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ABSTRACT

The early time response in the well testing of an homogeneous reservoir is expected to give a unit slope when log (pressure) is plotted versus log (time). It is shown that this response is a special case, and that in general another non-dimensional parameter must be defined to describe the set of curves that could take place for each value of C_D. This parameter, t_{Rw}, is the time response of the reservoir divided by the time response of the well. When t_{Rw} is large, a unit slope results (as in oil and gas fields where kh/μ is relatively low) while no unit slope should be measured for small values of t_{Rw} (as in geothermal fields where kh/μ is much larger than in an oil field). Using a numerical model of transient two-phase flow, the predicted early time behavior in well testing has been plotted for C_D = 25, 100, and for values of t_{Rw} = 10, 1, 0.1 in each case. It is shown that both C_D and t_{Rw} are needed to correlate the behavior. In addition, the effect of heat transfer on the downhole pressure change with time has been calculated using the assumption of thermodynamic equilibrium. If the well test data is analyzed without taking into account the heat loss, the calculations for kh/μ are wrong. It is also postulated that non-equilibrium effects in the well may lead to abrupt changes in the pressure versus time curve. Such changes have been observed in field tests of flashed geothermal systems.

INTRODUCTION

The established techniques of well testing in the petroleum industry, that are used to assess the characteristics of oil and gas reservoirs, has been extended to the geothermal field by a number of workers [1,2,3]. However, there are several important differences between a geothermal field and an oil or gas field, and it is necessary to understand how these differences influence the analysis of well test data. These differences include: (1) the value of kh/μ of a geothermal field is usually much larger than that of an oil or gas field (because the reservoir thickness is greater in a geothermal field and the viscosity is smaller); 2) heat loss in the wellbore must be considered in the analysis of the well test data from geothermal wells; and (3) non-equilibrium effects could be important when the geothermal brine flashes or condenses.

References and illustrations at end of paper.

Wellbore storage has been considered quite extensively [4,5]. Although there have been many more detailed studies,[6-8] the concept of wellbore storage is treated as a boundary condition on the reservoir flow. The boundary condition used is

$$\frac{q_{s.f.}}{q} = 1 + C\,\frac{dP}{dt}$$

where dP/dt is the flowing pressure change with time in the wellbore. However, dP/dt is not necessarily independent of position in the well and when dP/dt is dependent on the measurement point, a plot of log (P) versus log (t) will not result in an unit slope at early times. This study will consider wellbore storage by looking at the flow in the well itself while treating the reservoir as simple homogeneous radial flow.

Heat loss from the well has also been ignored because oil and gas fields can be treated as isothermal. Heat transfer from the well is usually a very slow process and one might be inclined to ignore it. But because it is slow, the heat transfer effect can be important for very long times. Once the early transient behavior is over and a semilog straight line of P vs log (t) is expected, the heat transfer from the well can alter the slope of that line, so that the slope would no longer be $q\mu/4\pi kh$. The duration and importance of this heat transfer will be considered.

The third important effect in the geothermal well test is that condensation or evaporation does not necessarily occur in an equilibrium manner. The pressure changes can appear to be a changing wellbore storage say from a high compressibility to a low compressibility, but it is important to recognize the difference between non-equilibrium effects and wellbore storage changes as defined in the petroleum industry. If the abrupt change in pressure is due to non-equilibrium, then heat transfer is still very important, and the semilog plot of P versus log (t) will be altered from that predicted in current well test analysis.

A numerical model of transient two-phase flow in the wellbore with heat and mass transfer has been developed. It is used to investigate the iteraction of the well flow with that of the reservoir, and the non-uniform behavior in the well.

CONCEPT OF WELLBORE STORAGE

Wellbore storage is the capacity for the well to absorb or supply any part of the mass flowrate out of the well. When the mass flowrate is increased (or decreased), the change in pressure will be initially felt only in the well. After a certain amount of time, depending on the properties of the reservoir and the conditions in the well, the reservoir will start to supply part of the flow. The sandface flow rate will increase and approach the surface flow rate as the transient changes in the well die out. One can think of the time for the reservoir to supply the surface mass flowrate as the time constant of that reservoir.

If the pressure changes with time in the well are not a function of position, then a graph of pressure versus time on a log-log plot will have unit slope. This unit slope indicates that $\Delta P \propto \Delta t$ with the well supplying the flowrate changes in a uniform manner. In this case, for a step change in flowrate at the surface, the sandface mass flowrate is

$$(\rho q)_{s.f.} = (\rho q)_s + \rho C \frac{dP}{dt} \quad . \qquad (1)$$

(Mass is conserved in a well, not volume.) When $t = \varepsilon$, the sandface rate is zero, and it is usually assumed that the slope of the curve dP/dt will give the storage coefficient. However, if P is the downhole pressure, then dP/dt must also be zero at $t = \varepsilon$, because there is a finite time for changes at the surface to arrive downhole. A correct interpretation of $C\, dP/dt$ is that it is the average of $C(dP/dt)$ over the whole length of the well.

When the wave nature of the step change in flow rate at the surface is important, changes in pressure in the well are not uniform. Nevertheless, wellbore storage curves are generated assuming that the fluid in the well is fully mixed. Before one can assume that this uniform mixed condition is valid, the wave nature of the original disturbance must be damped out. If the time for the reservoir to respond to a change made at wellhead is much longer than the time for these changes in the well to be described by one pressure measurement, then the effect of the non-uniform behavior in the well will not be important. This condition is true when oil or gas reservoirs are tested. Typical kh values are 2×10^{-13} m^3 (200 md-m). Also, the viscosity of oil is relatively high resulting in small values of kh/μ (say 10^{-6} m^3/Pa-s). Under these circumstances, the time response of the reservoir is orders of magnitude slower than the time response of the well and the non-uniform behavior in the well will damp out before the reservoir can respond. However, there are cases when the reservoir can supply fluid before dP/dt in the well is uniform, and the fully mixed well is not a good approximation. In geothermal wells, kh can be very large, say 10^{-11} m^3 (10,000md-m), and μ is low (9×10^{-5} Pa-s at 300 C). Because of the high value of kh/μ, the reservoir is capable of supplying a much larger quantity of fluid than an oil reservoir for a given pressure drop. When there non-uniformities of dP/dt in the well are considered, significantly different wellbore storage curves are generated. The curves will depend on another non-dimensional parameter defined as the time response of the reservoir divided by the time response of the well. These time constants are determined in terms of the conditions of the reservoir and those of the fluid in the well.

For a pressure change at wellhead, the disturbance will move at the local speed of sound through the well. (The fluid moves at a velocity, v, but a disturbance propagates at the speed of sound, a). The time for the disturbance to reach the bottom of the well is approximately L/a or

$$t_w = L/(\partial P/\partial \rho)_s^{1/2}$$

where $(\partial P/\partial \rho)_s^{1/2}$ is the average speed of sound in the well. The characteristic time of the well will be defined as this value. The time constant of the reservoir will be defined as the time when the reservoir can supply the surface mass flowrate. The expression for t_R can be determined from the special case of $t_R = t_w$. This situation occurs when the original pressure drop that propagates down the well is exactly the pressure drop needed at the well/reservoir boundary to have the sandface mass rate equal to the surface mass flowrate, $(\rho q)_{s.f.} = (\rho q)_s$. When the flowrate at the surface is changed, there will be a pressure pulse of some size ΔP_w that will propagate down the well. The initial sandface rate is

$$(\rho q_{s.f.})_i = 2\pi r_w \frac{kh}{\mu} \rho \frac{\partial P}{\partial r} = 2\pi r_w \frac{kh}{\mu} \rho \left(\frac{\Delta P_w}{r_w}\right) \qquad (2)$$

If $(\rho q_{s.f.})_i$ is just equal to the surface flowrate, $(\rho q)_s$, then the reservoir will be supplying the desired flowrate. The time for this to occur is just the time for the pulse to propagate down the well in this special case, or $t_R = t_w$. If $(\rho q_{s.f.})_i$ is less than $(\rho q)_s$, the reservoir is taking longer to respond than the transit time in the well, and if $(\rho q_{s.f.})_i$ is greater than $(\rho q)_s$, the reservoir can respond faster than the well. In general, one can estimate t_R/t_w as $(\rho q)_s/(\rho q_{s.f.})_i$. To obtain the latter ratio, it is necessary to determine the pressure drop, ΔP_w.

For a given surface flow rate, all the mass is taken initially from the well or $v_{in} = 0$ and $v_{out} = q/\pi r_w^2$. The decrease in the mass in the well must equal the total mass out, $(\Delta\rho)(A)(\Delta X) = \rho A \Delta t q/\pi r_w^2$ where x is the distance down the well that the mass is taken from. This distance is just how far the signal has propagated. Assuming the enthalpy is constant (an approximation), then

$$(\Delta\rho) \frac{\Delta x}{\Delta t} = \left(\frac{\partial \rho}{\partial P}\right)_h \Delta P \left(\frac{\Delta x}{\Delta t}\right) = \rho \left(\frac{q}{\pi r_w^2}\right)$$

or

$$\Delta P = (\partial\rho/\partial P)_h^{-1} \frac{\rho q}{\pi r_w^2} \left(\frac{\Delta t}{\Delta x}\right) \quad .$$

The disturbance travels at the local speed of sound so $(\Delta x/\Delta t) = a = (\partial P/\partial \rho)_s^{1/2}$

and the pressure drop ΔP_w is approximated as

$$\frac{(\partial\rho/\partial P)_s^{1/2}}{(\partial\rho/\partial P)_h} \frac{\rho q}{\pi r_w^2}$$

Using Eq. 2 and the above estimate for ΔP_w,

$$(\rho q_{s.f.})_i = 2\pi r_w \left(\frac{kh}{\mu}\right) \left(\frac{\rho q}{\pi r_w^2}\right) \frac{1}{r_w} \frac{(\partial\rho/\partial P)_s^{1/2}}{(\partial\rho/\partial P)_h} \rho_{s.f.}$$

The ratio t_R/t_w is just

$$\frac{t_R}{t_w} = t_{Rw} = \frac{(\rho q)_s}{(\rho q_{s.f.})_i} = \left(\frac{\mu}{kh}\right) \frac{r_w^2}{2} \left(\frac{1}{\rho_{s.f.}}\right) \frac{(\partial\rho/\partial P)_h}{(\partial\rho/\partial P)_s^{1/2}}$$

In many cases, $(\partial\rho/\partial P)_h \approx (\partial\rho/\partial P)_s$ over the region of interest so

$$t_{Rw} = \left(\frac{\mu}{kh}\right) \frac{r_w^2}{2} \frac{1}{\rho_{s.f.}} (\partial\rho/\partial P)^{1/2}. \tag{3}$$

This latter form will be used to determine t_{Rw} in the calculations below.

Now, t_{Rw} (as derived) is the quantity along with C_D necessary to characterize the flow if the initial pressure disturbance made at the wellhead is not changed significantly as it propagates through the well. This situation is true if the compressibility of the fluid is approximately constant in the well. However, even in this case, the initial flowrate from the reservoir will not exactly equal the surface mass flow rate because the initial pressure change does not propagate as a step function, and because the reservoir has a finite height h. When $t_{Rw} = 1$ (as calculated in Eq. 3), $(\rho q_{s.f.})_i$ will still be less than $(\rho q)_s$ as will be seen in the next section. For two phase wells, the compressibility changes considerably between the two-phase region and the liquid water region so the pressure pulse becomes distorted. The friction in the two-phase region, though, helps to dampen these large pressure fluctuations. The pressure pulse is also altered if there is any heat transfer. However, heat losses are usually more important at later times when dp_D/dt_D is small. Even though the approximations made in deriving t_{Rw} are not valid in all cases, the parameter can still be used to characterize the well/reservoir interaction in many circumstances.

Transient Flow in Well Bore

To investigate the nonuniform changes in the well in detail, a numerical model to simulate compressible transient flow in a wellbore has been developed. The model is capable of handling single-phase as well as two-phase flow with mass transfer (for example, steam-water flow). The heat transfer between the ground and the well is also included. To be able to look at the interaction between the reservoir and the well, a radial equation for a homogeneous, single-phase reservoir is included. To solve the one-dimensional flow in the well, the equations of mass, momentum, and energy were solved. The equations are

$$\frac{\partial\rho}{\partial t} + \frac{\partial}{\partial x}(\rho v) = 0 \tag{4}$$

$$\frac{\partial}{\partial t}(\rho v) + \frac{\partial}{\partial x}(\rho v^2) + \frac{\partial P}{\partial x} + \rho g + 1/2\,\frac{f\rho v^2}{D} = 0 \tag{5}$$

$$\frac{\partial}{\partial t}(\rho e) + \frac{\partial}{\partial x}(\rho e v) - \frac{2H}{r_w}(T_r - T_w) + P\frac{\partial v}{\partial x} = 0 \tag{6}$$

An equation of state is used to relate density to pressure and energy. A description of the numerical model is available in reference 9. For the calculations presented here, a constant friction factor was used. Many interesting and meaningful transient results are possible without going to a more elaborate description of the friction and slip. The program is used to investigate the initial transient nature of the wellbore and to determine the duration of heat loss effects. Initially, the behavior of dp_D/dt_D will be investigated assuming no heat loss. The effect of heat loss will be considered in the following section.

Adiabatic Flow

Using the developed numerical model, calculations were performed to generate the deviation of the drawdown (or buildup) curve from the unit slope for different values of t_{Rw} and C_D. The calculations were done for C_D = 25, 100, with t_{Rw} = 0.1 to 10.0. For all the calculations, the length of the well was 2000m and the radius was 0.082m. The mass flow rate out was kept constant at 500 kg/m^2-sec. No heat loss was assumed. The downhole pressure was adjusted to obtain flashing or no flashing. The reservoir parameters used for the calculations are: (1) in Fig. 1a, $\mu = 2\times10^{-4}$ Pa-s, $\phi ch = 3.2\times10^{-8}$ m/Pa downhole pressure = 2.9×10^{7} Pa, reservoir temperature = 200°C and kh = 6.4×10^{-14} to 6.4×10^{-12} m^3, and (2) in Fig. 1b, $\mu = 9\times10^{-5}$ Pa-s, $\phi ch = 5.3\times10^{-7}$ m/Pa, downhole pressure = 2×10^{7} Pa, reservoir temperature = 320°C and kh = 4×10^{-13} to 4×10^{-11} m^3. Included on each plot is both the traditional wellbore storage curve derived assuming $(dp_D/dt) \neq$ function of position in the well and the $C_D = 0$ curve. For $t_D > 1$, this latter curve is just the Theis curve. The general behavior of the transient flow in the well can be described using these figures.

In Figure 1a, liquid water was assumed to flow under a positive head to generate the curves for the different values of t_{Rw}. The average value of $(\partial\rho/\partial P)_h$ in the well was 7×10^{-7} and the C_D factor for this plot is 25. Included in the figure are points calculated for a flashed system where the average value of $(\partial\rho/\partial P)_h$ is 4×10^{-5} (of course, in a flashed well, the compressibility varies by orders of magnitude. However, the average compressibility can still be used to characterize the flow in many cases.) Figure 1b and some points in Fig 1a give calculations assuming that the water is flashing at about 500 m down the well, but the fluid is still flowing under a positive head. A friction factor of 0.04 was used for all calculations except for one case in Fig 1b. To generate the different curves, kh, μ, and ϕch were varied. The arrival time of the initial pulse downhole is the same if the average compressibility is not changed. However, the time has been non-dimensionalized by $(k/\mu c\phi r_w^2)t$, so the non-dimensionalized arrival time will be different when the reservoir parameters are varied.

The first case to consider is when $t_{Rw} > 1$. The fluid in the well may not be very compressible but because the reservoir is unresponsive, the well must supply the surface flowrate. The initial pressure drop that arrives downhole will cause a flowrate from the reservoir that is less than the surface flowrate. As the pressure in the well drops, the reservoir starts to supply the fluid, the p_D vs t_D curve approaches the unit slope plot on the log log scale. There will always be some initial delay but many times the delay will be a very small portion of the initial curve. Once the pressure disturbance arrives downhole, the pressure change with time increases abruptly, and it approaches the wellbore storage curve based on the uniform theory. This situation occurs in the oil and gas field tests. The value of kh/μ is so small that the unit slope persists for long times.

When $t_{Rw} = 1$, the pressure drop needed to achieve a step change in flow-rate at the surface is close to the pressure drop needed to obtain this same flowrate from the reservoir. The pressure change with time is initially zero but once the disturbance reaches downhole, it rises abruptly until it reaches the expected drawdown curve. Since $(\rho q_{s.f.})_i \approx (\rho q)_s$ this occurs after the expected wellbore storage curve is almost over. The plot is shown in the figures by $t_{Rw} = 1$. The near wellbore value of kh/μ can be obtained from this curve. If $t_{Rw} = 1$, and knowing the properties of the fluid in the well, one can estimate (μ/kh) as

$$\mu/kh \approx (2/r_w^2)\rho\,(\partial\rho/\partial P)_s^{1/2}/(\partial\rho/\partial P)_h \quad .$$

The third intersecting case is when $t_{Rw} < 1$. When the given pressure drop arrives downhole, the reservoir will be so responsive that it can supply more fluid than the well could for the same pressure drop. This situation produces an oscillation illustrated in the Figure 1a by $t_{Rw} = 0.1$. The pressure drop is too large so the reservoir supplies more fluid than is being taken out at the surface. The pressure in the well will be increased and this increase will be propagated up the well. The interaction between the reservoir and the well produces the oscillation which slowly dies out. For the liquid filled well in Figure 1a, the time of the oscillations is a couple of seconds. However, the large oscillations seen in Figure 1a for $t_{Rw} = 0.1$ are not observed in Figure 1b where a flashed system was used for the calculations. The oscillations have been damped out by friction effects. The friction term is dependent on the flow velocity squared, so there will be more dampening in the flashed system than the unflashed system for the same mass flowrate because the velocity is greater. One can see the influence of the friction factor in Figure 1b where one calculation was done with $f = 0$ in the case $t_{Rw} = 0.1$. The effect of the friction factor decreases as t_{Rw} increases.

One last observation that must be made in Figures 1a, 1b is the fact that the drawdown curve approaches the wellbore storage curve based on the uniform theory[4] but does not coincide with it. The C_D values used were calculated assuming that the enthalpy is constant. This situation is not strictly true even without heat loss because of the acceleration or deceleration of the flow. In a drawdown case, the fluid accelerates, the kinetic energy increases so the specific enthalpy decreases. The fluid will compress because of this decrease so less fluid can be extracted from the well for a given pressure drop. The drawdown pressure must be slightly greater than the typical C_D curve predicts. For the buildup case, the enthalpy increases because of the deceleration. Less mass can enter the well than expected, so again, the curve will "overshoot" the C_D curve that assumes constant enthalpy. The amount of "overshoot" is less for a liquid filled well than a two-phase system because the acceleration or deceleration is less.

A lack of one-to-one slope at early times has been observed in the field. Figure 2 plots data obtained from a field test of a liquid filled well at the Raft River Geothermal project.[10] The data was taken with the Hewlett Packard gage which is capable of providing readings every second with a resolution of 0.01 psi. There may be an error in the readings because of temperature effects on the instrument but the magnitude of these errors would not alter the general behavior of the build-up curve. (The fluid was flowing under a positive head before it was shut-in.) When this data was presented, the lack of the unit slope was observed but no explanation was given. The signal that the well was shut-in takes about 1-2 seconds to arrive downhole. The pressure then builds up very quickly and approaches the curve that would exist if the well behaved uniformly. Using the measured properties of the reservoir, ($\phi ch \approx x\ 10^{-6}$ m/Pascal, $kh \approx 15$ D-m, $\mu \approx .2$ cp), the wellbore storage coefficient is about 0.35 and $t_{Rw} \approx 0.2$. For this low value of t_{Rw} one should see oscillations in the p_D vs t_D curve. However, these oscillations are damped out if the flowrate change is less than a "step function." For the case plotted in Figure 2, it would probably be hard to achieve a "step rate change" because the typical time needed to close a valve is longer than the time for a pressure signal to propagate to the bottom of the well. Even without a "step rate" change in flowrate, the plot is still not a unit slope, emphasizing even more that the unit slope is only a special case when the reservoir is less responsive than the well.

A plot of the pressure pulse as it propagates into the well and interacts with the reservoir gives more insight into the behavior of the well and reservoir interaction. Figures 3a, 3b and 3c plot the pressure distribution in the well as a function of time for a drawdown test and for different values of t_{Rw}. The first two calculations are done with water throughout the well and the third case is for water that has flashed about 500 m down the well.

For case 3a and 3b, the propagation of the signal is the same until the pulse arrives at the formation/well boundary. Then the pressure distribution in the well will start to differ. The value of kh/μ is greater in case (3a) than in (3b), so t_{Rw} will be smaller in case 3a. The pressure changes with time and position have been plotted in a non-dimensional manner. Figure 3a has been split into 3 successive graphs to illustrate the oscillations in the well as a function of time. Figure 3b is only one graph because the pressure change with time quickly becomes uniform. To illustrate that there is no difference in the initial propagation of the pressure pulse, the first graph of Figure 3a and the graph of Figure 3b have been plotted so the dimensional units coincide. Once the pulse arrives at the reservoir, the two cases start to differ. For case (3a), the reservoir supplies more fluid than is being taken out at the surface and an increase in pressure travels up the bore canceling out part of the initial pressure decrease. This pulse produces an increase in pressure that is too large in the well. When this increase in pressure arrives at the surface, the pressure must decrease again to sustain the flowrate. There is a pressure oscillation in the well which slowly dies out. For case (3b), the reservoir has a relatively low value of kh/μ. Even when the initial pressure drop arrives downhole, the reservoir cannot supply very much fluid. The pressure must continue to drop in the well and dP/dt will be a very weak function of position in the well.

For case (3c), the signal propagation is different because there is a boundary between the two-phase system and the liquid. The boundary tends to distort the original pressure pulse because most of the pulse is reflected from the boundary while a small portion is transmitted. The pulse then oscillates in the two phase region. It is dampened by viscous dissipation and by the interaction with the well/reservoir boundary. The proagation of the signal is relatively slow in the two-phase region being about 70-150m/sec.

The sound speed is low in a two phase region because of the relatively high density and high compressibility. However, once the pulse reaches the liquid, the signal is propagated about 10 times faster because the compressibility is lower. Because of this increase in the propagation speed, the changes in the liquid are relatively uniform. For larger values of t_{Rw}, the pressure will drop faster in the liquid region, and the pressure change in the well will become more uniform quicker. For $t_{Rw} \geq 1$ the pressure drop will be closer to Figure 3b, even though there is a two-phase region.

One question is whether or not t_{Rw} can be used as a non-dimensional time to describe this interaction phenomenon when different fluids are used in the well, i.e. if C_D and t_{Rw} are kept the same value but the fluid conditions in the well and the reservoir properties are changed will the same curve be generated. It might be thought that changes in the two phase region could never be correlated by a term t_{Rw} which was derived assuming no abrupt changes in the initial pressure pulse. However, a pulse dampens both because of the interaction with the boundaries and because of viscous dissipation. In a two phase mixture, the interaction with the boundary is slow but the frictional effects are large, while the opposite is true in the single phase region. Because the two effects tend to compensate for one another, t_{Rw} can be used to correlate the behavior for both two phase and single phase flow in many cases.

If the fluid in the well is not varied, but μ, k, h are changed in a way such that kh/μ remains constant, the generated curve is the same. The calculation depends on kh/μ and if this is not varied, the interaction of the well and reservoir will not change. (There is a very slight difference in the calculation as h is varied but the size of the change is too small to be of any use.) A more interesting case is if the fluid properties in the well are varied but the reservoir properties are adjusted to give the same t_{Rw} and C_D. Under these circumstances will the same curve be generated. Figure 4 shows this comparison when $C_D = 100$ and $t_{Rw} = 1.0$. Two calculations are for a liquid filled well and the third one is for a flashed system. The reservoir values used were $kh = 6.4 \times 10^{-13}$ m^3, $\phi ch = 8 \times 10^{-9}$ m/Pa, $\mu = 2 \times 10^{-4}$ Pa-s for one liquid well; $kh = 4.5 \times 10^{-13}$ m^3, $\phi ch = 2.3 \times 10^{-8}$ m/Pa, $\mu = 9 \times 10^{-5}$ Pa-s for the second liquid filled well; and $kh = 4 \times 10^{-12}$ m^3, $\phi ch = 5 \times 10^{-7}$ m/Pa $\mu = 9 \times 10^{-5}$ Pa-s for the partly flashed well. For the liquid filled wells, $(\partial\rho/\partial P) = 7 \times 10^{-7}$ kg/m^{3}Pa and 1.4×10^{-6} kg/m^3 Pa and for the flashed system, $(\partial\rho/\partial P) \approx 4 \times 10^{-5}$. It is a little hard to contrive a case where t_{Rw} and C_D will be the same when the average compressibility in the well varies as much as it does between these two cases. Some of the reservoir properties used may be a little extreme. However, one can see that there is excellent agreement between the three different cases. Again the constant friction factor of 0.04 was used. The other properties of the well are the same as those used for the calculations done for Figure 1. The agreement is good when $t_{Rw} \geq 1$. As t_{Rw} decreases, pressure changes in the well become more non-uniform and the assumptions used in deriving t_{Rw} are less valid. A partly flashed well with two different regions, one single phase and the second a two-phase region, will distort the fluctuations more. The p_D vs t_D curve for this latter case will start to deviate at early times from the single phase case that has the same value of t_{Rw} and C_D. This deviation will be partly compensated for by the friction effects which are proportional to V^2. The main difference in the two cases is that the flash level acts as a second boundary. As the interaction at this boundary becomes more important, the pressure change with time will not be described very accurately with the single phase case. This situation exists when $t_{Rw} \ll 1$. However, from the very rough analysis used to estimate t_{Rw} it can describe the flow for both two phase and single phase flow over a wide range of cases.

Heat Loss Effects

The heat loss from the fluid in the well can have a significant effect on the downhole pressure change with time. Heat transfer is especially important when a new well is tested, because the rock surrounding the bore is still relatively cool. Even after the early time wellbore storage changes are over, heat transfer can alter the slope of the semilog plot of P vs log t from $q\mu/4\pi kh$ in a drawdown test, requiring a different analysis of the data than has been developed in the petroleum industry. The value of kh will be calculated to be too small if heat transfer is ignored and if changes in phase occur in an equilibrium fashion. (This latter assumption may not be valid.) The numerical model of the transient behavior of the fluid in the well has been used to model the flow with heat transfer. The analysis is done assuming no slip between the phases and that the fluid is in equilibrium. The effect of non-equilibrium or large changes in the heat transfer coefficient will be discussed at the end of this section.

Heat transfer is important in two-phase geothermal wells because of the large temperature changes that occur when the flash level rises or falls. Figure 5 is a plot of P vs t for a buildup and a subsequent drawdown test. To simulate the heat loss from the well, a typical geothermal temperature gradient was assumed far from the well, and a small temperature buildup was used near the bore. A non-dimensional representative temperature profile is given by the insert in Figure 5. This is a typical temperature buildup. In the figure, graph (a) is a plot of the pressure buildup and then drawdown when the heat loss is ignored and graph (b) is when heat transfer is allowed to take place. The fluid flowed into the well from a simple, homogeneous reservoir with a kh value of 6.7×10^{-12} m^3. The heat transfer coefficient used between the fluid and the wellbore was a function of of flow rate and of density. For turbulent flow in a pipe, $Nu \approx 0.023\, Re^{0.8}$ ($Pr = 1$), and $H = 0.023(\rho v)^{0.8} \mu^{0.8} d^{0.2}$. In the two-phase region the heat transfer coefficient was averaged between the steam and liquid which could be improved.

It can be seen from the figure that the heat transfer causes the presure to initially change at a slower rate both for the buildup and the drawdown test. During a buildup test, the enthalpy of the exiting fluid decreases because of the increased time that the fluid is in the well. As the enthalpy decreases, the fluid can condense or compress more for the same pressure so more fluid flows into the well with a smaller pressure rise. In a drawdown, the enthalpy of the fluid increase in time and the density will decrease. For the same pressure, more fluid will exit the well so the initial drawdown pressure is less. As the enthalpy change steadies out, the drawdown or (buildup) curve with heat loss must approach the curve without heat loss. The enthalpy changes because of acceleration or deceleration are not important in the pseudo steady region because these changes have already taken place. It is only the changes because of heat loss that effect the slope of the p_D vs. t_D curve in this region.

Figure 6a shows the error in the kh value if the test is analyzed assuming heat loss is not important. Figure 6a is a plot of P vs log $[(t + \Delta t)/\Delta t]$ for the buildup test. Assuming that $kh = q\mu/4\pi m$, where m is the slope of the straight line portion, then the kh obtained is about 6.5×10^{-12} m^3 in the buildup and about 6.9×10^{-12} m^3 in the drawdown for no heat loss. The actual value used was 6.7×10^{-12} m^3. However, if the same analysis is used when heat loss is important, different values for kh are obtained, i.e., 4×10^{-12} m^3 in the buildup and 5.3×10^{-12} m^3 in the drawdown. The longer the test is run, the less significant the heat loss is. One sees that the two slopes start to approach one another at later times. However, the straight line semilog plot is seen after about 10 minutes when heat loss is zero but only after 20 minutes when there is heat loss.

As indicated, the calculations made assume the changes in the well occur in a smooth, equilbrium fashion. However, actual well tests seem to indicate that this is not true. In 1978, well test data from a well in the French Territory of Afars and Issas was presented. [3] Abrupt changes in pressure were seen in the buildup tests. It was postulated that the change in pressure was because of a changing wellbore storage from a liquid level controlled storage to a comressibility controlled storage. There was no detailed reasoning of whether this situation was physically possible. The difference in the wellbore storage because of condensation (or evaporation) and because of an increase (or decrease) in the flash level are not very different. Condensation itself will result in an increase in the flash level. Also, a wellbore storage coefficient based on a changing liquid level assumes that the density above the level is much smaller than the liquid and can be ignored, and that the pressure above the liquid level is constant. In a two-phase system, this is not quite true. The density above the flash level is only slightly less than the liquid (although the compressibility has changed by many orders of magnitude), and the pressure changes with time throughout the well. As the liquid flashes further and further down the well, the wellbore storage coefficient approaches the storage coefficient based on a changing liquid level.

Figure 7 plots a buildup curve from a well test of M-91 at the Cerro Prieto site. The data was provided by the Comisión Federal de Electricidad de Mexico. Note that first there is a sudden buildup in pressure and then the pressure changes at a slower rate. After a couple of more minutes, another abrupt change in pressure is observed which levels out to a flatter pressure change with time. This behavior might be explained as a two-layer reservoir, which is quite possible although the well itself is though to tap only one reservoir. However, the changes may be due to the conditions in the wellbore itself.

(1) When the flow rate is decreased, the liquid level will slowly rise because the pressure has been increased. The brine will be able to flow further up the wellbore before the pressure is reduced to the satuation pressure corresponding to the downhole temperature. This increase in liquid level is the initial change in the pressure.

(2) Because the brine flashes higher up in the well, the temperature of the brine will be greater than the surrounding rock. The brine will lose heat to the rock. Under equilibrium conditions, the brine would steadily lose heat, and it would condense at the walls. However, condensation does not occur in an equilibrium manner. The brine must supercool until a threshold is reached. The amount of supercooling needed depends on the wellbore conditions. Once this threshold is reached, the fluid condenses suddenly and continues to condense until the fluid is in equlibrium. The downhole pressure would increase at a lower rate or even might decrease when the condensation took place. Also the fluid might "over condense" for the equilibrium conditions. As the condensation decreases, the pressure would start to increase again.

(3) Or it is possible that the heat transfer at the wall of the well is altered significantly when the flow rate is changed. When the flow steadies out, a liquid film may reform increasing the heat transfer abruptly.

If this situtation occurred, the pressure curve would have distinct changes as observed. The numerical model developed does not include these latter two effects yet. It is important that it be investigated, though, for the well test data to be analyzed correctly.

CONCLUSION

The early time response of a unit slope when log (P) is plotted vs log (t) is a special case and actually there are a whole series of curves for each value of C_D which can be defined by the non-dimensional time t_{Rw}. An expression for t_{Rw} was determined which is applicable when the compressibility in the well is relatively constant. However, even in two-phase wells where the compressibility changes by orders of magnitudes, t_{Rw} can still be used to correlate the flow for t_{Rw} close to 1 and $t_{Rw} > 1$. As t_{Rw} decreases, the pressure fluctuations in a two-phase well increase and the expression derived for t_{Rw} becomes less applicable.

In addition, it has been shown that heat transfer can both (1) alter the slope of the straight line plot of P vs log (t) and (2) increase the time before a straight line is seen on the semilog plot. It is also postulated that the rate of condensation and evaporation in a wellbore may not occur in an equilibrium manner or that the heat transfer between the fluid and the wall of the well may change considerably when a flow rate change is made. Either of these conditions may lead to changing slopes when P is plotted versus log t which might be analyzed as the response of the reservoir itself if these effects are not understood better.

NOMENCLATURE

A, A_w	Area of wellbore
C	isothermal compressibility, $(1/\rho)\ (\partial\rho/\partial P)$
c	compressibility of reservoir
C_D	wellbore storage coefficient
D, d	diameter of well
e	specific energy
f	friction factor
g	gravity
h	specific enthalpy
h	reservoir thickness
H	heat transfer coefffficient
k	permeability
L	length of wellbore
P	pressure in well
P_D	non-dimensional downhole pressure
ΔP_w	initial pressure drop in well
q	volume surface flow rate
$q_{s.f.}$	volume sandface flow rate
$(\rho q_{s.f.})_i$	initial change in sandface mass flow rate
$(\rho q)_s$	surface mass flow rate
$(\rho q)_{s.f.}$	sandface mass flowrate
r_w	radius of wellbore
s	specific entropy
t	time
t_w	time constant of wellbore
t_R	time constant of reservoir
t_{Rw}	t_R/tw, non-dimensional time
t_D	non-dimensional time, $(k/\phi c \mu r_w^2)t$
T_r	temperature in reservoir of wellbore
T_w	temperature of fluid in wellbore
V	velocity
ϕ	porosity
ρ	density
μ	absolute viscosity
ε	small number

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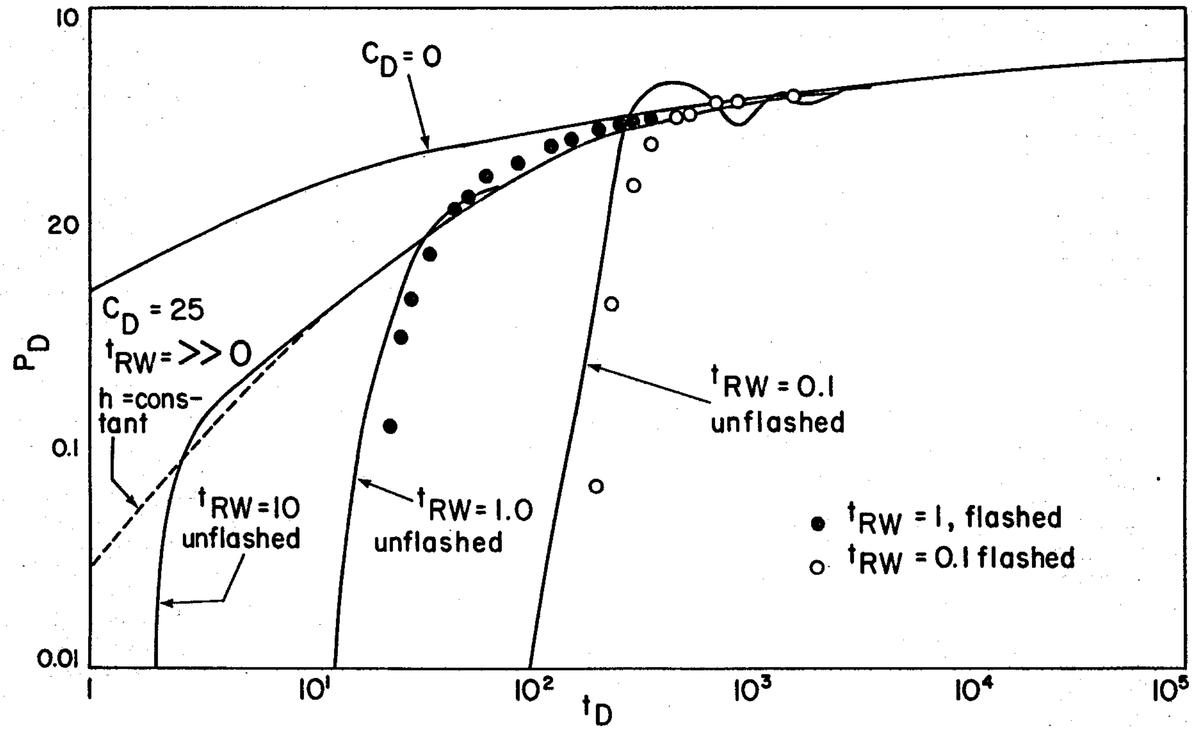

Fig. 1a - Non-dimensional plot of pressure vs. time for C_D= 25 and t_{RW}= 0.1 to 10.

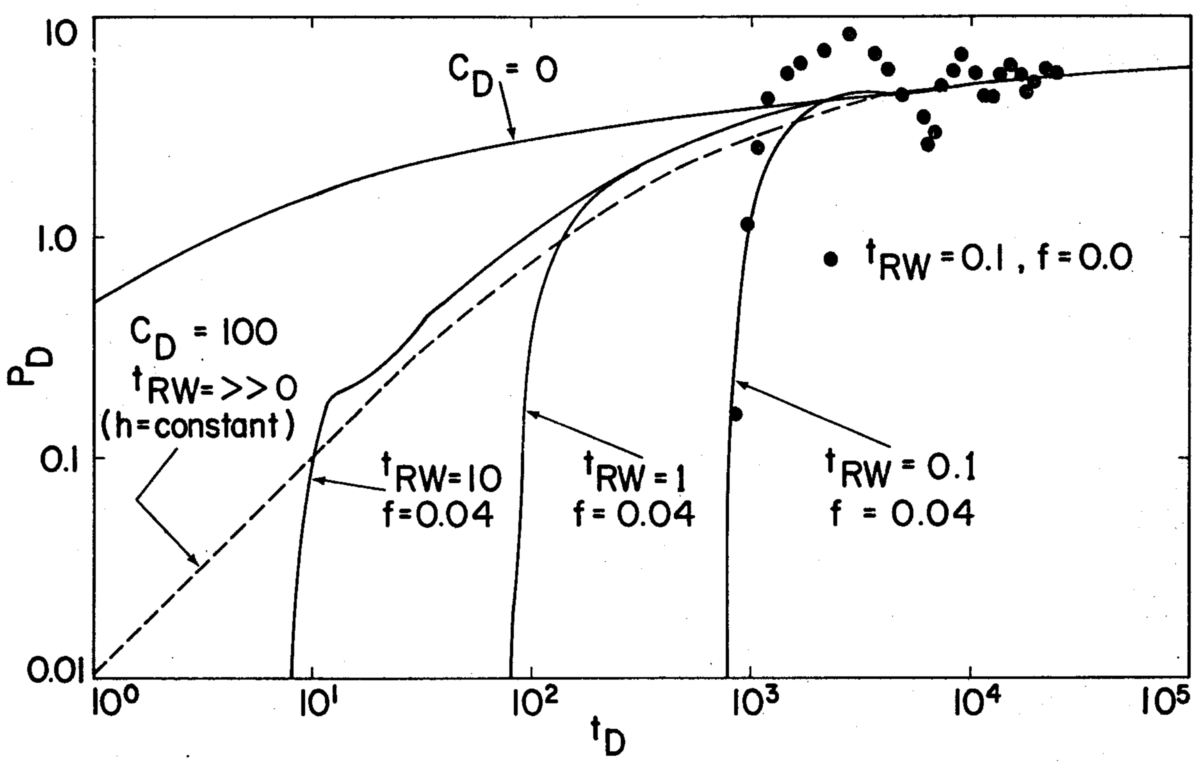

Fig. 1b - Non-dimensional plot of pressure vs. time for C_D= 100 and t_{RW}= 0.1 to 10.

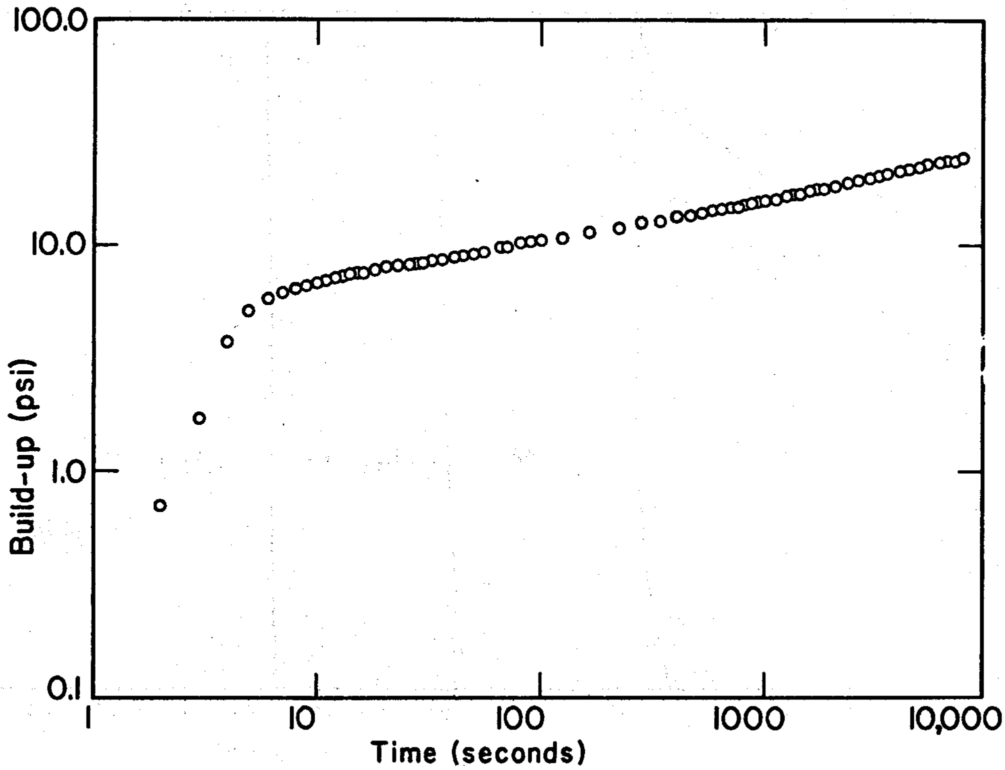

Fig. 2 - Buildup data from a geothermal well in Raft River.

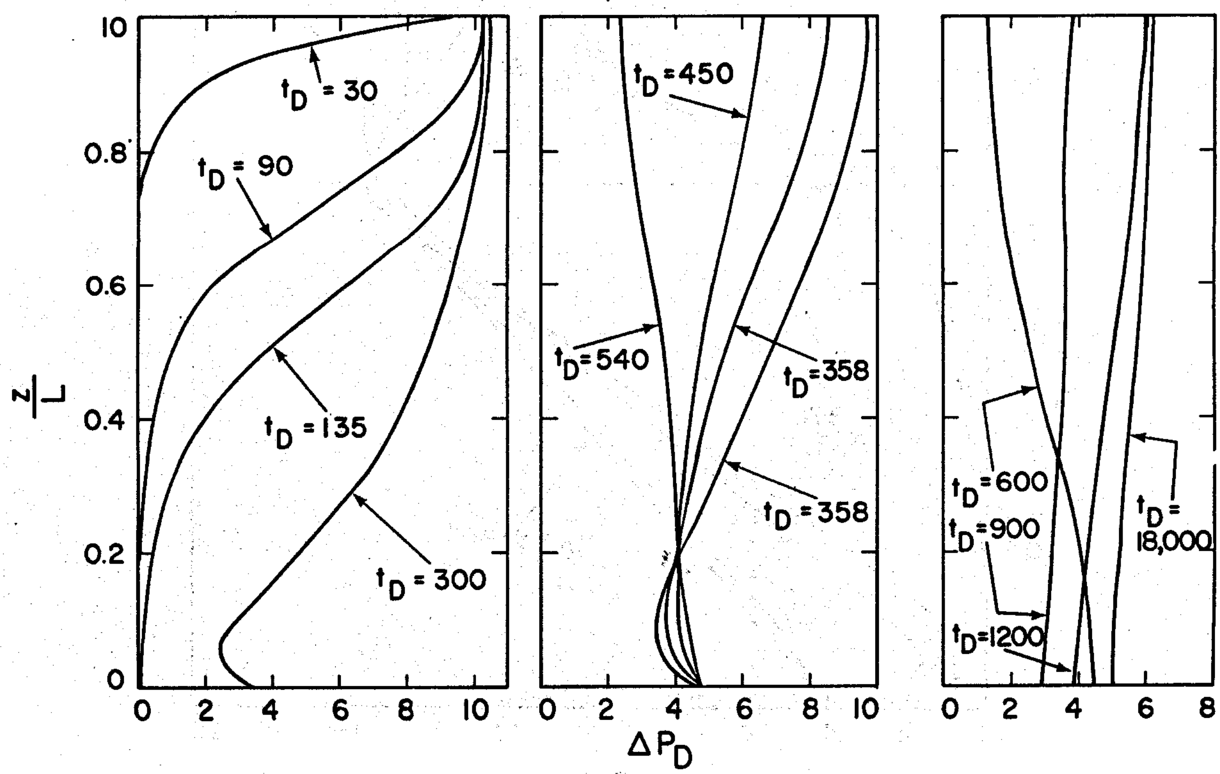

Fig. 3a - Pressure profile in a well as a function of time (t_{RW}=0.1, C_D= 25 and unflashed).

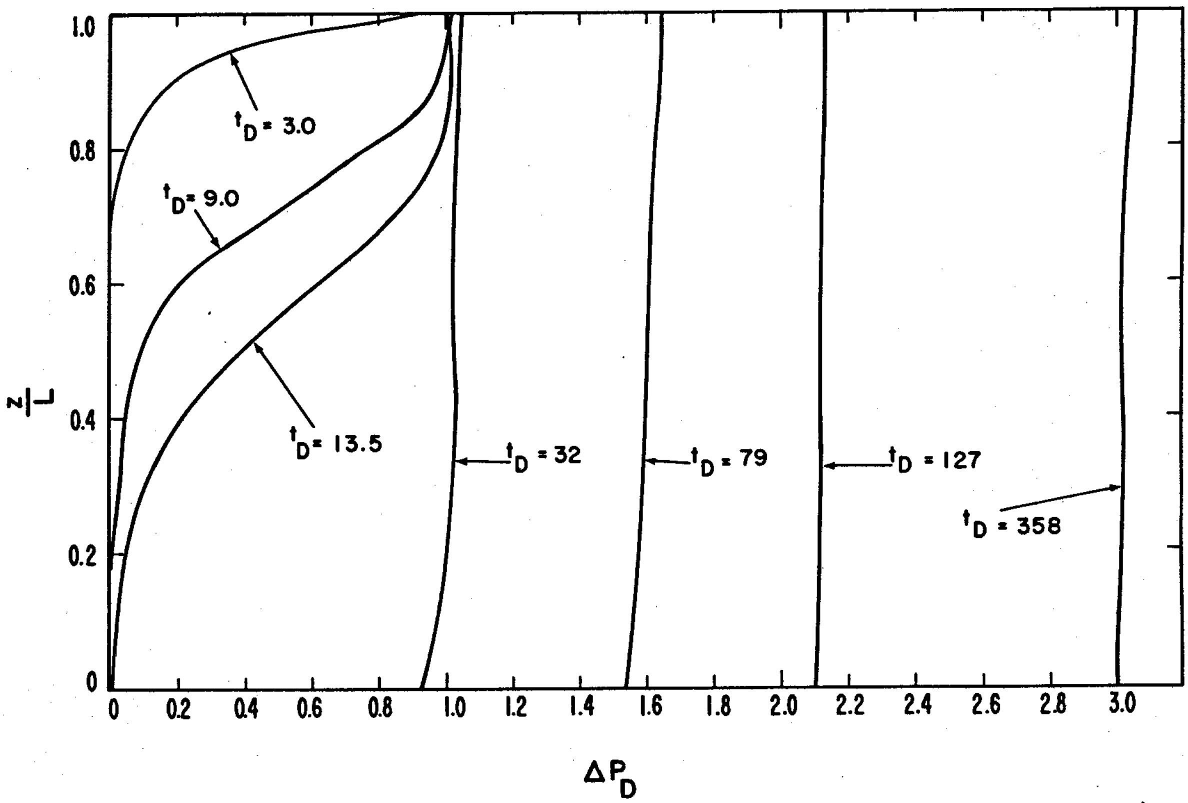

Fig. 3b - Pressure profile in a well as a function of time (t_{RW} = 1.0, C_D=25, unflashed).

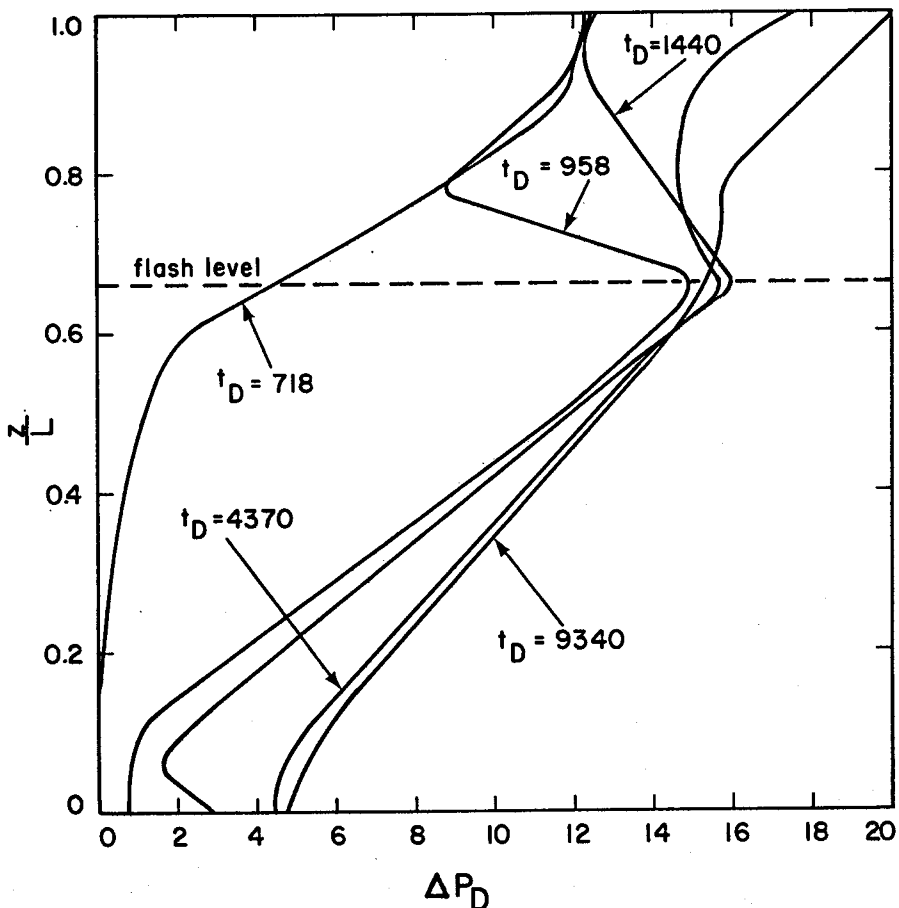

Fig. 3c - Pressure profile in a flashed well as a function of time (t_{RW}= 0.1 and C_D= 100).

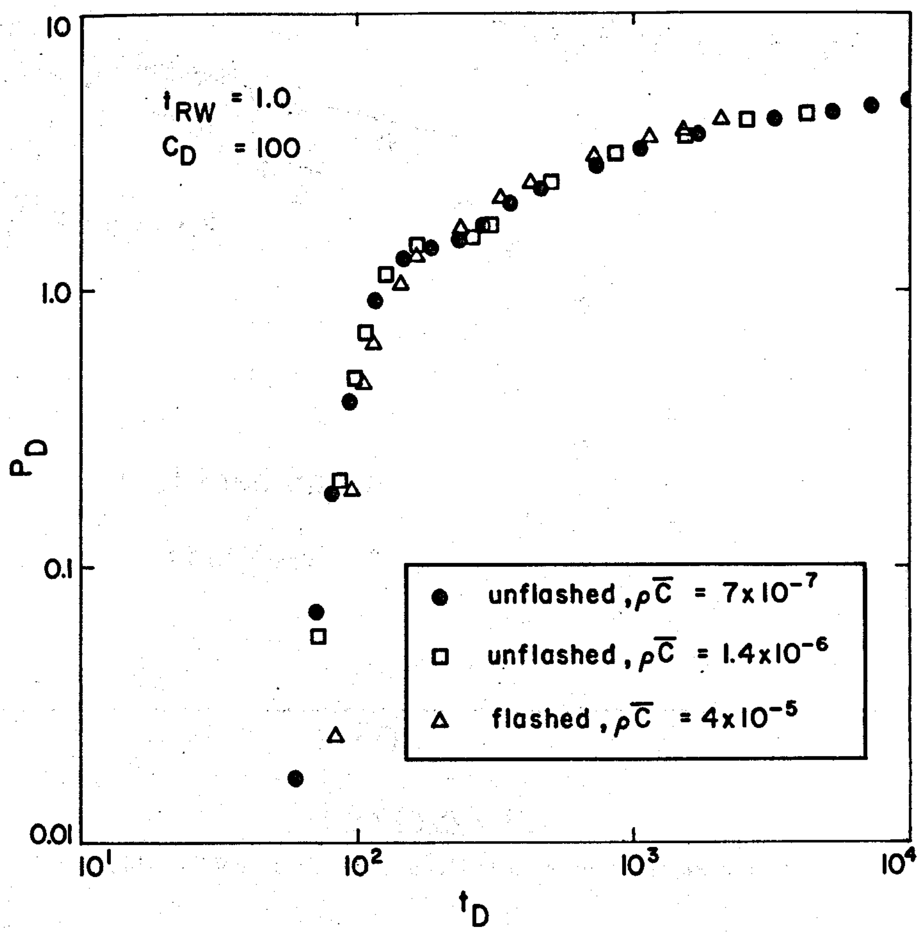

Fig. 4 - Non-dimensional plot of pressure vs time for different average compressibilities in the well.

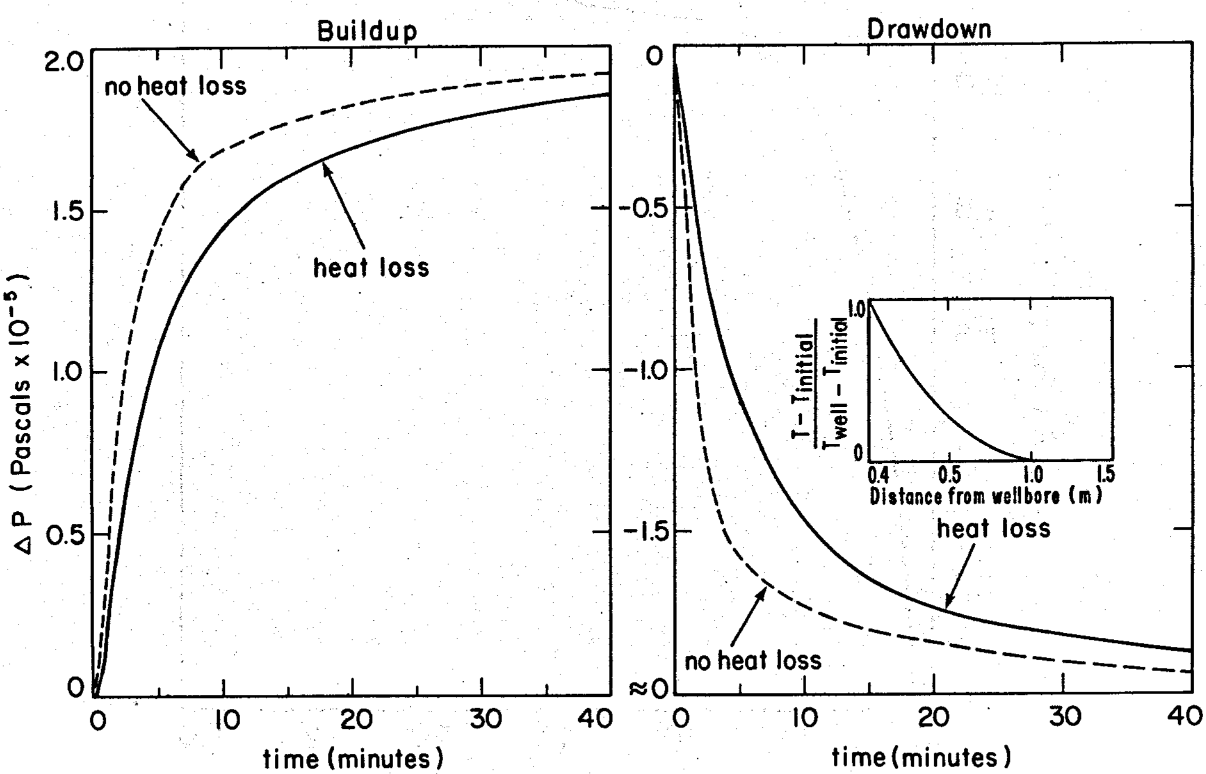

Fig. 5 - Effect of heat transfer on a buildup or a drawdown curve.

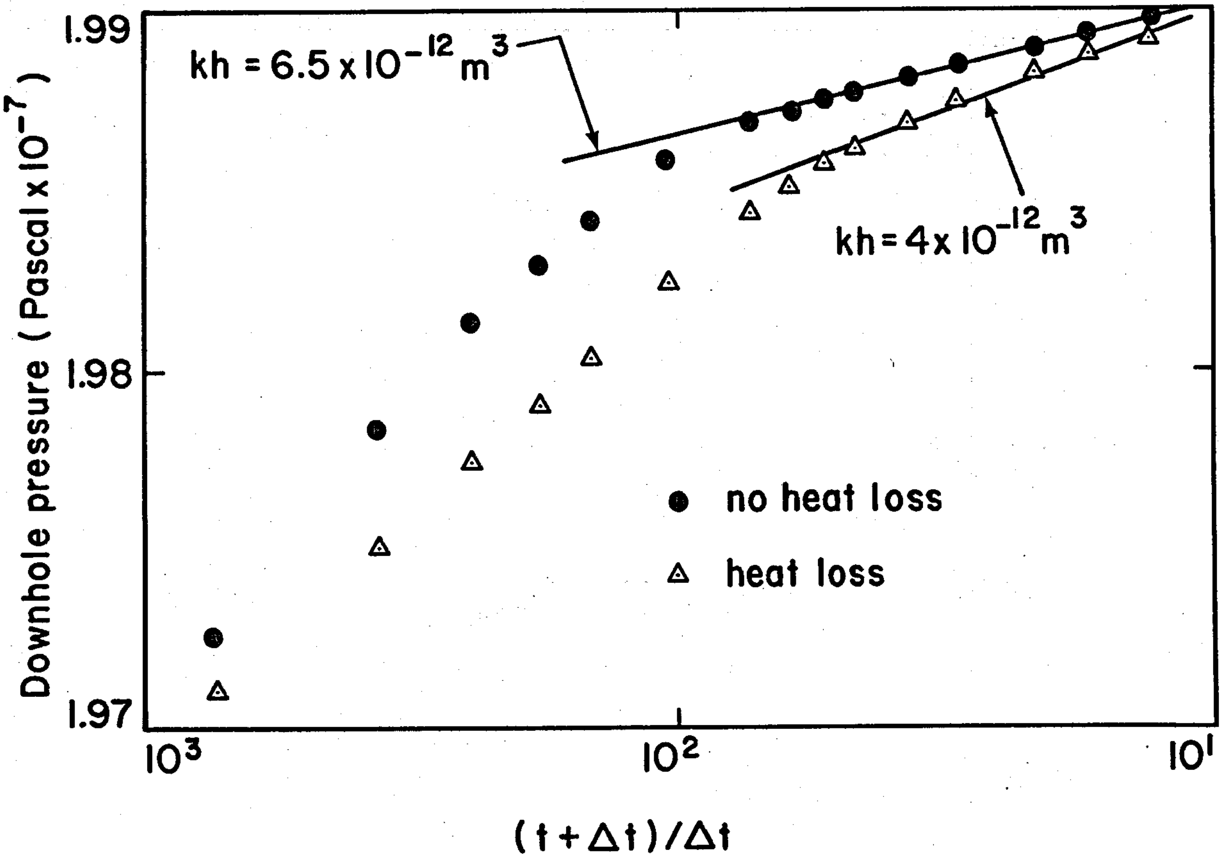

Fig. 6 - Effect of heat transfer on a buildup curve on a semilog plot.

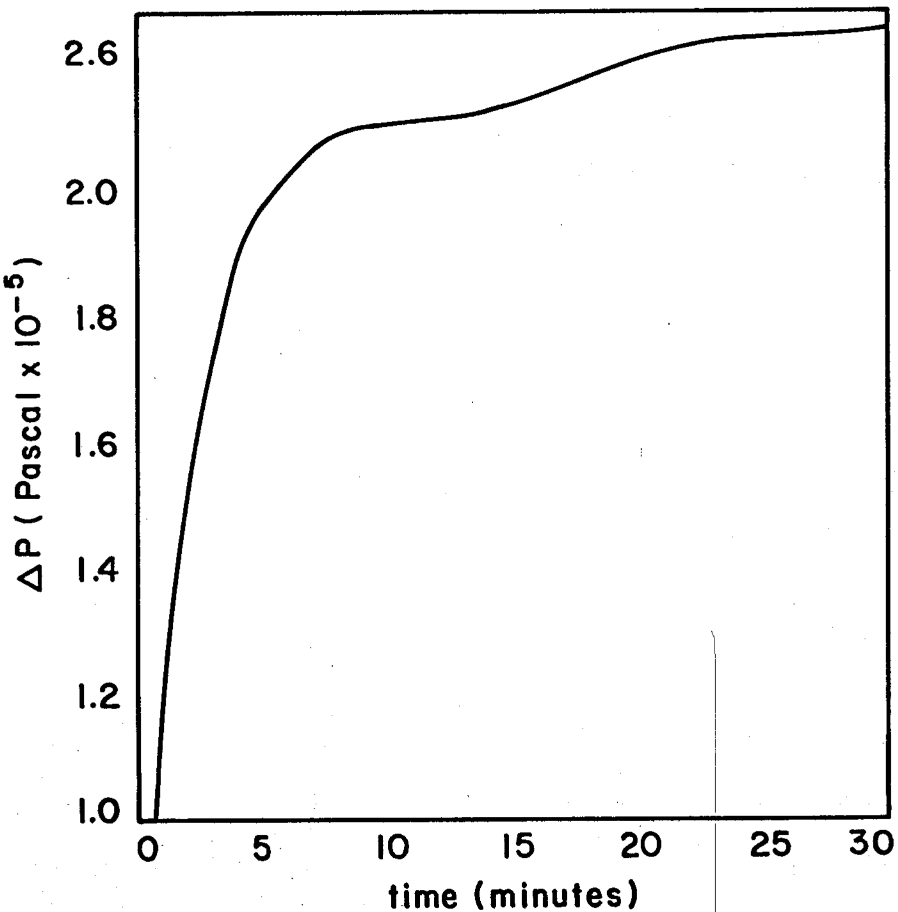

Fig. 7 - Build up curve for a flashed well at the C erro Prieto geothermal field.