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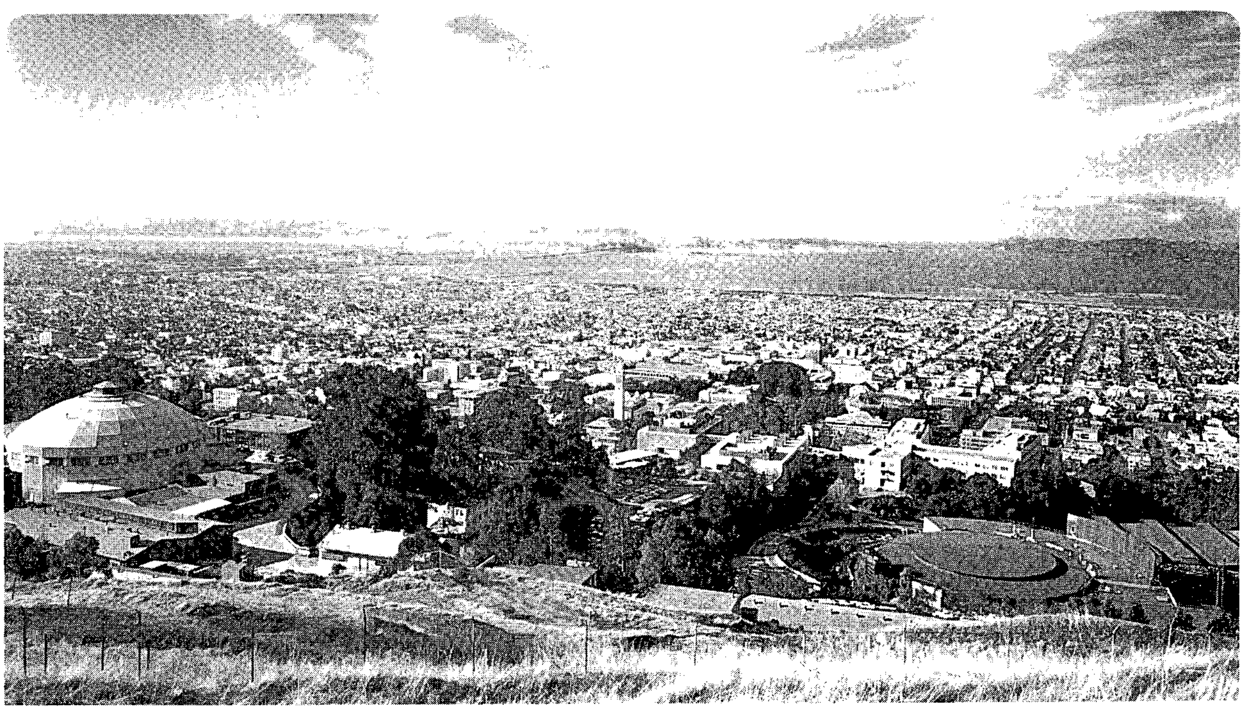

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Well Test Data Analysis from a Naturally Fractured Liquid-Dominated Hydrothermal System

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Abstract

Production test data from a moderate-temperature geothermal well in the Basin and Range Province have been analyzed. The well is completed in granitic basement rock. Both the pressure transient and spinner data confirm that fractures provide the major component of the reservoir permeability. The productivity index of the well decreases and the apparent skin factor increases with increasing flow rate. This behavior is attributed to non-Darcy flow in the fractures near the well bore. A mathematical relation between flow rate and drawdown has been established that includes the non-Darcy and Darcy flow components.

Introduction

Well WEN-1 was drilled by GeoProducts Corporation under the Department of Energy's User Coupled Drilling Program. In March 1982 the well was tested for a period of approximately one week. The geothermal group at Lawrence Berkeley Laboratory was invited to participate in the test by collecting downhole pressure data with a Hewlett Packard Downhole Pressure/Temperature gauge. In this report the analysis of the production test data is discussed.

The well, WEN-1, is located on the eastern side of the Honey Lake valley, California, near the Wendel and Amedee Hot Springs. It was drilled to a depth of 5837' and cased 5068' with a 9 5/8 in. casing. From a depth of 5068' to 5837' the well is open hole. The entire open interval of the well is completed in granitic basement rock. Pre-test temperature and spinner surveys were conducted, but space limitations do not permit their discussion here. It will suffice to say that the measured bottom-hole temperature was ~ 248°F and that ~ 80% of the flow comes from one major fracture zone.

Test Description

Figure 1 shows a plot of all the test data.

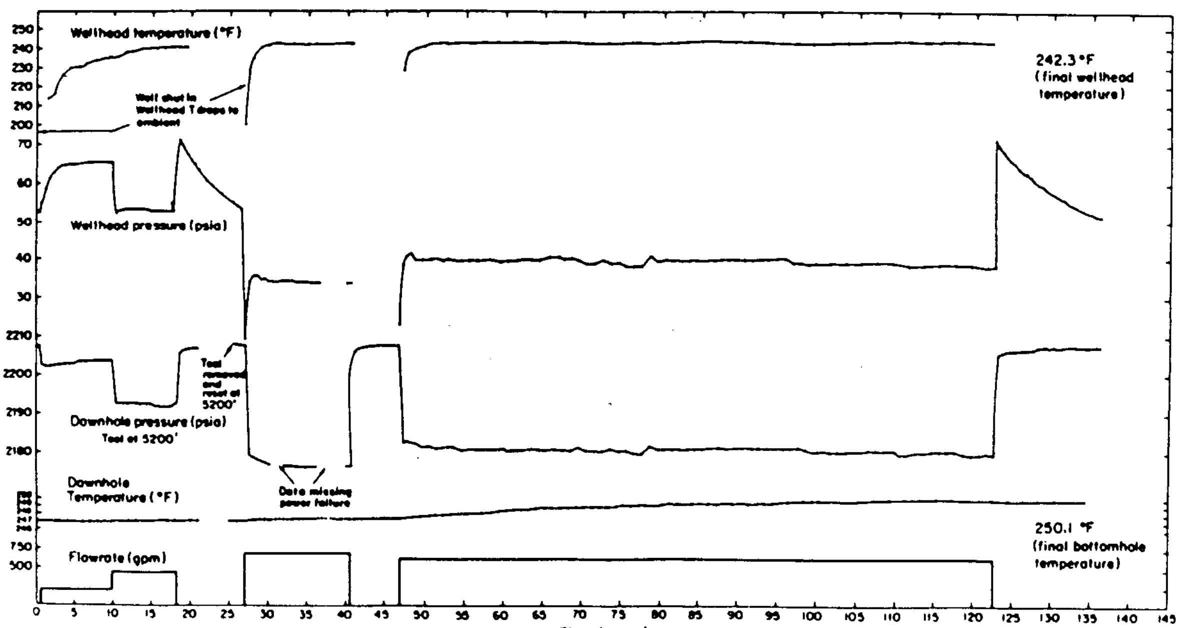

Figure 1. Test data from WEN-1 well test; wellhead pressure and temperature, downhole pressure and temperature, and flowrate.

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Downhole pressure data were obtained with a Hewlett Packard quartz crystal gauge. Wellhead pressure was measured with a Paroscientific gauge. Flow rates were metered by measuring pressure differential across an orifice with Paroscientific gauges. Downhole temperature was measured with a G.O. temperature tool. Wellhead temperature was measured with a thermocouple.

The well was flowed artesian at four rates. The first three rates (220 gpm, 440 gpm, and 680 gpm) were held at nearly constant values for a duration of approximatley 12 hours each. The fourth flow rate (620 gpm) was held nearly constant for a period of 75 hours. At each flow rate the downhole pressure quickly stabilized and showed little or no change for the duration of the flow period. Both wellhead and downhole temperature rose steadily throughout the test. The wellhead temperature rose from 240°F to 242.3°F, reflecting heating of the wellbore. The bottomhole temperatures increased from 246.8°F to 250.1°F over the test period.

WEN-1 Productivity Analysis

Table 1 summarizes the downhole productivity data from WEN-1. At 220 gpm the Productivity Index is ~ 49 gpm/psi as compared to ~ 22 gpm/psi at 680 gpm. In Figure 2 the downhole pressure change vs. flow rate is plotted. The relationship between the flow rate and drawdown, shown in Figure 4, can be expressed by Equation 1:

$$\Delta P(q) = 1.13 \times 10^{-2} q + 5.16 \times 10^{-5} q^2 \quad (1)$$

Table 1. Downhole productivity data for WEN-1.

Flow Rate (gpm)	Downhole ΔP (psia)	q/ΔP (gpm/psi)
220	4.5	48.9
440	15 0	29.3
620	26.5	23.4
680	31.5	21.6

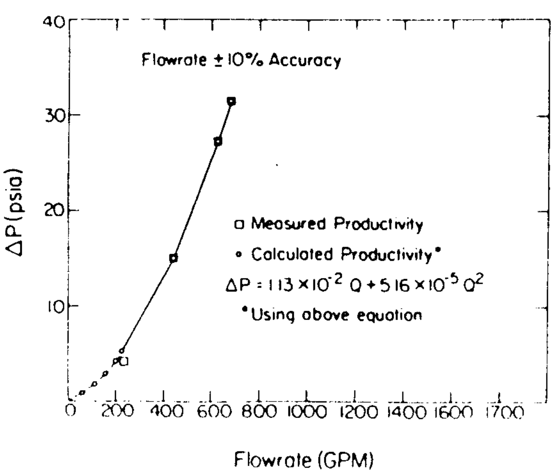

Figure 2. Downhole pressure change vs. flowrate for WEN-1.

Typically, the drawdown component proportional to q^2 is the result of well losses created by the pressure drop through the production liner and flow up the well bore (Jacob, 1947). However, since the well is completed with an open hole, and since downhole pressure data are used, the proportionality to q^2 must be a result of flow in the reservoir. This is discussed further in the following sections.

Pressure Transient Analysis

The pressure transient data were analyzed by the Horner and Miller-Dyes-Hutchinson techniques to obtain values for the reservoir transmisivity and skin factor (Mathews and Russell, 1967). Since the pressure drawdown quickly stabilizied and an absolutely constant flow rate was difficult to maintain, emphasis was placed on the analysis of the buildup data. A Horner plot of the buildup data following step 4 (620 gpm) is shown in Figure 3.

Each of the Horner plots has the same distinctive character demonstrated in Figure 3. When the well is shutin, the pressure immediately increases by nearly 95% of the total pressure drop. (Note that only the last 3 psi of pressure buildup are shown.) Then, a semilog straight line is apparent. After approximately one log cycle (10 min), the rate of pressure buildup decreases. Approximately half a log cycle later, the rate of buildup increases and once again a semilog straight line is apparent. In each case, the final semilog straight line gives nearly the same transmisivity, 3.3 - 3.5 x 10^6 md-ft/cp; moreover, the final semilog straight line extrapolates to the correct reservoir pressure. The later portion of the pressure transient data can be indicative of a double porosity or naturally fractured reservoir. Assuming a viscosity of 0.24 cp, the reservoir has a permeability-thickness of ~ 8.4 x 10^5 md-ft. Pressure data from these tests do not appear to be influenced by any reservoir boundaries. However, the relatively small drawdown and difficulty in analyzing the drawdown data may obscure boundary effects.

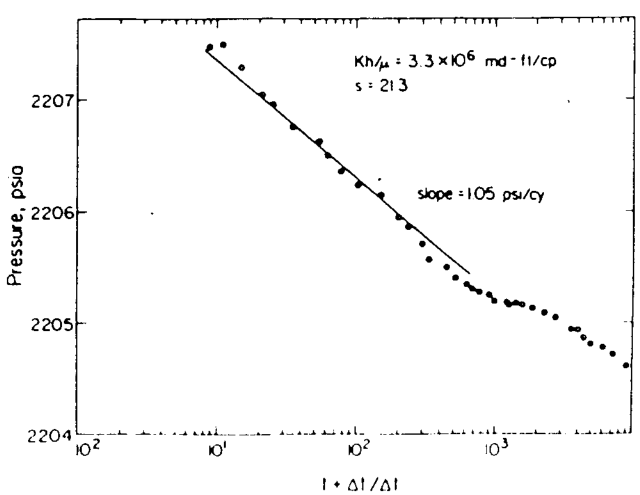

Figure 3. Horner plot of the pressure build-up data following step 4 (620 gpm).

The skin value, indicative of well bore damage or enhancement, was calculated for each of the pressure buildups. A storativity (ϕch) of 4.5×10^{-4} ft/psi was used in the skin value calculations. Even if this value is off by an order of magnitude, only a small error is introduced into the calculation because of the logarithmic dependence on ϕch. Table 2 lists the results of the analysis for each test segment. The skin value increases from 16 at 440 gpm to 24.1 at 680 gpm. These very high skin values are unusual for a geothermal well and very surprising, considering that the reservoir is fractured. Drilling fluid (water) and cuttings were lost in the production interval, but it is unlikely that this caused such a large permeability reduction. In addition, the skin value of a well should not be a function of the flow rate if the conventional definition of skin were applicable.

Table 2. Results of pressure buildup data analysis for WEN-1.

Segment	Flow Rate (gpm)	kh/μ (md-ft/cp)	Skin
2	440	3.3×10^6	16
3	680	3.5×10^6	24.1
4	620	3.3×10^6	21.3

Ramey (1965) discussed the concept of a skin effect in gas wells that included non-Darcy flow in the reservoir. The formulation he proposed is shown in Equations 2 and 3. Note that this formula assumes that q is measured in gallons/minute:

where $$s' = s + Dq \quad , \tag{2}$$

$$\Delta P(s') = 4840 \times qs'\mu/kH \quad . \tag{3}$$

D can be calculated from the slope of a plot of s' vs. q. In turn, s can be calculated from the intercept at q = 0. In Figure 4, s' vs. q is plotted. As shown, a single straight line with a slope of 3.54×10^{-2} gpm^{-1} can be drawn through the points. The q = 0 intercept is nearly zero, indicating a zero true skin value for the well.

To summarize, $kH/\mu \approx 3.5 \times 10^6$ md-ft/cp and $D = 3.54 \times 10^{-2}$ gpm^{-1}. The drawdown (at a single constant flow rate) can be calculated by

$$\Delta P(t) = \frac{4840q}{3.5 \times 10^6} P_D + \frac{4840q^2}{3.5 \times 10^6} \times 3.54 \times 10^{-2} \tag{4}$$

The match of the observed and calculated pressure, based on Equation 4, is shown in Figure 5. The calculated and observed pressure drops are in excellent agreement.

Discussion

Non-Darcy flow in gas wells is quite common due to the very high near-well-bore velocity (Smith, 1961; Swift and Kiel, 1962). Similar phenomena, related to well losses, are also discussed in the literature on groundwater hydrology (Rorabaugh, 1953). However, in the groundwater literature, the q^n ($n \sim 2$) drawdown component is usually due to pressure losses resulting from flow through the production liner and friction losses up the well bore. As mentioned earlier, the q^2 dependency discussed here is due strictly to flow in the formation.

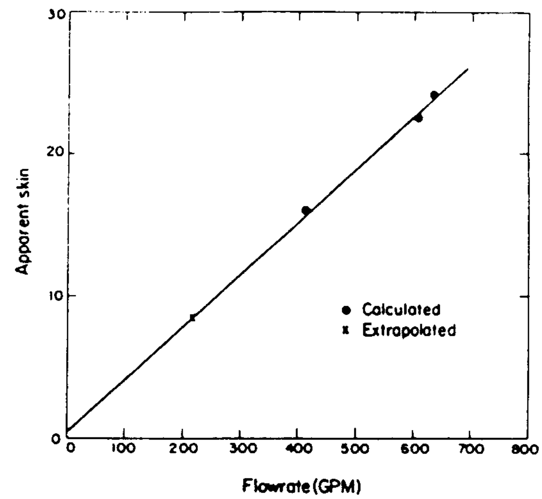

Figure 4. Plot of s' vs. q.

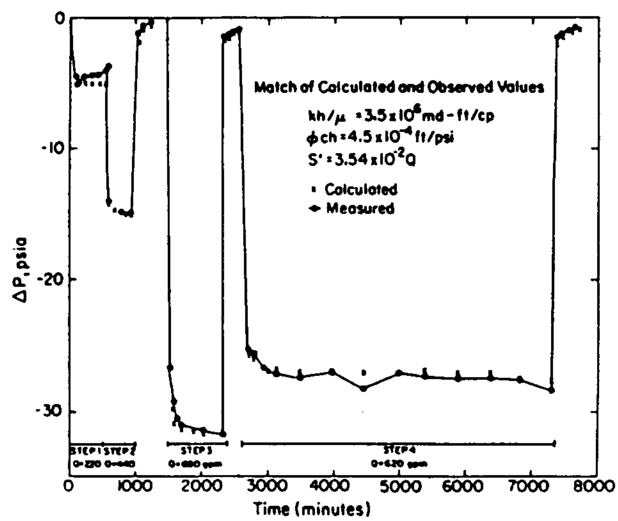

Figure 5. Match of observed and calculated data.

To obtain more insight into the problem, the velocity distribution in the formation was calculated. Because little is known of the precise fracture spacing, distribution, and aperture: velocity estimates were made for several cases. Knowing the permeability-thickness of the reservoir, the fracture aperture can be calculated from the cubic law (Snow, 1968):

$$kH = \frac{b^3}{12} \quad , \tag{5}$$

where b = fracture aperture (m).

Estimates of b were made assuming that 1, 10, and 100 equally sized fractures intersect the well bore. Table 3 lists the fracture apertures, equivalent fracture mobility-thickness (per fracture), and number of fractures for a total of kH of 8.4 x 10^5 md-ft (2.56 x 10^{-10} m^3).

Table 3. Fracture aperture, equivalent kH, and number of fractures for a total kH of 8.4 x 10^5 md-ft.

Number of Fractures	Aperture (mm)	kH (md-ft)
1	1.5	8.4 x 10^5
10	0.67	8.4 x 10^4
100	0.31	8.4 x 10^3

Assuming a fracture aperture, the flow velocity in the fractures (as a function of radial distance from the axis of the well bore) for each of the step rates was calculated. Table 4 summarize the results at the highest flow rate, 680 gpm.

One of the primary assumptions in Darcy's law is that a laminar flow regime exists in the reservoir. The flow regime in the reservoir is governed by the Reynolds number (R) and the roughness (ϵ) of the surface. Usually, for flow between parallel plates, at Reynolds numbers greater than 2000, the flow is no longer laminar. At Reynolds numbers greater than 2000, the flow regime is either transitional or turbulent (Knudsen and Katz, 1956). The Reynolds number for flow between parallel plates is calculated by

$$R = \frac{b\bar{v}\rho}{\mu} . \qquad (6)$$

Calculation of the Reynolds numbers for the flow velocities listed in Table 4 indicate that; at 680 gpm, turbulent flow will exist to more than 5 m into the reservoir if a single fracture feeds the well, up to 1 m into the formation if 10 fractures feed the well and most likely, will not exist if 100 fractures feed the well. A unique analysis of the fracture spacing and size is not possible with current fracture flow theory. However, the above analysis indicates that non-Darcy flow can significantly contribute to the drawdown if only a few major fractures feed the wellbore.

Conclusions

Both pressure transient analysis and productivity data indicate that the pressure drawdown has a component that is proportional to q^2. Analysis of the velocity distribution in the formation and the resultant Reynolds numbers indicate that turbulent flow in the near-well-bore formation may very well be the cause of the q^2 dependent component of the drawdown. Because the fracture aperture, roughness and distribution are unknown, it is not possible to fully evaluate the flow regime in the reservoir. However, an empirical relationship between flow rate and drawdown, with a very good correlation to the observed data, can be derived from this analysis. The analysis indicates a reservoir transmissivity of 3.5 x 10^6 md-ft/cp and a non-Darcy coefficient of 3.54 x 10^{-2} gpm^{-1}.

Table 4. Average fluid velocity in the fractures (m/sec)

No. of Fractures	Radial Distance from Well Axis (m) 0.2	0.6	1.	2.	5.
1	23.54	7.84	4.70	2.35	0.94
10	5.09	1.70	1.02	0.51	0.20
100	1.10	0.36	0.22	0.11	0.04

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Nomenclature:

- b - fracture aperture (m)
- c - total compressibility psi^{-1} (Pa^{-1})
- D - Non-Darcy coefficient gpm^{-1} (sec/m^3)
- H - formation thickness ft (m)
- k - permeability md (m^2)
- P_D - dimensionless pressure
- P - pressure psia (Pa)
- R - Reynolds number
- q - flowrate gpm (m^3/sec)
- s - infinitesimal skin
- s' - apparent skin = s + Dq
- v - average velocity (m/s)
- ϕ - porosity
- μ - dynamic viscosity cp (Pa-s)
- ρ - density (kg/m^3)

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