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# EVALUATION OF INJECTION TEST DATA FROM A BACA WELL

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## ABSTRACT

*Injection* test data from Baca well B-20 show that half of the fluid enters a fractured zone below ~ 5000 ft whereas the primary production zone is at ~ 4000 ft. The fracture created during the subsequent stimulation of B-20 apparently intersects the lower fluid-accepting zone rather than a production zone. Fracture stimulation must provide a channel to a productive region of the natural fracture system to be effective.

## INTRODUCTION

Non-productive wells in the Redondo Creek area of the Baca Geothermal Field have been used as injection wells. The ability of these wells to accept high injection rates implies that a well may penetrate a permeable zone which is a fluid acceptor but not a fluid producer. Interpretation of flow data from injection tests on wells in the Redondo Creek area, or other fractured geothermal systems, must consider this possibility.

As part of its evaluation of the geothermal reservoir in the Redondo Creek area, Union Oil Company performed both production and injection tests on several individual wells. S-CUBED independently analyzed available well test data under a contract funded by the U. S. Department of Energy. An earlier paper (Riney and Garg [1982]), described an analysis of the pressure buildup data for well B-20 subsequent to a 104-day production test (Flow Test No. 4). Data from an injection test performed on B-20 are analyzed here and the results compared with the results of the analysis of the production test data. This well is also one of two Baca wells (B-20 and B-23) which were hydraulically fractured by Republic Geothermal, Inc. The fracture stimulation of B-20 is discussed in view of the production and injection test analyses.

## BACKGROUND

Well B-20 was drilled during the period June 26 - August 30, 1980 from ground level elevation (9065 ASL) to a total measured depth of 6374 ft (3026 ASL). Drilling terminated when 547 ft of tools stuck in the hole with the top of the fish located at 5827 ft. The well was completed with the bottom of a blank 9-5/8" casing set at 2505 ft; a 7" blank and perforated liner was hung from 2390 ft to 5812 ft.

The pressure and temperature profiles recorded above the fish before and after a 104-day production test indicated that production was primarily from a permeable zone located at ~ 4000 ft (Riney and Garg [1982]). The reservoir pressure and temperature in this zone were estimated to be $P_o$ ~ 975 psig (p(a) = 67.9 bars) and $T_o$ ~ 488°F (253°C), respectively. A second permeable zone located towards wellbottom was tentatively identified but production from this zone was minor. The values of the pressure and temperature estimated from recordings above the fish (at depth 5750 ft) are considered representative of the reservoir values in the lower permeable zone, i.e., $P_o$ = 1443 psig (p(a) = 100.2 bars) and $T_o$ = 549°F (287°C).

A $CO_2$ mass fraction of $\alpha_o$ = 0.0147 has been measured in the discharge fluid from well B-20. This is the high end of the range of values measured for the Redondo Creek wells. If we assume that the $CO_2$ content in the primary production zone is the measured value, then the initial thermodynamic state of the upper permeable zone may be determined from the equation-of-state for $CO_2$/water mixtures (Pritchett, et al. [1982]). The estimated condition ($P_o$ = 67.9 bars, $T_o$ = 253°C, $\alpha_o$ = 0.0147) implies that the permeable zone at 4000 ft is initially two-phase with an in situ gas saturation of $S_g$ = 0.08. The initial condition of the lower permeable zone, represented by values at 5750 ft ($P_o$ = 100.2 bars, $T_o$ = 287°C, $\alpha_o$ = 0.0147), implies that the fluid there is single-phase liquid.

## INJECTION TEST ANALYSIS (BEFORE STIMULATION)

Injection Test No. 1 was performed on B-20 during July, 1981. During the 129 hour injection period a cumulative volume of 1,793,000 gallons of water at 158-175°F was accepted at the wellhead under vacuum.

Spinner surveys and pressure/temperature surveys were run during injection; pressure/temperature surveys were also recorded downhole changes after injection stopped.

The spinner surveys indicate that approximately 20 percent of the injected fluid is lost into the formation just below the casing in the interval 2500-3000 ft, approximately 30 percent in the interval 4000-5000 ft, and approximately 50 percent below the bottom of the perforated liner located at 5812 ft. Figure 1 shows downhole temperature surveys made before, during and after the injection period. The depressed temperatures below 4500 ft apparently result from the penetration of the cold injection fluid into the formation at these depths.

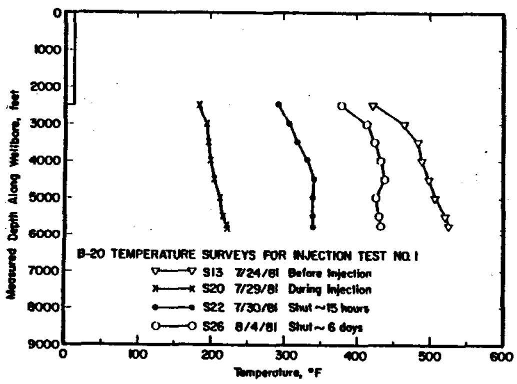


Figure 1. Temperature surveys for Injection Test No. 1.

It is noteworthy that the primary production zone at 4000 ft does not accept a significant portion of the injected fluid. Comparison of pressure profiles S13 and S20 (Figure 2) provides a partial explanation; the overpressure (pressure above reservoir pressure) during injection increases with depth.

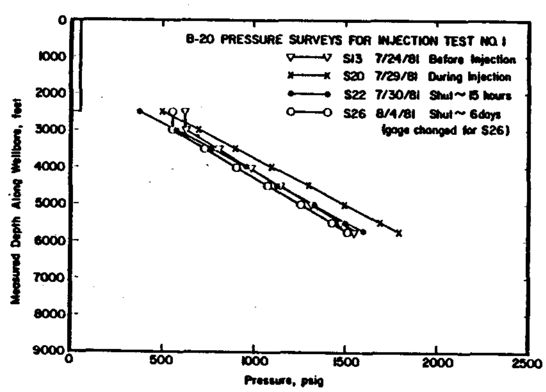


Figure 2. Pressure surveys for Injection Test No. 1.

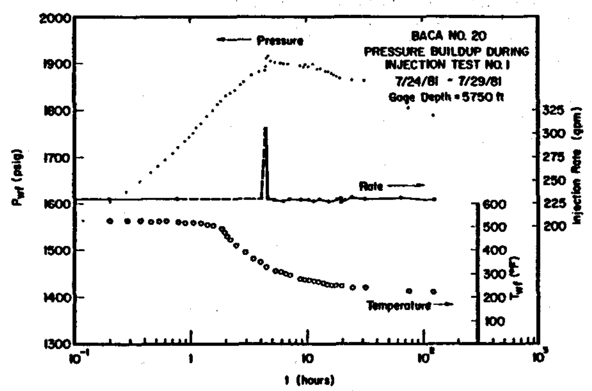


Figure 3. Bottomhole pressure and temperature and surface injection rate during Injection Test No. 1. Here t is time since injection started.

Figure 3 shows a semi-log plot of the pressure buildup and temperature data recorded by Union at a depth of 5750 ft during the injection period. The surface volumetric injection rate is also shown. A log-log plot of the pressure buildup data is given in Figure 4. The approximation of the data to the 1/2-slope line in this type curve indicates that the bulk of the injected fluid is entering a fracture. The fracture accepting the flow is towards wellbottom below the primary production zone. Both the injected fluid and the reservoir fluid are single-phase liquid at these depths; there is a nearly constant hydraulic head between the gage depth and the accepting horizon. Analysis of the pressure buildup data is complicated by the presence of the fracture flow and the temperature differences between the injected and reservoir fluids.

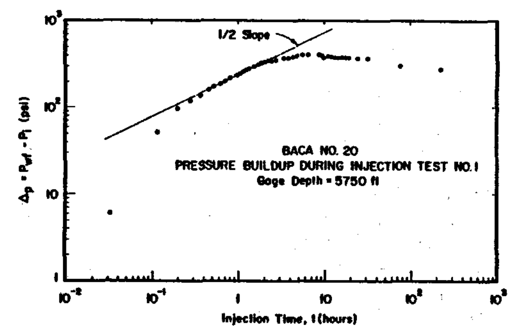


Figure 4. Log-log plot of pressure buildup during Injection Test No. 1. Here $P_i$ = 1509 psig.

Except for the isolated spike in the injection rate at t = 4.5 hours, the surface volumetric injection rate is essentially constant. The downhole temperature of the injected fluid starts to decrease rapidly at $t \sim 2$ hours from its initial value of ~ 520°F (271°C) to ~ 240°F (116°C). During the transition period the corresponding kinematic viscosity of the downhole injected fluid increases from $\nu \sim 1.3 \times 10^{-7}$ m$^2$/s to $\nu \sim 2.6 \times 10^{-7}$ m$^2$/s. Theoretical calculations by Pritchett and Garg [1980] have shown that the downhole viscosity of the injected fluid should be used when interpreting pressure buildup data.

The duration of the fit of the data to the 1/2-slope line in Figure 4 implies that pseudo-radial flow is not attained until the injection has been underway for at least t = 2 hours. The usual Horner methods of interpretation of the buildup data also fails in the temperature transition period ($2 < t < 10$ hours) because of the variation in the kinematic viscosity of the injected fluid. The reason for the rapid decrease in the downhole pressure required to sustain the injection rate at late times ($t > 10$ hours) is not known. Possible mechanisms include opening new injection fractures or increased mobility of the fluid in a two-phase entry (e.g., at 4000 ft) as the cold injection fluid decreases the steam saturation present earlier.

A log-log plot of the pressure falloff data recorded at 5750 ft is shown in Figure 5. The data are approximated by a 1/2-slope line for falloff at $\Delta t < 1$ hour subsequent to termination of injection. Figure 6 shows a Horner plot of the pressure falloff data; the temperatures recorded at depth 5750 ft are also shown.

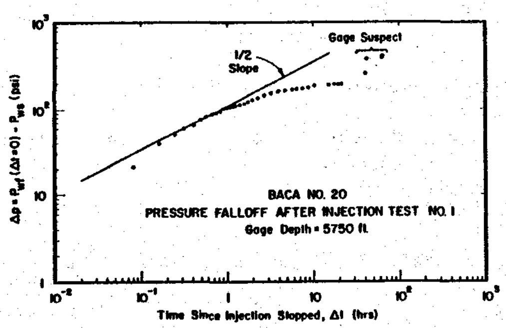


Figure 5. Log-log plot of pressure falloff subsequent to Injection Test No. 1. Here $P_{wf}(\Delta t = 0) = 1783$ psig.

The straight line of slope m = 68 psi/cycle ($4.70 \times 10^5$ Pa/cycle) approximates data points at dimensionless times $(t + \Delta t)/\Delta t < 40$, corresponding to falloff times of $\Delta t > 3.3$ hours. The flow is assumed to be pseudo-radial at this point in time; the slope m can be used to estimate the kinematic mobility-thickness product for well B-20.

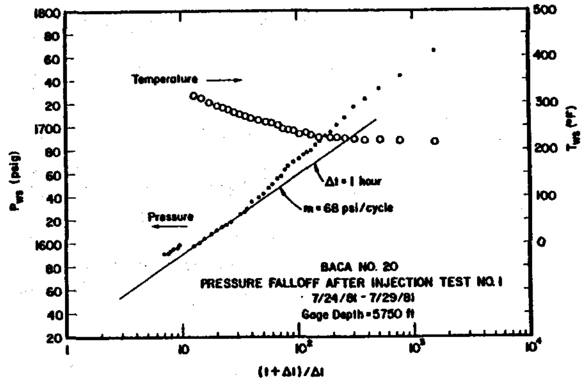


Figure 6. Pressure falloff and downhole temperature subsequent to Injection Test No. 1. Here the injection time is t = 129 hours.

The average mass rate corresponding to the injection of 1,793,000 gallons (6770 m$^3$) during the injection period of t = 129 hours is

$$\dot{M} = \frac{6770\ (975)}{129\ (3600)} = 14.2 \text{ kg/sec}$$

The kinematic mobility-thickness product is given by

$$\frac{kh}{\nu} = \frac{1.15\ \dot{M}}{2\pi m} = \frac{1.15\ (14.2)}{2\pi\ (4.7 \times 10^5)} = 5.53 \times 10^{-6} \text{ ms}$$

The theoretical calculations presented by Garg and Pritchett [1980] show that the kinematic viscosity of the reservoir fluid should be used when interpreting falloff data subsequent to reinjection. Since most of the injected fluid is assumed to enter the formation towards wellbottom, with representative initial reservoir conditions (287°C, 100.2 bars), the appropriate value is $\nu \sim 1.3 \times 10^{-7}$ m$^2$/s. The estimated formation kh product during falloff is

$$kh = (1.3 \times 10^{-7})\ (5.53 \times 10^{-6})$$

$$= 7.19 \times 10^{-13} \text{ m}^2 = 2400 \text{ md-ft}$$

Although this value is of the same order of magnitude as the value kh = 3030 md-ft estimated from Flow Test No. 4 production data, comparison should be made with reservations. During production the flow is two-phase from a permeable zone at 4000 ft; during injection this zone accepts only a fraction of the injected liquid.

## ANALYSIS OF DOWNHOLE DATA (AFTER STIMULATION)

During reworking well B-20 in preparation for fracture stimulation the 7" slotted liner was pulled, lost circulation zones plugged back to 3520 ft and then a 7" blank liner was cemented in place with the shoe at 4880 ft. Since the stimulation interval was designed to be from 4880 ft to 5120 ft, a sand plug was placed from the top of the fish at 5827 ft to 5400 ft and then capped with cement to 5120 ft (Morris and Bunyak [1981]).

Figure 7 presents temperature profiles recorded subsequent to the recompletion of B-20. Survey RGI, recorded by Republic Geothermal, Inc. just prior to the fracture stimulation, shows three zones that apparently accepted the cold workover fluids during recompletion; the zone at 4000 ft which was the primary production zone during Flow Test No. 4 prior to recompletion; the

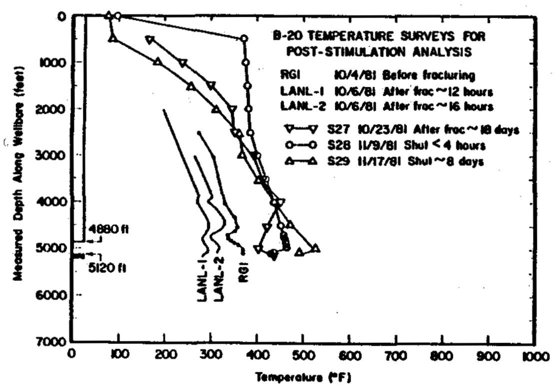


Figure 7. Temperature profiles before and after stimulation.

interval 4000-5000 ft which accepted approximately 30 percent of the injected fluid during Injection Test No. 1 prior to recompletion; a zone of less than 100 ft in height near the bottom of the open interval just above the top cement cap at 5120 ft.

The 240-foot interval (4880 ft - 5120 ft) stimulated was non-productive prior to fracture treatment, although there was a small rate of fluid loss during the well recompletion operation (Morris and Bunyak [1981]). This suggests that at least one lost circulation zone existed in the recompleted wellbore.

During the fracture treatment (October 5, 1981) approximately 9000 bbl of cold fluid was injected into the well. The first of several temperature surveys was made approximately 12 hours after the fracture stimulation. Surveys LANL-1 and LANL-2, shown in Figure 7, exhibit depressed temperatures at the same three zones as in survey RGI recorded prior to stimulation. The depression of the temperature near the bottom of the open interval, however, appears more pronounced.

The first post-stimulation temperature profile recorded by Union (S27) was eighteen days after the stimulation; the low temperature recorded at 5000 ft is noteworthy. Thereafter, a 14-day (October 26 - November 9, 1981) flow test (Flow Test No. 5) was performed to determine the wells productive capacity. Survey S28 was recorded by lowering the gage down the well immediately after shutin; the near-surface measurements were made several hours before the near-bottomhole measurements. The most noteworthy feature is the depressed temperature at the 5000 ft horizon. The survey taken 8-days after shutin (S29) verifies this characteristic which is attributed to cooling which accompanies the in-formation flashing of the fluid during Flow Test No. 5. The depressed temperatures presented earlier at the injection zones for the workover and injection fluids have disappeared.

In summary, the primary production zone in the stimulated well is at the center of the open interval, i.e., at 5000 ft. The initial reservoir temperature and pressure at this depth are estimated from S13 to be $T_0 = 507°F$ (264°C) and $P_0 = 1313$ psig (p(a) = 91.2 bars). If we assume a $CO_2$ content of $\alpha = 0.0147$, then the reservoir fluid would be initially single-phase but flash within the formation during Flow Test No. 5.

During the 14-day drawdown period of Flow Test No. 5, B-20 produced ~ 110,000 lbm/hr total mass flow initially, but declined rapidly to a final stabilized rate of ~50,000 lbm/hr (WHP = 25 psig). The steam fraction, based on mini-separator data, increased from ~50 percent to ~86 percent during drawdown. Since the well could not produce at commercial line pressures, buildup data sufficient for formation analysis were not obtained.

## CONCLUSIONS

The stimulated zone (4880-5120 ft) was located in a region which was naturally fractured. Our analysis of the pre-stimulation production data (Flow Test No. 4) and injection data (Injection Test No. 1) indicates that the natural fractures at this depth were good acceptors but poor producers. The induced fracture apparently intersected the existing fractures but the inherent non-producibility of the natural fracture system remained.


## ACKNOWLEDGEMENT

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