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T. N. Narasimhan and P. A. Witherspoon

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GEOTHERMAL WELL TESTING

by

T. N. Narasimhan and P. A. Witherspoon
Earth Sciences Division, Lawrence Berkeley Laboratory
and
Department of Materials Science and Mineral Engineering
University of California, Berkeley, California 96720, USA

ABSTRACT

Just as in the case of hydrogeology and petroleum engineering, well-testing is an invaluable tool in assessing the resource-deliverability of geothermal reservoirs. While the techniques of production- and interference testing already developed in hydrogeology and petroleum engineering provide a strong foundation for geothermal well-testing, the latter is challenged by some special problems. These special problems stem primarily from the difficulties associated with the measurement of mass-flowrate, pressure and temperature under the hostile environment prevalent within geothermal wells. This paper briefly looks into the state-of-the-art of geothermal well-testing and provides a few illustrative field examples.

INTRODUCTION

Well test, or aquifer test, as it is commonly understood in hydrology, is mainly carried out to evaluate the hydraulic parameters of the groundwater reservoir. It essentially consists in producing water at controlled rates from one or more wells and simultaneously monitoring water level or fluid pressure changes in the producing well(s) and/or neighboring observation wells. The data so collected are then interpreted in terms of time, distance from the production well and other factors to arrive at quantitative estimates of the parameters of the reservoir: reservoir geometry; leakage of water from adjoining groundwater bodies; hydraulic efficiency of the well and so on.

Traditionally, hydrogeologists have been concerned with groundwater systems seldom hotter than 60°C, from which the required data can be collected relatively easily and interpreted. A large body of literature currently exists both in hydrogeology and in the allied discipline of petroleum engineering on designing, executing and interpreting such well tests.

In recent times, especially within the past decade, there has grown, in the U.S. and elsewhere, a tremendous interest in the exploration and exploitation of geothermal groundwater systems. These systems are generally characterized by temperatures of up to 360°C or more. They may either contain water entirely in the liquid phase (Raft River Valley, Idaho; Imperial Valley, California; Cerro Prieto, Mexico); or contain water entirely in the steam phase (The Geysers in northern California; Larderello in Italy); or may have water and steam coexisting within the reservoir (Wairakei, New Zealand during the exploitation phase). The elevated temperatures, the presence of more than one fluid phase and the high concentrations of dissolved gases and solids usually present in geothermal fluids render geothermal well testing an

especially difficult field task. Although well testing experience so far gained in hydrogeology and petroleum engineering has provided a strong foundation, considerable research and development remains to be carried out in order to meet the problems peculiar to geothermal reservoirs.

The purpose of this paper is to briefly evaluate the state-of-the-art of geothermal well testing. In scope, the paper will be restricted to hydraulic tests conducted after well completion and development.

NATURE OF REQUIRED FIELD DATA AND THEIR MEASUREMENT

From the point of view of reservoir dynamics, field data primarily sought after in geothermal well testing include, a) mass flow rates from production or injection wells as a function of time, b) variations in reservoir fluid pressure as a function of space and time and c) the temperature of the reservoir fluid as a function of space and time. Of the three categories of data listed, variation of reservoir temperature even after several months of well testing may generally be so small that for normal transient well test analysis it is usually sufficient just to know the static distribution of temperature rather than its dependence on time. Recent studies by Lippmann et al (1978) suggest that in geothermal reservoirs dominated by horizontal flows, the isothermal assumption is a reasonable basis for analysis. Data on mass flow rate and fluid pressure variations constitute, therefore, the most important well test data to be collected from geothermal systems. Additionally, it may be possible, in some cases, to collect such ancillary data as the content of dissolved solids or dissolved non-condensible gases in the geothermal fluids. While these ancillary data help in an improved understanding of the reservoir as a

whole when considered in conjunction with the well test data, they are not essential for interpretation of reservoir dynamics.

Measurement of Mass Flow Rates

Many geothermal wells, with water temperatures exceeding 150°C are known to be self-flowing. The well-head pressures in these wells, while the well is discharging, may generally be less than the saturation pressure corresponding to the fluid temperature. As a result, the boiling effluent from the well is a two-phase mixture of steam and water, unless special efforts are taken to apply sufficient back pressure on the effluent to prevent boiling. The "steam quality" or the mass proportion of steam to that of water is a function of the water temperature and the exit pressure. The steam quality at the well-head may vary from less than 1 percent in liquid-dominated systems to more than 99 percent in vapor dominated systems. In these wells, the initiation of flashing may take place either in the discharge pipe, at the well-head or may take place at depths of several hundred meters below ground level, depending on the pressure-temperature regime of the flowing fluid.

In order to measure the mass flow rates of such two-phase effluents one could, when possible, maintain sufficient back pressure on the effluent through the use of orifice plates to assure single phase-flow. The flow rate can then be computed by measuring the pressure drop across the aperture. The measurement of flow rates of water by means of orifice-plates in water wells [Anderson, 1977] as well as in gas wells [Frick and Taylor, 1962] are well known. Witherspoon et al, (1978) used the aforesaid technique for measuring hot water flow rates (150°C water) in Raft River Valley, Idaho. A similar technique is routinely used in the Geyser's geothermal field of

California to measure steam flow rates.

When sufficient back pressure cannot be applied to prevent the formation of steam, one can measure flow rates by letting the hot water flash at the discharge pipe, passing the two-phase mixture through a steam separator, running the separated steam and water phases through two distinct orifice meters and measuring the flow rates separately. A schematic diagram of this method, as used by the Republic Geothermal Inc. at East Mesa in the Imperial Valley of California is shown in Figure 1. This technique was successfully used to measure total mass flow rates of up to 55 kgs/sec with steam quality of approximately 15 percent. In using orifice plates, it is customary to record the pressure differentials across the orifice on continuous recording charts providing a permanent document of flow variations.

A less accurate, but acceptable method of measuring flow rates may be to pass the water phase coming out of the separator through a V-notch weir and to evaluate the liquid phase flow rate from the level of fluid at the V-notch. Simultaneously, the temperature and pressure are monitored at the separator, from which the steam quality is estimated. With steam quality and the flow rate of the liquid fraction known, the total mass flow rate can be computed. Obviously, this method may not be very accurate, especially when steam quality is high.

An approximate but inexpensive and extremely useful method of measuring total mass flow rate and the heat content (enthalpy) of a two-phase geothermal effluent from a discharge pipe was suggested by James (1963-64) and has been used in several geothermal fields. This method, developed from the concept of critical flow of fluids (that is, when a compressible fluid travels at the velocity of sound,) consists in flowing the geothermal fluids to the atmosphere through a pipe of uniform cross section and measuring the fluid pressure

a fraction of a centimeter behind the lip of the discharge pipe. The lip pressure is then used to estimate the total mass flow-rate, the mixture enthalpy and steam quality provided that the liquid rate can be measured [Ramey, 1978]. A diagram of a setup for implementing James' technique is shown in Figure 2.

In using the orifice meters of the James' technique, a problem that is often encountered is that of scaling. Due to the sudden decrease of pressure downstream of the orifice, or due to shock phenomena accompanying critical flow, calcium carbonate and other materials may be deposited causing scale formation. These scales will often reduce the aperture diameter and affect flow rate computations. In order to minimize errors due to this problem during well tests, one could have two sets of orifice meters with a by-pass arrangement or use replaceable orifice plates.

The Problem of Variable Flow Rate

For ease of interpreting well test data it is often most desirable to conduct the well test at a constant rate or a step-wise rate, changing from one constant rate to another. However, it may not often be possible to maintain constant flow rates from geothermal wells. Some geothermal wells may no longer be self-flowing when they are shut-in and allowed to cool. In these wells, the increase in the weight of the cool water column may be such that the natural flow is choked. Indeed, at Niland in the Imperial Valley of California where the geothermal brine has total dissolved solids in excess of 250,000ppm, it is known [John Morse, Lawrence Livermore Lab, personal communication] that on shutting-in and cooling the geothermal well, the fluid level can drop down to as much as 50 meters within the well, creating a partial vacuum in the well casing between the fluid level and the well head. In order

to make these cold wells flow once again, they may have to be stimulated by means of air-lift or some other method. During the initial phases of the well production, therefore, there could be important departures from the desired constant flow rates and these departures have to be duly accounted for in interpreting the well test data.

Measurement of Fluid Pressures

Other important data collected during a well test are the fluid pressures. In most well tests in hydrogeology, such data consist of water level measurements either made manually with a steel tape or measured automatically with different types of water level recorders.

It is quite well known that well test analysis is based on the interpretation of pressure changes (drawdown, build-up) rather than the magnitude of absolute pressures. In a producing well where the temperature of the fluid column varies but little (as in most water wells) the pressure at the sand face is immediately reflected in water level fluctuations in the well bore or in fluid pressure changes at the well-head (except for possible well-bore storage effects) since the water density varies very little with depth in such wells. This, however, is not the case in a producing geothermal well. Indeed, due to the thermal gradients within the well-bore and because of flashing within the well-bore, the pressure changes at the sand face are considerably modified as they are transmitted to the well-head. In fact, it is often noted that when a cold geothermal well begins to produce, well-head pressure will actually rise for a time due to the lightening of the water column, before it begins to drop. Hence, to monitor reservoir pressure changes in the producing wells, well-head pressure measurements are of very little use and one has to rely almost exclusively on downhole measurements. The most challenging problems of geothermal well test instrumentation are directly

related to this need for downhole monitoring in producing geothermal wells.

Fortunately, such is not the case for non-producing observation wells. If such wells have positive well-head pressures and hence are completely filled with water, even small changes in the reservoir pressure are transmitted instantaneously to the surface due to the very low compressibility of water. Thus, in these wells, reservoir pressure changes can be accurately monitored by measuring well-head pressures. Witherspoon et al (1978) were successful in using such well-head measurements on non-producing wells to obtain interference test data in Raft River Valley, Idaho and at East Mesa California.

Downhole Pressure Monitors

Currently, three different types of downhole pressure monitors are used for downhole pressure measurements in geothermal wells. The first of these is the "bomb" type device (Amerada Bomb; Kuster Bomb) which is lowered by means of a wire-line to any desired depth within the well. Essentially the bomb-type device consists of two parts; a pressure monitor and a timing device. The pressure monitor is a Bourdon tube type instrument connected to a time-driven stylus. The stylus, driven by the clock along one axis and by the pressure sensor along the other, scratches the pressure-time curve on a small glass plate. On retrieval of the plate, the pressure-time data can be read off from the etched line with the help of a magnifier.

The bomb-type devices are compact (≈2.5cm in dia., and 1.8m long) and are simple and robust enough to withstand temperatures as high as 300°C. They also measure the actual reservoir pressure variations at the point of observation. However, they have two disadvantages. Firstly, the resolution of the etched data is very much related to the total pressures (e.g. 2% of full scale.) Thus, if the reservoir pressure is 17.2 M Pa (2,500psi), which can

be expected in a 1800m well, the accuracy is only about .03 M Pa (5psi). Secondly, once the bomb is lowered into the well, data will become available only on retrieval of the bomb and examination of the glass plate. Therefore, little is known about the success or progress of the test during the test itself. This is a significant handicap, since, ideally, one would like to modify the pattern of the test depending on the reservoir response observed during its progress.

A second type of downhole pressure monitoring system is the Sperry-Sun system which consists in monitoring the fluid pressure at the sandface but making the read out at the land surface. This system is schematically shown in Figure 3. A narrow tube (0.75 to 1.25cm dia) made of a corrosion resistant alloy such as stainless stell or "inconel" is lowered to the desired depth in the well. At the bottom, the tube is attached to a chamber ($\approx$2.5cm in diameter) through a micropore filter. The chamber, in turn, communicates with the well fluid through one or two openings of suitable size. At the well head, the tubing is connected to a pressure transducer.

In order to set up the system, the tubing is first lowered to the desired depth and a suitable gas (Nitrogen or Helium) is passed through it under pressures in excess of the expected reservoir pressure. When this is continued for several hours, the well fluids are expelled from the chamber and the gas will begin to bubble into the well. At this time, the supply of gas is cut off and the reservoir fluid, under existing pressure, compresses the gas and flows into the system. When carried out properly, the interface between the fluid and the gas will exist within the chamber. In this state, there exists a finite volume of gas in the tube-chamber system. As the reservoir pressure changes, the fluid-gas interface in the chamber will also change, causing the gas volume to increase or decrease. This volume change

is reflected as a pressure change in the pressure transducer at the well-head. Obviously, the pressure monitored at the well-head will differ from the downhole pressure by an amount equal to the weight of the column of gas and an appropriate correction has to be made in this regard. This pressure monitoring system has been used with success in geothermal wells in the Imperial Valley of California and elsewhere.

Because of its simplicity and the absence of any precision device downhole, this system has no temperature limitations, provided that the temperature gradient within the well is stable. However, during the early stages of production when temperatures are changing within the well, this system has some drawbacks.

Narasimhan et al (1978) found during a geothermal well test at East Mesa, California that the nitrogen pressure monitored by the Sperry-Sun system indicated an increase in the fluid pressure as much as .86 M Pa (125psi) during the first few hours of production while in fact pressure would be expected to show a decline with production. This anomalous increase in pressure was attributed to the heating up of the nitrogen tubing concomitant with the well flow. To some extent this effect was later reduced in a subsequent test by increasing the tubing diameter from 0.8 to 0.13cm (.31" to 0.54"). Another way of minimizing the temperature effect on the gas is to replace the gas in the tubing with an inert liquid such as silicone oil, since oil has much lower thermal expansivity than gas. Nevertheless, even in this case the early pressure data is noticeably perturbed by thermal effects [R.C. Schroeder, Lawrence Berkeley Laboratory, personal communication].

Miller and Haney (1978) have studied the transmission of a pressure-change signal in a fluid filled capillary tube. They found that the signal is noticeably distorted if there is temperature change along the tubing or if the

pressure transient is large. While even a small change in temperature (½°C) can accentuate the distortion, increasing the diameter of the tubing (from 0.07 to 0.25cm) tends to decrease it. Of the two fluids silicone oil and nitrogen, oil is preferable at high but steady temperatures while gas is recommended when temperature varies significantly with time. In order that one could estimate sand face pressure changes from well-head pressure data, not only must the exact time of flow-rate changes, but also the time-dependent variation of temperature within the well must be known.

The third category of pressure measuring devices is the precision quartz crystal device that has become practical in the past few years, thanks to the progress in electronic technology. This device makes use of the extremely predictable piezo-electric property of quartz crystal. Essentially, the pressure sensor consists of a carefully chosen natural, untwinned quartz crystal. The crystal is cut and drilled to have a precise shape with reference to its crystallographic orientation. The resonance frequency of this crystal is very closely related to its shape. Hence, as the crystal is deformed under even very small pressures, its resonance frequency changes in a detectable and predictable fashion. Thus, the instrument consists of an electronic oscillator circuit whose frequency is controlled by the quartz sensor and an external frequency counter. The actual pressure measurement consists of counting the frequency of vibration of the crystal system at the existing pressure and reading the corresponding pressure from the calibration tables.

Inasmuch as the frequency of quartz is also dependent on temperature, an accurate knowledge of the temperature at the point of measurement is essential for an accurate pressure determination. Ideally, a simultaneous downhole temperature measurement is very desirable in using the

device, which has an accuracy of about 70 Pa(0.01psi) over a pressure range of 70 M Pa(10,000psi).

The downhole quartz crystal devices invariably have a certain number of electronic components associated with them. Although the quartz crystal itself possesses very regular frequency properties up to temperatures of 260°C or more, the electronic components can seldom withstand temperatures of more than 150°C. While reliable downhole pressure measurements can be made at temperatures of up to 150°C [Witherspoon et al, 1978] over prolonged periods of time using these devices, such measurements at higher temperatures are not possible at present. Recent research at the Sandia Laboratories [Veneruso, 1977] indicates that the use of field effect transistors (FET) instead of popular bipolar silicon transistors can extend the application of quartz crystal devices to temperatures of 325°C.

In the environment where they can be used, however, the quartz crystal devices can provide data of extreme precision at very frequent intervals which can enable some very sophisticated reservoir interpretations that have not been possible so far. The pressure data collected from an observation well located 1,200m from the producing well in the Raft River geothermal area of Idaho is presented in Figure 4. The data was collected with a quartz crystal gauge placed at a depth of about 300m below surface. In Figure 4, one can clearly discern periodic fluctuations in pressure which are to be attributed to effects of earth tides [Witherspoon et al, 1978]. In addition, one can also see the long-term pressure decline caused by the interference effect of the production well. The availability of such precise data as shown in Figure 4 opens up the possibility of analyzing the response of aquifers to earth tides as a means of determining reservoir parameters.

In order to give an idea of the frequency with which drawdown or buildup can be measured with the electronic devices, the buildup data from a producing geothermal well in the Raft River Valley of Idaho is given in Figure 5. Note from this figure that within the first sixty seconds over 40 data points are available for analysis. In this particular case the instrument was located at a depth of 1,500m where the reservoir temperature was about 148°C. Although in this case the early data failed to reveal the presence of significant well-bore storage effects (unit slope) or the presence of fractures (half slope), the value of such early time data in well test interpretation cannot be overlooked.

SOME FIELD SAMPLES

The first example relates to an interference test conducted at the Raft River Valley geothermal field by Witherspoon et al, (1978). The interference data from this test is given in Figure 6. The primary problem in analyzing this data was to eliminate the perturbation on the fluid pressure data caused by earth tides. The fact that the data showed an excellent correlation between computed earth tides (dotted line in Figure 4) and the fluid pressure in the well, enabled a simple method of elimination of earth tide effects. Thus, one had only to choose the pressure values corresponding to those instants when the computed earth tide effect was zero and join those points by a smooth line (Figure 4). This smooth line was then used for interpretation using the conventional Theis type curve analysis, as in Figure 6. Note from Figure 6 that a barrier boundary is clearly suggested by the drawdown data.

The next illustration relates to a step-drawdown test conducted on a producing geothermal well at East Mesa in the Imperial Valley of Southern California [Narasimhan et al, 1978]. In this well, about 2,200m deep, downhole

pressure data were monitored during production with a Sperry-Sun nitrogen gas system. The pressure data so collected is shown in Figure 7. Note from Figure 7 that at the commencement of production and at each time the flow rate was raised, the measured pressures show a perceptible increase. This is due to the fact that every time the flow rate is increased, the temperature regime in the well also increased, causing heating of the nitrogen gas.

As can be inferred from Figure 7, the flow rate during each step was variable and as such the data cannot be reliably analyzed using constant flow rate concepts. Therefore, the data was analyzed using the variable flow rate analysis of Tsang et al, (1977). This computer-assisted analysis was used to treat all the data in Figure 7 (drawdown as well as buildup). The analysis indicated a permeability-thickness product (kH) of 730 md-meters.

Note that in the case of geothermal reservoirs, the conventional concept of transmissivity (which is defined for water at a temperature of 16°C) is of little use since different reservoirs have markedly different temperatures and hence markedly different fluid viscosities. Therefore, a more meaningful parameter to use is the absolute permeability, k (millidarcies) or the product, kH.

The next example serves to illustrate the fact if detailed interference data are available from a single-phase geothermal reservoir, one could use the hydrogeological techniques of well-test interpretation to decipher reservoir geometry. Several interference tests were conducted in the East geothermal field at East Mesa [Narasimhan et al, 1978] using multiple observation wells equipped with quartz crystal pressure devices. The lay-out of the well field can be seen in Figure 8.

During the interference tests, wells 38-30 and 16-29 served alternately as production wells while wells 31-1, 56-30, and 16-30 were used as observation wells. The data from 31-1 and 56-30 clearly picked up the effect of a barrier boundary and arcs drawn from these wells showed two possible locations for the image well. However, observations made on well 16-30 showed that this well did not show any communication with 38-30 or 16-29. Based on this third piece of information the image well location was uniquely chosen as shown in Figure 8 and the location of the barrier boundary was fixed.

The next illustration pertains to a non-artesian geothermal well in the former French territory of Afars and Issas in Africa [Gringarten, 1978]. This well was characterized by two-phase flow in the well-bore although the reservoir itself remained water dominated. The 1,130m deep well pierces a reservoir with a temperature of about 250°C and a pressure of about 8.3×10^6Pa (1,200psi). When shut-in and cold, the well is non-flowing with fluid level at about 200m below the surface. On stimulation, the well could self flow at rates varying from 6.3 kg/sec to 23 kg/sec, with the flash point (boiling point) within the well varying between 700m and 870m below ground level. The well was subjected to seven different flow periods ranging from a few hours to several days with intervening shut-in durations. The flow-rates were variable as already indicated. During the tests, a bomb-type pressure device was used to measure downhole pressure at a depth of 1,050m. A careful study of the pressure data showed that, well-bore storage effects were clearly discernable during early times of drawdown and buildup. Moreover, two of the tests, involving low flow rates, indicated a change in the nature of the well-bore storage effect, from one in which it was controlled by the liquid level change to one in which it was controlled by the compressibility of the steam water mixture. Gringarten showed that if sufficiently long-duration data

are available so that the semi-log approximation to the Theis equation is valid, then one can compute the reservoir permeability (in this case kH=16 Darcy-meter), and evaluate the extent of well-bore damage. To take into account the variable flow rate prevalent during the test, Gringarten was able to use a technique proposed by Odeh and Jones (1974), which essentially consists in superposing the semi-log solutions corresponding to each flow segment. It was found during this test that well bore effects lasted for a longer period during production than during buildup. Moreover, after about six hours of shutting down production, the buildup data was so markedly perturbed by effects of steam condensation that it was of no more practical use in interpretation.

A log-log plot of the pressure data collected during the different tests is presented in Figure 9.

The final illustration pertains to a geothermal well test from a steam well at the Geysers geothermal field in northern California. It is very well known in the petroleum literature that the radial flow solutions valid for liquid filled systems (aquifers, oil reservoirs) can be applied to gas filled systems if one were to replace drawdown, p by the quantity $(p^2-p_i^2)$ where p is the pressure at a given time and p_i is the initial, static pressure. Using this approach, Ramey and Gringarten (1975), analyzed data from a steam producing well at the Geysers, as illustrated in Figure 10. Note that the data could be analyzed to compute such information as reservoir permeability, storativity, well-bore storage (unit slope section, and presence of fractures (half-slope section).

CONCLUDING REMARKS

Geothermal well testing is, in many respects, similar to well testing as practiced in hydrogeology and petroleum engineering. Experience so far gained in testing geothermal wells shows that under many field situations it is still possible to directly apply conventional well test theory to evaluate geothermal reservoir parameters, geometry and well-bore damage when the reservoir is either liquid-dominated or vapor-dominated. The greatest challenge to geothermal well-testing, then, consists in developing instrumentation to provide downhole pressure data from producing geothermal wells. This implies that we need instruments with ability to measure downhole pressures accurately over prolonged periods of time at temperatures in excess of 150°C.

On the theoretical side, existing well-testing techniques are inadequate to handle those conditions in which the well pierces a reservoir under two phase conditions. Considering the fact that geothermal systems are usually several hundred meters thick, it is likely that a single well may be exposed to pure water at the bottom and steam at the top of the reservoir. The testing procedure becomes complicated in this case and it may be essential to make pressure measurements at more than one location within the well for proper interpretation. Only very recently have workers turned their attention to a systematic study of evaluating two-phase geothermal reservoirs. As a first step in the study, Garg (1978) and Pruess et al, (1978) have considered a simple system in which the flash front is vertical and moves laterally outward from the well. Their study shows that under certain assumptions, the pressure transient behavior in such a system is similar to the semi-log solution frequently encountered in hydrogeology. Nevertheless, these studies have not yet been applied to actual field situations. Further research work

in this area should prove to be of great practical importance.

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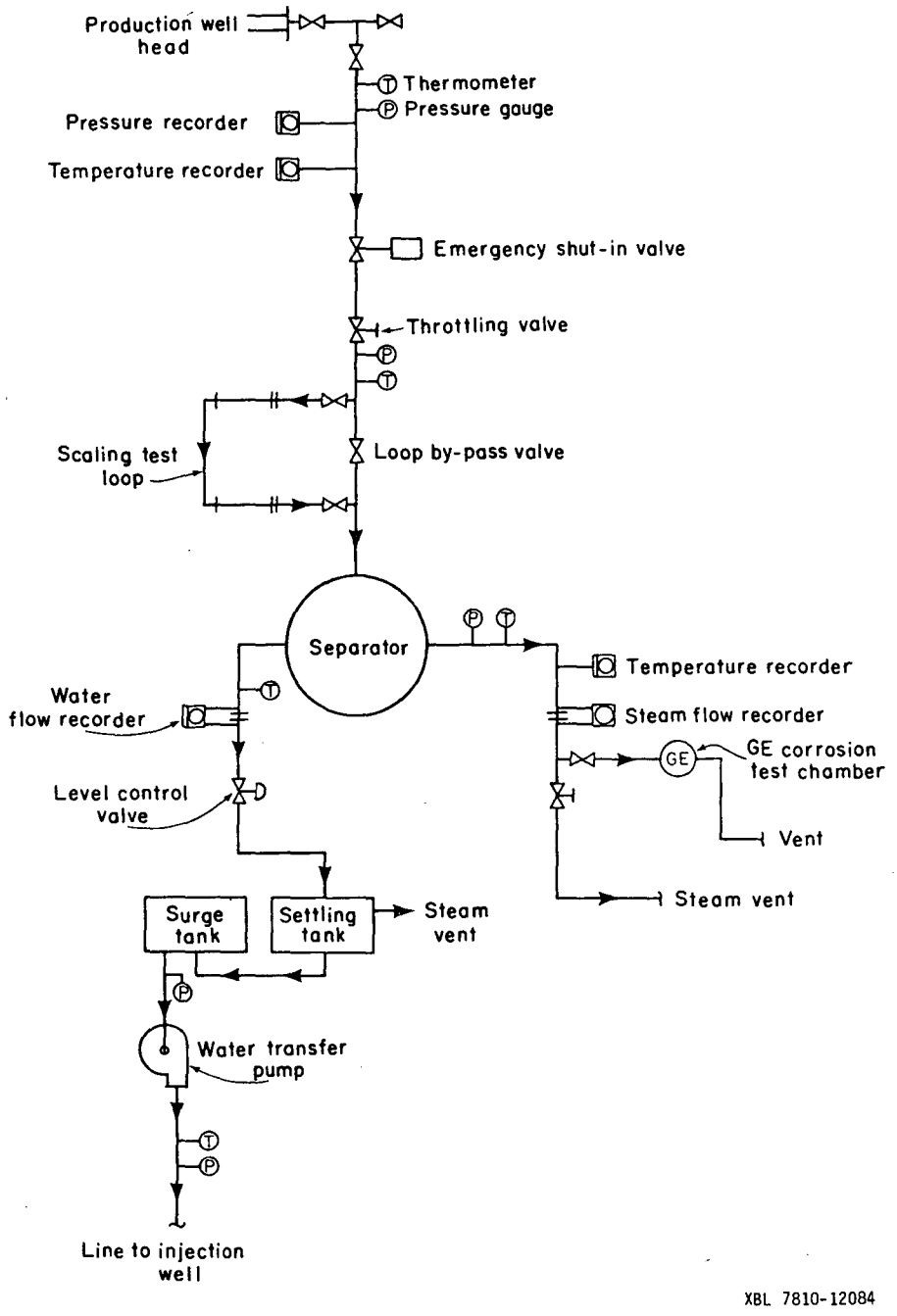

Figure 1. Schematic of measuring mass flow rate of water and steam separately (Courtesy of Republic Geothermal, Inc.)

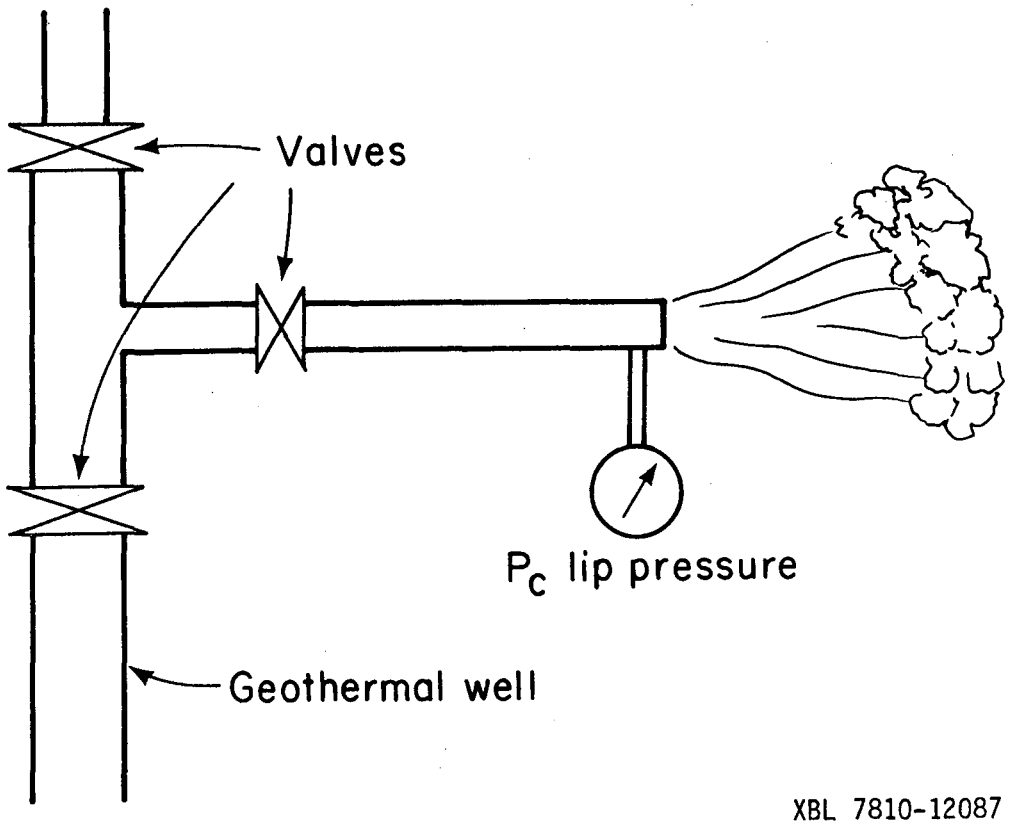

Figure 2. Schematic set-up for measuring mass flow rates by the James Method.

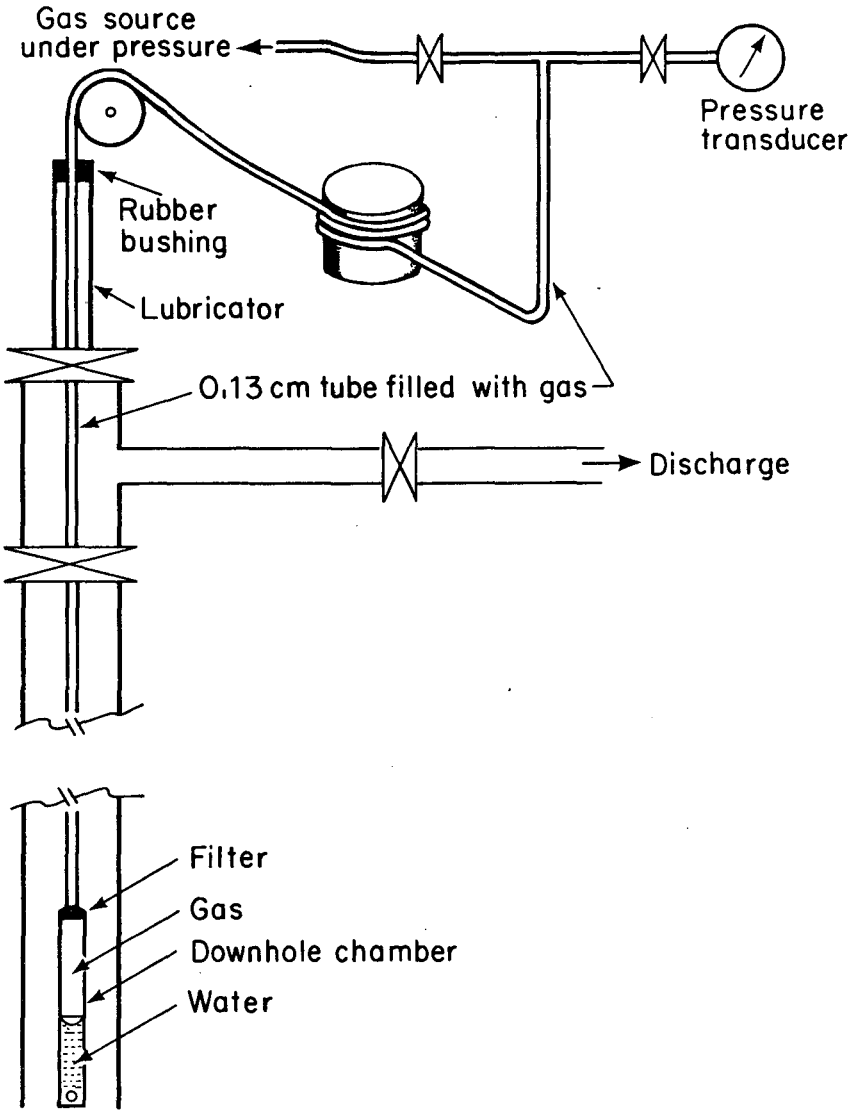

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Figure 3. Schematic of downhole pressure monitoring set-up using the gas-transmitter system.

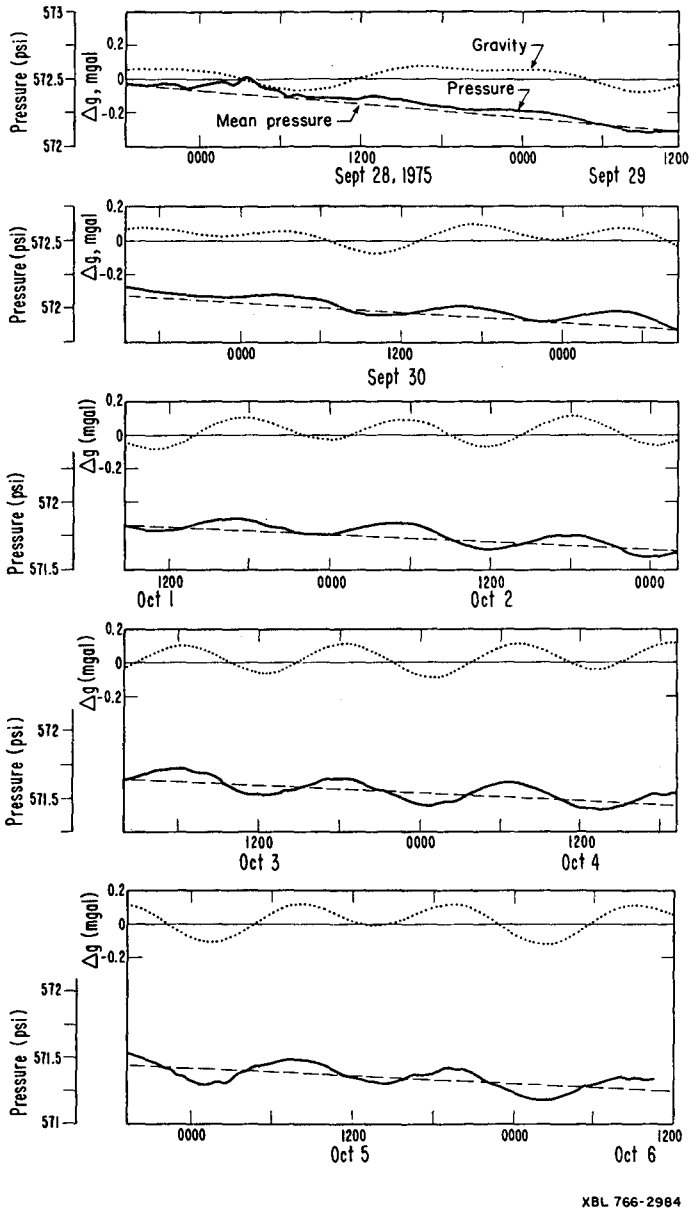

Figure 4. Correlation between reservoir pressure and computed changes in Earth's gravity in a geothermal well in the Raft River Valley of Idaho.

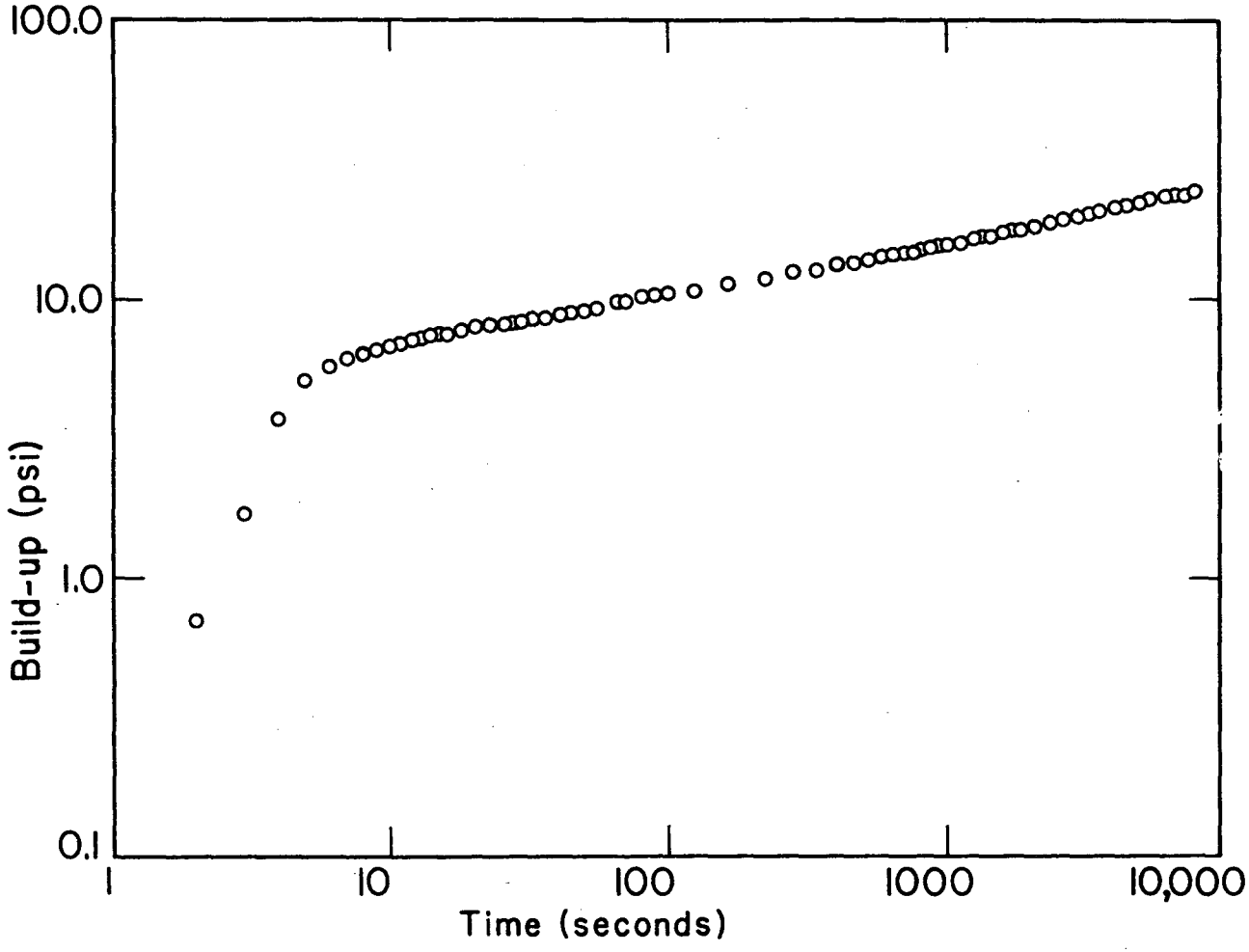

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Figure 5. Buildup data from a geothermal well in Raft River Valley, Idaho, showing resolution of early time data.

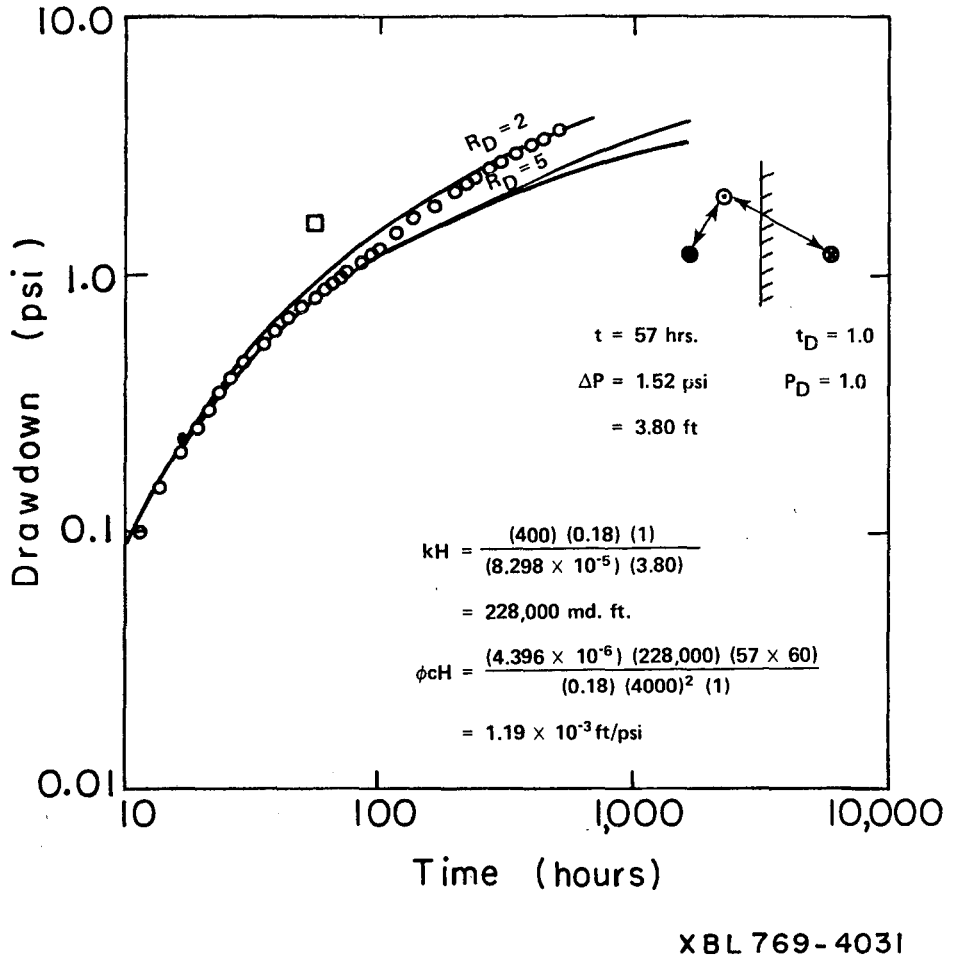

Figure 6. Interpretation of Interference Test between two geothermal wells in Raft River Valley, Idaho.

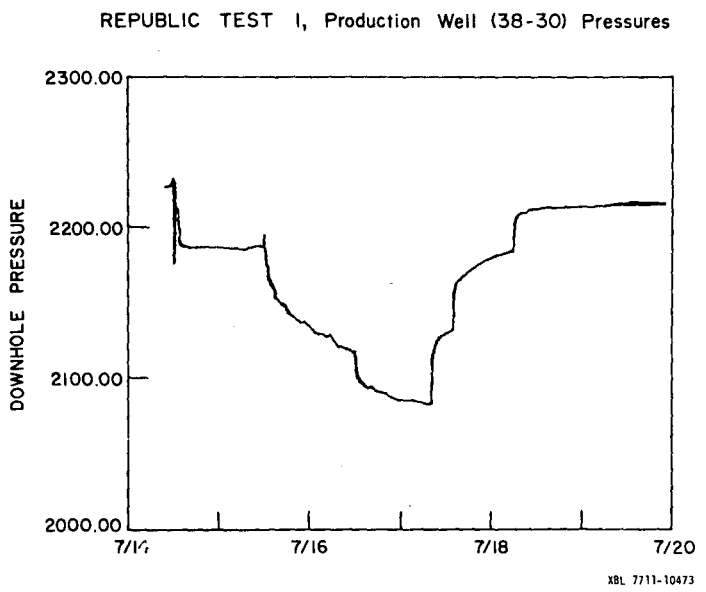

Figure 7. Step-drawdown data from a geothermal well at East Mesa in California.

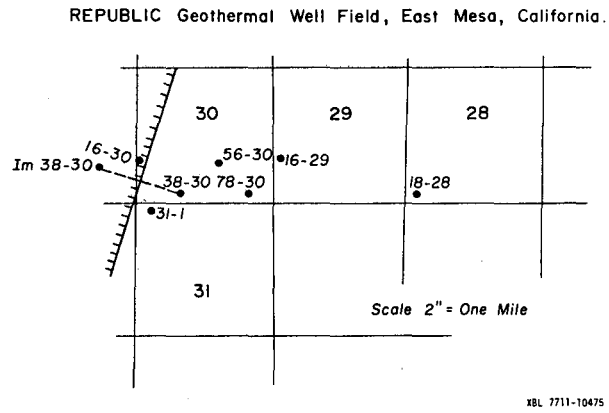

Figure 8. Well test analysis leading to inference of barrier boundary: East Mesa geothermal reservoir, California.

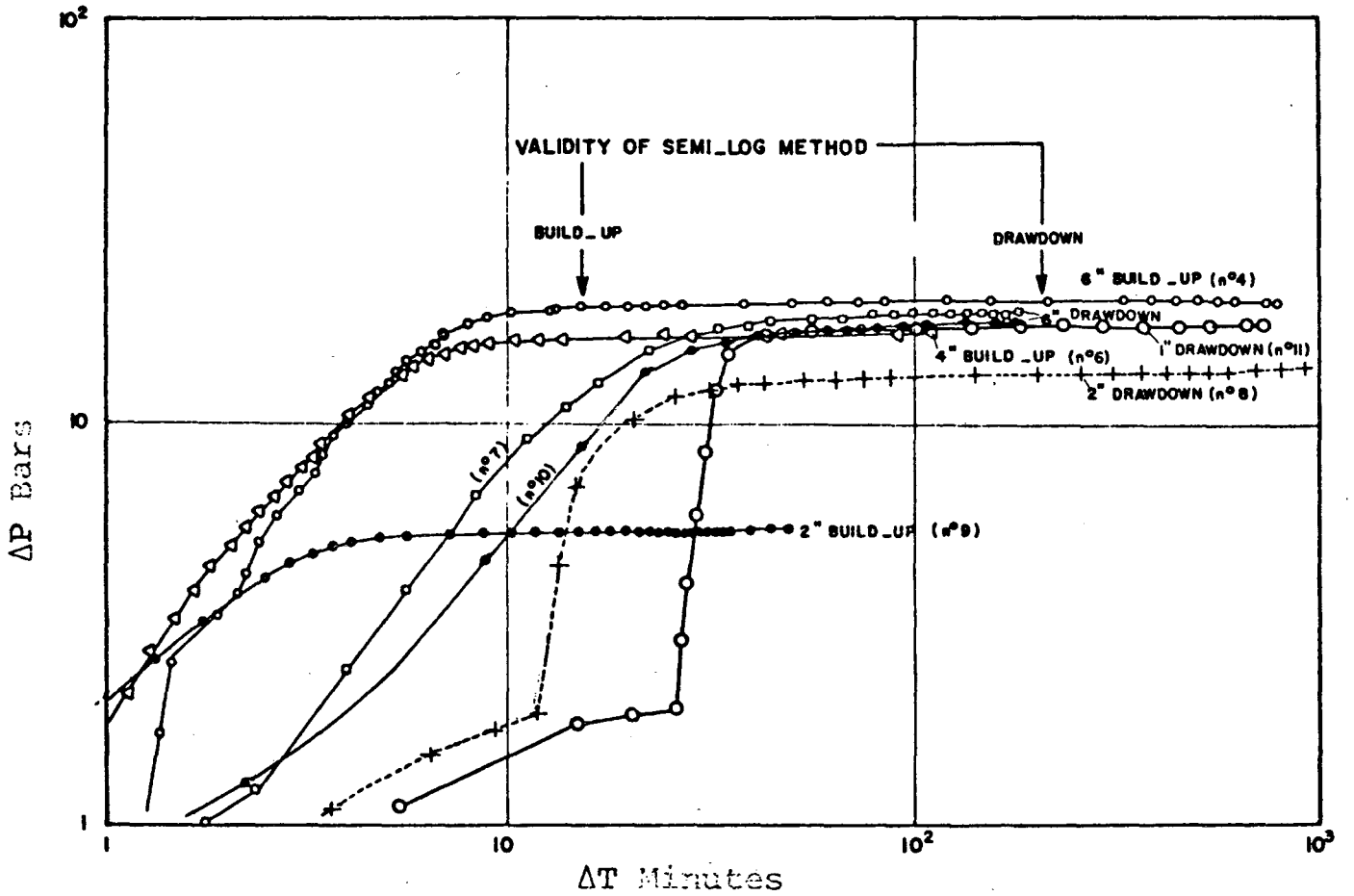

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Figure 9. Log-log plot of pressure transient data from several tests on a two-phase geothermal well in Africa (After Gringarten, 1978).

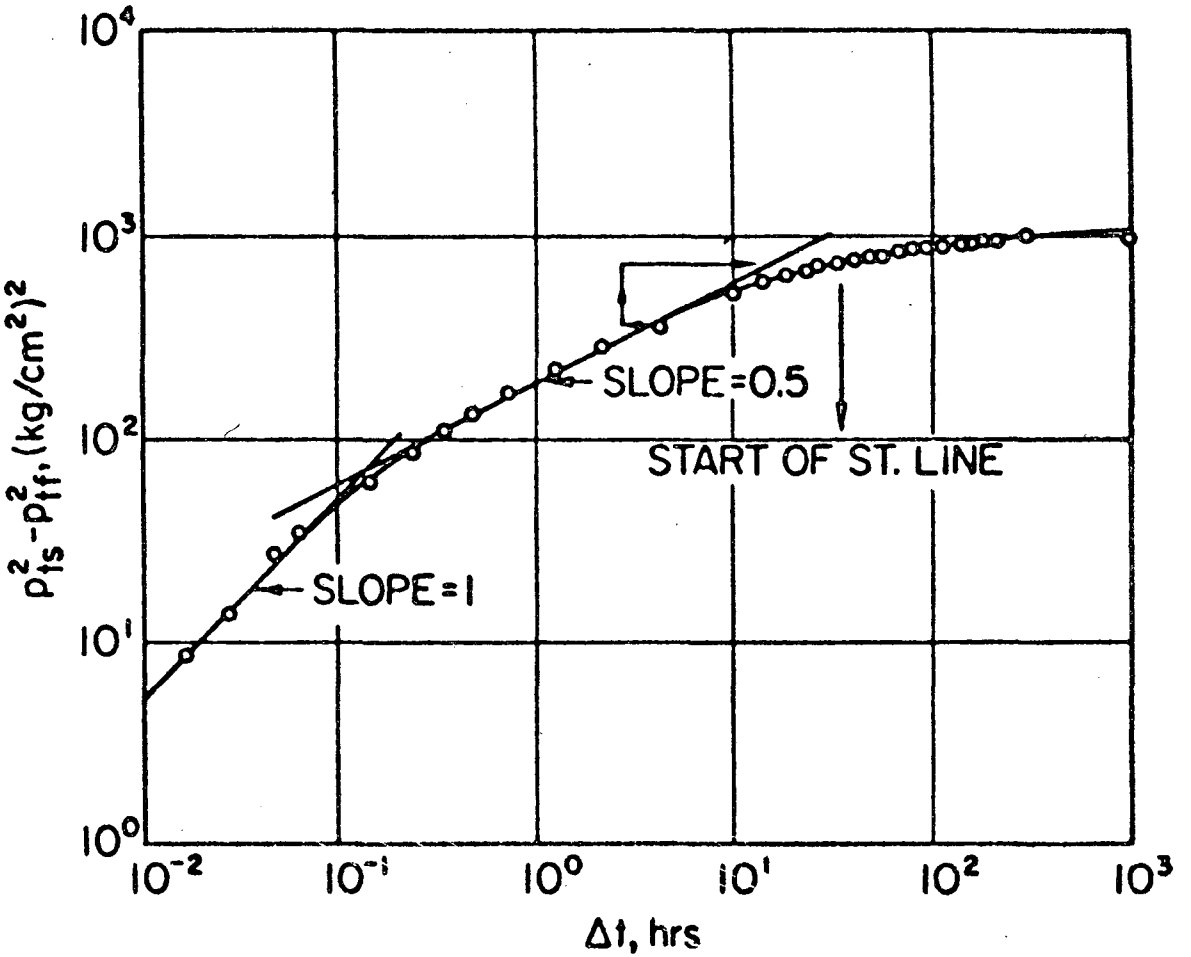

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Figure 10. Well Test Interpretation of a Steam Well at the Geysers (after Ramey and Gringarten, 1975).

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TECHNICAL INFORMATION DEPARTMENT
LAWRENCE BERKELEY LABORATORY
UNIVERSITY OF CALIFORNIA
BERKELEY, CALIFORNIA 94720