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Performance evaluation of enhanced geothermal system (EGS): Surrogate models, sensitivity study and ranking key parameters

Pranay Asai, Palash Panja*, John McLennan, Joseph Moore

University of Utah, USA

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ABSTRACT

Designing an efficient system to extract heat from an enhanced geothermal system (EGS) requires proper understanding of the behavior of the reservoir over a long period. Five key parameters namely well spacing, fracture spacing, well inclination angle, injection temperature and injection rate are considered in this study for a doublet well system. To study and evaluate the performance of an EGS, second order surrogate models for 'produced water temperature', at certain time intervals are developed as a function of these five factors. The in-situ properties of a candidate reservoir for designing the simulations are taken from the FORGE site, Utah. Simulations are designed using 'Box-Behnken' design of experiments techniques to minimize the number of simulations. The models are trained and tested with the simulated results. Fitness of the models is calculated by estimating the errors using the coefficient of determination (R^2) and the normalized root mean square error (NRMSE). These surrogate models are used to study the sensitivity of the aforementioned factors on the temperature of the produced water and the heat recovery over a time period of 30 years. Finally, the hierarchy of factors, as they impact the total heat recovery are represented as a tornado plot.

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1. Introduction

Although geothermal energy has been studied since the early 1900s, recently it emerges as a potential renewable source of energy [1–3]. Geothermal reservoirs also known as hot dry rock [4,5], usually should have three key properties, high temperature (200+ °C), highly conductive natural fracture system and availability of a working fluid to bring that heat to the surface. Usually it is possible to find high temperature reservoirs (at economically accessible depths) but the possibility of finding a highly conductive fracture system in such reservoirs is less likely. The development of enhanced geothermal system (EGS) has been visualized as a breakthrough because it only relies on the availability of high temperature reservoirs. It conceptually consists of drilling two or more parallel or near parallel wells (a few hundred meters apart, for example). These are connected by developing a network of hydraulic fractures in the reservoir, hence eliminating the requirement of a naturally occurring fracture system. One or multiple wells can be used to inject the working fluid (usually water) into the reservoir (via hydraulic fractures exiting the injection wells), allowing the fluid to extract the heat. This heated fluid is produced from the remaining wells (production wells). The network of fractures plays an important role because it increases the surface area inside the reservoir that is used to enhance the heat transfer rate from the reservoir to the working fluid.

Creating an efficient EGS is a major challenge faced by the industry. It requires a huge capital investment [4] and hence calls for the proper planning, design and development of the system. It is important to have a better understanding of the key parameters and their effect on the performance of the EGS. A good EGS system is able to generate sufficient heat to produce electricity and is sustainable for at least 30 years. One way to ensure proper planning of an EGS is by carrying out simulations to emulate the reservoir and then trying out various combinations of the five key parameters to enhance the performance. Unfortunately, this method takes quite a long time since all of the possible combinations need to be evaluated before choosing the best one. To get around this problem it is feasible to study the impact of individual parameters and rank them and then use this to optimize the design program. This helps to develop an efficient system in less time.

There have been studies focusing on different type of EGS to evaluate their performance. Sanyal et al. [5] studied a five-spot layout of a 3D EGS model (hypothetical) with one injection and four production wells. They analyzed their optimal performance on the basis of fracture spacing, reservoir permeability, and well

* Corresponding author.
E-mail address: ppanja@egi.utah.edu (P. Panja).

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geometry. Frash et al. [6] carried out studies on drilling doublet and triplet well systems (a triplet with one injector and two producer wells). They mentioned the importance of proper well trajectories to ensure that the wells intercept the hydraulic fractures to allow the fluid to be circulated. Sun et al. [7] evaluated the effect of different fracture geometries on heat extraction from the reservoir. Cao et al. [8] studied the effect of carrier fluid on the heat extraction. Guo et al. [9] investigated the effects of aperture heterogeneity on flow pattern evolution for only for a single fracture in an EGS. Chen et al. [10] showed that the performance of EGS would not increase by simply drilling more production wells. Later on, Chen at al [11]. performed sensitivity analysis on doublet EGS, and concluded that the heat extraction rate and life of the system is dominantly depended on the flow pattern in the reservoir. Zeng et al. [12] studied the performance of 2D EGS model with a horizontal doublet well layout. They concluded that the energy efficiency is the function of the reservoir permeability and the flow rate of water in the system. Jiang et al. [13] designed and simulated a 3D conceptual EGS with a triplet well layout operating over 40 years and concluded that it performs much better that the doublet system and elongates the lifespan of the system by 10 years. Other studies that have been carried out also include the simultaneous effects of two or more parameters. Xia at al [14]. performed a sensitivity study on fracture spacing, deviation angle of the parallel wells, and injection flow rates. Aliyu et al. [15] considered the effects of injection flow rate, fluid injection temperature, and lateral well spacing. Ekneligoda et al. [16] studied the effect of mass flow rate, number of fractures, fracture width, and production time on the EGS to obtain the fracture length and the half spacing for the system. Although these studies help to understand the importance of choosing the right values for the given parameters, they don't explore the impact of a particular parameter and the combined effect on the performance of the EGS.

The objective of this study is not only to determine the key factors that affect the efficiency of the EGS, but also to determine the effect of each individual parameter. The effect of each parameter on the total heat extraction is also studied. A step-wise approach to developing a high performance EGS is also discussed. On basis of the implementation stage in the EGS, the factors are grouped into three categories, natural parameters, completion parameters and operational parameters. The key factors that are analyzed and investigated in this study include well spacing, fracture spacing, well inclination, fluid injection temperature and fluid flow rate. All of these factors were studied individually to determine their impact on the heat recovery efficiency of a typical EGS over its lifetime.

2. Method of energy extraction

The earth's crust is a vast reservoir of heat source. The temperature increases with the depth depending on the geothermal gradient which varies with locations. Drilling to excessive depths becomes increasingly expensive. It is preferable to choose sites which have high temperature reservoirs at relatively shallow depths. The temperature and the dimension of the reservoir play an important role in deciding the heat capacity and life of the geothermal system. Two or more wells can be drilled into the reservoir, accessing this huge heat source, which are subsequently connected by a network of hydraulic fractures. A fluid is circulated in the system (which acts as a heat carrier), to extract the heat from the sub-surface to the surface. When this working fluid passes through the network of hydraulic fracture it comes in contact with the hot rock, where it extracts heat via convection and conduction. The driving factor for heat transfer is the temperature gradient between the reservoir and the fluid. The rate of heat transfer also increases with the temperature difference between the rock and fluid increases. This implies that a cooler fluid extracts more heat than a warmer fluid in the same amount of time. In addition, the surface area of the fracture network plays an important role because it facilitates the interaction of the fluid with the hot reservoir rock. If the fracture network is widespread and has good conductivity, there is an increased rate of heat transfer. Once the fluid comes back to the surface, a heat exchanger is used to extract the heat from the fluid before reinjecting it into the system.

3. Enhanced geothermal system (EGS)

EGS is a method of creating a fluid circulation system to extract the heat from the reservoir. An EGS is visualized to consist of an injection well, a production well and multiple stages of hydraulic fractures as shown in a schematic diagram in Fig. 1.

The fracture network provides an interaction pathway for the fluid and the reservoir rock. It also connects the injection and production wells to complete the circuit. Many possible combinations can be used in an EGS to extract the heat from the reservoir. In this study, a simple doublet system is used, consisting of an injection well and a production well, connected by multiple vertical hydraulic fractures. The working fluid used here is water because it is generally available and has a high heat capacity. The entire system is operated in a closed loop with a make-up line to account for fluid losses in the reservoir. The water is pumped under high enough pressure to maintain its state as liquid, which proves beneficial as this eliminates any fluid losses that may occur during flashing of the liquid (to extract heat) and also saves time as the water is not required to be condensed before reinjecting. The potential of any geothermal project can be determined by evaluating three parametric groups (categorized on the basis of their implementation stage), namely natural properties, completion parameters and operational parameters.

Natural properties are intrinsic properties of the geothermal reservoir and is the first stage for development of EGS. These include the thermal gradient of the system, the heat capacity, thermal conductivity, density of the formation, size of the reservoir and availability of natural fracture networks. These in-situ

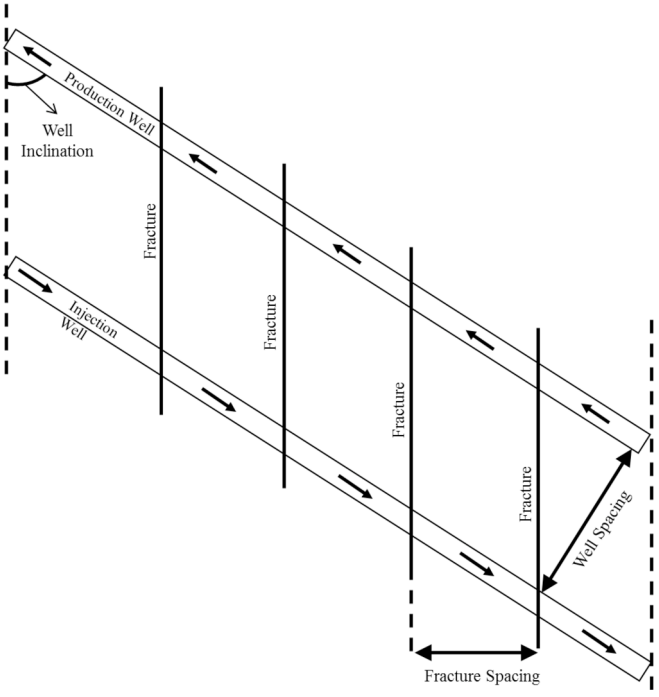

Fig. 1. Schematic diagram of a doublet EGS with multiple fractures (elevation view).

properties of a specific location cannot be readily manipulated or altered. These properties help to determine the total heat content of the reservoir and the facility for transferring heat to the working fluid. A good geothermal reservoir has high temperature (200 °C+) at shallow depths, high temperature gradient, high formation enthalpy and high thermal conductivity.

The next step is to decide on the completion parameters which helps to determine the type of EGS to be established to produce the energy from the geothermal reservoirs. These include the number of injection and production wells, type of well system (doublet, triplet, quadruplet etc.), angle of inclination of the wells, well spacing and number of hydraulic fractures or fracture spacing. These primarily control the total heat recovery factor for the EGS system. A system which has larger areal coverage in terms of fracture network is more efficient in extracting heat from the entire reservoir.

The final stage is to decide on the operational parameters. These include the type of working fluid, the fluid flow rate and the injection temperature. Once the recovery factor for the EGS is established by the completion parameters, operational factors determine the rate of heat extraction and the life of the EGS. For example, a system with a high flow rate and low injection temperature thermally depletes the reservoir faster than a system with low flow rate and high injection temperature.

Thus, in order to achieve better energy recovery, optimization of each individual group is extremely important. To optimize a system, it is necessary to study and evaluate the impact of each of these parametric groups by carrying out multiple simulations.

4. Simulation of EGS

To study the effect of different parameters on the efficiency of the EGS, multiple simulations are run to understand the effect of each factor individually. This study considers the effects caused by three completion parameters (wellbore inclination, well spacing and hydraulic fracture spacing) and two operational parameters (flow rate and injection temperature) on the overall efficiency of the EGS.

Parameters for the numerical simulations were derived from extensive field testing at the U.S. Department of Energy's FORGE (Frontier Observatory for Research in Geothermal Energy) site near Milford, Utah [17,18]. FORGE specifically is aimed at providing a field platform for drilling and technology testing, and to provide a commercial pathway to EGS. Historical context of this project is provided at the forge web site [19]. During the latter part of 2017, a vertical well was drilled on one of the future potential locations for an EGS field laboratory. This was drilled to approximately 7500 ft, mostly through granodiorite. Two 4-inch diameter cores were captured and laboratory permeability measurements were carried out. A complete logging suite (caliper, gamma ray, density and neutron porosity, dipole sonic and FMI (formation Microscanner) were undertaken to determine porosity, density, lithology, mechanical properties and the distribution and character of in situ fracturing. A three-dimensional seismic survey was completed in the last quarter of 2017. The lower 147 feet of this well were uncased. In this uncased, open hole section, a series of injection measurements were carried out to determine the magnitude of the horizontal principal stresses and the native equivalent permeability (matrix and natural fractures) [20]. Multiple pressure and temperature surveys were run in this well (R. Allis, Utah Geological Survey, personal communication, 2018). The nominal temperature gradient at this site is 60 °C/km, with a reference temperature of 200 °C at a true vertical depth (TVD) of 2500 m. This was determined from multiple maximum temperature recordings during drilling, from abundant regional data (thermal gradient wells), from pressure-temperature surveys run in the well following

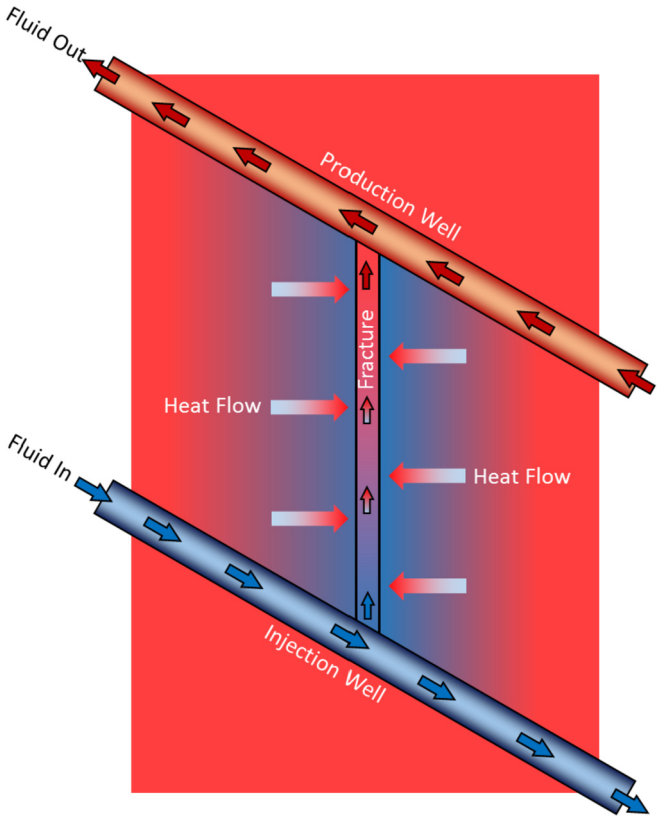

Fig. 2. Schematic diagram of heat flow in one out of many fractures for a doublet EGS.

accepted Horner-type extrapolation protocols and from a pressure-temperature survey performed in the well (logging on the way in) approximately 30 days after all well activity had ceased.

As indicated, and embodied in the numerical simulations this granodioritic reservoir has low porosity (1% or less – determined from well logging and laboratory measurements) and low permeability (on the order of 5–30 μD).[1] While there are natural fractures in the reservoir, the temperature gradients indicate a conductive geothermal reservoir, rather than a convective reservoir. The presence of natural fracture would aid in creating and propagating the hydraulic fractures created in the reservoir to ensure the flow conductivity between wells. The directionality of fracture propagation is governed by the stress field that was measured in this experimental well. Directions of fluid and heat flow in an EGS with one fracture, one production well and one injection well are shown in Fig. 2.

The EGS at the Utah FORGE site is planned to be a doublet system with two inclined wells (60° from the vertical). The injection well kicks off at the depth of 1460 m, the perforations starts from 1910m (TVD) and the toe of the well is at 2518 m. This provides a 1216 m lateral injection zone that can be hydraulically fractured to circulate water through the reservoir. Another well (production well) is drilled proximal to the injection well with the spacing (measured perpendicular to the well) of 200 m. The production well is located vertical above the injection well.

The data obtained from the FORGE site were used to prescribe natural factors in the simulations. The simulations were conducted

[1] Laboratory absolute liquid permeability on one core plug sample at 2500 psi confining pressure was 5 microdarcies. Permeability derived from in-situ post-closure Diagnostic Fracture Injection Testing (DFIT) was about 30 midcrodarcies (J. McLennan, University of Utah, personal communication, 2017).

Table 1
Dimension of entire reservoir model.

Dimensions	Entire Reservoir
Reservoir length (X-direction), m	900
Reservoir width (Y-direction), m	500
Reservoir height (Z-direction), m	Depends on well inclination and well spacing
Fracture width, m	0.01
Fracture height, m	200-600 (Depends on well inclination and well spacing)

in a commercially available thermal reservoir simulator, STARS developed by Computer Modeling Group (CMG), Calgary, Canada [21]. STARS is a three-dimensional, multi-component thermal, three-phase simulator. Numerical solution is based on fully implicit and adaptive implicit methods. Reservoir models in STARS can be built with Cartesian, cylindrical, or variable depth/variable thickness grid systems. The simulation model consists of a doublet with water as the working fluid. The wells were considered to be parallel. Well spacing, fracture spacing, wellbore inclination, fluid injection rate and injection temperature were varied to study their effect. Table 1 summarizes the dimensions of the reservoir that was modeled.

The hydraulic fractures in the model were simple planar fractures of rectangular shape, Gringarten et al. [22]. These consisted of grids with higher permeability and porosity than the surrounding reservoir, giving rise to highly conductive zones connecting the two wells. All of the simulated factures were assumed to be uniform and isotropic with the same fracture conductivity. The natural properties for the simulated model were taken from the FORGE site and are mentioned in Table 2.

5. Surrogate model

The surrogate models are the mathematical representations of physical system. In this study, surrogate models for the temperature of produced water and consequently the total heat extraction as a function of time were developed. One surrogate model represents temperature at particular time for a set of inputs. It is not realistic to develop surrogate models for thousands of points on temperature versus time profile. To avoid this complication, few selective time interval such as 1 day, 2 day, 3 day etc. are chosen for surrogate models. The values for intermediate time such as time between 1 day and 2 day or 2 day and 3 day are interpolated. The discretization method to obtain data from the time continuous results for the surrogate model are shown in Fig. 3 with two example temperature profiles.

The nature of the temperature decline was not the same for all

Table 2
Natural Properties of the FORGE site.

Properties	Value
Density of the rock, (kg/m^3)	2700
Permeability of the formation, (mD)	0.01
Permeability of the fractured zone, (mD)	50000
Porosity of the formation	0.01
Porosity of the fractured zone, (%)	10
Water Saturation, (%)	100
Thermal conductivity of formation, $(J/(m.day.^\circ C))$	2.592×10^5
Thermal conductivity of water, $(J/(m.day.^\circ C))$	5.18×10^4
Volumetric heat capacity of the formation, $(J/(m^3.^\circ C))$	2.133×10^6
Specific heat capacity of the fluid, $(J/(m^3.^\circ C))$	4818
Formation compressibility, (1/kPa)	4.4×10^{-7}
Temperature gradient, $(^\circ C/m)$	0.06
Reference depth, (m)	2520
Reference temperature, $(^\circ C)$	200

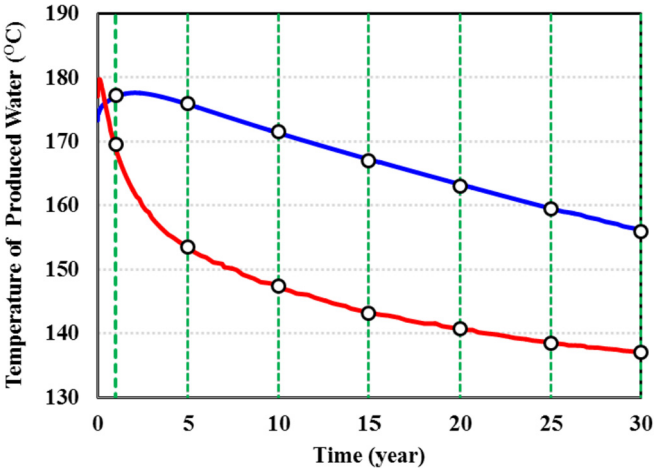

Fig. 3. Discretization of results of temperature decline curves in time.

operating, completion, and natural parameters. For clarification, two different type of temperatures profiles obtained from simulation of EGS are shown in Fig. 3. In one curve (red line), the decline is sharp from very early time. On the other hand, in the second curve (blue line) the temperature increases and then decreases slowly. This difference in the nature of decline curve, may have an effect on the surrogate model in that particular time frame.

Smaller time steps are considered near the curve with sharp changes such as time before 5 years. Few example points are shown in Fig. 3. In this study, 59 time points were taken over the entire operational time span of 0–30 years. As expected, increasing the number of times sampled over the 30 year plant life provides more accurate results, but the computational time increases proportionally. It is mentioned earlier that one surrogate model is developed for each chosen time and hence 59 surrogate models were developed. Temperature profile for entire time period was determined by interpolation and smoothing.

Surrogate models having second order polynomial functions were developed as shown in Equation (1)

$$\log(f(X_1,\ldots,X_5)) = a_0 + \sum_{k=1}^{n} a_k X_k + \sum_{i=1}^{n}\sum_{j=i}^{n} a_{ij} X_i X_j \quad (1)$$

In this model, second order interactions among variables are also considered. The number of coefficients depends on the number of independent variables. For 5 input variables, there are 5 coefficients, 'a_k', 15 s order interaction coefficients, 'a_{ij}' and one intercept, 'a_0' as shown in Equation (1). These 21 parameters are obtained for 59 models of the temperature of the produced water. All the coefficients and intercept are obtained from an in-built optimization routine in Matlab (Matworks Inc.) computer programming platform. In the optimization method, the error between the model and the training data is minimized. To avoid any unexpected results predicted by the model (such as negative temperature), the logarithm of the temperatures was taken before developing the surrogate models. Finally, results are obtained from the surrogate model by converting to the power of ten (in the case of a logarithm which uses base 10) securing positive values. The workflow for developing surrogate models is shown in Fig. 4.

It starts by determining the number of parameters or variables to study. Once that is decided, the next step is to design a set of experiments to study their impacts (in this study, Box-Behnken design of experiments was used) by choosing a range of inputs. Other parameters (natural properties of the reservoir) are also

taken into account to design the simulation. The data used to develop the surrogate models are referred as the training data. An initial model is trained with these data. After that, a randomly generated test data set (within the range of inputs) is used to validate the developed model. If the errors are not in acceptable range, the models are trained again either by different set of training data or by using different surrogate models. This process is repeated until a satisfactory model is developed.

5.1. Design of experiments

To evaluate the effects of each individual parameter (well spacing, fracture spacing, wellbore inclination, injection temperature, and total injection rate) on the total heat extraction in EGS, experiments were designed using the Box-Behnken [23] method. Box-Behnken uses a three level model (maximum, medium and minimum) to reduce the number of experiments and yet provides sufficient cases for regression of second order model. For five variables (as shown in Table 3) 41 simulation models were designed, each having its maximum value (+1), medium value (0), and minimum value (−1) as shown in Table A2.

All of the parameter's maximum, medium and minimum values were chosen linearly, except for the angle of well inclination. Since the well inclinations chosen for this study (45°, 60° and 90°) are not linear, the inverse of angle was chosen to get linear values. All the real values are then converted to +1, 0 and −1, using the relationship as shown in Equations A.1 and A.2.

These 41 simulations as prescribed by Box-Behnken method are referred as the training data. 10 other simulations (approximately 20% of total data combining training and test) were also designed with random values of inputs (within the maximum and minimum range), referred to as test data. The purpose of the test data is to validate the model produced using the training data. The fitness is determined by two measures, the coefficient of determination (R^2) and the normalized root mean square error (NRMSE). Further details of the experiment design are summarized in Appendix A. The fitness of a model with training data and test data both are discussed in the next section.

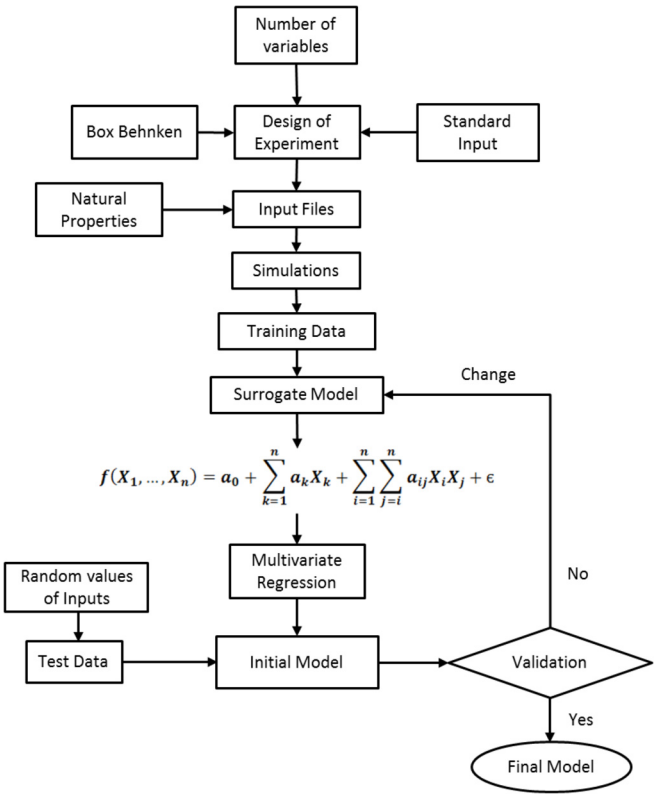

Fig. 4. Workflow of the methodology to develop surrogate model.

5.2. Training

Since multiple models are created for an individual time, it is important to assess them and check for any discrepancies. The surrogate model in this study predicts the temperature decline curve for given sets of input. A comparison of the training data and the data obtained from the model is plotted in Fig. 5. Although there are 59 models, only 6 models are shown here. Fig. 5 (a), includes the data points for the first day, first year and the fifth year, and Fig. 5 (b) includes the data points for the tenth, twentieth and thirtieth years.

To estimate the error for the generated model the R^2 and NRMSE (Normalized Root Mean Square Error) are calculated. All of the models have R^2 values close to 1 as shown in Table A3. This indicates that the model has relatively small errors and does not deviate much from the training data. Most of the time-based models have around 1–6% NRMSE, but there is an observable peak for a few of the models. This peak is the result of having different nature of temperature decline curves because of different well spacing, which leads to different temperature decline curve for produced water. Despite that, the model is well trained and can be used because the errors are in an acceptable range.

5.3. Testing

Since the models were generated using the training data, it is expected to replicate the results more accurately with the exact same data set, but it might not be able to give good results with another data set chosen randomly within the range. To check the validity of the generated model, it is important to create a random data set (within the range of the training data set) and evaluate the performance of the trained model and compare it with the results from test data (See Fig. 6). Usually 20% of the total data are used as test data to validate the model [24]. Fig. 6 (a) shows a comparison of test data with the data obtained from the trained surrogate model, for the first day, first year and fifth year. Fig. 6 (b) shows the same comparison for tenth year, twentieth year and thirtieth year. The test data show a poorer fit as compared to the training data. Despite that, the test data performed efficiently without any major discrepancies and hence validate the trained model.

The errors were calculated for the test data using R^2 and NRMSE. Except for a few time-based models, most of them have good R^2 values (close to 1) and less percentage of NRMSE. Overall, the test data show good results and hence successfully validate the trained model.

6. Results and discussion

Results are discussed in terms of temperature decline and the total heat recovery over time. The study of temperature decline is important because of the constraint on minimum operational temperature in a binary power plant. Moreover, the lower the temperature the lower the efficiency of the Organic Rankine Cycle plant [25]. When the system starts producing water below this temperature, it either needs to be shut down or the surface equipment - such as the heat exchanger or other associated units - are modified to work with this low temperature (which is not possible in a commercial scenario).

The heat recovery for the system with flowrate Q, fluid density ρ, fluid heat capacity c_p, injection temperature T_{inj} and temperature of

Table 3
Input parameters.

	Variable	Symbol	Minimum (−1)	Medium (0)	Maximum (+1)
1	Well spacing, (meter)	X1	100	200	300
2	Fracture spacing, (meter)	X2	50	75	100
3	Angle of well inclination, (1/degree)	X3	1/90	1/60	1/45
4	Injection temperature (°C)	X4	80	100	120
5	Total injection rate (m^3/day)	X5	5000	7500	10000

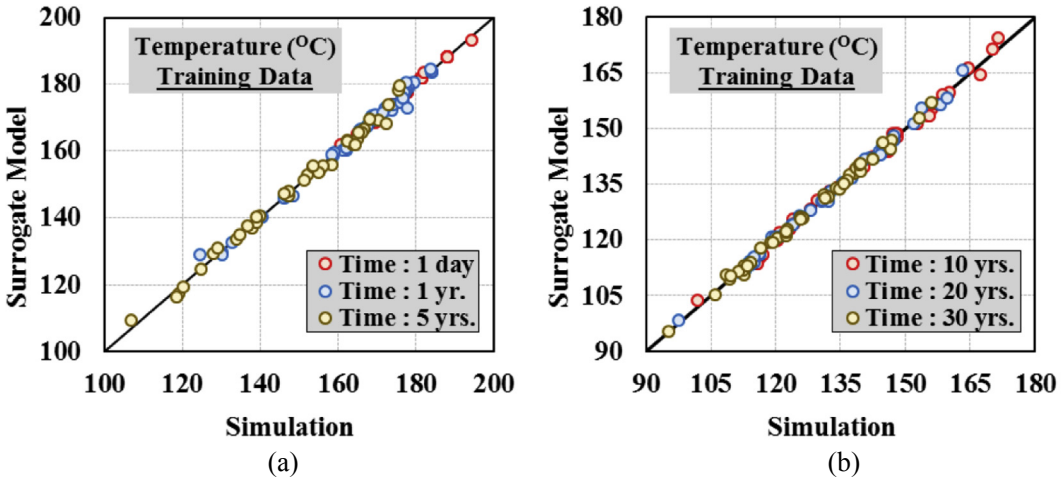

Fig. 5. Comparison of training data with the data obtained from the model (a) Data comparison for 1st day, 1st year and 5th year, (b) Data comparison for 10th year, 20th year and 30th year.

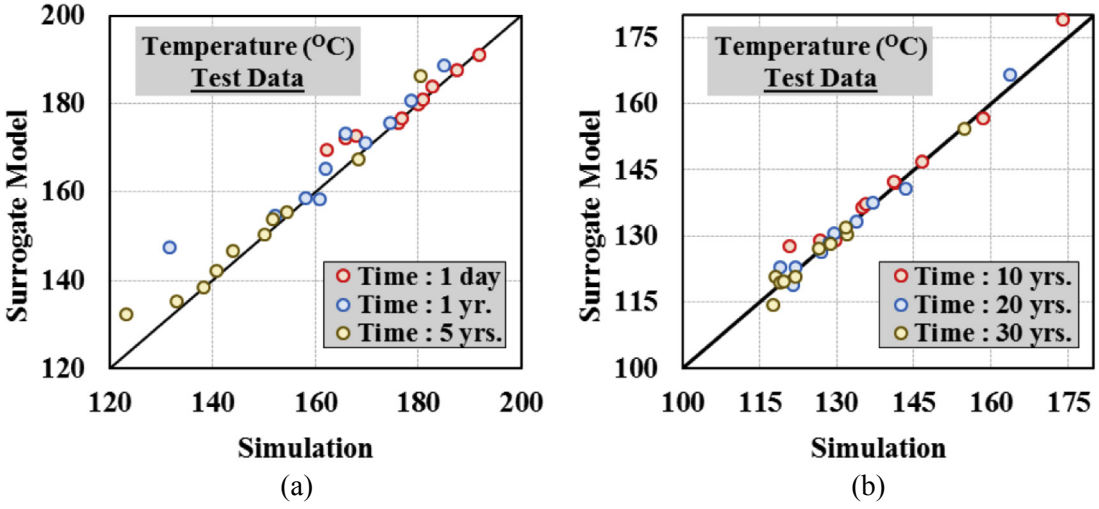

Fig. 6. Comparison of test data with the data obtained from the model (a) Data comparison for 1st day, 1st year and 5th year, (b) Data comparison for 10th year, 20th year and 30th year.

produced water T_p. over time period t is calculated using Equation (2). The influence of well spacing, fracture spacing, well inclination, injection temperature, and flow rate, on the temperature of produced water and total heat recovery is discussed in the next sections.

$$\textit{Total Heat Extraction},\ H = \int_0^t Q\rho c_p (T_p - T_{inj})\,dt \qquad (2)$$

Once the surrogate models are trained, the total heat extraction with time is calculated from the temperature profile and values of inputs using Equation (2). The effects of the various factors and their overall influence on heat recovery are discussed in the next sections. While effect of one factor is investigated, the other factors are kept at their medium values.

6.1. Well spacing

Fig. 7 (a), is a surface plot for temperature decline, obtained from surrogate models at different well spacing, with 100 m being the least and 300 m being the maximum. All other parameters were kept at their medium values. It shows that when the well spacing is

the least (100 m), the temperature of produced water drops drastically in the initial 10 years and then it becomes stable. When the well spacing is maximum (300 m), the temperature is quite stable and does not drops below 150 °C. In Fig. 7 (b), it is a representation of the total amount of heat extracted by the EGS over 30 years. For 300 m well spacing the heat extracted is almost three times more than that extracted by a system with 100 m well spacing. This demonstrates the critical importance of well spacing.

Decline in total heat production is observed because the distance between the wells determines the primary coverage volume of the EGS. When the well spacing is reduced, the wells encompasses a smaller volume than they do when the spacing is greater. Since the volume of rock is directly proportional to the available heat content, the smaller volume of heated rock encompassed for 100 m well spacing is depleted faster than the larger volume associated with a 300 m well spacing; all other parameters being constant. Thus, well spacing determines the primary heat recovery factor for the given geothermal reservoir. Although this indicates that maximum well spacing is preferred in order to achieve maximum recovery factor, this is usually restricted by physical limitations. Since the well spacing increases, it becomes more difficult to connect the two wells with a regular fracture network.

6.2. Fracture spacing

The 50 m fracture spacing gives a steady decline curve for the temperature than the 100 m fracture spacing as shown in surface plot in Fig. 8. Alternatively, Fig. 8 (b) represents the cumulative heat extracted at variable fracture spacing over 30 years.

In EGS with fixed well lengths, lower fracture spacing implies more fractures and more fracture spacing means fewer fractures. It is advantageous to have smaller fracture spacing (more fractures) because this increases the surface area for rock-fluid interaction. Since the well spacing is already fixed, more fractures lead to the extraction of more heat in a shorter time. However, if the fracture spacing drops below a certain level, the interference occurs and this negatively affects the EGS's performance.

6.3. Well inclination

It was observed that horizontal wells (90° to the vertical) performs better than the inclined wells (45°). Of more importance, the total heat extracted in 30 years is higher in the horizontal well as seen in Fig. 9 (b).

When the two wells are horizontal, all of the fractures lie in the same temperature zone. When the wells are not horizontal, the fractures reside in different temperature zones (at different positions along the wells), hence producing water at different temperatures. Since the first fracture's location (located at the toe of the well), is kept fixed, in an inclined well system the second last fracture lies in a lower temperature zone. Thus, inclined wells perform less efficiently than the horizontal wells. In addition, the volume of rock contained between two horizontal wells system has a higher average temperature than the volume of rock contained between the inclined wells system (because of the temperature gradient). This means that the horizontal wells system contains more heat than the inclined wells system.

6.4. Injection temperature

Fig. 10 (a), represents the temperature decline surface plot at different injection temperatures, from 80°C to 120°C (other parameters were kept at their medium values). It also indicates that when the water is injected at the minimum temperature (80°C), the temperature of the produced water drops more rapidly than for the maximum injection temperature (100°C). In addition, the temperature of the water produced with 80°C injection is much lower than that with 120 °C injection after 30 years. The cumulative amount of heat extracted over 30 years is more for the lower injection temperature (see Fig. 10 (b)).

The difference in the temperature is the driving factor for heat exchange in a system. The temperature difference also determines the rate of heat transfer from a hot body (rock) to the colder fluid (fluid flowing in the fractures). When cooler water is injected, it extracts more heat from the reservoir and thus drops the temperature of the reservoir more rapidly in a short time. However, warmer injectate helps to maintain a steady decline in reservoir temperature with time. Since the total amount of recoverable heat remains constant in this case, the temperature of the injected fluid regulates the rate of heat extraction. Hence the fluid with lower temperature extracts more heat in a 30-year operational period.

6.5. Injection rate

The rate of fluid injection is directly proportional to the rate of heat extraction as shown in Fig. 11. A system with high water

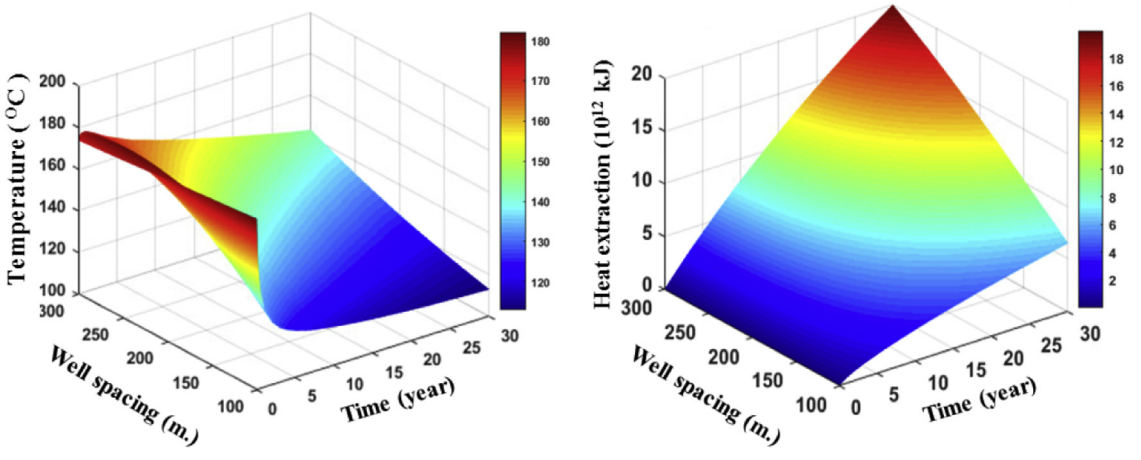

Fig. 7. Surface plot of variable well spacing with other parameters at their medium values, (a) Temperature decline in the reservoir (b) Cumulative heat production from the reservoir.

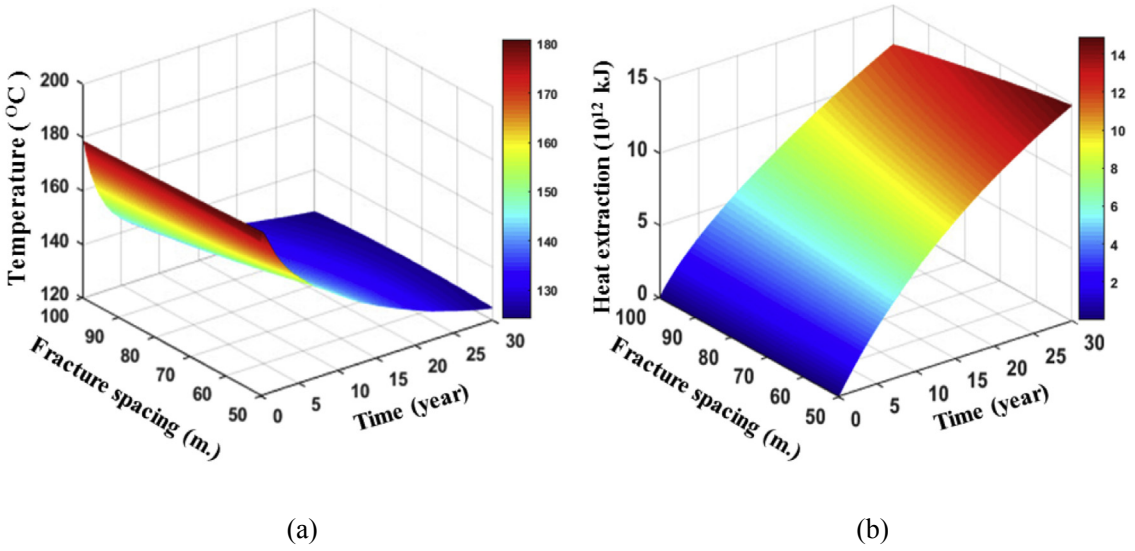

Fig. 8. Surface plot of variable fracture spacing with other parameters at their medium values, (a) Temperature decline in the reservoir (b) Cumulative heat production from the reservoir.

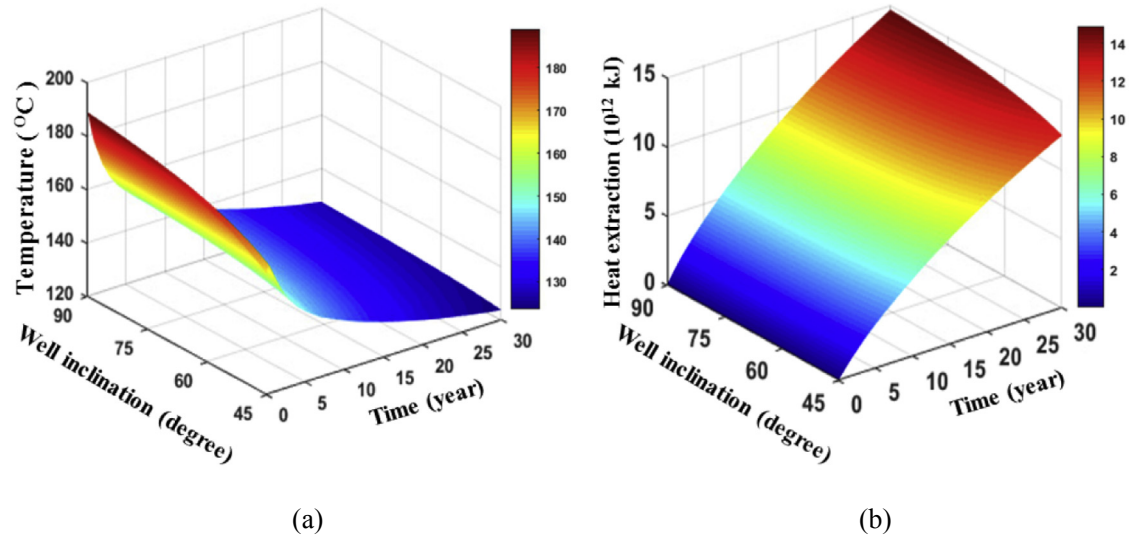

Fig. 9. Surface plot of variable angle of well inclination with other parameters at their medium values, (a) Temperature decline in the reservoir (b) Cumulative heat production from the reservoir.

injection rate depletes the reservoir faster by extracting more heat and rapidly dropping the temperature in given time period. However, higher flow rates are not always desirable because there is less residence time within the fracture.

With lower residence time, the water is not able to extract much heat from the rocks and hence the temperature of produced water is expected to be less. However, since the heat content of any material is the function of the volume and the temperature of the material, the fluid injected at high flow rates having low temperature can still produce more amount of heat compared to low flow rates.

6.6. Hierarchy of factors

Various cases were assessed using surrogate models to determine the hierarchy importance of well spacing, fracture spacing, well inclination angle, injection temperature and rate of water injected as they affect the temporal heat extraction. One factor was varied at a time while the other four factors were kept constant at their base or central values i.e., medium values (0). In particular, three outputs are produced from three levels (i.e., low, high and medium) for the factor of interest while holding other factors at their medium value. Each bar in the tornado plot (Fig. 12) represents the variation of outputs produced when each variable is set to low (−1), high (1). The result from medium values (0) of all variables represents the base result and divides the entire range of each variable into two zones. One side depicts the influence of high value of a variable and other side represents the effects of low value.

After repeating the simulations for every factor, bars are arranged from top to bottom according to the total range of output. In other words, the factor that produces the largest variation in results is placed on the top of the chart - representing highest impact. On the other hand, the smallest bar produced by the factor is placed at the bottom. This arrangement of the bar in a single figure takes the

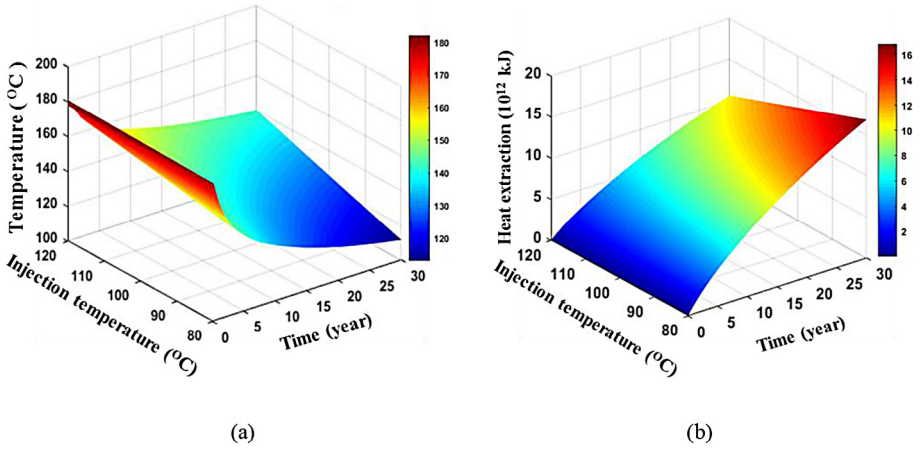

Fig. 10. Surface plot of variable injection temperature with other parameters at their medium values, (a) Temperature decline in the reservoir (b) Cumulative heat production from the reservoir.

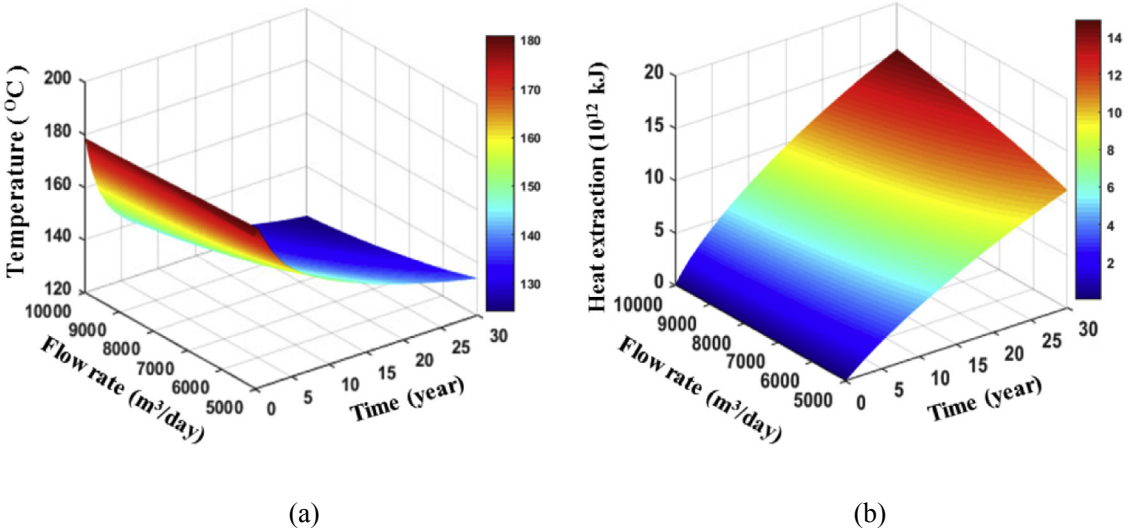

Fig. 11. Surface plot of variable flow rate with other parameters at their medium values, (a) Temperature decline in the reservoir (b) Cumulative heat production from the reservoir.

appearance of a "tornado". A tornado plot for heat extraction after 1 year, 5 years, 15 years and 30 years is shown in Fig. 12.

A light green bar indicates the impact of the high (1) value, and the brown bar indicates the impact of the low value (−1), on the total heat production. The blue vertical line represents the base value where all factors were taken to have their medium values (0).

Fig. 12 indicates that all factors do not affect the heat extraction in same manner. Well spacing, injection flow rate and the well inclination[2] are directly proportional to the amount of heat extracted. Higher values of these three factors are favorable for higher heat extraction. On the other hand, injection temperature and fracture spacing are inversely proportional to the amount of heat extracted. Low injection temperature and smaller fracture spacing lead to higher heat recovery.

Fig. 12, represents the hierarchy of factors after the end of first year, fifth year, fifteenth year and thirtieth year. After one year, the injection flow rate dominates with injection temperature being the second most relevant parameter and spacing is the least relevant. By the end of the first year there is no interaction among the fractures or among the wells. That is, two consecutive fractures are not competing with each other to extract the heat - similarly for the wells. This indicates that the total amount of heat extracted is mainly function of the flow rate and injection temperature. However, as time passes, the fractures and the wells start interacting and compete for heat. The well spacing assumes top priority in terms of recoverable heat. With time, an increase in well spacing leads to more heat production. Injection temperature, which is inversely proportional to heat extraction, remains the second most relevant parameter. Low injection temperature leads to more rapid heat extraction. Flow rate is the third most important parameter; higher flow rate is required to produce more heat. Although fracture spacing does not have a high impact after the end of first year (because there is no interference), after five years it becomes somewhat more importance for the cases evaluated. As mentioned previously, well inclination affects the total heat content or the average temperature of the reservoir (a horizontal well has the highest average temperature and a well inclined at 45° has the lowest). For the in situ properties specified here, it has the least impact on heat production. The individual impacts of the parameters are summarized in Table 4.

[2] The factor is taken as the reciprocal of the angle. A high angle – i.e., a horizontal well at 90° - gives a lower value for the parameter than an inclination to the vertical of 45°).

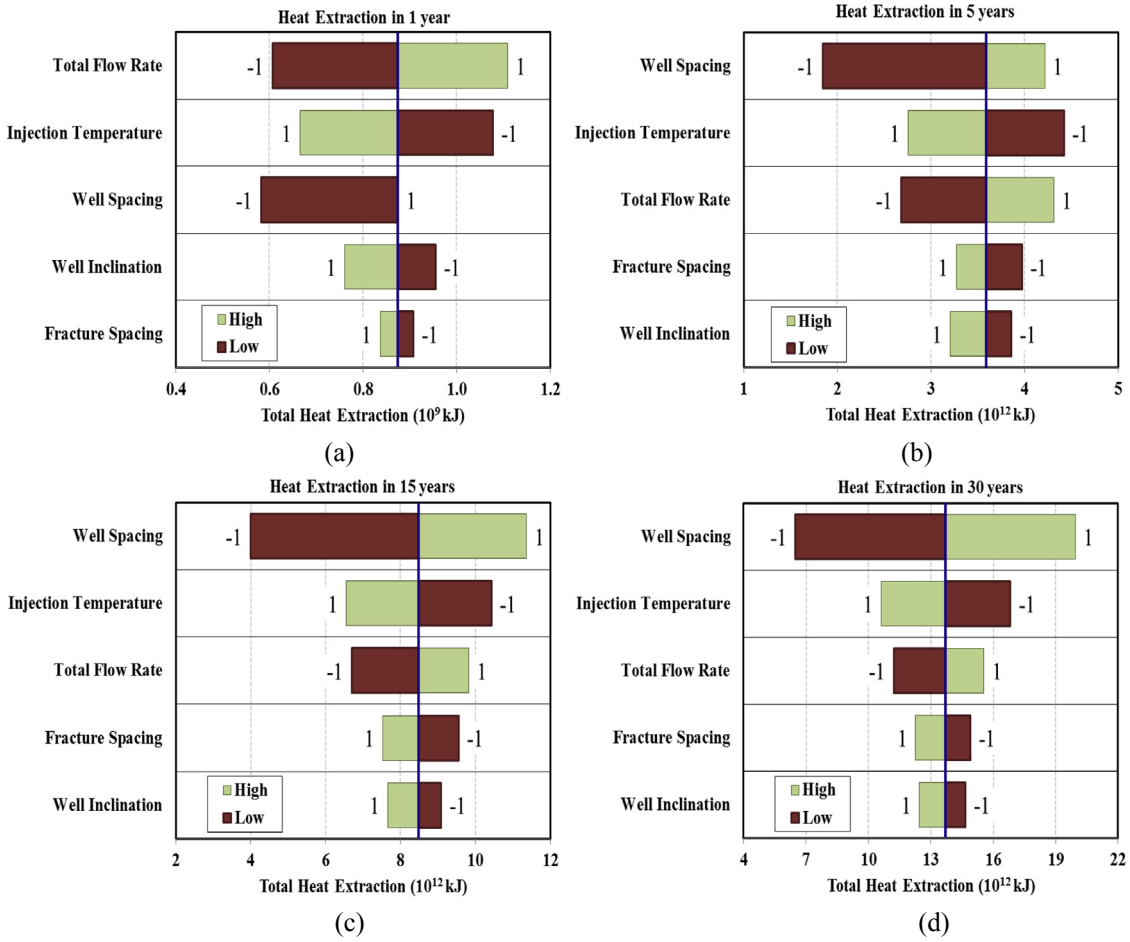

Fig. 12. Hierarchy of all the parameters with time, (a) At the end of the first year, (b) At the end of five years, (c) At the end of 15 years, (d) At the end of 30 years.

Table 4
Parameter ranks, relation with heat extraction and their physical effects on EGS over 30 years.

Impact Rank	Parameter	Relation with Heat output	Physical Impacts
1	Well spacing	Direct	Affects the primary heat recovery factor for the EGS.
2	Injection temperature	Inverse	Affects the rate of heat extraction for the EGS
3	Total injection rate	Direct	Affects the rate of heat extraction for the EGS
4	Fracture spacing	Inverse	Affects the secondary heat recovery factor
5	Angle of well inclination	Direct	Affects the average temperature of the volume "enclosed" by the two well system.

7. Conclusions

This study considers dominant factors affecting the performance of an EGS and ranks them according to their impact on heat extraction from a reservoir with the properties of the Utah FORGE reservoir. Five important parameters were chosen and their range of values was established by taking data from the Utah FORGE site. The parameters varied in the simulations were grouped in two categories: completion parameters (consisting of well spacing, well inclination, and fracture spacing), and operational parameters (injection temperature and injection flow rate).

Well spacing was identified as the most crucial parameter in terms of the total heat output. Greater well spacing (when possible) also gives the smallest temperature decline over the prescribed 30-year project life. Since well spacing is directly proportional to the total heat output, wells that are widely spaced extract more heat than closely spaced wells (doublet configuration with one well vertically above and parallel to the other). Injection temperature fell out as the second most important parameter. Since heat production is a function of temperature difference between the reservoir and the circulating fluid, a low temperature injection extracts more heat than a relatively warmer fluid. The third most important parameter for the scenario evaluated is the injection flow rate. A greater volume of fluid provides more capacity to extract heat, hence depleting the reservoir faster. Less fracture spacing or higher number of fractures provides more area for the heat transfer and hence increases the efficiency of the EGS. The least important parameter for the scenario imagined was the well inclination. A high angle well system (90° to the vertical) performs better than a low angle well system (45°) because the high angle wells have slightly higher reservoir temperature.

In order to establish a superior EGS, the first priority is to select a location with excellent natural parameters - high temperature reservoirs at shallow depth. The second priority is to design the well system by carefully considering the impacts of the completion and operational parameters. The natural parameters give the total

heat content of the reservoir. By studying the hierarchy of completion parameters, it is possible to design a system to maximize the heat recovery factor. Finally, operational parameters (injection temperature and injection flow rate) can be manipulated to get appropriate rate of heat extraction from the EGS.

Appendix: A

All variables except well inclination are transformed from their actual values to encompass a range from −1 to +1 as follows.

$$\text{Transformed variable, } X = 2\frac{\text{Actual value} - \text{Low}}{\text{High} - \text{Low}} - 1 \tag{A.1}$$

Well inclination angle is transformed as follows

$$\text{Transformed variable, } X = 2\frac{\frac{1}{\text{Actual value}} - \frac{1}{\text{Low}}}{\frac{1}{\text{High}} - \frac{1}{\text{Low}}} - 1 \tag{A.2}$$

Table A.1
Values of inputs for simulations of training data

Simulation No.	Input Factors				
	Well spacing	Fracture Spacing	Well inclination	Injection temperature	Injection rate
1	−1	−1	0	0	0
2	−1	1	0	0	0
3	−1	0	1	0	0
4	−1	0	−1	0	0
5	−1	0	0	−1	0
6	−1	0	0	1	0
7	−1	0	0	0	−1
8	−1	0	0	0	1
9	0	0	1	−1	0
10	0	0	1	1	0
11	0	0	−1	−1	0
12	0	0	−1	1	0
13	0	−1	0	0	−1
14	0	−1	0	0	1
15	0	1	0	0	−1
16	0	1	0	0	1
17	0	0	0	−1	−1
18	0	0	0	−1	1
19	0	0	0	1	−1
20	0	0	0	1	1
21	0	−1	1	0	0
22	0	−1	−1	0	0
23	0	1	1	0	0
24	0	1	−1	0	0
25	0	0	1	0	−1
26	0	0	1	0	1
27	0	0	−1	0	−1
28	0	0	−1	0	1
29	0	−1	0	−1	0
30	0	−1	0	1	0
31	0	1	0	−1	0
32	0	1	0	1	0
33	0	0	0	0	0
34	1	−1	0	0	0
35	1	1	0	0	0
36	1	0	1	0	0
37	1	0	−1	0	0
38	1	0	0	−1	0
39	1	0	0	1	0
40	1	0	0	0	−1
41	1	0	0	0	1

Table A.2
Values of inputs for simulations of test data

Simulation No.	Input Factors				
	Well spacing	Fracture Spacing	Well inclination	Injection temperature	Injection rate
1	−0.500	0.200	0.000	0.533	0.138
2	0.500	−0.800	0.000	−0.199	0.122
3	−0.800	−0.200	0.000	0.377	0.420
4	−0.150	−0.600	0.500	0.102	0.598
5	0.900	−0.400	−1.000	−0.195	−0.847
6	0.300	0.600	0.000	0.168	0.634
7	0.100	0.200	−1.000	0.424	0.533
8	−0.250	0.800	0.500	0.041	0.435
9	0.600	−0.200	0.500	−0.769	0.683
10	−0.600	−0.800	−1.000	−0.002	0.748

Table A.3
Error analysis of various models

Model No.	Model (day)	R^2		NRMSE	
		Training	Test	Training	Test
1	1	0.997	0.852	1.3	11.8
2	2	0.997	0.852	1.3	11.7
3	3	0.997	0.853	1.3	11.6
4	4	0.996	0.853	1.4	11.6
5	5	0.996	0.852	1.4	11.6
6	6	0.996	0.850	1.4	11.6
7	7	0.995	0.847	1.6	11.8
8	8	0.994	0.842	1.8	11.9
9	9	0.993	0.836	2.1	12.2
10	10	0.991	0.828	2.3	12.5
11	15	0.981	0.773	3.6	14.7
12	18	0.974	0.744	4.2	16.0
13	21	0.969	0.711	4.7	17.6
14	24	0.965	0.687	5.1	19.1
15	27	0.961	0.668	5.5	19.1
16	30	0.959	0.653	5.8	19.1
17	35	0.959	0.630	5.9	19.3
18	40	0.959	0.616	5.7	19.2
19	45	0.960	0.609	5.4	18.8
20	50	0.963	0.606	5.2	18.4
21	55	0.962	0.607	5.1	18.1
22	60	0.965	0.609	4.9	17.8
23	70	0.969	0.612	4.6	17.4
24	80	0.973	0.612	4.3	17.2
25	90	0.976	0.621	4.0	16.9
26	100	0.978	0.636	3.9	16.6
27	120	0.983	0.663	3.4	16.1
28	150	0.987	0.692	3.0	15.3
29	181	0.988	0.720	2.8	14.4
30	365	0.992	0.828	2.4	11.1
31	730	0.991	0.903	2.4	8.4
32	1095	0.991	0.928	2.4	7.4
33	1461	0.992	0.939	2.3	6.8
34	1826	0.992	0.944	2.3	6.6
35	2191	0.993	0.949	2.1	6.3
36	2556	0.993	0.952	2.0	6.1
37	2922	0.994	0.955	1.9	5.9
38	3287	0.994	0.957	1.8	5.8
39	3652	0.995	0.961	1.8	5.6
40	4017	0.995	0.962	1.6	5.4
41	4383	0.996	0.968	1.6	5.0
42	4748	0.996	0.965	1.5	5.2
43	5113	0.996	0.966	1.4	5.2
44	5478	0.996	0.967	1.4	5.1
45	5844	0.997	0.969	1.4	4.9
46	6209	0.997	0.971	1.3	4.8
47	6574	0.997	0.972	1.3	4.7
48	6939	0.997	0.973	1.3	4.6
49	7305	0.997	0.974	1.3	4.5
50	7670	0.997	0.975	1.3	4.5
51	8035	0.997	0.975	1.3	4.4
52	8400	0.997	0.976	1.3	4.4
53	8766	0.997	0.977	1.3	4.3
54	9131	0.996	0.978	1.4	4.2
55	9496	0.997	0.979	1.3	4.2
56	9861	0.997	0.979	1.3	4.2
57	10227	0.997	0.979	1.3	4.1
58	10592	0.997	0.979	1.3	4.2
59	10957	0.997	0.980	1.3	4.1

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