-scale microstructural model indicate that, within a certain range of operating conditions, increasing the injection flow rate enhances convective heat transfer and expands the effective heat exchange volume, thereby improving the rate of heat extraction. A higher reservoir temperature, by increasing the temperature difference between the rock matrix and the working fluid, further enhances the instantaneous heat transfer intensity of the system and the recoverable thermal energy.

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