Numerical Simulation on Heat Recovery Efficiency of Different Working Fluids in High-Temperature Rock Mass

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1. Introduction

The huge consumption of coal, oil, and other fossil fuels not only leads to energy crisis but also causes significant environmental and climate problems [1, 2]. Therefore, the global efforts are to seek green and sustainable alternative energy. As a kind of low-carbon renewable energy, hot dry rock (HDR) geothermal resources have attracted worldwide attention in recent years [3–5]. In the process of developing hot dry rock, it is necessary to form a fracture network connecting injection well and production well by some means, such as hydraulic fracturing, so as to establish a “heat recovery and electricity generation” closed cycle-enhanced geothermal system, as shown in Figure 1 [6, 7].

Conventional EGS uses water as the heat-carrying medium, and there are a lot of researches on this technology at home and abroad [8–11]; it is found that the heat extraction of H2O-EGS has great advantages in the presence of in situ fluid in the reservoir [12]. However, some scholars pointed out that the use of H2O-EGS will cause a lot of water resource loss [13] and also cause a series of problems that are not conducive to the operation and maintenance of geothermal system [14–17]. To solve these problems, in 2000, Brown first proposed that it can use supercritical CO2 (SCCO2) instead of water as a heat-carrying medium [18]. Since then, many studies have been carried out on the feasibility of using CO2 as heat extraction fluid [12, 14, 19–23]. In addition, many studies on the factors affecting the thermal extraction of CO2-EGS (such as CO2 injection rate, permeability, purity of CO2, and injection temperature of CO2) have been carried out [24–27]. CO2 has low density and viscosity, which can obtain large mobility ratio and buoyancy and reduce the pumping power in the heat recovery cycle [18, 28]. However, low specific heat capacity of CO2 leads to lower effective energy of heat extraction than that of water, and the mass flow rate of CO2 is easily affected by reservoir temperature and pressure. At present, domestic and foreign experts and scholars have analyzed the influence of reservoir temperature, gas injection pressure, temperature, water injection temperature, and hot dry rock fracture...
morbidity on CO₂-EGS and H₂O-EGS through theoretical analysis and numerical simulation, but there is little research on the difference of thermal recovery efficiency of water injection and gas injection in high-temperature rock mass under the same conditions. Therefore, this paper will carry out relevant research on this issue.

This study focuses on the influence of the change of reservoir seepage field, reservoir temperature field, and reservoir stress field on the seepage and heat transfer of a heat-carrying medium, establishes a thermal-fluid-solids coupling model, and, respectively, analyzes the influence of injection pressure, sample temperature, and the change of confining pressure on the heat recovery efficiency when H₂O and CO₂ are used as working fluids. This study will provide technical guidance for improving hot dry rock productivity under different geological conditions.

2. Governing Equations

The coupling relationship among temperature field, seepage field, and stress field in geothermal exploitation is shown in Figure 2. The coupling of the three fields is realized by the seepage movement of the heat-carrying medium, the deformation of the fractured rock mass, and the heat transfer. Therefore, the first step is to determine the governing equations of each physical field.

2.1. Rock Deformation. The constitutive equation based on Biot’s theory [29] is as follows:

\[
\varepsilon_{ij} = \frac{\sigma_{ij}}{2G} - \frac{\nu}{2G(1+\nu)} \sigma_{kk} \delta_{ij} + \frac{\alpha(1-2\nu)}{2G(1+\nu)} p_F \delta_{ij},
\]

(1)

where \(\varepsilon_{ij}\) is the solid strain tensor component, \(\sigma_{ij}\) is the stress tensor component, \(p_F\) is the pore fluid pressure, \(\sigma_{kk}\) is the normal stress component, \(\alpha\) is the Biot coefficient of rock, \(G\) is the shear modulus, and \(\nu\) is the Poisson ratio.

2.2. Fluid Flow. This study is based on the geothermal reservoir dominated by tight crystalline rocks such as granite. Here, only the fluid flow in fractures is considered. Fluid flow in the fracture is a saturated single-phase flow process, and the mass conservation equation of fluid flow is

According to Equation (1), the elastic constitutive equation of stress component is obtained as follows:

\[
\sigma_{ij} = 2G \varepsilon_{ij} - \frac{2G}{1-2\nu} \varepsilon_{kk} \delta_{ij} - \alpha p_F \delta_{ij} + \beta_s \Delta T \delta_{ij},
\]

(2)

where \(\varepsilon_{kk}\) is the volumetric strain, \(E\) is the elastic modulus, \(\beta_s\) is the coefficient of thermal expansion of rock mass, and \(T_s\) is the temperature of rock mass.

Relationship between strain and displacement under small deformation and deformation geometry equation is as follows:

\[
\varepsilon_{ij} = \frac{1}{2} \left( \frac{\partial u_i}{\partial x_j} + \frac{\partial u_j}{\partial x_i} \right).
\]

(3)

According to Terzaghi’s [30] effective stress principle, the total stress of the reservoir is as follows:

\[
\sigma = \sigma' + \lambda p_F,
\]

(4)

where \(\sigma\) is the total stress, \(\sigma'\) is the effective stress, and \(I\) is the equivalent tensor.

Without considering inertial force effect, the momentum conservation equation is as follows:

\[
\sigma_{ij,\ell} = -F_i, \quad (5)
\]

Through combining Equations (2), (3), (4), and (5), the equilibrium differential equation expressed by displacement is obtained as follows:

\[
G \nabla^2 u_i + (\lambda + G) u_{k,i} - \alpha p_F \frac{\beta_s E}{1-2\nu} \Delta T_{s,i} + F_i = 0, \quad (6)
\]

where \(u_i\) is the displacement component, \(\nu\) is the Poisson ratio, \(F_i\) is the volume force component, and \(\lambda\) is the lame elastic constant.

Figure 2: Thermal hydraulic mechanical coupling in geothermal exploitation.
expressed by the following formula:

$$\frac{\partial (\rho f \varphi)}{\partial t} - \nabla \left( \rho f \frac{k}{\mu} \nabla p_f \right) = Q_f,$$  \hspace{1cm} (7)

where $\rho_f$ is the fluid density, $Q_f$ is the source (sink) term of the fluid, $\mu$ is the dynamic viscosity of the fluid, $p_f$ is the fluid pressure, $\varphi$ is the porosity, and $k$ is the permeability.

Considering the roughness of fracture, the permeability of fluid in fracture is as follows [31]:

$$k = \frac{b^2}{12f},$$  \hspace{1cm} (8)

where $f$ is the roughness coefficient of fracture, $f = 1 + 17(a/2b)^{1.5}$.

Under the influence of pore pressure and thermal stress, the fracture width is as follows [32]:

$$b = b_0 e^{-\sigma_v/K_s},$$  \hspace{1cm} (9)

| Parameter                                      | Value       | Unit       |
|-----------------------------------------------|-------------|------------|
| The density of sample ($\rho_s$)              | 2700        | kg/m$^3$   |
| Dynamic viscosity of CO$_2$ ($\mu_g$)         | $9.3832 \times 10^{-5}$ | Pa·s       |
| Universal gas constant ($R$)                   | 8.314510    | J/(mol·K)  |
| Molar mass of CO$_2$ ($M$)                     | 44.009      | g/mol      |
| Thermal conductivity of CO$_2$ ($\kappa_g$)   | 0.109       | W/(m·K)    |
| Thermal conductivity of rock sample ($\kappa_r$) | 2.1        | W/(m·K)    |
| Specific heat capacity of CO$_2$ ($C_{pg}$)   | 1955.6      | J/(kg·K)   |
| Specific heat capacity of rock sample ($C_{pr}$) | 920        | J/(kg·K)   |
| Porosity ($\varphi$)                          | 0.04        |            |
| Permeability ($k$)                             | $3.94 \times 10^{-15}$ | m$^2$       |
| Elastic modulus ($E$)                          | 37.5        | GPa        |
| Poisson ratio ($\nu$)                          | 0.25        |            |
| Fracture aperture ($w$)                        | 0.1         | mm         |
| Density of water ($\rho_w$)                    | 1000        | kg/m$^3$   |
| Dynamic viscosity of water ($\mu_w$)           | 0.001       | Pa·s        |
| Convection heat exchange coefficient ($h_{sf}$) | 2           | W/(m$^3$·K)|
where $\sigma_n$ is the normal stress and $K_n$ is the normal stiffness of the crack.

The change of porosity under the influence of stress field, seepage field, and temperature field is as follows:

$$\phi - \phi_0 = \left(1 - \frac{1}{3K}\right)\left(1 - \frac{1}{3K_0}\right)\left(1 - \frac{3p_f}{1 - \frac{1}{K_0}}\right) - \phi_0\left(1 - \frac{1}{K} - \frac{1}{K_0}\right)\rho_f$$

$$+ \phi_0\left(1 - \frac{1}{K_0}\right)\left(\beta_p - \beta_s\right)\Delta T_s.$$

(10)

2.3. Heat Transfer. The heat transfer process in fractured rock mass can be expressed by the following formula:

$$\frac{d\Delta T_s}{dt} + \nabla \cdot \left(\rho_f C_{pf} \Delta T_s \mathbf{u}\right) - \nabla \cdot \mathbf{q} = Q_T,$$

$$\mathbf{q} = -\kappa_{eff} \nabla T_s,$$

$$\left(\rho_f C_{pf}\right)_{eff} = (1 - \phi)\rho_f C_{pf} + \phi \rho_f C_{pf},$$

$$\kappa_{eff} = (1 - \phi)\kappa_s + \phi\kappa_g,$$

where $T_s$ is the temperature of the rock sample, $\rho_f$ is the density of the fluid, $C_{pf}$ is the specific heat of the fluid, $\mathbf{u}$ is the flow velocity, $Q_T$ is the source term, $\mathbf{q}$ is the heat conduction flux, $\kappa_{eff}$ is the effective thermal conductivity, $\phi$ is the porosity, $\rho_f$ is the density of the rock sample, $\kappa_s$ is the thermal conductivity of rock sample, and $\kappa_g$ is the thermal conductivity of fluid.

### Table 2: Simulation scheme.

| Number | Working fluids | Influence factor | Axial compression (MPa) | Confining pressure (MPa) | Injection pressure (MPa) | Boundary heat source (W/mm²) | Initial temperature (K) |
|--------|----------------|------------------|------------------------|-------------------------|--------------------------|-----------------------------|-------------------------|
| 1      | Water/CO₂      | Confining pressure | 35                     | 26/28/30/35             | 2                        | 0.001                       | 473                     |
| 2      |                | Initial temperature | 35                     | 26                      | 2                        | 0.001                       | 373/403/433/493         |
| 3      |                | Injection pressure | 35                     | 26                      | 8/9/10/11                | 0.001                       | 473                     |

3. Numerical Model and Simulation Scheme

3.1. Model Description. Previous laboratory tests have studied the thermal recovery efficiency of alternating injection of H₂O and CO₂ into standard granite samples with single fracture; combined with the experimental results of H₂O-SCCO₂ alternate injection, the model of rock seepage heat extraction under THM coupling is established [33]. Therefore, the size of the model is consistent with the standard rock sample (50 × 100 mm), and there is a thorough crack in the axial direction of the model; the geometric model is shown in Figure 3. It contains 3324 free triangle units, the minimum unit size is 1 mm, and the maximum unit size is 6 mm. The finite element software COMSOL Multiphysics is used to solve the problem. The solving module includes structural mechanic module, groundwater flow module, and heat transfer module.

3.2. Initial and Boundary Conditions. The boundary conditions of stress field include the following: the upper boundary applies axial force, the right boundary applies lateral force, and the left and lower boundaries apply roller support.

Boundary conditions of temperature field include the following: the upper boundary applies axial force, the right boundary applies lateral force, and the left and lower boundaries apply roller support.

Boundary conditions of seepage field include the following: the upper boundary and the lower boundary are constant pressure boundaries, and the left boundary and right boundary are both zero flux boundaries.

After reading the relevant literature [34, 35], the thermophysical parameters of CO₂ and other fluids are determined, and the relevant parameters in the model are shown in Table 1.

3.3. Simulation Scheme and Data Process. The simulation scheme is shown in Table 2.

The measuring points (25 mm and 50 mm) selected in the model are shown in Figure 4.

The heat energy of heat-carrying fluid is the product of instantaneous sensible enthalpy and mass flow rate, and
the net heat productivity of the production well is as follows:

\[ E = Q_{\text{out}}(t)h_{\text{out}}(t) - Q_{\text{in}}(t)h_{\text{in}}(t), \tag{12} \]

where \( E \) is the heat energy extracted by the heat-carrying fluid, \( Q_{\text{out}} \) is the mass flow rate of the heat-carrying fluid flowing out of the rock mass (kg/s), \( Q_{\text{in}} \) is the mass flow rate of the heat-carrying fluid flowing into the rock mass (kg/s), \( h_{\text{out}} \) is the specific enthalpy of the fluid at the injection end (J/kg), and \( h_{\text{in}} \) is the specific enthalpy of the fluid at the outflow end (J/kg).

4. Results and Discussions

4.1. Effect of Confining Pressure. In the simulation of the influencing factors of confining pressure, the initial temperature of the model is 473 K, and the boundary heat source is 0.001 W/mm². The fluid injection pressure is 2 MPa, the axial pressure is 35 MPa, and the confining pressure is 26 MPa, 28 MPa, 30 MPa, and 35 MPa, respectively. After, respectively, injecting water and CO\(_2\) under different confining pressures, the temperature change at the measuring point is shown in Figure 5.

The results show that the temperature at the measuring point increases with the increase of confining pressure after water injection (or CO\(_2\)), and there are three stages of temperature change: initial stable stage (short time), rapid decrease stage, and final stable stage. When the confining pressure is low, the first stage is not obvious. With the increase of confining pressure, the duration of the initial stable stage is prolonged, and the start of the second stage is delayed. In the third stage, the higher the confining pressure,
the higher the temperature is when the pressure is stable. Comparing the temperature after water injection and the temperature after CO$_2$ injection, it is found that the temperature at the measuring point after water injection is slightly higher than that after CO$_2$ injection, especially under the confining pressure of 35 MPa, the temperature difference between the two conditions in the third stage at the measuring point is about 10 K.

Figures 6 and 7 show the stress distribution of rock samples after 600 s water injection and 600 s CO$_2$ injection under 26-35 MPa confining pressure, respectively. It can be seen that when the confining pressure increases, the internal stress of the model increases. According to Equation (9), the model fracture opening decreases with the increase of stress, which reduces the permeability and affects the heat recovery efficiency.

Figure 8 shows the change of net heat with time after water and CO$_2$ injection under different confining pressures. It can be seen that the net heat decreases with the increase of confining pressure in the process of water injection and CO$_2$ injection. Increasing confining pressure reduces fluid velocity, prolongs heat exchange time between fluid and rock mass, but also reduces permeability and fluid mass flux in corresponding time; under the combined influence of the two factors, the net heat decreased, indicating that the latter factor had a greater influence.

Comparing with the previous experimental research, the results are generally consistent with the experimental results [36]. Comparing the net heat results after water injection and CO$_2$ injection, it is found that the net heat extracted after water injection is slightly higher than that of CO$_2$ injection.
Figure 9: Temperature distribution after 600 s water injection under different confining pressures.

Figure 10: Temperature distribution after 600 s CO₂ injection under different confining pressures.

Figure 11: Variation of net heat with injection time at different initial temperatures. (a) Thermal recovery by water injection. (b) Thermal recovery by CO₂ injection.
under the same confining pressure. This difference is not obvious under low confining pressure, but with the increase of confining pressure, the heat recovery efficiency of water is significantly higher than that of CO₂.

Figures 9 and 10, respectively, show the temperature distribution of rock samples after water injection for 600 s and CO₂ injection for 600 s under confining pressure of 26-35 MPa. It can be seen that the heat loss of rock sample under low confining pressure is obviously lower than that under high confining pressure, and the heat loss of rock sample after water injection is slightly lower than that of CO₂ injection under the same confining pressure. It can be seen that the thermophysical properties of fluid have an obvious effect on the heat recovery rate. Although the low mass flow rate of CO₂ leads to lower thermal recovery under the same conditions, the heat loss of rock samples by CO₂ is higher than that by water.

### 4.2. Effect of Initial Temperature

In the simulation of the influence factors of initial temperature of rock sample, boundary heat source is 0.001 W/mm², fluid injection pressure is 2 MPa, axial compression is 35 MPa, and the confining pressure is 26 MPa. We simulated the thermal recovery process of water injection and CO₂ injection at the initial temperature of 373 K, 403 K, 433 K, and 493 K, respectively. Figure 11 shows the rule of net heat variation with water and CO₂ injection time at different temperatures.

It can be seen that in the process of water injection heat recovery, the net heat increases with the increase of the initial temperature of the rock sample. In the process of CO₂ injection heat recovery, the net heat decreases with the increase of initial temperature of rock sample. Comparing with the previous experimental research, the results are generally consistent with the experimental results [37]. Due to the small size of rock sample, the temperature of
fracture surface decreases rapidly after fluid injection, resulting in the rapid decrease of initial net heat. In the actual EGS reservoir, the heat recovery area will be compensated by the nearby high-temperature rock mass. When boundary heat source is added to the model, the net heat curve fluctuates slightly, which is the result of the interaction between heat recovery and heat compensation. Figures 12 and 13 show the stress distribution of rock samples after 600 s water injection and 600 s CO₂ injection at the initial temperature of 373 K-493 K, respectively. It can be seen that when the initial temperature increases, the internal stress of the model increases. Generally, the density viscosity ratio of CO₂ is larger than that of water, and the sensitivity of the two fluids to temperature and pressure is quite different. This ratio of water is mainly a function of temperature and less affected by pressure. However, for CO₂, this ratio is significantly affected by temperature and pressure. When the temperature of rock sample increases from 373 K to 493 K, the density viscosity ratio of water increases by 0.5, and the specific enthalpy increases by 120 kJ/kg, and the net heat of water increases with the increase of rock temperature. However, the above changes in the rock sample temperature decrease the density viscosity ratio of CO₂ by 1 and increase the specific enthalpy by only 30 kJ/kg. The former plays a leading role in the influence of the net heat, while the net heat of CO₂ decreases with the increase of rock temperature.

**Figure 14:** Temperature distribution after fluid injection at different initial temperatures.

**Figure 15:** Change of net heat with CO₂ injection time at different injection pressures.
Figure 14 shows the temperature distribution characteristics of rock samples after water injection and CO₂ injection for 600 s at 373-493 K initial temperature. It can be seen that the heat loss of rock sample after CO₂ injection is slightly higher than that of water injection under the same initial temperature of rock sample. This is consistent with the results of the influence of confining pressure. Therefore, the thermal recovery efficiency of CO₂ can be higher than that of water by reasonably selecting the injection conditions of CO₂.

4.3. Effect of Injection Pressure. In the simulation of factors affecting CO₂ injection pressure, the initial temperature of rock sample is 473 K, the boundary heat source is 0.001 W/mm², axial pressure is 35 MPa, and the confining pressure is 26 MPa. The model simulates the thermal recovery process of CO₂ under high injection pressure of 8 MPa, 9 MPa, 10 MPa, and 11 MPa, respectively. Figure 15 shows the rule of net heat variation with CO₂ injection time under different injection pressures.

It is found that the net heat extracted by CO₂ increases with the increase of injection pressure in the same amount of time. Comparing with the previous experimental research, the results are generally consistent with the experimental results [37]. The increase of gas injection pressure leads to the increase of gas volume flow in unit time and the heat exchange of gas in rock fracture. The increase of gas injection pressure leads to the increase of rock permeability, resulting in the increase of CO₂ mass flow rate at the outflow end. At the same time, it also reduces the heat exchange time.
of CO₂ in fracture. Under the combined influence of the two factors, the net heat increases with the increase of injection pressure, which indicates that the mass flow rate plays a leading role.

Figure 16 shows the stress distribution of rock sample after CO₂ injection for 600 s under different injection pressures. It can be seen that the increase of CO₂ injection pressure has little effect on the internal stress of the model, and the crack opening will not change much. Compared with the effect of CO₂ mass flow rate increasing, the effect of stress can be neglected.

The temperature distribution of rock sample after CO₂ injection for 600 s under different injection pressures is shown in Figure 17. It can be found that the heat loss of rock sample gradually increases with the increase of injection pressure in a certain period of time. Therefore, increasing the injection pressure of the fluid is beneficial to the thermal recovery of EGS, but suppresses the thermal compensation effect, and significantly reduces the production life of the reservoir.

5. Conclusions

In this paper, a numerical model is established to simulate the influence of confining pressure and initial temperature of rock sample on the thermal recovery rate during water injection and CO₂ injection of fractured rock sample, and the influence of CO₂ injection pressure on the thermal recovery rate. This paper compares and analyzes the advantages of heat recovery by water injection and CO₂ injection and obtains the following main conclusions:

(1) After water injection (or CO₂), the temperature at the measuring point increases with the increase of confining pressure, and there are three stages of temperature change: initial stable stage, rapid decrease stage, and final stable stage. After thermal recovery by water injection, the temperature of the measuring point is slightly higher than that of CO₂ injection, especially under the confining pressure of 35 MPa. The temperature difference of the measuring point between the two conditions in the third stage is about 10 K. The net heat decreases with the increase of confining pressure, and under the same confining pressure, the net heat extracted after water injection is slightly higher than that of CO₂ injection. This difference is not obvious under low confining pressure, but with the increase of confining pressure, the thermal recovery efficiency of water is significantly higher than that of CO₂.

(2) The net heat of water increases with the increase of rock sample temperature, while the net heat of CO₂ decreases with the increase of rock sample temperature. At the temperature of 393 K rock sample, the maximum net heat ratio of CO₂ to water is about 3. With the increase of sample temperature, the maximum net heat ratio of CO₂ to water decreases to 0.4 at 493 K. Therefore, with the increase of rock temperature, the heat extraction rate of CO₂ is gradually lower than that of water.

(3) In the same amount of time, the net heat extracted by CO₂ increases with the increase of injection pressure. With the increase of injection pressure, the velocity of CO₂ in fracture increases, which increases the mass flow rate of CO₂, but also reduces the heat exchange time of CO₂ in fracture. The net heat increases with the increase of injection pressure, which indicates that the mass flow rate plays a leading role; increasing the injection pressure of the fluid is beneficial to the thermal recovery of EGS, but suppresses the thermal compensation effect and significantly reduces the production life of the reservoir.

Data Availability

The data used to support the findings of this study are available from the corresponding author upon request.

Conflicts of Interest

The authors declare that there is no conflict of interest regarding the publication of this paper.

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