MODELING DISCHARGE REQUIREMENTS FOR DEEP GEOTHERMAL WELLS AT THE CERRO PRIETO GEOTHERMAL FIELD, MEXICO

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Abstract

During the mid-1980's, Comisión Federal de Electricidad (CFE) drilled a number of deep wells (M-200 series) at the Cerro Prieto geothermal field, Baja California, Mexico to investigate the continuation of the geothermal reservoir to the east of the Cerro Prieto-II and III production areas. The wells encountered permeability at depths ranging from 2,800 to 4,400 m but due to the reservoir depth and the relatively cold temperatures encountered in the upper 1,000 to 2,000 m (< 50°C), it was not possible to initiate discharge in all of the wells.

The wells at Cerro Prieto are generally discharged by injecting compressed air below the water level using 2-3/8-inch tubing installed with either a crane or workover rig. The impact of heat loss on the stimulation process is believed to be significant and was investigated using both a numerical model of the reservoir/wellbore system and steady-state wellbore modeling. The results from the study show that if flow rates of at least 300 liters/minute can be sustained, the well can probably be successfully stimulated; this is consistent with the successful stimulations of wells M-202 and M-203. If the flow rate is closer to 60 liters/minute, the heat loss is significant and it is unlikely that the well can be successfully discharged. These results are consistent with the unsuccessful discharge attempts in wells M-201 and M-205.

INTRODUCTION

The Cerro Prieto geothermal field is located in Baja California, Mexico approximately 30 km SE of Mexicali and was the first geothermal field in Mexico to be developed on a commercial scale. The field development was undertaken by Comisión Federal de Electricidad (CFE) and production began in April 1973, with the start-up of the Cerro Prieto-I (CP-I) power plant which was initially equipped with two turbine-generators of 37.5 MW capacity each. In 1977 construction began on the second stage of the CP-I development and two additional turbine-generators, identical to the first two, began operations in April 1979, bringing the total installed capacity to 150 MW. In 1982, a fifth generating unit was placed into service with a capacity of 30 MW, increasing the total installed capacity to 180 MW.

In 1980, CFE began field development planning and drilling for the CP-II and CP-III power plants. The production areas for these plants, as well as the CP-I production area, are shown in figure 1. CFE decided to proceed with the installation of 220 MW generating capacity at each site, in part due to the signing of two long-term power purchase contracts with Southern California Edison (SCE) and San Diego Gas & Electric Company (SDG&E) for a total of 220 MW. Construction began in 1982 and by September 1986 CFE brought on line three generating units of 110 MW each. The fourth unit was operational in 1987, bringing the total installed capacity at Cerro Prieto to 620 MW. In recent years, CFE have maintained an overall capacity factor at Cerro Prieto in excess of 90%.

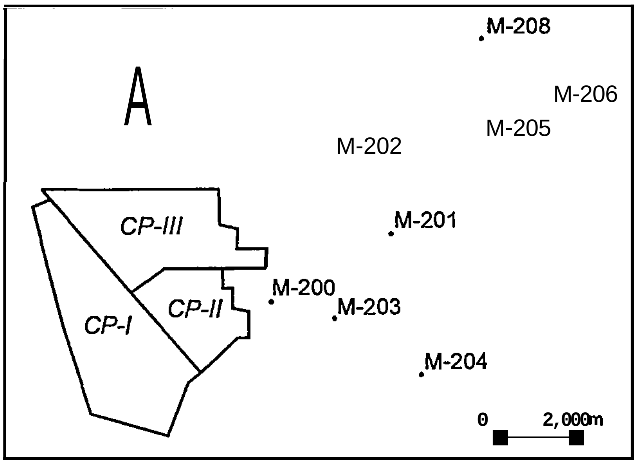

Figure 1: Location map showing production areas for the Cerro Prieto power plants and the locations of the M-200 series wells

In addition to drilling wells for the CP-11 and CP-III developments, CFE also completed a number of deep wells (the M-200 series wells) to investigate the continuation of the geothermal reservoir to the east of the CP-11 and CP-III production areas. A total of eight wells (M-200, M-201, M-202, M-203, M-204, M-205, M-206 and M-208) were drilled from 1983 through 1986; well locations are shown in figure 1. Of the eight wells drilled, five were completed for possible production (M-200, M-201, M-202, M-203 and M-205), two were suspended without running 7-inch cemented liner (M-204 and M-206) and well M-208 was abandoned at 2,406 m. Basic well information for the five completed wells is shown in table 1.

The five completed wells encountered permeability at depths ranging from 2,800 m to 4,400 m and temperatures generally greater than 300°C. The depth to the reservoir increases towards the east; this trend is consistent with data from the CP-11 and CP-III production wells. Attempts were made to flow the wells using air injection and this was successful in wells M-200, M-202 and M-203; however, discharge attempts were not successful in wells M-201 and M-205 which are located further to the east. It is believed that the lack of success was due to a number of possible factors, including well blockages, low productivity, high heat loss due to cold casing (<50°C) in the upper 1,000 to 2,000 m of the wells and difficulty in maintaining continuous air injection.

CFE are now considering adding additional capacity at Cerro Prieto, including an 80 MW development in the area of the M-200 series wells (Hiriart-LeBert and Gutiérrez-Negrin, 1994). However, due to limited flow data that was collected from the wells during the 1980's, further flow testing is required to determine the commercial viability of new wells that would be drilled in this area of the field, particularly in view of the significant cost that would be involved in drilling to the required depths. The available well data were therefore reviewed and, based on the data summarized in table 1, it was recommended that well M-203 be cleaned out and used for additional testing, including a six month flow test. The results from the flow testing would then be used to design new wells to maximize well productivity. The present wells, except for M-200, were completed with 6-inch open hole and 4-1/2-inch slotted liner and their productivity is therefore restricted.

	Completion	Open Interval (m)	Temperature (°C)	Status
M-200	Feb. 5, 1984	2,482-2,834	>320	Flowed 1985/1986; well open
M-201	Sep. 24, 1985	3,600-3,816	≈350	Blocked @ 7-inch liner (2,340 m)
M-202	June 7, 1984	3,700-3,987	>330	Flowed during 1984; killed by cool inflow from 7-inch liner lap; drillpipe lost in well in 1985
M-203	July 26, 1984	3,538-3,993	285+	Flowed 1984-1986; blocked 3,710 m
M-205	Aug. 30, 1985	3,766-3,909 4,209-4,389	>350	Blocked @ 780 m

Table 1: Basic information from completed M-200 series wells

The study also included an evaluation of the requirements for a successful well discharge as it is likely that difficulties will be encountered in stimulating the existing wells to flow in addition to any new wells that may be drilled in the future. It was recommended that CFE consider using nitrogen injection with a coiled tubing unit for well stimulation rather than their present technique of injecting compressed air below the water level through 2-3/8-inch tubing installed with either a crane or workover rig. Both techniques are similar but the use of nitrogen and a coiled tubing unit would allow for greater flexibility and control during the stimulation process which should reduce the possibility of casing damage caused by thermal shock. The coiled tubing unit can also be used to clean-out the wells, assuming the blockages are due to scale or sand; at present CFE use a rig to clean out scale from their wells.

The stimulation process was investigated using both a numerical model of the reservoir/wellbore system and by running a series of steady state wellbore simulations. The temperature and pressure conditions used in both the numerical model and the wellbore simulation model were based on measured data from well M-201. Basic well completion information and representative pressure and temperature surveys are shown in figure 2.

MODELING THE STIMULATION PROCESS

As discussed above, the requirements for successful well stimulation were evaluated by constructing a numerical model of the reservoir/wellbore system and by using a wellbore simulator. A numerical model was used as it can include the transient effects of fluid flow within the wellbore and heat transfer to the surrounding cold formation. Wellbore simulation can also include heat transfer but generally assumes steady state flow conditions. It is therefore necessary to run a series of steady state simulations in time to obtain information on the transient effects.

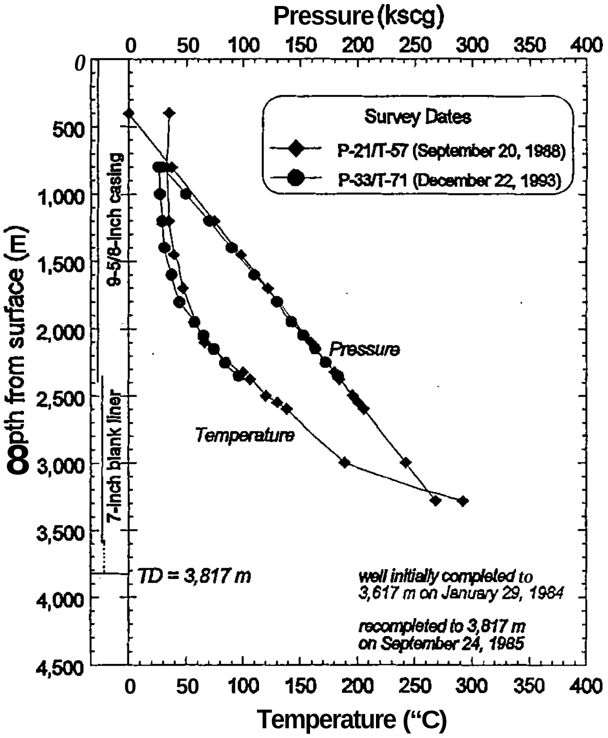

Figure **2:** Well completion information and downhole survey data, Well **M-201**

Numerical Model Results

In the numerical model, a radial grid was constructed which included the reservoir, wellbore and allowed for heat transfer from the wellbore to the surrounding rock (figure **3).** The grid extends from 550 to **3,900** m in the vertical direction and from the wellbore to **200** m **in** the radial direction, with a total of 670 grid blocks. In figure **3,** the radial grid is shown on a logarithmic axis to show the number of grid blocks more clearly. To model the wellbore, a very high vertical permeability **(1** m^2) was specified and the porosity was set to **100%** in the wellbore blocks. The horizontal permeability within the wellbore blocks and the blocks above and below the geothermal reservoir blocks was set to zero permeability. Within the reservoir blocks and the wellbore blocks opposite the reservoir, the horizontal permeability was set to 10^{-14} m^2; this is equivalent to a reservoir transmissivity of **2** Darcy meters, which is reasonable for the deep wells based on available data.

The temperatures and pressures used in the model were based on the measured data from well M-**201** (figure **2);** this well has the greatest length of casing under **50°C (1,900** m) and therefore reflects the most difficult conditions for well stimulation.

The simulation runs were made by setting a constant rate fluid extraction from the upper wellbore grid block. Four runs were made at flow rates of 60, **300, 600** and **1,200** liters/minute. The lower flow rate of 60 liters/minute is similar to the fluid extraction rates obtained during the unsuccessful stimulation

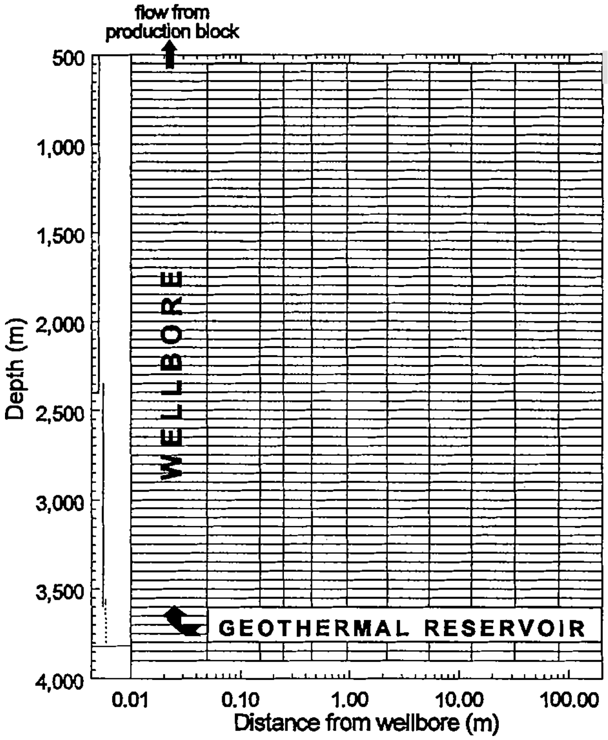

Figure 3: Radial grid block layout used in numerical simulation model

attempts at wells M-201 and M-205 while the 300 liters/minute flow rate is similar to the fluid extraction rates obtained during the successful stimulations of wells M-202 and M-203.

The model required a significant run time as the maximum time step size never exceeded 13 secs which limited the overall simulation time to only a few hours. This limited the amount of information that could be obtained and for the 60 liters/minute run, the simulated time of 1 to 2 hours was too short to provide useful results. For the other runs, however, the simulated time was long enough to provide some interesting insights into the stimulation process; the results from the 300 liter/minute run are presented as changes in pressure and temperature at various wellbore depths in figure 4. The changes in pressure and temperature in the production block at the top of the wellbore for the three different extraction rates are compared in figure 5.

The results in figure 4 show that in the deep wellbore block at 3,625 m, pressure decline occurs as expected but in the upper part of the wellbore, a significant pressure increase occurs with time during the stimulation process. The large pressure increase is due to the replacement of the long column of initially cold water with hot, less dense water from the reservoir, as shown by the increasing temperature with time.

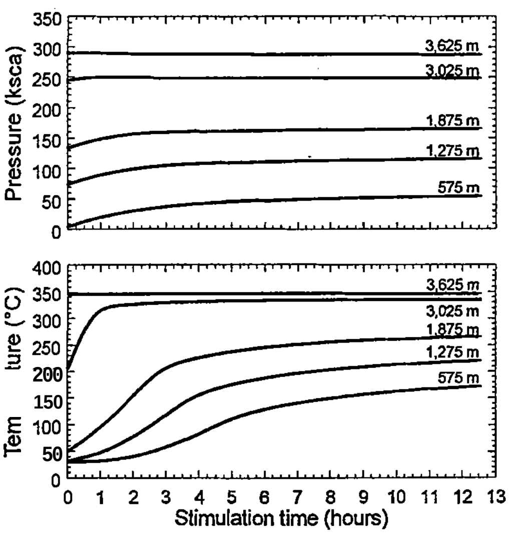

Figure 4: Simulation results for 300 liters/minute extraction rate

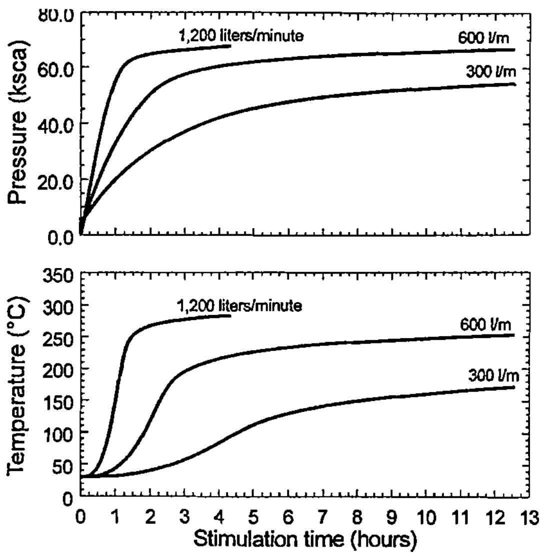

Figure 5: Simulation results from production block at top of wellbore

Assuming an average temperature of 100°C in the upper 575 m of the wellbore, the well should start to flow without the need for stimulation when the pressure in the production block reaches 55 ksca. The results in figure 5 indicate that this condition is reached after 1 hour at 1,200 liters/minute, after 2.5 hours at 600 liters/minute and at greater than 13 hours at 300 liters/minute. As expected, there is a significant reduction in the required stimulation time at higher flow rates. However, the results in figure 5 also show that at higher flow rates, significant heating occurs in a relatively short period of time which may result in damage to the casing. .

The model results also show that when the well starts to flow by itself, it will be flowing single phase water under artesian conditions. This is consistent with data available from the successful stimulations of wells M-202 and M-203. It was reported that both wells produced single phase water at positive wellhead pressures and temperatures of between 86°C and 90°C after air injection had stopped and prior to the onset of flashing flow.

As mentioned above, the successful stimulations of wells M-202 and M-203 occurred at induced flow rates close to 300 liters/minute but a stimulation time of several days was required instead of the several hours suggested by the numerical model results. This may be due in part to the assumption of continuous flow in the numerical model whereas in the field situation, air injection was not continuous and the discharge water flow rates were probably not constant. The model also does not account for any cooling of the fluid column due to the air injection and it is also possible that the heat transfer parameters are not correctly specified.

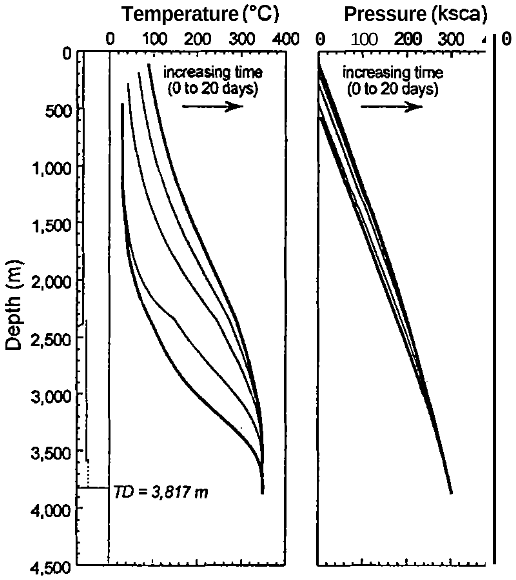

Figure 6: Wellbore simulation results; flow from well = 60 liters/minute

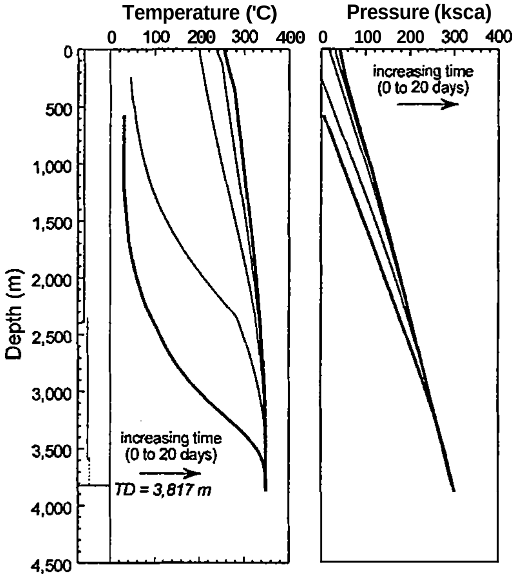

Figure 7: Wellbore simulation results; flow from well = 300 liters/minute

Wellbore Simulation Results

A series of wellbore simulation runs were also conducted to provide additional information on the discharge process. For these runs, the static conditions from M-201 were again used as the initial conditions and runs were made after flow times of 0.1, 1, 5 and 20 days for extraction rates of 60, 300, 600 and 1,200 liters/minute.

The results from the wellbore simulation runs at 60 and 300 liters/minute are presented in figures 6 and 7. These cases approximate the conditions during the previous stimulation attempts of the deep wells. The initial static conditions are also included on the plots. The results show that a flow rate of 60 liters/minute is not sufficient to stimulate the well to flow, even after 20 days of flow time, due to heat loss to the cold casing in the upper 1,900 m of the well. These results are consistent with the unsuccessful attempts to flow wells M-201 and M-205. At the higher flow rate of 300 liters/minute, the results show that successful discharge should occur in less than 1 day. These results are consistent with the numerical model results; however, as noted above, the estimates of stimulation time are significantly shorter than has been found in the field situation.

The calculated profiles plotted in figures 6 and 7 clearly show that as the hot water moves up the wellbore, the increase in temperature has a dramatic impact on wellbore pressures. The increase in pressure helps considerably in stimulating the well to flow.

CONCLUSIONS

From the results of the modeling study of well discharge requirements at Cerro Prieto, it is apparent that the deep wells can probably be successfully stimulated if a discharge rate of at least 300 liters/minute can be sustained. This is consistent with the previous successful stimulations of wells M-202 and M-203. If the sustainable flow rate from the well is closer to 60 liters/minute, then it is unlikely that the well can be successfully stimulated in a reasonable time. These results are consistent with the unsuccessful attempts in wells M-201 and M-205. If the flow rates are much greater than 300 liters/minute, the results also suggest that heating of the casing may occur too quickly which could lead to casing damage.

The model results also suggest that stimulation times of less than one day should be required, assuming a fluid discharge rate of greater than 300 liters/minute can be sustained. These times are significantly less than noted in actual field operations, where stimulation times of up to 11 days have been required. This suggests that the ideal conditions assumed in the model runs probably deviate significantly from actual field conditions.

One of the reasons for the difference between estimated and observed stimulation time is probably the assumption of continuous flow. In practice, it is not possible to maintain continuous flow with air injection due to the need to change tubing depth or to service the compressors. It is therefore recommended that CFE consider using nitrogen injection with a coiled tubing unit for future discharge attempts on the M-200 series wells. This will allow for significantly more flexibility and control over the stimulation process which will also lessen the risk of casing damage associated with thermal shock.

One of the more interesting observations from the model study was the significant increase in pressure that occurs in the wellbore due to the replacement of the cold water column with hot water from the reservoir; an overall increase of up to 50 ksc was calculated near the top of the well. This helps the stimulation process considerably and allows the well to initially flow under artesian conditions. It is also probably one of the factors that explains the very high productivity of the production wells within the Cerro Prieto field.

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REFERENCES

Hiriart-LeBert, G. and L.C.A. Gutiérrez-Negrin (1994), "Geothermal Development in Mexico", Geothermal Resources Council TRANSACTIONS, Vol. 18, October 1994, pp 269-274.