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What Could We See at The Production Well Before The Thermal Breakthrough?

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ABSTRACT

In the EGS Collab project, hydraulic fracturing is being studied through laboratory tests, field experiments, and mathematical modeling, in order to improve understanding of fluid and heat flow in Enhanced Geothermal Systems (EGS). The first field experiment is designed to create possibly penny-shaped fractures that connect parallel injection and production wells, and a subsequent thermal injection test is planned to help characterize fracture parameters. We performed thermal-hydrologic simulations of the planned thermal test to estimate the minimum injected flow rate necessary for obtaining a temperature signal at the production well within a reasonable time period. Using the largest injection rate based on our pumping capacity, the simulation results indicate that the injected thermal signal will not reach the production well within 15 days, which may be the maximum time considered feasible for thermal test duration. However, small thermal perturbations at the production well could be observed within this time frame, due to both thermodynamic effects and the non-uniform initial temperature distribution in the fracture. These perturbations are more sensitive to flow parameters than thermal parameters, but could be useful for fracture characterization, provided field temperature measurements are sensitive enough.

1. INTRODUCTION

The EGS Collab project is a collaborative effort to provide a field site where the subsurface modeling research community will establish validations against controlled, small-scale, in-situ experiments focused on rock fracture behavior and permeability enhancement. One of the specific objectives is to test the predictive and verification capabilities of existing codes via controlled field experiments. The related activities are designing these field experiments and optimizing monitoring networks so critical monitoring data can be obtained to inform us on key subsurface parameters. The first field experiment is designed to create fractures that connect parallel injection and production wells. Then a number of subsequent thermal and tracer tests are planned to help characterize fracture parameters (Kneafsey et al., 2018). In this paper we present numerical simulations that are aimed at helping thermal test design. The goal is to estimate the minimum injected flow rate necessary for obtaining a temperature signal at the production well within a reasonable time period (i.e., less than 15 days). In this paper we present some unexpected results from a large injection rate, which illustrates how predictive modeling can provide insights in experimental design.

2. NUMERICAL MODEL

In this section, we first have a brief introduction to the simulators. Then we summarize the assumptions we use related to fracture geometry, the simplifications we made in our numerical simulations, as well as the parameters we used.

TOUGH2/EOS1 (Pruess et al., 2012) is a simulator to perform the fluid and heat transport simulations in a fractured geothermal system. EOS1 of TOUGH2, developed mainly for geothermal applications, can simulate water in both liquid and steam phase. iTOUGH2 (Finsterle, 2017) solves the inverse problem by automatically calibrating a TOUGH model (or any other model) against observed data, or perform any other inverse-related analysis (e.g., sensitivity analysis, uncertainty quantification). We choose to use iTOUGH2/EOS1 for our simulations, for potential future inverse analysis capabilities.

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An efficient semi-analytical solution for heat exchange between reservoir fluids and confining beds is implemented in TOUGH2/iTOUGH2. The solution is based on the method of Vinsome and Westerveld (1980), and highly accurate. Therefore it provides a possibility for modeling heat exchange with confining beds that have very small or vanishing permeability, without including confining beds into the numerical mesh for flow simulations.

The model assumptions, simplifications and properties are:

1. A vertical penny-shaped fracture with a radius of 15m (as shown in Figure1) is created from the stimulation test. The aperture is assumed to be 0.1mm. The injection well, which also serves as the stimulation well, is at the center of the fracture. The production well is 10m away from the injection well.
2. Even though there could be some matrix leak-off, we ignore matrix flow at the moment. The heat exchange with the matrix is modeled through the semi-analytical solution for heat exchange.
3. The grid for modeling the fracture is discretized into 10cm in the x and z directions. There is no discretization in the Y direction, which has a size of 0.1 mm. The properties used in the simulation are in Table 1. The initial pressure of the fracture is set as around 14 MPa (with fluctuations due to hydrostatic pressure). Pressure at the production well is held constant at 13.5 MPa.

Radius (m)	Aperture (m)	Permeability (m^2)	Porosity	Thermal diffusivity (m^2/s)
15	1.e-4	1.e-10	0.95	8.e-7

Table 1: The penny-shaped fracture properties used in the simulation

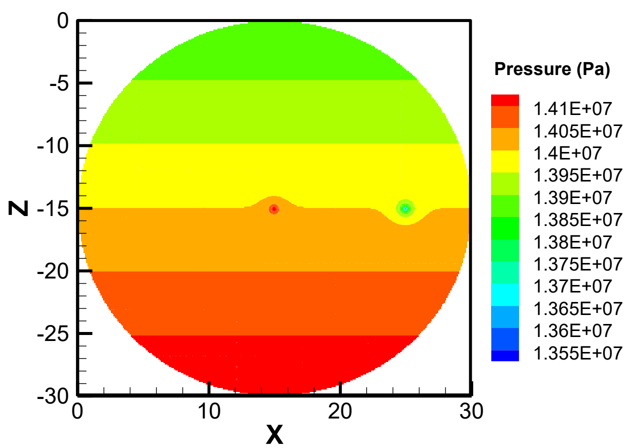

Figure 1. Model setup and initial fluid pressure, perturbed by fluid injection. The pressure build-up at the center corresponds to the injection well, the lower pressure at 10m away corresponds the production well.

3. SCENARIOS AND RESULTS

Here we consider two scenarios in which: (1) 26°C water is injected into the fracture, which is assumed to have an initial uniform temperature of 29.5°C; and (2) 31°C water is injected into the fracture, which is assumed to have an initial temperature distribution between 28~31°C. The temperature distribution is roughly estimated from kISMET temperature measurements below the drift (White et al., 2018). We present both temperature and pressure distribution at 15 days, which is considered the maximum time allowed in the experiment.

3.1 Scenario 1

For this scenario, we consider two pumping rates. Figure 2 shows the temperature and pressure distribution at 15 days based on the maximum pumping capacity, which is 400 mL/min (6.67 g/s). Figure 3 shows the temperature and pressure distribution at 15 days for a rate of 800 mL/min (13.3 g/s), twice as much as the maximum pumping capacity.

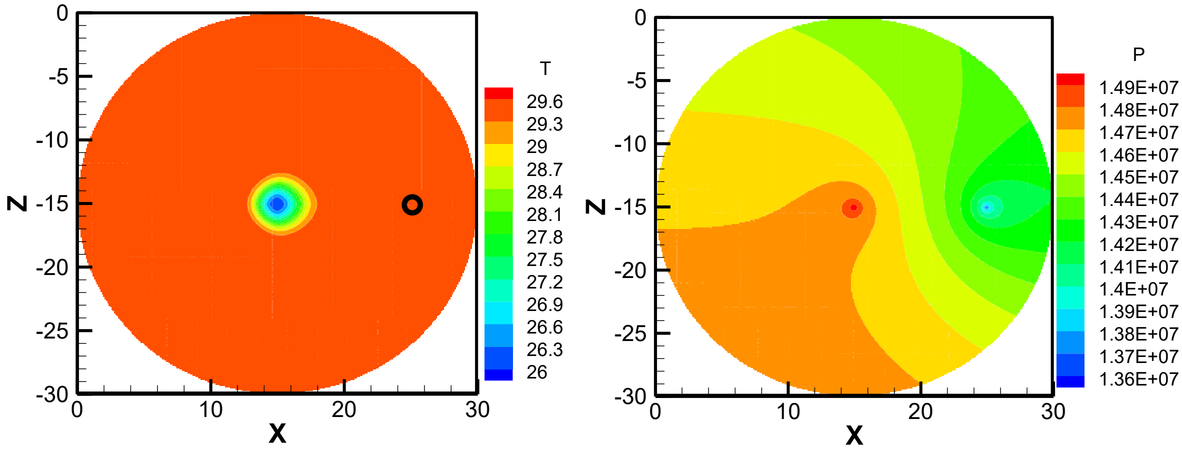

Figure 2. Temperature (black circle indicating production well location) and pressure distribution of the fracture plane after 15 days of water injection.

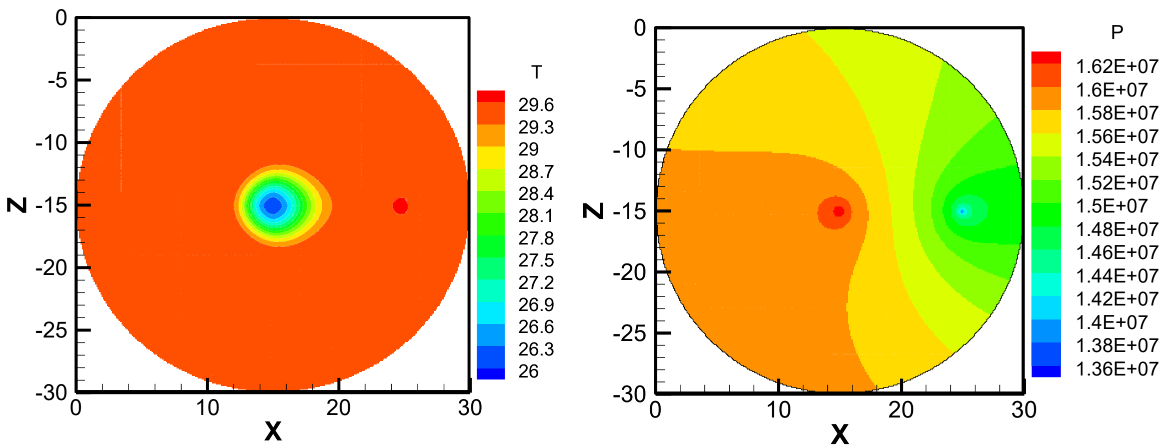

Figure 3. Temperature and pressure distribution of the fracture plane after 15 days of water injection at the higher injection rate. Note there is a slight temperature increase around the production well (0.3°C).

<u>Observation</u>: With both injection rates, the thermal signal from the injected cold water is still far away from the production well. Comparing the two figures, the thermal signal travels a little further away for the double rate, which is as expected. However, a local warm region is developed around the production well for the higher injection rate, which is unexpected. We will discuss the reason for this in the later discussion session. The pressure difference between the injection-production wells is about 14bar and 28bar in Figure 2 and 3 respectively.

3.2 Scenario 2

The initial fracture temperature distribution is shown in Figure 4, and is based on a temperature gradient observed away from the drift in the kISMET wells (White et al., 2018). For this scenario, we modified the iTOUGH2 code to accommodate the initial temperature distribution for the semi-analytical heat solution between the fracture and matrix. The injection rate used for this scenario is 400 mL/min.

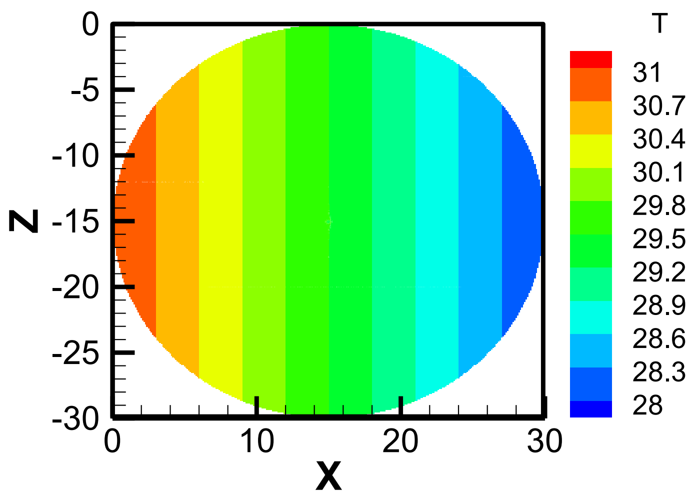

Figure 4. Initial temperature distribution used in Scenario 2. This temperature distribution is roughly estimated from kISMET temperature measurements below the drift. There a large uncertainty in this assumption. The initial temperature difference between the injection and production well is about 1°C.

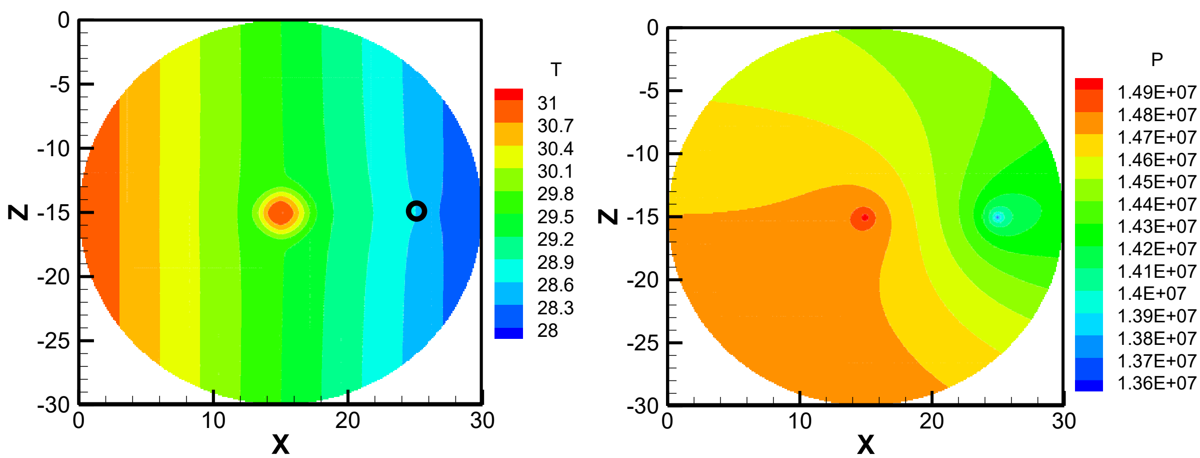

Figure 5. Temperature and pressure distribution of the fracture plane after 15 days of water injection for Scenario 2

Observation: Temperature at the production well is slightly different than its initial temperature. Figure 5 shows that although the injected thermal signal is still far away, the temperature at the production well is perturbed by the flow between the two wells, or the different fluid temperature next to the production well. The pressure difference between the two wells is similar to the one in Figure 2 because the same injection rate is used.

4. DISCUSSION

During the simulations a temperature increase around the production wellbore is observed. To understand why this happens we set up a simple 1D horizontal model (i.e., no gravity) with a length of 30m. The injection element is at the center and the production element is 10m to the right of the injection element. The column has an initial uniform pressure at 14 MPa, temperature at 30°C. Liquid water at 30°C is injected at a constant rate, and the pressure well is held at 14 MPa. There is no heat exchange between the column and the surrounding environment.

Figure 6 shows the pressure and temperature at 30 days, long after the flow reaches steady-state. At this time the energy flow in and out of the system is the same, indicating the liquid water follows an isenthalpic process along the injection-production flow line. A linear increase in temperature and decrease in pressure along the line gives a dT/dP=-0.2176 (C/MPa), the same as the Joule-Thomson coefficient for water at 30°C over the pressure range given from NIST webbook (http://webbook.nist.gov/chemistry/). The negative Joule-Thomson coefficient indicates the temperature increases when pressure drops in an isenthalpic process. The temperature to the right side of the production well stays at 30°C because there is no flow in that region (pressure at the production well is kept at the initial pressure of 14MPa).

Returning to the penny-shaped fracture simulation, the temperature profile along the flow line is a combination of a few effects. The negative Joule-Thomson coefficient of water under the pressure and temperature condition causes a slight temperature elevation near the production well. In addition, the injected water has a different temperature than the formation, and there is heat exchange between the fracture and the formation. The injected temperature affects temperature around the injection well and the heat loss to the formation affects temperature in the entire model domain.

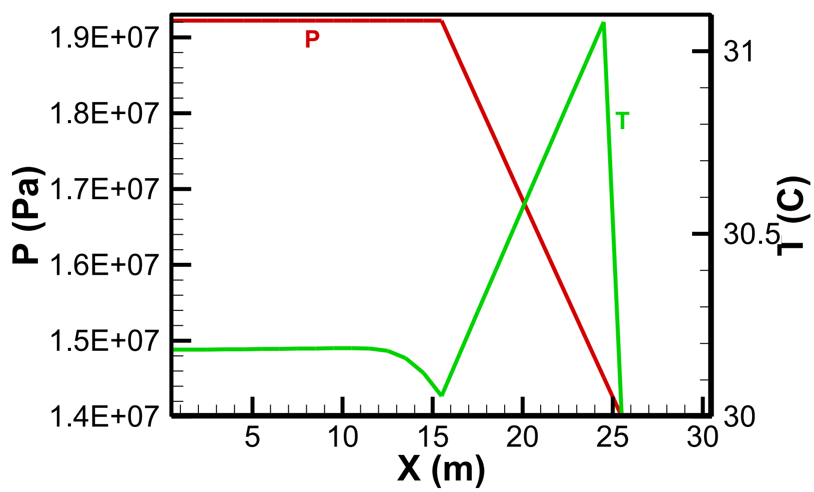

Figure 6. The temperature and pressure of the 1D column at 30 days.

CONCLUSIONS

- With the injection rate investigated (twice as much as the maximum pumping rate), the thermal signal from the injected fluid temperature will not reach the production well before 15 days.
- However, if the injection rate is large enough, or the permeability of the fracture is relatively small, the pressure gradient could be large, causing a local warm up around the production well where the pressure is lowest. Conversely, a warm-up (and its magnitude) during a large rate injection may be used to infer the pressure gradient, therefore the effective permeability of the fracture plane. This warming happens at the beginning of the experiment and reaches a steady-state quickly.
- A thermal perturbation may be observed at the production well due to initial temperature distribution in the fracture.
- Since a strong thermal signal due to thermal breakthrough may not be achieved within a reasonable time frame, the thermal test may rely on the small temperature change at early times due to large pressure gradient and initial temperature distribution. Very accurate measurements are needed for correct interpretation of data.
- The above conclusions are based on simulations without considering heterogeneity. However, the thermal breakthrough time could be significantly different if a fast flow path exists.

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