INFLUENCE OF BOREHOLE CAPACITY ON PRESSURE BUILDUP DURING COLD-WATER INJECTION

NAKAO, S., YANO, Y., KIKUCHI, T., and ISHIDO, T.
Geological Survey of Japan, Higashi 1-1-3, Tsukuba 305, Japan

1. Introduction

Pressure-transient testing of wells is the standard procedure for estimating the transmissivity structure of geothermal reservoirs. While long-term discharge/buildup tests involving downhole pressure measurements in both the flowing wells and nearby shut-in observation wells are to be preferred, relatively short-term cold-water injection tests are routinely carried out shortly after well completion in Japan. Typically, substantial amounts of data of this type are obtained before long-term discharge tests are performed during the exploration and preliminary development of a new geothermal prospect. In recent years it has become common practice to employ downhole instruments which record the pressure (and occasionally temperature) of the well feedzone during and after injection testing.

2. Interpretation of Injection-Test Pressures

For a variety of reasons, the best way to establish the transmissivity (permeability-thickness product) from a test of this type is to examine the pressure history during falloff (after injection ceases). Sometimes however, falloff data are not available or are of dubious quality. In any case, it would clearly be desirable to be able to analyze the pressure buildup history during injection in order to verify the results of the falloff analysis.

Interpretation of the buildup pressure history for such a test is difficult for several reasons. First, injection rate history may be irregular and/or poorly known. Second, previous activities associated with drilling or prior injection episodes may have created a "bank" of cold fluid around the well feedzone; the present of such a pre-cooled region will influence the pressure response on buildup, but not on falloff (see Cox and Bodvarsson, 1985). Third, the character of the buildup response will often depend upon whether the system is most accurately regarded as a "porous medium" or a "fracture network". Again, on falloff, these ambiguities are absent.

In this paper, an additional complication is examined. Cold water injection tests are usually of only a few hours duration, and the total quantity of injected fluid may represent only a few wellbore volumes. For example, a well 1500 meters deep lined with 9 5/8" casing will hold about 60 tons of cold water. At injection rates typically employed in preliminary well testing, this quantity of fluid would require 1 hour or more to inject. The difficulty is that the standing water within the well prior to the test has presumably had some substantial period of time to heat up by heat transfer from the surrounding geothermal reservoir. When injection begins and cold water starts to enter the wellhead, the fluid entering the formation at bottomhole will not cool to wellhead temperature until a quantity of fluid comparable to the the borehole capacity has been injected. Therefore, for a period of time which may not be negligible compared to the total test duration, hot water will be injected into the reservoir. This paper discusses some of the consequences concerning pressure-transient interpretation of buildup data from injection tests.

3. Typical Pressure-Buildup Solutions

To examine this problem, we consider a very idealized situation. We will treat an aquifer of constant thickness (H), horizontal orientation, uniform formation properties, and unbounded lateral extent. The aquifer is bounded above and below by impermeable surfaces, and contains a single fully-penetrating vertical well of radius R_W. Thus, the problem is one-dimensional in space. Initially, the pressure (P_0) and temperature (T_0) are uniform. At $t = 0$, injection begins (at a constant flow rate M_0), but the temperature of the injected fluid is initially equal to the reservoir temperature. This continues until $t=t^*$, at which time the temperature of the injected fluid changes to T_i (the cold water injection temperature). The initial pressure (P_0) is sufficient that the flow remains single-phase liquid throughout.

While an approximate analytical solution for the above problem may be developed if the reservoir consists of a classical porous medium, the problem is much more complex if the reservoir made up of relatively impermeable country rock penetrated by a fracture network. Here we consider both cases. Solutions were obtained numerically (even for the porous medium case, to facilitate comparison of results) using the TOUGH reservoir simulator (K.Pruess, 1985). For the porous-medium case, thermal equilibrium was assumed between rock and fluid. To represent fractured systems, we assume that the system consists of regularly spaced horizontal fractures as indicated in Figure 1. In these cases, the porous country rock was assumed to occupy 99% of the system volume, and the highly permeable fractured zone the remaining 1%. Cases were run with fracture separations (D) of 0.1m, 0.3m, and 1.0m for comparison with the porous-medium case (equivalent to D=0). The fractured system calculations were carried out by the MINC method (Pruess and Narasimhan, 1982). The overall radial transmissivity and storativity were the same in all cases. for simplicity, the well skin factor and the compressibility of the rock were taken as zero. The initial reservoir temperature was 270°C; after $t = t^* = 1$ hour the temperature was changed to 100°C. Other pertinent problem parameters are listed in Table 1. The first grid block in the numerical grid (0.1m in space) represents the well itself, and is characterized by very high porosity and permeability. The grid block size increases geometrically, with $r_{i+1} = 1.2\ r_i$, so that the outer radius of the grid (50 blocks) exceeds three kilometers. This is sufficient that no pressure signal reached the outer boundary during the 24-hour period studies.

Figure 2 shows the pressure-buildup history for all four cases (D = 0, 0.1, 0.3, 1.0 meters), the vertical axis represents the increase in the well-block pressure relative to the initial value, and the horizontal axis measures the logarithm of time since injection began. The classical line-source solution indicates that the solution for constant injection temperature will be a straight line with slope;

$$dP/d(\log_{10}t) = 2.303\ M_0 \nu / 4\pi kH$$

where M_0 is injection rate, kH is the permeability-thickness product, and ν is a kinematic viscosity. For a porous-medium reservoir, the proper value to use for ν is that for the injected cold fluid (ν_{cold}). Cox and Bodvarsson(1985) have shown that, for fractured reservoirs at late times, the proper value of ν is given by the average of injected and reservoir fluid viscosities. For the present case, the various kinematic viscosities of water are;

$$\nu_{cold}(100°C) = 3.0 \times 10^{-7}\ m^2/s$$
$$\nu_{hot}(270°C) = 1.3 \times 10^{-7}\ m^2/s$$
$$\nu_{avg} = 2.2 \times 10^{-7}\ m^2/s\ .$$

These computations (Figure 2) show that, with the injection temperature changing from 270°C to 100°C at $t = t^* = 1$ hour, the solutions are characterized by these distinct regions. Prior to t = 1 hour, of course, a constant slope region associated with $\nu = \nu_{hot}$ is observed. Then, pressures increase very rapidly for a short time in all cases. Finally, another straight-line region is approached. For the porous-medium and D = 0.1m cases (which are essentially indistinguishable), this asymptotic slope is associated with $\nu = \nu_{cold}$. For D = 1 m, on the other hand, the fluid slope is associated with $\nu = \nu_{avg}$. For D = 0.3m, transition between $\nu = \nu_{avg}$ and $\nu = \nu_{cold}$ behavior is observed; at intermediate times, the asymptotic slope is associated with $\nu = \nu_{avg}$ but the final slope is associated with $\nu = \nu_{cold}$. The time required for the transition between the two slopes in the fractured cases seems to increase with fracture spacing (D). For small fracture separations, the time of transition is small compared to t^*.

4. Conclusion

The calculations presented here have shown that, for practical test durations, the downhole pressure response to a cold water injection test (into a hot aquifer) will consist of three portions when pressure disturbance is plotted as a function of the logarithm of time. The first is a straight-line portion of which the slope is dictated by the viscosity of hot water. This initial period lasts until approximately one wellbore volume has been injected. Next, when cold water begins to enter the formation, pressure begins to increase very rapidly. The slope of the [P - log(t)] curve becomes very steep. Finally, at later times, another asymptotic straight-line region is approached. In the porous-medium case, or the fractured-medium case when its fracture spacing is not too great, the slope of this late-time asymptotic region will be governed by the viscosity of cold water. For larger fracture separations, the average viscosity should be used.

Of these regions, only the first and the last have any potential utility for practical test interpretation. Furthermore, in practice the first straight-line region may not provide good result owing to thermal wellbore storage effects which may make the actual injection rate history (into the formation) difficult to relate to the wellhead injection rate.

It appears that only the final asymptotic straight-line region is likely to provide a reasonable basis for buildup-phase injection test interpretation. It is very important to notice, however, that in both the porous-medium and fracture-network cases, the slope of the asymptotic region does not begin to become apparent until at least ten wellbore volumes of fluid have been injected. This means that it is essential to inject at least this much cold water (and preferably more) to have any hope whatever of interpreting the buildupportion of the injection test. If insufficient fluid is injected, it is quite likely that the steeply-slope transition region will be mistaken for the asymptotic-slope portion, resulting in erroneous (and very pessimistic) estimates of reservoir permeability.

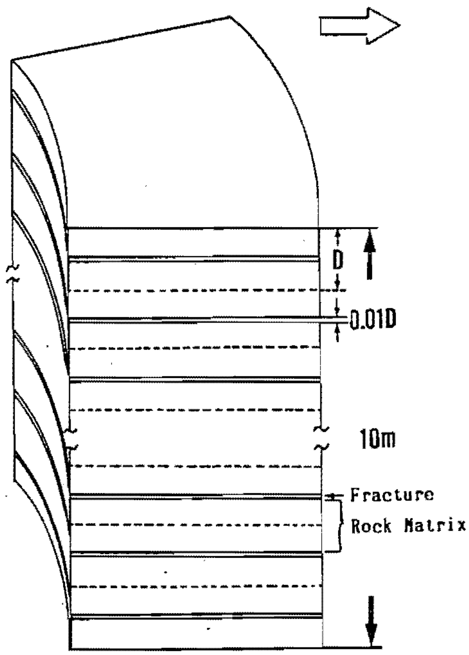
5. References

Cox, B. L. and Bodvarsson, G. S., "Nonisothermal Injection Tests in Fractured Reservoirs", Proceedings Tenth Workshop on Geothermal Reservoir Engineering, Stanford Univ., pp.151-162, 1985.

Pruess, K. and Narasimhan, T. N., "A Practical Method for Modeling Fluid and Heat Flow in Fractured Porous Media", J. Geophys. Res., Vol. 87, 9329-9339, 1982.

Table 1 Parameters used in simulations

Initial Conditions		Porous reservoir	
Pressure, MPa	10.0	Porosity	0.1
Temperature, °C	270	Permeability, m^2	10^{-13}
Fixed Rock Properties		Fractured reservoir	
Grain density, kg/m^3	2650	Porosity of fracture block	0.595
Thermal conductivity, W/(kg°C)	2.0	Porosity of matrix block	0.095
Specific heat, J/(kg°C)	1000	Permeability of fracture block, m^2	10^{-11}
		Permeability of matrix block, m^2	10^{-18}
Well parameters			
Porosity	0.99		
Permeability, m^2	10^{-12}		
Injection rate, kg/sec	5		



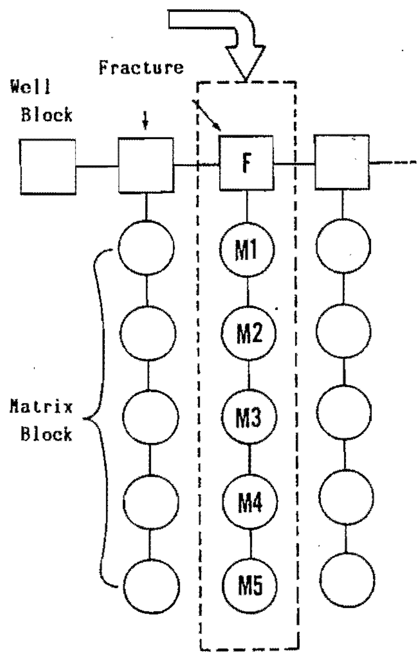


Fig.1 Fractured reservoir model geometry (left diagram) and MINC-mesh (right diagram) for radial flow problems.

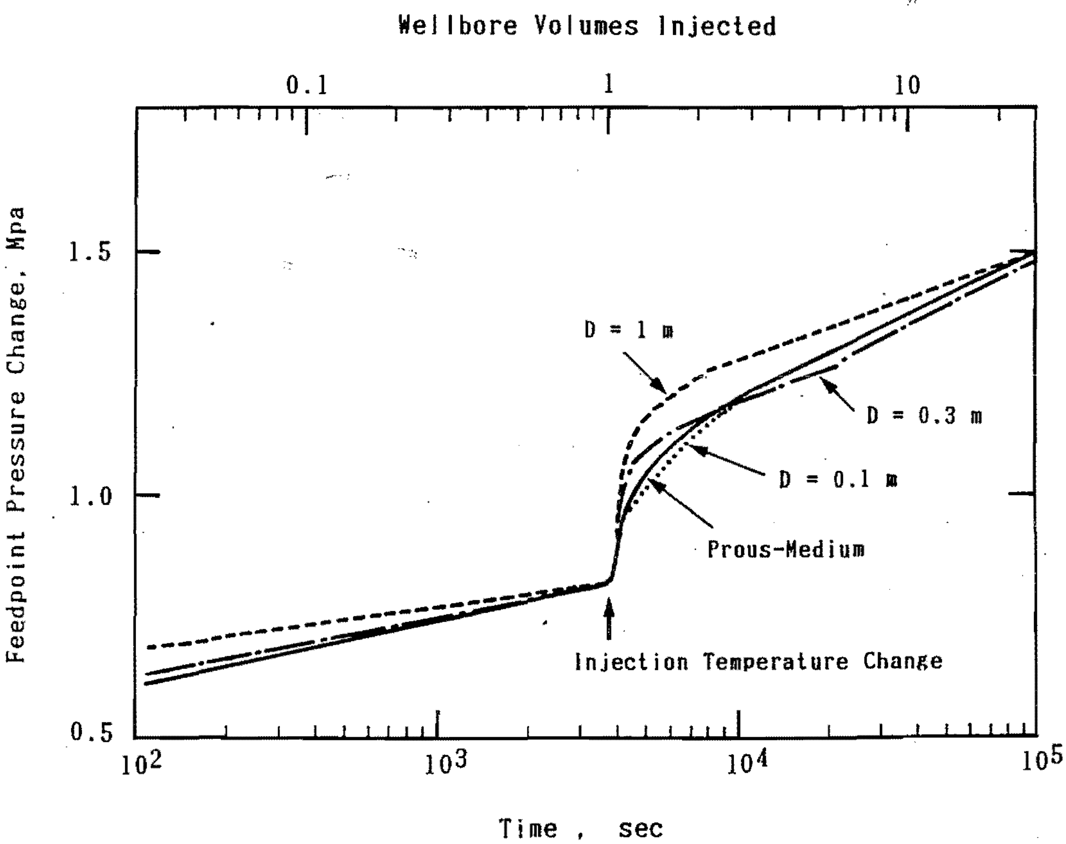


Fig.2 Computed pressure buildup history.