Effects of injection parameters on heat extraction performance of supercritical CO$_2$ in enhanced geothermal systems

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Abstract
Supercritical CO$_2$ (SCCO$_2$) is considered as a promising alternative heat extraction fluid in the enhanced geothermal system (EGS) which can reduce atmospheric CO$_2$ emissions and water waste. However, the heat extraction performance of SCCO$_2$ is greatly affected by its thermophysical properties, which are high sensitivity to temperature/pressure. In this study, by considering the impacts of temperature and pressure on thermophysical properties of SCCO$_2$, a thermo-hydro-mechanical coupling numerical model was established to investigate the effects of the initial reservoir temperature as well as the SCCO$_2$ injection pressure and temperature on heat extraction. The variations of reservoir permeability and mass productivity as well as the net heat extraction rate (HER) were simulated by implementing the model into COMSOL Multiphysics, which showed a good consistency compared with the high-temperature/high-pressure triaxial seepage experiments. Simulation results indicate that there are three distinct stages in mass productivity including the slow decline stage, the rapid increase stage, and the stabilization stage. Increasing the initial reservoir temperature or the injection temperature will reduce the net HER to varying degrees. Appropriate increase of the injection pressure and injection temperature can extend Stage 2 duration which can subsequently enhance the mass productivity and the net HER. Meanwhile, the higher injection pressure or the lower injection temperature will inhibit heat compensation within rock masses and accelerate the reservoir heat depletion. This study provides guidance for optimizing the injection parameters of CO$_2$-EGS and aims to enhance the net HER while ensuring a reasonable reservoir production life.

KEYWORDS
enhanced geothermal system, heat extraction experiment, high temperature/high-pressure, numerical simulation, supercritical CO$_2$
INTRODUCTION

As a clean, renewable energy, geothermal energy has gradually received more attention worldwide. In particular, the development of enhanced geothermal system (EGS) technology makes this energy to have a great potential in the future.\textsuperscript{1,2} For conventional EGS projects, water is used as the circulating fluid to extract thermal energy (i.e., H\textsubscript{2}O-EGS). However, H\textsubscript{2}O-EGS projects are associated with some problems, with regard to the amount of water loss, forming scale in ground conveying pipes, and heat exchange equipment.\textsuperscript{3,4} Thus, the use of supercritical CO\textsubscript{2} (SCCO\textsubscript{2}) instead of water as the heat extraction fluid was proposed.\textsuperscript{5} Since then, many studies on the feasibility of using CO\textsubscript{2} as the heat extraction fluid have been carried out.\textsuperscript{6-13}

In recent years, some factors affecting the CO\textsubscript{2}-EGS heat extraction (such as CO\textsubscript{2} injection rate, permeability, CO\textsubscript{2} purity, as well as CO\textsubscript{2} injection temperature) have been investigated. The CO\textsubscript{2} injection rate affects the flow rate in thermal reservoir. Increasing CO\textsubscript{2} injection rate can not only accelerate the gas flow in reservoir, but can also reduce the heat loss, which occurs inevitably between CO\textsubscript{2} and the rock mass around the production well.\textsuperscript{14} The permeability is an important parameter that affects fluid flow in thermal reservoir. In addition to the permeability of thermal reservoir, the permeability of the surrounding formation also shows a large impact on the HER. With an increase in the permeability of the surrounding formation, the CO\textsubscript{2} storage amount increases, while the HER decreases slowly.\textsuperscript{15} Because of the large amount of usage in an enhanced geothermal system, the CO\textsubscript{2} is always captured from the power plants, which means the CO\textsubscript{2} is impure and includes some impurities such as nitrogen oxides and solid particles. The study indicated that as the impurity content increased, the heat extraction efficiency of impure CO\textsubscript{2} decreased.\textsuperscript{16} From the aspects of the HER and CO\textsubscript{2}-EGS sustainability, the effect of gaseous CO\textsubscript{2} injection temperature at 291-315 \textdegree K was studied, and it had a larger impact on the former.\textsuperscript{17}

The heat transfer coefficient is a key parameter for heat transfer model when considering the local thermal non-equilibrium between the fluid and the fracture surface. Studying heat transfer coefficient can help to optimize the numerical model of heat extraction and predict the HER.\textsuperscript{18,19} Therefore, theoretical analysis and experiments had been conducted to investigate the heat transfer coefficient.\textsuperscript{20-22} The existing studies had found that fracture roughness can increase the fluid flow friction effect and the heat transfer area, which had a great influence on heat transfer coefficient.\textsuperscript{23-26} In a single fracture, as the fracture roughness increases, the heat transfer performance of SCCO\textsubscript{2} also increases.\textsuperscript{27} However, when the heat transfer performance of SCCO\textsubscript{2} in a smooth parallel fracture and a rough winding fracture was compared, it was found that the channeling effect of the rough tortuous fracture reduced the heat exchange efficiency and HER of SCCO\textsubscript{2} to a greater extent.\textsuperscript{28} Therefore, fracture shape is also an important factor affecting the heat transfer coefficient.

There are still other influential factors, such as CO\textsubscript{2} injection pressure, injection temperature, and initial reservoir temperature, that play important roles in CO\textsubscript{2}-EGS formation. However, there are relatively few investigations on these factors, especially regarding the overall effects of temperature and pressure on CO\textsubscript{2} thermophysical properties and reservoir permeability. In this study, a thermo-hydro-mechanical coupling numerical model was established to analyze the effects of SCCO\textsubscript{2} injection pressure and temperature as well as the initial reservoir temperature on heat extraction. In this model, the effects of CO\textsubscript{2} density, dynamic viscosity, specific heat capacity, and thermal conductivity variations induced by temperature/pressure on CO\textsubscript{2} flow and heat transfer were considered. Under the influence of thermo-hydro-mechanical coupling, the effects of permeability changes on mass productivity and net HER were analyzed. Meanwhile, the heat compensation effects of different initial reservoir temperatures, different injection pressures, and different injection temperatures were investigated. In addition, the heat transfer experiments of SCCO\textsubscript{2} were conducted in the granite sample containing multiple fractures, and the experimental results were compared with the simulation results obtained under the similar conditions. This research provides direction for optimizing CO\textsubscript{2}-EGS production and ensuring a reasonable reservoir production life.

GOVERNING EQUATIONS

2.1 Reservoir deformation

It is assumed that the EGS reservoir is a homogeneous and isotropic porous medium, so the reservoir deformation contains the strains caused by effective stress and thermal stress after fluid injection. The total strain based on thermo-poroelasticity theory can be expressed as:\textsuperscript{29}

\[
\varepsilon_{ij} = \frac{\sigma_{ij} - \nu}{2G} - \frac{\nu}{2G(1+\nu)} \sigma_{kk} \delta_{ij} + \frac{\alpha(1-2\nu)}{2G(1+\nu)} p_i \delta_{ij} + \beta \Delta T_i \delta_{ij} \tag{1}
\]

where \(\varepsilon_{ij}\) is the solid strain tensor component; \(\sigma_{ij}\) is the stress tensor component; \(p_i\) is the pore fluid pressure; \(\sigma_{kk}\) is the normal stress component; \(\Delta T_i\) is the difference between the real-time temperature and the initial temperature of the rock mass; \(\alpha\) is the Biot coefficient of rock; \(G\) is the shear modulus; \(\nu\) is the Poisson ratio; and \(\delta_{ij}\) is the Kronecker symbol.
The thermo-poroelasticity constitutive equation of the stress component is obtained according to Equation 1:

\[
\sigma_{ij} = 2G\varepsilon_{ij} - \frac{2G}{1-2\nu}\varepsilon_{kk}\delta_{ij} - \alpha p_t\delta_{ij} - \frac{\beta_s E}{1-2\nu}\Delta T_s\delta_{ij}
\]  

(2)

Combining the relation between strain and displacement \(\varepsilon_{ij} = (u_{i,j} + u_{j,i})/2\) and according to the momentum conservation equation \(\sigma_{ij,j} = -F_i\), the differential equation of thermo-poroelasticity equilibrium equation can be written as:

\[
G\nabla^2 u_i + (\lambda + G)u_{k,k,i} - \alpha p_t u_i - \frac{\beta_s E}{1-2\nu}\Delta T_{s,i} + F_i = 0
\]  

(3)

where \(\varepsilon_{kk}\) is the volumetric strain; \(E\) is the elasticity modulus; \(u_i\) is the displacement component; \(F_i\) is the volume force component; and \(\lambda\) is the lame elastic constant.

### 2.2 | Fluid flow

It is assumed that the fluid flow is a single-phase flow process in saturated porous medium. Therefore, the mass conservation equation for compressible fluid flow is represented as \(^{30,31}\):

\[
\frac{\partial (\rho_f \phi)}{\partial t} - \nabla \cdot (\rho_f k \nabla p_f) = Q_t
\]  

(4)

where \(\rho_f\), \(\mu\), and \(p_f\) are the density, dynamic viscosity, and pressure of fluid, respectively; \(\phi\) and \(k\) are the porosity and permeability of porous medium, respectively; and \(Q_t\) is the source (sink) term.

The porosity variation model of the reservoir can be represented by the coupling effect of the fluid flow and the reservoir deformation\(^{32}\):

\[
\phi - \phi_0 = (1 - \phi_0)\left(\frac{1 - \phi_0}{3K_s} - \frac{1}{3K_s}\varepsilon_{kk} + 3p_t\right) - \phi_0 \left(\frac{1}{K_s} - \frac{1}{K_s}\right)p_t + \phi_0(1-\phi_0)(\beta_p - \beta_s)\Delta T_s
\]  

(5)

The relationship between permeability and porosity can be expressed as\(^{33}\):

\[
k = k_0\left(\frac{\phi}{\phi_0}\right)^{(1 - \phi_0)^2}
\]  

(6)

The relevant parameters in Equation 5 can be given by the following expressions:

\[
K_s = \frac{KB(1-2\nu)(1-\nu_u)}{B(1-2\nu)(1-\nu_u)-\nu_u}
\]  

(7)

\[
K_s^* = \frac{K_s\phi_0 K}{B\phi_0 K - (1-B)K_s\alpha}
\]  

(8)

where \(\phi_0\) is the initial porosity; \(B\) is the Skempton pore pressure coefficient; \(\nu_u\) is the non-drainage Poisson ratio; \(k_0\) is the initial permeability; \(K\) is the bulk modulus; \(K_s\) is the bulk modulus of the solid component; and \(K_s^*\) is the secondary bulk modulus of the solid component; the difference between \(K_s\) and \(K_s^*\) is caused by the pores that are not connected in the rock mass.

### 2.3 | Heat transfer

Considering the heat convection and heat conduction processes in fluid, heat conduction in rock mass, and heat transfer between the fluid and the rock mass, the local thermal imbalance model is obtained\(^{34}\):

Energy equation of fluid

\[
\frac{\partial}{\partial t}(\rho_c c_{pf} T_f \phi) + \nabla \cdot [(\rho_c c_{pf} T_f)\mathbf{v}] - \nabla \cdot (\kappa_f \phi \nabla T_f) - a q_{id} = 0
\]  

(11)

Energy equation of rock

\[
\frac{\partial}{\partial t} \left[\rho_s c_{ps} T_s (1-\phi)\right] - \nabla \cdot (\kappa_s (1-\phi) \nabla T_s) + a q_{id} + (1-\phi) \frac{\partial q}{\partial t} = 0
\]  

(12)

where, \(\kappa_f\) and \(\kappa_s\) are the thermal conductivities of fluid and rock, respectively; \(\rho_s\) is the density of rock; \(c_{pf}\) and \(c_{ps}\) are the specific heat capacities of fluid and rock, respectively; \(a\) is the interface area of solid phase and fluid phase per unit volume; \(\mathbf{v}\) is the velocity vector of the fluid; \(q_{id}\) is interfacial heat flux between solid phase and fluid phase; \(q\) is unit volume heat source of reservoir; and \(T_f\) and \(T_s\) are the intrinsic average temperatures of the fluid and the rock mass, respectively.

The interfacial heat flux between the solid phase and the fluid phase in Equations 11 and 12 is obtained from\(^{35}\):

\[
q_{id} = \frac{k_s}{d_p}(T_s - T_c)
\]  

(13)

where \(T_c\) is the average temperature of the interface; \(I\) is the internal heat transfer penetration depth in the solid phase (dimensionless); \(d_p\) is the unit size of solid matrix; and \(h_{id}\) is the interface heat exchange coefficient between solid phase and fluid phase.
The net HER at the production well is defined as\textsuperscript{14}:

\[
\dot{E}_{\text{pro}} = Q_{\text{out}}(t)h_{\text{out}}(t) - Q_{\text{in}}(t)h_{\text{in}}(t) \tag{14}
\]

where \(\dot{E}_{\text{pro}}\) is the net HER (in W); \(Q_{\text{out}}\) and \(Q_{\text{in}}\) are the mass flow rates of fluid at the production well and injection well, respectively (in kg/s); and \(h_{\text{out}}\) and \(h_{\text{in}}\) are specific enthalpies of fluid at the production well and injection well, respectively (in J/kg).

3 | MODEL SOLUTION

3.1 | Model description

Referring to the five-spot well pattern of geothermal extraction in deep EGS project, one fourth of the extraction area near the bottom of the wells is selected as the simulation area (see Figure 1). The simulation area is a square with the size of 500 × 500 m\(^2\). The injection well and production well are located in the diagonals of square, with a diameter of 0.2 m and a distance of about 707 m. Besides, it is assumed that the in situ geological fluid of the reservoir is hot CO\(_2\), which has the same temperature to that of reservoir.

The simulation model has 2344 free triangle cells and 1258 vertices, and is solved by the software of COMSOL Multiphysics 5.4. This finite element software can customize the grid density and size, and the maximum and minimum grid cell sizes in this model are 18.5 and 0.0625 m, respectively. Without involving the free flow of fluid in the wells, the 2D model only considered the flow and heat transfer process in the porous reservoir. The built-in modules including the Geomechanics Module, the Subsurface Flow Module, and the Heat Transfer Module were used in this study.

3.2 | Initial and boundary conditions

In this study, three cases are proposed to investigate the effects of variations in initial reservoir temperature, SCCO\(_2\) injection pressure, and injection temperature on heat extraction, respectively. It is assumed that there are no volume and boundary heat sources. That is, the other four boundaries are the thermal insulation boundaries (see Figure 2) except for the one-fourth boundary of the injection/production well. The minimum in situ horizontal stress is 44.8 MPa (\(\sigma_h\), for the upper boundary), and the maximum in situ horizontal stress is 51.7 MPa (\(\sigma_h\), for the right boundary). The initial conditions for each case and the boundary conditions are shown in Table 1.

The related thermophysical parameters varied with temperature and pressure and were evaluated using the REFPROP software (as shown in Figure 3). The relationship of density, specific heat capacity, thermal conductivity, and dynamic viscosity with pressure/temperature is presented in the fitting Equations 15-18, which are applied in numerical solving process. Other parameters used in the model are listed in Table 2.

\[
\rho = \frac{a_1 + a_2 + a_3 + a_4 + a_5 + a_6 P^2}{1 + a_7 + a_8 + a_9 P + a_{10} P^2} \quad T \in [0, 300] \quad P \in [0, 60] \tag{15}
\]

\[
c_p = \frac{b_1 + b_2 + b_3 + b_4 + b_5 + b_6 + b_7 T + b_8 P^2 + b_{11} P}{1 + b_2 + b_3 + b_4 + b_5 + b_6 + b_7 + b_8 P^2 + b_{10} P} \quad T \in [0, 300] \quad P \in [0, 60] \tag{16}
\]

\[
\kappa = \frac{c_1 + c_2 + c_3 + c_4 + c_5 + c_6 P^2}{1 + c_2 + c_3 + c_4 + c_5 + c_6 + c_{10} + c_{11} P} \quad T \in [0, 300] \quad P \in [0, 60] \tag{17}
\]

\[
\mu = \frac{d_1 + d_2 + d_3 + d_4 + d_5 + d_6 + d_7 T + d_8 P^2}{1 + d_2 + d_3 + d_4 + d_5 + d_6 + d_{10} + d_{11} P} \quad T \in [0, 300] \quad P \in [0, 60] \tag{18}
\]
**TABLE 1** Initial conditions and boundary conditions in the model

| Case | Initial reservoir temperature (K) | SCCO₂ injection pressure (MPa) | SCCO₂ injection temperature (K) | Initial reservoir pressure (MPa) | Production pressure (MPa) |
|------|----------------------------------|--------------------------------|---------------------------------|---------------------------------|--------------------------|
| I    | 423                              | 51.7                           | 313                             |                                 |                          |
|      | 473                              |                                |                                 |                                 |                          |
|      | 523                              |                                |                                 |                                 |                          |
|      | 573                              |                                |                                 |                                 |                          |
| II   | 473                              | 43.7                           | 313                             | 34.5                            | 31.7                     |
|      | 45.7                             |                                |                                 |                                 |                          |
|      | 47.7                             |                                |                                 |                                 |                          |
|      | 51.7                             |                                |                                 |                                 |                          |
| III  | 473                              | 51.7                           | 313                             |                                 |                          |
|      | 313                              |                                |                                 |                                 |                          |
|      | 343                              |                                |                                 |                                 |                          |
|      | 373                              |                                |                                 |                                 |                          |

**FIGURE 3** Variations of (A) density, (B) specific heat capacity, (C) thermal conductivity, and (D) dynamic viscosity of CO₂ with pressure/temperature


where \( T \) is the temperature (in °C); \( P \) is the pressure (in MPa); \( \mu \) is the dynamic viscosity of \( \text{CO}_2 \) (in Pa·s); \( c_p \) is the specific heat capacity of \( \text{CO}_2 \) (in kJ/(kg·°C)); \( \rho \) is the density of \( \text{CO}_2 \) (in kg/m\(^3\)); and \( \kappa \) is the thermal conductivity of \( \text{CO}_2 \) (in mW/(m·°C)). The corresponding coefficients in the Equations 15-18 are listed in Table 3.

### Table 2: Related physical and mechanical parameters in the model

| Parameters                          | Values | Unit   | Parameters                          | Values | Unit |
|-------------------------------------|--------|--------|-------------------------------------|--------|------|
| Density of rock, \( \rho_s \)      | 2700   | kg/m\(^3\) | Pore pressure coefficient, \( B \) | 0.85   |       |
| Specific heat capacity of rock, \( c_p \) | 920   | J/(kg·K) | Initial porosity, \( \phi_0 \) | 0.04   |       |
| Thermal conductivity of rock, \( \kappa \) | 1.83  | W/(m·K) | Intrinsic permeability, \( k_0 \) | 3.94   | mD   |
| Minimum horizontal stress, \( \sigma_h \) | 44.8  | MPa    | Young’s modulus, \( E \) | 37.5   | GPa  |
| Maximum horizontal stress, \( \sigma_t \) | 51.7  | MPa    | Poisson ratio, \( \nu \) | 0.25   |      |
| Thermal expansion coefficient of rock, \( \beta_r \) | \( 2.4 \times 10^{-5} \) | 1/K     | Undrained Poisson ratio, \( \nu_u \) | 0.33   |      |
| Thermal expansion coefficient of pore, \( \beta_p \) | \( 1.3 \times 10^{-5} \) | 1/K     | Shear modulus | 15 | GPa |

### Table 3: Related coefficients of the fitting equations

| No. | \( a_i \) | \( b_i \) | \( c_i \) | \( d_i \) |
|-----|----------|----------|----------|----------|
| 1   | -2E4     | 0.9      | 14.7     | 1.8E-5   |
| 2   | -52      | -1.6E-2  | 45.3     | 1.5E-6   |
| 3   | -1.4     | -3.4E-2  | 1.8      | 2.4E-8   |
| 4   | 4.0E-3   | -1.4E-2  | 2.6E-3   | 1.4E-10  |
| 5   | 8.5E3    | -1.2E-6  | 2.1E3    | 7.6E-5   |
| 6   | -18      | 8.7E-4   | 56       | 4.9E-7   |
| 7   | 1.3      | 1.2E-3   | 3.3      | 0.2      |
| 8   | 6.9      | 2.6E-2   | 0.1      | 2E-3     |
| 9   | -0.02    | 3.8E-2   | -1.0E-4  | 0.58     |
| 10  | /        | -6.7E-3  | 18.4     | /        |
| 11  | /        | -9.5E-3  | 2.9E-4   | /        |

where \( T \) is the temperature (in °C); \( P \) is the pressure (in MPa); \( \mu \) is the dynamic viscosity of \( \text{CO}_2 \) (in Pa·s); \( c_p \) is the specific heat capacity of \( \text{CO}_2 \) (in kJ/(kg·°C)); \( \rho \) is the density of \( \text{CO}_2 \) (in kg/m\(^3\)); and \( \kappa \) is the thermal conductivity of \( \text{CO}_2 \) (in mW/(m·°C)). The corresponding coefficients in the Equations 15-18 are listed in Table 3.

### 4 | Simulation Results and Discussions

#### 4.1 | Effect of Initial Reservoir Temperature

Based on Case I, the effect of the initial reservoir temperature on heat extraction was simulated. Figure 4A,B show the variations of mass productivity and net HER with time at different initial reservoir temperatures, respectively. Obviously, the mass productivity decreases with increasing initial reservoir temperature. In particular, there are three stages in the variation of mass productivity:

1. Stage 1 is a slow decline stage. The starting points of the mass productivity at the initial reservoir temperature of 523 and 573 K are higher than the other two. During this period, in situ CO\(_2\) with relatively low density flows out, and the mobility of CO\(_2\) (\(\rho/\mu\)), ratio of density to dynamic viscosity) is the main factor affecting mass productivity. The pressure of CO\(_2\) gradually decreases when it is close to the production well, which reduces the value of \(\rho/\mu\). Moreover, there will be a greater decrease in \(\rho/\mu\) when the pressure of CO\(_2\) is reduced at higher temperature. Hence, the mass productivity declines obviously at higher initial reservoir temperature.

In the initial period of Stage 1 (very short time), the in situ hot CO\(_2\) (which is assumed to have the same temperature with reservoir) is replaced by the injected cold CO\(_2\). At initial reservoir temperatures of 523 and 573 K, the in situ hot CO\(_2\) has lower viscosity than that at the 423 and 473 K conditions (see Figure 3). At this time, the mobility of SCCO\(_2\) at 523 and 573 K is greater than that observed at 423 and 473 K. Therefore, the mass productivity also follows a similar pattern.

2. Stage 2 is a rapid increase stage. The mobility of SCCO\(_2\) determines the mass productivity at the production
well and affects the HER. As the mobility is closely related to density and dynamic viscosity, the effects of temperature and pressure on these parameters should be considered.\textsuperscript{36} However, the mechanical stability of the reservoir is impaired during the operation of the EGS, resulting in a dynamic evolution of reservoir porosity and permeability. Therefore, in addition to considering its density and dynamic viscosity, the assessment of CO\(_2\) mobility should also consider the impacts of reservoir permeability changes. The effect of temperature/pressure on the thermophysical properties of CO\(_2\) and the porosity-permeability evolution model under multifield coupling should be considered comprehensively. At this stage, the coupling effect of poro-thermo-hydro-mechanical model may result in aperture changes of pore/fracture as the cold SCCO\(_2\) is injected continuously.\textsuperscript{37} The volumes of rock masses near the surface of the fracture or pore begin to shrink, which increases porosity and permeability. As shown in Figure 5, the permeability of the reservoir is increased from 4.03 to 5.13 mD by the cold shrinkage effect of the rock mass. Because of the combined effects of permeability \((k)\) and the \(\rho/\mu\), mass productivity increases rapidly, especially at the lower initial reservoir temperature. Considering the heat conduction within the CO\(_2\) molecules, the CO\(_2\) temperature after heating is lower than the reservoir temperature. At this time, the SCCO\(_2\) mobility is mainly affected by density. As the initial reservoir temperature increases, the SCCO\(_2\) density decreases significantly, which in turn results in the reduction of mass productivity. Therefore, the mass productivity at 523 and 573 K is lower than that observed at 423 and 473 K.

3. Stage 3 is a stabilization stage. As shown in Figure 6, as the cold CO\(_2\) front in contact with the hot rock mass moves toward the production well, the permeability at the cold front increases under the cold shrinkage effect.
However, the permeability after the cold front decreases due to the change of the effective stress and the expansion effect caused by the heat compensation of the nearby hot rock mass. To some extent, the effects of permeability changes at different reservoir locations may become complementary at this stage, which results in a gradual stabilization of mass productivity.

Higher initial reservoir temperatures increase the temperature gradients between the rock mass and SCCO$_2$. During the heat transfer process, the value of $k\rho/\mu$ decreases as the temperature gradient increases. Under the constant pressure difference between injection well and production well, mass productivity is positively correlated with $k\rho/\mu$. Therefore, an increase in initial reservoir temperature will reduce mass productivity.

At a constant injection pressure or injection flow rate, the produced fluid temperature will go through three stages: the ascending stage, the stabilizing stage, and the lowering stage. However, the heat extraction process has not yet reached the last stage in this study. Due to the same heat of inflow SCCO$_2$ at each initial reservoir temperature, according to Equation 14, the evolution of net HER directly depends on the mass productivity and SCCO$_2$ temperature of production well. Compared with mass productivity, a similar evolution trend can be observed in the net HER.

### 4.2 Effect of SCCO$_2$ injection pressure

Based on Case II, the effect of injection pressure on heat extraction was simulated. Figure 7A,B show the variations of mass productivity and net HER with time under different injection pressures, respectively. It can be noticed that similar three stages occur in the variation of mass productivity. However, the starting point of Stage 3 is slightly delayed with increasing injection pressure. This fact indicates that higher injection pressures are more likely to overcome the frictional effects of fracture or pore walls, which may relatively prolong Stage 2 and greatly increase the mass productivity and net HER.

Moreover, raising the injection pressure will increase the pore pressure (as shown in Figure 8), which can reduce the effective stress of the reservoir. Meanwhile, it results in corresponding increases in porosity and permeability. So it can be seen from the stabilization stage that the mass productivity and net HER increase by 17.5 kg/s and 1.57 MW, respectively, when the injection pressure is raised from 43.7 to 51.7 MPa. In addition, the pore pressure does not change in Stage 1, and the increased speed of pore pressure in Stage 2 is lower than that of the mass productivity. Therefore, at the same reservoir temperature, the variations of mass productivity in Stage 1 and Stage 2 are mainly influenced by cold shrinkage effect.

Figures 9-12 show the temperature distribution of reservoir inflow SCCO$_2$ at each initial reservoir temperature, according to Equation 14, the evolution of net HER directly depends on the mass productivity and SCCO$_2$ temperature of production well. Compared with mass productivity, a similar evolution trend can be observed in the net HER.
production life. In this study, 47.7 MPa injection pressure is suitable for ensuring high net HER and production life.

### 4.3 Effect of SCCO$_2$ injection temperature

Based on Case III, the effect of injection temperature on heat extraction was simulated. The variations of mass productivity and net HER with time at different injection temperatures are presented in Figure 13A,B, respectively. When the injection temperature is increased from 313 to 373 K, there is not much difference in mass productivity throughout Stage 1 and earlier Stage 2. This result indicates that during the initial stage of in situ hot CO$_2$ replacement at the same reservoir temperature, due to less difference in density/viscosity values at different injection temperature gradients, increasing the injection temperature has little effect on mass productivity. During the end
of Stage 2 until Stage 3, mass productivity decreases about 2 kg/s with increasing injection temperature. Nevertheless, there is a distinct difference in net HER. Because of a little difference in mass productivity, increasing the injection temperature raises the initial specific enthalpy, which greatly reduces the net HER. It can be seen that the net HER is decreased from 2.8 to 0.2 MW when the injection temperature is increased by 60 K. This variation is also applicable when the CO₂ injection temperature is increased from 293 to 313 K.\textsuperscript{41}

Figure 14 illustrates the effects of injection temperature on the permeability and pore pressure at a point (100 m, 100 m), respectively. It can be observed that the permeability and pore pressure begin to increase from 0.3 and 0.03 years, respectively. About one year later, the pore pressure gradually
becomes stable, while the permeability decreases slowly. Meanwhile, the permeability and pore pressure decline with increasing injection temperature. This is because increasing the injection temperature reduces the temperature gradient between SCCO₂ and the rock mass, resulting in a decrease in thermal strain. The deformation of the reservoir under the thermal effect is reduced, so that the volume shrinkage of the rock mass at a higher injection temperature is lower than that at the low injection temperature. Therefore, the fracture or pore volume in rock mass increases at low injection temperatures, which in turn enhances the flow rate of SCCO₂.

Figures 15-17 show the reservoir temperature distribution under the injection temperature of 313-373 K after different heat extraction time. It indicates that the heat compensation of rock mass is very obvious after the cold front when the injection temperature is increased. Therefore, increasing the injection temperature is beneficial for the small recovery of thermal energy of reservoir rock mass after SCCO₂ takes away the heat. However, this is the only process in which the thermal energy locally tends to balance. Although the boundary heat compensation of the study area is not considered, the temperature near the injection well is only reduced by 80 K after 50 years of heat extraction when the injection temperature is increased by 60 K. Considering the net HER and the reservoir production life, the injection temperature should be chosen near the critical temperature of CO₂. That is, CO₂ separated and purified from the waste gas of the power plant needs to be cooled if the residual temperature is too high. A study considering a complex fractured system has found that the use of pure CO₂ instead of cooled water has more potential for heat extraction. However, further purification of large amounts of captured CO₂ will add more extra costs.

**FIGURE 13** (A) Variations of mass productivity with time at different injection temperatures and (B) variations of net HER with time at different injection temperatures

**FIGURE 14** Variation of (A) permeability and (B) pore pressure of the point (100 m, 100 m) with time at different injection temperatures
Compared to water, the thermophysical properties of CO\(_2\) are more sensitive to pressure and temperature. On cooling the thermal reservoir, the mobility of CO\(_2\) changes greatly. Therefore, when CO\(_2\) captured by the power plants is used as the working fluid, utilizing the variable mobility through optimization of injection scheme can increase the HER and prolong the reservoir production life.

### 5 | COMPARATIVE EXPERIMENTS

#### 5.1 | Experimental system and procedure

Due to the limitation of rock sample size, the purpose of the experiments is only to find whether the heat extraction performance of SCCO\(_2\) is similar to the simulation results when changing the same influencing factors. The high-temperature/
The pressure triaxial seepage equipment used in this study is shown in Figure 18A. This system can perform the seepage and heat extraction experiments with the axial (confining) pressure of up to 60 MPa and the temperature of up to 573.15 K.

Figure 18B shows the schematic diagram of the experimental system. In this experiment, the rock sample (see Figure 19) is a cylindrical granite of 50 × 100 mm (diameter × height). The axial pressure and confining pressure are 35 and 26 MPa, respectively. Before the experiment, the prepared rock sample is placed into the triaxial seepage chamber and other mountings are installed accordingly. The rock sample is then heated in a control system until the temperature reaches the test value. Then the gas cylinder is connected to the system and the air compressor, as well as the booster pump, is turned on to add high pressure CO$_2$ (up to 25 MPa) into the gasholder. The operation of the booster pump is controlled by an electrode point pressure gauge matched with the gasholder. When the fluid pressure of the gasholder reaches the lower limit (or the upper limit), the booster pump starts to operate (or stops). Subsequently, the preheater is turned on and the fluid shut-off valve is opened to adjust the injection pressure through the CO$_2$ pressure-regulating valve until the injection pressure/temperature reaches the setting values. At this time, the CO$_2$ reaches the supercritical state.

During the experiment, the confining pressure and axial pressure are applied by pump 2 and pump 3, respectively. The injection/production pressures and temperatures of SCCO$_2$ are collected by inlet/outlet pressure sensors and temperature sensors.
sensors, respectively. The injection rate and outflow rate of SCCO₂ are measured through supercritical fluid mass flowmeters. CO₂ with high temperature at the outlet is cooled by a condenser and the water vapor is absorbed by the gas dryer. The controlling temperature probe (representing the heating temperature) and measuring temperature probe (representing...
the rock temperature) are installed in triaxial seepage chamber. All pressures, temperatures and mass flow rates are collected in real time by data collection system. The experimental scheme of this study is shown in Table 4. Experiments 1#, 2#, and 3# correspond to the research works on the effects of the initial rock sample temperature, the SCCO₂ injection pressure, and the injection temperature on heat transfer, respectively.

5.2 | Experimental results and discussions

5.2.1 | Effect of initial rock sample temperature

It can be observed from Figure 20 that the rock sample permeability is reduced from 0.79 to 0.38 mD when the rock sample temperature is increased by 50 K. A study pointed out that rock permeability was sensitive to temperature and showed the phenomena of the occurrence of high-temperature subsection and temperature thresholds. In addition, the temperature thresholds for permeability changes are different for different rock types. Thus, in this experiment, the temperature range of 423-473 K is just within the temperature threshold of the decrease in the granite permeability. In this temperature range, some mineral particles of rock sample expand to different degrees with increasing temperature, which will cause the micropores to become smaller and the micro-fractures to partially close, thus resulting in a decrease in permeability.

FIGURE 19  Sample of granite core (left) and CT scan of fractures (right)

FIGURE 20  Variation of permeability with initial rock sample temperature

FIGURE 21  (A) Variations of mass productivity with time at different initial rock sample temperatures and (B) variations of net HER with time at different initial rock sample temperatures
**FIGURE 22** Variation of permeability with injection pressure

**FIGURE 24** Variation of permeability with injection temperature

**FIGURE 23** (A) Variations of mass productivity with time under different injection pressures and (B) variations of net HER with time under different injection pressures

**FIGURE 25** (A) Variations of mass productivity with time at different injection temperatures and (B) variations of net HER with time at different injection temperatures
The increase of temperature causes volume expansion of rock sample and closure of fractures, resulting in reduction of mass productivity. Accordingly, the net HER decreases with increasing rock sample temperature as well, as shown in Figure 21A,B. Compared to the simulation results, there are varying degrees of fluctuations in the net HER curve, especially at the higher initial rock sample temperature. This is because the rock sample is continuously heated during the experiment, which causes an interaction between heat loss and external heat compensation.

5.2.2 | Effect of SCCO₂ injection pressure

The result in Figure 22 shows that the permeability of the rock sample increases with increasing injection pressure. When the SCCO₂ injection pressure increases and exceeds the breakdown pressure of the preexisting fractures, it causes the propagation and damage of the micro-fractures. In addition, an increase in the temperature of the injected SCCO₂ results in its volume expansion and viscosity reduction, accompanied by a decrease in the fracture temperature. These changes lead to an increase in permeability. However, this effect is affected by the fluid phase state and the properties of the porous medium. Meanwhile, the permeability of the rock sample may be affected by the Klinkenberg effect at injection pressures of 8 and 10 MPa. However, when the injection pressure exceeds 10 MPa, the effect will disappear.

Therefore, in this experiment, when the injection pressure is increased from 8 to 11 MPa, the mass productivity and the net HER are increased by about 2.3 g/s and 87 W, respectively (as shown in Figure 23A,B). It is noteworthy that the obvious heat compensation effect will occur in the net HER under the lower injection pressure. Because the higher injection pressure increases the flow rate of SCCO₂, it constantly takes away a lot of heat, so that the thermal energy of the rock sample through which SCCO₂ flows cannot be recovered slowly. Therefore, as with the simulation results, lower injection pressure is beneficial to prolong the production life of the thermal reservoir.

5.2.3 | Effect of SCCO₂ injection temperature

The cold shrinkage effect of the lower injection temperature causes the volume reduction for some of the temperature-sensitive mineral particles in the granite, which increases the micropore volume and opening of micro-fractures, thereby increasing the permeability. Therefore, raising the injection temperature will not only reduce the SCCO₂ viscosity, but will also reduce the SCCO₂ density and the reservoir permeability. Moreover, thermal cracking of the rock will occur after heating by high temperatures. The granite sample continue to be cooled slowly during the continuous injection of SCCO₂. The decrease of the injection temperature increases the temperature gradient between the rock sample and SCCO₂, which leads to an increase of permeability. As presented in Figure 24, the permeability increases from 0.42 to 0.74 mD when the injection temperature decreases by 30 K.

Correspondingly, the mass productivity and the net HER decrease with increasing injection temperatures, as shown in Figure 25A,B. It can be seen that the experimental process quickly reaches a steady state due to the small sample size. Therefore, there are no obvious three stages of change in mass productivity (including the results in Section 5.2.1 and Section 5.2.2). In addition, when the rock sample temperature drops from 473 K to 423 K and the injection temperature increases by 30 K, the net HER values at 8 MPa injection pressure are not significantly affected by the heat compensation effect.

6 | CONCLUSIONS

By a coupled thermo-hydro-mechanical model, the impact of the SCCO₂ injection pressure, injection temperature, and initial reservoir temperature on heat extraction in the CO₂-EGS model were studied. Meanwhile, the impacts of temperature/pressure on the thermophysical properties of CO₂ as well as the reservoir permeability and the pore pressure were comprehensively considered in the model, and the variations in the mass productivity and the net HER were analyzed. In addition, the heat transfer experiments of SCCO₂ were conducted in the granite sample containing multiple fractures. The main results are summarized as follows:

1. According to the simulation results, when at the lower initial reservoir temperature, selecting the lower injection pressure and injection temperature slightly above the CO₂ critical temperature can improve the reservoir production life and ensure the high net HER. When at the higher initial reservoir temperature, a suitably higher injection pressure and lower injection temperature can extend the rapid increase stage of mass productivity and enhance the net HER while maintaining a longer reservoir life.
2. Both the results of the simulation and the experiments show a good consistency under the similar injection parameters. In the stabilization stage of mass productivity, the permeability decreases with increasing initial reservoir temperature (or initial rock sample temperature), while increasing the injection temperature or decreasing the injection pressure will reduce the permeability in varying degrees. In this simulation study, the permeability change caused by reservoir deformation is only considered. In fact, some of the water molecules will
remain in the fractures after the hydraulic fracturing. Therefore, during the injection of SCCO$_2$, a series of chemical reactions may occur which will lead to mineral dissolution and precipitation of reservoir. The permeability change caused by this process is also affected by temperature and pressure.

3. In this study, it is assumed that the boundaries of the model are adiabatic except for the wells boundaries. However, it can be seen from the experimental results that the heat compensation of the external boundaries will cause small fluctuations in the net HER. Moreover, this heat compensation effect becomes noticeable with an increase of the reservoir temperature or a decrease of the injection pressure. Meanwhile, the simulation results also show similar laws of heat compensation between the rock masses.

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CONFLICTS OF INTEREST

The authors have no conflicts of interest to declare.

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