HOT DRY ROCK GEOTHERMAL RESERVOIR MODEL DEVELOPMENT
AT LOS ALAMOS

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HOT DRY ROCK GEOTHERMAL RESERVOIR
MODEL DEVELOPMENT AT LOS ALAMOS

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ABSTRACT

Discrete fracture and continuum models are being developed to simulate Hot Dry Rock (HDR) geothermal reservoirs. The discrete fracture model is a two-dimensional steady state simulator of fluid flow and tracer transport in a fracture network which is generated from assumed statistical properties of the fractures. The model's strength lies in its ability to compute the steady state pressure drop and tracer response in a realistic network of interconnected fractures. The continuum approach models fracture behavior by treating permeability and porosity as functions of temperature and effective stress. With this model it is practical to model transient behavior as well as the coupled processes of fluid flow, heat transfer, and stress effects in a three-dimensional system. The model capabilities being developed will also have applications in conventional geothermal systems undergoing reinjection and in fractured geothermal reservoirs in general.

INTRODUCTION

Reservoir engineers have long recognized the importance of fractures to fluid flow and tracer transport in underground porous media. The typical approach of employing the convective-dispersion equation with an adjustable dispersion coefficient is usually an unrealistic simplification. Multidimensional forms of the convective-dispersion equation can often provide good fits to the data, but at the expense of introducing more adjustable parameters of questionable physical significance. Furthermore, the fundamental assumption of a homogeneous porous medium may be incorrect for a fractured porous medium unless it is highly fractured (Bear, 1975).

Further complexities arise in modeling HDR reservoirs. First, since most reservoirs will be operated at pressures only slightly lower than that required to induce hydraulic stimulation, fractures will either be completely open or on the verge of
opening. For a fractured medium in this state, the porosity and permeability will be strong functions of pressure. Also, heat extraction will result in large temperature drops in the rock mass. The resulting flow patterns will be affected through the temperature-dependence of viscosity and the impact of cooling on the effective stress on joints.

Models currently under development at Los Alamos are designed to handle these complexities. First, a fracture network model has been developed to examine the steady state pressure drop and solute transport through a fracture network consisting of a realistic number of fractures. With this model, we can study the effects of parameters such as mean fracture spacing, average aperture and aperture distribution, reservoir size, and rock matrix properties on the pressure drop and tracer response. Bounds can be placed on these parameters by matching steady state field data.

However, when modeling transient behavior in three-dimensional systems which possess temperature and pressure dependent reservoir and fluid properties, the fracture network approach becomes impractical due to the enormous memory and computational time requirements. Therefore, we are also developing a continuum model which assumes an equivalent porous medium with porosity and permeability relationships designed to mimic fracture flow and transport. Using the fracture network simulations to place bounds on the reservoir properties, we may then employ the continuum code to simulate pressure and temperature dependent effects and transient behavior, thereby further constraining our model of the reservoir. This paper briefly outlines the assumptions and development of each model and presents sample calculations demonstrating the capabilities of the codes.

FRACTURE NETWORK MODEL

This section summarizes the model assumptions and capabilities of the fracture network code FRACNET. A more complete description of the model may be found in Robinson (1989).

Fracture Network Generator

A fracture network generator has been developed so that steady-state flow between two wellbores with a no-flow outer boundary can be simulated. To model fluid flow, a two-dimensional, interconnected
network of fractures is generated within a circular region. The diameter of this region is based on an estimate of the geometry of the fracture network. The outer boundary is a no-flow boundary, with wellbores simulated as constant-pressure line segments within the region.

The technique used to generate the fracture network is similar to that of Long et al. (1982). The network consists of two sets of fractures, each with a preferred orientation. The center of each fracture is located randomly in space, and then its direction, length, and aperture are generated from the given statistical distributions. When all fracture locations are generated, the code then determines the intersection points of each fracture with other fractures, the wellbores, and the outer boundary. Finally, dead-end pathways, which are nodes or groups of nodes not connected to the rest of the network or connected through only one node, are eliminated from the network.

Solution for Fluid Flow and Pressure Field

Assuming that flow in a given fracture can be modeled as laminar flow between parallel plates, the fracture aperture, the fluid velocity \( u \) is given by

\[
u = \frac{-w^2 \Delta P}{12 \mu L} ,
\]

where \( w \) is the fracture aperture, \( P \) is the pressure, \( \mu \) is the fluid viscosity, and \( L \) is the fracture length. The volumetric flow rate per unit depth of fracture \( q \) is

\[
q = \nu w = \frac{-w^3 \Delta P}{12 \mu L} .
\]

Witherspoon et al. (1979) showed that Eqn. (2) is valid for fracture flow at low Reynolds number. The aperture \( w \) is an equivalent hydraulic aperture accounting for the effects of fracture roughness and flow constrictions. Deviations from this law have been shown to be present at high effective stress (Cooke, 1988), which corresponds to a tightly closed fracture. However, since HDR reservoirs will be operated at pressures such that the effective stress is low, the cubic law should be valid. Also, matrix permeability is assumed to be small, which should be a valid assumption for granitic reservoirs, especially during long term
simulations in which matrix flow effects will have dissipated.

To solve the pressure and flow fields, an equation for the pressure at each intersection of two fractures, or node, is written from Eqn. (2). The resulting equation set is solved with the successive overrelaxation (SOR) method. Finally, the flow rate between any two nodes is calculated from Eqn. (2).

Particle-Tracking Technique

The assumption underlying the particle tracking technique is that a tracer response can be approximated by passing a large number of individual tracer molecules through the steady-state flow system, measuring the residence time of each, and accumulating the overall response as the residence time distribution of the individual molecules. The technique assumes that the transport processes are independent of the concentration of tracer, or, equivalently, that each molecule is a separate entity exerting no influence on other tracer molecules. This assumption is valid for all linear transport processes. Therefore, in addition to conservative tracer transport, equilibrium adsorption with a linear adsorption isotherm, tracer diffusion into a porous matrix, and linear adsorption on the matrix material can all be modeled with particle-tracking techniques. For geothermal reservoir modeling, matrix diffusion may be important, but adsorption generally will not be important since tracer tests are usually designed to eliminate adsorption.

To calculate the residence time of an individual molecule traveling from the source to the sink, the residence time within a fracture must first be determined, and then an appropriate rule governing tracer transport at a node must be assumed. Within a fracture, we assume that dispersion is negligible compared with overall dispersion levels caused by the large-scale heterogeneities of the fracture network (Robinson and Tester (1984)). This assumption will generally be valid unless the system is dominated by flow through one or two fractures. The fluid residence time $t_f$, or particle residence time in the absence of matrix diffusion or adsorption, is obtained from Eqn. (2) using the relationship that $t_f = \frac{wL}{q}$. Then, to simulate sorption and matrix diffusion within a
fracture, the model outlined by Starr et al. (1985) is used. Plug flow occurs within the fracture, and, although fluid flow in the matrix is assumed to be minimal, tracer transport by molecular diffusion is allowed into and out of the stagnant fluid in the matrix. In addition, equilibrium adsorption with a linear adsorption isotherm is assumed, with constant retardation factors of \( R \) for the fracture face and \( R' \) for the matrix material. From Starr et al. (1985), the outlet concentration-time response to a step change in tracer concentration at the inlet is

\[
\frac{C}{C_{in}}\text{STEP} = \text{erfc} \frac{\phi(R'R' D_f t_f)^{1/2}}{\sqrt{\pi} (\theta-R)^{1/2}}
\]

for \( \theta > R \). In Eqn. (3), \( \theta = t/t_f \), \( \phi \) is the matrix porosity, \( C_{in} \) is the inlet concentration, \( \tau \) is the matrix tortuosity, \( D_f \) is the free molecular diffusion coefficient of the tracer in water, \( R \) is the retardation factor in the fractures, and \( R' \) is the retardation factor in the matrix.

To incorporate this relationship into the particle tracking formulation, the residence time of a tracer particle in a single fracture is calculated stochastically by generating a random number between 0 and 1 and calculating the time corresponding to that value for \( C/C_{in} \). This methodology for simulating tracer transport processes within a single fracture is valid for any linear transport process. At a fracture intersection, we assume complete mixing so that the tracer partitions to the different fractures in the same proportion as the flow rate. A random number generator is used to choose which path a molecule takes. When the particle reaches the sink, the total residence time is the sum of the residence times of the individual fractures. The histogram obtained by performing this calculation for a large number of particles is the residence time distribution, equivalent to the response of the system to a short slug of tracer injected at the inlet.

One additional complication is the effect of fracture roughness on the fluid flow and tracer transport laws. The cubic law [Eqn. (2)] is generally valid for flow through fractures at low Reynolds numbers (see Iwai, 1976, Witherspoon et
al., 1979). The aperture calculated from Eqn. (2) is called the hydraulic aperture \( w_h \). This aperture is a weighted average accounting for the distribution of apertures encountered by fluid passing through the fracture. Because of the \( w \) dependence on flow rate, the narrow apertures will cause most of the pressure drop, and \( w_h \) will be much smaller than the value obtained from an arithmetic average of the apertures. On the other hand, since tracer molecules sample the entire flow volume, the tracer aperture \( w_t \) is a straight average of apertures encountered in the flowpath. Thus, the tracer aperture \( w_t \) should always be larger than \( w_h \).

Long and Billaux (1987) and Gelhar (1987) have taken experimental and theoretical approaches to addressing this issue, but additional flow and tracer experiments in cores and in the field in single fractures are needed to determine the true relationship between \( w_t \) and \( w_h \) and to examine scale effects. At present, the computer code FRACNET assumes that the ratio \( f_\psi = w_t/w_h \) is constant for all fractures in the network, and the value is set by the user as input. Then, the equations derived above involving the aperture are revised to account for fracture roughness.

Sample Calculation

A simulation of the Fenton Hill Phase I reservoir (Dash et al., 1983) has been carried out using the FRACNET code. The following parameters were used in the simulation:

Table 1. Parameters for Fracture Network Model of the Phase I Reservoir

<table>
<thead>
<tr>
<th></th>
<th>Fracture Set 1</th>
<th>Fracture Set 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of Fractures</td>
<td>300</td>
<td>300</td>
</tr>
<tr>
<td>Average Length (m)</td>
<td>100</td>
<td>100</td>
</tr>
<tr>
<td>Std. Dev. of Length (m)</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Average Angle</td>
<td>( \pi/2 )</td>
<td>0</td>
</tr>
<tr>
<td>Std. Dev. of Angle</td>
<td>0.1</td>
<td>0.1</td>
</tr>
<tr>
<td>Average Tracer Aperture (mm)</td>
<td>0.18</td>
<td>0.18</td>
</tr>
<tr>
<td>Std. Dev. of Aperture (ln(m))</td>
<td>0.5</td>
<td>0.5</td>
</tr>
</tbody>
</table>

Other Parameters:
Figure 1 shows the connected node network generated for one realization using the parameters listed above. After choosing a reservoir thickness consistent with our estimate of total reservoir rock volume, the values for the average fracture aperture and $f_w$ are adjusted to match the flow rate and tracer response. Figure 2 shows the match between the model and data for the tracer pulse response curve. The agreement suggests that these fracture network parameters describe the available steady state data for this reservoir.

The average hydraulic aperture ($w_t/f_w$) of 0.066 mm suggests that despite the hydraulic fracturing used to create the reservoir, the fractures are tightly closed shut, resulting in a high pressure drop across the reservoir. If this situation is present in future HDR reservoirs, then new methods of fracture stimulation will be required to effect a permanent increase in the hydraulic aperture. Fluid storage in the fractures is larger than would be expected on the basis of the hydraulic aperture due to the roughness effects outlined above in the discussion of the parameter $f_w$. Tracer response curves must be interpreted with this fact in mind. Finally, the mean fracture spacing derived from the fracture network parameters chosen is 12 m. Similar matches to the data could have been obtained with different fracture densities. However, this result shows that the mean spacing of the Phase I reservoir could be large enough that the system cannot be treated as an equivalent porous medium for heat transfer purposes.

Continuum Model

The example calculation using the fracture network model showed how bounds can be placed on certain properties of the network. The next stage in developing a model of a given reservoir is to simulate the observed transient behavior and the

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$u$</td>
<td>$1.95 \times 10^{-10}$ mPa-s</td>
</tr>
<tr>
<td>$\Delta P$</td>
<td>9 mPa</td>
</tr>
<tr>
<td>$\phi$</td>
<td>0.001</td>
</tr>
<tr>
<td>$\tau$</td>
<td>0.65</td>
</tr>
<tr>
<td>$D_f$</td>
<td>$2.5 \times 10^{-8}$ m$^2$/s</td>
</tr>
<tr>
<td>$R$</td>
<td>1 (conservative tracer)</td>
</tr>
<tr>
<td>$R'$</td>
<td>1 (conservative tracer)</td>
</tr>
<tr>
<td>$R_{inf}$</td>
<td>300 m</td>
</tr>
<tr>
<td>$f_w$</td>
<td>2.727</td>
</tr>
</tbody>
</table>
effect of pressure and temperature dependent properties. Then, having matched all available data, the resulting model can be used to predict future behavior. A continuum modeling approach has been adopted to handle these complexities and to provide the ability to model a three-dimensional system.

The computer code Finite Element Heat and Mass Transport (FEHM) has been developed at Los Alamos to simulate geothermal reservoirs (Zyvoloski et al., 1988). The code solves the three-dimensional conservation of mass and energy equations subject to the assumption that Darcy's law applies. In addition, tracer tests can be modeled through solution of the solute transport equation. In this paper modifications to the code that allow simulation of the reservoir porosity and permeability dependence on temperature and pressure are presented.

Birdsell and Robinson (1988) used FEHM to develop a three-dimensional, equivalent-porous-medium model of fluid, heat, and tracer transport during a 30-day flow test of the Fenton Hill Phase II HDR reservoir. They show calculations that suggest that, unlike the Phase I reservoir, the Phase II system can be modeled as an equivalent porous medium. The modeling approach was to incorporate as much of the transient hydraulic, temperature, tracer, and logging data into a single model, thereby increasing the confidence in the model. Although the model provided a better understanding of HDR reservoirs, one of the conclusions of the study was that a more detailed model, one that includes earth-stress effects, is required in order to match the data. This was most noticeable in the tracer data. The heat and mass transfer solution in FEHM could not account for the large differences in tracer responses in tests that were conducted only two weeks apart. Comparison of the tracer responses showed that the fluid volume of the reservoir had grown by almost 300% (Robinson et al., 1987). Growth of this magnitude can be ascribed to fluid storage caused by a widening of the fracture apertures.

To simulate the relationship between the effective stress and the porosity at a given location in the reservoir, the "bed of nails" model of Gangi (1978) has been incorporated into FEHM. This model assumes that fracture surfaces are covered with asperities that hold the fracture open when it is in compression. Gangi assumed that the asperities
were elastic rods and that the lengths of the rods could be characterized by a power-law distribution. Therefore, as a fracture is compressed, and more asperities come into contact, it becomes increasingly more difficult to further reduce the aperture of the fracture. A decrease in stress caused by cooling of the rock (Timoshenko and Goodier, 1951) or increased fluid pressure at a given location in the reservoir results in an increase in the local porosity \( \phi \) according to the equation

\[
\phi = \phi_0 \left[ 1 - \left( \frac{P_c}{P_i} \right)^m \right]
\]

\[
P_c = \sigma - P - \alpha E \Delta T
\]

where \( P_c \) is the closure stress, \( \sigma \) is the in-situ stress, \( P \) is the fluid pressure, \( \alpha \) is the coefficient of thermal expansion, \( E \) is the Young's modulus, \( \Delta T \) is the temperature drop from the initial value, \( P_i \) is the closure stress when the fractures are compressed to the point of zero permeability, and the subscript \( o \) indicates the values at zero closure.

The change in permeability \( k \) with porosity \( \phi \) is governed by the cubic law for fracture flow

\[
k/k_o = \left( \phi/\phi_o \right)^3.
\]

In addition to \( k_o \) and \( \phi_o \), the other parameters in the model are \( m \), the exponent in the power-law distribution of asperity heights, and \( P_i \). The effects of these parameters have been parametrically explored using FEHM.

A cube 250 m on a side was used for the reservoir geometry for the parametric study. A source-sink doublet was centered in the cube with 100 m separating the source and sink. The injection flow rate, production pressure, and other model inputs for the base case are shown along with the parameter values for the base case in Table 2. The injection pressure, production flow rate, and the response to an injection of a pulse of tracer after 10 days of simulated flow are determined for different values of the model parameters. During this time period, significant changes in the temperature field do not occur, so the effects demonstrated in the calculations are due almost exclusively to pressure changes. Figure 3 shows
the variation of the porosity and permeability versus closure stress (Eqns. 4-6) at a position between the wellbores for the base case. The closure stress varies from 50 to 0.15 MPa, which results in a billion-fold change in the permeability ($4 \times 10^{-24}$ to $3.4 \times 10^{-15} \text{ m}^2$) and a thousand-fold change in the porosity ($2 \times 10^{-6}$ to $1.9 \times 10^{-3}$). Depending on the values of $m$ and $P_i$, the magnitudes of the changes in $k$ and $\phi$ can vary from zero to a very large change. Figure 4 shows the temporal variation of the porosity and permeability at this position. This plot depicts how the local permeability and porosity change as pressure wave passes through a HDR reservoir.

Table 2. FEHM Simulation Parameters for the Base Case

<table>
<thead>
<tr>
<th>Inputs</th>
<th>15 kg/s</th>
</tr>
</thead>
<tbody>
<tr>
<td>Injection flow rate</td>
<td>15 kg/s</td>
</tr>
<tr>
<td>Production pressure</td>
<td>10 MPa</td>
</tr>
<tr>
<td>Initial reservoir temperature</td>
<td>250°C</td>
</tr>
<tr>
<td>Injection fluid temperature</td>
<td>25°C</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Parameters</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>$m$</td>
<td>0.50</td>
</tr>
<tr>
<td>$P_i$</td>
<td>50 MPa</td>
</tr>
<tr>
<td>$k_o$</td>
<td>$4 \times 10^{-15} \text{ m}^2$</td>
</tr>
<tr>
<td>$\phi_o$</td>
<td>0.002</td>
</tr>
</tbody>
</table>

Figures 5-7 show the effects of the model parameters. Since the injection rate is 15 kg/s, production rates below 15 kg/s in Figure 5 represent fluid storage in the reservoir. The time required for the production flow rate to approach the injection flow rate can be varied over a wide range with the appropriate choice of these parameters.

Figure 6 shows a local maximum in the injection pressure versus time plot for all the curves except the low permeability case. These maxima represent the time at which the pressure wave traveling outward from the injection well reaches the production well and subsequently, the pressure field is affected by the sink pressure. If the simulation were carried out to longer times, the permeabilities in the reservoir would increase according to Eqns. 4-6 and the injection pressure would begin to decline.

The shape of the tracer response (Figure 7) is controlled primarily by the porosity of the
interwell region at the time of the tracer injection, which is dependent on $\phi_0$, $P_i$, and $m$, and to a lesser degree by the rate of change of porosity during the tracer test. In one extreme, if the porosity is small and changing slowly, the tracer response will have an elevated peak with little dispersion, while in the other extreme, if the porosity is large and changing rapidly, the tracer response will be more dispersed. Thus, the tracer response of a HDR reservoir will initially exhibit less dispersion, and then become more dispersed as the porosity between the wellbores increases.

Effects such as these have been observed in the Fenton Hill Phase II reservoir during a 30-day closed-loop flow test. Future modeling studies will attempt to describe this behavior quantitatively using FEHM.

ACKNOWLEDGEMENTS

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NOMENCLATURE

$C$ concentration of tracer ($kg/m^3$),
$C_{in}$ inlet tracer concentration ($kg/m^3$)
$D_f$ free molecular diffusion coefficient of tracer in water ($m^2/s$)
$E$ Young's modulus
$f_w$ ratio of tracer aperture to hydraulic aperture (or $w_2/w_h$)
$k$ permeability ($m^2$)
$k_o$ permeability at zero closure stress ($m^2$)
$L$ fracture length ($m$)
$m$ exponent in the power-law distribution of fracture-asperity lengths
$P$ pressure (MPa)
$P_i$ stress at which porosity is reduced to zero (MPa)
$q$ volumetric flow rate per unit depth ($m^2/s$)
$q_{i}$ flow rate per unit depth from node o to node i ($m^2/s$)
$R$ sorption retardation factor on fracture faces
$R'$ sorption retardation factor on matrix material
$T$ temperature ($^\circ C$)
$t$ time (s)
\( t_f \) mean fluid residence time in a fracture (s)

\( u \) velocity (m/s)

\( w \) fracture aperture (m)

\( w_h \) hydraulic aperture (m)

\( w_t \) tracer aperture (m)

\( \alpha \) thermal expansion coefficient (K\(^{-1}\))

\( \sigma \) in-situ earth stress

\( \phi \) porosity

\( \phi_0 \) porosity at zero closure stress

\( \mu \) fluid viscosity (mPa-s)

\( \tau \) tortuosity of matrix material

\( \theta \) \( t/t_f \)

REFERENCES


Figure 1. Connected node network generated for the sample fracture network calculation.

Figure 2. Comparison of data and model calculation for a step change tracer response in the Phase I reservoir. The curve labelled "data" is the integral of the measured pulse tracer response curve.
Figure 3. Permeability and porosity as functions of closure stress at a position between the wellbores.

Figure 4. Permeability and porosity as functions of time at a position between the wellbores.
Figure 5. Production flow rate as a function of time for the base case and for cases in which a parameter was varied from the base-case value.

Figure 6. Injection pressure as a function of time for the base case and for cases in which a parameter was varied from the base-case value.
Figure 7. Production well tracer response to a pulse of tracer injected at 10 days for the base case and for cases in which a parameter was varied from the base-case value.