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Heat Mining Process of Enhanced Geothermal Systems, A Numerical Study of Gonghe Basin

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ABSTRACT

Enhanced Geothermal System (EGS) can achieve the development and utilization of Hot-dry Rock, which will be one of the most important resources in the future. There are very abundant Hot-dry Rock resources in Gonghe Basin, Qinghai province. There are complex water-thermal coupling processes when water flows in the reservoir, and power generation capacity dependents on the EGS operation scheme. Based on the deep geological condition of Qiabuqia in Gonghe Basin, we established a numerical model to characterize the hydrothermal features of EGS, researched the temporal and spatial distribution of temperature field, pressure field, and analyzed the influence of injection temperature and flow rate on heat extraction rate. The results show that the maximum heat extraction rate can be 11 MW under the base scheme (20 kg/s, 60 ºC), reservoir life is 22 years. Heat extraction rate will increase by about 10% as 10 °C increase of injection temperature, while reservoir life remain the same. Increased flow rate will lead to a greater rate of heat extraction, but shorter reservoir life. The research results can provide a theoretical basis for the implementation of the EGS Project in the future.

1. INTRODUCTION

Due to its clean renewable nature and wide spatial distribution, geothermal resources have become one of the most competitive energy sources. Geothermal resources can be divided into hydrothermal geothermal resources and dry hot rock geothermal resources according to their origin and production conditions. Hot and dry rock (HDR) resource reserves are huge and not limited by region, which is a new energy source that may change the future [1][2]. According to a preliminary estimation, the resource amount of hot dry rock within the depth of 3 km to 10 km in mainland China is about 2.5×10^{25} J (equivalent to 856 trillion tons of stand coals), among which, the resource of hot dry rock within 3 km to 5.5 km is about (equivalent to 106 trillion tons of stand coals). Considering the difficulty in exploring and utilization of HDR type geothermal energy, the hot-dry-rock type geothermal energy that buried between 3 km to 5.5 km are the priority research areas in the next 15 to 30 years.

Enhanced Geothermal Systems (EGS) was presented based on hot dry rock technology and refers to adopt the method to build a geothermal reservoir from the low permeability of rock mass [4]. The flow process of geothermal fluid has complex changes in space and time. Numerical simulation can fully and accurately describe this complex coupling process, which plays a huge role in EGS research. Pashkevich et al. [6] studied the thermal performance of the Mutnovsky volcanic EGS system and found that well flow rate, production area permeability, injection/production well pressure difference, and well layout all have an impact on the thermal productivity of the EGS system. Baujard et al. [7] studied the fracturing process and water cycle characteristics of EGS fractured reservoir, and the results showed that the density of injected water had a significant impact on the distribution of pressure field, fracture distribution and volume. Pruess[8], Spycher[9] and Borgia[10] studied the advantages and disadvantages of supercritical CO_2 as heat carrier. Watanabe studied the thermal extraction process of a single fissure by numerical simulation, and pointed out that the density and viscosity of water have a significant impact on the thermal extraction rate. Lei hongwu et al. [11] simulated the thermohydrodynamic coupling process of EGS development in songliao basin, and studied the influences of permeability and porosity of pore matrix and fracture medium, rock thermal conductivity, well diameter, injection pressure, injection temperature and matrix factors around fractures on geothermal energy development.

Based on the Qinghai Gonghe Basin Qiabuqia HDR Project, we establish a numerical model of hydrothermal characteristics, research the process of spatial and temporal distribution of temperature field, pressure field during EGS development, evaluate EGS heat extraction rate and predict the reservoir life, the results can provide theoretical basis for the implementation of the EGS project in the future.

2. RESEARCH AREA

The Gonghe Basin is located between the Kunlun Mountains and the Qinling Mountains. It is a diamond-shaped intermountain basin that is distributed in the NWW direction. The geotectonic unit belongs to the junction of the Qinkun-Kun fault-segregation system of the East Kunlun and West Qinling orogenic belts. It is a fault basin formed since the Mesozoic, surrounded by faults and folds. It has a large thickness of Quaternary and Neogene strata with the thickness of 900~1440 m. The intrusive rocks are mainly Indosinian. - Yanshan period, with granite, granodiorite, quartz diorite and porphyritic granite (Fig. 1). The data show that the heat flow value in the basin is higher, and the average geothermal gradient of the basement granite is greater than 5 °C/100 m.

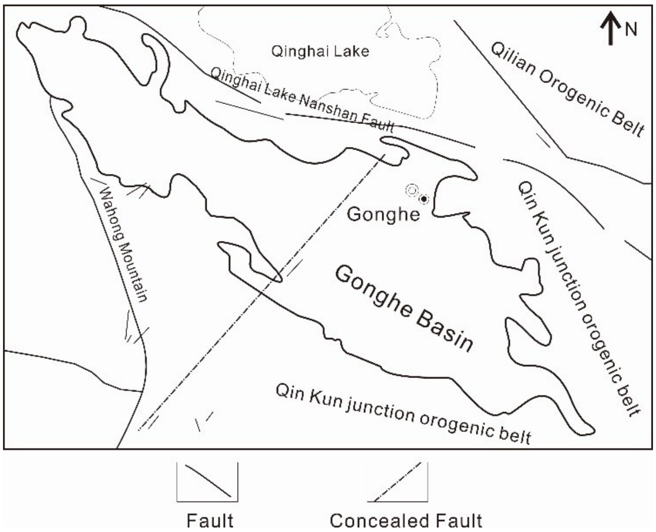


Figure 1. Geologic profile of Gonghe Basin

The Qiabuqia geothermal area is located in Gonghe County in the northeast of the Gonghe Basin. It is located in the Qinqikun orogenic belt on the regional scale, and is located in the structural joints of Qilian, East Kunlun and Xiqinling. Previous research results show that the geothermal energy in this area is conductive geothermal, the heat source comes from the deep underground, and is related to the thermal anomaly in the crust-mantle structure. The well temperature measurement curve has linear characteristics.

2. MODELING

2.1 Simulation code

After decades of development of numerical simulation technology, there are many simulation tools for HDR, such as FRACTURE [15], GEOTH3D [16], TOUGH2 [17] and so on. The TOUGH2 series software is an advanced non-isothermal, multi-phase, multi-component simulation code that solves the spatial and temporal distribution of pressure, temperature, saturation, and component mass fraction during multiphase flow based on component mass and energy conservation. The method is the integral finite difference, the time dispersion is the implicit difference, and the nonlinear equation is solved by the Newton-Raphson iteration [17]. TOUGH2 can solve the hydrothermal coupling problem of one-dimensional, two-dimensional and three-dimensional pore and fracture media, and is widely used in geothermal research. Xu et al. [18] used TOUGHREACT to study the clogging of mineral deposits during the operation of geothermal systems. Zeng et al. [19] established a numerical model of the double horizontal well at the Desert Peak site. The study found that the power production capacity is related to the water injection rate and the injection temperature. The heat extraction efficiency depends on the reservoir permeability and the water production rate.

TOUGH2 software adopts modular design for different problems. The EOS1 module can accurately describe the pure water and water vapor two-phase coexistence system with a maximum temperature of 647.3 K. This article uses the EOS1 module, and the detailed mathematical equations are found in Reference 17.

2.2 Generalization

Deep thermal storage porosity and permeability are generally low, requiring manual fracturing to form a fracture network to achieve increased production capacity. Artificial fracturing is a complex project, and research shows that it is now possible to establish a 1 km^3 fracture network [4]. In this study, the granite at 3 km was selected as the target reservoir, and it was assumed that the ideal artificial fracturing had been carried out to form a uniform fracture network of 500 m×1000 m×50 m, and the fracture spacing was assumed to be less than 2 m (Fig. 2).

The fracture system is divided into two parts: fracture and matrix. At present, there are mainly three methods for characterizing the hydrothermal migration of fracture systems, which are equivalent temperature method, matrix-fracture temperature method and rock-fluid temperature method [20][21]. When the fracture spacing is less than 2 m, it can be assumed that the fracture and the matrix are in thermal equilibrium, and the fracture medium can be characterized by a single pore medium. This method can not only accurately describe the hydrothermal state of the fracture medium under this condition, but also greatly reduce the amount of calculation of the model and is widely used [19]. In this study, the fracture reservoir was generalized into a single homogeneous porous medium with a model size of 500 m × 1000 m × 50 m. The porosity was determined to be 3% according to the logging data, and the permeability after fracturing was 50 $\times 10^{-15}$ m^2[19], and assume that the physical properties of the model (such as fracture spacing, etc.) remain unchanged during the simulation. The detailed reservoir parameters are as follows: length 1000 m, width 500 m, thickness 50 m, heat transfer coefficient 2.1 W / (m · K), specific heat capacity 1100 J / (kg · K), density 2850 kg / m^3, porosity 3%, permeability $K_x = K_y = K = 50 \times 10^{-15}$ m^2. The initial temperature is 192 °C and initial pressure is 30 MPa. The injection rate (Base scheme) is 20 kg/s and injection ratio is 262.12 kJ/kg, the production index is 8.18×10^{-12} m^3, and the production well pressure is 29 MPa. We use a rectangular grid of 20 m × 20 m × 50 m for a total of 1,250.

Granite has low permeability at non-fracturing conditions, the geothermal resources in the Gonghe Basin are conductive, and convective exchange is not obvious. Compared with the volume of artificial reservoirs, the boundary effects are negligible [22]. Thus, both the top, bottom and surrounding boundaries are set to zero flow zero heat exchange boundaries. The target reservoir is located at 3 km underground. According to the hydrostatic pressure distribution, the initial pressure is 300 bar (1 bar=105 Pa). From the ground temperature of 2800 m and the average geothermal gradient, the initial temperature at 3000 m is about 192 °C.

2.3 Simulation Scheme

The simulation uses a dual well mode, a single injection well and a production well (Fig. 2) with a well spacing of 1 km. A production index model is used to characterize production well flow [17]: production index PI = 8.18×10^{-12} m^3.

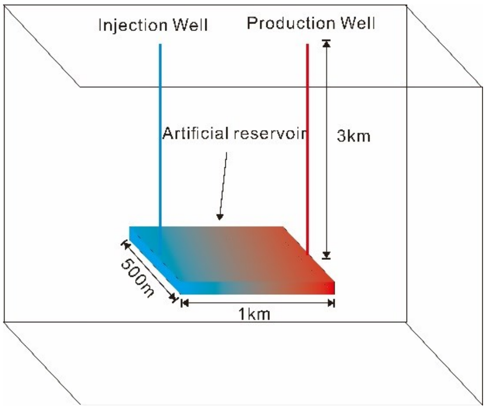


Figure 2. Scheme of the artificial reservoir and well pattern

The ideal EGS system has a production temperature of 180 °C and a production flow rate of 40 kg/s, but most of the sites have failed to achieve this goal [5]. Taking into account the actual possible fracturing effect, this simulation uses a circulating flow of 20 kg/s, the temperature of the injection water is 60 °C (represents injecting well bottom temperature), the production well is 10 bar below the reservoir pressure (290 bar) and the system running time is 30 years. On this basis, the parameter sensitivity analysis of the two controllable factors of circulating flow and injection temperature is carried out. See Table 1 for details.

Table 1 Parameters of simulation schemes

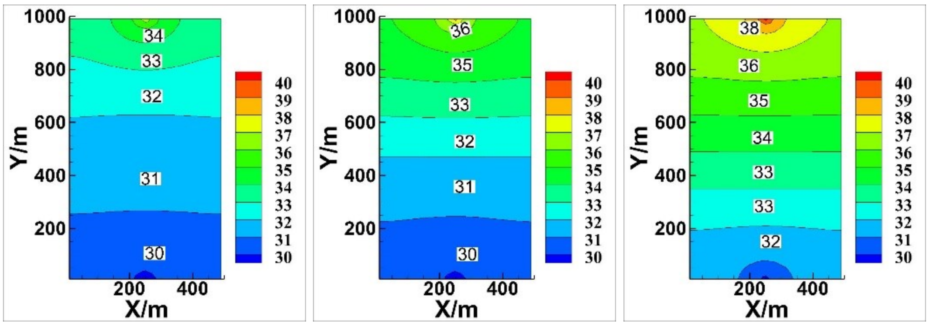
NO.	circulating flow / （$kg \cdot s^{-1}$）	Injecting temperature/°C
Base	20	60
V15	15	60
V25	25	60
T50	20	50
T70	20	70

3. RESULTS AND ANALYSIS

3.1 Pressure field variation characteristics

From the spatial and temporal distribution characteristics of the reservoir pressure field (Fig. 3), it can be seen that as the water is continuously injected, the pressure of the entire reservoir is increasing, especially in the vicinity of the injection well. At 10 years, the pressure near the injection well increased from the initial 30 MPa to about 36 MPa, 38 MPa at 20 years, and rose to 40 MPa at 30 years. The production well is a constant low pressure zone (29 MPa), which forms a pressure cascade distribution of the injection well high pressure zone to the low pressure zone of the production well, forming a circulating flow from the injection well to the production well.

It can also be seen from Fig. 3 that the pressure gradient near the injection well at the beginning of the cycle is larger than that near the production well, and the gap is gradually reduced with time, and the pressure distribution tends to be uniform. This is because the mobility of water [11] (ρ/μ, ρ and μ are fluid density and viscosity, respectively) is different. At the beginning of the system cycle (Fig. 3(a)), the injecting well temperature is rapidly reduced near the injection well, resulting in greatly reduced water mobility, obvious water flow impedance, large pressure gradient, but there is no significant influence on the vicinity of the production well. In the later stage (Fig. 3(c)), the reservoir heat has been extracted, and most of the reservoir temperatures tend to be at the same level (Fig. 4), so the pressure distribution tends to be uniform.

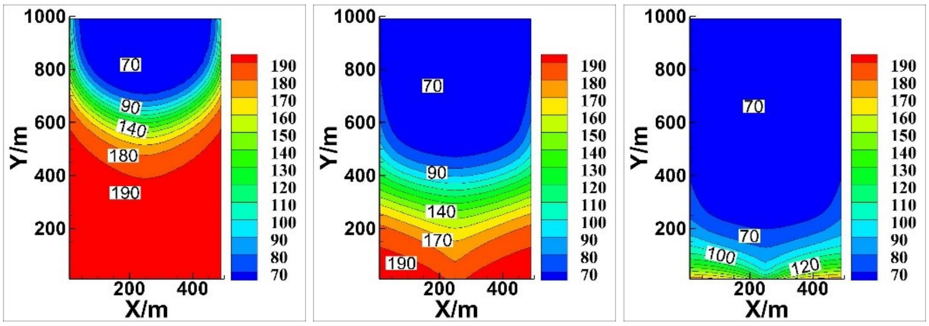


（a） 10 years （b） 20 years （c） 30 years

Figure 3. Spatial and temporal distribution of pressure

3.2 Temperature field variation characteristics

Figure 4 shows the spatiotemporal distribution characteristics of the reservoir temperature. The injection of cold water (60 °C) causes the temperature near the injection well to rapidly decrease, forming a low temperature zone of about 70 °C, and expanding with time. At 10 years (Fig. 4(a)), the temperature of 70 °C is about 700 m from the production well, about 450 m at 20 years, and only about 150 m at 30 years, indicating that the heat of the reservoir is gradually extracted. Figure 5 shows the variation of the water temperature in the production well over time. It can be seen that the water temperature of the production well began to decrease at about 18 years, indicating that the cold water has approached the production well in 18 years, and a thermal breakthrough occurred. At 22 years, the production well temperature reduces to 180 °C. According to MIT's 10 °C temperature drop standard, the stable running time of the system was determined to be 22 years.



（a） 10 years （b） 20 years （c） 30 years

Figure 4. Spatial and temporal distribution of temperature

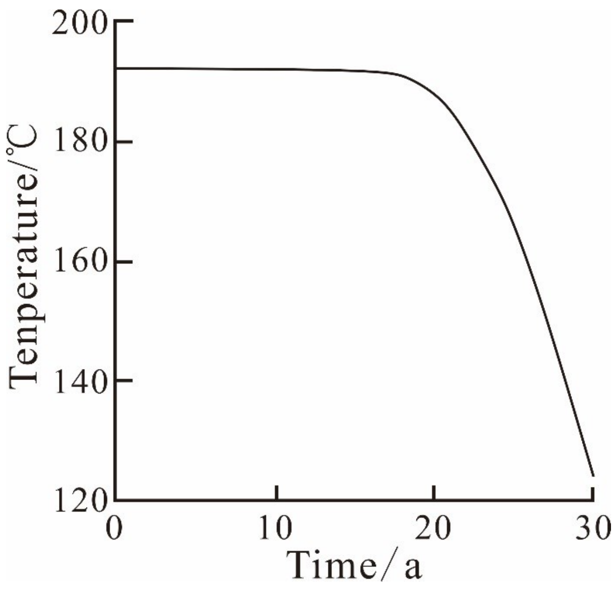


Figure 5. Temperature variation with time at production well

3.3 Thermal extraction efficiency

The heat extraction efficiency is a key indicator for evaluating the EGS engineering power generation capacity, and is also an important reference factor for judging the reservoir operation cycle. The heat extraction efficiency of this study was evaluated according to the heat extraction rate parameter (Pruess et al. [17]): $G=F_{pro}h_{pro}-F_{inj}h_{inj}$. Where G represents the heat extraction rate, F_{pro} and F_{inj} represent the production well and injection well flow, respectively, and h_{pro} and h_{inj} represent the specific enthalpy values of the production well and the injection well fluid, respectively.

Figure 6 shows the changes in production well flow and heat extraction efficiency during system operation. The production flow can reach 20 kg/s in a short time, the same as the injection flow, establishing a continuous circulation system that remains unchanged. As with the trend of production flow, the heat extraction rate remains stable of 11 MW until about 18 years. Since then, it has started to decline, about 10 MW in 22 years and 5 MW in 30 years. The main reason is that from the 18th year, the temperature of the production well fluid began to decrease, and the heat extraction rate decreased correspondingly with the same flow rate.

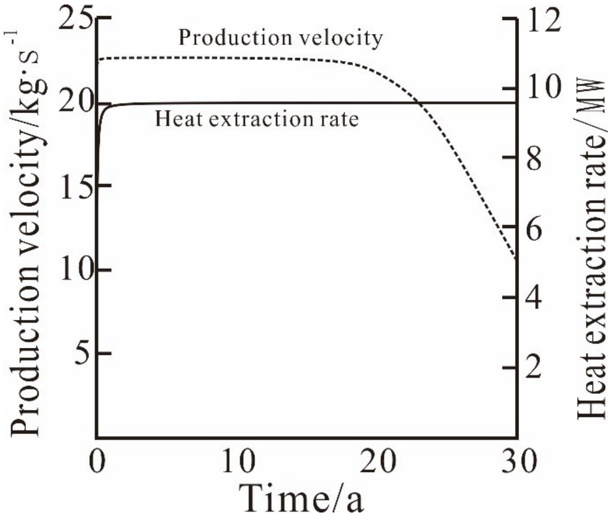


Figure 6. Production velocity and heat extraction rate variation with time

4. PARAMETER SENSITIVITY ANALYSIS

4.1 Injection temperature

Figure 7 shows a comparison of the heat extraction rates for different injection temperatures (50 °C, 60 °C, and 70 °C). The injection temperature of 50 °C can reach a heating rate of about 12 MW, and only about 10 MW at 70 °C. It can be seen that the lower the injection temperature, the higher the heat extraction rate in the case of a certain circulating flow rate; moreover, different injection temperatures have no significant effect on the reservoir life. For every 10 °C increase in injection temperature, the maximum heat extraction rate of the system is increased by about 10%. Therefore, EGS power generation should reduce the temperature of the injected fluid as much as possible to obtain a larger heat extraction rate and power generation.

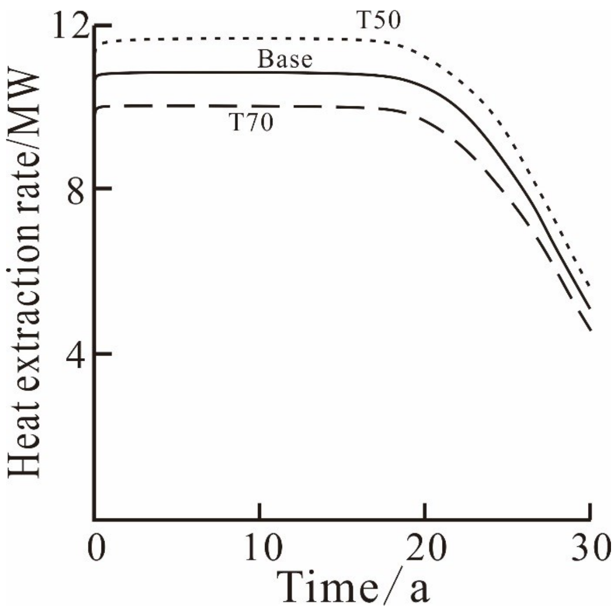


Figure 7. Heat extraction rate variation with time under different injection temperature

4.2 Circulating flow rate

Figures 8 and 9 show the difference in heat extraction at different circulating flow rates. The maximum heat extraction rate of 25 kg/s is up to 13 MW, but the reservoir life is reduced to 18 years. The heat rate of 15 kg/s is 8 MW, but it is basically unchanged within 30 years, the reservoir has a long life. It can be seen that increasing the circulation flow rate can result in a larger heat extraction rate, but will correspondingly reduce the reservoir life. If the cycle rate of 15, 20, and 25 kg/s is used for the 22-year cycle of the Base scheme, the total heat extraction amounts are 5.1×10^{15}, 6.8×10^{15} and 8.3×10^{15} J, respectively (Fig. 9). During the same operating cycle (22 years), the larger the circulating flow rate, the greater the total amount of heat extraction.

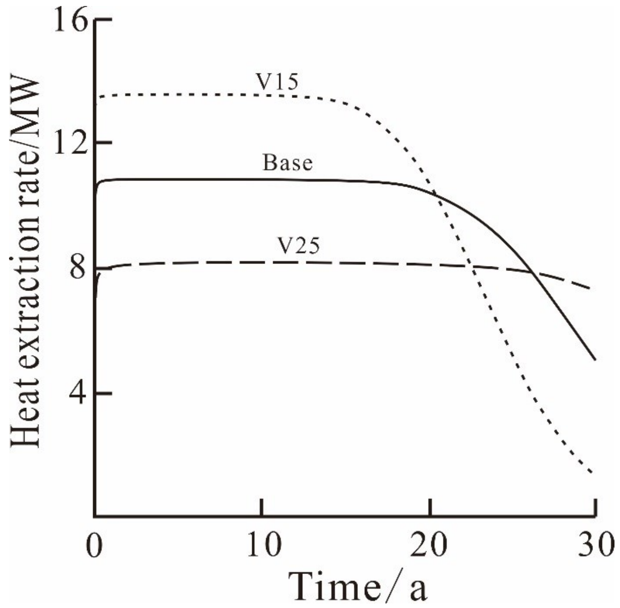


Figure 8. Heat extraction rate variation with time under different circulation velocity

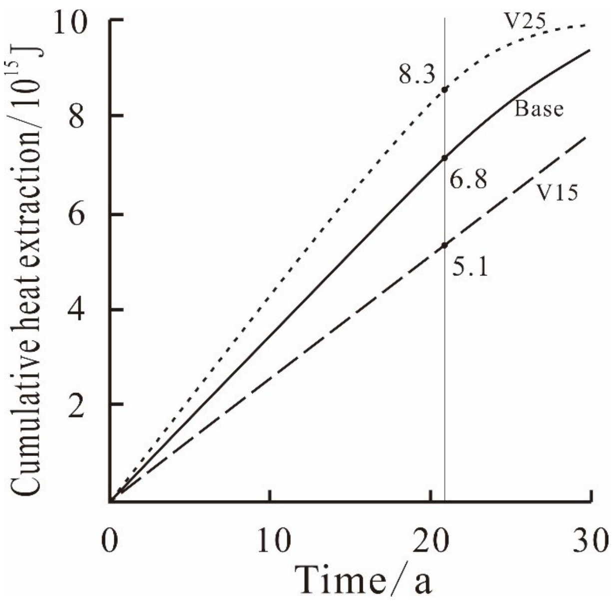


Figure 9. Cumulative heat extraction under different circulation velocity

5. CONCLUSIONS

1. The Qiabuqia region of the Gonghe Basin has obvious thermal anomalies, high geothermal gradient, and a buried depth of 3 km to 190 °C. Its lithology is granite with low porosity and permeability. It will be a good EGS reservoir after ideal artificial fracturing.

2. At a constant flow rate (20 kg/s), the reservoir pressure is increased and different pressure gradient zones are formed due to differences in water flow. It takes 18 years for cold water to break through to the production well, the reservoir life is 22 years, and the maximum heat extraction rate can reach 11 MW.

3. When the circulation flow rate is constant, the lower the temperature of the injection fluid, the higher the heat extraction rate, and the maximum heat extraction rate of the system increases by about 10% for every 10 °C increase in the injection temperature. The injection temperature has no significant effect on reservoir life.

4. When the injection temperature is constant, increasing the circulation flow rate can result in a larger heat extraction rate, but will reduce the reservoir life. During the same operating cycle (22 years), the larger the circulating flow rate, the greater the total amount of heat extraction.

The results of this study were obtained under specific parameters. There are still many factors not considered, such as the influence of stress field and chemical field, the change of reservoir physical properties during fluid flow, and the influence of wellbore flow on heat extraction. And the actual EGS project is more complicated, so it needs to be further explored in future research.

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