ELIMINATING THE WELLBORE RESPONSE IN TRANSIENT WELL TEST ANALYSIS

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Introduction

When testing a production well to determine the characteristics of a fluid filled reservoir, one usually waits until wellbore storage is over, and then one determines both the slope of the downhole pressure versus log (time) plot (to calculate kh/μ), and the intercept of the line (to obtain ϕchr_e^2). However, in a geothermal field it may not always be possible to run a test for a sufficiently long time to insure an accurate measurement of these parameters. The testing of a geothermal field requires instrumentation that can withstand high temperatures and high salinities, and, at present, available instrumentation is limited. Another problem is that non-isothermal effects in the bore increase the time of wellbore storage. The slow heating of the fluid in the well results in a slight change in slope of the p versus log t plot, and the duration of this heating effect can be much longer than wellbore storage due to pressure changes alone. In addition, the slope of the p versus log t graph can be very flat because of the large values of kh/μ in geothermal fields. With a positive skin effect wellbore storage lasts longer, so the slope will be even flatter in this pseudo-steady region.

Very small changes in pressure must be measured over long times requiring accurate instrumentation. It is desirable to be able to use the pressure transient data taken while wellbore storage is important. The transient test can be relatively short (say 20 minutes) and the changes in pressure are still large enough (say on the order of a psi/minute) so that the error in the measurements because of the accuracy and resolution of the pressure gauge is small. The pressure data taken at early times can be used if the response of the wellbore is eliminated from the well test data, and a variable flowrate pressure transient analysis is performed. By modeling the transient flow in the well, it is also possible to explain differences between the pressure transient data from a geothermal field and that of an oil field.

The response of the flow in the wellbore is eliminated by calculating the actual conditions at the sandface (well/reservoir boundary). Given the sandface flow and enthalpy and knowing the downhole pressure, one can use a variable well test analysis method to determine kh/μ and ϕchr_e^2. For a liquid filled reservoir, a variable well test method that uses a minimization technique is available (Benson and McEdwards, 1980). For a two-phase reservoir, a method of analyzing transient flow data is more difficult than from a single phase reservoir for even a constant mass flowrate. However, one could use a numerical simulator and try to match the pressure data by varying the reservoir parameters until a "best fit" is obtained.

A numerical model of transient, one-dimensional two-phase flow in a well has been developed (Miller, 1979). This model is used to simulate the wellbore flow in the calculations below. Numerous steady state wellbore flow models have been reported (Gould, 1974; Nathenson, _974; Sugiura and Farouq, 1979). However, in such models, one must naturally have the flow into the bore equal to the flow out of the bore. Therefore, these models cannot be used to obtain the sandface flowrate when wellbore storage is important.

The main purpose of this work is to show that it is possible to calculate the sandface flowrate given wellhead conditions and the downhole pressure transients. It is not necessary to know anything about the reservoir itself. First, it is of interest to look at the nonuniform pressure changes in the well, and to illustrate nonisothermal effects on pressure transient data.

Pressure Transients

When calculating the amount of mass that exits the wellbore during a transient test, it is not possible to calculate some average wellbore compressibility, and then say the difference between the wellhead and downhole flowrate is just $\rho c_s(dp/dt)$. The problem lies in the fact that the downhole pressure change with time is not characteristic of the average pressure change throughout the bore. This problem is illustrated in Figure 1 where both the wellhead and downhole pressure change with time is plotted for a flowrate change at wellhead from 20 to 40 kg/s and from 40 to 60 kg/s. One can see that initially the pressure at wellhead drops suddenly to achieve the desired flowrate while the downhole pressure hardly changes. Also, even after the initial transients in the well die out, the pressure change at wellhead is slower than the change downhhole. No one pressure measurement will give the average pressure change in the bore during a well test.

Figure 2 shows the effect of a slow heating of the fluid in the wellbore on the pressure transient data. The well is 4500 m deep and is liquid filled. Two cases are plotted here. In one case, the temperature is held constant at 150°C throughout the bore. In the second case, the initial temperature of the stagnant fluid in the bore goes from 20°C at wellhead to 150°C downhole. The mass flowrate in the well was changed from 0 to 28.7 kg/s over 1 minute. The duration of wellbore storage based on pressure changes only should last about 20 s after the flowrate change is completed. One can see that the heating in the bore lasts orders of magnitude longer than these initial pressure transients. The effect of the heating is to make the sandface flow be slightly less than the wellhead flow until the energy change in the well is negligible. The energy change in the well is becoming small after 40 minutes. If one calculates the actual sandface flow during this time, the data taken in these first 40 minutes could be used.

To determine the sandface flowrate in the well, it is necessary to know the wellhead flowrate and enthalpy and the downhole pressure change as a function of time. Enthalpy for a flashing system is obtained by measuring the quality and pressure. For a single phase system, enthalpy is obtained from pressure and temperature. If the reservoir is single phase then the enthalpy flowing out of the reservoir is not a function of flowrate, so it only needs to be measured once. For a two-phase reservoir, the flowing enthalpy from the reservoir changes when the steam saturation is altered around the bore because of relative permeability effects, and therefore, the enthalpy into the bore will change during a test. In such a case, one must measure the flowing quality at wellhead and correct it to obtain the downhole conditions.

Examples

The sandface flowrate is calculated for two different cases. In the first case the reservoir remains liquid filled, while in the second case the reservoir is two-phase. Included also is a calculation of a match of the pressure transients in a field case where wellbore transients are important, and an example of the two-phase flow in a well during shut in.

Because no field data were available, the data needed for the calculation of the sandface flow were generated numerically. To generate the downhole pressure used for the calculation of the sandface flowrate, the wellbore model was connected to a reservoir model. For the single phase case, the radial diffusion equation was finite differenced with a variable grid spacing. For the two-phase case, the reservoir model was provided by M.J. O'Sullivan and is a modified form of that given in Zyvoloski and O'Sullivan, 1979. A kh of 3×10^{-11} m^3 was used for both cases. The resultant drawdown pressure for the single phase case is given in Figure 3a. A similar drawdown profile was obtained for the two-phase case. For the single phase case, the temperature downhole corresponded to an enthalpy of 1.5 MJ/kg.

Single Phase Reservoir

Given the downhole pressure and the wellhead flowrate change (20 to 40 kg/s), the sandface flowrate was calculated. Because there is no change in enthalpy from the reservoir during the test, the calculated sandface flow, plotted in Figure 3b, and corresponding to slip as a function of flow regime, is exactly equal to the sandface flow calculated when the drawdown pressure was generated. (The exact correlations used for slip are given in Miller, 1980a). However, since accurate correlations for the slip between the phases is not well known, the sandface flowrate was calculated for two additional cases, 1) $s = 0$, and 2) $s = \sqrt{\rho_f/\rho}$. The same drawdown pressure as given in Figure 3a was used. Agreement is good except at very early times when $s = 0$. When $s > 0$, the steam quality of fluid in place is less than when $s = 0$. The compressibility of the two-phase mixture is greater for a lower steam quality mixture, so the wellbore is able to supply more of the surface flow for longer times than for the $s = 0$ calculations.

Two Phase Reservoir

It is more difficult to calculate the sandface flowrate when the reservoir fluid is two phase. The problem that arises is that the value of the flowing enthalpy from the reservoir as a function of time must be known to calculate the sandface flowrate. Figure 4a is a plot of wellhead and downhole enthalpy as a function of time calculated when the downhole pressure data were generated. (The reservoir was initialized at a liquid saturation of .78. The system was steadied out at a flow of 12.7 kg/s before the flow was increased to 25.4 kg/s so the drawdown pressure could be generated.) The enthalpy can only be measured at wellhead, but changes in enthalpy occur downhole first. The sandface flowrate was calculated using the wellhead enthalpy as the downhole enthalpy, but corrected for the delay in the arrival at the wellhead. To calculate the sandface flow, the wellhead enthalpy starting at 420 s was assumed to be the downhole enthalpy that occurred at time 0. Figure 4b shows both the sandface flowrate calculated when the downhole and wellhead data were generated, and then the sandface flow calculated, using the corrected wellhead enthalpy, the wellhead flowrate, and downhole pressure. The agreement is reasonable as this is a first attempt. A better correction of the wellhead enthalpy would result in a better agreement.

Field Case

Figure 5 illustrates how the transient wellbore model plus a reservoir can be used to match field data. The important point here is that the initial slope of log p vs log t is greater than unity. The downhole pressure data is from a buildup test at Raft River on RRGE2 taken by Narasimhan and Witherspoon (1977), using a Hewlett Packard Model 2811A quartz pressure gauge. The well was flowing 13 kg/s before being shut in. Because the time to shut in the well was not recorded, and because wellbore storage lasts only about 1 s, it is not reasonable to look at different values of kh and ϕch to determine the best fit from the early time data. The values of kh and ϕch given in the figure are close to those obtained previously. However, pressure transients in the well last longer than wellbore storage, and a model of the transient flow in the well is needed to explain this very early data. More detail of this effect is given in Miller, 1980b.

Build-up Analysis

The transient wellbore program can also be used to investigate the response of the fluid in the well when the bore is completely shut in. One can look at the sandface flow when the two phases separate out. Figure 6 is a plot of the density profile in the well after a shut in. However, these calculations are merely illustrations because the slip correlation used has no experimental basis. The liquid is flowing down while steam is rising. The slip function used was $5.6\ \alpha^3(1 - \alpha)^{1/3}$ where α is the steam quality in place. This function was used so that the constraint $s = 0$ when $\alpha = 0$ or 1 was satisfied, and so it would be approximately the size of the slip in the bubble regime. The calculation shows a transition from steam to liquid. The density profile in the well after thirty-five minutes does show one point that does not follow the smooth transition. The reason for this deviation could be in the choice of a slip correlation that is too small. Nevertheless, one sees the two phases separate out and liquid can flow back into the reservoir.

Conclusions

It is possible to use pressure data obtained during a well test when wellbore storage is still important if one uses a transient wellbore flow model to calculate the actual sandface flow. The calculation is more difficult for a two-phase reservoir and some improvement of the calculation given in this study can be made. Given a technique of analyzing a variable flow test, one can use all data obtained during a well test. It is possible to explain the initial slope of the log p_{dh} vs log t plot that is greater than unity. Also, in the future, it may be possible to analyze shut in tests where phase redistribution is important.

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NOMENCLATURE

c	reservoir compressibility
c_s	average isentropic compressibility, $(1/\rho)(d\rho/dp)_s$
h	reservoir thickness
k	permeability
p	pressure
r_e	effective radius
s	slip
t	time
μ	viscosity
ϕ	porosity
ρ	density

SUBSCRIPT

dh	downhole
f	liquid

ACKNOWLEDGEMENT

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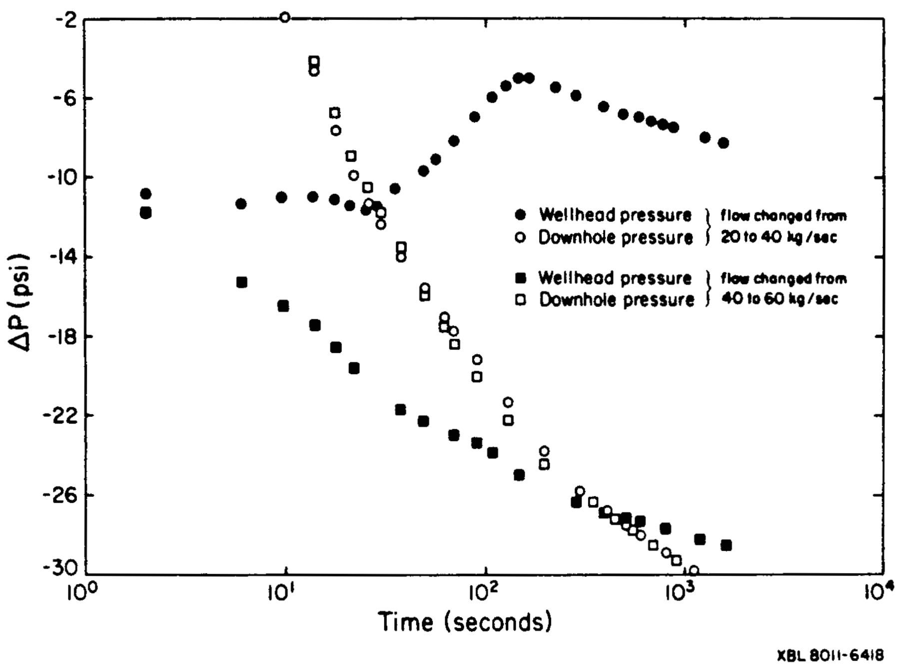

Figure 1. Plot of wellhead and downhole pressure transients for two drawdown tests.

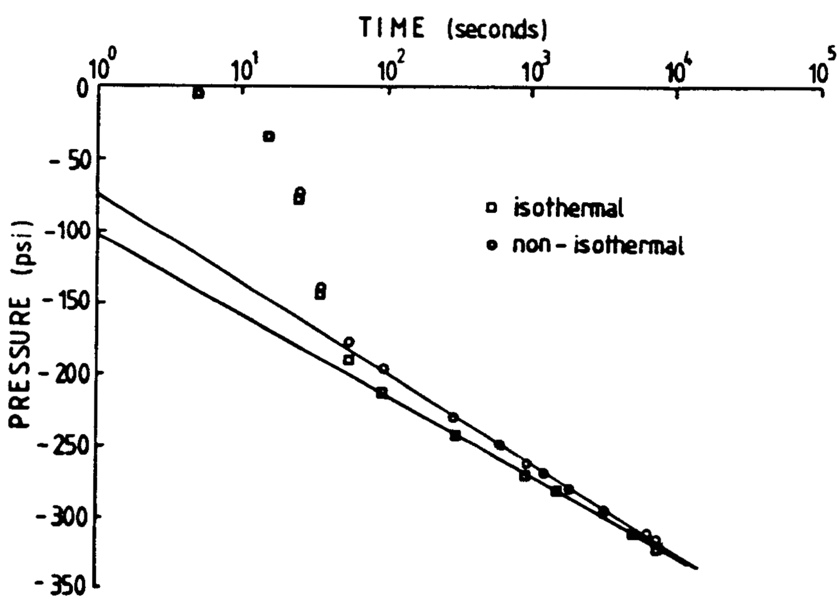

Figure 2. Effect of energy changes of fluid in the well on pressure transient data.

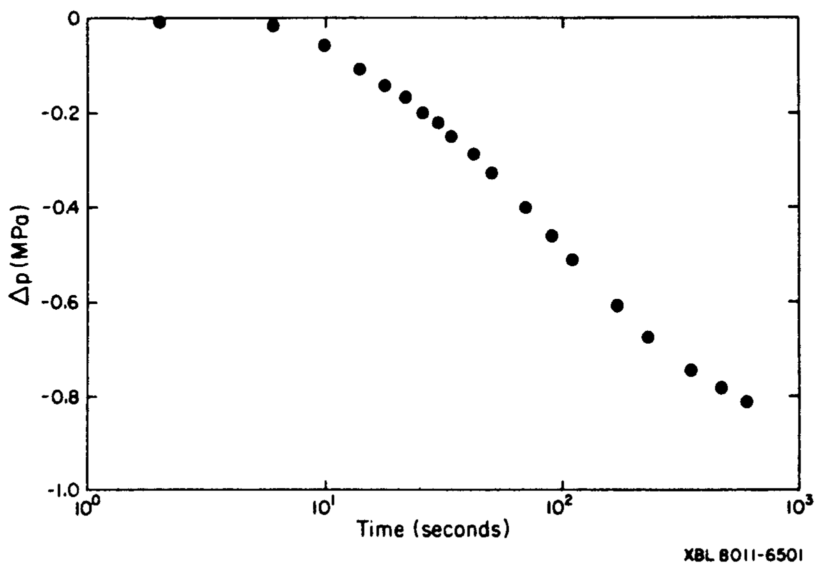

Figure 3a. Generated drawdown pressure.

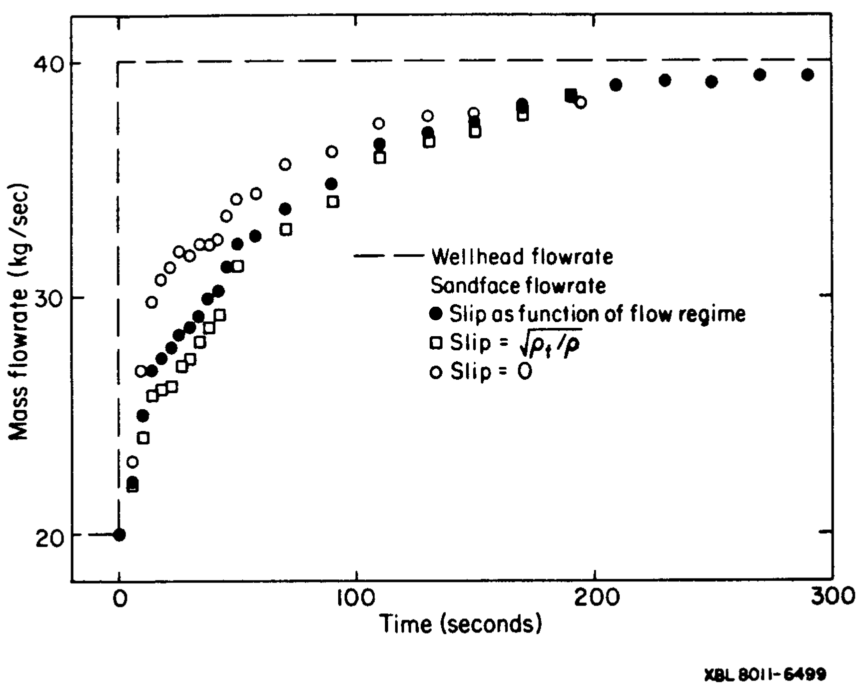

Figure 3b. Calculation of sandface flowrate using different slip correlations.

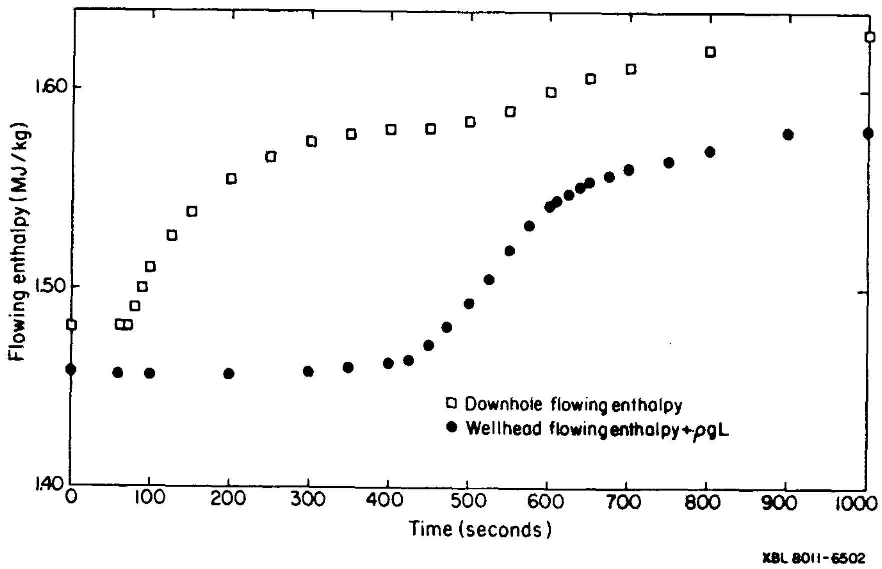

Figure 4a. Wellhead and downhole enthalpy as a function of time after a flowrate change.

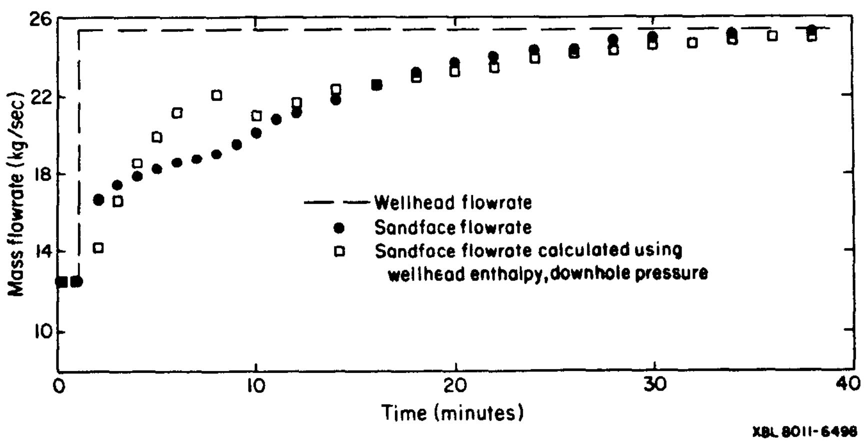

Figure 4b. Calculation of sandface flowrate for two-phase flow throughout the well.

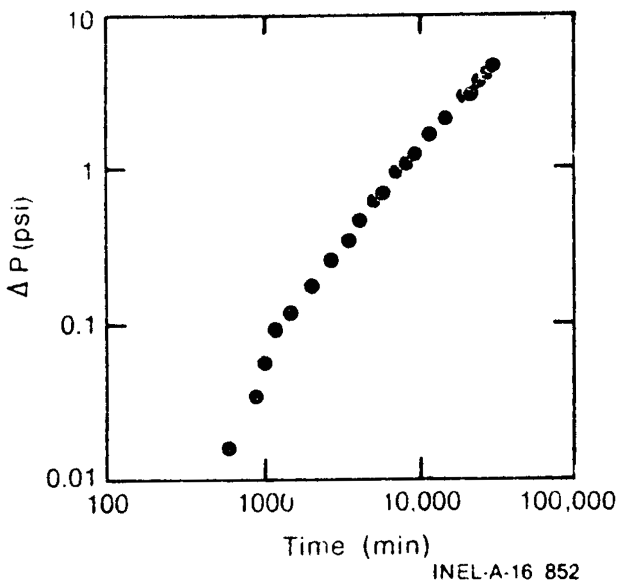

Figure 1 Drawdown at RRGP-4 during production from RRGP-5.

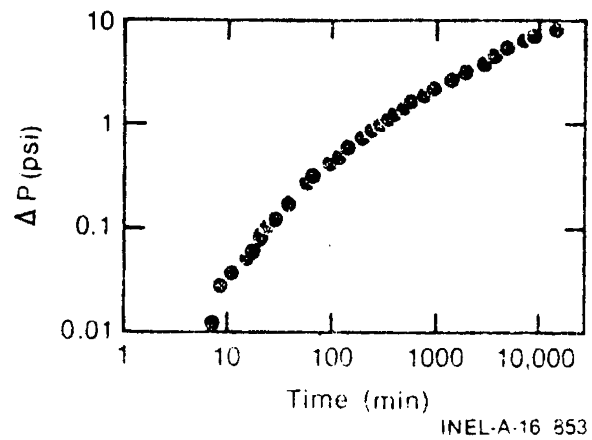

Figure 2 Drawdown at RRGE-1 during production from RRGP-5.

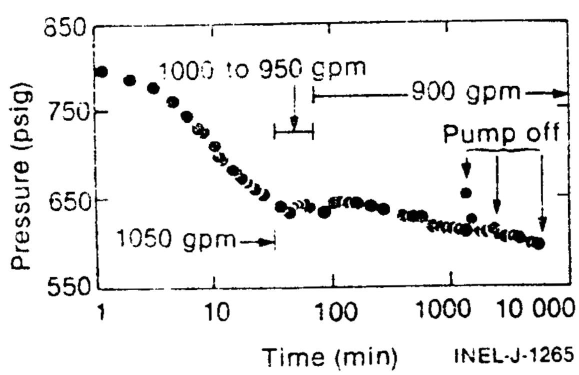

Figure 3 96 hours production at RRGE-1

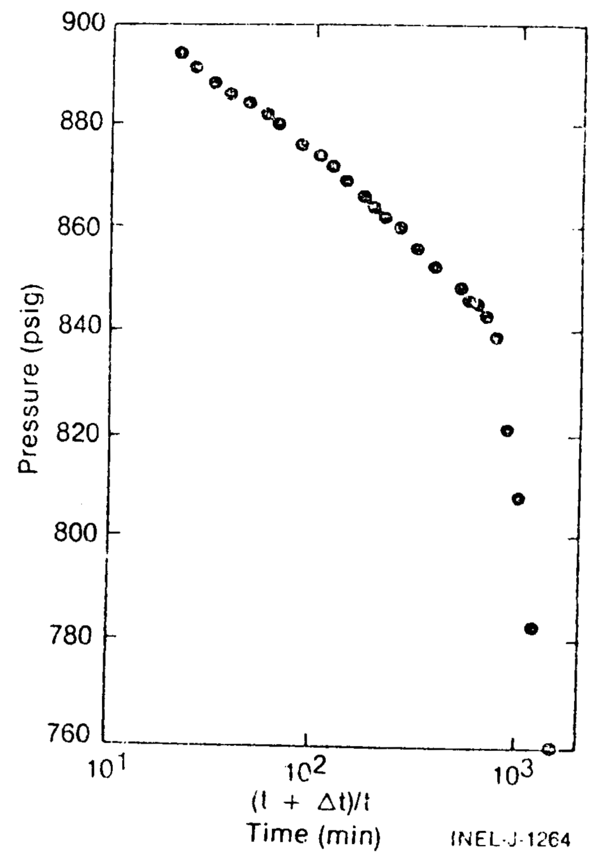

Figure 4 Recovery from production at RRGE-1

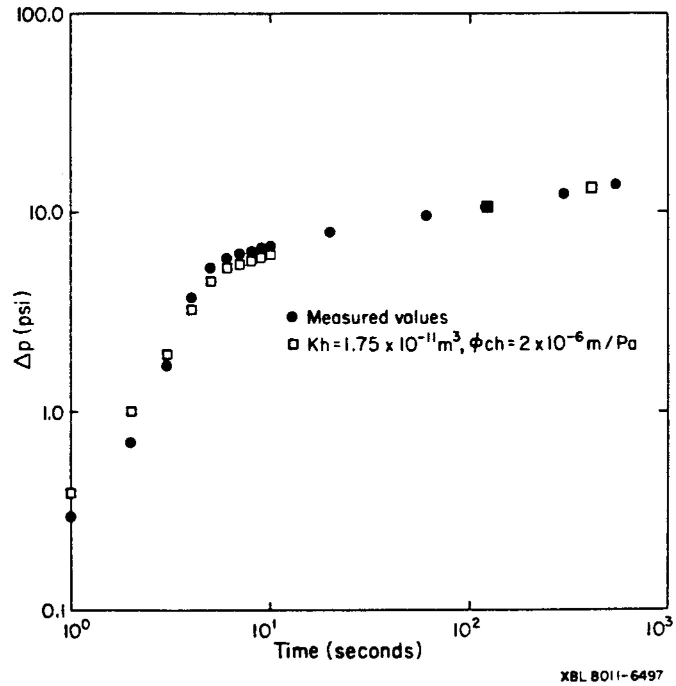

Figure 5. Match of pressure data with a field case.

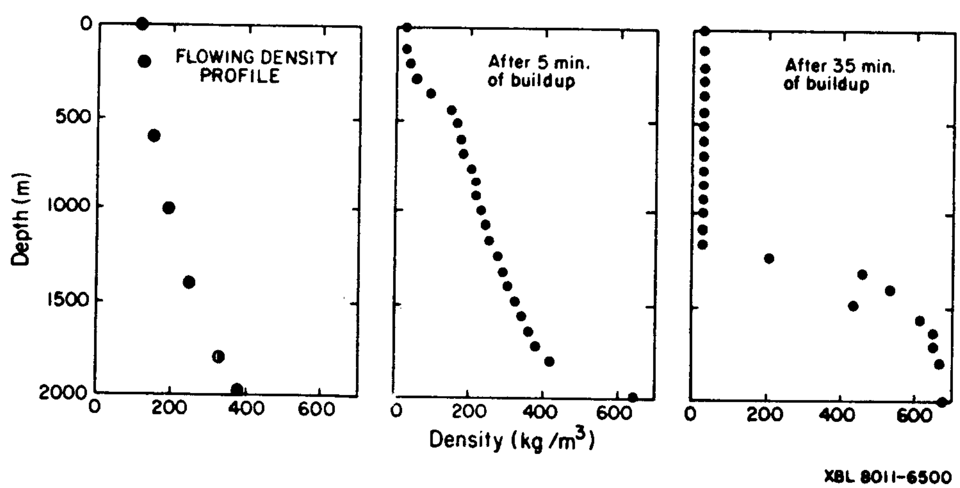

Figure 6. Calculation of density profile in a two phase well during a shut in test.