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PRELIMINARY STUDIES OF TWO-PHASE EFFECTS ON PRESSURE TRANSIENT DATA

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INTRODUCTION

Presently, there are few methods available for analyzing pressure transient data from two-phase reservoirs. Methods published in the oil and gas literature (Earlougher, 1977) have been adapted for analyzing data from geothermal reservoirs, assuming a uniform initial steam saturation. However, it is well known that two-phase conditions often prevail only in parts of the reservoir, primarily in the top portion, and that vapor saturations are not uniform. Thus, there is a need to examine the pressure behavior during well tests considering more realistic conditions.

Two-phase effects are important in pressure transient analysis because the mobility of two-phase mixtures can differ significantly from that of single-phase fluids. Also, the compressibility of two-phase mixtures is orders of magnitude higher than for single-phase liquid and vapor (Grant and Sorey, 1979).

In this paper we perform scoping calculations on the effects of two-phase zones on well pressure transients. Three different cases are considered (Figure 1). The first is that of a fully two-phase system (e.g. Krafla, Iceland; Stefansson, 1981). This problem has been studied by various authors, including Moench and Atkinson (1977, 1978), Grant (1978), Garg (1978, 1980), Grant and Sorey (1979), and Aydelotte (1980). Some of the complexities of this type of system are discussed. The second problem is that of a single-phase liquid reservoir with a localized two-phase zone. Possible field examples include Cerro Prieto, Mexico and Baca, New Mexico, USA. This problem was studied by Sageev and Horne (1983a,b) and Sageev (1985); they used a constant pressure approximation for the two-phase zone. In this paper we investigate the pressure transients in a well located near an isolated two-phase zone in a single-phase liquid reservoir, and compare them to type curves based upon the constant pressure approximation. The third problem considered is that of a two-phase layer overlying a single-phase liquid layer. One example of such a reservoir is the Svartsengi geothermal field in Iceland (Gudmundsson et al., 1985). Little research has been done on pressure transients in such systems. The numerical code MULKOM (Pruess, 1983) is used to simulate the three cases.

FULLY TWO-PHASE RESERVOIR

The fully two-phase system (Figure 1, case A) is modeled with a radial, single-layer mesh with fine uniform grid spacing near the well, and logarithmically increasing grid size farther away. The grid extends sufficiently far from the well so that no boundary effects occur. The well fully penetrates the reservoir, and produces at a constant flow rate. The parameters assumed in the simulation are shown in Table 1. The accuracy of the numerical grid was verified by running a single-phase liquid case and the results compared to the conventional Theis solution (Theis, 1935). In this case the calculated transmissivity and storativity agreed with the input values to within 5%.

Various simulations were carried out using uniform two-phase initial conditions. Figure 2 shows the resulting pressure transients for an initial vapor saturation of 5%; results are given for the production well and several observation wells. The shape of the pressure transient curves is similar to the conventional Theis curve for single-phase liquids. Using the methods of Grant and Sorey (1979) and Garg (1978, 1980), these curves were matched to the Theis curve, and the total kinematic viscosity corrected to account for the two-phase effects. The total kinematic viscosity (ν_t) can be calculated with the following equation:

$$\nu_t = \left(\frac{k_{rl}\ \rho_l}{\mu_l} + \frac{k_{rv}\ \rho_v}{\mu_v} \right)^{-1} \qquad (1)$$

where μ and ρ are the viscosity and density of the different phases (l for liquid, v for vapor), and k_r is the relative permeability. The transmissivity (kH) and storativity (ϕCH) can then be calculated using conventional equations (Earlougher, 1977). Complications arise because the total kinematic viscosity depends on relative permeabilities,

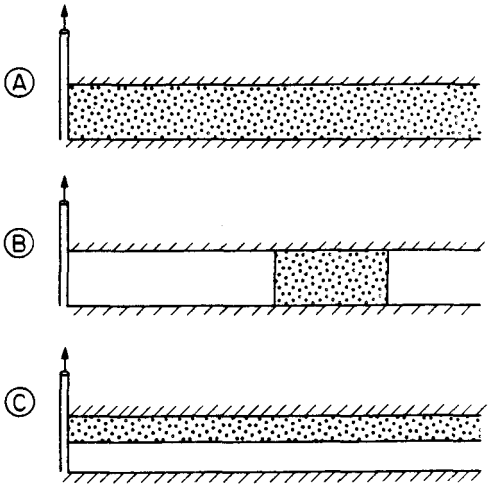

Figure 1. Problems considered: A) fully two-phase reservoir; B) isolated two-phase zone in a single-phase liquid reservoir; C) layered system.

Table 1. Parameters used in simulations.

Rock Properties	
absolute permeability	$5 \times 10^{-15} m^2$
thermal conductivity	2 J/m/s/°C
heat capacity	1000 J/kg°C
porosity	0.05
density	2650 kg/m^3
Well Parameters	
well radius	0.1 m*, 5.0 m**
production rate	25 m^3/s
distance from well to two-phase zone	500 m
Reservoir Parameters	
thickness of reservoir	500 m
size of two-phase zone	100 m^2, 1500 m^2

which presently are not well known. The sensitivity of (ν_t) to variations in the relative permeability function was investigated by Bodvarsson et al. (1980) and O'Sullivan (1981). Further studies, not described here, indicate that if one assumes different relative permeability curves from those used in the simulation, calculated values of kH and ϕCH could be off by an order of magnitude. Therefore, because of uncertainties regarding relative permeabilities, the values of kH and ϕCH for two-phase systems should only be considered as first-order estimates.

A further complication arises because the total kinematic viscosity also depends on pressure and enthalpy, which change with time. The pressure transients from both the production well and several observation wells were analyzed, assuming either initial or final pressures to investigate which value would give most accurate results. For all cases tested, the final pressures and enthalpies gave the best results, and calculated values of kH and ϕCH were within 10 to 15% of the actual values used in the simulations.

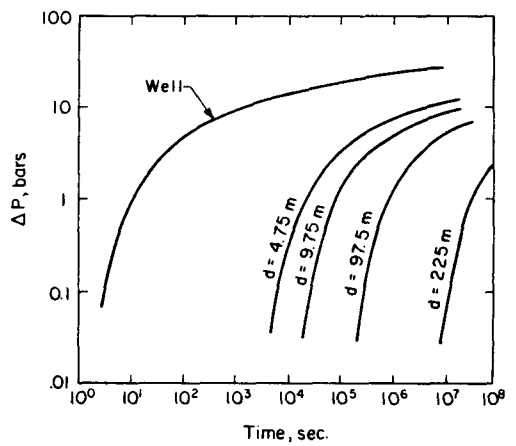

Figure 2. Pressure transients for a production well and several observation wells in a fully two-phase reservoir, where d is the distance from the production well to the observation well.

LOCALIZED TWO-PHASE ZONES

In many geothermal systems, the main single-phase liquid reservoir contains isolated two-phase zones. Field examples are Baca, New Mexico (Grant, 1979) and Cerro Prieto, Mexico (Lippmann and Bodvarsson, 1983). Analytical methods for studying pressure transient data from such systems were developed by Sageev and Horne (1983a,b) and Sageev (1985), who treated the two-phase zone as a constant pressure circular subregion (Figure 3). They justified this approximation by the high compressibility of two-phase fluids compared to that of single-phase fluids. Using this approach, Sageev and Horne (1983a,b) developed type curves for estimating the size of the circular subregion and distance from the well. In this paper we simulate the problem of an isolated two-phase subregion surrounded by a single-phase liquid region. Our primary interest is to investigate the effects of the two-phase zone on the pressure transients of a well located in the single-phase region. We also investigate the applicability of the constant pressure approximations to two-phase zones.

In order to calibrate the grid, simulations were run for the case of an actual constant pressure zone using a single layer two-dimensional mesh (Figure 4). To simplify the numerical model we use a rectangular rather than a circular subregion. Two cases are simulated, one with a large subregion (1500 m^2), and the other with a small subregion (100 m^2). Figure 5 shows the comparison of our results with those of Sageev and Horne (1983a,b) for the large constant pressure zone. The match is reasonably good at all times and enabled the calculation of the correct kH and ϕCH from the early time data. From the later time data we were able to obtain the correct distance between the well and the zone, as well as the correct size of the constant pressure zone.

The grid used to simulate the isolated two-phase zone is identical to that used for the constant pressure zone except that the internal subregion is discretized to allow for throughflow to the well. A uniform initial pressure of 100 bars is assigned to all the elements in the mesh. The

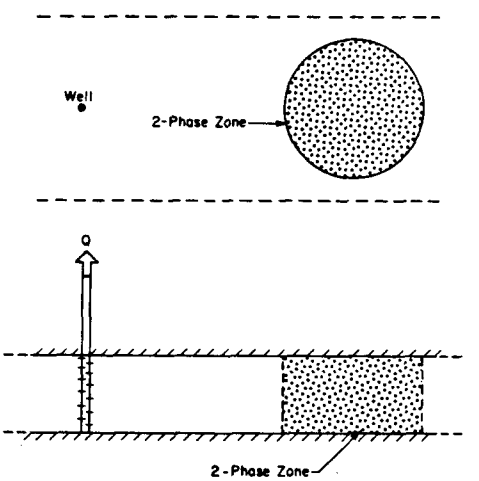

Figure 3. Top and side view of a well producing in a single-phase liquid reservoir with an isolated two-phase zone.

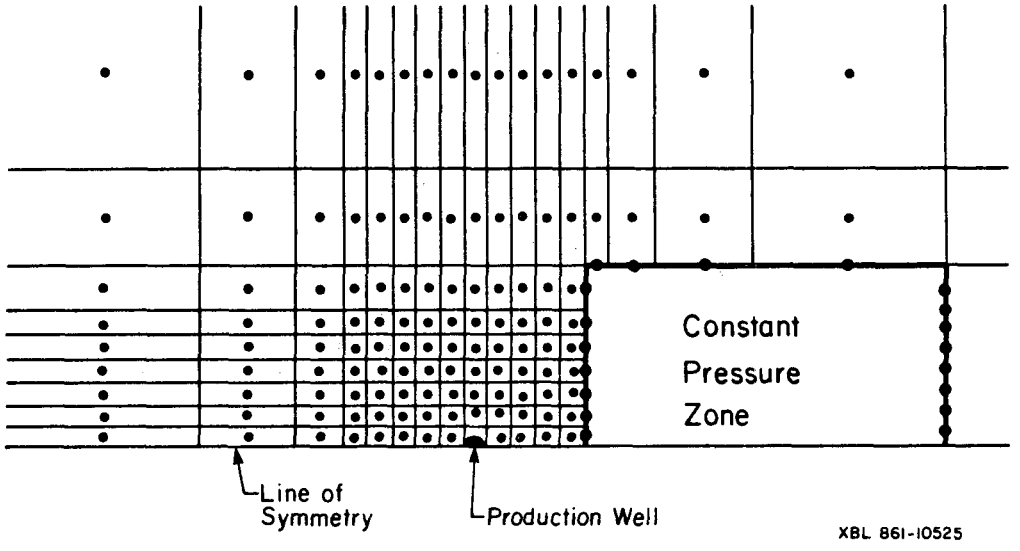

Figure 4. Two-dimensional grid used to simulate a constant pressure zone in a single-phase liquid reservoir.

single-phase outer region is assigned a uniform initial temperature of 250 °C. A uniform initial vapor saturation is assumed for the two-phase subregion. The temperature of the two-phase zone corresponding to the initial pressure is 310 °C.

Although the initial pressure distribution is stable, the initial temperature distribution is not; the temperature of the two-phase zone is about 61 °C higher than that of the outer region. Hence, conductive heat transfer will tend to equilibrate the temperatures. The effects of thermal conduction were tested by running a simulation with no production from the well. The results indicate that the effects of thermal conduction for the time periods considered in this study are minimal. After 3 years, the areal extent of the two-phase zone is reduced by about 5%, but the vapor saturation distribution is only slightly affected. However, most importantly, there is no pressure change at the well.

After confirming the stability of the initial conditions, the simulations were carried out for a period of 3 years, assuming a constant production rate. The computed pressure transients for the cases of small and large two-phase subregions are shown in Figures 6 and 7, respectively. For both cases the pressure transients differ significantly from those obtained when the constant pressure approximation is used. This is because of the higher total kinematic viscosity (and therefore lower mobility) of two-phase fluids as compared to the single-phase fluids. For times up to about 2 months, the pressure transients for the case with a large two-phase zone are similar to those of the constant

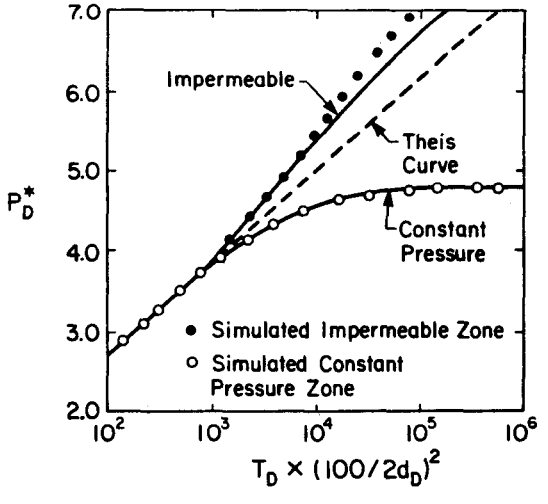

Figure 5. Comparison of the analytical (solid lines; Sageev and Horne, 1983a,b) and computer generated pressure transients for large constant pressure and impermeable zones in a liquid reservoir. XBL 862-10630

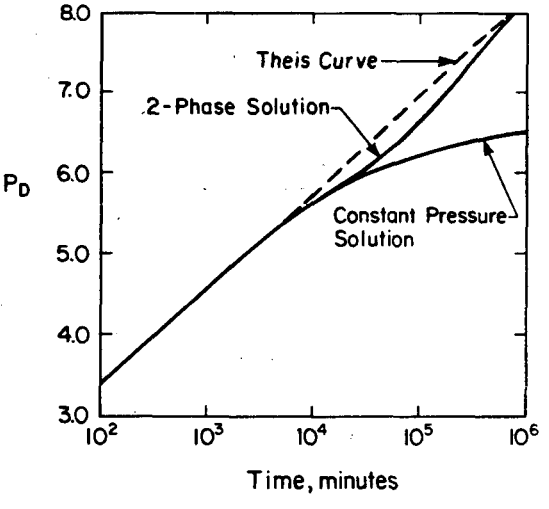

Figure 6. Computed pressure transients from a well producing in a single-phase liquid reservoir with a small two-phase zone and with a constant pressure zone. XBL 861-10508

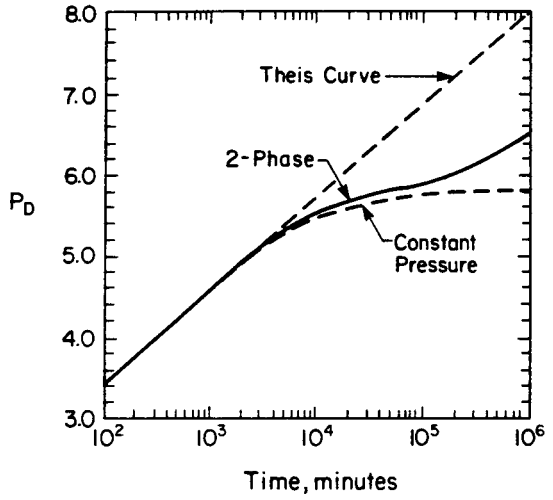

Figure 7. Computed pressure transients from a well producing in a single-phase liquid reservoir with a large two-phase zone and with a constant pressure zone. XBL 861-10507

pressure approximation. This suggests that if the two-phase zone is very large or the well is very close to it, for certain periods of time, the pressure transients will be similar to those using constant pressure approximations. The presence of the two-phase zone will cause a deviation from the Theis solution, similar to that observed for the case with a constant pressure zone. However, at later times, the relatively low fluid mobility in the two-phase zone causes much more rapid pressure changes, in some cases even resulting in a steeper slope than that given by the Theis solution.

Sensitivity Studies

From the sensitivity studies we found that the presence of the two-phase zone affects the pressure transients at the well for two primary reasons. First, the high compressibility contrast will cause a plateau in the pressure response, and second, the fluid mobility in the two-phase zone will control the late-time pressure behavior. The higher the initial vapor saturation, the higher the total kinematic viscosity of two-phase mixtures, and the lower the fluid mobility. Thus, high initial vapor saturations shorten the duration of the plateau region and cause a steepening in the late-time pressure response. Consequently, the constant pressure approximation will be significantly in error for high initial vapor saturations.

Similar effects were found using different relative permeability curves. For most of the simulations we use linear relative permeability curves (X-curves), with immobile liquid and steam cutoffs of 0.40 and 0.05, respectively. When the Corey (1954) relative permeability curves were used (with the same cutoffs), a smaller plateau and a steeper late-time slope were obtained. This is because the Corey curves give lower liquid mobilities than the X-curves. Porosity effects shift the curves along the time axis, because the total fluid storage is affected. However, for this problem porosity effects are practically negligible.

The effects of varying the distance between the well and the two-phase zone are shown in Figure 8. All of the slopes follow the Theis curve at early time, then flatten out due to the high compressibility of the two-phase zone. Finally the slopes steepen due to the low mobility of the two-phase zone. The shorter the distance between the well and the two-phase zone, the sooner the divergence from the Theis curve. Also, for a well near the two-phase zone, the flattening of the curve is more extreme, and the late-time slope is steeper. It is possible to estimate the distance from the well to the two-phase zone by analyzing the deviation time, and using a constant pressure type approximation. Data from several observation wells can be used to estimate the size of the two-phase zone.

The effects of an isolated two-phase zone on the pressure transient curve are summarized on Figure 9. The early-time slope follows the Theis curve, as the well sees only the single-phase fluids. The effect of storage in the two-phase zone is seen next; as the curve bends, its shape ressembles that of the constant pressure solution. Next, the slope steepens due to the lower mobility of the two-phase fluids. The curve eventually parallels the Theis curve, as the two-phase zone acts as a positive skin around the producing well.

LAYERED SYSTEM

The final problem considered is that of an infinite two-phase layer overlying a single-phase liquid zone. A two-layer radial grid (Figure 10) was used in the simulations. By using only two layers, we cannot accurately resolve the early time interaction between the two-phase zone and the underlying liquid region. For initial conditions we use a stable hydrostatic pressure distribution. All of the elements in the top layer have the same initial conditions ($P \approx 40$bars; $S_v = 0.10$; $T \approx 250\,^\circ$C). The bottom liquid layer initially has a temperature of 250 °C and a pressure of 60 bars. Two cases are considered, one with production from the overlying two-phase layer and the other with production from the underlying single-phase liquid layer.

The pressure transients resulting from producing fluids from the liquid zone are shown in Figure 11, for the production well and several observation wells. In all cases, the slopes of the early-time pressure transient data reflect

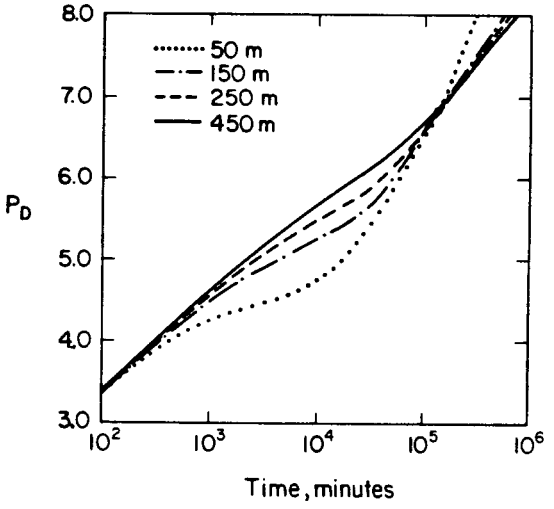

Figure 8. Simulated pressure transients from a well producing in a single-phase liquid reservoir with a two-phase zone, with varying distance between the well and the two-phase zone. XBL 861-10509

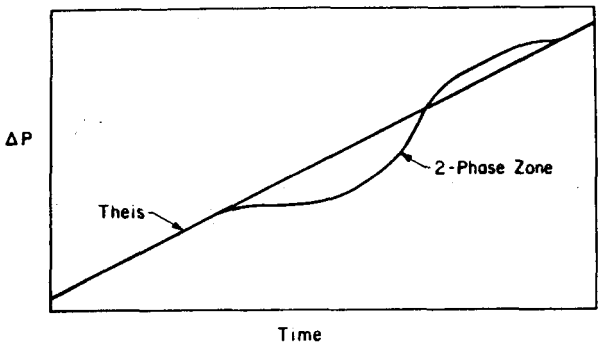

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Figure 9. Hypothetical pressure transient from a well producing in a single-phase liquid reservoir with an isolated two-phase zone.

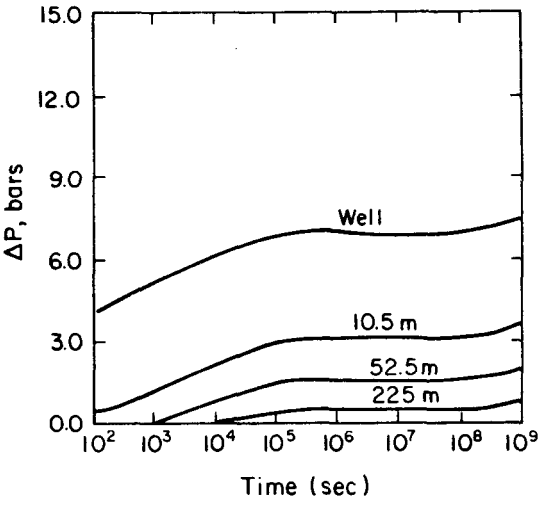

Figure 11. Computed pressure transients from a well producing from a single-phase liquid layer beneath a two-phase layer and from several observation wells at varying distances from the production well. XBL 861-10520

the liquid portion of the reservoir, and yield the correct kH and ϕCH of that layer. However, at later times the slope decreases and the pressure levels off, resembling the pressure transients for a system with a constant pressure boundary.

The cause of this behavior can be explained by the physics of the problem. Production from the liquid zone results in a pressure decrease in that zone, and fluid drainage from the overlying two-phase layer. This causes boiling and increases the vapor saturation in the two-phase zone because gravity forces will cause only the liquid and not the steam to drain downwards. The drainage and boiling in the two-phase zone causes a slight pressure drop, which in turn activates horizontal steam and liquid flow in the two-phase zone. Although this helps to maintain the downward drainage of liquid water, the steam inflow also stabilizes the pressure in the two-phase zone. The steam condenses, increasing the temperature and pressure. Thus, this steam flow tends to stabilize the pressure, so that the pressure transient curve looks similar to that resulting from a constant pressure zone. Figure 12 shows the pressure drop in the liquid zone after about 6 months of production, but no pressure changes in the two-phase zone.

The plateau in the pressure-log time plot (Figure 11) only lasts for a limited time (a few years); after that the slope increases again. This late-time increase in the slope is due to the development in the upper layer of an expanding zone with immobile liquid water. If the initial vapor saturation is large enough that the liquid is immobile everywhere in the two-phase zone, there is no drainage of liquid water, and the two-phase zone does not at all affect the pressure transients (Figure 13).

For the case of production from the two-phase zone (Figure 14), the initial slope is steeper than in the previous case, because of the lower mobility of the two-phase fluids relative to the single-phase liquid. Again, the correct kH and ϕCH can be estimated from this early-time data. At later time the two-phase zone is recharged from the liquid layer, causing a drop in enthalpy. This in turn causes pressures to stabilize and eventually increase.

The pressure increase resulting from the enthalpy decline is an interesting effect. During production, most wells produce at a constant bottom-hole pressure and not at a constant flow rate. In such tests, the recharge from the liquid layer into the two-phase layer would result in a flow rate increase. This has been observed in several two-phase geothermal fields (e.g., Krafla and Namafjall, Iceland; Stefansson and Steingrimsson, 1980).

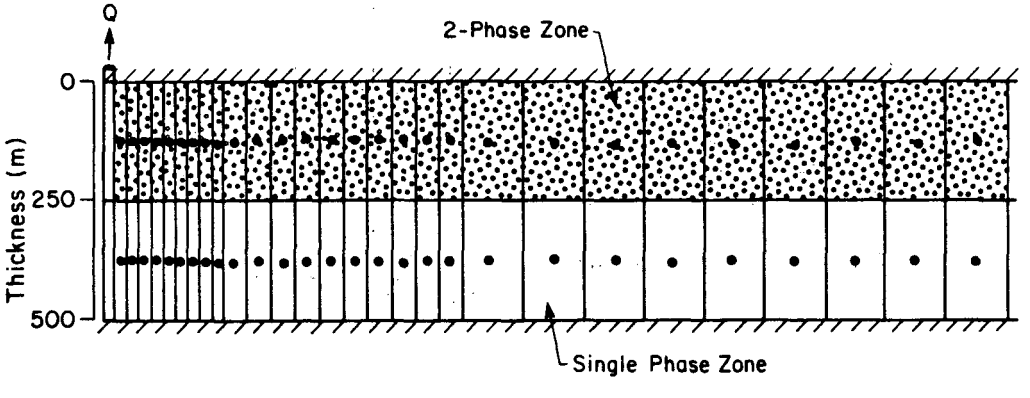

Figure 10. Radial grid used to simulate a system with a two-phase layer overlying a single-phase layer. XBL 861-10526

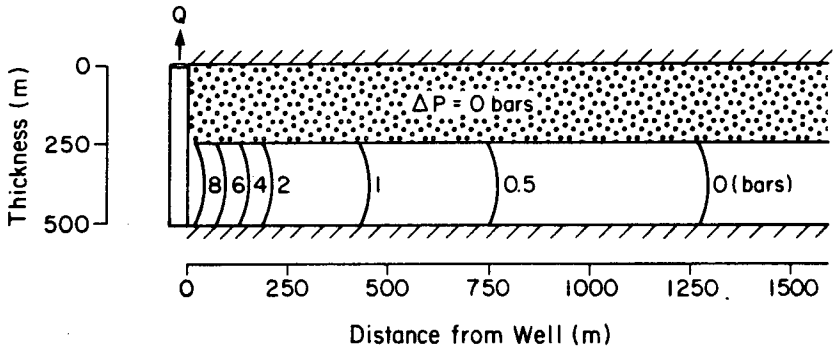

Figure 12. Pressure drawdown in a layered system after 2 years production from the underlying single-phase liquid layer. XBL 861-10513

CONCLUSIONS

We have carried out scoping calculations for several well test problems involving two-phase zones. For the fully two-phase reservoir, wrong assumptions regarding relative permeability curves can yield order-of-magnitude errors in kH and ϕCH. Therefore, pressure transient analysis methods should be used with caution. Late-time pressure and enthalpy values, yield the best estimates of kH and ϕCH.

In single-phase liquid reservoirs with an isolated two-phase zone, the constant pressure approximation generally appears not to be valid. The high storage of two-phase zones causes a bend in the semi-log pressure transient curve, followed by a steeper slope due to the relatively lower mobility of two-phase fluids. The time of deviation from the line source (Theis) solution could be used to estimate the distance between the producing well and the two-phase zone. Furthermore, data from several observation wells can be used to estimate the size of the two-phase zone.

In geothermal reservoirs with a two-phase zone overlying a single-phase liquid layer, drastically different pressure responses are obtained when feed zones are assumed to be in the liquid zone rather than in the two-phase zone. Production from the liquid zone results in pressure transients that resemble constant pressure effects. Pressure in the overlying two-phase zone remains practically constant because the 'steam phase' is trapped. If only vapor is mobile in the two-phase zone (steam cap), effects on the pressure transients in the liquid layer are negligible. Production from the overlying two-phase layer causes initially a high pressure response due to the low mobility of the two-phase mixture. Later on, recharge from the underlying liquid layer causes an enthalpy decline in the steam cap and an associated leveling (or increase) in fluid pressure. This agrees with data obtained from several two-phase geothermal fields, where flowrate increases occur at late-time.

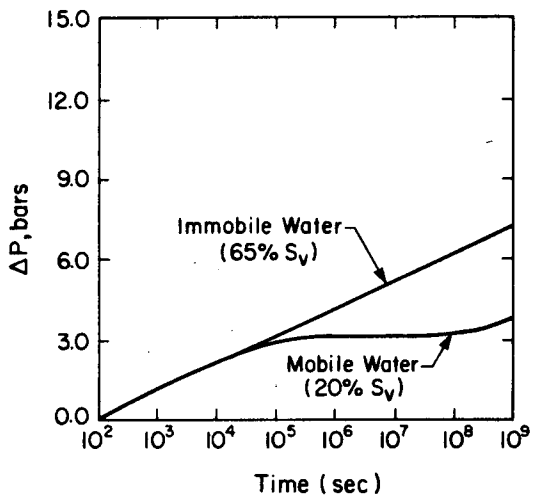

Figure 13. Computed pressure transients resulting from fluid production from the underlying liquid layer, assuming different initial vapor saturations in the overlying two-phase layer. XBL 861-10518

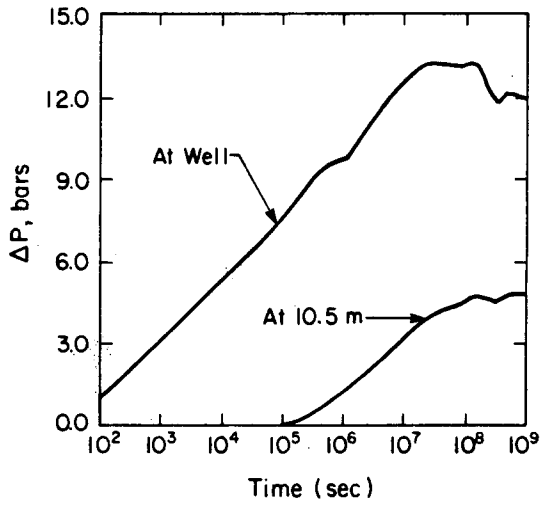

Figure 14. Computed pressure transients resulting from fluid production from the upper two-phase layer. Pressure transients shown are for a producing well and a nearby observation well. XBL 861-10519

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