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A THREE-DIMENSIONAL MODEL OF FLUID, HEAT, AND TRACER TRANSPORT IN THE FENTON HILL HOT DRY ROCK RESERVOIR

Stephen A. Birdsell* and Bruce A. Robinson

Los Alamos National Laboratory
Los Alamos, NM 87545
*Contractor

ABSTRACT

A three-dimensional model of the Fenton Hill Hot Dry Rock reservoir has been developed. The model matches hydraulic, thermal, tracer, and water loss data during a 30-day flow test. Wellbores were placed in the finite element mesh at their relative positions. The data match to this flow test was used to make long-term simulations, and to predict the effect on reservoir performance of redrilling the damaged production wellbore. Increasing the length of producing interval by drilling was found to significantly improve reservoir power production and the temperature of produced fluids, while increasing the wellbore separation distance was found to result in only small improvements.

INTRODUCTION

A 30-day flow test was conducted at the Fenton Hill Hot Dry Rock (HDR) reservoir in May and June, 1986. Although a large quantity of data was recorded, previous attempts to model the test have focused on only portions of the data, such as pressure transient analyses and models for tracer transport. In this study, the computer code Finite Element Heat and Mass Transfer (FEHM) (Zyvoloski et al., 1988) was used to incorporate all of the relevant hydraulic, thermal, tracer, and water loss data into one model.

FEHM is a three-dimensional computer code that was designed for the analysis of geothermal reservoirs. The code solves the conservation of mass and conservation of energy equations subject to the assumption that Darcy's law applies. In addition, tracer tests can be modeled through the solution of the noncoupled solute transport equation. Reservoirs can be modeled as porous media, or discrete fractures can be placed in the mesh. To be practical, a three-dimensional computer code must require little computer memory and execute rapidly. The incomplete factorization method used in FEHM has both of these characteristics.

MODEL DEVELOPMENT

Construction of the model begins with the choice of the outer reservoir boundary and wellbore positions. A cube was chosen for the boundary since it allowed the finite element mesh to be created most easily and could be used to approximate the current limits of the reservoir. The open hole intervals of the injection and production wellbores were placed in the mesh at approximately their known relative positions, thus providing the reservoir fluid source and sink (Figure 1). Wellbores were placed vertically in the cube since excessive computer memory and execution time would be required to mesh in their exact inclined positions. This is a good approximation since the actual injection and production intervals deviated only slightly from the vertical. The injection interval was determined from temperature logs since injection did not appear to be occurring over the entire open hole section of the wellbore. The production interval was taken as the distance from the casing shoe to the sanded-back point (Table 1). North and East locations of the wellbores were determined by the midpoint of the respective injection and production zones. The injection interval, which is longer than the production interval, is centered in the depth direction of the cube, while the wellbore pair is centered in the N-S and the E-W directions, as shown in Figure 1.

For this initial study, the reservoir was assumed to be an equivalent isotropic porous medium. The fluid volume of the reservoir has been estimated to be 8440 m^3 by analysis of a tracer experiment conducted during the flow test (Robinson et al., 1986). Hence, the volume of the reservoir (rock plus fluid) can be calculated by choosing a porosity. For example, the porosity which best matched the 30-day flow test data was $\phi = 0.0002$. Therefore, the length of the sides of the cube are 350 m. To simulate the observed water loss, flow through the faces of the cube was allowed if the local pressure reached a prescribed pressure, roughly equivalent to the fracture extension pressure (i.e., the water loss was assumed to be due to fracture extension).

The following data was input for the simulation of the 30-day test: injection flow rate, production pressure, injection temperature, and the background temperature log. Data that were matched are: production flow rate, water loss flow rate, injection pressure, production temperature, and the tracer response curve. Temperatures and pressures at the reservoir inlet and outlet were estimated from surface data using the computer code WBHT (Dash and Zyvoloski, 1982). Porosity, permeability, and the water loss pressure were adjusted to obtain the match. The procedure used to match the data is:

1. Using the reservoir fluid volume (calculated from tracer data) and a chosen porosity, calculate the volume of the cube. Center the injection and production zones in the cube. The original background temperature log in the injection well is used to place a temperature gradient on the cube.

2. Set the injection flow rate, injection temperature, production pressure, permeability, and water loss pressure.

3. Run the simulation for 25 days (the day of the tracer experiment). If the injection pressure, production flow rate, water loss flow rate, and production temperature do not match the known values, adjust the permeability and/or water loss pressure. If these values are matched, restart the simulation including a tracer test on day 25. If the simulated peak tracer response matches the experimental peak tracer response, the simulation is completed. If not, adjust the permeability, porosity, and water loss pressure. Then return to 1. and repeat the process.

RESULTS AND DISCUSSION

The Fenton Hill reservoir can be modeled as an equivalent porous medium if the reservoir is highly fractured with many interconnected flow paths linking the source and sink, as is suggested by reservoir data. The tracer data can give a rough estimate of the number of fractures in the reservoir if assumptions are made about the geometry of individual fractures. Assuming that each fracture has an aperture of 1 mm (Dash and Murphy, 1985) and length and width of 100 m (approximately the separation of the wellbores), then the number of fractures is the reservoir fluid volume divided by the volume of each fracture

$$n = 8440 / (0.001 \times 100 \times 100) = 844 \text{ fractures.} \tag{1}$$

Thus, the reservoir appears to be highly fractured. If the fracture network does not channel flow preferentially, then the isotropic porous media assumption appears appropriate for modeling the fluid flow. However, porous media flow may not be appropriate for heat transfer modeling if the fractures are separated by distances such that heat conduction in the rock limits heat transfer to the reservoir fluid. Robinson and Jones (1987) show that for HDR reservoirs, fracture spacing greater than about 3 m will result in heat transfer that is conduction limited. Evenly distributing the number of fractures calculated in eq (1) over all three dimensions of the cube gives a fracture spacing of 1.2 m. Therefore, by assuming that the fractures are roughly evenly distributed throughout the reservoir, the porous flow model will also accurately model heat transfer.

The source and sink in the cube model represent open wellbores separated by a porous medium. If many fractures intersect the wellbores, this is a good approximation. However, if only a few fractures intersect a wellbore, they should be modeled as individual fractures connected to the porous medium. A temperature log conducted in the injection wellbore about 6 days after the flow test showed a fairly constant temperature depression over the injection interval. Therefore, it can be assumed that the injection wellbore was connected to the reservoir by many fractures. A temperature log was not obtainable in the production zone. Given this uncertainty, the porous media assumption was also applied to the production zone.

The mesh used for the simulation of the 30-day flow test is shown in Figure 2. The mesh is composed of 14 x 15 x 14 nodes for a total of 2940 nodes. The fineness of the mesh was checked by adding one node in each direction in the interwell region. Since most of the flow occurs in the interwell region, error due to a coarse mesh should be evident. However, no significant changes in flow, temperature, or tracer responses resulted. Time step size was also checked. The initial time step was changed from 10^{-4} days to 10^{-5} days and the time step multiplier was reduced from 2 to 1.5, resulting in smaller time steps throughout the simulation. No significant changes resulted from this reanalysis.

The matched and observed hydraulic and temperature results are given in Table 2 and the matched and observed tracer responses are shown in Figure 3. These data were matched with a porosity of 0.0002, a permeability of 1.1×10^{-3} darcy, and water loss pressure at the surfaces of the cube of 53 MPa. The peak tracer response was matched and the shape of the simulated tracer response is similar to but higher than that of the experimental tracer response. The tail of the experimental curve cannot be measured accurately, but can be estimated using techniques developed by Robinson and Tester (1986). Since the area under the two curves between zero and infinite time must be the same, the tail of the experimental curve must be much longer than that of the simulation.

Therefore, the porous cube model results in a less disperse estimate of reservoir flow than the tracer data indicates.

During the 30-day flow test, production occurred over only a short depth interval. In order to improve reservoir performance during the upcoming year-long flow test, this wellbore was redrilled. The new wellbore, referred to as the close-in trajectory, was drilled with essentially the same trajectory as the old wellbore, but the length of the producing interval was increased. An alternative redrilling plan that was considered, the step-out trajectory, was to move the production wellbore about 125 m farther away from the injection wellbore in the horizontal plane and increase the producing interval. The locations of the production wellbore for the two cases are shown in Table 1. In order to define a producing interval for each case, fracture planes identified by a statistical treatment of microseismic events in the reservoir were used (Dreesen et al., 1987). Meshes for close-in and step-out were similar to the mesh used for simulation of the 30-day flow test, but the nodes defining the wellbores were moved to their respective positions.

Figure 4 shows the experimental tracer response from the flow test, the matched tracer response from the flow test, and the predicted responses for the close-in and step-out configurations for the production wellbore. The close-in and step-out simulations were performed with the same inputs and matched parameters as those from the 30-day flow test. The close-in prediction has a more disperse tracer response than the flow test match due to the larger flow sink. The step-out tracer response has a more disperse tracer response than the close-in prediction due to the greater wellbore separation.

Figure 5 shows long-term simulations of power output for the 3 cases. The initial power production is greater for close-in and step-out for two reasons. First, the production wellbore is drilled deeper into the reservoir where higher temperatures are encountered. Second, the prediction based on the flow test has a greater water loss. Power production is greatest for the step-out case since flow in the cube is the most uniform for this case, resulting in more efficient energy extraction.

Figure 6 shows the simulated downhole injection pressure out to 20 years for each of the production wellbore configurations. The prediction based on the flow test match has the largest pressures due to its small fluid-flow sink. Injection pressures are predicted to be larger for the step-out case than for the close-in case despite the fact that the sink is the same size in each case. This is because the step-out case has a larger wellbore separation. Figure 7 shows the production flow rates. Water loss increases throughout the simulation of the flow test match due to increasing interwell flow impedance (i.e., flow rate divided by pressure drop). This behavior is caused by the increasing fluid viscosity which results from thermal drawdown between the wellbores. For water, viscosity increases by a factor of 10 when cooled from 260 to 25°C. Therefore, as the interwell region becomes cooled, flow through the leak-off nodes on the surfaces of the cube increases. Since the larger sinks of the close-in and step-out cases result in less interwell pressure drop, no water loss occurs in the close-in case, while water loss just begins in the final year of the simulation for the step-out case.

The trend of increasing interwell impedance may not be observed in long-term operation of HDR reservoirs. This is because thermal contraction of the rock mass may open fractures and, according to the parallel plate law, impedance would decrease as the cube of the fracture aperture. However, fractures need not open uniformly. If the interwell pressure drop is dominated by relatively few asperities, impedance would not be greatly affected by thermal contraction and the effect of increasing viscosity may have a significant effect on the interwell impedance.

Hence, instead of short-circuiting of flow between wellbores due to fracture opening, flow in HDR reservoirs may prefer hot flow paths, resulting in a reservoir in which flow diverges away from the previously cooled paths. Also, the trend of increasing water loss may not be observed in HDR reservoirs. While the cube model has fixed boundaries through which water loss flows, in reality the points of fracture extension will move away from the injection wellbore with time. Therefore, the pressure drop to the points of fracture extension can be expected to increase with the age of the reservoir, and eventually pressures will not be high enough to cause further fracture extension.

Figure 8 shows the predicted downhole production temperatures for the three simulations. The difference in initial temperatures, as mentioned earlier, is due to the deeper wellbores of the close-in and step-out case.

Further development of the model is planned. Elimination of the water loss pressure as an adjustable parameter can be achieved by using values determined from hydraulic stimulation tests (Kelkar, et al., 1986). Temperature and pressure effects on permeability and porosity can be included given appropriate models. This is desirable since increases in water loss and permeability due to temperature and pressure induced fracture opening could be accounted for. Also, discrete fractures located by a statistical treatment of microseismic events in the reservoir could be placed in the cube (Dreesen et al., 1987). Finally, pressure transients were not matched in the present cube model. Future matches will attempt to use these data.

CONCLUSIONS

1. Hydraulic, thermal, tracer, and water loss data from a 30-day flow test at the Fenton Hill HDR reservoir were matched using a porous medium flow model on the basis of reasonable assumptions regarding reservoir characteristics. Porosity, permeability, and water loss pressure were adjustable.

2. Both power production and water loss were predicted to improve considerably for the close-in and step-out redrilled production wellbores. The small difference in power production between close-in and step-out suggests that the increased risk of not connecting to the fracture network with the step-out target was not justifiable, unless a larger reservoir was a paramount goal of the project.

3. The interwell impedance increases with time due solely to the increase in viscosity with decreasing temperature. This effect may be counteracted by fracture opening, which was not considered in this model.

ACKNOWLEDGEMENTS

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Table 1. Wellbore locations for the three cases: flow test, close-in, and step out.

Wellbore	Midpoint of Producing Zone (m)	Producing zone (True vertical depth) (m)	North (m)	East (m)
Production	3539	3529-3550	- 218	- 357
Injection	3516	3466-3565	- 334	- 327
		Close-in		
Production	3582	3427-3737	- 197	- 355
Injection	same	same	same	same
		Step-out		
Production	3582	3427-3737	- 97	- 382
Injection	same	same	same	same

Table 2. Modeled hydraulic and temperature data from the 30-day flow test. Input data are: inlet flow rate = 18 Kg/s, inlet temperature* = 47°C, production pressure* = 32 MPa, and the initial temperature profile varied linearly with depth from 230°C at the top of the reservoir to 261°C at the bottom.

	Injection Pressure (MPa)	Production Flow Rate (Kg/s)	% Water - Loss	Production Temperature (°C)
Measured*	65.3	12.6	30%	232
Model	66.9	12.6	30%	242

* Downhole pressure and temperatures were calculated from surface data using the computer code WBHT.

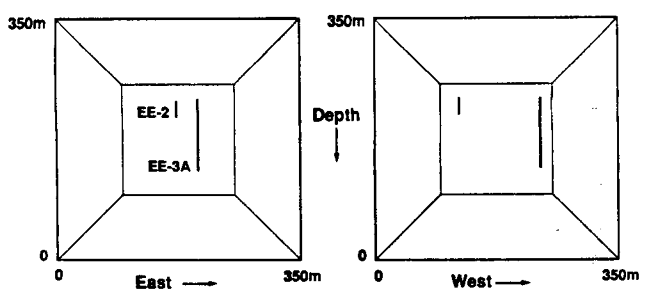

Figure 1. Orientation of the injection and production zones within the cube.

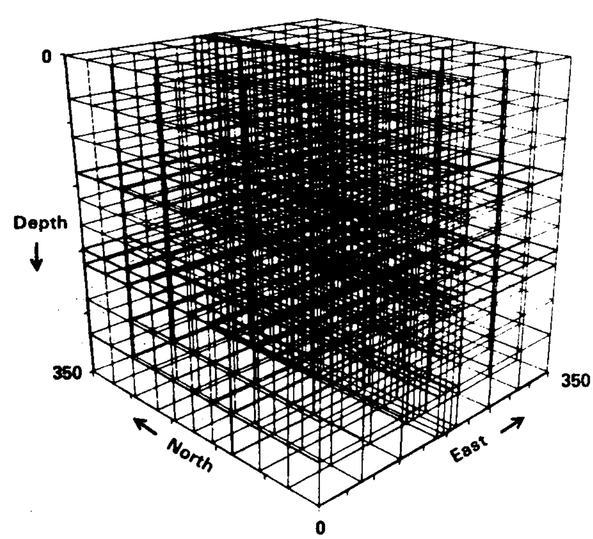

Figure 2. Finite element mesh used for the simulations.

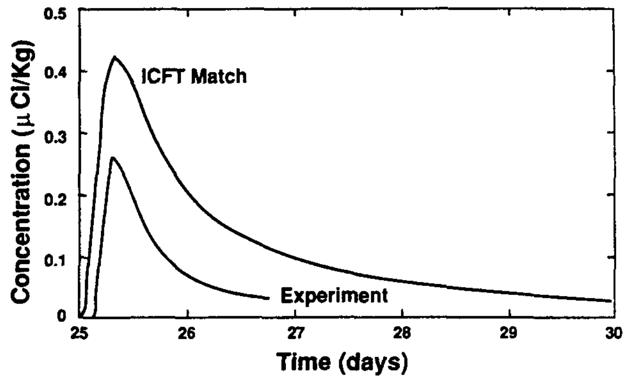

Figure 3. Experimental and matched tracer response for the 30-day flow test.

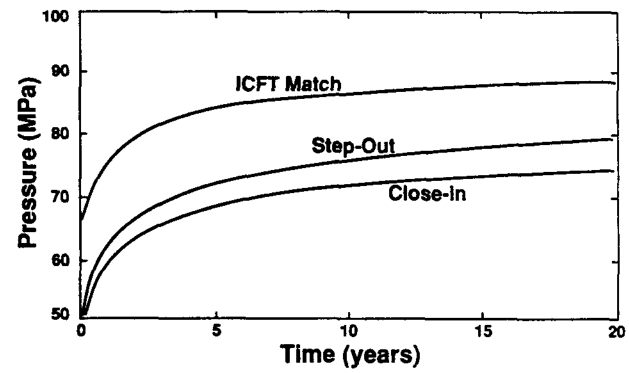

Figure 6. Injection pressure for twenty year simulations of the flow test match, close-in and step-out cases.

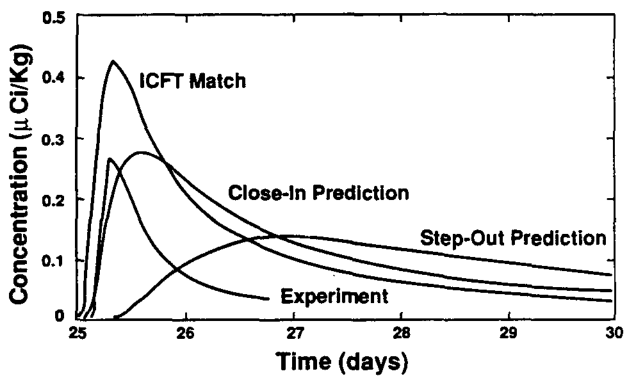

Figure 4. Experimental and matched tracer response for the flow test and predicted tracer response for the close-in and step-out cases.

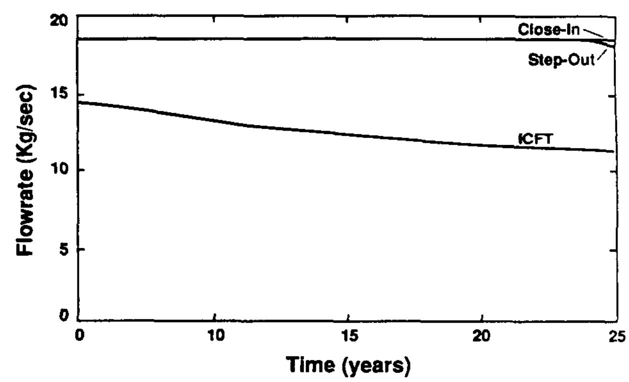

Figure 7. Production flow rate for twenty year simulations of the flow test match, close-in and step-out cases.

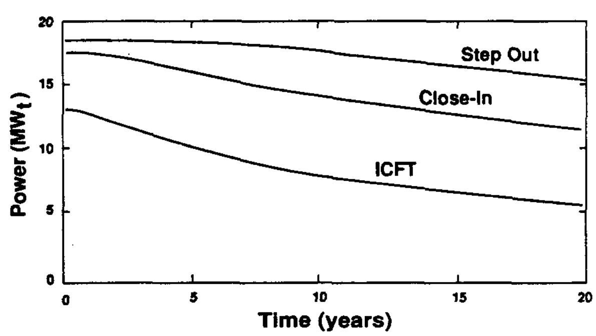

Figure 5. Power production for twenty year simulations of the flow test match, close-in and step-out cases.

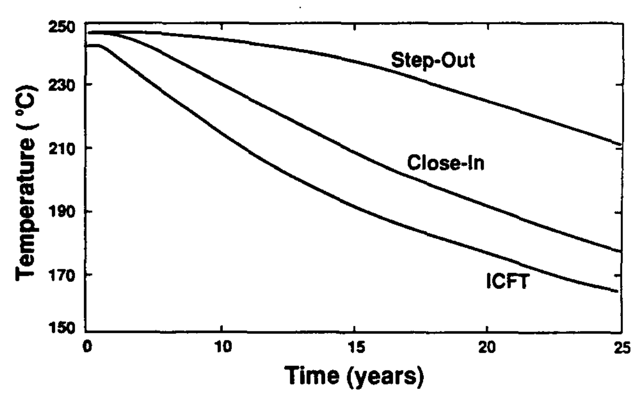

Figure 8. Production temperature for twenty year simulations of the flow test match, close-in and step-out cases.