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COMPUTER SIMULATION OF WELLBORE COOLING BY CIRCULATION AND INJECTION

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ABSTRACT

The high temperatures existing within a geothermal well preclude the use of most logging instrumentation which is necessary to study the wellbore and surrounding rock matrix. Possible solutions to this problem include cooling the wellbore and the surrounding rock by circulating fluid in the wellbore and by injecting fluid directly into the rock matrix. The latter method, however, is not preferred since it contaminates the formotion a considerable distance from the wellbore. The potential cooling effects of both these methods are investigated using the computer code, GEOTEMP2, which simulates heat transfer from the wellbore to the surrounding rock formation. Two different wells from the Salton Sea Known Geothermal Resource Area (KGRA) are simulated. The first is a shallow, hot well having a depth of 1400 m and a bottom-hole temperature of 330°C. The second is a deep well of depth greater than 3000 m and a bottom hole temperature of 380°C. Circulation of several different fluids for one day at flow rates of 16, 32, 47, and 63 l/s, followed by a shut-in period, is simulated to study the effect of different fluid properties and flow rates. Also, the temperatures obtained by using two different flow rates, each for one day, are compared to the temperatures found when using only the lower flow rates. Finally, the temperature recovery in the wellbore is investigated when fluid injection occurs at the bottom of the hole.

Heat conduction is the only heat transfer mechanism considered to warm the wellbore. Following steady-rate circulation. the wellbore temperatures were found to warm quickly after shut-in, approaching the undisturbed formation temperature within one day. Temperature recovery had a half-life on the order of six hours. Furthermore. the use of a higher initial flow rate did not significantly reduce the temperatures below those for the lower flow rate alone. Injecting fluid a relatively short distance into the formation was found to substantially decrease the rate of warming in the wellbore following injection.

INTRODUCTION

A large energy resource exists in the U.S. in the geothermal reservoirs which are primarily present in the western half of the country. However, developing these geothermal areas presents extreme problems for drilling and well logging operations due to the high temperatures reached in the well. Maximum downhole temperatures, which depend upon the specific geothermal area and the depth of the hole, can exceed 330°C. Bentonite-based drilling muds form a high viscosity gel in the temperature range of 120 to 230°C while downhole logging equipment has a typical maximum temperature limit near 175°C. Many geothermal well operations require some form of downhole cooling to overcome the lack of high temperature materials.

One method of wellbore cooling is circulating a fluid, such as water, mud, or air, through the wellbore. Several studies have attempted to calculate the downhole temperatures obtained when circulating water or mud through the wellbore. Raymond (1969) calculated the transient temperature profiles of a circulating mud column. He found that a true steady-state temperature was never reached, but the temperature did not change much after only one or two mud circulations. The fluid was found to warm quickly after circulation was stopped, reaching within 10% of the undisturbed geothermal gradient after 16 hours Holmes and Swift (1970) used a steady-stake analytical model to calculate the circulating mud temperatures in the wellbore. They found that decreasing the diameter of the drill pipe decreased the fluid temperatures within the annulus. Increasing the fluid flow rate was also found to produce cooler temperatures. Keller, et a1 (1973) used a two-dimensional transient heat transfer model which also included the contribution due to several casing strings around the wellbore and the effect of additional energy sources in the system. Traeger, et al (1981), performed a computer calculation for circulation in a hypothetical well in a magma-hydrothermal region. They found that it was possible to cool the wellbore to below 200°C at a depth of 4.5 km, but the minimum attainable temperature increased as the well depth increased. In a previous study (Duda. 1984), wellbore temperatures were calculated for four geothermal well models using several flow rates, different fluid types, soil thermal conductivities, and tubing diameters. The results of these calculations agreed with the earlier work especially confirming the rapid increase in temperature following shut-in reported by Raymond (1969).

Additional cooling within the wellbore may be obtained by fluid injection into the rock formation. Injection zones have been shown to warm less rapidly than the rock either above or below these zones (Smith and Steffensen, 1970, 1975), and this can result in a substantial decrease in the rate of warming of the wellbore fluid. In this study the effects of both fluid circulation and injection into the rock formation on wellbore cooling are investigated. Two wells from the Salton Sea KGRA are simulated. In each well, the effect of changing the fluid flow rate and fluid properties upon the wellbore temperatures, in particular the bottom-hole temperatures, are studied for the case of heat transfer by conduction within the rock formation. Finally, the rate of warming of the fluid at the bottom of the hole after shut-in, when injection is simulated, is compared to the circulation case.

CALCULATIONS

Two hypothetical wells from the Salton Sea KGRA were simulated. The first well. called the shallow well, extended to a total well depth of 1400 m (4600 ft). The casing program, described by Carson, et al (1983), and used in a previous paper (Duda, 1984), consisted of a 20-inch casing set to a depth of 183 m (600 ft) and cemented to the surface. A 13-3/8-inch casing extended to 396 m (1300 ft) and was also cemented to the surface. A third casing of 9-5/8 inches was set at a depth of 914 m (3000 ft) and was cemented from 335 m (1100 ft) to the bottom of the casing.

The undisturbed geothermal profile consisted of two linear temperature components (Riney, et al, 1978). The first linear profile extended from the surface (set nominally at 21°C (70°F)) to a depth of 747 m (2450 ft) where the temperature was fixed at 288°C (550°F). The second temperature profile begins at this depth and extends to the bottom of the hole where the temperature was set at 332°C (630°F).

The second well, called the Elmore well. extended to a total well depth of 3050 m (10,000 ft). The casing program was identical to that for the shallow well to a depth of 914 m (3000 ft). In each case the hole was completed without casing from 914 m to its total depth. Also both cases used a 2-7/8-inch tubing which extended to the bottom of the hole for fluid injection/circulation.

The undisturbed geothermal profile for the Elmore well consisted of two linear temperature components (Helgeson, 1968). The first linear profile extended from the surface (set nominally at 21°C (70°F) to a depth of 900 m (2950 ft) where the temperature was fixed at 300°C (572°F). The second temperature profile begins at this depth and extends to the bottom of the bole where the temperature was set at 360°C (680°F).

The soil thermal conductivity of the Salton Sea KGRA is reported near 0.0041 cal/cm s °C (1.0 Btu/ft hr °F) (Riney, et al, 1978) which is the value used in these calculations.

For the circulation study, four flow rates and four fluids were used in the calculation. The flow rates used were 250. 500, 750, and 1000 gpm (16, 32, 47, and 63 l/s). For each flow rate, downhole temperatures were calculated for two days of circulation. Then, the effect of an initial high flow rate followed by a lower flow rate was studied. One day of circulation at a flow rate of 1000 gpm was followed by one day of circulation at flow rates of 250, 500, and 750 gpm. Calculations were made using four fluid types whose properties are given in Table 1. Fluid 1 is water while fluids 2 through 4 cover a range of mud types.

Injection was simulated by setting the first four radial grid blocks extending from the wellbore at the bottom of the hole equal to the fluid temperature after one day of circulation. The center of the fourth grid block was 0.76 m (2.5 ft) from the wellbore centerline for the shallow well and 0.55 m (1.8 ft) from the wellbore centerline for the Elmore well. Setting the temperatures in the formation equal to the fluid temperature is not strictly correct since some heating will occur due to the injection process and will warm the fluid and rock above the minimum bottom-hole temperature

Table 1. Fluids used in the pure conduction circulation study.

Fluid NO.	Density[1] (g/cm^3)	Plastic Viscosity (cp)	Yield Point ($lbm/100\ ft^2$)
1	1.00 (8.34)	1	0
2	1.20 (10.0)	19	8
3	1.68 (14.0)	38	12
4	2.16 (18.0)	59	18

[1]Numbers in parentheses have units of lbm/gal.

of the fluid (Smith and Steffenson. 1970, 1975). However this temperature increase is small and was ignored for this study. After one day of circulation. the well is shut-in and the wellbore temperatures calculated as a function of time for the first day after shut-in. Note that following shut-in. heat conduction is considered to be the only heat transfer process. Similar calculations were done for the circulation case to compare the computed temperatures with those for the injection case.

The GEOTEMP2 computer code was used in this study to simulate fluid circulation in the well models. This code and the fluid flow and heat transfer equations and correlations employed have been treated in detail elsewhere (Mondy and Duda. 1984; Mitchell, 1982; Uooley, 1980a). The ability of this code to accurately predict temperatures down the wellbore has been evaluated previously (Wooley, 1980b). Good agreement was found between the code predictions and field data.

GEOTEMP2 employs a finite difference scheme to calculate heat transfer within and between the wellbore and the soil formation. A radial geometry is used by the code with the wellbore centerline as the origin of the coordinate system. Vertical grid size is constant and was set at 61 m (200 ft) for these calculations. The size of the grids in the radial direction is not constant but exponentially increases away from the wellbore centerline. Ten grids are used in the radial direction with the tenth grid set at a distance of 15 m (50 ft) from the centerline. This last grid defines the boundary conditions for the temperature and is set at the undisturbed temperature gradient of the specific geothermal area. The first three radial grids define the wellbore. The first grid contains the tubing. the second grid consists of the annulus. and the third grid contains the region consisting of all the casing. cemented intervals. and, finally. the beginning Of the soil formation.

As with any computer code, certain assumptions and limitations are inherent in the implementation of the code. Some of the assumptions and limitations of GEOTEMP2 are:

1) Forced and natural convection of the fluid is only treated within the tubing and the annulus; only heat conduction is treated in the grids located in the soil formation.

2) Only radial heat conduction is treated in the tubing and the annulus; vertical heat conduction is assumed negligible compared to convection because of the larger grid size in the vertical direction compared to the radial direction.

3) All casings are assumed to extend to the surface from the setting depth.

4) The cemented interval outside of a casing is not required to extend to the surface. Fluid is contained in the annuli between the casings where the casings are not cemented. This fluid was chosen to be the same as the circulating fluid for all the calculations. For this case, water was placed in the uncemented casing annuli.

5) Radiative heat transfer in the wellbore and soil was assumed to be negligible.

6) Initial conditions: Fluid temperatures in the tubing and annulus were initially set at the geothermal gradient temperature values.

RESULTS AND DISCUSSIOU

The effects on wellbore cooling of changing the flow rates and fluid properties for the pure heat conduction case within the formation will first be discussed. Figure 1 shows the bottom-hole temperatures inside the tubing for the shallow well using water as the circulating fluid. There is a substantial cooling at higher flow rates. Uote in Figure 1 that little difference exists between the bottom-hole tempefature for the 1000-gpm and 750-gpm flow rates. Even the 500-gpm flow rate can cool the fluid to neaa 50°C in a relatively short time (about 6 hours). The lowest flow rate used in the calculations. 250 gpm, can cool the fluid to about 100°C in the shallow well. In general, it appears that a low flow rate can substantially cool the wellbore in the shallow well. The other point to note in Figure 1 is that a high initial flow rate

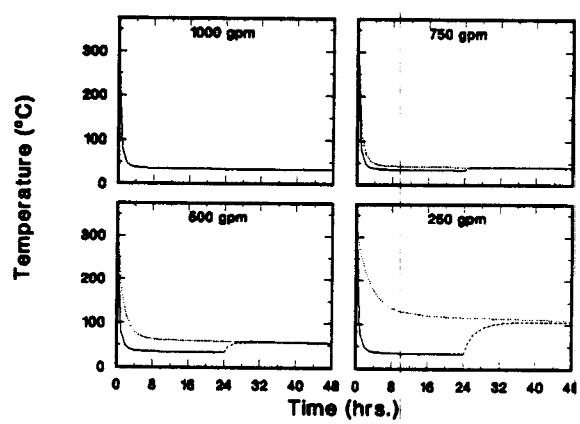

Figure 1. The bottom-hole temperatures inside the tubing for the shallow Salton Sea well at four flow rates using water as the circulating fluid. The solid line is the 1000-gpm flow rate. The dottpd line is the specified flow rate extending to two days of circulation. The dashed line shows the temperature when the flow rate is changed at one day from 1000 gpm to the specified flow rate.

shows no benefit since there exists little difference between the two final temperatures even at the lowest flow rate after two days of circulation. The calculations for the other three drilling fluids show similar trends. The results are summarized in Figure 2 which plots the bottom-hole temperature inside the tubing as a function of the Reynolds number. The lines in the figure connect points of the same fluid

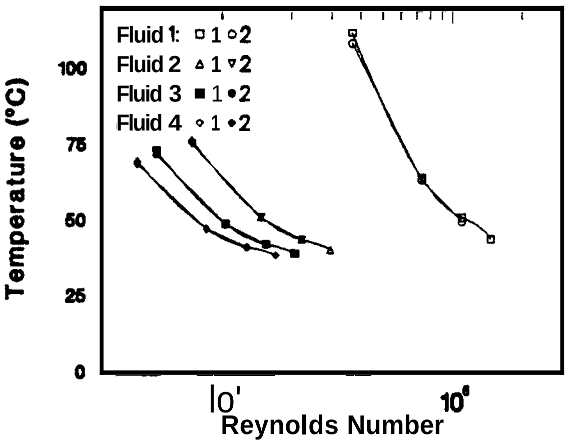

Figure 2. The bottom-hole temperatures inside the tubing for the shallow Salton Sea well as a function of the Reynolds number for four flow rates and the four fluid types given in Table 1. Lines connect points of the same fluid type. The number 1 refers to the temperature after 48 hours of circulation using only one flow rate while the number 2 refers to the temperature at 48 hours after one day of circulation at 1000 gpm followed by one day of circulation at a lower flow rate.

type. As the fluid number increases (thus going to higher mud weights). the bottom-hole temperature decreases as shown in Figure 2, with the largest difference between water and the different mud types. The lower temperature calculated for the drilling muds can in part be attributed to the change in the heat transfer coefficient, which decreases as the fluid viscosity increases (Duda. 1984). Note also in Figure 2 that, as for water, there is no benefit to a higher initial flow rate for any of the drilling muds.

Figure 3 shows the bottom-hole temperature as a function of circulation time for the Elmore well. There is a substantial difference between these plots and those in Figure 1. The deeper well causes the fluid to warm more as it flows down the tubing thus producing warmer bottom-hole temperatures. The temperature after 48 hours of circulation for a flow rate of 1000 gpm is only about 20°C lower than the temperature calculated for a 250-gpm flow rate in the shallow well. In addition, at the lower flow rates the high initial flow rate has produced lower temperatures after two days of circulation. The temperature difference is 10°C at 500 gpm and 30°C at 250 gpm. Evidently, a higher initial circulation rate followed by a lower rate can produce lower wellbore temperatures than the lower rate alone for deep wells. The higher initial rate can more effectively cool the wellbore since the fluid has less time to warm in the tubing than at a lower flow rate. The results for all the fluids used in the calculations for the Elmore well are summarized in Figure 4 which plots the bottom-hole temperature as a function of the Beynolds number. In contrast to Figure 2, note that there is a substantial diffenence in temperature between the one and two flow rate cases at low flow rates. Also note that the temperatures plotted in Figure 4 are much

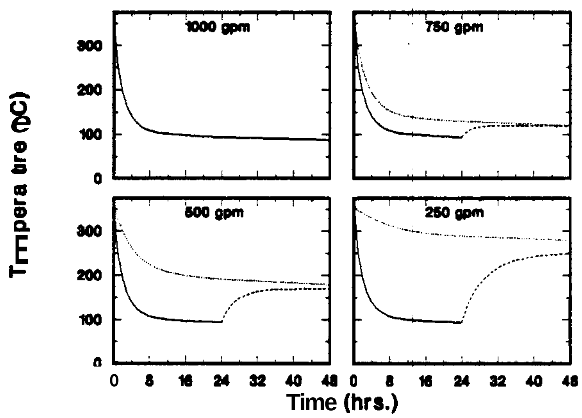

Figure 3. The bottom-hole temperatures inside the tubing for the Saltpn Sea Blmore well at four flow rates using water as the circulating fluid.

higher than in Figure 2. This is. of course due to the greater well depth which allows the fluid a longer contact with high

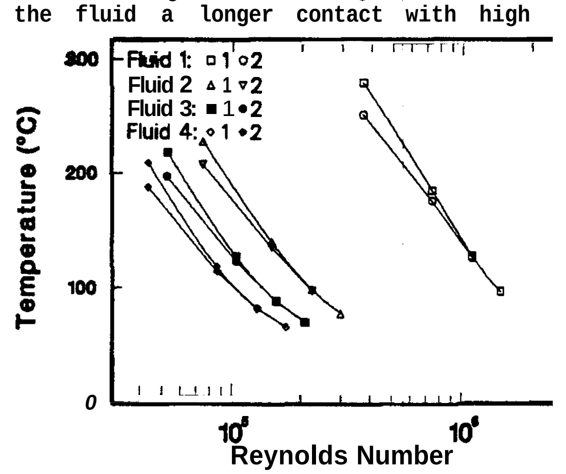

Figure 4. The bottom-hole temperatures inside the tubing for the Salton Sea Elmore well as a function of the Reynolds number.

temperatures. The curves shown in Figure 4 are more linear than the corresponding curves in Figure 2. In Figure 2 the slope of the curves at high Reynolds number. particularly for fluids 2. 3, and 4. decreases much more than the slope of the corresponding curves in Figure 4. This implies that some improvement in wellbore cooling may be realized in the deeper well by using higher flow rates. but this tends to become impractical both economically and due to the limitations of equipment.

Even though circulation is an effective method for wellbore cooling. temperature will rapidly rise once circulation has stopped (Raymond. 1969; Duda. 1984). The problem is that the rock formation surrounding the wellbore is generally not cooled very much by heat conduction when fluid is circulating in the wellbore. The rock may be cooled to a lower temperature at a greater distance from the wellbore if the fluid is injected or can be transported by convection into the rock. The results of calculations simulating injection at the bottom of the hole are shown in Figure 5 for the shallow well. After shut-in. the temperatures rapidly increase for the

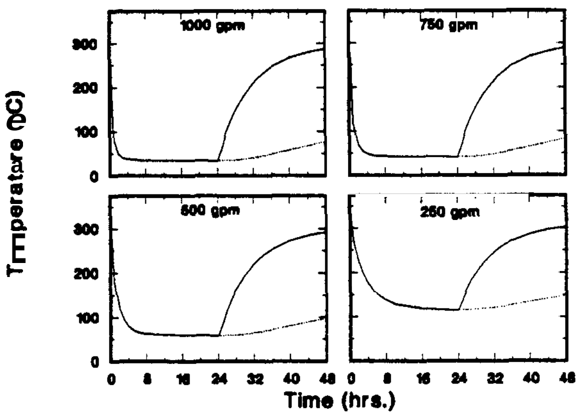

Figure 5. The bottom-hole temperatures inside the tubing for the shallow Salton Sea well. The solid lnes show temperatures for one day of circulation followed by shut-in for the pure conduction case. The dotted lines are the shut-in temperatures when fluid was injected at the bottom of the hole.

circulation case, but for injection the warming rate has been substantially slowed. For example. the bottom-hole temperature for the 250-gpm flow rate has increased only 30°C at one day following shut-in compared to a temperature rise of 185°C for the conduction case.

Figure 6 shows the calculations for the Elmore well. Qualitatively, the results are similar to the shallow well case except for the higher temperatures due to the greater well depth. Fluid injection even a short distance (less than 1 m) into the formation is an effective method to maintain cool wellbore temperatures for a reasonable time

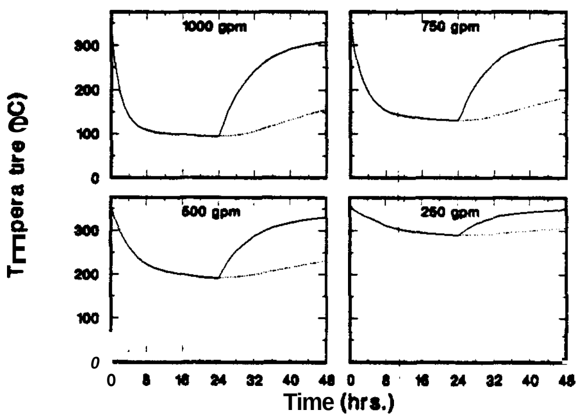

Figure 6. The bottom-hole temperatures inside the tubing for the Salton Sea Elmore well for circulation and shut-in for circulation and injection.

after shut-in. It is important to note that these calculations were done for fluid injection only at the bottom of the well. The fluid in the wellbore above this point was not affected by the injection and thus warmed quickly after shut-in. Hence, to be an effective cooling method, the fluid must be allowed to infiltrate over most of the wellbore rather than over some small region.

CONCLUSIONS

In this study wellbore temperatures were calculated for two Salton Sea geothermal wells using the computer code GEOTEMP2 at several flow rates and for four fluid types. Results of the calculations showed that higher flow rates produce cooler wellbore temperatures. high initial flow rates may be effective in cooling the wellbore for deep wells. muds tend to give lower wellbore temperatures as the mud weight is increased, and shut-in fluid temperatures rise rapidly when the only cooling mechanism is circulation. Injection into the rock formation will decrease the rate of wellbore warming after shut-in.

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