Presentation at the
National Heat Transfer Conference
Salt Lake City
August 1977

HEAT TRANSFER IN FORMATION AS A GEOTHERMAL RESERVOIR ENGINEERING TOOL

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ABSTRACT

Temperature profile logging of a geothermal well under thermal non-equilibrium conditions has proven to be a most useful tool in deducing production zone locations, width and for estimating the porosity within the production zone. The non-equilibrium conditions can be established by injecting cold water into the well from above and observing the time dependent temperature changes as this water is reproduced from the formation. The technique requires a surface readout downhole temperature logging tool. The use of a non-centralized temperature probe in the well bore, one which rests against the wall, enhances the usefulness of the data. Results to date on the Raft River, Idaho Geothermal Well (RRGE) No. 2 are reported, largely qualitatively in terms of production zone characteristics.

THE PROBLEM

The extraction of geothermal waters at moderate temperatures requires techniques of discovery different from those so long practiced and perfected in the oil industry. The principal question is one of resource location within the well bore, what its temperature is in the formation, and what the productivity rate of a particular strata of the formation is. As an example, Figure 1 shows the three Raft River deep geothermal production wells, in south central Idaho near the Utah border. The practical question of concern, during drilling, is where the casing should be set and cemented vs which part of the well should be left open to produce the desired geothermal fluids. Unlike oil and gas drilling, one cannot just sniff the circulating drilling fluids for the presence of hydrocarbons as the drill penetrates deeper. A small amount of geothermal fluid mixed with the drilling fluid creates insignificant physical differences, making detection during normal drilling difficult if not impossible. Furthermore, unlike oil and gas production, not only the volume of geothermal fluid but its temperature as well are of major concern in the decision of where the casing should be set. For instance, one may not want to double the flow from a well if it means mixing equal quantities of 200^{O}F water with 300^{O}F water, since the net amount of electric power generated from such well production could actually decrease. Finally, and not unimportantly, the basic understanding of geothermal reservoir engineering dynamics depends on understanding the production zones within the reservoir.

Using relatively inexpensive temperature logging of a geothermal well, the study of the temperature profile before, during and after reinjection, and during and after subsequent production of the well has proven to be a valuable means of understanding the stratigraphy of the reservoir. These techniques have been applied to a completely liquid dominated geothermal system in the deep wells at Raft River. In the effort to define and understand one cannot afford the luxury of continuous coring in a large diameter production well. Hence $\emptyset$, K, ΔH of the producing strata, and even the location of the producing strata remain a mystery, or at least an uncertainty. To date, conventional oil well logging techniques (electric, sonic, and nuclear) do not give more than minor clues to reservoir characteristics. Flow meter measurements are difficult or unreliable in the temperature and hole diameter* environment encountered, principally because of bearing failure in mechanical flow meters and temperature limitations on the radioactive isotope flow meters.

APPROACH TO SOLUTION

Once a geothermal well develops flow for a period of time, the well bore assumes a rather uniform or monotonically changing temperature characteristics. It is then impossible to delineate the production zones. The reference curve of Figure 2 shows this effect. The reference temperature profile was taken after the well was drilled to 5,988 feet and flowed for only 45 minutes. After several months of static conditions, the well was flow tested extensively and then a total of 10.5 million gallons of cooled ($\sim$120^{O}F) geothermal water was injected into the well. The injection period extended over a four-month period (December 1975 to March 1976) and in early March the well was deepened to 6,534 feet. Curves No. 1 and 2 of Figure 2 were taken immediately after the well was deepened and show the effects of the cool water injection. The production zones (zones 1, 2 and 3) were delineated based on significant temperature differences that were observed between the well bore and the then cooled production zones.

*Hole diameter ranges from 12 to 20 inches due to washing during the drilling process.

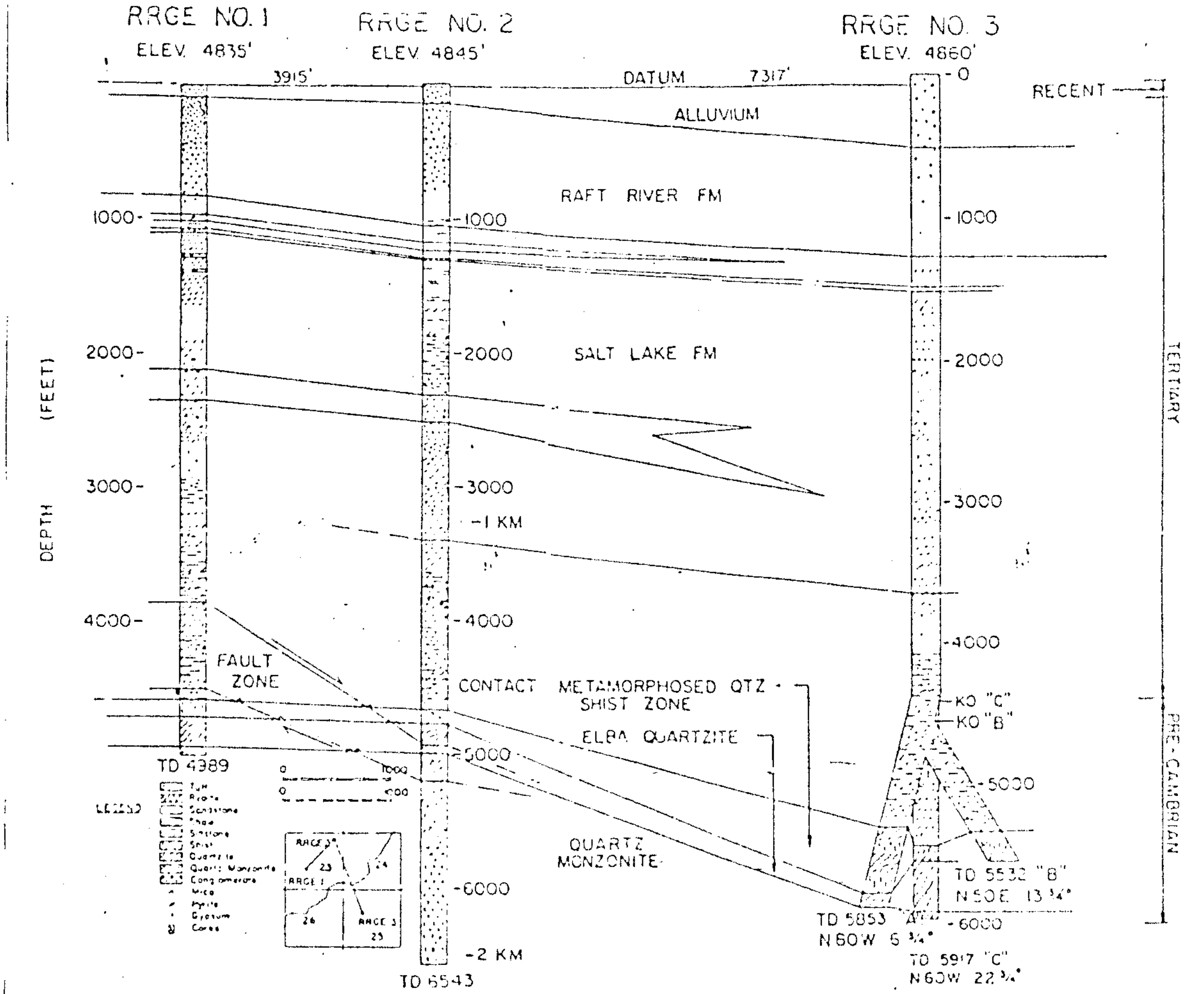


Figure 1 Details of the Raft River Wells. The distance between the wells is shown on the datum plane, No. 1 ... No. 3 being 6400 ft apart. The three wells are located on a triangular pattern.

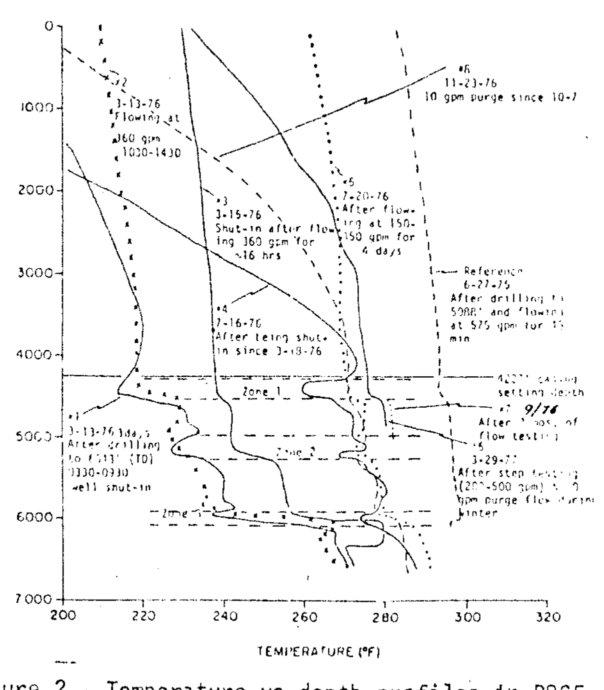


Figure 2 - Temperature vs depth profiles in RRGE No. 2 at various times after reinjection of cold water.

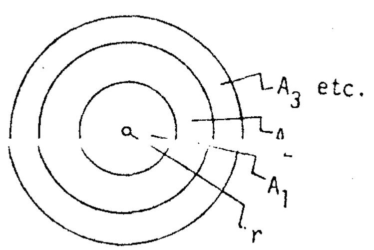
Figure 2, curves No. 1 through 6, depict the slow progressive recovery of the production zones due to flowing the cooled water back out of the well.

Clearly the temperature inversions and sharp breaks are indicative of productive zones. The question is what might be learned about the production zones' characteristics from the time-dependent temperature profiles.

Assume that a reservoir is of known constant temperature and cooler water is available on the surface in sufficient quantities to displace a significant quantity of water surrounding the well bore. When the cooler water is reinjected, it will enter the permeable zones, displacing the reservoir water nominally as slug flow. The rock in the permeable regions will also quickly equilibrate, but it will take considerable time for convective and conductive heat transfer to occur into the adjacent strata that are poor (or non) producers.

If the well is then allowed to produce, the initially cool water will come back out of formation, at a temperature depending primarily on the formation porosity (and hence relative heat capacities of water and rock in formation) and to some extent on the rate of heat transfer with the adjacent non-producing strata and the time that was available for heat to transfer. As the well continues to produce, eventually all of the injected water will be gone and the original geothermal water will again be produced, but at a cooler temperature than the initial main reservoir temperature. As the well continues to produce, the produced water temperature gradually increases as the producing rock strata near the well bore are brought back to normal reservoir temperature. This recovery process may require producing many times the original amount of reinjected water. By allowing periods of quiescence (weeks or months) to interrupt these flowing periods, equilibration with the non-producing strata is allowed to take place. Thus a program of repeated periods of reinjection, production, and static conditions can lead to information about the reservoir's stratigraphy, structure, porosity, and relative permeability.

Consider the two dimensional flow and heat transfer problem, azimuthally symmetric, with a single variable as a function of radius from the well bore. Divide this radial problem into equal areas, dA_i, of increasing radius. This treatment assumes heat transfer only as a result of slug flow through the formation.



Consider the time dependent problem of injection of cold water into this hot reservoir, with a pore space fraction (porosity) $\emptyset$.

The heat capacity of the water (per unit volume) is

$$W = \rho_w (C_p)_w \, \emptyset \qquad (1)$$

while that of the rock formation (solid) is

$$S = \rho_s (C_p)_s \cdot (1-\emptyset) \qquad (2)$$

Let $T(A_{i-1})$ be the temperature of the ring A_{i-1}

and $T(A_i)$ be the temperature of the ring A_i

As the water from A_{i-1} is forced into A_i, the new equilibrium temperature at time t + dt is

$$(W + S)\, T(A_i, t + dt) = ST(A_i, t) + WT(A_{i-1}, t)$$

$$T(A_i\ t + dt) = \frac{S}{W+S} T(A_i\ t) + \frac{W}{W+S} T(A_{i-1}, t) \qquad (3)$$

The above time step duration is just the amount required to displace the full quantity of water contained in these equal elements of area dA_1.

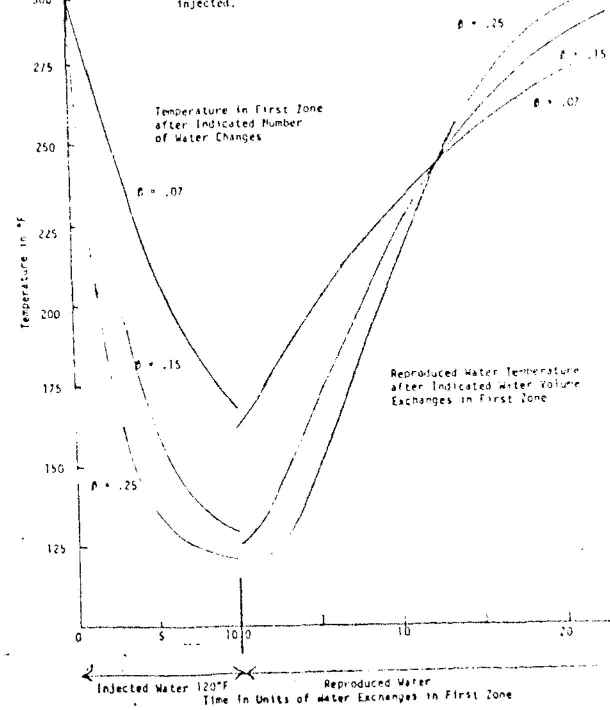
The quantity of water injected into a given layer of formation of height H is Q, and will extend to a radius given by

$$\pi r^2 \emptyset H = Q \qquad (4)$$

If the total area out to radius "r" is divided into n elements of equal area A_i, then the size of the elements will vary depending on the quantity of water, the height of formation, and the porosity. However, equation (3) has no dependence on the area size, except as this affects the numerical accuracy of the iterative approximation of the eventual extension to the time-space dependent integral. Thus, equation (3) depends only on the formation variables. Since specific heat and density vary little among rock types, the porosity is the only variable of importance.

Figure 3 is a plot of the general solution to equation (3) for three different porosities, as a function of dimensionless time. The initial condition is water of 120°F injected into a 300°F reservoir. The temperature is the average in the zone around the well through which injected water of ten times the initial volume in the zone passes. Figure 4 is a plot of the temperature looking from the well bore into the formation up to the edge of the cold water front (hydraulic front). Again, the abscissa is a dimensionless function, this time of area (not of radius). Figure 3 then further extends these curves showing the temperature of the water as it re-enters the well bore, again in dimensionless time units. On the right of the abscissa axis the 10 index is when all of the injected water is moved back out of the well, 20 is when two times this amount has been reproduced, etc.

Figure 3 Temperature profiles of first zone around well after up to 10 times its pore volume of cold injected water has passed through it, followed by temperature vs time profiles for given multiples of this volume of water to be reproduced. Results for three different porosities in a 300°F reservoir into which 120°F water is injected.



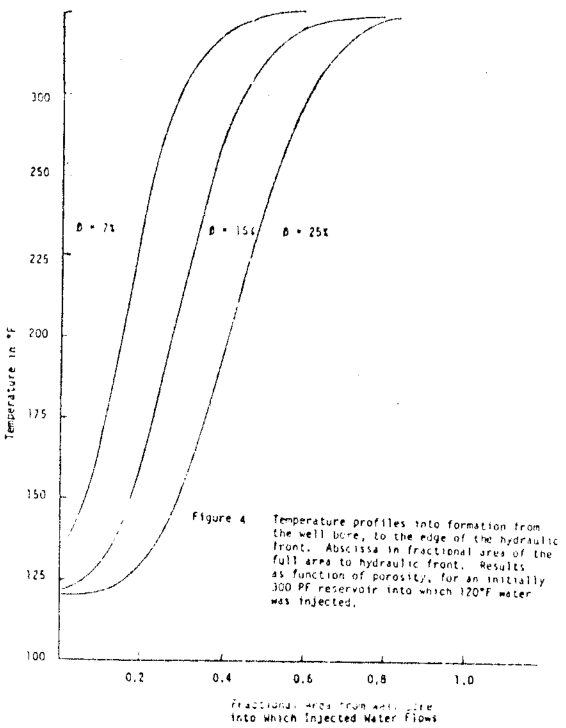


Figure 4 Temperature profiles into formation from the well bore, to the edge of the hydraulic front. Abscissa in fractional area of the full area to hydraulic front. Results as function of porosity, for an initially 300 °F reservoir into which 120°F water was injected.

The testing of the hydraulic parameters of geothermal wells, once the drilling fluids have been cleared out, involves measurement of flow and pressure (or drawdown). From this data, the parameters in the two dimensional time-dependent diffusion equation can be solved.[1, 2, 3]

These are generally designated as the transmissivity and storage coefficient, or alternately

$K\,H_{eff}$ and $\emptyset\,C\,H_{eff}$

K = permeability

H_{eff} = Effective height of the producing regions, which may be many discrete regions of small width adding up to H_{eff}

$\emptyset$ = fractional porosity

C = compressibility, typically 5×10^{-5}/atm for geothermal reservoirs

The averaged value deduced for KH between the first two deep Raft River wells* is approximately 220 darcy feet and for ØCH is approximately 10^{-3}. On the other hand, testing of the well itself, under its own drawdown condition leads to a KH $\approx$ 15 darcy feet (an order of magnitude lower) and ØCH $\approx 10^{-2}$ (an order of magnitude larger). The net result is the product of parameters, with no specific information about H_{eff} or K or Ø. As a practical matter these parameters need to be separated in order to determine the ultimate thermal effects of producing and reinjecting into the reservoir. A small "H_{eff}" and large K would imply a thin highly fractured permeable zone. Such a condition might result in apparent channelling of the flow. This is an undesirable condition, leading to rapid cooling near the channel boundaries while the non-permeable portions of the reservoir remain hot. The opposite situation is more desirable, leading to treatment of the entire reservoir as one large mass, at least over the long term. The overall average effective porosity is also needed to improve the estimate of the heat capacity of the reservoir.

*Calculated by interference testing between the two wells.

RESULTS AND INTERPRETATIONS

The technique described above can be used to deduce reservoir parameters from the thermal effects resulting from pulsing the reservoir by injection through the permeable strata that intersect the well bore. This initially cool water is then sampled via temperature logging as it comes out of formation. The use of the technique does require producing and reinjecting facilities, i.e. surface water storage and supply capacities and pumping capability adequate to displace water a significant distance from the well bore, say at least out to 50 feet. The temperature logging technique also needs to be one that is sensitive to the inlet water temperature from the formation to the bore hole, not to the mixed mean bore hole temperature at a given depth. This is, therefore, a case for not using centralizers on the tool, but allowing the tool to rest up against the barefoot well wall (which it generally will, except in the case of a perfectly vertical hole). Mixing lengths, even with Reynolds numbers of well above 10^5, turn out to be many well diameters, so the side-wall traveling temperature tool is indeed sensitive to the input water temperature. Figure 5 shows the results of these mixing experiments.

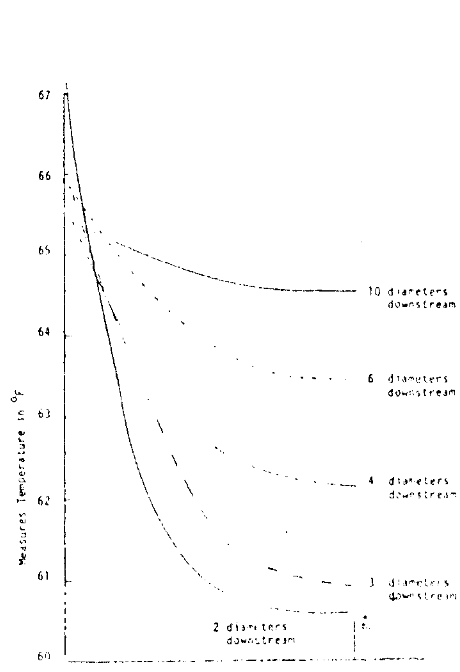


Figure 5 Mixing effect for scale model test. Axial flow = 2.8 gpm (Re = 2?,?00) of 61°F water in 3/4-inch tube; injected flow 0.20 gpm of 104°F water. Profiles are at various distances downstream from injection point.

Now consider heat transfer between formation zones. Once flow has been stopped, whether injection or production flow, the various temperature zones will begin to equilibrate. However, barring vertical convection patterns, such heat transfer is slow over the vertical distance usually considered. For instance, characteristically a thermal penetration distance may be defined from the solution of the time dependent heat diffusion equation as that distance into a slab, heated on its edges for which the temperature is still within 99% of its initial temperature. (4)

$$\text{Thermal penetration distance} = \delta_T = 4\sqrt{\frac{k}{\rho C_p}t} = 4\sqrt{\alpha t} \qquad (5)$$

Using a value of 0.5 Btu/hr-ft-^{o}F for the thermal conductivity of a typical rock-water reservoir, Ref (5), gives δ_T = 3.1 feet after one month. Or using the diffusion equation for a slab heated from both sides, integrating the temperature distribution, and solving for the time to bring this slab, on the average, up to 50% of the total temperature difference, (see Ref 4),

$$\text{i.e. } \overline{T_{1/2}} = 1/2 \text{ (T edge - T initial)} \qquad (6)$$

$T_{1/2}$ = time for half-heating, in days $\approx$ 0.12W^2 (ft^2) where W is the full width

Equations (5) and (6) are only guides, indicative of the magnitude and effect of the heating of a strata of rock and water from above and below. The real problem is not as simple as a uniform slab heated at constant temperature, but is one of two slabs of different temperature and different thermal conductivity exchanging heat. These exact solutions are an overkill at this time, since the temperature data in Figures 3 and 4 are being examined for semiquantitative indications of the characteristics of the production zones.

Figure 2 shows an example of the types of temperature profiles to be expected from such an experiment. Let's examine this figure in more detail. On the far right is the temperature profile after initially drilling and briefly flow testing the well (labelled "Reference" 6-27-75). Except for a small temperature inversion near the 4,300 foot depth, the log has no detail and therefore, gives little information about the production zones (except that there is probably one around 4,300 to 4,500 feet where cold drilling fluid is still coming out of formation).

Refer now to temperature logs No. 1 and No. 2 in Figure 2, first static, then flowing; both taken a month after reinjection experiments ended with 8 million gallons of 120^{o}F water injected (see Table 1). There are three main zones that apparently contain cold water and are producing cold water as the well is flowed. Figure 6 gives more detail of the profiles in these zones, with the left most curve giving a profile at even an earlier time. (That profile was taken with an Amerada bomb - a clock driven, self contained capsule, and therefore, the depth detail is less accurate than for the other curves, which were made with surface readout real-time logging instruments.) It would appear that there were two other minor production zones, at 4,800 feet and 5,800 feet, in addition to the three main zones.

Refer now to profile No. 4 in Figure 2 made after 4 months of well shut-in, and in particular, compare it with profile No. 3, after the last flow test. The entire formation has heated up, but the zones of cold water from injection still persist. Because of the very small thermal penetration distance expected, even after 4 months, this profile rather precisely defines the production zones.

TABLE 1

HISTORY OF INJECTION AND SUBSEQUENT FLOW, RRGE NO. 2

June to December 1975	Flowed 2.7 million gallons
December 1975 to March 1976	Injected 8.3 million gallons of $\sim$ 120^{o}F water and reproduced 4.3 million gallons of this
March 1976	Drilled 500 feet deep, 3.1 million gallons of circulated drilling fluid (water) needing 1.8 million gallons makeup
March to July 1976	No flow
July to November 1976	Flowed 16 million gallons
December 1976 to March 1977	Flowed 5 million gallons

Production of the well has continued periodically, principally for further determination of the hydraulic parameters. The temperature in the well has continued to increase, more so from the lower production zones than from those above (No. 6 profile, Figure 2). About 25 million gallons has been flowed back out, compared to 10.5 million gallons of cold water that was flowed into the well. By referring to Figure 3, the dimensionless time plots for the water returning to the well bore, it is apparent the lower porosity formations require more time to return to near the initial reservoir temperature and conversely cool off less rapidly during cool water injection. Also, from Figure 4, dimensionless in distance from the well bore, the lower porosity formation has its temperature effect confined close to the well bore.

In interpreting the results, a basic assumption that should be valid is that zones will produce water at the same relative rates as they accept injected water. Therefore, the dimensionless time curves of Figure 3 should be similar for all zones on the same time scale, and differences in temperature as the well develops into production should only imply differences in heat transfer between the production and the non-production layers. Those production zones that return in fastest time are (1) either the most porous, or (2) the most heterogeneous mixture of narrow slabs of production and non-production zones allowing rapid vertical heat transfer into the narrow production slabs. The first explanation seems incorrect, because as Figure 3 shows high porosity should be the coldest after reinjection. But zone 2 and zone 3 were not the coldest, hence, explanation No. 2 must apply. They must have the most heterogeneous producing characteristics. Further confirmation of this conclusion qualitatively comes from the effect noted in Figure 2 (profile No. 7) between high flow and subsequent virtually static conditions 2 months later in zone No. 2. The production temperature cooled off during this time. The explanation is, that on September 28, zone No. 2 was producing

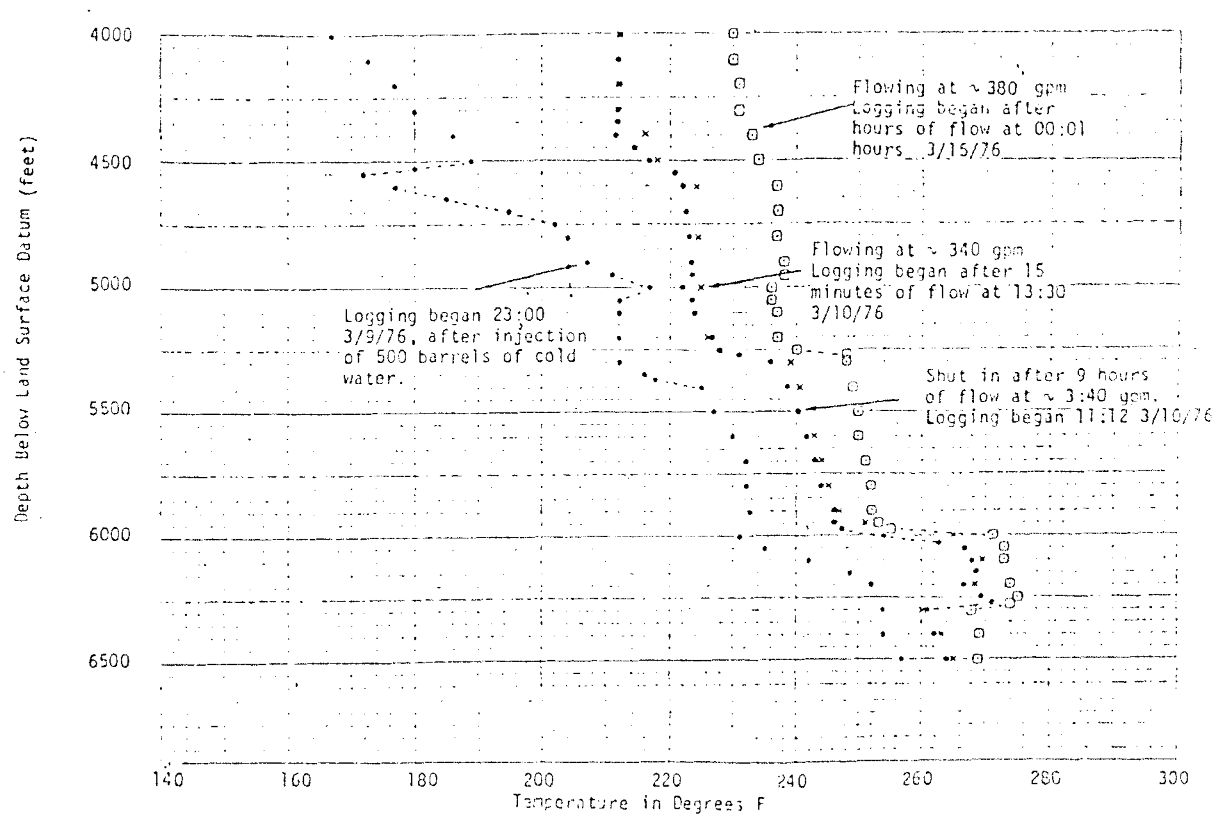


Figure 6 RRGE No. 2 temperature logs following injection of 10.5 million gallons of water, and then recording changes in the profile as flow out of the well was re-initiated.

from its fractures at nearly normal reservoir temperature, but the interbedded non (or poorly) permeable layers were still cool from the previous effects. During the nearly static (very low flow) conditions over the next 2 months (see profile 8), the zone No. 2 production water transferred some of its heat to those cooled layers.

CONCLUSIONS

The results of thermal cooling ideas applied to reinjection temperature logging experiments on RRGE No. 2 are only qualitative at this time. The importance is that significant changes in local temperature do occur within the well as a result of thermal cycling by injection and reproduction, and these temperature differences can lead to a better understanding of the production zones and their characteristics. On RRGE No. 2, it appears that zone No. 1 is the principal producer, from 4,300 to 4,500 feet, and probably produces 60% of the flow. Zone No. 2 perhaps adds 30%, from 4,950 to 5,250 feet, zone No. 3 and several other smaller zones contribute the rest of the flow. It also appears that the effective producing porosity is significantly lower, such as 7 to 10%, than the 15% average measured on core samples. This conclusion comes from Figure 3 which shows that 15% porosity should have given much lower formation temperatures after injection than were observed. Also, zones No. 2 and No. 3 would appear to allow significant heat transfer between non-permeable and permeable strata within the producing zone. Finally net effective height of the reservoir appears to be about 600 feet, with a corresponding permeability averaged over these zones of 25 millidarcies in the region of the well bore. But when applied to the connecting strata between wells 4,000 feet apart, an order of magnitude higher product of KH is implied. Apparently the separate strata of production and "non-production" zones near the wells communicate with each other over this 4,000 foot distance, resulting in a relatively uniform and thick reservoir, in essence, it is this thicker H that should be used in calculating reservoir capacity.

The authors intend to carry out a better planned, better instrumented injection-reproduction experiment in the near future. When the first experiment was conducted, the local detail of the temperature logs and overall usefulness of the experiment was not anticipated. It is hoped that this paper will serve as a stimulus to others to try similar experiments as a key to better understanding of the production zones in a geothermal well.

NOTE: More complete details on the three wells at Raft River can be found in references 6, 7, and 8.

LIST OF SYMBOLS

A_i = element of area as a radial ring

C_p = specific heat

C = compressibility of water, 5×10^{-5}/atmosphere

H = height of producing zone

k = thermal conductivity

K = permeability

r = radius

S = heat capacity of rock (solid) per unit volume of reservoir

t = time

T = temperature

W = heat capacity of water in reservoir, per unit volume of reservoir

$\sigma = \frac{k}{\rho C_p}$ = thermal diffusity

$\emptyset$ = porosity (fractional)

ρ = density

ACKNOWLEDGEMENTS

The authors wish to acknowledge the contributions of L. G. Miller, C. G. Cooper and D. H. Suckling in gathering the data. Larry Bills, student at the University of Utah, conducted the experiments on mixing effects for a temperature probe resting against the sidewall of the well. We are grateful to P. A. Witherspoon and N. A. Narisimhan of Lawrence Berkeley Laboratory for the initial analyses of the hydrological data from well testing.

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