PROCEEDINGS, Fifteenth Workshop on Geothermal Reservoir Engineering
Stanford University, Stanford, California, January 23-25, 1990
SGP-TR-130

PRESSURE TRANSIENT MODELING OF A FRACTURED GEOTHERMAL RESERVOIR

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ABSTRACT

A fracture network model has been developed to simulate transient fluid flow behavior in a fractured rock mass. Included is a pressure-dependent aperture submodel to simulate behavior often seen in fractured systems. The model is used to simulate data from the Fenton Hill Hot Dry Rock (HDR) geothermal reservoir. Both low-pressure/low-flow-rate and high-pressure/high- flow- rate transient data are adequately simulated. The model parameters obtained suggest ways in which the model can be refined to achieve even more realistic fits to the data. The model is then used to demonstrate more efficient operating modes than the two-well circulating mode usually proposed for HDR reservoirs.

INTRODUCTION

Pressure transient modeling is commonly used in reservoir engineering to determine reservoir properties such as transmissivity and to identify the presence of boundaries. A consistent, though not necessarily unique, description of the reservoir can be obtained through application of a numerical model to slug test or pressure interference data. Most commonly, the reservoir is modeled as a porous medium with a given value of permeability, porosity, and compressibility.

Often, in fractured geothermal reservoirs, the equivalent porous medium assumption often cannot be made. Thus, one must explicitly account for the presence of fractures. Most finite difference or finite element schemes cannot easily handle more than a few fractures, making it difficult to simulate flow in highly fractured reservoirs. Furthermore, the assumption of constant compressibility is not valid for fractures. Typically, the hydraulic aperture is a strong function of the effective stress (i.e., the earth stress minus the fluid pressure) on the joint (e.g. Goodman, 1980, Gangi, 1978). This behavior cannot be adequately simulated using an effective compressibility, since the form of the mathematical expressions for conductivity and fracture volume will be different.

To handle these complexities, a numerical simulator has been developed which computes transient fluid flow in a network of fractures with pressure-dependent apertures. Since the model potentially has more adjustable parameters than a traditional porous medium continuum model, more data are required to constrain the choice of parameters. Both short-term and long-term injection tests and interwell pressure interference tests will typically be required to adequately constrain the results.

The Fenton Hill Hot Dry Rock (HDR) geothermal reservoir has been tested sufficiently to provide an excellent data set for validation of the model. An experiment is currently being carried out to determine the storage capacity and leak-off rate at the boundaries of the system at several different mean reservoir pressures (Brown, 1989). The data consist of

← forget all these "–", use spaces

[illegible]jection well and a shut-in [illegible]tion, the system was operated [illegible]g reservoir at high pressures [illegible]st carried out in 1986 (Dash et al., 1989). A measure of the comprehensiveness of the model will be its ability to match both types of data.

MODEL DESCRIPTION

The model developed for this study is a two-dimensional simulator of transient fluid flow in a fracture network. The current model is an extension of a steady state simulator developed at Los Alamos (Robinson, 1988, Robinson, 1989a and b). A two-dimensional fracture network is either generated stochastically subject to given statistical distributions or entered directly as input. For simplicity, a regular fracture network was chosen to obtain the results described below, although the effects of more complicated fracture patterns will be tested in the future. The code solves the transient mass and momentum balance equations within each fracture. Assuming the cubic law for flow in a fracture, is given by the following equation:

$$\frac{\partial(\rho w)}{\partial t} = \frac{\partial}{\partial x}\left[\frac{w^3\rho}{12\mu}\frac{\partial P}{\partial x}\right] \tag{1}$$

where ρ is the fluid density, w is the aperture, t is time, P is fluid pressure, x is the flow direction in the fracture, and μ is the fluid viscosity. Witherspoon et al. (1979) showed that the cubic law is valid for flow in fractures at low Reynolds number. However, the aperture w is an equivalent hydraulic aperture, which is probably smaller than the actual gap width. Gelhar (1987), Long and Billaux (1987), and Robinson (1988) have all observed this effect and have proposed that fracture roughness could be the cause. Fracture roughness causes flow constrictions and channeling, which introduces additional pressure drops beyond what would be observed in flow between two smooth parallel plates. In other words, if Eqn. (1) is used with w representing the hydraulic aperture, it may be necessary to assume that the fluid storage aperture is larger. Thus an additional parameter in the model is f_w, the ratio of the fluid storage aperture to the hydraulic aperture. Equation (1) is then revised to obtain

$$f_w \frac{\partial(\rho w)}{\partial t} = \frac{\partial}{\partial x}\left[\frac{w^3\rho}{12\mu}\,\frac{\partial P}{\partial x}\right] \qquad (2)$$

An additional complication is introduced by the fact that fracture aperture is a strong function of effective stress, especially at effective stresses approaching zero. For the Fenton Hill HDR reservoir, we are clearly operating in a regime in which the aperture is a strong function of pressure, as evidenced by the large increase in permeability with pressure. In the fracture network model, the pressure dependence of the hydraulic aperture of each fracture is given by Gangi's "Bed-of-Nails" model (Gangi, 1978), which correlates the aperture with the effective stress on a joint:

$$w = w_o\left[1 - \left(\frac{\sigma - P}{P_{ext}}\right)^m\right] \qquad (3)$$

where w_o, m, and P_{ext} are parameters of the Bed-of Nails model, and σ is the earth stress on the fracture. Figure 1 shows the aperture as a function of fluid pressure for reasonable values of the three parameters in the model. The Bed-of Nails model is applicable only for pressures less than the earth stress σ. At $P=\sigma$, the fracture faces will part and the fracture will either fail in shear, becoming realigned with a mismatch in the roughness profiles of the two fracture faces, or it will become jacked open with the two faces not touching anywhere on the fracture. Either situation requires a solution of the combined fluid flow and mechanical stress equations. This problem has not yet been addressed.

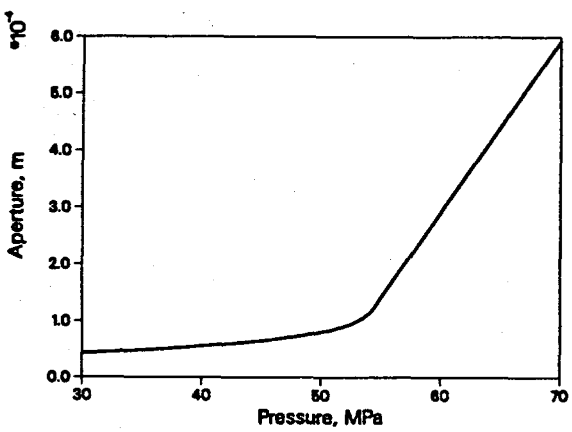

Figure 1. Aperture versus fluid pressure for reasonable values of the Bed-of-Nails Model parameters: m=0.1, P_{ext}=150 MPa, $w_o=3\times10^{-4}$ m, σ=55 MPa.

Nonetheless, in experiments at high injection pressures and flow rates in HDR reservoirs, it is observed that only a small increase in pressure is required to significantly increase the flow rate. This behavior suggests that the hydraulic aperture increases dramatically with pressure at values above the original earth stress σ. For simplicity, the model in the present study assumes a linear increase in aperture with pressure starting at a pressure slightly less than the original earth stress on the fracture. The slope of the aperture versus pressure curve is assumed to be that given by the Bed-of-Nails model at this transition pressure, so that w and $\partial w/\partial P$ are continuous functions. Theoretical research is required to provide a more fundamentally based constitutive relation at high pressures. Nonetheless, this heuristic relationship should enable the model to duplicate the behavior observed in HDR reservoirs at high pressures and flow rates.

CODE DESIGN AND CAPABILITIES

The model used in the present study is based on an earlier steady state version of the code. The code uses finite difference techniques to solve Eqns. (2) and (3) for the fracture network. A difference equation is written for the pressure at each node (intersection of two fractures or endpoint of a fracture) based on the pressures at adjacent nodes. To solve the resulting system of equations, each equation is written in residual form and the solution for the pressure at each node at a given time is determined using the Newton-Raphson technique. Derivatives of aperture and fluid density with respect to pressure are calculated from analytical expressions: $\partial w/\partial P$ is derived from Eqn. (3) and the fluid compressibility formulation is used to obtain $\partial\rho/\partial P$.

Boundary conditions are needed for the intersections of fractures with the wellbores. For a constant pressure boundary condition, a series of constant pressure nodes are used instead of unknowns at these positions. For a specified flux boundary (used to set the flow rate as a function of time), the transient mass balance equation is written for the fractures connected to the boundary, and the pressure of this boundary becomes an unknown.

To simulate field data, the capability of varying the boundary conditions in complex ways is required. In the present version of the code, a complicated pressure or flux profile can be implemented as a series of piecewise continuous line segments. When a change in the boundary condition is encountered, the code starts with a small time step and takes successively larger steps until a solution cannot be obtained or a preset maximum is reached.

The code is currently run on a Sun SPARCstation 1. All of the simulations in the present study were run on this computer system, with a typical execution time of 5 to 30 minutes, depending on the complexity of the specified flow rate and pressure input at the wells. Larger networks consisting of a greater number of fractures will require correspondingly greater CPU time.

THE FENTON HILL RESERVOIR DATA SET

The fracture network model described above was used to match data recently obtained from the Fenton Hill HDR reservoir. For the past nine months, fluid has been slowly injected into one well while monitoring the pressure response at a second, shut-in well. This experiment has provided important information about the reservoir storage and water loss characteristics.

The present study focused on data from the first 80 days of this experiment. The calculated downhole pressures of the injection and observation wells are shown in Figure 2a for the injection flow rate schedule of Figure 2b. The constant pressure of the observation well from days 10 to 30 and days 60 to 80 were deliberate attempts to determine the permeation water loss to the far field country rock beyond the fracture system at two different reservoir pressure levels: downhole pressures of 37.5 and 45 MPa.

Several characteristics suggest that a model

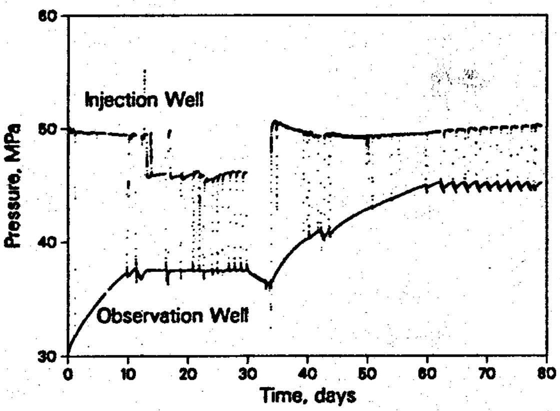

Figure 2a. Injection and observation well pressures during the low-flow-rate/low-pressure experiment. Downhole pressures are calculated from surface pressure measurements by determining the weight of the column of fluid to the depth of the reservoir.

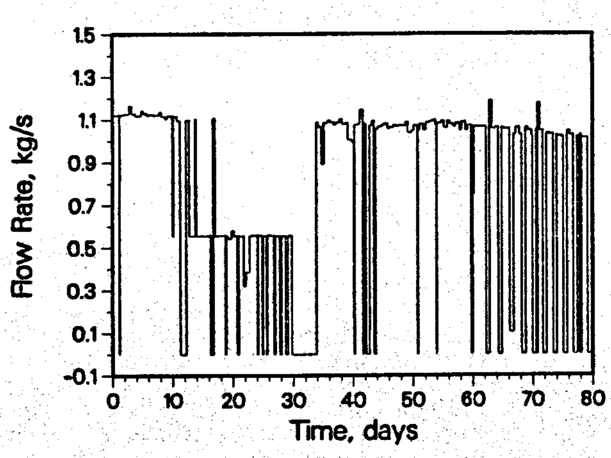

Figure 2b. Injection flow rate schedule during the low-flow-rate/low-pressure experiment.

incorporating discrete fractures with pressure-dependent apertures is required. First, the injection well pressure does not respond linearly to an increase in flow rate. Each increase in flow rate results in a smaller rise in the injection pressure, suggesting that the hydraulic aperture of the fracture increases with pressure. Furthermore, during shut-ins of the injection well, the pressure declines very rapidly to the value at the observation well. This response can be explained as a large pressure drop in the fractures near the injection well during injection. Finally, the observation well, stationed about 110 m from the injection well, responds within about 15 minutes to a change in the injection well pressure, implying that a high permeability connection exists between the wells. However, the slow rise in the observation well pressure suggests a large storage capacity.

The Initial Closed-Loop Flow Test (ICFT) of May and June, 1986 provides the other important data set which was simulated to gain an understanding of the flow characteristics of the reservoir at high injection pressures and flow rates. Figures 3a and 3b show the hydraulic response of the reservoir at two injection flow rates. In this test, the second well was a production well, since the goal of the experiment was to test the capacity of the reservoir as a two-well recirculating system. When the injection flow rate was approximately doubled on day 15, the injection pressure rose only by about 4 MPa, providing further evidence of the pressure dependence of the apertures of fractures connected to the well. To gain confidence in the usefulness of the model as a predictive tool, both the low pressure and high pressure data must be simulated.

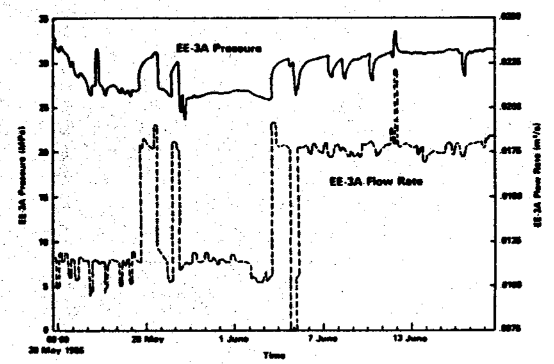

Figure 3a. Injection well surface pressure and flow rate during the ICFT.

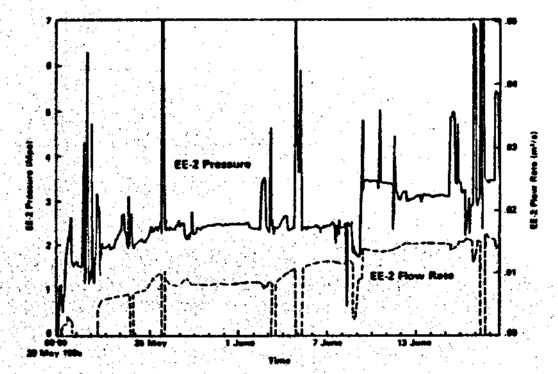

Figure 3b. Production well surface pressure and flow rate during the ICFT.

A FRACTURE NETWORK MODEL OF THE RESERVOIR

A plausible conceptual model of the reservoir is a fracture network to provide the high permeability pathways between the wells combined with a somewhat permeable rock matrix or dead end fractures in which significant volumes of fluid are also stored. Although the model does not currently include matrix storage, the parameters of the model can be set so as to roughly simulate a dual porosity medium. In the future, this limitation will be overcome by including matrix storage and transport. In addition, permeation water loss is observed beyond the boundaries the fracture system.

Figure 4 shows the regular fracture network used in the simulations. A single fracture is connected to the injection well and the observation well. The parameters of the fracture opening law are allowed to vary independently for these two fractures to capture the details of the pressure transient data. The rest of the network consists of an array of joints with the same fracture parameters. These joints also have pressure dependent apertures. To model the permeation loss, a set of fractures connecting the main network to the outer boundaries is utilized. The parameters of these fractures are set to simulate permeation into the rock matrix. As such, the apertures are set lower than those of the main fractures in the network, but a very large value of f_w is selected, corresponding to a matrix porosity on the order of 0.001. This approximation in effect results in one-dimensional fluid permeation off the four faces of the fracture network, which is probably an excellent approximation of the actual situation.

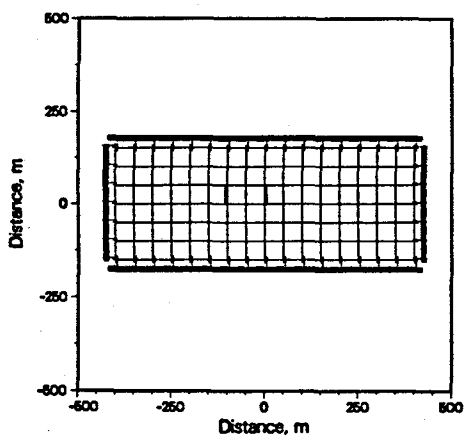

Figure 4. Fracture network used in the simulation.

MODEL RESULTS

The process of matching the data consisted of many trial and error runs in which the minimum number of parameters were adjusted while other unknowns were kept constant at reasonable values. Table 1 lists the fracture parameters used for the final match to the data.

The overall fit to the low pressure, 80-day experiment is shown in Figure 5. The general features of the pressure responses of both wells is captured, although further refinements are needed to match some of the details. The injection pressure is characterized by a rapid rise upon initiation of pumping, followed by a leveling off. The predicted change in injection pressure as a function of flow rate is also approximately correct. Another characteristic of the injection well behavior simulated reasonably well by the model is the shut-in behavior (Figures 6a and b). The injection well pressure drops rapidly to the pressure of the reservoir at large, indicating that a large pressure drop is occurring near the injection well. The model captures this behavior.

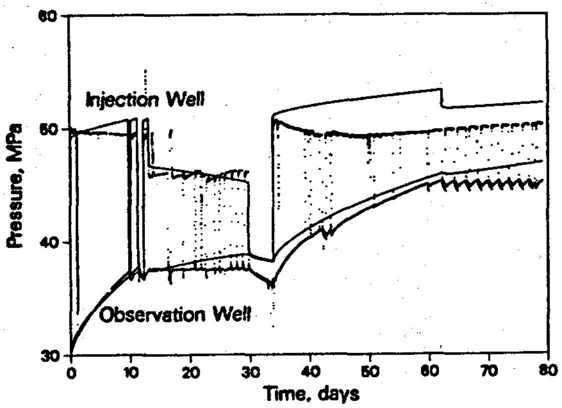

Figure 5. Overall fit of the model to the data in the low-pressure/low-flow-rate experiment.

Table 1. PARAMETERS USED IN THE SIMULATIONS

	Inlet Fracture	Outlet Fracture	Main Fractures	Matrix Fractures
p_{ext}	150	150	150	117
w_o	1.1×10^{-4}	3×10^{-4}	3×10^{-4}	3×10^{-4}
f_w	8	8	20	5000

$m = 0.1$ and $\sigma = 55$ MPa for all fractures.

The key area in which improvement can be made is in the injection pressure response during long-term pumping. The model prediction continues to rise slowly, while the data stays constant and even drops slightly. Part of the discrepancy is due to wellbore cooling effects, which increase the weight of the fluid column over time. If the data are corrected for this effect using the wellbore heat transmission solution of Ramey (1962), the downhole pressures would actually be about 2 MPa greater than shown in the figures. However, the trend would still not be captured adequately by the model. Other ways to improve the model are either to use somewhat different parameters for the fracture connected to the injection well or to include thermal effects in the fracture itself, which in theory should result in an opening of the fracture as it cools. These approaches will be the subject of further study.

The simulated observation well pressure response is also shown in Figures 5, 6a, and 6b. The general features of the response are captured quite well by the model, except for the rise in pressure observed during periods in which the data had reached a plateau from days 10 to 30 and 60 to 80. Nonetheless, the initial pressure rise and the rapid response due to shut-ins at the injection well (shown on an expanded scale for two shut-ins in Figure 7) are captured quite well by the simulation.

To improve the fit, it appears that the permeation water loss to the far field should be adjusted. With larger permeation loss, the pressure plateaus mentioned above would be more faithfully matched. Also, the pressure during the four-day shut-in starting at day 30 would decline more rapidly, thereby matching the field data. Finally, the problem of rising injection well pressure at long times also may be corrected if more fluid is allowed to drain from the main fracture system.

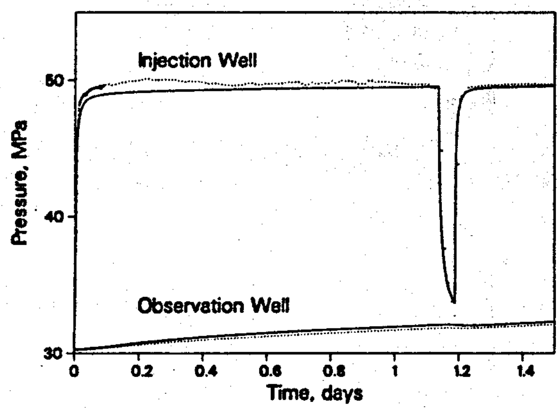

Figure 6a. Pressure response for a shut-in of the injection well.

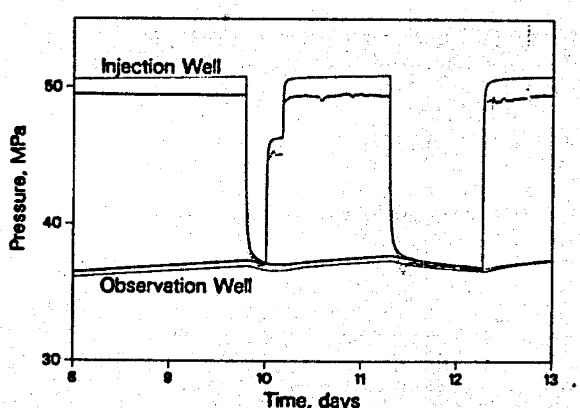

Figure 6b. Pressure responses for two shut-ins of the injection well.

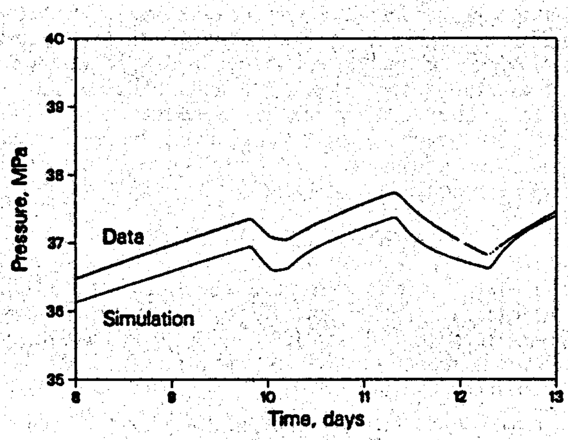

Figure 7. Data and simulated monitoring well pressure response for two injection well shut-ins.

The ICFT experiment differed from this low pressure test in that the observation well was used as a production well, and the flow rates were roughly 10 times as large. The inlet flow rate and outlet pressure were provided as input, and the outlet flow rate and inlet pressures were calculated and compared to the model. The results of Figure 8 show that the model also accurately simulates the outlet flow rate versus time during this experiment. The inlet pressure in the simulation rose rapidly and leveled off at 60.5 MPa for the first 15 days of the test, and after the flow rate change rose to 62.0 MPa. Although this pressure rise is somewhat less than was observed in the field (4 MPa), these values are reasonably close to the pressures measured at the surface after correcting for the weight of the fluid column and wellbore heat transfer effects.

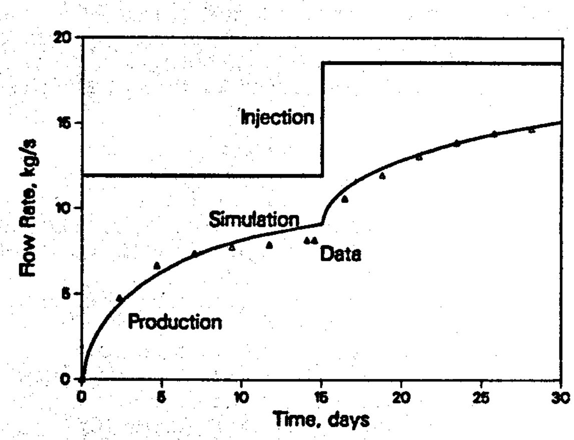

Figure 8. Comparison of data and model for the production flow rate during the ICFT. The discrete data points are taken off the curves of Figure 3.

The parameters used in the simulation provide insight into the properties of the reservoir and how the model can be enhanced to obtain even more realistic results. However, any refinements to the model must retain the pressure dependent aperture model to capture the observed increase in permeability with pressure.

The term f_W plays an important role in the behavior of the model. For the main fractures f_W=20, meaning that within the main fracture system there is 20 times the fluid storage capacity than would be suggested by the permeability measurement alone. This storage may actually reside in dead-end fractures or in the porosity of the matrix blocks defined by the main fractures. Alternatively, more fractures may exist, each of which possess somewhat smaller apertures, so that the overall permeability remains the same but the storage is increased. Even the fractures connected to the inlet and outlet wells required f_W=8 to achieve an adequate fit. This result could be modeled more realistically with several fractures connecting each well, each of which has a somewhat smaller aperture and f_w. Future work will attempt to arrive at a fracture system which better fits the observed data with more realistic fracture parameters and a greater number of fractures.

RESERVOIR SIMULATIONS USING DIFFERENT OPERATING MODES

Given adequate fits to the available data, the next step is to simulate how the reservoir will perform under operating modes different than that carried out in the ICFT. It has been proposed that raising the pressure of the production well would allow the system to be operated with lower pumping costs while sacrificing little in terms of flow rate. In theory, a higher backpressure would open the fractures connected to the production well, thus overcoming the negative effect of a lower overall pressure drop across the system.

In three transient simulations of a high backpressure experiment, the backpressure was assumed to rise linearly from the initial reservoir pressure to the specified value over a period of 1 to 20 days, depending on the backpressure chosen. The inlet pressures for the three simulations fell within 1 MPa of each other, and the outlet flow rates all approached the nearly the same value after 100 days. Thus, the proposal appears to have merit, in that the flow rate through the system is predicted to be practically constant for any backpressure within the range simulated.

A cyclic, two-well huff-puff mode of operation has also been proposed to enhance the efficiency of HDR systems. Experiments have shown that large inlet flow rates can be achieved with only small additional increases in injection pressure, presumably because of the fracture opening law depicted in Figure 1. By injecting at high pressures during the night when electric power demands are lowest, and producing in the daytime when additional power is typically required, a huff-puff HDR scheme could fit neatly into an electric power generation process by utilizing excess power when it is available and generating large amounts of electricity when it is needed. An additional advantage of cyclic operation would be more efficient heat extraction, since a larger volume of rock would be accessed than in the steady state circulating mode.

Figure 9 shows a simulation of the initial filling of the reservoir, followed by two cycles of a huff-puff operation in which fluid is injected for 12 hours with no production, followed by 12 hours of production with no injection. The model predicts that the production flow rate could be increased by at least a factor of 5 above that which is contemplated for a steady state mode of operation. Furthermore, since the production flow rate can be achieved at high backpressure, the net pumping power requirements would be less than is required in steady state, low-backpressure circulation. The main question to be answered is whether this operation could be carried out without significant water loss and microseismicity. Revision of the model to represent the mechanism of fracture extension is required to simulate this phenomenon. Of course, a field test of the concept would also be necessary to validate any model results obtained.

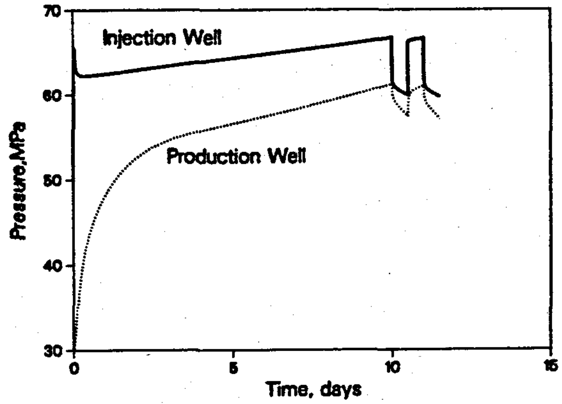

Figure 9. ·Injection and production well pressure responses during huff-puff operation. The reservoir is filled at 53 kg/s for 10 days, followed by two 12-hour cycles of production at 45 kg/s with a 12-hour, 53 kg/s injection in between.

CONCLUSIONS

With proper adjustment of fracture opening and storage parameters, the fracture network chosen to represent the Fenton Hill reservoir adequately simulates the hydraulic data both for low-pressure/low-flow-rate and high-pressure/high -flow-rate conditions. Refinements are needed to better capture the far-field permeation water loss and the injection well pressure response to changes in flow rate, but key aspects of the data are matched quite well using the model. Regardless of the unavoidable nonuniqueness in such a model, the fracture apertures clearly must be a strong function of pressure to match the data. Furthermore, the fluid storage capacity is much larger than can be explained by the permeability data alone. This suggests that fluid is stored either in dead-end fractures or in the rock matrix, neither of which contribute to the pressure drop across the reservoir when it is operated as a two-well recirculating system. Refinements to the model will be made to directly simulate these possibilities.

Two alternative modes of operation were shown to be potentially superior to the two-well recirculating concept. High backpressure simulations demonstrated the possibility of obtaining nearly the same flow rate through the system with lower pressure drops. The huff-puff operating mode would allow much larger flow rates and power production to be obtained, also at lower pressure drops. Model enhancements and simulations, followed ultimately by field tests, are recommended to determine if these operations could be performed without unwanted fracture extension and microseismicity.

ACKNOWLEDGEMENTS

This work was performed under the auspices of the U.S. Department of Energy, Geothermal Technology Division. I would like to thank Don Brown for many helpful technical discussions and Zora Dash for her editorial comments.

NOMENCLATURE

f_w	ratio of storage aperture to hydraulic aperture
m	parameter in fracture opening law

P	fluid pressure, MPa
P_{ext}	parameter in fracture opening law
t	time, s
w	hydraulic aperture, m
w_0	aperture at 0 effective stress, m
x	flow direction in a fracture, m
ρ	fluid density, kg/m^3
μ	fluid viscosity, MPa-s
σ	earth stress, MPa

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