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BACA GEOTHERMAL DEMONSTRATION PROJECT

MASTER

PRESSURE TRANSIENT ANALYSIS FOR HOT WATER AND
TWO-PHASE GEOTHERMAL WELLS: SOME NUMERICAL RESULTS

TOPICAL REPORT

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ABSTRACT

A geothermal reservoir simulator has been employed in a series of calculations which describe the response of geothermal reservoirs to fluid production/injection from a single well. The numerical solutions were analyzed to generate interpretation techniques for pressure transient data from either single-phase or two-phase geothermal reservoirs. The investigations include (1) the drawdown/buildup response of hot water wells, (2) the drawdown/buildup behavior of initially two-phase (liquid water/steam) reservoirs, (3) the drawdown/buildup response of initially single-phase reservoirs which undergo flashing as a result of fluid production and (4) the effect of cold water injection into single-phase and two-phase reservoirs.

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SECTION 1: INTRODUCTION

1.1 Introduction

The line source solution (or Theis solution) has been traditionally used in hydrology and petroleum engineering to analyze pressure transient data from isothermal single-phase (water/oil/gas) and isothermal two-phase (oil with gas in solution, free gas) reservoir systems. For a constant flow rate well test, a plot of pressure drop versus logarithm of time asymptotes to a straight line after a short initial period. The slope and intercept of this line yield the mobility-thickness product and the total formation compressibility. The total formation compressibility depends upon, among other variables, fluid compressibility. Although very often it is not explicitly stated, the fluid compressibility in traditional applications is the one measured at constant temperature.

Extension of the Theis solution to analyze pressure transient data from geothermal reservoirs involves several difficulties. Geothermal reservoirs by their very nature contain fluid at elevated temperatures. Very often the in situ fluid is either boiling or near boiling. For single-phase hot liquid reservoirs, it is not self-evident whether or not the isothermal fluid compressibility is the appropriate one. (This question will be examined in detail in Section 2, and it will be shown that the isothermal fluid compressibility should be replaced by isenthalpic fluid compressibility at elevated temperatures.) In recent years, several investigators (Garg [1978], Grant [1978], Moench and Atkinson [1977]) have examined the production (or drawdown) behavior of two-phase geothermal reservoirs. The geothermal reservoir may be initially two-phase or may evolve into a two-phase reservoir as a result of fluid production. The plot of pressure drop versus logarithm of time asymptotes to a straight line after an initial non-linear period; the slope of the straight line can be used to calculate the kinematic mobility-thickness product. The intercept

of the straight line, however, provides a very poor approximation of the total formation compressibility which is primarily governed by phase change effects. Sorey, et al. [1980] have also numerically examined the buildup behavior in initially two-phase reservoirs; the plot of pressure versus $\log [(t+\Delta t)/\Delta t]$ (t = production time, Δt = shutin time) gives a straight line. The slope of this straight line again can be related to the kinematic mobility-thickness product; the kinematic mobility-thickness product calculated from buildup data is, however, different from that obtained from drawdown data due to nonlinear effects in two-phase non-isothermal flow. These nonlinear effects imply that the superposition principle does not apply in two-phase geothermal systems. As the present time, there exists little or no information in the literature on either the (1) buildup response of initially single-phase reservoirs which undergo flashing as a result of fluid production, or (2) the effect of cold water fluid injection into two-phase geothermal reservoirs.

The numerical results presented in the report form a theoretical framework which will be used in interpreting the flow data from the production/injection wells at the Baca Geothermal Demonstration Power Plant (GDPP) Project. The application of the techniques to the data from the Baca wells will be the subject of a separate topical report. The results contained herein, however, are of fundamental interest to geothermal reservoir engineers and applicable to other geothermal systems.

1.2 Scope of the Report

The main purpose of this report is to develop interpretation techniques for pressure transient data from either single-phase or two-phase geothermal reservoirs. More specifically, the Systems, Science and Software (S^3) reservoir simulator CHARGR (Pritchett [1980]) will be employed in a series of one-dimensional radial flow problems to investigate (1) the drawdown/buildup response of hot water wells, (2) the drawdown/buildup behavior of initially two-phase reservoirs, (3) the drawdown/buildup response of initially

single-phase reservoirs which undergo flashing as a result of fluid production and (4) the effect of fluid injection into single-phase and two-phase reservoirs. The numerical results are employed to generate guidelines for calculating mobility-thickness product from pressure transient data.

1.3 Summary and Conclusions

The numerical simulations presented herein demonstrate some of the difficulties associated with analyzing pressure transient data from hot water and two-phase geothermal reservoirs. It is demonstrated that production data (drawdown/buildup) from single-phase hot water and initially two-phase reservoirs may be analyzed in the usual manner to yield absolute permeability/kinematic mobility provided the total formation compressibility is defined differently from its conventional usage in petroleum engineering and hydrology. Drawdown data from initially single-phase reservoirs which undergo flashing during production can be made to give two-phase kinematic mobility; the buildup data from such reservoirs offers the possibility of determining absolute formation permeability. It is further shown that injection data for single-phase and two-phase reservoirs can be interpreted in a straightforward manner to give absolute formation permeability; the fall-off data (especially in two-phase systems) appear, however, to be of lesser utility.

1.4 Recommendations for Future Study

This report contains the results of theoretical calculations simulating transient production and injection testing of single-phase and two-phase reservoirs. The simulations provide a quantitative understanding of the phenomena which may be expected to occur during the pressure testing of wells in such a reservoir. The results are of direct relevance to the Baca reservoir system and will be used by S^3 in evaluating the available flow test data for the Baca wells.

SECTION 2: THEORETICAL PRODUCTION BEHAVIOR ANALYSES

2.1 Introduction

In this section numerical simulations are presented which describe the production data (drawdown/buildup) for a single well producing fluid from a geothermal reservoir. The S³ geothermal reservoir simulation CHARGR is used to study all-liquid reservoirs, initially two-phase reservoirs and initially single-phase reservoirs which undergo flashing as a result of fluid production.

2.2 Summary

It is demonstrated that production data from single-phase hot water and initially two-phase reservoir may be analyzed, respectively, to yield absolute formation permeability and two-phase kinematic mobility. Drawdown data from initially single-phase reservoirs which undergo flashing during production can be made to give kinematic mobility; the buildup data may be used to determine absolute permeability.

2.3 Production Behavior of Hot Water Reservoirs

The classical methods of analyzing groundwater and petroleum fluid production data may be extended to interpret single-phase geothermal fluid production data. However, the extension requires a careful examination of the fluid compressibility factor which occurs in the classical solution. In this section it is shown that for hot water reservoir flow data it is necessary that the isenthalpic fluid compressibility be used instead of the isoenergetic or isothermal fluid compressibility. Both drawdown and buildup flow tests are simulated.

2.3.1 Background of Theory

In groundwater hydrology and petroleum engineering, the line source solution to the linearized diffusivity equation is used to interpret pressure transient data. For constant rate of mass production M , the pressure at the bottom of the well $p_w(t)$ is given by

$$p_w(t) = p_i + \frac{Mv}{4\pi Hk} \text{Ei} \left[-\frac{r_w^2 \phi \rho C_T v}{Hkt} \right], \quad (2.1)$$

where

- p = initial reservoir pressure
- v = kinematic fluid viscosity
- H = formation thickness
- r_w = well radius
- ρ = fluid density
- k = absolute formation permeability
- ϕ = porosity
- t = time
- C_T = total formation compressibility
 $(= \frac{1-\phi}{\phi} C_m + C)$
- C_m = uniaxial formation compressibility
- C = fluid compressibility

If $\frac{4tk}{\phi r_w^2 \rho v C_T} > 100$, Equation (2.1) can be approximated as follows:

$$p_w(t) = p_i - \frac{1.15 vM}{2\pi Hk} \left[\log \frac{kt}{\phi r_w^2 \rho v C_T} + 0.351 \right] \quad (2.2)$$

Equation (2.2) implies that a plot of p_w versus $\log t$ should be a straight line. If m denotes the slope of this straight line, then

$$k = \frac{1.15 vM}{2\pi Hm} \quad (2.3)$$

$$C_T = \frac{kt}{\text{antilog} \left[\frac{p_i - p_w(t)}{m} - 0.351 \right]} \cdot \frac{1}{\phi r_w^2 \nu \rho} \quad (2.4)$$

Superposition can be utilized to construct solutions for buildup (i.e., shutin after production for time t). The solution implies that a plot of p versus $\log(t+\Delta t/\Delta t)$ (Δt = shutin time) should be a straight line. The slope of the straight line can be used, together with Equation (2.3), to calculate formation permeability. (In the above, consideration of skin effect and well storage have been ignored. These effects, while important in practical well testing, are not germane to the present discussion.)

The fluid compressibility C can be defined in a number of ways (at constant internal energy C_E ; at constant temperature C_t ; at constant enthalpy C_h).

$$C_E = \frac{1}{\rho} \left(\frac{\partial \rho}{\partial p} \right)_E \quad (2.5)$$

$$C_t = \frac{1}{\rho} \left(\frac{\partial \rho}{\partial p} \right)_T \quad (2.6)$$

$$C_h = \frac{1}{\rho} \left(\frac{\partial \rho}{\partial p} \right)_h \quad (2.7)$$

Table 2.1 gives liquid water compressibilities as a function of pressure and temperature. (Note that the data in Table 2.1 are based on S³ CHARGR equation-of-state for water (Pritchett [1980]), and may be in error by a few percent. Nevertheless, it is believed that the relative values of C_E , C_t and C_h are approximately correct.) At 0°C, all three compressibilities are practically identical; thus for groundwater or petroleum reservoirs it is of little concern as to which fluid compressibility is used. However, at elevated temperatures characteristic of geothermal systems, substantial differences do exist between the different

Table 2.1

CONSTANT ENERGY (c_E), ISOTHERMAL (c_t), AND ISENTHALPIC (c_h) COMPRESSIBILITIES FOR LIQUID WATER AS GIVEN BY THE S^3 CHARGE EQUATION-OF-STATE.

All compressibilities are in GPa^{-1} ($1\text{GPa}^{-1} = 10^{-9} \text{Pa}^{-1}$)

T(°C)	0			50			100			150			200			250			300		
P(MPa)	c_E	c_t	c_h	c_E	c_t	c_h	c_E	c_t	c_h	c_E	c_t	c_h	c_E	c_t	c_h	c_E	c_t	c_h	c_E	c_t	c_h
0.1	0.491	0.491	0.495	0.411	0.424	0.512	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2.5	0.490	0.490	0.497	0.411	0.424	0.512	0.416	0.465	0.597	0.499	0.602	0.753	0.624	0.820	0.970	-	-	-	-	-	-
5.0	0.490	0.490	0.498	0.410	0.423	0.512	0.415	0.464	0.595	0.498	0.600	0.750	0.622	0.815	0.964	0.831	1.27	1.32	-	-	-
7.5	0.489	0.489	0.498	0.410	0.423	0.512	0.415	0.463	0.594	0.497	0.598	0.747	0.620	0.810	0.959	0.826	1.25	1.31	-	-	-
10.0	0.488	0.488	0.499	0.409	0.422	0.512	0.414	0.462	0.592	0.496	0.596	0.744	0.618	0.806	0.954	0.821	1.24	1.30	1.24	2.49	2.01
12.5	0.488	0.488	0.500	0.409	0.422	0.512	0.413	0.461	0.590	0.495	0.594	0.741	0.616	0.801	0.948	0.817	1.23	1.28	1.22	2.42	1.97
15.0	0.487	0.487	0.501	0.409	0.422	0.512	0.413	0.460	0.589	0.493	0.592	0.738	0.614	0.797	0.943	0.812	1.21	1.27	1.21	2.35	1.94

compressibilities. One may speculate that for hot water reservoirs, isenthalpic fluid compressibility C_h is the appropriate one to use in the definition for total formation compressibility.

Hot water flow in geothermal reservoirs follows a complex thermodynamic path. Although the variations in internal energy, temperature, and enthalpy are small, they do nevertheless occur. The fluid flow cannot be simply treated as isoenergetic, isothermal or isenthalpic. The flowing enthalpy does, however, approach a definite limit as $r \rightarrow 0$ or $t \rightarrow \infty$. (It is worth emphasizing that the constancy of enthalpy means that internal energy and temperature must be varying.) The equations governing one-dimensional radial flow will now be considered to prove that

$$\lim_{\substack{r \rightarrow 0 \\ \text{or } t \rightarrow \infty}} h_f \rightarrow h_{f0} .$$

Assuming that (1) the rock porosity depends only on the fluid pressure, (2) the rock matrix and the fluid are in local thermal equilibrium (3) the global heat conduction is negligible, and (4) the fluid flow is governed by Darcy's law, the balance equations for mass and energy in radial geometry can be written as follows:

Mass (liquid)

$$\frac{\partial}{\partial t} (\phi \rho) - \frac{1}{r} \frac{\partial}{\partial r} \left[\frac{rk}{v} \frac{\partial p}{\partial r} \right] = 0 \quad (2.8)$$

Energy

$$\frac{\partial}{\partial t} \left[(1-\phi) \rho_r h_r + \phi \rho h - \phi p \right] - \frac{1}{r} \frac{\partial}{\partial r} \left[\frac{rk}{v} h \frac{\partial p}{\partial r} \right] = 0 \quad (2.9)$$

where

ρ_r = rock grain density,
 h_r = rock enthalpy.

The differential equations (2.8) and (2.9) are subject to the following boundary and initial conditions:

Boundary Conditions

$$\lim_{r \rightarrow 0} r \frac{\partial p}{\partial r} = - \frac{M_v}{2\pi H k} \quad (2.10)$$

$$\lim_{r \rightarrow \infty} p = p_i, \quad h = h_i \quad (2.11)$$

Initial Conditions

$$t = 0: \quad p = p_i, \quad h = h_i \quad (2.12)$$

Following O'Sullivan [1980], the similarity variable η is introduced:

$$\eta = r^{0.5}/t \quad (2.13)$$

Substituting from (2.3) into (2.8)–(2.12), one obtains the following transformed equations:

Mass

$$\frac{d(\phi \rho)}{d\eta} + \frac{2}{\eta} \frac{d}{d\eta} \left[\frac{k}{v} \eta \frac{dp}{d\eta} \right] = 0 \quad (2.14)$$

Energy

$$\frac{d}{d\eta} \left[(1-\phi) \rho_r h_r + \phi \rho h \right] - \phi \rho + \frac{2}{\eta} \frac{d}{d\eta} \left[\frac{k}{v} h \eta \frac{dp}{d\eta} \right] = 0 \quad (2.15)$$

Boundary and Initial Conditions

$$\lim_{\eta \rightarrow 0} \eta \frac{dp}{d\eta} = - \frac{M_v}{2\pi H k} \quad (2.16)$$

$$\lim_{\eta \rightarrow \infty} p = p_i, \quad h = h_i \quad (2.17)$$

Also, note that

$$\frac{d\phi}{dp} = (1-\phi)c_m, \quad (2.18)$$

$$h = c_r T \quad (2.19)$$

where T is the common local temperature of the rock matrix and the pore fluids, and c_r is the rock grain heat capacity.

Regarding p and h as independent thermodynamic variables and utilizing (2.18) and (2.19), Equations (2.14) and (2.15) may be algebraically manipulated to yield:

$$\phi \rho \left\{ \frac{1-\phi}{\phi} c_m + c_h - \frac{1}{\rho} \left(\frac{\partial \rho}{\partial h} \right)_p \frac{(1-\phi) \rho_r c_r \left(\frac{\partial T}{\partial p} \right)_h - (1-\phi) c_m (\rho_r h_r + p) - \phi}{(1-\phi) \rho_r c_r \left(\frac{\partial T}{\partial h} \right)_p + \phi \rho + \frac{2}{n} (k/v) \frac{dp}{dn}} \right\} \\ \cdot \frac{dp}{dn} + \frac{2}{n} \frac{d}{dn} \left[\left(\frac{k}{v} \right)_n \frac{dp}{dn} \right] = 0 \quad (2.20)$$

$$\frac{dh}{dn} = - \frac{\left\{ (1-\phi) \rho_r c_r \left(\frac{\partial T}{\partial p} \right)_h - (1-\phi) c_m (\rho_r h_r + p) - \phi \right\}}{(1-\phi) \rho_r c_r \left(\frac{\partial T}{\partial h} \right)_p + \phi \rho + \frac{2}{n} \left(\frac{k}{v} \right) \frac{dp}{dn}} \cdot \frac{dp}{dn} \quad (2.21)$$

Equations (2.16) and (2.21) can be combined to give:

$$\lim_{n \rightarrow 0} \frac{dh}{dn} = 0 \quad (2.22)$$

Equation (2.22) demonstrates that the fluid enthalpy approaches a constant value in the limit $n \rightarrow 0$ (i.e., in the limit $r \rightarrow 0$ or $t \rightarrow \infty$). Since

$$\lim_{n \rightarrow 0} n \frac{dp}{dn} \neq 0,$$

Equation (2.22) also implies that internal energy E and temperature T are varying even as $t \rightarrow \infty$.

Although Equation (2.22) is only valid as $\eta \rightarrow 0$, it is now assumed that $dh/d\eta = 0$ is a reasonable approximation to use in interpreting pressure transient data. With Equation (2.22) and taking k/v to be constant, Equation (2.21) leads to the usual diffusivity equation:

$$\phi \rho C_T \frac{dp}{d\eta} + \frac{2}{\eta} \frac{k}{v} \frac{d}{d\eta} \eta \frac{dp}{d\eta} = 0 \quad (2.23)$$

with

$$C_T = \frac{1-\phi}{\phi} C_m + C_h \quad (2.24)$$

The solution of Equation (2.23) subject to the boundary conditions, Equations (2.16 and (2.17)), is identical with the classical Theis solution.

2.3.2 Single-Phase Reservoir Production Behavior

To test the validity of the preceding theory, the S^3 reservoir simulator CHARGR was exercised in its one-dimensional radial mode. The radially infinite reservoir was simulated using a 60-zone [$\Delta r_1 = 0.11$ m; $\Delta r_2 = 1.2 \Delta r_1$; $\Delta r_3 = 1.2 \Delta r_2$, ..., $\Delta r_{60} = \Delta r_{59}$] radial grid. The outer radius of the grid is 25,825 m and is sufficiently large such that no signal reaches this boundary for production/shutin periods. The formation thickness is $H = 250$ m. The well is assumed to be coincident with Zone 1. (In the CHARGR code, a well can be represented as an integral part of the grid by assigning to the well-block sufficiently high permeability and porosity.) The reservoir rock is assumed to be a typical sandstone. The relevant rock properties are given in Table 2.2. (Although the present problem is purely single-phase, Table 2.2 also lists relative permeabilities, and residual liquid and

Table 2.2
ROCK PROPERTIES EMPLOYED IN NUMERICAL SIMULATION

	<u>Well-Block</u> (i = 1)	<u>Rock Matrix</u> (2 ≤ i ≤ 60)
Porosity, ϕ	0.9999	0.1
Permeability, $k(m^2)$	50×10^{-12}	5×10^{-14}
Uniaxial Formation Compressibility, $C_m(MPa^{-1})$	0	0
Rock Grain Density, $\rho_r(kg/m^3)$	1	2650
Grain Thermal Conductivity, $K_r(W/m-^{\circ}C)$	0	5.25
Heat Capacity, $c_r(kJ/kg^{\circ}C)$	0.001	1
Relative Permeability (k_{rl}, k_{rg})	Straight Line*	Corey**
Residual Liquid Saturation, S_{lr}	0	0.3
Residual Gas Saturation, S_{gr}	0	0.05

* $k_{rl} = S_l$, $k_{rg} = S_g = 1 - S_l$, $S_l(S_g)$ = liquid (gas) volume fraction.

** $k_{rl} = \frac{(S_l^*)^4}{(S_l - S_{lr}) / (1 - S_{lr} - S_{gr})}$, $k_{rg} = \frac{(1 - S_l^{*2})(1 - S_l^*)^2}{(1 - S_{lr} - S_{gr})}$, $S_l^* =$

vapor saturations for later use in sections on two-phase flow.) The mixture (rock/fluid) thermal conductivity is approximated by Budiansky's formula (Pritchett [1980]).

The initial formation pressure and temperature are 9.3917 MPa and 300°C respectively. The reservoir is produced at a constant rate of 35 kg/s for $t = 5.868 \times 10^5$ s, and is then shut in for $\Delta t = 1.3932 \times 10^6$ s⁺. Figures 2.1 and 2.2 show the calculated drawdown and buildup response of the well. The drawdown curve has a slope m of 0.0644×10^6 Pa/~. With $\nu = 1.244 \times 10^{-7}$ m²/s (= kinematic viscosity of fluid at initial reservoir pressure and temperature), we obtain for formation permeability k

$$k = \frac{1.15 \nu M}{2\pi H m} = \frac{1.15 \times 1.244 \times 35 \times 10^{-7}}{2\pi \times 250 \times 0.0644 \times 10^6} \sim 4.95 \times 10^{-14} \text{ m}^2$$

The slope of the buildup curve ($\sim 0.0653 \times 10^6$ Pa/~) yields $k = 4.88 \times 10^{-14}$ m². Both drawdown and buildup data thus yield permeability values in close agreement with the actual permeability of 5.00×10^{-14} m². With $\rho = 713.9$ kg/m³ (fluid density at initial reservoir conditions), the following is obtained for total formation compressibility C_T (= fluid compressibility C since $C_m = 0$):

$$\begin{aligned} C_T &= \frac{1}{\phi r_w^2 \nu \rho} \frac{kt}{\text{antilog} \left[\frac{p_i - p_w(t)}{m} \right] - 0.351} \\ &= \frac{1}{0.1 (0.11)^2 1.244 \times 10^{-7} \times 713.9} \frac{4.95 \times 10^{-14} \times 5 \times 10^5}{\text{antilog} \left[\frac{9.3917 - 8.8490}{0.0644} \right] - 0.351} \\ &= 1.93 \text{ GPa}^{-1} \end{aligned}$$

⁺ For the various cases discussed in the following sections, the grid, formation properties, production (injection) rate, drawdown (injection) time and shut in (falloff) time specified in this section will be used. The initial fluid state will, however, vary from case to case.

Figure 2.1. Drawdown data for hot water geothermal reservoir ($p_i = 9.3917 \text{ MPa}$, $T_i = 300^\circ\text{C}$).

Figure 2.2. Buildup data for hot water geothermal reservoir ($p_i = 9.3917 \text{ MPa}$, $T_i = 300^\circ\text{C}$).

The calculated fluid compressibility value is in reasonable agreement with the isenthalpic fluid compressibility ($\sim 2.01 \text{ GPa}^{-1}$) but is considerably different from the isoenergetic ($\sim 1.24 \text{ GPa}^{-1}$) and isothermal ($\sim 2.49 \text{ GPa}^{-1}$) compressibilities. This verifies the speculation that the isenthalpic fluid compressibility should be used in the definition for total formation compressibility. Finally, for the sake of completeness, Figure 2.3 shows the enthalpy variation with $1/n^2$. Although $\max |\Delta h/h|$ ($0.20/1344 \sim 1.5 \times 10^{-4}$) is very small, the fluid does undergo enthalpy changes. Furthermore, Δh (and hence h) approaches a constant value for $1/n^2 > 10^4$ (or $n < 10^{-2}$).

2.4 Production Behavior of Initially Two-Phase Geothermal Reservoirs

Approximate analytical solutions of limited applicability have been presented for cases in which a geothermal reservoir, initially boiling everywhere is produced at a constant rate. In this section detailed numerical results are presented for two cases simulating the response of such two-phase geothermal reservoirs. The bottomhole fluid pressure and temperature variations with time are examined as well as the radial distributions of flowing kinematic viscosity and steam saturation at selected times. Both drawdown and buildup flow tests are simulated.

2.4.1 Background of Theory

Recently Garg [1978], Grant [1978] and Moench and Atkinson [1977] have examined the drawdown response of initially two-phase geothermal reservoirs. The plot of pressure drop versus logarithm of time asymptotes to a straight line after an initial nonlinear period; the slope m of the straight line is related to the kinematic mobility as follows:

$$(k/v)_t = \frac{1.15 M}{2\pi H m} \quad (2.25)$$

where

Figure 2.3. Enthalpy variation as a function of $1/n^2$ for hot water reservoir.

$$(k/v)_t = k/v_t \quad (2.26)$$

$$\frac{1}{v_t} = \frac{k_{rl}}{v_l} + \frac{k_{rg}}{v_g} \quad (2.27)$$

Given flowing enthalpy h_f , it also is possible to obtain the separate liquid- and vapor-phase kinematic mobilities.

$$\frac{kk_{rl}}{v_l} = (k/v)_t \left[\frac{h_g - h_f}{h_g - h_l} \right]; \quad \frac{kk_{rg}}{v_g} = (k/v)_t \left[\frac{h_f - h_l}{h_g - h_l} \right] \quad (2.28)$$

The intercept of the straight line can be used to calculate an effective total formation compressibility C_T ; however, as noted by Garg [1978] and Sorey, et al. [1980], the inferred value often provides a very poor approximation to the actual value.

Sorey, et al. [1980] have numerically investigated the buildup behavior in initially two-phase reservoirs; the plot of pressure versus logarithm of time gives a straight line. The slope of the straight line can be used to calculate total kinematic mobility from Equation (2.25). The kinematic mobility inferred from the buildup data is, however, different from the one given by drawdown data; this illustrates the nonlinear nature of two-phase flow in porous media. Sorey, et al. also observed over-recovery of liquid saturation near the wellbore during buildup.

2.4.2 Two-Phase Reservoir Production Behavior

In the following, two cases will be considered in which the reservoir, initially boiling everywhere, is produced at a constant rate. The initial fluid state is given in Table 2.3.

Table 2.3
INITIAL FLUID STATE FOR TWO-PHASE CASES

<u>Case No.</u>	<u>Pressure, MPa</u>	<u>Steam Sat.</u>	<u>Enthalpy (kJ/kg)</u>
A.1	8.5917	0.28	1466
A.2	8.5917	0.05	1345

Figures 2.4 and 2.5 show the drawdown and the flowing enthalpy data. The drawdown data closely fit a straight line; the slope of the straight line m yields the flowing kinematic viscosity v_t .

$$v_t = \frac{2\pi H m}{1.15 M} k \quad (2.29)$$

The inferred values of v_t (Figures 2.4 and 2.5) are representative of a large region surrounding the producing well (see Figures 2.8 and 2.9) wherein $\partial S_g / \partial r$ is small (Figures 2.10 and 2.11). After an initial nonlinear period, the flowing enthalpy approaches a more or less constant value (Figures 2.4 and 2.5) as predicted by the linear theory of Grant [1979a]; the flowing enthalpy does, however, undergo small fluctuations even at late times. With $h_l = 1345$ kJ/kg and $h_g = 2749$ kJ/kg (values corresponding to 8.5917 MPa), the separate liquid- and vapor-phase relative permeabilities as calculated from Equation (2.28) are given in Table 2.4.

The calculated relative permeability values are representative of the reservoir region wherein $\partial S_g / \partial r$ is small. Agreement between the calculated and inferred values (especially gas) could be improved by evaluating v_l and v_g at actual bottom-hole conditions.

The pressure and temperature buildup data are given in Figures 2.6 and 2.7. For the high saturation case (case A.1), pressure buildup data fit a straight line; the inferred v_t from the straight line is characteristic of the two-phase region (see Figure 2.8). In the low-saturation case (case A.2), more than one straight line can be fit to the pressure buildup data indicating a nonlinear buildup response; the calculated v_t 's can, however, still be identified with those obtained in the two-phase region (Figure 2.9). Figures 2.10 and 2.11 show the vapor saturation distribution at different times; during buildup substantial liquid over-recovery is seen. The condensation front (Figures 10 and 11) eventually engulfs most of the reservoir region affected during the

Table 2.4

CALCULATION OF LIQUID- AND VAPOR-PHASE RELATIVE PERMEABILITIES

Case	h_f (kJ/kg)	h_l (kJ/kg)	h_g (kJ/kg)	$\frac{kk_{rl}}{v_l}$ (s)	$\frac{kk_{rg}}{v_g}$ (s)		
A.1	2158	1345	2749	1.41×10^{-8}	1.95×10^{-8}		
A.2	1414	1345	2749	7.70×10^{-8}	0.40×10^{-8}		
Case	v_l (m ² /s)*	v_g (m ² /s)*	k_{rl}	k_{rg}	k_{rl} (actual)	k_{rg} (actual)	
A.1	1.245×10^{-7}	4.283×10^{-7}	0.035	0.167	0.033 - 0.056	0.27 - 0.20	
A.2	1.245×10^{-7}	4.283×10^{-7}	0.192	0.034	0.18 - 0.25	0.69 - 0.042	

* Values at $P \sim 8.5917$ MPa, $T \sim 300^\circ\text{C}$

Figure 2.4. Pressure drawdown and flowing enthalpy for case A.1 ($p_i = 8.5917 \text{ MPa}$, $S_{gi} = 0.28$, $h_i = 1466 \text{ kJ/kg}$).

Figure 2.5. Pressure drawdown and flowing enthalpy for case A.2 ($p_i = 8.5917 \text{ MPa}$, $S_{gi} = 0.05$, $h_i = 1345 \text{ kJ/kg}$).

Figure 2.6. Pressure and temperature buildup data for case A.1.

Figure 2.7. Pressure and temperature buildup data for case A.2.

Figure 2.8. Radial distribution of flowing kinematic viscosity ν_t at selected times for case A.1.

Figure 2.9. Radial distribution of flowing kinematic viscosity v_t at selected times for case A.2.

Figure 2.10. Radial distribution of steam saturation S_g at selected times for case A.1.

Figure 2.11. Radial distribution of steam saturation S_g at selected times for case A.2.

drawdown period. The reason for liquid-phase over-recovery during buildup is fairly straightforward. During drawdown, a decrease in pressure is accompanied by a corresponding reduction in temperature. (Note that pressure and temperature in two-phase flow are not independent.) On shutin, the pressure tends to recover to the initial formation pressure. The temperature recovery beyond the saturation point at local reservoir conditions occurs on a much longer time scale than the one for pressure recovery. (Temperature recovery is mainly governed by heat conduction.) A puzzling aspect of pressure recovery is that it appears to be essentially governed by the two-phase region in the reservoir. The reason for the latter behavior must be sought in the great difference between the liquid- and two-phase compressibilities. Since the liquid compressibility is much smaller (by 2 to 3 orders of magnitude) than the two-phase compressibility, the liquid-phase will reach pressure equilibrium (i.e., zero pressure gradient) on a much faster time scale than the two-phase region. Numerical calculations show that the liquid-region pressure gradients are essentially zero for the entire buildup period. Finally, it is noted that the condensation front does not obey the law ($R \propto t^{1/2}$); this demonstrates that the similarity solution (see e.g., O'Sullivan [1980]) does not apply to buildup in two-phase reservoirs.

2.5 Production Behavior of Hot Water Reservoirs which Flash on Fluid Withdrawal

In this section the response of an initially single-phase reservoir which undergoes flashing on fluid production is considered. Detailed numerical results are presented which simulate both the propagation of the flash front during production and the propagation of a condensation front, during buildup. The presence of these fronts is shown to greatly complicate the interpretation of the well test data.

2.5.1 Background of Theory

Garg [1978] has considered the drawdown response of an initially single-phase reservoir which undergoes flashing on fluid production. In this case, the reservoir exhibits single-phase response until some time t_f when the well pressure falls below the saturation pressure at the local reservoir temperature; for $t > t_f$, a flash front starts propagating into the formation. The reservoir (for $t > t_f$) is two-phase for $r < R$ [$R = R(t)$ denotes the location of the flash front], and is single-phase for $r > R$. The drawdown curve ($t > t_f$) asymptotes to a straight line; the slope of the straight line yields the total kinematic mobility $(k/v)_t$ (c.f., Equation (2.25)). The buildup behavior of such reservoirs has apparently not been previously investigated.

2.5.2 Hot Water Reservoirs which Undergo Flashing

To study the drawdown/buildup behavior of hot water reservoirs which undergo flashing on production, two cases will be considered. The initial fluid-state for these cases is given in Table 2.5.

Table 2.5
INITIAL FLUID-STATE FOR HOT-WATER RESERVOIRS WHICH UNDERGO
FLASHING ON PRODUCTION

<u>Case No.</u>	<u>Pressure, MPa</u>	<u>Temperature, °C</u>
B.1	8.7917	300
B.2	8.9917	300

Figures 2.12 and 2.13 show the simulated drawdown histories for the two cases; these figures show only the two-phase part of the drawdown response. In case B.1 (low pressure case), the flash front propagates to approximately 20 m at the end of the drawdown period (Figure 2.18); for the high-pressure case (B.2), the flash front

Figure 2.12. Pressure drawdown and flowing enthalpy for case B.1 ($p_i = 8.7917 \text{ MPa}$, $T_i = 300^\circ\text{C}$)

Figure 2.13. Pressure drawdown for case B.2 ($p_i = 8.9917 \text{ MPa}$, $T_i = 300^\circ\text{C}$)

Figure 2.14. Pressure and temperature buildup data for case B.1.

Figure 2.15. Pressure and temperature buildup data for case B.2.

Figure 2.16. Radial distribution of flowing kinematic viscosity v_t at selected times for Case B.1.

Figure 2.17. Radial distribution of flowing kinematic viscosity ν_t at selected times for case B.2.

Figure 2.18. Radial distribution of steam saturation S_g at selected times for case B.1.

advances to only 1 m (Figure 2.19). The drawdown data closely fit straight lines; the slopes of the straight lines yield flowing kinematic viscosities which are representative of the two-phase part of the reservoir wherein $\partial S_g / \partial r$ is small (see Figures 2.12, 2.13, 2.16 and 2.17).

The buildup behavior is shown in Figures 2.14 and 2.15. Referring to Figure 2.14, it may be seen that in the low pressure case, the initial buildup behavior is governed by the two-phase region of the reservoir; the slope of this curve yields v_t which is characteristic of the two-phase region created during drawdown (see Figure 2.14 and 2.16). The pressure buildup is accompanied by the propagation of a condensation front, originating at the well, into the formation (Figure 2.18); the condensation front eventually engulfs the entire two-phase region after which the buildup behavior is essentially that of a single-phase fluid. The two-buildup segments (single-phase and two-phase) are separated by approximately one log cycle (Figure 2.14). The single-phase buildup behavior (Figure 2.14) extends over less than one-half cycle; the slope of this straight line yields a kinematic viscosity $v_t \sim 1.73 \times 10^{-7} \text{ m}^2/\text{s}$ which is approximately 40 percent larger than the actual value of $1.245 \times 10^{-7} \text{ m}^2/\text{s}$. The divergence between the inferred and actual values of v_t is really not surprising in view of the fact that single-phase buildup response in this particular instance is observed for less than one-half log cycle. In the high pressure case (B.2), the two-phase buildup behavior lasts for only a very brief period (at most a few minutes, see Figures 2.17 and 2.19); the single-phase buildup, however, lasts for approximately two-log cycles (Figure 2.15). The slope of the straight line in case B.2 yields a v_t in good agreement with the actual value of $1.245 \times 10^{-7} \text{ m}^2/\text{s}$.

The above discussion of buildup behavior illustrates the importance of selecting the correct straight line. If sufficiently long (at least one-log cycle) straight line segments can be identified, then the buildup data may be interpreted to give both

Figure 2.19. Radial distribution of steam saturation S_g at selected times for case B.2.

single- and two-phase kinematic mobilities. In many practical situations, however, it is likely that the buildup data will not be such as to make possible the unambiguous determination of both single- and two-phase mobilities.

SECTION 3: THEORETICAL INJECTION BEHAVIOR ANALYSES

3.1 Introduction

In this section numerical simulations are presented which describe the injection data for a single well injecting into a geothermal reservoir. The S^3 geothermal reservoir simulator CHARGR is used to analyze single-phase and two-phase reservoirs.

3.2 Summary

It is demonstrated that injection data for single-phase and two-phase geothermal reservoirs can be interpreted to yield absolute formation permeability. The pressure fall-off data subsequent to injection are of lesser utility.

3.3 Cold Water Injection into a Hot Water Well

In this section, a case is considered wherein cold water is injected into a single-phase (all liquid) hot water well. The initial formation pressure and temperature are 8.7917 MPa and 300°C respectively; the temperature of the injected fluid (injection rate = 35 kg/s) is approximately 151°C. The pressure buildup (Injection) data are seen to fit a straight line (Figure 3.1); the slope of this straight line yields $v_t \sim 1.985 \times 10^{-7} \text{ m}^2/\text{s}$ which is in good agreement with the kinematic viscosity of the injected fluid ($\sim 1.955 \times 10^{-7} \text{ m}^2/\text{s}$). Figure 3.2 shows the radial distribution of v_t and temperature T at the end of the injection period ($\sim 5.868 \times 10^5 \text{ s}$); the thermal front is seen to have propagated approximately 6 m into the formation. The fall-off (shutin) data are plotted in Figure 3.3; the fall-off data asymptote to a straight line whose slope yields a value of $v_t \sim 1.20 \times 10^{-7} \text{ m}^2/\text{s}$ which is in good agreement with the kinematic viscosity of hot water ($\sim 1.25 \times 10^{-7} \text{ m}^2/\text{s}$). No straight line corresponding to cold water pressure fall-off can, however, be identified on Figure 3.3; the reason for this is tied to the relatively small radius ($\sim 6 \text{ m}$) affected by cold

Figure 3.1. Pressure buildup (Injection) data for cold water injection into a hot water well ($p_i = 8.9917 \text{ MPa}$, $T_i = 300^\circ\text{C}$, $T_{\text{injection}} \sim 151^\circ\text{C}$).

Figure 3.2. Radial distribution of flowing kinematic viscosity and temperature at $t \sim 5.868 \times 10^5 \text{ s}$ (end of injection period). O denotes the location of the front (defined as the mid point).

Figure 3.3. Pressure fall-off data for cold water injection into a hot water well.

water injection. The time to investigate a particular radius r during fall-off is approximately given by (see e.g., Matthews and Russell [1977]):

$$\Delta t = \frac{r_{inv}^2}{4} \frac{\phi \mu C_T}{k} \quad (3.1)$$

where

- Δt = Fall off time in sec
- r_{inv} = Radius of investigation in meters
- μ = Dynamic fluid viscosity in Pa-s
- C_T = Total formation compressibility in Pa^{-1}
- k = Formation permeability in m^2

with $r_{inv} = 6$ m, $\phi = 0.1$, $\mu = 1.8 \times 10^{-4}$ Pa-s, $C_T = 0.075 \times 10^{-8} \text{ Pa}^{-1}$ (μ and $C_T = C_h$ are evaluated at 151°C), we have $\Delta t \sim 2.4$ s. The first point on the fall-off curve corresponds to a Δt of 14 s.

3.4 Cold Water Injection into Two-Phase Reservoirs

Although cold water injection into two-phase reservoirs has been suggested by several investigators for evaluating formation properties (see e.g., Grant [1979b]), yet theoretical analyses of pressure buildup/fall-off data are currently unavailable in the published literature. In order to investigate the effects of cold water injection into two-phase reservoirs, two cases will be considered. The initial fluid state for these cases is given in Table 3.1; the fluid injection rate (35 kg/s) and the injected fluid temperature, are identical with those employed in the preceding section.

Table 3.1
INITIAL FLUID STATE FOR COLD WATER INJECTION INTO
TWO-PHASE RESERVOIRS

<u>Case No.</u>	<u>Pressure, MPa</u>	<u>Temperature, °C</u>	<u>Steam Sat.</u>
C.1	8.5917 MPa	300	0.28
C.2	8.5917 MPa	300	0.05

The pressure buildup (injection) data (Figures 3.4 and 3.5) closely fit straight lines with identical slopes. The slope implies a flowing kinematic viscosity of $2.02 \times 10^{-7} \text{ m}^2/\text{s}$ which is in good agreement with the kinematic viscosity of the cold injected water ($\nu \sim 1.96 \times 10^{-7} \text{ m}^2/\text{s}$). Figures 3.6 and 3.7 show the radial distribution of steam saturation and temperature at the end of the injection period ($t \sim 5.868 \times 10^5 \text{ s}$). The condensation front (especially in the low steam saturation case C.2) is seen to have advanced further into the formation than the edge of the thermal front. The latter effect is due to the fact that pressure changes are experienced over a much larger portion of the reservoir than the one undergoing cooling as a result of cold fluid injection.

Horner plots of pressure fall-off data are given in Figures 3.8 and 3.9. Three regions can be identified on these plots:

- (i) for large $(t + \Delta t)/\Delta t$ (i.e., small shutin times), pressure falls off relatively rapidly
- (ii) for moderate values of $(t + \Delta t)/\Delta t$, pressure is essentially constant
- (iii) for small values of $(t + \Delta t)/\Delta t$ (i.e., large buildup times), pressure again starts to fall rather rapidly.

The first region (i.e., $(t + \Delta t)/\Delta t$ large) of the fall-off curve is governed by the pressure response of the condensed fluid region. Due to the large contrast in single-phase and two-phase compressibilities, the two-phase region remains practically unaffected during this time period (see e.g., steam saturation

Figure 3.4. Pressure buildup (Injection) data for case C.1.

Figure 3.5. Pressure buildup (Injection) data for case C.2.

Figure 3.6. Radial distribution of temperature and steam saturation at selected times for case C.1.

Figure 3.7. Radial distribution of temperature and steam saturation at selected times for case C.2.

Figure 3.8. Pressure fall-off data (Horner plot) for case C.1.

Figure 3.9. Pressure fall-off data (Horner plot) for case C.2

profiles in Figures 3.6 and 3.7). The condensed fluid region behaves like a reservoir with a constant pressure (= pressure at the edge of the condensation front) boundary. These early pressure fall-off data are replotted in Figures 3.10 and 3.11; these figures clearly demonstrate that the early fall-off behavior in the present cases resembles that of a reservoir with a constant pressure boundary. The condensation front radius, r_e , can, therefore, be calculated from the formula (Earlougher [1977]):

$$r_e = \left(\frac{k \Delta t_s}{1.25 \phi \mu C_T} \right)^{0.5} \quad (3.2)$$

where

- k = formation permeability
- Δt_s = time to startup of semi-steady reservoir behavior (time at which pressure curve bends over)
- μ = viscosity of injected liquid water
- C_T = Total formation compressibility in the condensed region.

The condensation front radii inferred from Equation (3.2) and data of Figures 3.10 and 3.11 are compared with the actual values in Table 3.2.

Table 3.2
CONDENSATION FRONT RADII

($\mu = 1.8 \times 10^{-4}$ Pa-s; $C_T = 0.075 \times 10^{-8}$ Pa $^{-1}$)

<u>Case No.</u>	<u>Δt_s</u>	<u>r_e (inferred)</u>	<u>r_e (actual)</u>
C.1	72 s	14.6 m	(15.5 $\pm$ 1.5) m
C.2	753 s	47.2 m	(57.1 $\pm$ 5.2) m

Although the inferred values for r_e are in reasonable agreement with the actual values, a note of caution is in order here. In practical situations, the early fall-off data (such as that utilized

Figure 3.10. Early pressure fall-off data for case C.1.

Figure 3.11. Early pressure fall-off data for case C.2.

in the above calculation for r_e) are liable to be dominated by wellbore storage, and it may well be impossible to identify the time at which the well starts exhibiting "semi-steady" response.

An examination of the numerical results shows that at the end of the first part of the fall-off curve, the pressure gradient in the single-phase (condensed) region is essentially zero whereas the pressure at the edge of the condensation front remains at its value at $\Delta t = 0$ (start of shutin period). Also, the edge of the condensation front is stationary throughout this initial period (Figures 3.6 and 3.7 - See steam saturation profiles for $t = 5.868 \times 10^5$ s to $(t + \Delta t)/\Delta t = (2610$ in Figure 3.6, and 653 in Figure 3.7)).

During the middle fall-off period, the condensation front starts moving towards the wellbore. This part of the well response is characterized by an essentially constant pressure. At the end of this period, the condensation front becomes coincident with the edge of the thermal front (see e.g., steam saturation curve labeled $(t + \Delta t)/\Delta t = 3.43$ in Figure 3.7). The condensation front once again becomes stationary at this point.

For large fall-off times (i.e., for the third fall-off period), the well response is governed by the two-phase region. As can be seen from Figures 3.8 and 3.9, the pressure fall-off data do not, however, asymptote to a straight line. It is convenient to plot the fall-off data in a somewhat different manner. Figures 3.12 and 3.13 are plots of $\log \Delta p$ ($\Delta p = |p_w(\Delta t) - p_f|$ where p_f is the last flowing pressure) versus $\log \Delta t$. Referring to Figure 3.13, it may be seen that the two-phase fall-off data lie on the unit slope line. A unit slope line can also be identified on Figure 3.12. It is well known that the presence of a unit slope line indicates that the well response is controlled by storage effects; this part of the fall-off data is useless for analysis purposes in the absence of data regarding the location of the condensation front (~ effective wellbore radius for two-phase fall-off regime). For

Figure 3.12. Plot of $\log \Delta p$ versus $\log \Delta t$ for case C.1. ($\Delta p = |p_w - p_f|$; p_w is the well pressure at Δt and p_f is the last flowing pressure.) Note that the vertical and horizontal scales are different.

Figure 3.13. Plot of $\log \Delta p$ versus $\log \Delta t$ for case C.2. ($\Delta p = |p_w - p_f|$; p_w is the well pressure at Δt and p_f is the last flowing pressure.) Note that (1) the vertical and horizontal scales are different, and (2) the vertical scale is discontinuous.

single-phase flow, a rough rule of thumb is that the semi-log straight line starts at a time which is one and one-half log cycles removed from the time at which the pressure data begins to deviate from the unit slope straight line. Utilizing the latter criterion, it is seen from Figure 3.12 that only the last point or two may be expected to lie on the semi-log line. In view of the nonlinear nature of two-phase flow in porous media, especially prior to the start of semi-log straight line, it would very likely be futile to try to analyze the two-phase fall-off data of Figure 3.12 to derive kinematic mobility.

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