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# Integrated technological and economic feasibility comparisons of enhanced geothermal systems associated with carbon storage

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## HIGHLIGHTS

- $CO_2$-EGSs show the best performance in power generation but potential negative NPV.
- Mixed $CO_2$-water horizontal-well-EGS demonstrates the best economic performance.
- Fluid injectivity is a critical concern for EGS technically and economically.
- Uncertain electricity retail price also affects the profitability of EGS.

## ARTICLE INFO

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## ABSTRACT

Enhanced geothermal system (EGS) demonstrates low carbon intensity for supplying electricity but it has not been widely developed commercially. Although the engineering feasibility of different operational strategies has been illustrated, the energy industry is still ambiguous in economic aspects; in particular, incorporating carbon policies into the decision-making process is necessary. In this study, an evaluation framework from technical and economic perspectives considering the impact of carbon credit is introduced for the first time to compare six EGS working schemes including two well configurations and three flow strategies. Afterwards, sensitivity analyses are performed with respect to six technical parameters and four economic constraints. Key findings in this study prove that mixed $CO_2$-water horizontal-well-EGS achieves the most profitability with an NPV of $35.3 million. $CO_2$-EGS can produce the greatest geothermal power and carbon storage, but the high $CO_2$ consumption is a major obstacle to achieving profitability. Compared to water-EGS, mixed $CO_2$-water EGS shows a greater profit gained the advantage from carbon storage even with less geothermal energy harvesting. Regarding various well types, the horizontal well system can earn more profits than the vertical well system if the thermal breakthrough is not serious. The sensitivity analyses suggest that the parameters that dominate fluid injection amount and flow rate shall be assigned the highest priority. The electricity market price is another critical factor, and a mixed $CO_2$-water EGS project is recommended to start according to the rising trend of the electricity sale price. This study provides an informative decision-making strategy for EGS stakeholders.

## 1. Introduction

Fossil fuels, currently, still dominate global energy production and development, and approximately 80% of global energy is supplied from crude oil, coal and natural gas [1]. However, with a rapid increment in energy demand and a serious deterioration in climate change, an energy transition from dependence on fossil fuels to renewable and clean resources has been an international agreement [2]. Geothermal energy has been acknowledged as one of the most effective strategies to achieve the decarbonization goal due to its sustainability and low-carbon intensity

*Abbreviations:* EGS, Enhanced geothermal system; HDR, Hot dry rock; NPV, Net Present Value; CAPEX, Capital expenditure; OPEX, Operating expenses; CMG, Computer Modelling Group; O&M, Operation and maintenance; GHG, Greenhouse gas; IRC, Internal Revenue Code.

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[3]. It has been estimated that over one billion tons of carbon emissions can be mitigated by 2050 through the development of geothermal energy [4].

To date, enhanced geothermal system (EGS) has been given priority in the research area as it can significantly reduce the carbon intensity of the electricity supply. Extracting geothermal energy from hot dry rock (HDR) after creating a highly conductive space underground to improve the fluid mobility and heat extraction potential is a large-scale promising EGS design [5]. Despite the EGS technology has been developed over the past 40 years, only a few projects have been recorded as commercial EGS power plants, such as Soultz in France and Landau in Germany [6]. As a result, the installed power capacity from EGS only accounted for less than 1% of the global installed power capacity by 2015. However, this ratio is expected to rise to 50% by 2050 based on government reports [7]. Developing a commercial-scale EGS power plant is the key to achieving this goal, and therefore, a solid understanding of its feasibility is necessary both technologically and economically.

From the technical standpoint, the geothermal power extracted from an EGS is expected to be at high-level sustainability, which is influenced by different operational strategies, such as well configurations, well spacing, fluid flow rate and the properties of engineered fractures [8]. For example, Lei et al. [9] found that the geothermal production of an EGS was highly different in vertical wells and horizontal wells systems. Zinsalo et al. [10] observed that fracture permeability and energy productivity presented a nonlinear relationship. The working fluid is another critical influence factor. Currently, water has been widely adopted for heat mining owing to its high heat capacity and thermal stability. $CO_2$ is an alternative heat transmission fluid, which is more probable to exist as a supercritical phase in a geothermal reservoir [11]. Although the mass heat capacity of supercritical $CO_2$ ($sCO_2$) is 40% $\sim$ 60% that of water, it shows a 2 $\sim$ 5 times larger mobility than water because of its large density and low viscosity [12,13]. In addition, $sCO_2$ can efficiently prevent scaling problems in wellbores due to the extremely low solubility of minerals in $sCO_2$ [14]. Furthermore, the injected $CO_2$ can be stored underground to mitigate the $CO_2$ emission and obtain the benefits from carbon policies [15]. In recent years, $CO_2$ has been proven to provide a comparable geothermal heat extraction compared with water, and even to show a better economic performance at certain working conditions [16,17]. However, the most important concern of injecting $CO_2$ into an EGS is the salt precipitation caused by interactions between the fluid and a reservoir, which could damage the geological formation and further reduce the $CO_2$ mining rate [18]. Nevertheless, the reservoir without the formation water or a low-salinity water slug before $CO_2$ injection has been proven to effectively mitigate salt precipitation [19,20]. Another flow scheme that is being considered is a mixture injection of $CO_2$ and water, which has not only a better ability to control a fluid mobility subsurface but also a potential to sequester injected $CO_2$ to reservoirs [21–25].

From the economic perspective, an EGS project is expected to earn profits as much as possible. Variations of operational schemes could significantly influence its profitability. Specifically, the drilling costs of vertical wells and horizontal wells are varied, and the corresponding costs of engineered fracturing also perform diversely [26,27]. Additionally, the investments in surface facilities and the operation and maintenance of an EGS are affected by the installed geothermal power capacity [28]. Furthermore, potential benefits from carbon policies can also improve the profitability of an industrial project [15]. In addition to these uncertainties, some external factors, such as fluid purchase costs and electricity market prices, are also critical driving factors for an EGS investment. Although the co-benefits of utilizing $CO_2$ in an EGS include improving the energy harvesting efficiency and $CO_2$ sequestration potential, the costly $CO_2$ purchasing is still a major economic challenge. Therefore, an accurate and comprehensive understanding of the interactions between economic performance and various uncertainties is essential. Previous studies have used different methods to evaluate the profitability of an EGS project. Lei et al. [26] generated a levelized cost of electricity (LCOE) objective function to explore the feasibility of a water-based horizontal-well-EGS under different operational parameters. The results illustrated that the LCOE increased from 0.047 $/kWh to 0.066 $/kWh with a decrease in well spacing and a fluid injection rate. Xie et al. [27] used a numerical model to simulate the exploitation performance of a water-based pinnate-horizontal-well-EGS and further assessed the costs of exergy flows by an LCOE model. The results suggested that the injection flow rate and reservoir permeability affect heat mining and economic performance. Liu et al. [29] indicated that the well spacing is one of the most important factors affecting the total net costs of a water-based vertical-well-EGS. Wang et al. [30] demonstrated that the geofluid mass flow rate is a critical parameter for a successful $CO_2$-EGS project based on calculated LCOE. Raos et al. [31] showed that the discount rate and the energy market price show different effects on the LCOE of two water-EGSs. Li et al. [32] used the total economic costs, EGS lifetime and cumulatively produced electricity to perform a probabilistic analysis of the LCOE, and the results showed that the LCOE approximately conformed to the normal distribution. Yu et al. [33] calculated the cost per net power to evaluate the economic performance of water-EGS and $CO_2$-EGS, and the results indicated that $CO_2$-EGS leads to a lower cost per net power compared to water. Gao et al. [34] estimated the Payback Period of $CO_2$-EGS during the system lifetime. The results presented that the Payback Period shows a rapid downward trend with the increasing mass flow rate. Erdeweghe et al. [35] generated a Net Present Value (NPV) objective function to study the feasibility of a low-temperature geothermal power plant, and the sensitivity analysis results showed that external and internal economic conditions affect NPV differently. Daniilidis et al. [36] highlighted that an effective flow rate is the most important parameter for the energy costs of a deep geothermal system based on the NPV.

To the best of our knowledge, the limitations of the existing technological and economical EGS evaluation methods can be summarized from three aspects, which remain an incomplete understanding for operators. Firstly, using mixed $CO_2$ and water as a heat transmission fluid for an EGS was rarely investigated in pioneered studies, and there is no thorough perception underlying the economic effectiveness of an EGS under the mixture working fluid containing $CO_2$ and water simultaneously. Secondly, no sufficient evidence comprehended the impacts of different well configurations for EGS projects from the economic perspective. Thirdly, a consistent technical and economic performance comparison between different flow schemes needs to be established considering both energy extraction and $CO_2$ storage so that solid technological decision-making strategies can be provided to the operators at the commercial scale. Lastly, there is no economic and environmentally beneficial interpretation of $CO_2$ utilization in an EGS given carbon credit policy. Given the environmental benefits of $CO_2$ utilization and the potential for reducing greenhouse gas emissions, it is crucial to consider carbon credit policy in economic assessments.

In this study, an operational approach incorporating a mixture of $CO_2$ and water as the working fluid associated with the engineering and economic feasibility studies is proposed for the first time. Subsequently, a techno-economic assessment to comprehensively evaluate an EGS under various operational strategies is carried out. The Qiabuqia geothermal field is adapted as a study case. Three flow schemes (i.e., $CO_2$ injection, mixed $CO_2$ and water injection, and water injection) and two well configurations (i.e., a vertical well and a horizontal well) are contemplated in addressing the technical and economic feasibilities considering the impact of a carbon credit policy to provide a more deeply understanding from the $CO_2$ sequestration standpoint. Additionally, six technical parameters, including well spacing, injection flow pressure, injection fluid temperature, production flow pressure, fracture conductivity and a $CO_2$ ratio of the injected fluid, and four economic constraints, containing an electricity market price, $CO_2$ purchase price, water purchase price and carbon credit rate, are investigated for their economic influences by performing sensitivity analyses. From this research, not only has the economic feasibility of a novel EGS working scheme been proved but also a comprehensive evaluation framework for an EGS has been formularized so that a consistent comparison can be drawn both technically and economically. Hence, practical guidance can be suggested to the EGS operators in their decision-making process.

The rest of this study is structured as follows: Section 2 describes the geological background of the Qiabuqia geothermal field and the brief methodology involved in this study. Section 3 introduces the basic reservoir properties and operational parameters of numerical models and the settings of six scenarios. Section 4 clarifies the compositions of the economic model. Section 5 discusses the results for six scenarios and the impacts of different technical and economic parameters. Finally, Section 6 summarizes the key findings of this study.

## 2. Methodology

In this study, for the purpose of investigating the technological and economic feasibility of an EGS, the Qiabuqia geothermal field is considered as the case study where different operational schemes are studied by deploying the numerical approach with the reservoir properties from this field. Previous studies have detailed the characteristics of the Qiabuqia field, which have been widely used as a promising case for EGS numerical studies [3,9,23,25,33–37].

Qiabuqia geothermal field is in the eastern part of the Gonghe basin, Northwest China. The location of this field and the main HDR borehole are present in Fig. 1. This field has abundant HDR resources that are equivalent to approximately 200 billion tons of standard coal. Presently, geological exploration has been completed, which concludes that the HDR resource is abundant at the depth of 3200 ~ 3700 m and the geothermal gradient is about 7.1 °C/100 m in granite strata [37]. Based on the drilled exploration wells, the most successful geothermal drilling is the well GR1 (3705 m) since its bottom-hole temperature stabilized at 236 °*C* after continuous monitoring, illustrating a stable and sufficient heat supply in this area [26]. According to the drilling cores from well GR1, natural fractures are abundantly distributed in the HDR section with an approximately 10 m fracture spacing, which can benefit the formation of heat exchange paths during reservoir stimulation [26]. Considering the promising potential of the Qiabuqia field for establishing a long-term EGS power generation system, this study investigates the feasibility of an EGS development in this field.

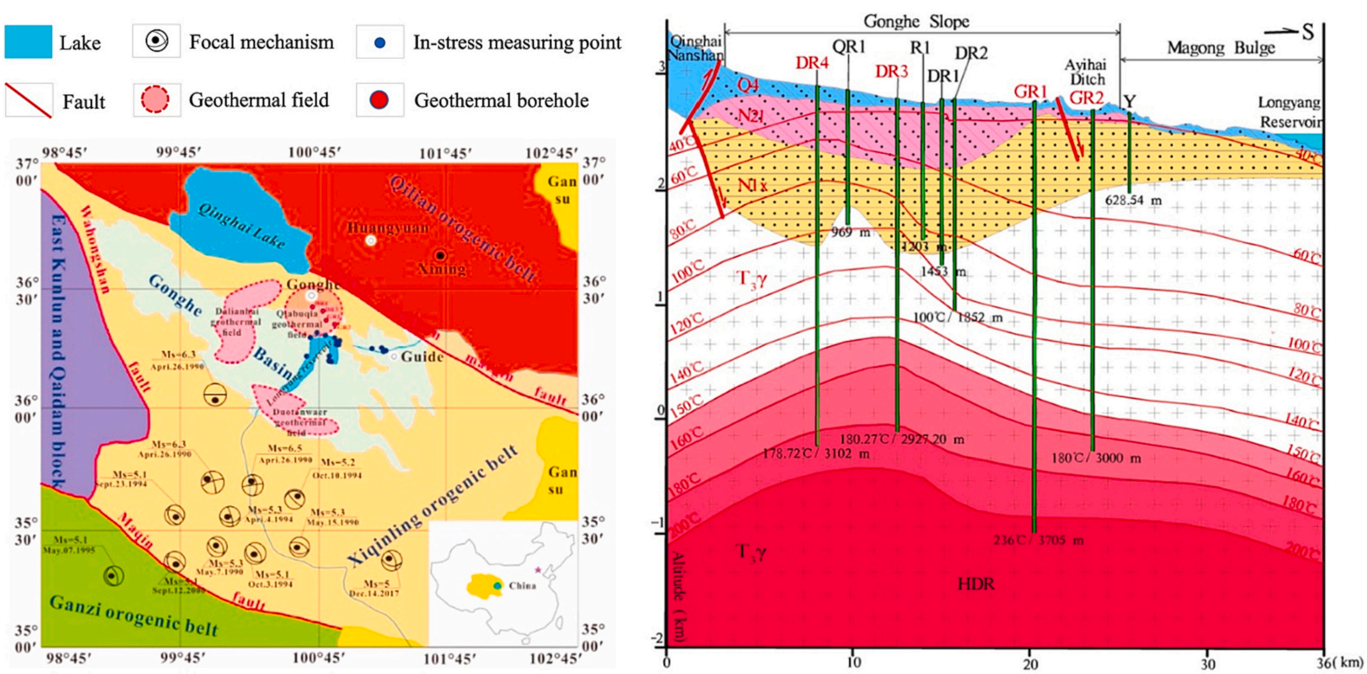
Firstly, technical models are constructed by using CMG STARS software to investigate the heat mining and $CO_2$ storage performance of the Qiabuqia geothermal field under different working schemes, including a $CO_2$-based vertical-well-EGS, a $CO_2$-based horizontal-well-EGS, a mixed $CO_2$-water based vertical-well-EGS, a mixed $CO_2$-water based horizontal-well-EGS, a water-based vertical-well-EGS, and a water-based horizontal-well-EGS. Secondly, NPV is adopted as the objective function to evaluate the economic performance of proposed scenarios. The capital expenditure (CAPEX), operation expenditure (OPEX), and the revenue and tax of each scenario are calculated based on the operation strategy and corresponding in-depth geothermal performance. Finally, sensitivity analysis is utilized to determine the impacts of different uncertainties on economic performance. Six technical parameters and four external factors are taken into account in this part. The flow chart of this study is shown in Fig. 2.

## 3. Technical models

The technical models are used to investigate geothermal energy production and $CO_2$ storage capacity of the Qiabuqia field. In this study, the CMG STARS software is adopted to create numerical models and simulate the heat extraction process, which is a well-acceptable numerical simulator to solve a nonlinear system for multi-dimensional fluid flow analysis and heat transfers in multi-phase, multi-component fluids in porous and fractures media [44].

### 3.1. Computational models

Technical models in this study are created based on our previous Qiabuqia EGS model, which has been evaluated [40,41]. To investigate the potential heat mining and $CO_2$ storage in this field, the research domain in this study focuses on the HDR section (3200 ~ 3700 m). The base model is simplified to describe the area of 2000 × 1000 × 3800 $m^3$ with a total of 36,480 grid blocks. The reservoir is assumed to be saturated with pure water since the formation with a pore water elimination




(a) (b)

**Fig. 1.** Location of the Qiabuqia field (a) and the formation based on drilling data [9,26,38,42,43].

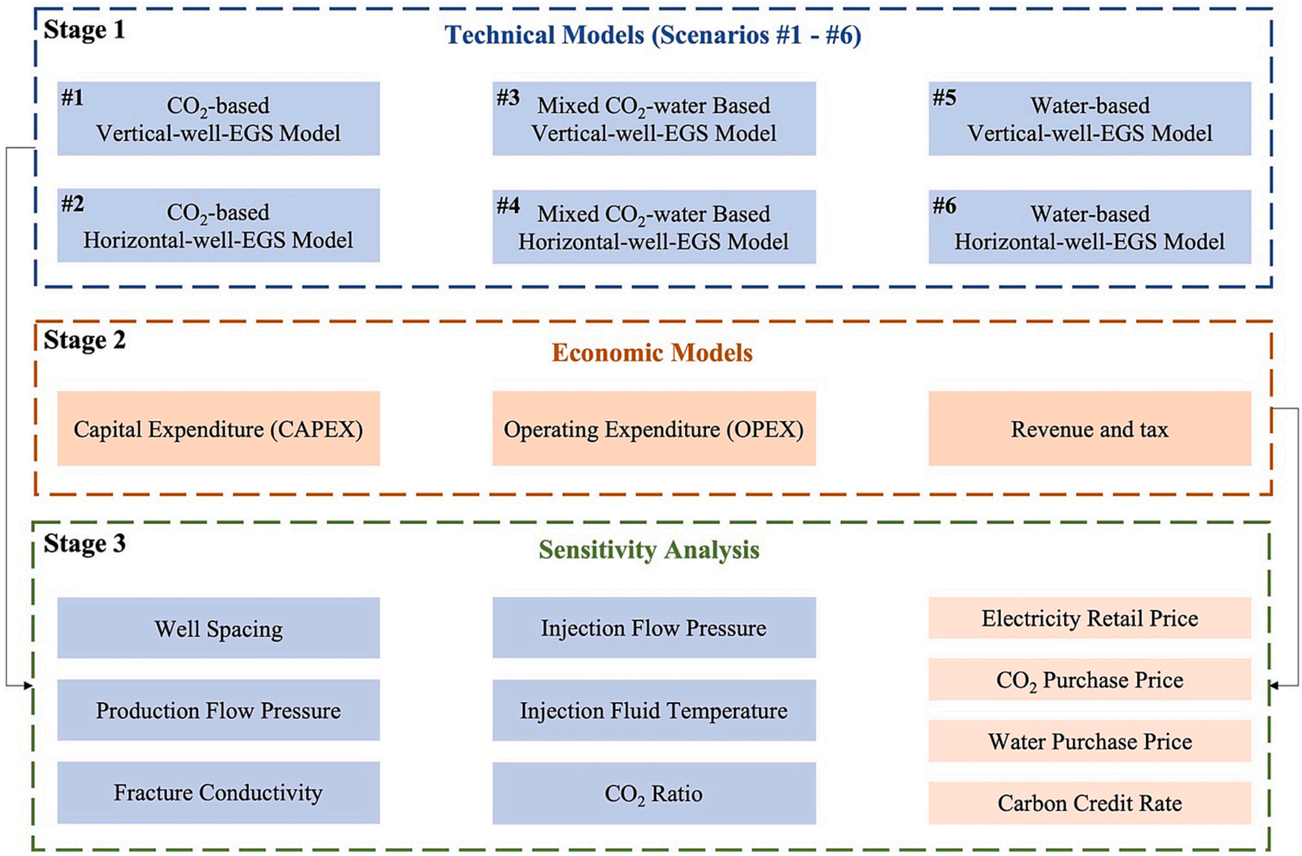



**Fig. 2.** Diagram of the flow chart in this study.

or a low-salinity water injection before $CO_2$ injection can reduce the formation damage caused by salt precipitation [18–20]. The reservoir properties of this model are shown in Table 1.

To explore the effect of well configuration, a vertical-well-EGS model and a horizontal-well-EGS model are developed separately. For the purpose of exploiting geothermal energy from HDR to the maximum extent, both vertical wells and horizontal wells are drilled at a depth of 3700 m. Due to the promising geothermal properties that have been obtained from the exploration well GR1, this well is assumed as the injection well (GR1). Two production wells (PR1 and PR2) are generated on both sides of the well GR1. In this study, a well spacing of 500 m for both vertical-well-EGS and horizontal-well-EGS models is set as a base case. The horizontal section length is assumed to be 500 m in the horizontal well system. The longitudinal section of the base numerical model and corresponding well configuration designs are shown in Fig. 3.

For an EGS, it is necessary to develop a high-conductive area for fluid flow and heat transfer. According to the previous study, hydraulic fractures with a half-length from 250 to 670 m, a height of 100 m and a conductivity of approximately 10 mDm can be effectively created by injecting different amounts of slickwater in the Qiabuqia granite formation [9,25,39,40]. Due to the low porosity and permeability of the Qiabuqia granite formation, the injected fluid is hard to flow in the reservoir without a high-conductive area. Therefore, the half-length of hydraulic fractures is assumed to be equal to the well spacing in this study between injection and production pairs. The well spacing is set to be from 400 to 600 m, meaning the hydraulic fractures with the corresponding half-length developed in this study can be reasonably created. In vertical-well-EGS, five fractures are created in the enhanced reservoir (3200 $\sim$ 3700 m) for the purpose of extracting geothermal energy from the HDR area at maximum. In horizontal-well-EGS, the enhanced reservoir is 3600 $\sim$ 3700 m in depth, and the fracture spacing is set to be 50 m according to the previous fracturing study on the Qiabuqia granite formation [9,26,40]. The grids of the enhanced reservoir are refined five times in the horizontal directions and three times in the vertical directions for an accurate calculation.

**Table 1**
Reservoir and operational properties [9,26,40].

| Parameter | Value |
|---|---|
| Granite density ($kg/m^3$) | 2623 |
| Original porosity (%) | 2.49 |
| Original permeability (md) | 0.26 |
| Granite heat conductivity (W/(m•°C)) | 3.0 |
| Granite specific heat (J/(kg•°C)) | 980 |
| Horizontal natural fracture spacing (m) | 10 |
| Vertical natural fracture spacing (m) | 10 |

### 3.2. Initial and boundary conditions

For boundary conditions, fluid flow is not allowed at both top and bottom boundaries. The temperature at the bottom of the model is set according to the temperature distribution of this field. At the top boundary, the heat loss model is used to govern heat losses from the top surface to the atmosphere. For initial conditions, the temperature and pressure distributions are assumed based on the logging data from well GR1, where the reservoir temperature and pressure are distributed based on the equations $T = 25 - 0.057z\ (^{\circ}C)$ and $p = 1.01 \times 10^5 - 10000z\ (Pa)$ respectively, where $z$ represents the depth [9,26,40].

### 3.3. Operating parameters

Water and $CO_2$ are employed as heat transmission fluids for geothermal energy extraction. Three flow strategies are developed in this study, including a pure $CO_2$ injection, a mixed $CO_2$-water injection

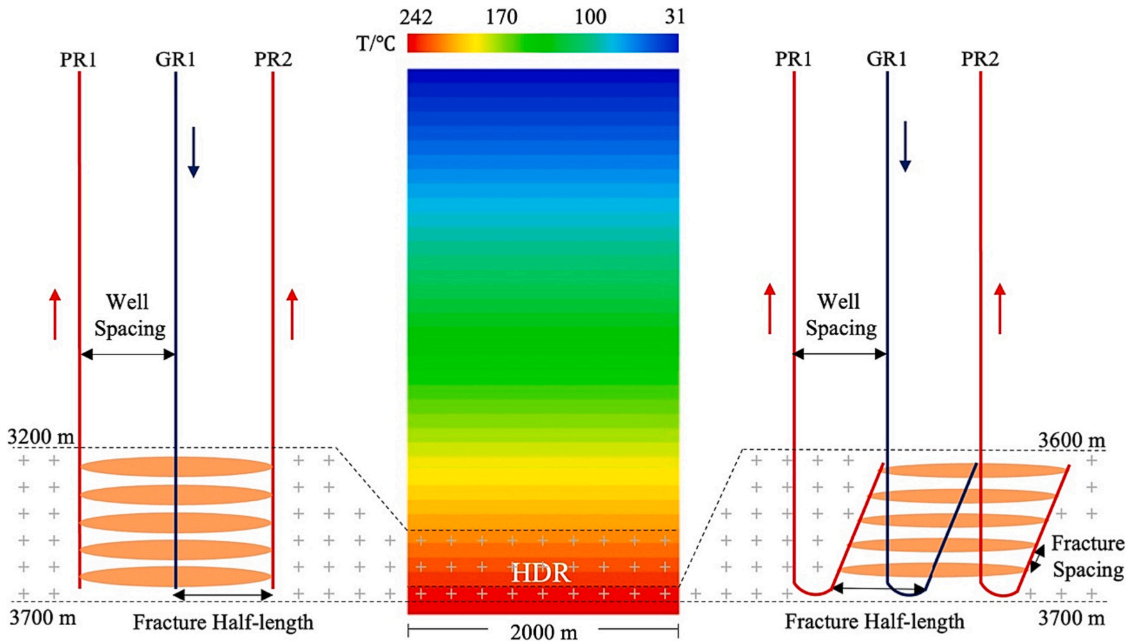



**Fig. 3.** Longitudinal section of the base numerical model and various well configurations.

and a pure water injection. Due to the high variance of injectivity between $CO_2$ and water, the working fluid is assumed to be injected into the reservoir at a fixed injection flow pressure and produced at a fixed production flow pressure to effectively compare the technical performance of different flow schemes. Considering the field operation constraint, the injection flow pressure should not exceed the minimum principal stress in the formation (60 MPa) to prevent slippage from occurring [45]. By jointly considering the minimum principle stress and initial reservoir pressure, the injection pressure is assumed to be 50 MPa, and the production pressure is set to be 35 MPa in base cases. For the mixed $CO_2$-water EGS models, the $CO_2$ ratio is set to be 10%wt in base scenarios, which means the mass of injected $CO_2$ is 10% of the total injected fluid [46]. The geothermal productivity and $CO_2$ storage capacity are calculated after a twenty-year operating cycle.

In summary, six scenarios are developed (Table 2): scenario #1: $CO_2$-based vertical-well-EGS; scenario #2: $CO_2$-based horizontal-well-EGS; scenario #3: mixed $CO_2$-water based vertical-well-EGS; scenario #4: mixed $CO_2$-water based horizontal-well-EGS; scenario #5: water-based vertical-well-EGS and scenario #6: water-based horizontal-well-EGS.

## 4. Economical model

In this study, the economic evaluation of the Qiabuqia EGS project includes the capital expenditure, operating expenditure, revenue of generated geothermal electricity, tax cost and potential $CO_2$ credit. Subsequently, the net present value (NPV) is calculated to assess economic performance.

### 4.1. Capital expenditure (CAPEX)

For an EGS project, CAPEX can be divided into surface facilities costs and subsurface costs (i.e., drilling and reservoir stimulation). The finance of surface facilities cost increases with the installed power capacity ($\dot{W}$) but the unit cost is inversely proportional to the capacity, where a unit cost decreases from 2000 $/kW for a 5 MW plant to 1000 $/kW for a 150 MW plant [47]. The drilling cost varies for different well types. The drilling price per meter for a vertical well is estimated at $600/m and that for a horizontal well is set at $1500/m [26]. The investment in reservoir stimulation is affected by the well configuration, which can be estimated to be 30% of the drilling cost [27]. A near-ideal hypothetical situation for $CO_2$ pipeline construction is assumed in this study (scenarios #1 - #4), where a field-scale $CO_2$ resource can be directly utilized. Therefore, the CAPEX of the Qiabuqia EGS project can be calculated by Eq. (1):

$$CAPEX = C_{surface} + C_{drilling} + C_{stimulation} \tag{1}$$

$$Subject\ to: \left\{ \begin{array}{c} C_{surface} = 2000 \bullet exp\left( -0.045 \bullet \left( \dot{W} - 5 \right) \right) \bullet \dot{W} \\ C_{drilling} = (600H_v + 1500H_h) \times 10^{-6} \\ C_{stimulation} = 0.3 \bullet C_{drilling}. \end{array} \right.$$

where *CAPEX* is the capital expenditure of the project; $C_{surface}$ is the cost of surface facilities; $C_{drilling}$ is the drilling cost; $C_{stimulation}$ is the investment on reservoir stimulation; $\dot{W}$ is the installed power capacity; $H_v$ and $H_h$ are the lengths of the vertical well and horizontal well.

### 4.2. Operating expenditure (OPEX)

The OPEX of an EGS project includes the operation and maintenance (O&M) costs and fluid purchase costs. The annual O&M cost is proportional to the geothermal power generation and the unit O&M cost also shows an exponential decline with extracted geothermal electricity increases [47]. It has been estimated that a unit facility O&M cost decreases from 20 $/MWh for a 5 MW plant to 14 $/MWh for a 150 MW plant [28]. Based on the published data on fluid price for energy extraction projects, the water make-up cost is estimated to be 0.66 $/ton

**Table 2**
Summary of base scenarios.

| | Scenario #1 | Scenario #2 | Scenario #3 | Scenario #4 | Scenario #5 | Scenario #6 |
|---|---|---|---|---|---|---|
| Well type | Vertical well | Horizontal well | Vertical well | Horizontal well | Vertical well | Horizontal well |
| Injection fluid | $CO_2$ | $CO_2$ | Mixed $CO_2$-water | Mixed $CO_2$-water | Water | Water |

as a base price [48,49], and the $CO_2$ purchase cost is assumed to be 22.7 $/tonne in base scenarios [50–52]. Therefore, the OPEX for the development of Qiabuqia EGS can be expressed by Eq. (2):

$$OPEX = C_{O\&M} + C_{fluid\_purchase} \tag{2}$$

$$Subject\ to: C_{O\&M} = 20 \bullet exp\left(-0.0025 \bullet \left(\dot{W} - 5\right)\right) \bullet \dot{W}$$

where $OPEX$ is the operating expenditure of the project; $C_{O\&M}$ is the cost of operation and maintenance (O&M); and $C_{fluid\_purchase}$ represents the cost of fluid purchase.

### 4.3. Revenue and tax

The revenue of an EGS project is fundamentally dependent on the installed power capacity and potential carbon pricing. Based on the total installed geothermal electricity ($W$), the electricity market price is adopted to predict the revenue from selling geothermal electricity in this study. The electricity market price is a yearly dynamic factor or even a monthly-changed parameter, which is influenced by fuel costs, government regulations, market structure, natural disasters and economic factors [53–55]. For example, the electricity market price ranged from 0.075 $/kWh to 0.118 $/kWh during the period from 2017 to 2022 [56]. Regarding the current price, 0.093 $/kWh is set as a benchmark electricity market price.

The tax and royalty payments for an EGS project mainly vary depending on the location and the size of the project, as well as the local regulations. Based on the available data in previous studies [57–62], 15% of obtained revenue from EGS development is determined as the total related tax and royalty payments in this study. Consequently, the revenue and tax can be expressed by Eqs. (3) and (4):

$$C_{revenue} = W \bullet P_{electricity} \tag{3}$$

$$C_{tax} = 0.15 \bullet C_{revenue} \tag{4}$$

where $C_{revenue}$ is the revenue obtained from selling generated electricity; $W$ is the cumulative geothermal electricity generation; and $C_{tax}$ is the tax and royalty payments for the project.

### 4.4. Carbon policy

Carbon pricing is an instrument to measure external costs associated with GHG emissions through a price on $CO_2$ emissions to prevent climate change and achieve the carbon-neutral goal. Some environmental regulations, such as carbon tax and carbon credit policies, have been established to guide enterprises to green exploitation based on low-carbon technologies [63]. The carbon tax is a form of a pollution tax on $CO_2$ emissions. The carbon credit is a tradable certificate that represents the right to emit a set amount of $CO_2$ [64]. Under the carbon credit policy, corporations can resell carbon credits on the corresponding carbon market when the amount of $CO_2$ emission is less than their limit [65,66]. The United States also issued a policy called Credit for Carbon Dioxide Sequestration (Internal Revenue Code (IRC) Section 45Q) to incentivize investments in renewable resources development and innovations in low-carbon technologies [67,68]. The tax credit is provided for $CO_2$ storage in IRC 45Q, and based on the 2022 changes to 45Q, the tax credit was increased to $60 per tonne of $CO_2$ stored for the projects that are associated with GHG emissions, such as enhanced oil recovery and other industrial uses of $CO_2$ [69]. In terms of promoting the investment and development of the EGS, the tax credit policy is applied to calculate carbon credits in this study. Due to there being no well-developed carbon credit policy in China, by considering the carbon price in the world, this study adjusted the carbon credit policy with $60 per tonne of $CO_2$ stored.

### 4.5. NPV model

Cooperated with the established cost models of each component, including the CAPEX, OPEX, revenue and tax, an NPV model is conducted as Eq. (5). The escalation rate is assumed to be 0% per year. The discount rate is mainly used in a range of 8% to 12% and is mostly estimated to be 10% in energy extraction projects [51,70]. Therefore, the discount rate of 10% per year is adapted to discount the future cash flow into the present monetary value. The summary of input parameter values of base scenarios is summarized in Table 3.

$$NPV = -CAPEX + \sum_{t-1}^{T} \left(C_{revenue} - OPEX - C_{tax} + C_{credit}\right) \Big/ \left(1 + r_d\right)^t \tag{5}$$

where $NPV$ is the Net Present Value of the project; $r_d$ is the discount rate; and $t$ is the operation time of the project.

## 5. Results and discussions

### 5.1. Technic assessments

Figs. 4 and 5 demonstrate the generated geothermal power and production temperature of six scenarios, and Fig. 6 shows corresponding production mass flow rates. The generated geothermal power can be ranked by: scenario #1 > scenario #2 > scenario #6 > scenario #4 > scenario #5 > scenario #3. Compared with different flow schemes, scenarios #1 and #2 produce the most geothermal power due to their significantly higher production mass flow rates (Fig. 6). It can be explained by that $CO_2$ has better injectivity than water and mixed $CO_2$-water stream. Therefore, a larger amount of $CO_2$ can be injected into the reservoir and faster flow to the production wells. Accordingly, the production temperature of scenarios #1 and #2 encounter the largest drop and the thermal breakthrough occurs (Fig. 5). Under the same well configuration, water-EGSs provide a higher geothermal power production than mixed $CO_2$-water EGSs (scenario #5 > scenario #3; scenario #6 > scenario #4). This is because a slightly higher production mass flow rate in water flow cases contributes more produced water for geothermal energy extraction.

In contrast to different well configurations, horizontal well systems show better geothermal energy extraction performance than vertical well systems (scenario #4 > scenario #3; scenario #6 > scenario #5), which can be concluded by reservoir temperature and mass flow rate. Although the drilled depths of vertical wells and horizontal wells are the same (3700 m), the research area of vertical well systems is a vertical

**Table 3**
Summary of input parameters values.

| Input parameter | Base value | Lower value | Upper value |
|---|---|---|---|
| TECHNICAL FACTORS | | | |
| Injection well number | 1 | N.A | N.A |
| Production well numer | 2 | N.A | N.A |
| Well depth (m) | 3700 | N.A | N.A |
| Well spacing (m) | 500 | 400 | 600 |
| Fracture conductivity (mDm) | 10 | 8 | 12 |
| Injection fluid temperature (°C) | 60 | 48 | 72 |
| $CO_2$ ratio (%wt) | 10 | 8 | 12 |
| Injection flow pressure (MPa) | 50 | 40 | 60 |
| Production flow pressure (MPa) | 35 | 28 | 42 |
| ECONOMIC FACTORS | | | |
| Electricity market price ($/kWh) | 0.093 | 0.074 | 0.112 |
| Water purchase cost ($/ton) | 0.66 | 0.53 | 0.80 |
| $CO_2$ purchase cost ($/ton) | 22.7 | 18.1 | 27.2 |
| Carbon credit rate ($/ton) | 60 | 48 | 72 |
| Tax rate (%) | 15 | N.A | N.A |
| Operation time (years) | 20 | N.A | N.A |

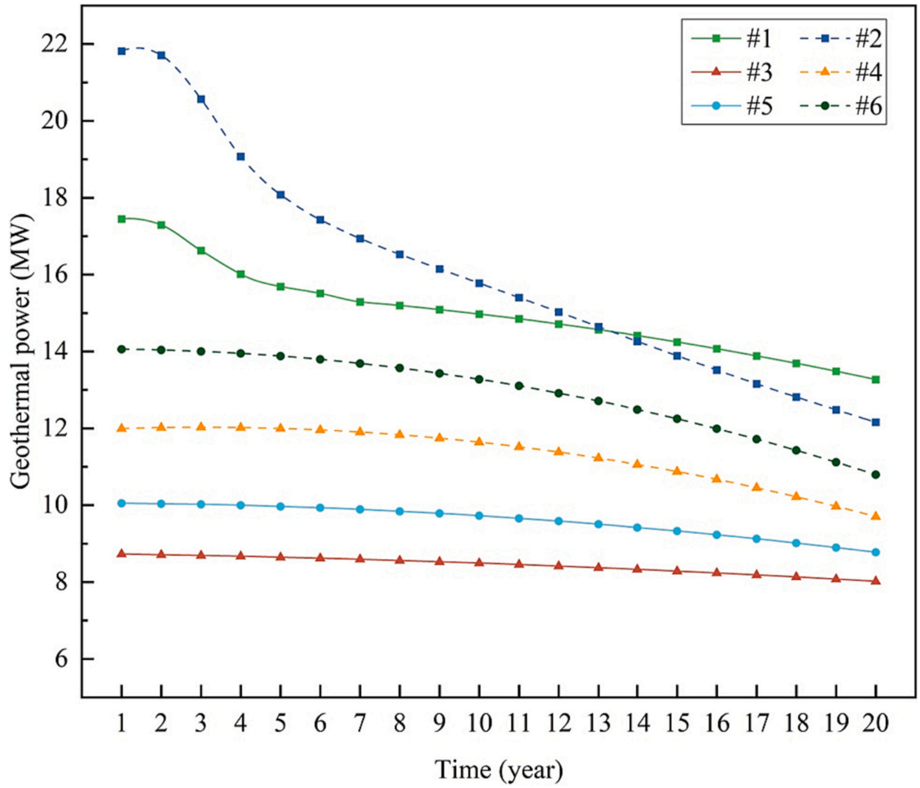



**Fig. 4.** Generated geothermal power of base scenarios.

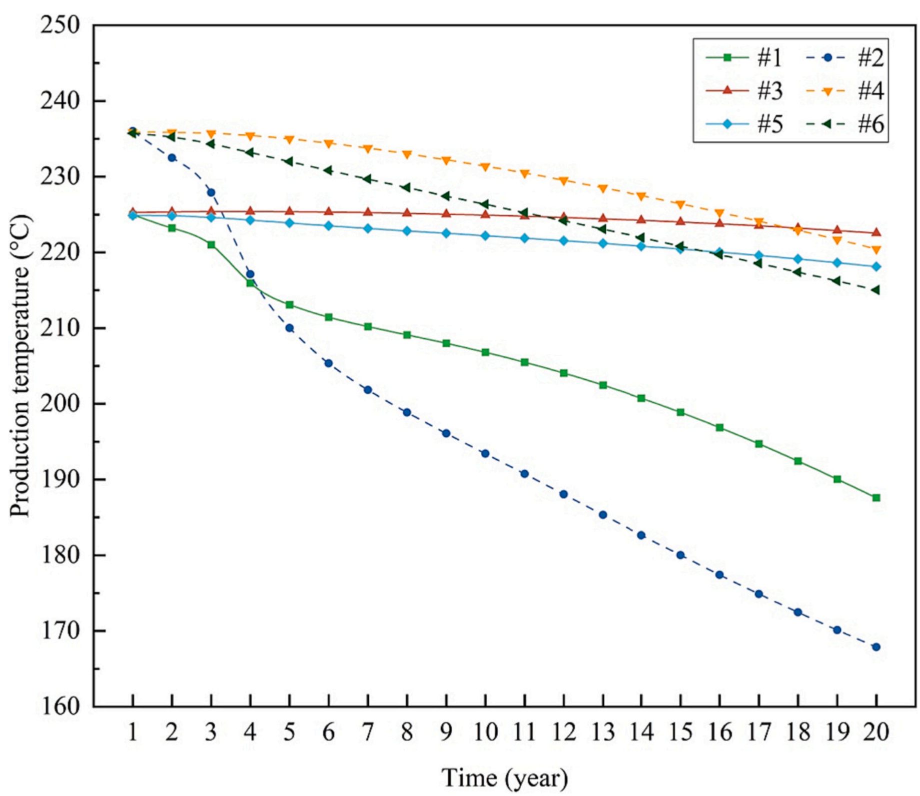



**Fig. 5.** Production temperature of base scenarios.

section from 3200 m to 3700 m and that of horizontal well systems is a horizontal section at 3700 m. Therefore, horizontal well systems have a higher temperature in the research area, resulting in more heat energy being extracted. Additionally, the higher production mass flow rates in horizontal well systems contribute to more geothermal power generation (Fig. 6). However, this phenomenon in $CO_2$-EGSs is reversed

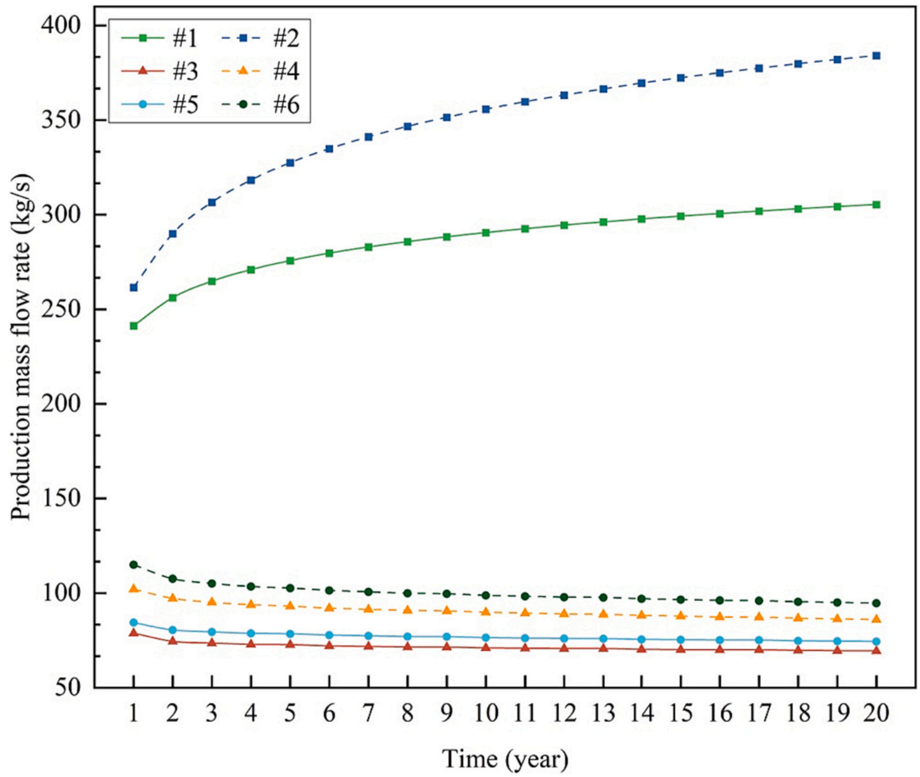



**Fig. 6.** Production mass flow rate of base scenarios.

(scenario #2 < scenario #1) because of the serious thermal breakthrough caused by the extremely high production flow rate in scenario #1.

Fig. 7 presents the $CO_2$ sequestration results for the EGS scenarios which are considered as the partial paybacks of $CO_2$ utilization. Compared to mixed $CO_2$-water EGSs (scenarios #3 and #4), $CO_2$-EGSs (scenarios #1 and #2) present larger $CO_2$ storage capacity though their production flow rates are extremely higher. The reason is that larger

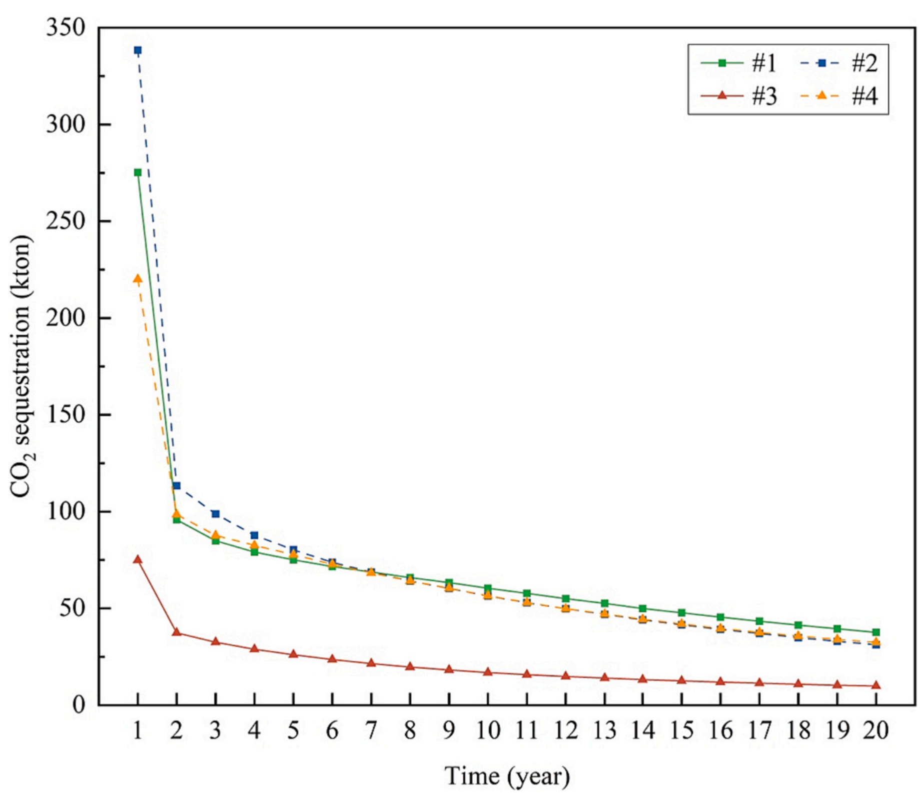



**Fig. 7.** $CO_2$ sequestration per year of EGSs under $CO_2$ utilization.

volumetric $CO_2$ is injected accordingly due to the better injectivity of $CO_2$. However, the injected $CO_2$ is preferentially produced through the fracture network at a higher rate as the injectivity increases. Therefore, horizontal-well systems exhibit a larger downward trend in $CO_2$ storage capacity than vertical-well systems. Especially in $CO_2$-EGSs, scenario #2 shows a larger $CO_2$ storage capacity than scenario #1 in the initial phase but less $CO_2$ can be stored after a seven-year operation.

In conclusion, benefiting from higher production flow rates, $CO_2$-EGSs can bring more geothermal production than water-EGSs and mixed $CO_2$-water EGSs. Similarly, under the same flow scheme, the generated geothermal power of horizontal well systems is higher than that of vertical well systems. However, an extremely high production rate also causes a serious thermal breakthrough in $CO_2$-EGSs, which is undesirable for long-term and sustainable geothermal energy development. On the other hand, the expensive $CO_2$ purchase price and the higher drilling cost of a horizontal well may bring a difference in economic performance. Additionally, the cases with more installed geothermal capacity are accompanied by higher investments in surface facilities and O&M. Importantly, various $CO_2$ sequestration capacities also increase the diversity of economic benefits. Therefore, it is necessary to investigate their economic performance to provide a reference for the operators, which is discussed in the next section.

### 5.2. Economic assessments

NPV is determined as the key indicator for assessing the financial viability of an EGS project. A positive NPV at the conclusion of the operational phase indicates that the EGS initiative is a profitable venture. Otherwise, the income generated from the geothermal energy extracted and potential $CO_2$ credit is insufficient to compensate for the expenses incurred in the development phase.

Fig. 8 shows the NPV of base scenarios, which can be ranked by: scenario #4 > scenario #6 > scenario #3 > scenario #5 > scenario #1 > scenario #2. All NPV curves show a similar trend, where the NPV is negative in the early period because the EGS project is capital-intensive and requires a high initial investment. Especially, the initial NPV of $CO_2$-EGSs (scenarios #1 and #2) are extremely lower than other scenarios due to the high investment in purchasing $CO_2$. Following, the NPV increases gradually with the revenues from selling geothermal electricity and earning carbon credit. However, it should be noted that $CO_2$-EGSs start to profit from the second year since the incomes in the first year still cannot cover the cost of $CO_2$ consumption. When the original cash investment is covered, the project starts to be profitable and the payback period can be determined. From the results, scenario #4 shows the lowest payback period (4 years). Scenarios #3, #6 and #5 have similar payback periods, which are 7 years, 8 years and 9 years respectively. Adversely, scenarios #1 and #2 are not profitable during this operation period. Although NPV increases with the development processing, all the curves present a slowing growth trend in speed since the geothermal energy output gradually decreases and the annual revenue presents a corresponding decrease tendency. A similar phenomenon can also be found in the annual $CO_2$ credit where $CO_2$ storage retention shows a declining trend and maintains a steady point as the development processes. Therefore, All scenarios exhibit a trend of reaching a bottleneck in terms of economic profit. At this point, the operators should contemplate suspending the project to allow the injected fluid to fully absorb heat energy before restarting the project.

Fig. 9 presents the results of NPV breakdowns. The profit from selling generated geothermal electricity mainly contributes to the revenue. In addition, $CO_2$ sequestration can enable a higher income by applying the carbon credit policy. However, more extracted geothermal energy and $CO_2$ storage retention also cause higher investments in CAPEX and OPEX, especially in purchasing $CO_2$. Consequently, $CO_2$-EGSs (scenarios #1 and #2) cannot be paid back until the end of the operation period although their received economic benefits are the highest. In contrast, mixed $CO_2$-water EGSs (scenarios #3 and #4) and water-EGSs (scenarios #5 and #6) are all profitable projects. Although the incomes of these cases are lower than $CO_2$-EGSs, corresponding substantial disparities in CAPEX and OPEX can be observed, especially in considerable cost savings on $CO_2$ purchases. In mixed $CO_2$-water EGSs, less

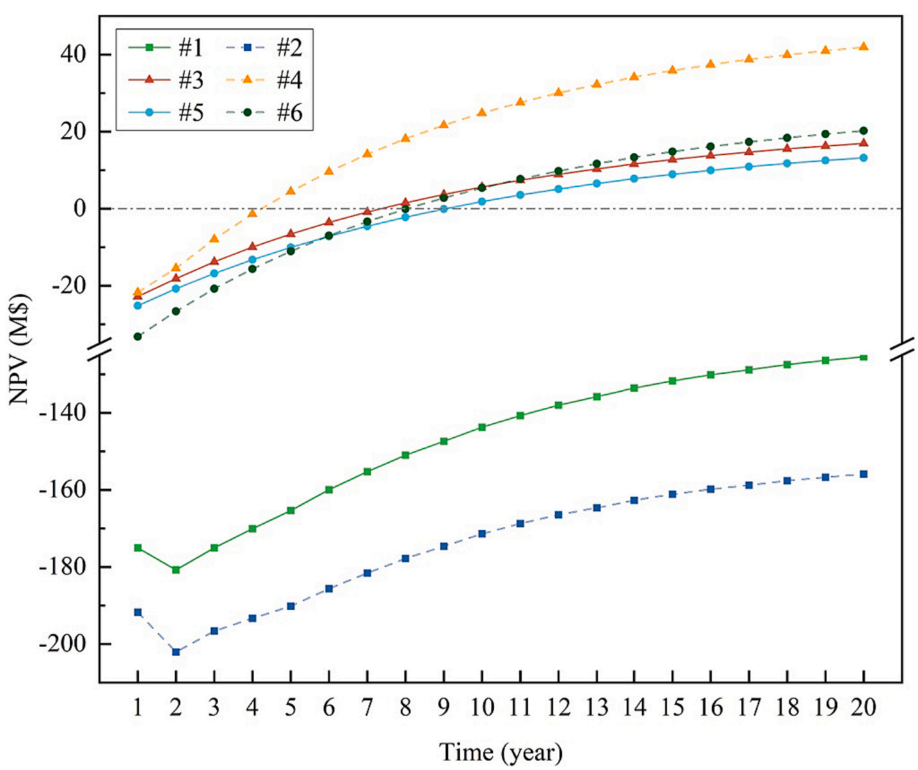



**Fig. 8.** Net present values of base scenarios.

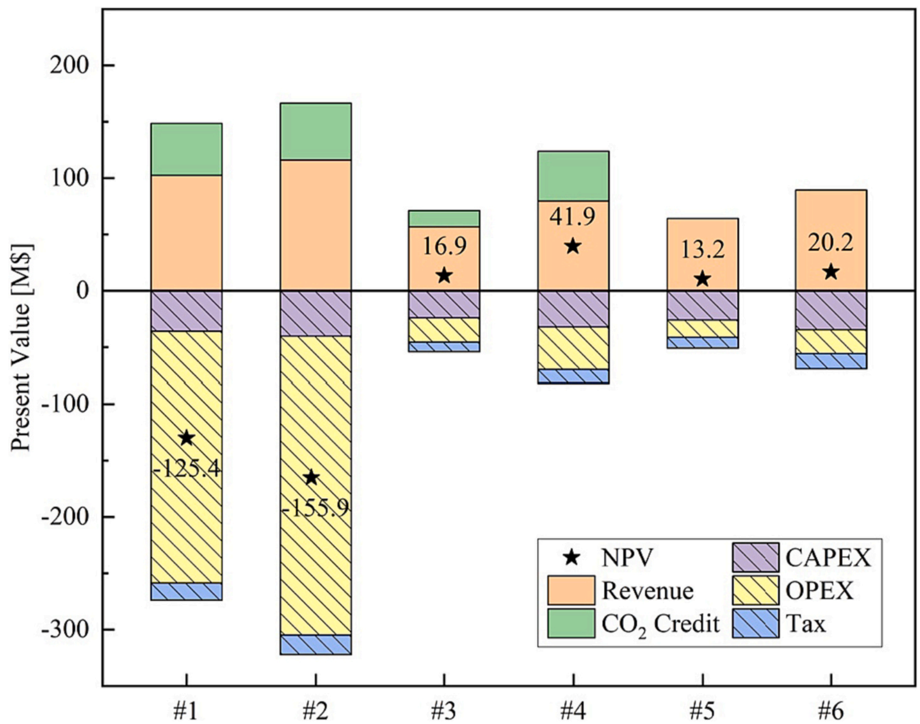



**Fig. 9.** NPV breakdowns of base scenarios.

geothermal power extraction leads to lower revenues than water-EGSs. However, their additional $CO_2$ credits bring more income in total. In relation to different well configurations, higher geothermal power production and more stored $CO_2$ induce that the horizontal-well systems of mixed $CO_2$-water EGSs and water-EGSs show a higher final NPV than corresponding vertical-well systems (scenario #4 > scenario #3, scenario #6 > scenario #5). However, it shows inversely in $CO_2$-EGSs (scenario #2 < scenario #1) since the increment in revenues is lower than that in expense.

The EGS project is primarily reliant on the generation of geothermal energy as it is the main source of income. Therefore, the electricity market price is a significant external parameter that impacts investment

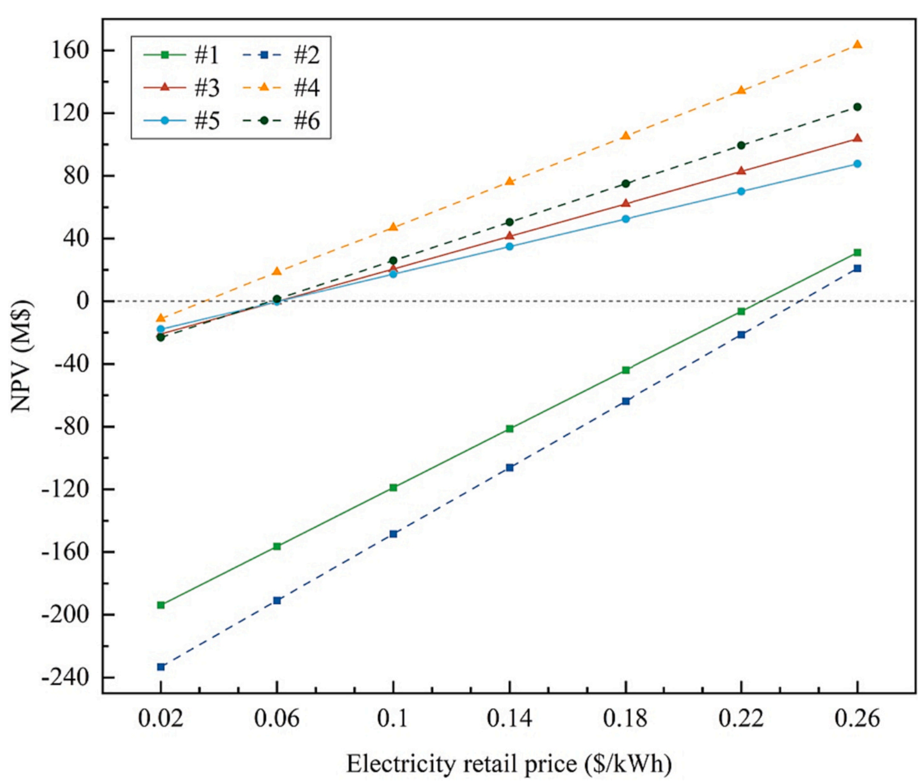



**Fig. 10.** Relationship between NPV and electricity market price.

decisions. For the operators, the breakeven price is important to evaluate the economic gains. In cases where the electricity market price exceeds the breakeven price, the project generates profits, otherwise, the project fails to deliver desirable economic efficiency. From the relationships between NPV and electricity market price (Fig. 10), the lowest breakeven electricity market price can be observed in scenario #4 (0.036 \$/kWh), while scenario #2 brings the highest breakeven price of 0.241 \$/kWh. The summary of economic assessments in these scenarios is shown in Table 4.

Consequently, mixed $CO_2$-water based horizontal-well-EGS is highly recommended if the carbon credit policy is applicable. Otherwise, the water is a more economical heat transmission fluid. Although the $CO_2$-EGSs can bring more profits, their high $CO_2$ consumption causes a large cost in OPEX and results in a negative NPV eventually. The amount of $CO_2$ injection should be a critical factor in balancing the income and expense for $CO_2$-EGSs.

### 5.3. Sensitivity analysis

In this section, the results from the sensitivity analysis have been outlined. For each parameter, ±20% boundaries have been compared with the base NPV across each scenario. The tornado charts are plotted to indicate the contributions of individual factors to the NPV. The ranking in tornado charts provides a valuable reference for investors to enhance efficiency in making investment decisions.

Fig. 11 is the sensitivity analysis results of $CO_2$-EGSs (scenarios #1 and #2). From the results, injection flow pressure and production flow pressure are the two most significant factors. A lower injection flow pressure or a higher production flow pressure results in a higher NPV. In addition, fracture conductivity also causes 15% of the NPV variation, where a lower fracture conductivity brings more profits. Summarily, these factors mainly control the $CO_2$ injection amount and flow rate, and the results demonstrate that less $CO_2$ injection and a lower flow rate are more beneficial for $CO_2$-EGSs. Subsequently, the factor that directly affects expenditures ($CO_2$ purchase price) contributes to around 30% of the NPV variation, while the properties that directly influence revenue (electricity market price and carbon credit rate) only explain less than 10% of the variation in NPV. It illustrates that the investment in $CO_2$ purchase dominates the economic results of $CO_2$-EGSs. In different well spacing, the changes in the variance between injection and production flow rates are limited under a fixed production pressure difference. Therefore, well spacing only accounts for approximately 10% of the NPV variation. Injection fluid temperature shows the lowest impact on the NPV since this parameter only affects the geothermal energy recovery performance.

Fig. 12 shows the tornado charts of mixed $CO_2$-water EGSs (scenarios #3 and #4). In the results, electricity market price affects the NPV the most and its influence is greatly higher than other economic factors, which means selling electricity dominates the profits. In addition, the parameters that influence the amount of fluid injection and flow rate (i.e., injection flow pressure, production flow pressure and fracture conductivity) are also ranked at the top. However, more injected fluid and a higher fluid flow rate account for a higher NPV in mixed $CO_2$-water EGSs, which is opposite to those in $CO_2$-EGSs. The $CO_2$ ratio of the injected fluid is another important parameter. When the fluid with a smaller $CO_2$ ratio is injected into the reservoir, a lower NPV is observed since less $CO_2$ can be stored and less geothermal energy can be extracted due to the lower fluid flow rate. On the contrary, a higher $CO_2$ ratio brings a higher economic benefit, while the corresponding higher $CO_2$ consumption cost also leads to a lower NPV. Similar to the $CO_2$-EGS scenarios, injection fluid temperature and well spacing demonstrate little influence on NPV. Water purchase price shows the lowest impact since the investment of water purchase only accounts for a tiny part of the total expenditure owing to the cheap water purchase price.

Fig. 13 shows the tornado charts of water-EGS projects (scenarios #5 and #6). Under this flow scheme, the generated geothermal energy is the only revenue, and therefore, the electricity market price is important for NPV. In addition, the factors which determine the water injection amount and flow rate (injection flow pressure, production flow pressure and fracture conductivity) present great effects on NPV, where a higher flow rate results in a higher NPV. Similarly, injection fluid temperature, well spacing and water purchase price affect the NPV at a low level.

In conclusion, the fluid injection volumes and flow rate are the most important factors for the EGS project. In $CO_2$-EGS, a lower $CO_2$ flow rate can benefit sustainable and long-term geothermal energy generation and a lower amount of $CO_2$ injection should be considered to reduce the investment in $CO_2$ purchases. Considering the impact degree and the operation convenience, a lower injection pressure and a higher production pressure can be given priority. In mixed water-$CO_2$ EGS, a reasonable configuration of fluid flow rate and $CO_2$ ratio of the injected fluid should be investigated so that more profits can be generated from geothermal energy extraction and the expense of $CO_2$ purchase can be effectively controlled. In water-EGS, higher water injection amount and flow rate are desirable but the thermal breakthrough problem should also be considered, which may cause the NPV to reach the bottleneck at an early stage. In addition, the operators should consider starting a mixed water-$CO_2$ EGS project or a water-EGS project when the electricity market price increases.

## 6. Conclusions

In this study, the engineering feasibilities and the techno-economic performance of six EGS scenarios with three flow strategies and two well configurations are examined. The NPV of all scenarios has been compared, where the carbon credit policy is applied to those with $CO_2$ sequestration. Furthermore, the sensitivity analysis of six technical factors and four economic parameters is performed to identify the influential parameters.

As a result, $CO_2$-EGSs are the best in terms of electricity generation, while the early thermal breakthrough and costly $CO_2$ supply can drive the EGS to a negative NPV. Comparatively, with the consideration of the carbon credit policy, the mixed $CO_2$-water EGSs can potentially reach the greatest economic profitability. Regarding various well types, the horizontal well systems of mixed $CO_2$-water EGS and water-EGS can bring more economic benefits than their corresponding vertical well systems. However, the thermal breakthrough and expensive $CO_2$ purchase price are the main reasons for the reverse phenomenon in $CO_2$-EGS. Consequently, scenario #4 has the lowest breakeven electricity

**Table 4**
Economic results of base scenarios.

| | Scenario #1 | Scenario #2 | Scenario #3 | Scenario #4 | Scenario #5 | Scenario #6 |
|---|---|---|---|---|---|---|
| Revenue (M\$) | 102.5 | 115.9 | 56.8 | 79.5 | 64.1 | 89.4 |
| $CO_2$ tax credit (M\$) | 46.0 | 50.5 | 14.3 | 44.1 | 0 | 0 |
| CAPEX (M\$) | 35.9 | 40.4 | 24.0 | 32.2 | 26.0 | 34.7 |
| OPEX (M\$) | 222.6 | 264.5 | 21.5 | 37.6 | 15.3 | 21.1 |
| Tax (M\$) | 15.4 | 17.4 | 8.5 | 11.9 | 9.6 | 13.4 |
| NPV (M\$) | −125.4 | −155.9 | 16.9 | 41.9 | 13.2 | 20.2 |
| Payback period (year) | N.A | N.A | 7 | 4 | 9 | 8 |
| Breakeven price (\$/kWh) | 0.227 | 0.241 | 0.061 | 0.036 | 0.071 | 0.069 |

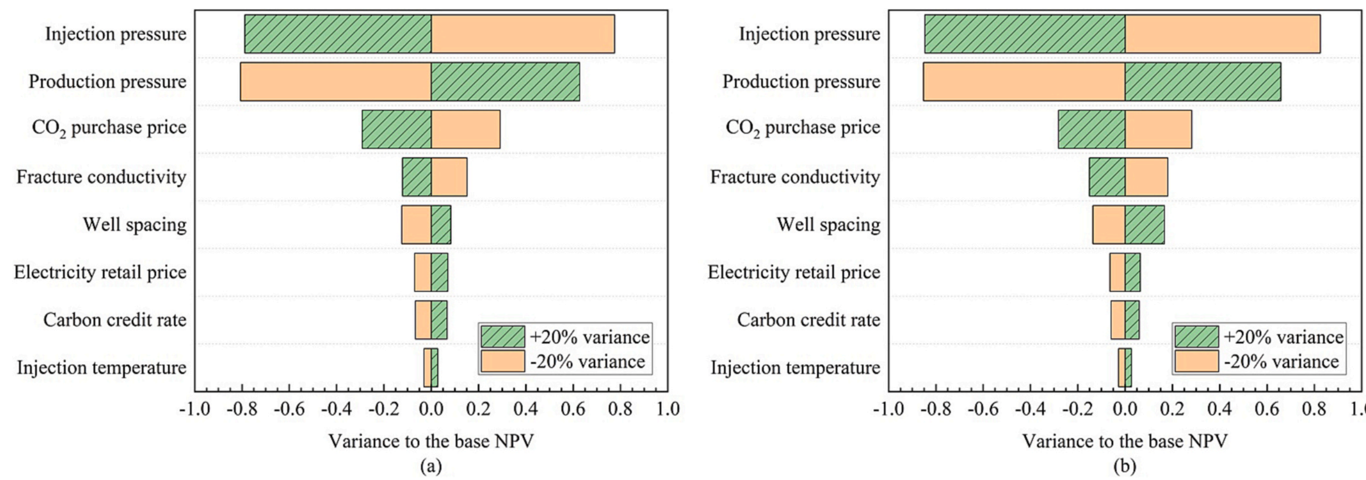



**Fig. 11.** Tornado charts of $CO_2$-EGSs: (a) scenario #1 and (b) scenario #2.

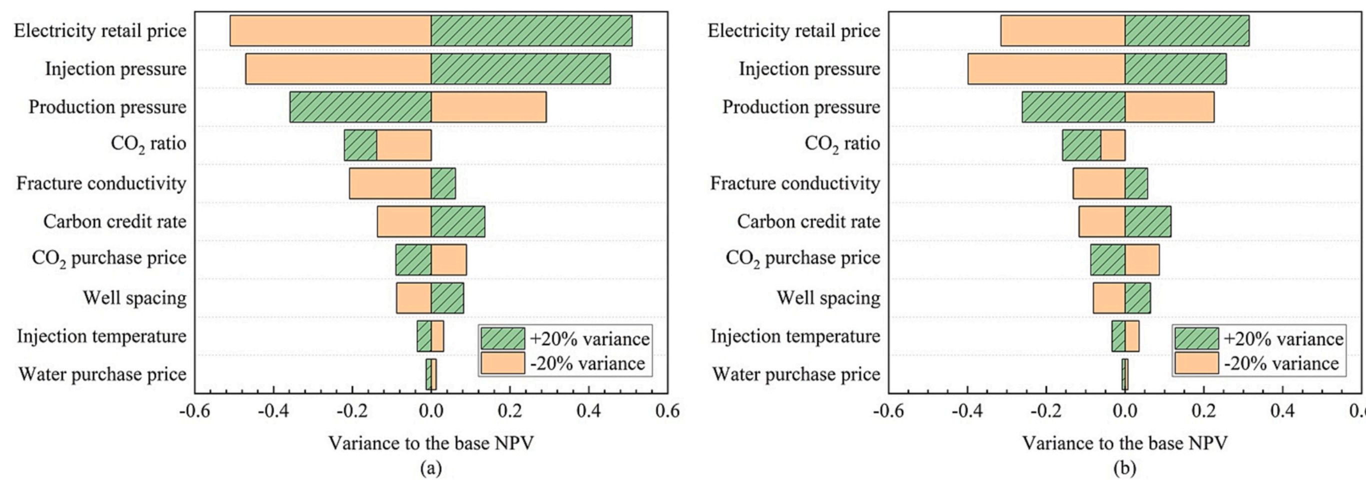



**Fig. 12.** Tornado charts of mixed $CO_2$-water EGSs: (a) scenario #3 and (b) scenario #4.

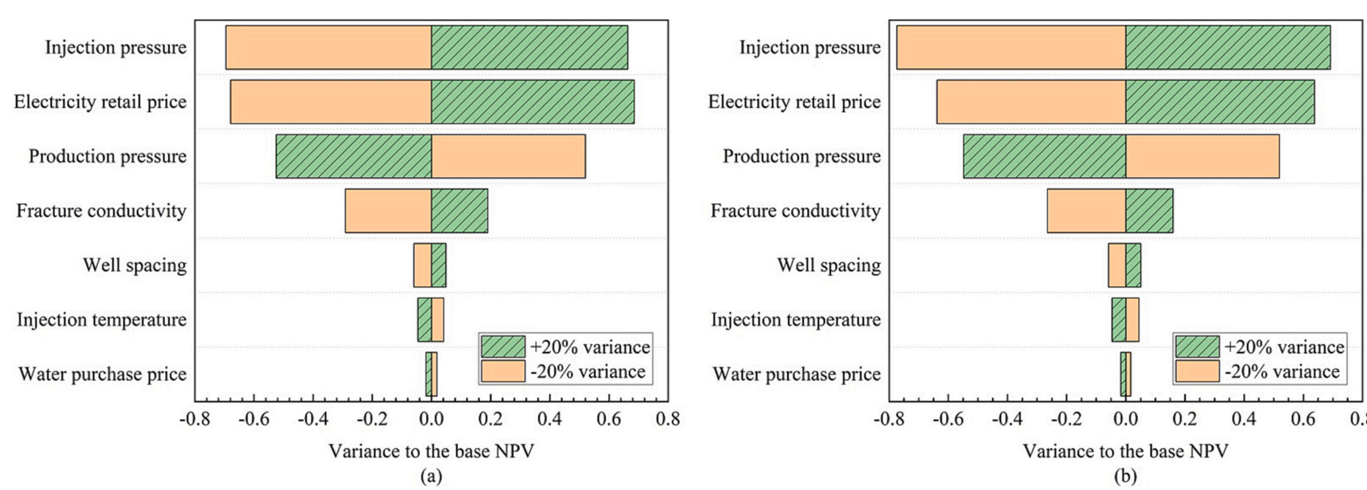



**Fig. 13.** Tornado charts of water-EGSs: (a) Scenario #5 and (b) Scenario #6.

market price at 0.036 $/kW because it can earn the highest NPV from selling promising generated geothermal electricity and obtaining a carbon credit from storing a favourable amount of $CO_2$ in the reservoir. However, scenario #2 requires the highest breakeven electricity market price at 0.241 $/kWh because of its extremely high investment in $CO_2$ purchase.

According to the sensitivity analysis, the parameters that dominate the injectivity (i.e., the injection flow pressures, production flow pressures, $CO_2$ ratio and fracture conductivity) are most sensitive from a technical perspective. For $CO_2$-EGSs, profitability is possible when an appropriate amount of $CO_2$ is injected with a lower flow rate in the reservoir. In mixed $CO_2$-water EGSs, the $CO_2$ ratio can play a crucial role. The optimal $CO_2$ ratio associated with $CO_2$ injection amount and flow rate should be further inferred to generate the most profit from heat recovery and $CO_2$ sequestration perspectives. In water-EGSs, a higher flow rate is preferred to generate more profits from selling geothermal electricity but the thermal breakthrough is needed to be observed. In terms of economic factors, the $CO_2$ purchase price is the biggest concern in $CO_2$-EGSs because of the high level of $CO_2$ consumption. Electricity market price influences economic performance for mixed $CO_2$-water EGSs and water-EGSs, especially for mixed $CO_2$-water EGSs. Therefore, according to the possible increasing trend of the electricity market price, operators can consider investing in an EGS project by injecting $CO_2$-water mixture fluid.

This study provides an informative decision-making strategy for both operators and investors in determining the appropriate operational schemes of an EGS under different external conditions. However, the limitation of this study is that only the Qiabuqia geothermal field is considered as a case study. In the future, more geothermal fields can be conducted to expand the technical and economic assessment framework to a wider scope.

## CRediT authorship contribution statement

**Zhenqian Xue:** Writing – original draft, Validation, Software, Resources, Methodology, Formal analysis, Data curation. **Haoming Ma:** Writing – review & editing, Methodology. **Yizheng Wei:** Writing – review & editing, Software, Methodology. **Wei Wu:** Writing – review & editing, Software. **Zhe Sun:** Writing – review & editing, Software. **Maojie Chai:** Writing – review & editing, Software. **Chi Zhang:** Writing – review & editing, Methodology. **Zhangxin Chen:** Writing – review & editing, Visualization, Supervision, Conceptualization.

## Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

## Data availability

Data will be made available on request.

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