Proceedings Ninth Workshop Geothermal Reservoir Engineering
Stanford University, Stanford, California, December 1983
SGP-TR-74

THE DEVELOPMENT AND USE OF A HIGH TEMPERATURE DOWNHOLE FLOWMETER FOR GEOTHERMAL WELL LOGGING

R.D. Solbau, C.B. Goranson*, and S.M. Benson

Earth Sciences Division
Lawrence Berkeley Laboratory, University of California
Berkeley, California 94720
*BGI, 2000 Center St., Berkeley, CA. 94704

ABSTRACT

This paper discusses the development and use of a high temperature (300°C) downhole flowmeter for geothermal well logging. The availability of the instrument gives the reservoir engineer a powerful tool for formation evaluation and studying wellbore dynamics. The instrument components, their function, and temperature limitations are discussed in detail. Several field examples of spinner log interpretation are also presented.

INTRODUCTION

The Earth Sciences Division at the Lawrence Berkeley Laboratory has developed a reliable high temperature (300°C) downhole flowmeter. The utility of downhole flowmeters for locating production and injection zones in petroleum reservoirs has resulted in their use for many years. The high temperatures, corrosive brines and very high fluid velocities encountered in geothermal wells prohibited the use of conventional downhole flowmeters. In the mid 1970's both the U.S. government and private industry put a significant effort into developing high temperature instruments (including downhole flowmeters) suitable for use in geothermal wells (Veneruso et al, 1979; Lawton et al, 1982). This ongoing effort has resulted in the development and testing of high temperature components and instruments. However, the difficulty in making reliable high temperature instruments persists. Using a very simple design concept and a minimum of downhole electronic components, a successful design for a reliable high temperature (300°C) downhole flowmeter (spinner) has been realized. The availability of a high temperature spinner has demonstrated its use for several purposes:

1) Locating production and injection zones;

2) Indicating changes in production and injection zones resulting from acidizing or fracturing;

3) Locating the flashpoint or bubble point in a wellbore;

4) Reflecting scale buildup, casing damage, plugged perforations or thief zones.

To make downhole measurements, the flowmeter is attached to a high temperature single conductor armored logging cable. It is lowered into the well with a conventional logging hoist. As the flowmeter is lowered into the well, the vertical fluid velocity causes an impeller to rotate. The rotational speed is sensed and recorded at the surface. Changes in the vertical fluid velocity can be used to indicate the items previously mentioned.

BACKGROUND

A general utility geothermal downhole flowmeter should have a temperature rating of at least 300°C and an operating pressure of 10,000 psi. In 1977, when research in this area began, the only high temperature downhole flowmeter available was a subsurface recording unit with a temperature rating of 260°C (Kuster). A stylus would scribe a number of marks on a metal chart located inside the body of the flowmeter. Each mark on the chart represented a certain number of turns of the impeller. A survey would require making stops of equal length in time at various well depths, never knowing if the instrument was still functioning or if zones of interest had been located and properly identified. Other downhole flowmeters had been used extensively in oil wells but were not well suited for the high temperatures in geothermal wells. Most of these used pivot bearings and had rather sophisticated downhole electronics. The downhole electronic packages typically had a maximum temperature rating of 177°C. Due to the high wellbore velocities, thermal and mechanical shock, scaling and the corrosive nature of geothermal fluids, conventional pivot bearings and unprotected ball bearings were unreliable.

FLOWMETER

The basic concept of the spinner is that the fluid flowing up or down a wellbore and passing through the flow passage of the instrument will rotate the impeller inside the flowmeter at a rate that is proportional to the fluid velocity. The impeller in turn rotates a magnet assembly. The rotating magnet opens and closes a reed switch, thus generating a frequency signal which is recorded electronically at the surface. The frequency signal is proportional to the number of revolutions per minute at which the impeller is rotating. The spinner rotates at approximately 150 revolutions per minute for each foot per second of fluid velocity (for liquid water). The volumetric flowrate is calculated by multiplying the measured fluid velocity by the cross-sectional area of the bore. A photograph of the flowmeter is shown in Figure 1. The total length of the instrument is 2 feet and its maximum outside diameter is 2 inches without the centralizer. The flowmeter makes a pressure tight connection to a high temperature cablehead with the aid of metal to metal seals and high temperature elastomer o-ring seals.

Components

Table 1 lists the major components used in the instrument. The advantages of these components in hostile downhole conditions are discussed below. Downhole geothermal environments are particularly harsh on instruments due to:

1) High temperatures;
2) Corrosive liquids and gases;
3) Scale formation;
4) Sand production;
5) Very high fluid velocities in the flash zones.

To design and fabricate a high temperature flowmeter that will function reliably under these conditions, several design criteria must be met. First, the downhole electronics should be simple and function reliably at high temperatures. Second, the bearings must be shock resistant, have a high operating temperature and be protected from the geothermal brine. Finally, all components exposed to the brine must be corrosion and abrasion resistant in the operating environment.

The first objective was accomplished by using a reed switch* to sense the rotation of the impeller. This simple device eliminates the need for any active downhole electronics such as voltage regulators, voltage to frequency converters or signal amplifiers which may be temperature sensitive. The reed switch assembly operates in the following manner. The reed switch, enclosed in a stainless steel tube, is placed in close proximity to a magnet which is fastened to the top of the shaft (Figure 2). As the impeller rotates it opens and closes the reed switch. This creates a frequency signal which can be monitored and recorded at the surface. Two types of bearings are frequently used in downhole flowmeters, pivot bearings and ball bearings. Pivot bearings are more commonly used in conventional flowmeters but for the reasons discussed previously they may not be best suited for geothermal applications. Ball bearings, if kept clean and well lubricated will function extremely

*A reed switch is a passive electronic device. It has electrically insulated contacts that can be made to close by passing a magnetic field in close proximity of the device, and will open when the magnetic field is removed.

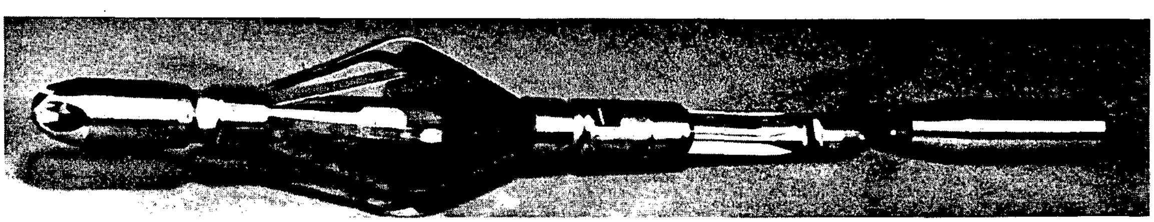

Figure 1. Photograph of the downhole flowmeter.

reliably at high temperatures and high rotational speeds. In addition, their successful use in the early subsurface recording units made them a logical choice. Two bearings are used (shown in Figure 2), one close to the impeller and the other near the top of the shaft. The two precision bearings let the 1/8 inch diameter impeller shaft rotate freely. They are protected from the corrosive wellbore fluid by an oil bath reservoir. The oil is prevented from leaving the enclosure at the lower bearing by capillary action due to the close fit of the impeller shaft and the shaft exit port located below the bottom bearing. After the flowmeter is lowered into a well, the higher specific gravity and the pressure of the brine prevents the turbine oil from leaving the enclosure.

To protect the instrument from the corrosive and abrasive downhole environments in geothermal wells the body was fabricated of type 304 stainless steel. A titanium impeller was chosen and fabricated because of the very high strength to weight ratio and high resistance to corrosion in geothermal brines. The aluminum and plastic impellers used in many downhole flowmeters are usually destroyed within a short time by the brines and high temperatures.

The fluid in production wells enters the flowmeter through the holes in the bullnose, rotating the impeller, and escapes through the externally fluted area of the bearing and shaft housing (see Figure 2). During use in injection wells, a collapsible funnel is usually attached at the fluted area of the bearing and shaft housing, which diverts the well fluid through the impeller housing, rotating the impeller and exiting at the bullnose.

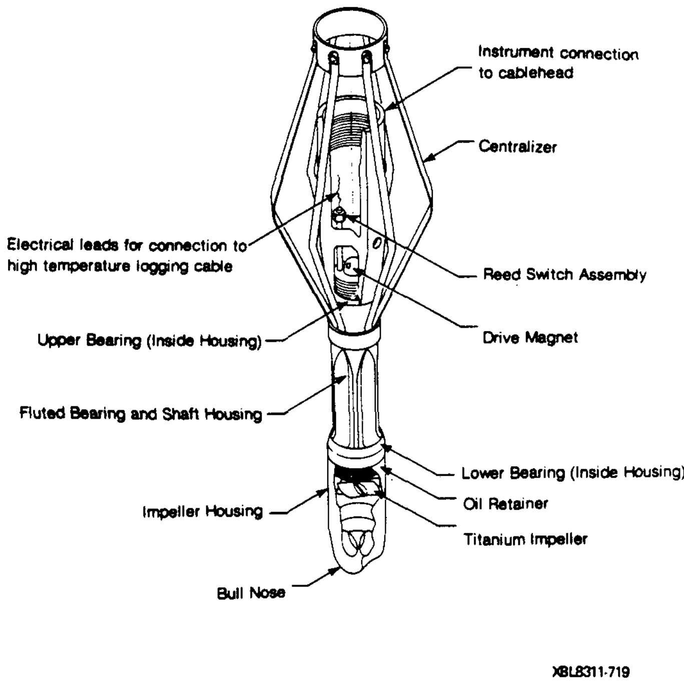

Figure 2. Schematic of the downhole flowmeter.

EXAMPLES

Downhole flowmeters have many applications in geothermal well testing, formation evaluation, and wellbore dynamics. In the following section three examples are given which demonstrate their utility and illustrate some of the difficulties with the interpretation of spinner logs. In theory, interpretation of spinner logs is very straight forward, but in practice it is often complicated by bore diameter variation and erratic

Table 1. Spinner components and temperature ratings.

Component	Type	Temperature Rating
Bearings	Shielded Precision Ball Bearings (many manufacturers)	480°C
Reed Switch	Hermetically Sealed (many manufacturers)	300°C*
Lubricating Oil	High Temperature Turbine Oil (Union 32 or equivalent)	300°C
Magnet	Alnico 5 or Alnico 8	400°C

*No temperature rating given. This value was determined experimentally and the true value may be significantly higher. The only reed switch tested is manufactured by the Calectro Company.

fluid flow near fractures or perforations. Methodical evaluation of the spinner log can resolve some of these complications and result in quantitative evaluation of production and injection zones. The first two examples are spinner surveys obtained from wells in the Imperial Valley, Calif. The first one demonstrates a conventional interpretation of a spinner survey from a well completed in a sandstone and shale reservoir. The second demonstrates flash point location in a very hot well which produces highly saline brine. The last example demonstrates the interpretation of a spinner log in a well with an openhole completion.

Flowmeter logs are obtained by lowering the instrument into the well. The log can be obtained while the instrument is lowered down the bore at a constant rate or with stops made at regular intervals. Logging at a constant speed has the advantage that the line speed can be sufficient to overcome the starting velocity (0.25 ft/s) of the spinner. On the other hand, it has been found that the precision of the survey is far greater if stops are made. During logging runs it is also important to ensure that the instrument is adequately centralized in the bore throughout the survey. This can be a problem in large diameter wells or wells with significant bore diameter changes. In that case the centralizer is chosen to fit the region of major interest.

Imperial Valley, California: Well 1

Wells completed in sandstone formations may have an even permeability distribution over the bore length or it may be concentrated in discrete intervals. Wells in the Imperial Valley may have open intervals up to several thousand feet. Detailed reservoir engineering studies and well workovers require knowledge of the permeability distribution in the formation(s) penetrated. Correlation of geophysical borehole logs can be used for this purpose but rarely with sufficient confidence. Spinner surveys provide a direct method of determining the distribution of well productivity over the borehole length. Comparison of the productivity distribution to cuttings and borehole log analyses can be used to infer both the formation permeability and near-bore permeability damage.

A typical spinner survey from such a well is shown in Figures 3 and 4. The well completion is shown in Figure 5. In Figure 3, the casing profile is shown. At the very top of the well the fluid velocity is relatively high (reflected by the rotation rate of over 300 RPM). At 225 feet, the fluid velocity drops to zero. This reflects the transition from the flashed to the unflashed brine in the wellbore (the flash depth). From 225 feet to 1750 feet the fluid velocity is below the starting velocity of the spinner. Therefore no fluid velocity is registered. From 1750 feet to the bottom of the casing (4700 feet), the fluid velocity remains nearly constant (with the exception of the higher velocities at the casing shoe).

Data from the spinner survey in the slotted liner is shown in Figure 4. Analysis of the data indicates that two intervals produce at least 73% of the fluid. The upper zone located between 4700 feet and 4720 feet produces approximately 18% of the total flow. Between 4720 feet and 4980 feet only 7% of the total flow is produced. The second major productive interval lies between 4980 feet and 5100 feet. At least 55% of the flow is produced from this interval. Because of the low fluid velocity below 5100 feet, it is not possible to determine if any fluid is being produced. Approximately 20% of the total fluid may be produced from below this depth.

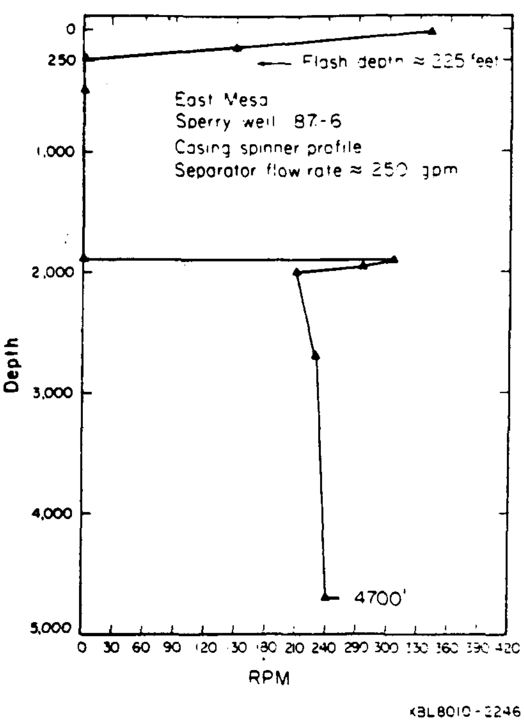

Figure 3. Casing spinner survey from well 87-6, Imperial Valley, Calif.

This is a good example of a conventional spinner log interpretation, and several key points are illustrated. First, the spinner easily detects the flash depth in the well. Second, the low flowrate (25Ø gpm) at which the survey was conducted created a relatively large uncertainty in the quantity of flow that was coming from below 51ØØ feet (2Ø% uncertainty). Therefore, it would seem desirable to conduct the survey at a higher flowrate. However, there is a disadvantage to this, in that the flow regime in the vicinity of the perforations may become erratic at higher production rates. This results in a further ambiguity in the interpretation of the survey.

Imperial Valley, California: Well 2

The depth of the flash point in a well is typically inferred from abrupt changes in the slopes of flowing temperature and pressure profiles. In wells producing from gas rich reservoirs with highly saline brine, the slope of the pressure and temperature profiles change gradually, creating uncertainty in the true depth of the flashpoint. The spinner profile obtained from the upper portion of such a well is shown in Figure 6. Near the top of the well the fluid velocity is very high, reflecting a high steam content in the fluid. With increasing depth the fluid velocity gradually decreases (due to lower steam quality). Below 3ØØØ feet the fluid velocity stabilizes, indicating that only a liquid phase is present. The spinner survey precisely locates the flash depth.

Wendel, California

The velocity of the fluid as it travels up the well is inversely proportional to the square of the bore radius. Therefore, even small changes in the radius can result in large changes in the fluid velocity. In openhole completions the bore diameter is often highly variable resulting in erratic fluid velocities. These changes are often so large that interpretation of the spinner data is very difficult. However, if a caliper survey is available, careful correlation of the two logs can result in quantitative evaluation of the spinner survey. This is demonstrated by the following example which was obtained from a geothermal well completed in a naturally fractured granitic rock. The spinner and caliper surveys from this well are shown in Figure 7. From the caliper survey (right side of Figure 7) it can be seen that the bore diameter is highly

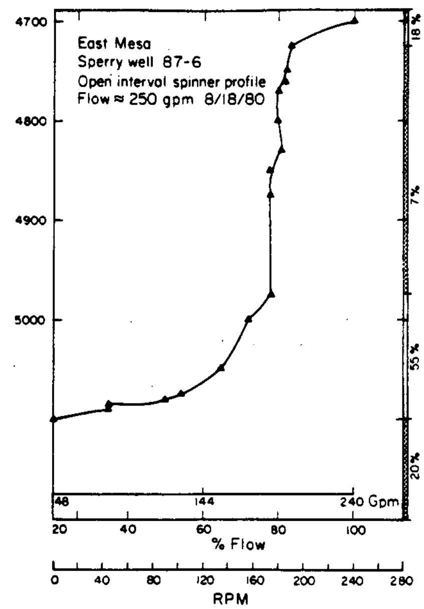

Figure 4. Open interval spinner survey from well 87-6, Imperial Valley, Calif.

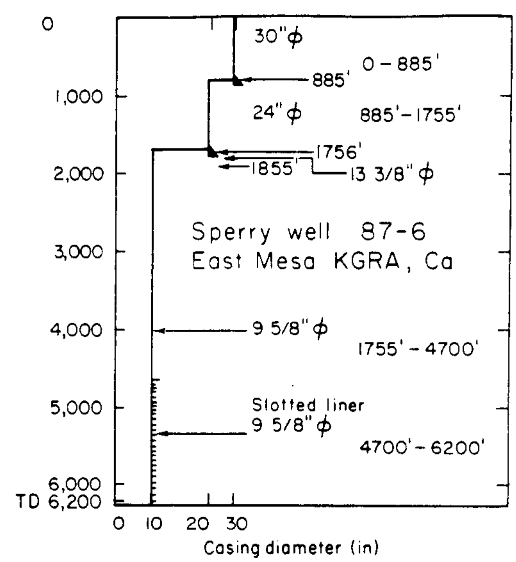

Figure 5. Casing schedule, well 87-6, Imperial Valley, Calif.

erratic. This is reflected in the variations in the fluid velocity shown in the spinner survey (left side of Figure 7). By comparing the flow velocity to the caliper survey at the depths at which the bore diameter is that of the originally drilled hole (13 inches to 53ØØ feet) the distribution of production intervals can be determined. The survey showed that 7% of the flow was entering the bore between 512Ø feet to 518Ø feet, 13% between 519Ø feet and 526Ø feet, and the remaining 8Ø% between 528Ø feet and

5320 feet. Below 5320 feet the impeller stopped rotating, indicating that the fluid velocity had dropped below the running velocity. Because the survey was conducted at a relatively high flowrate (680 gpm) it can be determined that less than 6% of the flow (40 gpm) was entering the well below 5320 feet.

This example demonstrates the extreme sensitivity of the flowmeter results to changes in the bore diameter. Whereas for conventional applications this may be a drawback, it can be very useful for detecting scale buildup or casing collapse in a wellbore. Because the spinner can be run while the well is under production, the spinner can be used as a production mode borehole caliper. This has the advantage in that scale buildup or casing problems can be diagnosed without shutting in the well.

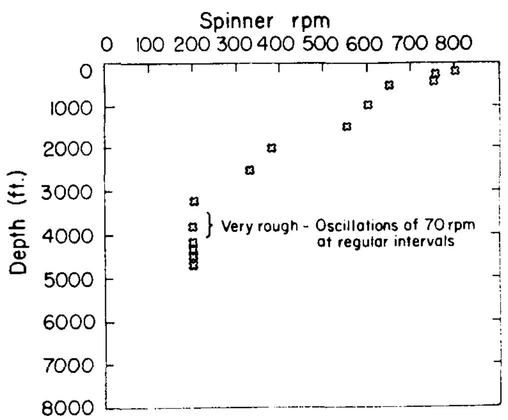

Figure 6. Spinner survey through the flash zone.

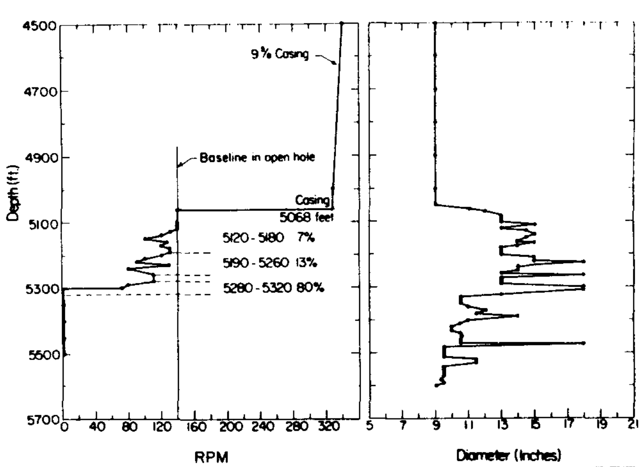

Figure 7. Spinner and caliper surveys from a well with an open hole completion.

CONCLUSION

By using existing technology a high temperature (300°C) downhole flowmeter can be constructed. In addition to the conventional uses, downhole flowmeters can be used for 1) locating the flash point in a well, and 2) as a very sensitive production mode borehole caliper. Careful analysis is required to avoid erroneous interpretation of the data and to extract the maximum amount of information from the survey. If a caliper survey is available, a spinner survey can be used successfully in an openhole completion.

There are several practical guidelines to follow in order to obtain the best quality spinner data.

1) Ensure that the instrument is adequately centralized during the survey.

2) A combination of logging at a constant line speed with regular stops throughout the regions of interest will provide the most accurate record.

3) Conduct the survey at the maximum flowrate possible without developing a highly erratic flow regime around the perforations. This flowrate must be determined empirically.

4) Expect to spend a fair amount of time on the analysis of the data.

ACKNOWLEDGEMENTS

This work was supported by the Assistant Secretary for Conservation and Renewable Energy, Office of Renewable Technology, Division of Geothermal and Hydropower Technologies of the U.S. Department of Energy under Contract No. DE-AC03-76SF00098.

REFERENCES

Kuster Flowmeter MK II: Instructions, Operations and Maintenance Manual, Kuster Company, Long Beach, CA.

Lawton, R., Kolar, J., and Todd, B. (1982), Fluid Velocity Sensor Development Report, Hot Dry Rock Geothermal Energy Development Project, Los Alamos National Laboratory, Los Alamos, New Mexico 87545.

Veneruso, A.F., Simpson, R.S., Charles, A. (1980), High Temperature and Instrumentation Seminar Proceedings, Sandia National Laboratory, Albuquerque, New Mexico 87185.

Proceedings Ninth Workshop Geothermal Reservoir Engineering
Stanford University, Stanford, California, December 1983
SGP-TR-74

NONISOTHERMAL INJECTIVITY INDEX CAN INFER WELL PRODUCTIVITY AND RESERVOIR TRANSMISSIVITY

Omar Sigurdsson, Gudmundur S. Bodvarsson+ and Valgardur Stefansson

Orkustofnun, Grensasvegur 9, 108 Reykjavik, Iceland.

ABSTRACT

In geothermal wells injection tests are commonly used to obtain well and reservoir data. These tests are typically conducted in a series of step rates followed or preceded by a complete shutin. Usually the temperature of the injected fluid is different from that of the reservoir fluid. Because of the strong temperature dependence of fluid viscosity and to a lesser extent, fluid density, nonisothermally related pressure responses must be considered. The nonisothermal injectivity index obtained from these tests depends on the mobility ratio of the cold region to the hot reservoir and the extent of the cold spot. This paper proposes a method of estimation of the apparent viscosity which accounts for these effects and relates the nonisothermal injectivity index to the isothermal injectivity index.

INTRODUCTION

In geothermal wells injection tests are commonly used to obtain well and reservoir data. The temperature of the injected fluid is invariably different from the temperature of the in situ reservoir fluid. Since fluid mobility, k/μ, plays the major role in pressure transient behavior, the strong temperature dependence of fluid viscosity and to a lesser extent, fluid density, has a large impact on the test. The dynamic viscosity of water changes by an order of magnitude between 20 °C and 300 °C, the major changes ocurring between 20 °C and 100 °C. However, the decrease in fluid density from 20 °C to 300 °C is approximately 30%. To interpret such tests the nonisothermally related pressure transient must be considered.

Several authors have discussed the interpretation of pressure transients during cold water injection into hot reservoirs. In particular, Bodvarsson and Tsang (1980) and Mangold et. al. (1981) considered the behavior of nonisothermal pressure transients in geothermal reservoirs and illustrated the effect of the temperature dependent fluid properties, viscosity and density. Tsang and Tsang (1978) developed a semi-analytic solution for pressure transients during cold water injection tests. O'Sullivan and Pruess (1980) and Garg (1980) discussed the analysis of injection and falloff tests in two-phase geothermal reservoirs. These studies demonstrated that the pressure transients during injection tests can be used to determine the transmissivity of the reservoir. In recent studies by Benson and Bodvarsson (1982) and Benson (1982) methods for calculating the skin factor and reservoir properties from nonisothermal injection tests were developed and the conditions in which the pressure transients behaved like a composite reservoir or moving front dominated problem for both single- and step-rate tests discussed. In the present study their work is extended by relating the nonisothermal injectivity to the reservoir transmissivity.

+ Lawrence Berkeley Laboratory, Berkeley, California

References and illustrations at end of paper.

FORMULATION OF THE PROBLEM

Injection of cold water is frequently used as a testing procedure for geothermal wells, as for example in completion tests at the end of drilling. Injection tests are typically conducted in a series of step rates followed or preceded by a complete shutin. Since the duration of each step is seldom very long, usually few hours, stabilized time is usually not reached. The observed pressure is therefore transient and the injectivity so obtained only an approximation.

Now consider the system illustrated in Figure 1. It is that of a single well at the axis of a radial system of two concentric regions which can have different properties. Defining nondimensional time, radius and pressure as:

$$t_{DR} = \frac{k_1 t}{\phi_1 \mu_1 c_1 R^2} \qquad ....(1)$$

$$r_D = \frac{r}{R} \qquad ....(2)$$

$$P_{D1} = \frac{2\pi k_1 h\rho_1}{q\,\mu_1}(P_i - P_1)\ ;\ 0<r_D<1 \quad (3)$$

$$P_{D2} = \frac{2\pi k_2 h\rho_2}{q\,\mu_2}(P_i - P_2)\ ;\ 1<r_D \quad (4)$$

Then the flow equations in the two regions are:

$$\frac{\partial^2 P_{D1}}{\partial r_D^2} + \frac{1}{r_D}\frac{\partial P_{D1}}{\partial r_D} = \frac{\partial P_{D1}}{\partial t_{DR}} \quad ....(5)$$

and

$$\frac{\partial^2 P_{D2}}{\partial r_D^2} + \frac{1}{r_D}\frac{\partial P_{D2}}{\partial r_D} = \frac{1}{\gamma}\frac{\partial P_{D2}}{\partial t_{DR}} \quad ....(6)$$

where

$$\gamma = \frac{\{k/\phi\mu c\}_2}{\{k/\phi\mu c\}_1} \quad ....(7)$$

Initial conditions are P_1 and P_2 are P_i everywhere so:

$$P_{D1}(r_D,0) = P_{D2}(r_D,0) = 0 \quad ....(8)$$

There are three boundary conditions to consider; the inner boundary, the discontinuity and the outer boundary. At the inner boundary the condition is:

$$\lim_{r_D\to 0} r_D \frac{\partial P_{D1}}{\partial r_D} = -1 \quad ....(9)$$

At the discontinuity, the flux and pressure must be continuous so:

$$P_{D1} = P_{D2} \quad ....(10)$$

$$\frac{\partial P_{D1}}{\partial r_D} = \delta \frac{\partial P_{D2}}{\partial r_D} \quad ....(11)$$

where

$$\delta = \frac{\{k\rho/\mu\}_2}{\{k\rho/\mu\}_1} \quad ....(12)$$

Here, only the infinite outer boundary case is considered. Then the outer boundary condition is:

$$\lim_{r_D\to\infty} P_{D2}(r_D,t_{DR}) = 0 \quad ....(13)$$

RESULTS

Following the procedure of Horne et. al. (1980) the long time solution for P_{D1} can be written as:

$$P_{D1} = \frac{1}{2}\{-\,\mathrm{Ei}(-\frac{r_D^2}{4t_{DR}}) + \mathrm{Ei}(-\frac{1}{4t_{DR}}) - \frac{1}{\delta}\mathrm{Ei}(-\frac{1}{4\gamma t_{DR}})\} \quad ....(14)$$

For a large time this may be approximated as:

$$P_{D1} = \frac{1}{2}\{\ln(r_D^2) + \frac{1}{\delta}\ln(\frac{1.781}{4\gamma t_{DR}})\} \quad (15)$$

In real space Eq. 15 becomes:

$$P_1 = P_i + \frac{q\mu_1}{4\pi k_1 h\rho_1}\{\ln(\frac{R}{r})^2 + (\frac{k_1\rho_1\mu_2}{k_2\rho_2\mu_1})\ln(\frac{2.246k_2 t}{\phi_2\mu_2 c_2 R^2})\} (16)$$

For an isothermal homogeneous geothermal system the pressure at the well during injection can be written as:

$$P_{wf} = P_i + Bq + Cq^2 \quad ....(17)$$

where C is a constant governed by the pore structure of the porous medium, the radius and the condition of the well. The quadratic flow rate term accounts for the non-Darcy's flow effects. Assuming these effects to be negligible for the purpose of this study, the injectivity index can be expressed as:

$$II = \frac{q}{P_{wf} - P_i} = \frac{1}{B} \quad ....(18)$$

Because of the relatively short duration of each injection step in the test, the pressure at the well is considered to be transient. Then B can be approximated as:

$$B = \frac{\mu}{4\pi kh\rho}\ln(\frac{2.246kt}{\phi\mu c_t r_w^2}) \quad ....(19)$$

For homogeneous rock properties and single phase condition, Eqs. 16 and 17 along with Eq. 19 yield:

$$\frac{\mu_a}{\rho_a}\ln(\frac{2.246kt}{\phi\mu_a c_t r_w^2}) = \frac{\mu_1}{\rho_1}\{\ln(\frac{R}{r_w})^2 + (\frac{\rho_1\mu_2}{\rho_2\mu_1})\ln(\frac{2.246kt}{\phi\mu_2 c_t R^2})\} \quad ...(20)$$

Eq. 20 is a root solving problem to find the apparent viscosity which will represent the nonisothermal effect in a conventional manner. Figures 2 - 4 show how this apparent viscosity is related to the position of the thermal front and the duration of the injection steps for the properties listed in table I. Thus the nonisothermal injectivity index is for engineering purposes approximately related to the isothermal injectivity index as:

$$II_{ISOTH} \simeq \left(\frac{\mu_a \rho_2}{\rho_a \mu_2} \right) II_{NONISOTH} \qquad (21)$$

DISCUSSION

Figure 5 has been constructed using the data in table I and the apparent viscosity relative to the cooled radius. It shows the transmissivity of the hot reservoir as a function of the injectivity depending on the size of the cooled radius. Figure 5 could equally well have been constructed from a rearrangement of Eq. 16. Figure 5 shows that when the nonisothermal injectivity and the size of the cooled zone are known (see Benson, 1982), the transmissivity of the reservoir can be determined. If the transmissivity and the nonisothermal injectivity are known, the size of the cold spot can be estimated. It is also possible to project the well productivity as its temperature recovers from the injection and the cold zone diminishes. Here it is assumed that the reservoir transmissivity does not change between injection and production. However, as Grant (1982) has pointed out, the injection transmissivity is in many instances observed to be several times greater than that for production. This might be due to an increase in permeability with injection either because of hydraulic fracturing or thermal contraction of rock and opening of fissures.

It has been pointed out (Benson and Bodvarsson 1982, Benson 1982) that the presence of a cooled zone around the well acts as an apparent positive skin. Hence, the presence of a positive skin will shift the curves on Figure 5 up and to the left while the presence of a negative skin will shift them down and to the right. Of particullar interest is the effect of fractures, since transmissivity or injectivity is usually dominated by natural fractures in geothermal systems. The presence of fractures will contribute to a negative skin, but the extent of a cooled zone is much greater at the fracture feed points than in the rock matrix. How these effects counteract each other is not fully known, but numerical studies indicate that the heat transfer from rock matrix to fissures significantly changes the radius of the zone occupied by the cold injection fluid (Bodvarsson and Tsang 1982).

EXAMPLES

A simulated nonisothermal step rate injection test was run on the numerical simulator, PT (Pressure - Temperature) (Bodvarsson 1981). The test consisted of three six-hour steps with injection rates of 0.10, 0.15 and 0.20 kg/s/m of 20 °C fluid into a 300 °C reservoir followed by a complete shutin. The reservoir properties used for the simulation are given in table I. The reservoir is a liquid saturated homogeneous porous medium. No cold spot exists around the well prior to injection. The observed injectivity at the end of each step is shown in Figure 6, which is similar to Figure 5. Since the transmissivity of the hot reservoir is constant during the test, one can see that the decrease in injectivity is a result of an increasing cold spot around the well. The size of the cold spot as determined by the transmissivity and the injectivity for each step is in good agreement with the location of the thermal front according to the simulator which is shown in Figure 6. Assuming that the isothermal injectivity is identical to the well productivity, the production index can be estimated by extrapolation, using Figure 6, as the well warms up.

The transmissivity and the injectivity index for a few of the wells in the Krafla geothermal field are plotted in Figure 7. The Krafla geothermal reservoir is fracture dominated so an average skin factor of $s = -5$ is assumed for the field. Following the methodology developed by Benson and Bodvarsson 1982, and Benson 1982, the size of the cold spot around the wells due to drilling and injection testing is estimated to be 2 to 3 m on the average. However, since the reservoir is fracture dominated, the distance to the thermal front can be considerably greater in the fractures or around the feed points in the wells. On the other hand the distance to the thermal front in the nearly impermeable rock matrix, between the feed points in the wells, can be of the order of a few cm and is controled by the thermal conduction of the rock matrix. The size of the cold spot as obtained from Figure 7 when the data is plotted according to the methodology of this paper is therefore some weighted average of these two distances. It seams therefore that the existence of a cold spot around the feed points in a well in a hot fractured reservoir has very litle effect on the relationship between transmissivity and injectivity. Other factors such as the skin effect are problably dominating the effect of the cold invasion zone in fracture dominated reservoirs.

CONCLUSIONS

Through theoretical considerations an apparent viscosity has been established which relates the nonisothermal injectivity index, obtained from nonisothermal step rate tests, to the isothermal injectivity index. Thus it is possible to use the nonisothermal injectivity index to estimate the reservoir transmissivity and infer the well productivity.

NOMENCLATURE

c_t = total system compressibility, Pa^{-1}

C_r = specific heat capacity, J/kg°C

h = thickness, m

II = injectivity index, kg/sPa

k = permeability, m^2

P = pressure, Pa

q = mass flow rate, kg/s

r = radius, m

R = radius of cold spot, m

t = time, s

T = temperature, °C

μ = dynamic viscosity, Pa s

ρ = density, kg/m^3

ϕ = porosity

λ = thermal conductivity, W/m°C

Subscripts

a = apparent

c = cold

D = dimensionless

i = initial

inj = injection

r = rock

w = well

wf = well flowing

1 = inner (cold) region

2 = outer (hot) region

ACKNOWLEDGMENTS

We thank Rafmagnsveitur Rikisins, Krofluvirkjun for permission to use data from the Krafla geothermal field.

REFERENCES

1. Benson, S. M. and Bodvarsson, G. S.: "Non-isothermal Effects During Injection and Falloff Tests," paper SPE 11137, presented at the SPE 57th Annual Fall Technical Conference and Exhibition, New Orleans, Louisiana, 1982.

2. Benson, S.: "Interpretation of Nonisothermal Step-Rate Injection Tests," Proceedings 8th Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California (Dec. 1982).

3. Bodvarsson, G. S. and Tsang, C. F.: "Thermal Effects in the Analysis of Fractured Reservoirs," 3rd Invitational Well Testing Symposium, Lawrence Berkeley Laboratory Report, LBL-12076, Berkeley, California (March 1980).

4. Bodvarsson, G. S.: "Mathematical Modelling of the Behavior of Geothermal Systems Under Exploitation," Ph. D. dissertation, University of California, Berkeley, 1981.

5. Bodvarsson, G. S. and Tsang, C. F.: "Injection and Thermal Breakthrough in Fractured Geothermal Reservoirs," J. Geophys. Res., v. 87, No 82 (Feb. 1982) 1031-1048.

6. Garg, S. K.: "Pressure Transient Analysis for Two-Phase (Water/Steam) Geothermal Reservoirs," Soc. Pet. Eng. J. (June 1980) 206-214.

7. Grant, M. A.: "The Measurement of Permeability by Injection Tests," Proceedings 8th Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California (Dec. 1982).

8. Horne, R. N., Satman, A. and Grant, M. A.: "Pressure Transient Analysis of Geothermal Wells with Phase Boundaries," paper SPE 9274 presented at the SPE 55th Annual Fall Technical Conference and Exhibition, Dallas, Texas (1980).

9. Mangold, D. C., Tsang, C. F., Lippmann, M. J. and Witherspoon, P. A.: "A Study of Thermal Discontinuity in Well Test Analysis," J. Pet. Tech. (June 1981) 1095-1105.

10. O'Sullivan, M. J. and Pruess, K.: "Analysis of Injection Testing of Geothermal Reservoirs," Geothermal Resources Concil Transactions, vol. 4 (1980).

11. Tsang, Y. W. and Tsang, C. F.: "An Analytic Study of Geothermal Reservoir Pressure Response to Cold Water Reinjection," Proceedings 4th Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, California (Dec. 1978).

Table I. Reservoir Properties

Permeability, k_r	$1.0 \cdot 10^{-14}$ m^2
Thickness, h	1.0 m
Porosity, ϕ	0.20
Specific heat capacity, C_r	1000.0 J/kg°C
Density, ρ_r	2200.0 kg/m^3
Thermal conductivity, λ	2.0 W/m°C
Total system compressibility, c_t	$1.0 \cdot 10^{-9}$ Pa^{-1}
Wellbore radius, r_w	0.10 m

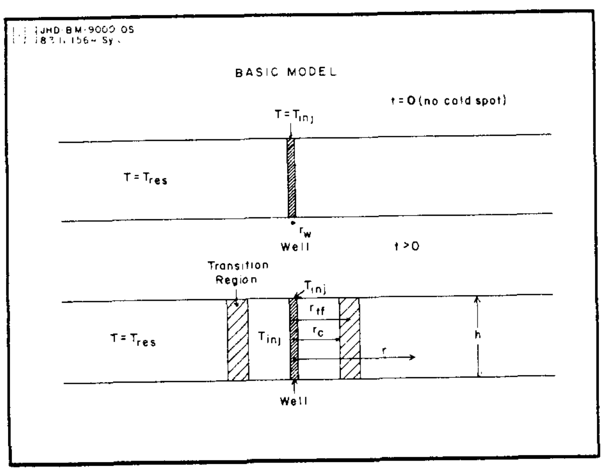

Figure 1. Schematic picture of the reservoir system before and after noniso-thermal injection

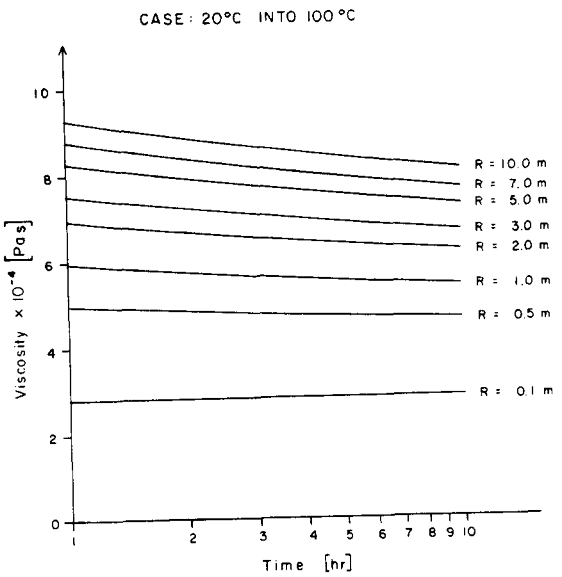

Figure 2. Apparent viscosity as a function of the duration of the injection steps and the size of the cold spot for injection of 20 °C water into 100 °C reservoir.

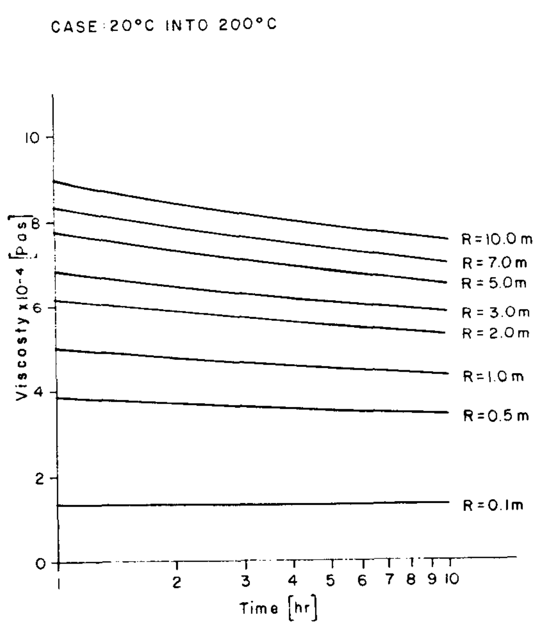

Figure 3. Apparent viscosity as a function of the duration of the injection steps and the size of the cold spot for injection of 20 °C water into 200 °C reservoir.

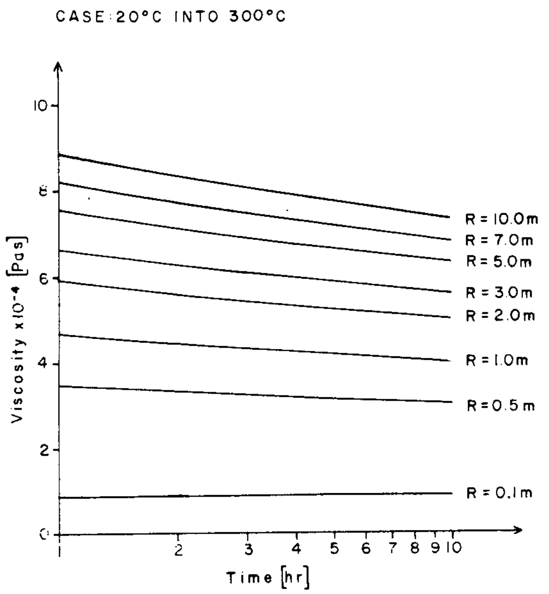

Figure 4. Apparent viscosity as a function of the duration of the injection steps and the size of the cold spot for injection of 20 °C water into 300 °C reservoir.

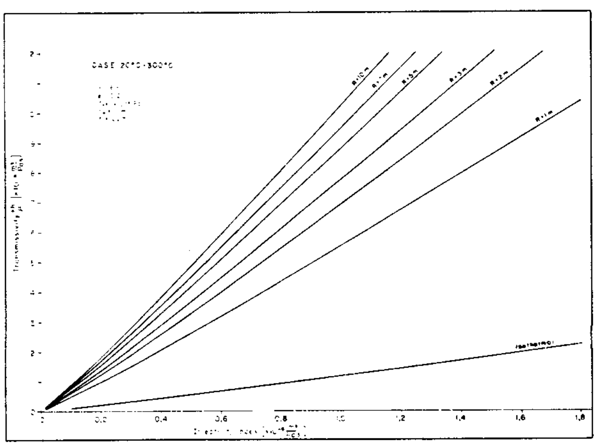

Figure 5. Transmissivity as a function of the injectivity and the size of the cold spot.

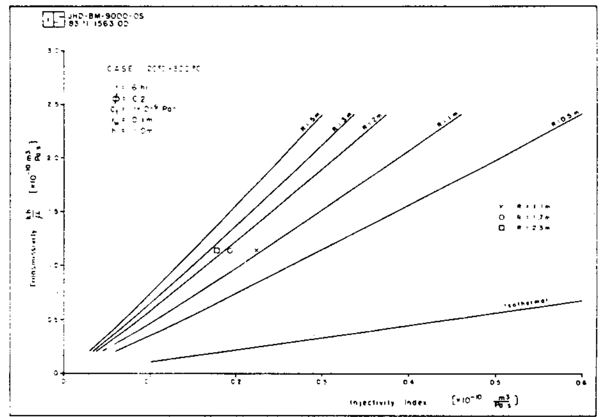

Figure 6. The relationship between transmissivity and injectivity for the simulated example.

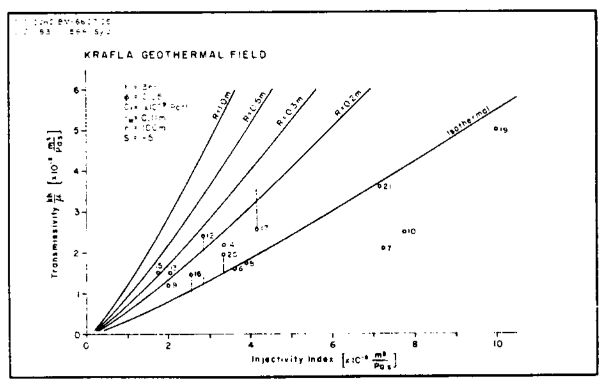

Figure 7. The relationship between transmissivity and injectivity for a few of the wells in the Krafla geothermal field.