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Sensitivity Analysis of Low-Temperature Geothermal Reservoirs: Effect of Reservoir Parameters on the Direct Use of Geothermal Energy

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ABSTRACT

Geothermal energy is a vast source of renewable energy. The latest improvements in the field of Engineered Geothermal Systems (EGS) have opened a new chapter for the use of geothermal energy. The areas lacking conventional hydrothermal resources can harness geothermal power with the help of EGS. Low-temperature geothermal reservoirs using EGS technology to increase the permeability to geothermal fluids can be used for residential as well as commercial space heating, thus, reducing the carbon footprint of space heating compared to using natural gas or other fossil resources.

The eastern United States generally has lower temperature gradients than the western United States; However, West Virginia, in particular, has higher temperature gradients compared to other eastern states. A recent study at Southern Methodist University by Blackwell et al. has shown the presence of a hot spot in the eastern part of West Virginia with temperatures reaching 150°C at a depth of between 4.5 and 5 km. This study examines a reservoir at a depth of around 5 km resembling the geology of West Virginia, USA. The temperature gradients used are in accordance with the SMU study.

In order to assess the effects of the reservoir conditions on the lifetime of a low-temperature geothermal system, we have performed a sensitivity analysis study on seven natural and human-controlled parameters within a geothermal reservoir: reservoir temperature, injection fluid temperature, injection flow rate, porosity, rock thermal conductivity, water loss (%) and well spacing.

The sensitivity analyses used two different methods of parameter variation, 'One Factor At a Time (OFAT) method' and a Plackett-Burman design. For both the OFAT and Plackett-Burman designs, all seven of the parameters mentioned above were used. The OFAT method was performed by changing one parameter at a time, while keeping the rest at constant base case values. A 30-year timeframe of operation was used to run the reservoir simulations using TOUGH2 numerical simulation software developed at the Lawrence Berkeley National Laboratory using the EOS1 equation of state module for pure water. A porous medium approach was taken to design the reservoir. For the full-parameter sensitivity analysis, a two-level (L=2) Plackett-Burman experimental design was used, with the cumulative hot water production discounted to the current year as the measured variable for comparison. The discount rate chosen was 5% (to illustrate direct-use systems incorporated into public utilities), resulting in the contribution to the net present value of a reservoir. The effects of the parameters on the real and discounted production rates were assessed in this analysis.

The results of this study provide a preliminary assessment of the effects of various reservoir parameters on the economic viability of low-temperature geothermal utilization. They also provide a comparative approach between the parameters for the optimized exploitation of a reservoir. As expected, the initial reservoir temperature has the most significant effect on the reservoir productivity.

1.0 Introduction

This paper focuses on the low-temperature geothermal resources in the eastern United States. The higher temperature gradients in the western United States facilitate temperatures higher than 150°C (Williams et al., 2008). These high-temperature reservoirs have proven to be economic for electricity generation. However, there is still a large part of the Eastern United States, which has low-temperature geothermal reservoirs that might be economically profitable in the future. These low-temperature geothermal reservoirs are characterized by temperatures ≤150°C by the Department of Energy. This definition does not include the depths at which 150°C is reached, so for the purposes of this analysis we will consider the definition of low-temperature to include areas with temperature gradients less than about 50°C/km.

As shown by Blackwell et al., (2010), there is a hot spot in the eastern part of West Virginia with temperatures reaching 150°C at a depth of around 4.5 to 5 km. Thus, this is a comparatively warmer region than other low-temperature geothermal regions, but not warm enough to be considered a high-temperature resource. Among the states in the eastern US, it may have the highest geothermal potential (Tester et al., 2006).

Before exploiting a geothermal resource, it is necessary to carry out a preliminary analysis involving knowledge about the geology of the reservoir, general understanding of the potential problems a project might face and the benefits gained from extracting energy from the resource. This research study identifies seven parameters and their interactions, which can provide preliminary indications of the potential productivity of the reservoir. The study also evaluates the significance of individual parameters with respect to the others and their relative effects on productivity of the reservoir. The parameters studied here are likely to have the largest effects on the utilization of a geothermal reservoir.

These parameters are divided in the following two categories:

- Naturally-occurring parameters (or, reservoir properties)
    - Reservoir temperature
    - Porosity
    - Rock thermal conductivity
- Human-controlled parameters
    - Injection flow rate
    - Production flow rate
    - Injection fluid temperature
    - Well spacing

A reservoir can be classified on the basis of the sub-surface temperature. Reservoir temperature and the geothermal gradient are thus, the most important parameters to verify before initializing primary analysis.

The rock geology of the reservoir also plays a significant role in the hot water production. It affects the flow rates and the pressure profile of the reservoir. Some reservoirs have a number of fractures in all possible directions while others are with virtually nonexistent porosity, preventing fluid circulation. Porosity is needed for passage of the flow of injection fluid, thus making it an important factor. Similarly, the thermal conductivity is responsible for recharging the heat to the fracture surface and moving heat into a reservoir from the surrounding rock.

The extraction of heat from a reservoir decreases its temperature over time. Therefore, in order to optimize the overall life of a reservoir, an optimum injection flow rate is needed. Also, the production flow rate needs to satisfy the economic constraints and serve the energy demands. The major benefit of having a range of values for these flow rates is for the flexibility to change the flow rates in accordance with the economic and technical factors. In the framework of an average plant life of 30 years, one must consider the cost of capital investments and their return over time. In the early years of a project, the productivity will need to be at its maximum as the *present value* is significantly higher than the *future value*. Thus, a maximum flow rate will be required in the initial years with a very little change over the years. However, higher flow rate means more heat is extracted from the reservoir, which can result in a rapid decrease in the reservoir temperature. Hence, an optimization of these flow rates is required from an economical perspective. In this study, the *water loss* in percentage (which can be defined as the fraction of water that is lost to the reservoir) is used as a parameter instead of production flow rate. This change does not affect the comparison as the water loss and production flow rate have the following linear relationship:

$$Water\ \ loss = \left(1 - \frac{production\ \ flow\,rate}{injection\ \ flow\ rate}\right) \times 100 \tag{1}$$

where the water loss is calculated as a percentage.

The injection fluid temperature is representative of the heat enthalpy being returned to the reservoir. Higher injection fluid temperatures provide lower thermal drawdown and thus longer life spans of the reservoirs. However, higher injection temperatures result in lower rates of energy extraction on the surface.

The well spacing (L) is the distance between an injection well and a production well. The pressure gradient between the injection and production well is the driving force for fluid flow. For a larger well spacing, the force of the gradient may be insufficient. Thus, well spacing affects the net flow from injection well to the production well and needs to be examined.

The purpose of this study is to analyze the effect of the above factors on reservoir economics. Furthermore, this study can be expanded to other low temperature zones in the eastern United States. The six identified factors, namely reservoir temperature, porosity, rock thermal conductivity, injection fluid temperature, injection flow rate and water loss are analyzed individually (OFAT), as well as taking into account their interactions (Plackett-Burman design).

The function that was used to compare cases and scenarios is the net discounted amount of heat extracted (ΔE_{disc}). An advantage of using this function is its ease of use. The following equation is used where ΔE_i (energy extraction during the i^{th} year) is obtained using (2):

$$\Delta E_i = M_i \times C_p \times \Delta T \tag{2}$$

where, ΔE_i is the annual energy extracted in the i^{th} year, M_i is the total production of hot water in i^{th} year, C_p is the specific heat of water and ΔT is the temperature difference between produced and injected fluid. The calculated ΔE_i is discounted at a rate of 5% to provide a discounted net heat produced:

$$\Delta E_{disc} = \sum_{i=1}^{30} \frac{\Delta E_i}{\left(1 + 0.05\right)^i} \tag{3}$$

2.0 Data Collection

As stated earlier, the study region is a hot spot in West Virginia, USA. The temperature gradients used for this study were in accordance with the study at SMU (Blackwell et al., 2010). The range of depths was between 4,500 m and 5,500 m. Since there are no field data available on the porosity, permeability, and rock thermal conductivity at these depths in West Virginia, they were calculated from the available rock composition obtained from the WVGES core sample library (McDowell, 2011). The type of rock present at that depth is high percentage of limestone, constituting mainly of Chazy and Conasauga limestone. Thus the physical properties of the reservoir are obtained by applying the properties of Chazy limestone (Carpenter, 1965) and Conasauga limestone (Hasson and Haase, 1988).

3.0 Base Model

This study was performed using TOUGH2 simulator with EOS1 module (Pruess et al., 2011) and Petrasim 5 (Alcott et al., 2006) was used for data visualization. The reservoir is 1500 m long, 1500 m wide and 400 m deep with 100 m long, 100 m wide and 100 m deep grid-blocks. In the reservoir geometry, x and y are the horizontal axes while z is the perpendicular axis or the depth. The bottom of the reservoir is at z = 0 m while the top is at z = 400 m. In the real values, the top of the reservoir is at a depth of 4,500 m for the OFAT study, while for the PB analysis the top of the reservoir is either 4,500 m (lower limit) or 5,500 m (upper limit). The fluid used for all simulations is single-phase pure liquid water. Since the reservoir is a low-temperature reservoir, there is no steam production. The problem of representing a fractured system was solved by using a simplistic porous medium approach. There are other approaches to represent the system, such as using fractures or the MINC system (Pruess, 1985). However the main purpose of this study is the comparison of the effects of averaged reservoir properties, this simple porous media approach is used. The simulations were carried over 30 years and the net amount of heat extracted over 30 years was taken as the comparative parameter for all scenarios. The graphical representation of the reservoir model is shown in Figure 1.

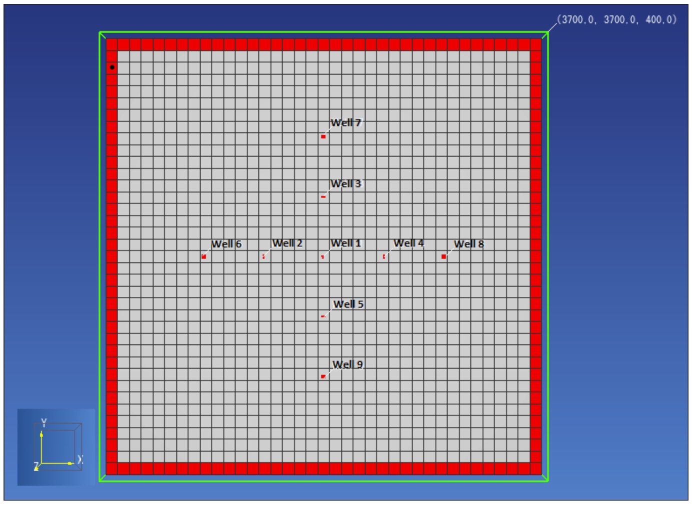

Figure 1. Top view of the base system (with injection well at the center of the reservoir (well 1) and two equidistant sets of production wells each with four wells around the injection well).

The model is based on the five-spot geometry for geothermal injection production provided by TOUGH2 user's guide, version 2.0 (Pruess et al., 1999). The red dots within the reservoir in Figure 1 are eight production wells, while the injection well is at the geometrical center of reservoir. All the wells operate at a constant flow rate. The red squares along the boundaries are *fixed state* grid-blocks, which are maintained at natural state of the reservoir at all times. These fixed state grid-blocks serve as sinks. During any given simulation, only a fraction of the production wells are operational, they are illustrated in Figure 1 to show various well spacing scenarios. The reservoir initial conditions that were used for the base case are shown in Table 1.

Table 1. Conditions for the base model.

Reservoir temperature	150°C
Bottom depth	4,500 m
Pressure	465 bar
Injection fluid temperature	15°C
Injection flow rate	80 kg/s
Porosity (volume fraction)	0.02
Permeability	1.00E-15 m^2
Rock thermal conductivity	0.5 W/(m°C)
Water loss	0%
Well spacing	500 m

The base model conditions reflect the most common geology while considering the effect of economic constraints on the variables. The expected reservoir temperature at the reservoir bottom is taken as 150°C, mainly because the hotspot is characterized by this temperature at a lower depth of around 4.5 km. Although, this resource is useful mainly for the direct use of hot water, a binary cycle power plant, with marginal economics, could produce electricity from this hot water. A simple hydrostatic pressure gradient is used for the pressure profile of the reservoir. The production flow rate generally is about 20-30 kg/s per well; therefore, the injection flow rate used here is 80 kg/s to produce 20 kg/s from four production wells. The porosity, permeability and rock thermal conductivity values are in accordance with WVGES (McDowell, 2011). Considering an ideal case scenario, the water loss is taken to be at 0% or no water loss and a moderate well spacing of 500 m is considered.

4.0 One Factor at a Time Study (OFAT)

The One Factor At a Time study was performed to analyze the effect of each of the individual parameters on the discounted heat produced. The base case conditions were simulated to obtain the expected changes in pressure, temperature and flow rates over 30 years. The parameter under study was changed over the range of values which are acceptable for the geology (McDowell, 2011) of the West Virginia hot spot, while keeping all other parameters and conditions constant.

4.1 Effect of Reservoir Temperature

The reservoir temperature was changed over the range of 120°C to 180°C for the OFAT analysis. Although the temperature is at 150°C at a depth of around 4.5 km at the hot spot, there is still uncertainty involved when considering a specific reservoir. Thus, a 30°C variation from 150°C is an appropriate assumption. The depth is 4,500 m as in the base case. All other parameters from the base case were kept constant. The heat extracted (ΔE) is discounted at a rate of 5% and the variable, ΔE_{disc} from Equation 3 is used in all other calculations. Figure 2 shows the increasing profile of ΔE_{disc} with temperature.

The large variation in values indicates the importance of reservoir temperature. Since, the depth has been kept constant at 4,500 m, the pressure in the reservoir in all cases is constant. The apparent leveling effect is due to the low number of data-points and low water enthalpy at such temperature and pressures.

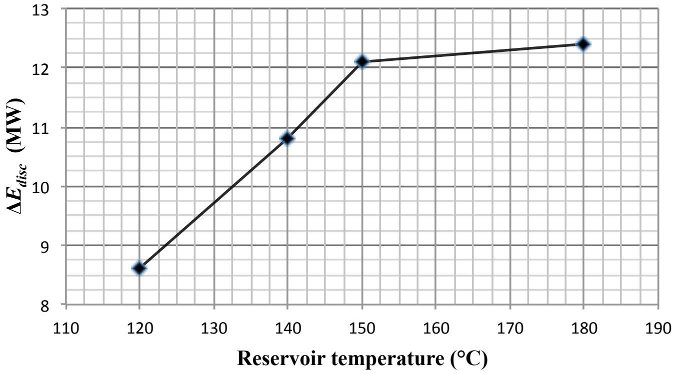

Figure 2. Variation of ΔE_{disc} with reservoir temperature.

4.2 Effect of Porosity

the porosity range used for this study is from 0.01 to 0.1 of the volume fraction. The permeability values change with porosity. Thus, for this study, corresponding permeability values (Ehrenberg et al., 2006) are used. It is expected that higher porosity should cause low values of the extracted heat (ΔE_{disc}), due to the lower amount of hot rock. Figure 3 shows the effect of porosity on ΔE_{disc}.

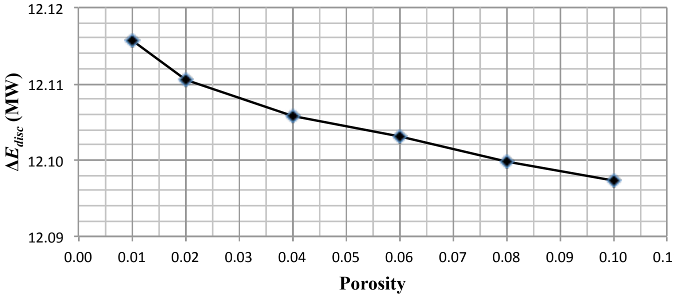

Figure 3. Variation in ΔE_{disc} with Porosity.

Thus, as we can see from Figure 3, due to the decreasing fraction of hot rock in the reservoir, ΔE_{disc} decreases as porosity increases. However, it is important to note that even a 10-fold increase in porosity does not affect the ΔE_{disc} significantly. This may suggest that the porosity, as an independent parameter, does not significantly affect the net heat extracted.

4.3 Effect of Rock Thermal Conductivity

The rock thermal conductivity (k_{rock}) is the property of the composition of the rocks in a reservoir. A higher rock thermal conductivity is expected to hasten the recovery of a reservoir. Table 2 shows the variation in the ΔE_{disc} with the rock thermal conductivity.

Table 2 shows that the change of ΔE_{disc} with the variation in rock thermal conductivity is not significant. This is because the rate at which reservoir heat is extracted is much higher compared with the conductive heat from the surrounding rock, and thus the effect of rock thermal conductivity on energy production is minimal.

Table 2. Variation of ΔE_{disc} with k_{rock}.

k_{rock} (W/(m°C))	ΔE_{disc} (MW)
0.5	12.109
1.0	12.108
2.0	12.108
3.0	12.108

4.4 Effect of Injection Fluid Temperature

The injection flow temperature governs the heat enthalpy being injected into the reservoir apart from the heat enthalpy being conducted from the surrounding rock. It can be shown that the energy balance when the reservoir is a closed system is as follows:

$$H_{Reservoir} + H_{Surroundings} + H_{Injection} = H_{Out} + H''_{Reservoir} \tag{4}$$

where H" is the remaining heat content of the reservoir.

If the injection flow temperature is higher, ΔE_{disc} is lower as the ingoing heat is higher. Unlike the effect of other parameters discussed, this decrease in ΔE_{disc} is not a negative factor. It just means that less heat is extracted from the reservoir than if fresh water is used, instead of reusing the water which is extracted from the reservoir and processed for reuse. This in turn prolongs the life of the reservoir. Thus, with higher injection fluid temperatures, ΔE_{disc} decreases but the reservoir life is longer for the production of hot water with the same temperature. Figure 4 shows the variation of ΔE_{disc} with respect to the injection fluid temperature.

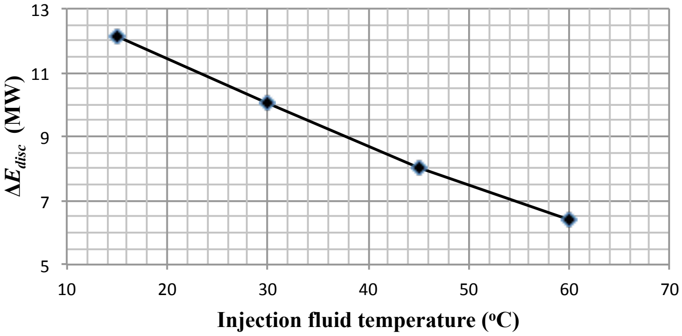

Figure 4. Variation of ΔE_{disc} with Injection fluid temperature.

Thus, Figure 4 shows that increase in injection fluid temperature decreases ΔE_{disc} significantly, and thus is an important factor. This is to be expected, because as T_{in} increases, ΔT decreases linearly, and this results in a linear profile of ΔE_{disc}. The impact of this on the production is significant. This particular result means that a higher temperature of injection fluid does not exhaust the reservoir as fast as the use of colder water. Hence, a careful study of the injection fluid temperature is necessary for the life of the reservoir, total energy being extracted and the reservoir lifetime.

4.5 Effect of Injection Flow Rate

The injection flow rate is a human-controlled parameter and the most useful tool for the optimization of reservoir life with the quality of hot water. The production rate is the other side of the injection flow rate, as higher injection rates lead to higher production rate. Thus, higher injection flow rates will result in higher extraction of heat from the reservoir. This is based on following simple thermodynamics:

$$\Delta H = \dot{m} \times C_P \times \Delta T \tag{5}$$

where, ΔH is the heat extracted, $\dot{m}$ is the mass flow rate, C_P is the specific heat capacity and ΔT is the temperature difference.

Eq. (5) shows that higher $\dot{m}$ results in higher amounts of heat extracted. This quicker depletion of reservoir leads to lower life span of the reservoir. Again, higher flow rates are necessary in the initial years when higher returns on the financial investment are expected. So, it is a trade-off between the expected reservoir life, the economics over the years, the demand and the quality of hot water required.

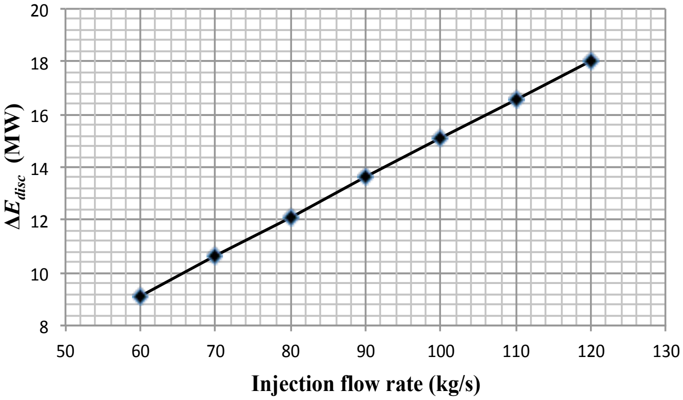

Figure 5. Variation of ΔE_{disc} with injection flow rate.

Thus, we can say from Figure 5 that the injection flow rate has a positive linear relationship with ΔE_{disc}. Higher injection flow rates in the initial years can be beneficial from an economic point of view, but an optimization considering the reservoir life and economics is necessary. The injection flow rate should be closely monitored for the profitability of a geothermal reservoir.

4.6 Effect of Water Loss

For any reservoir, water loss is unavoidable. The range of variation used for this study is from an ideal no water loss condition (0% water loss) to 4% water loss condition.

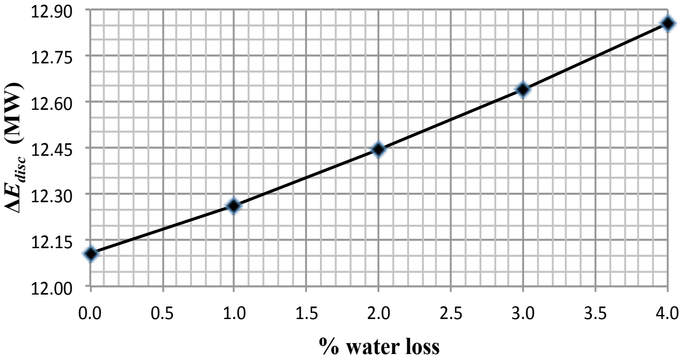

Figure 6. Variation of ΔE_{disc} with % water loss.

As Figure 6 shows, ΔE_{disc} calculated over 30 years, increases with water loss. However, the increase in ΔE_{disc} is not significant enough to conclude that higher water loss is better, as a considerable amount of utility is lost.

4.7 Effect of Well Spacing

The wells in a reservoir are placed at an optimum distance from each other. Their locations are determined by the underground geology, ease of drilling and operation and the maximum production flow rates. A large well spacing provides larger reservoir size, but it can also result in more loss of fluid, while a smaller well spacing results in a smaller reservoir, but most of the fluid can be recovered. So, the well spacing needs to be optimized in order to assure optimum sized reservoir and maximum production flow rate. Figure 7 shows the variation in ΔE_{disc} with respect to the well spacing.

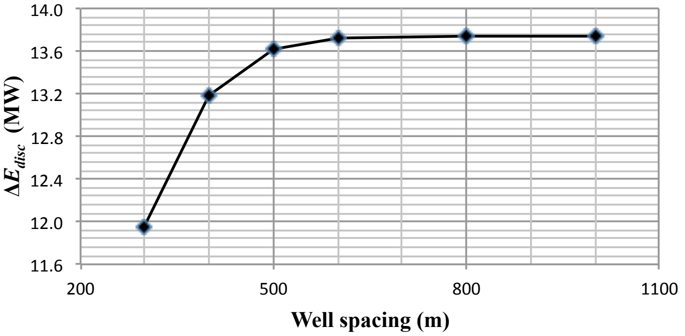

Figure 7. Variation of ΔE_{disc} with well spacing.

The initial increase in ΔE_{disc} is due to the availability of a large reservoir and thus more opportunity of heat extraction. However, as the well spacing starts getting even larger, the geologic issues such as porosity, permeability, fractures and water channels become dominant. The pressure drop to overcome all these constraints becomes too high and thus the production starts to deplete, unless a very high pressure-difference is applied. In the above case, a well spacing of about 600 m is the optimum for maximum production. In a reservoir, the well spacing should be determined so that the geologic factors and the size of the reservoir are optimized.

5.0 Plackett-Burman (PB) Design

To understand the effect of interactions between various independent parameters, a complete factorial design, a type of design of experiments, can be used. For each parameter, a high and low value is assigned and all the possible combinations are evaluated. The number of runs required for any given scenario is 2^n, where n is the number of study parameters. Thus, for this case with 7 sensitivity parameters, 128 simulations would need to be performed.

The Plackett-Burman design (Plackett and Burman, 1946) reduces the number of simulation needed while providing the ability to extract relevant sensitivity information.

The algorithm to implement the sensitivity analysis involves the following steps.

1. Select a base case
2. Determine the possible upper and lower limits of the parameters
3. Create Plackett-Burman sensitivity analysis matrix
4. Run the scenarios
5. Calculate effect of each parameter on production rates
6. Interpret the results

Table 3. Range of values for the parameters used in the reservoir simulations using the Plackett-Burman design.

Designation	Parameters	Range of Values	
		UL	LL
A	Reservoir temperature (°C)	180	150
B	Injection fluid temperature (°C)	60	15
C	Injection flow rate (kg/s)	120	80
D	Porosity (volume fraction)	0.08	0.02
E	Rock thermal conductivity (W/(m°C))	3	0.5
F	Water loss (%)	0	4
G	Well spacing (m)	1000	500

The base case was defined in the Table 1 and the upper and lower limits for the PB analysis are listed in Table 3:

As discussed earlier, the hot spot has a relatively high geothermal gradient resulting in temperatures as high as 150ºC at depth of 4.5 km. The upper limit of 180ºC is taken where a higher temperature system can be reached by drilling a well to about 5,500 m. For the injection fluid temperatures, an upper limit of 60ºC for the reuse of produced water and a lower limit of 15ºC for fresh-water is defined. A 50% higher value *i.e.* 120 kg/s than a general injection flow rate of 80 kg/s is chosen as the upper limit for injection flow rate, as this allows flexibility in the initial years for higher flow rates. The porosity and rock thermal conductivity ranges are derived from WVGES (McDowell, 2011). Well spacing varies from 500 m to 1,000 m.

For the water loss, an ideal system with a water loss of 0% is taken as an upper limit. It should be noted that the water loss is the variation of the values of injection and production flow rates only and does not indicate where it originates. If the reservoir has some water content of its own (as is the case for many reservoirs), it finds its way to the production well. Thus, although ideally 0% appears unachievable, it can be obtained based on the reservoir. A modest water loss of about 4% is used as the lower limit.

Using the seven factors in Table 3, a design matrix with 16 runs is shown in Table 4. The upper limit (*UL*) is denoted by '+', while lower limit (*LL*) is denoted by '-'.

Table 4. Design Matrix for the simulations of Plackett-Burman design.

Run Number	A	B	C	D	E	F	G
1	+	+	+	-	+	-	-
2	-	+	+	+	-	+	-
3	-	-	+	+	+	-	+
4	+	-	-	+	+	+	-
5	-	+	-	-	+	+	+
6	+	-	+	-	-	+	+
7	+	+	-	+	-	-	+
8	-	-	-	-	-	-	-
9	-	-	-	+	-	+	+
10	+	-	-	-	+	-	+
11	+	+	-	-	-	+	-
12	-	+	+	-	-	-	+
13	+	-	+	+	-	-	-
14	-	+	-	+	+	-	-
15	-	-	+	-	+	+	-
16	+	+	+	+	+	+	+

For the PB analysis, the 16 simulations listed in Table 4 were performed for a plant life-time of 30 years. For each run, a yearly value of ΔE_i was obtained. After this, ΔE_{disc} for each run was calculated using Equation 3.

Here, ΔE_i is the heat extracted in i^{th} year (annual heat extraction). The factor 0.05 is the 5% discount rate (offered in public sector and government subsidies) to discount the future production. ΔE_{disc}^{n} is the net discounted amount of heat extracted for the run *n* over 30 years. So, the future production value is discounted in order to give a present value for the total heat extracted over 30 years. After calculating ΔE_{disc}^{n} for each run, the effect (E_J) of each parameter is calculated using following relation:

$$E_J = \sum_{n=1}^{16} \frac{\pm \Delta E_{disc}^{n}}{8 \times \%\ change\ in\ J^{th}\ parameter\ between\ limits} \qquad (6)$$

where, J is from 1 to 7 corresponding to the designation of each parameter (i. e. from A to G in Table 3). The sign of ΔE_{disc}^{n} has a specific meaning. '+' is used when for a particular parameter in a particular run, the design matrix value is '+'; '-' is used when for a particular parameter in a particular run, the design matrix value is '-'. For example, the effect of A can be calculated by dividing ($\Delta E_{disc}^{1} - \Delta E_{disc}^{2} - \Delta E_{disc}^{3} \ldots + \Delta E_{disc}^{16}$) with (8×20) where 20 is the percentage change between upper limit (180ºC) and lower limit (150ºC) with respect to the lower limit.

6.0 Results of Plackett-Burman Design

The results that we obtained from the Plackett-Burman design are illustrated in Figure 8.

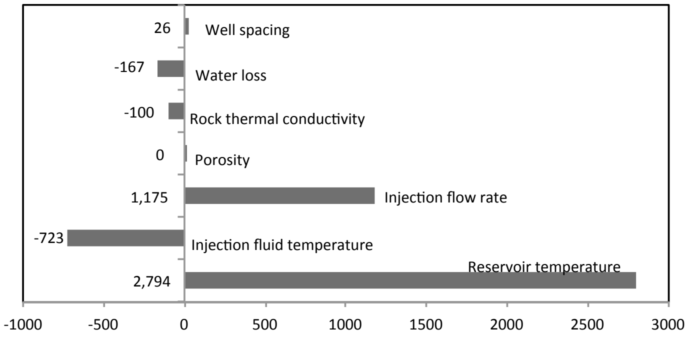

Figure 8. Comparison of the effects of parameters, obtained from the Plackett-Burman analysis.

As it can be seen from Figure 8, the effect values that we obtained for reservoir temperature, injection fluid temperature and injection fluid rate are much higher in comparison with other parameters.

The positive value of the effect of a parameter means that an increase in that parameter will result in increase of the heat extracted while the negative value means the decrease in the heat extraction. Thus, an increase in reservoir temperature, injection flow rate and well spacing results in increase of the total heat extracted, while an increase in the injection fluid temperature, rock thermal conductivity and water loss results in less heat being extracted from the reservoir over 30 years. The numerical value indicates the strength of a parameter's effect on heat extraction. Thus, the reservoir temperature has the strongest effect, followed by injection flow rate, injection fluid temperature, water loss, rock thermal conductivity, well spacing, and finally, porosity.

Higher injection fluid temperatures result in lower ΔT, thus decreasing the amount of heat extracted from a reservoir and hence it is a negative parameter. However, higher injection fluid temperatures result in increased reservoir life given a constant production rate.

The comparison between the parameters is made purely on the basis of their effect on the production. For instance, porosity does not seem to make any difference to the production from productivity point of view. However, if we consider it in economic sense, low porosity will increase the cost of production and drilling significantly. Thus, it is to be noted that the effect of parameters listed here is based purely on the productivity and not on the economic viability or ease of operation.

7.0 Conclusion

A number of issues regarding the engineering, economical factors and the reservoir properties need to be addressed while setting up a geothermal plant. Among these, the reservoir properties form a pre-requisite. Thus, having an understanding of the parameters which can be beneficially exploited forms the basis of further research. The main objective of this paper, as stated before, is to achieve that understanding of the effects geothermal reservoir parameters on discounted heat production.

As it was expected, the reservoir temperature is the most important parameter to affect the production. It is a natural property of a reservoir, which cannot be altered, thus making it a decisive factor. This is proven from both the OFAT and PB design.

From the OFAT analysis, we can conclude that the variation in porosity and rock thermal conductivity does not affect the reservoir performance significantly. The Plackett-Burman analysis proves the same results. However, a reservoir with higher porosity provides ease of operation and does not require advanced engineering or EGS. The trade-off is between having a higher porosity and using the EGS technology. Higher costs of EGS can make a high porosity condition more favorable for the reservoir operation, because EGS technology is not yet economical in most cases. In fractured reservoirs, the rock thermal conductivity is not a highly sensitive parameter as the dominant force is again the fluid convection, but these reservoirs will offer ease of fluid flow and improved porosity.

The injection flow rate is a human-controlled parameter, while water loss can be controlled to some extent. The demand of hot water is the main factor, which affects these parameters. For a higher demand, higher injection flow rate with a minimum water loss is desired, but it will hasten the exhaustion of the reservoir. These two parameters are limited by the available reservoir. Thus, they can be manipulated once the reservoir analysis is complete.

Higher injection fluid temperatures decrease the amount of heat being extracted from a reservoir. It is a negative effect parameter of significant strength. Larger well spacing provides a larger reservoir volume for the extraction of heat. Thus, the productivity increases with the increase in the well spacing, but it is not as strong of a factor as reservoir temperature or injection flow rate.

8.0 Acknowledgements

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