Variation of Rock and Fluid Temperature During Thermal Operation in Porous Media

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Abstract: The temperature distribution in a reservoir formation is an important indicator of various reservoir conditions, such as the state of water or gas influx, type of fluid encroachment, etc. This information is necessary for better reservoir management. This study investigates the temperature propagation pattern and its dependence on various parameters during thermal recovery operations. The model equation has been solved for temperature distribution throughout the reservoir for different cases. It was found that the fluid and rock matrix temperature difference is negligible. Results show that formation fluid velocity and time have an impact on the temperature profile behavior.

Keywords: formation fluid velocity, reservoir fluid, reservoir rock, steam injection, temperature distribution

INTRODUCTION

The temperature distribution is very important in thermal oil recovery. Increasing the temperature in a formation leads to an increase in the mobility of viscous fluid. As the steam moves away from the well, its temperature drops as it continues to expand in response to the pressure drop. At some distance from the well, the steam starts to condense and forms a hot water zone. In the steam zone, oil is displaced by the gaseous steam. In the hot water zone, physical changes in the characteristics of oil and reservoir rock take place and result in oil recovery. An understanding of temperature propagation through a formation is important in the design of thermal injection projects. Temperature profiles may be used to predict the fracture characteristics in the reservoir. It can be applied to identify water or gas entries in the reservoir. It is

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also important to guide the action of sliding sleeves or other down-hole flow control devices. Therefore it is useful to investigate the pattern of temperature propagation and heat exchange between fluid and rock in a formation.

The properties of fluid and matrix are functions of the media temperature and pressure. So it is necessary to know the temperature and pressure distribution to predict these properties. When rock and fluid temperature are different in the formation, it behaves like hydraulic fracture flow in the formation. Atkinson and Ramey (1977) presented mathematical models to study heat transfer behavior in fractured and nonfractured porous media. The models are used to calculate the temperature distributions caused by nonisothermal fluid flow through a uniform porous media. They concluded that their models are useful to find the relative importance of different heat transfer mechanisms. They assumed a uniform and constant fluid flow in the formation. They also considered a uniform temperature in the reservoir for both fluid and rock matrix. They neglected the heat transfer in the solid rock matrix.

Crookston et al. (1979) presented a model for numerically simulating thermal recovery processes. The simulator describes the flow of water, oil, and gas. They showed the temperature distribution with time. They included gravity and capillary effects, but did not include the effects of formation fluid velocity and injection steam velocity. They showed heat transfer by conduction, convection, and vaporization condensation of both water and hydrocarbons. However, they discarded the effects of the rock and fluid temperature difference.

Meyer (1989) proposed a combined convection along a vertical fracture with conduction and convection in the reservoir. He investigated temperature distribution throughout the reservoir for both fracture and nonfracture conditions by varying the heat rate. He took into account that the rock and fluid temperatures are the same. He did not study the different parameters that may affect temperature distribution.

Akin (2004) proposed a mathematical model for gravity drainage in heavy oil reservoirs and tar sands during steam injection. In his model, he assumed a temperature profile that is only time dependent and declines exponentially with distance from the interface. However, he acknowledged that with an increase in steam temperature, the oil flow rate increases. He did not validate this argument and did not consider other influential factors such as fluid velocity, steam velocity, and temperature differences between the rock and fluid.

Cheng and Kuznetsov (2005) studied heat transfer in a helical pipe filled with a fluid-saturated porous medium. They investigated the effects of the Darcy number, Forchheimer coefficient, Dean and Germano numbers on the axial flow velocity, secondary flow, temperature distribution, and the Nusslet number (Nu). Their numerical simulations of heat transfer in a media were based on laminar flow of a Newtonian fluid in a helical pipe filled with a fluid-saturated porous medium subjected to a constant wall heat flux. They

did not study the effects of fluid velocity on rock and fluid temperature distribution.

Yoshioka et al. (2005) presented a model for predicting the temperature profile in a horizontal well. This is for a steady-state flow condition. They assumed the reservoir is ideally isolated with each segment. They considered a box-shaped homogeneous reservoir. They investigated the effects of production rate, permeability, and fluid type on temperature profiles. However, they did not investigate the effects of formation fluid and steam injection velocity.

Dawkrajai et al. (2006) studied the water entry location identification by temperature profile in a horizontal well. They varied the production rate and types of oil to see their effects on temperature profile. They assumed that flowing fluid and rock temperature are the same. They did not check the effects of fluid velocity and injection steam velocity on temperature distribution.

Jiang and Lu (2006) investigated fluid flow and convective heat transfer of water in sintered bronze porous plate channels. The numerical simulations assumed a simple cubic structure with homogeneous particles. They also considered a small contact area and a finite-thickness wall subject to a constant heat flux at the surface. They numerically determined some fluid and rock properties. They also studied temperature distributions in the porous media. They only minimally investigated the effects of fluid velocity on temperature distribution. They recommended further investigations of the boundary characteristics and internal phenomena controlling heat transfer in a porous media. In the present study, these criteria have been investigated to find the role of these parameters in temperature distribution throughout the reservoir.

A lot of work has been done on fluid property changes due to heat loss in a reservoir formation. However, there is little in the literature that deals with temperature propagation in a formation. The effects of formation fluid velocity and steam velocity on temperature distribution are still ignored by researchers. There is no existing literature that investigates the effects of fluid and rock temperature separately. This study investigates these aspects.

THEORETICAL DEVELOPMENT

To determine temperature distribution with space and time, the energy balance equation is considered as the governing equation for both rock and fluid separately. The partial differential equations have a familiar form because the system has been averaged over representative elementary volumes (REVs). A right-handed Cartesian coordinate system is considered where the x axis is along the formation length. The general form of differential energy balance equations in three dimensions may be given as (Chan and Banerjee, 1981; Kaviany, 2002)

$$\nabla(k_s \times \nabla T_S) = (1 - \phi)(\rho c_p)_s \, \frac{\partial T_s}{\partial t} + h_c(T_s - T_f) \tag{1}$$

$$\nabla(k_f \times \nabla T_f) - (\rho c_p)_f (\nabla \overline{V}) T_f = \phi(\rho c_p)_f \, \frac{\partial T_f}{\partial t} + h_c(T_f - T_s), \tag{2}$$

where T_s and T_f are the rock matrix and fluid temperatures, respectively. Eqs. (1) and (2) represent the thermal state of each phase in the same REV.

It is taken into account that a porous media of homogeneous and uniform cross-sectional area is considered along the x axis. It is normal practice to consider that the fluid flow in porous media is governed by Darcy's law. Since the media is homogeneous, the pressure along the x direction may be considered to vary linearly. It is also considered that the thermal conductivity of the fluid and solid rock matrix is not a function of temperature and is constant along the media. Therefore Eqs. (1) and (2) can be written in one-dimensional form as

$$k_S \frac{\partial^2 T_s}{\partial x^2} = (1 - \phi)\rho_s c_{ps} \, \frac{\partial T_s}{\partial t} + h_c(T_s - T_f) \tag{3}$$

$$k_f \, \frac{\partial^2 T_f}{\partial x^2} - \rho_f c_{pf} u \, \frac{\partial T_f}{\partial x} = \phi \rho_f c_{pf} \, \frac{\partial T_f}{\partial t} + h_c(T_f - T_s), \tag{4}$$

where

$$\rho_f c_{pf} = \rho_w c_{pw} S_w + \rho_o c_{po} S_o + \rho_g c_{pg} S_g \tag{5}$$

$$k_f = k_w + k_o + k_g \tag{6}$$

$$\rho_f = \rho_w S_w + \rho_o S_o + \rho_g S_g \tag{7}$$

$$S_w + S_o + S_g = 1. \tag{8}$$

The length of the heated region can be estimated using a model developed by Marx and Langenheim (1959). The amount of energy required to increase the temperature of a porous rock is easily calculated from thermodynamic tables and heat capacity data at constant pressure. If we consider a constant rate of heat generation per unit volume, Q_g, is maintained, then Eq. (9) gives the total energy required to increase the temperature of 1 ft^3 of reservoir rock from an initial temperature, T_s, to a higher temperature, T_{hs} (in °F) (Green and Willhite, 1998):

$$Q_g = M(T_{hs} - T_s), \tag{9}$$

where

$$M = (1 - \phi)\rho_s c_{ps} + \phi S_o \rho_o c_{po} + \phi S_w \rho_w c_{pw} + \phi S_g \rho_g c_{pg}. \tag{10}$$

The mean heat capacities of each component are based on the temperature difference. It can be defined as (Green and Willhite, 1998)

$$c_{pw} = (H_{wTf} - H_{wr})/(T_f - T), \quad c_{po} = (H_{oTf} - H_{oTi})/(T_f - T_i),$$

$$c_{ps} = (H_{sTf} - H_{sTi})/(T_f - T), \quad c_{pg} = (H_{gTf} - H_{gTr})/(T_f - T_r) \quad (11)$$

In order to render Eqs. (3) and (4) dimensionless, the following nondimensional parameters have been defined as

$$T^* = \frac{T}{T_i}, T_s^* = \frac{T_s}{T_i}, T_f^* = \frac{T_f}{T_i}, t^* = \frac{u_i t}{L},$$

$$x^* = \frac{x}{L}, p^* = \frac{p}{p_i}, \text{and } u^* = \frac{u}{u_i}, \quad (12)$$

where L is the distance between the production and injection well. Let $M_1 = (1 - \phi)\rho_s c_{ps}$ and $M_2 = \phi \rho_f c_{pf}$. and using Eq. (12), the dimensionless forms of Eqs. (3) and (4) are given as

$$\frac{\partial T_s^*}{\partial t^*} - \frac{k_s}{M_1 L u_i} \frac{\partial^2 T_s^*}{\partial x^{*2}} + \frac{h_c L}{u_i M_1}(T_s^* - T_f^*) = 0 \quad (13)$$

$$\frac{\partial T_f^*}{\partial t^*} + \frac{u^*}{\phi} \frac{\partial T_f^*}{\partial x^*} - \frac{k_f}{M_2 u_i L} \frac{\partial^2 T_f^*}{\partial x^{*2}} + \frac{h_c L}{M_2 u_i}(T_f^* - T_s^*) = 0. \quad (14)$$

These two partial differential equations should be solved simultaneously to find the temperature distribution for fluid, T_f^*, and rock matrix, T_s^*, in the formation. These equations are subjected to

$$T_f(x, 0) = T_s(x, 0) = T_i$$

in dimensionless form as $T_f^*(x, 0) = T_s^*(x, 0) = 1$

$$T_f(0, t) = T_s(0, t) = T_{steam}$$

in dimensionless form as $T_f^*(0, t) = T_s^*(0, t) = T_{steam}/T_i$

$$\quad (15)$$

$$T_f(L, t) = T_s(L, t) = T_i$$

in dimensionless form as $T_f^*(L, t) = T_s^*(L, t) = 1$

that present the initial and boundary conditions.

If the temperatures of the fluid and rock matrix are the same, the energy balance equations can be combined. Combining Eqs. (3) and (4) for both fluid and rock matrix in the formation, the energy balance is given in single equation as

$$\{\phi \rho_f c_{pf} + (1 - \phi)\rho_s c_{ps}\}\frac{\partial T}{\partial t} + \rho_f c_{pf} u \frac{\partial T}{\partial x} - (k_s + k_f)\frac{\partial^2 T}{\partial x^2} = 0. \quad (16)$$

Using Eq. (10) and the dimensionless parameters in Eq. (12), Eq. (16) reduces to

$$\frac{\partial T^*}{\partial t^*} + \frac{\rho_f c_{pf}}{M}(u^*)\frac{\partial T^*}{\partial x^*} - \frac{(k_s + k_f)}{MLu_i}\frac{\partial^2 T^*}{\partial x^{*2}} = 0. \tag{17}$$

This equation gives the dimensionless temperature profile along the formation length when the rock and fluid temperature are considered to be same. The initial and boundary conditions are

$$T^*(x, 0) = 1, T^*(0, t) = T_{\text{steam}}/T_i, \text{ and } T^*(L, t) = 1. \tag{18}$$

Darcy's law may be written in nondimensional form according to the definition of dimensionless parameters in Eq. (12) as $u^* = -(p_i k/u_i L\mu)\partial p^*/\partial x^*$. Accordingly, the velocity of the fluid can be written as $u^* = ag(t^*)$. Hence the coefficient a is a function of the initial reservoir pressure, distance between the injection and production wells, initial injection velocity, permeability of the media, viscosity of the fluid, and pressure gradient of the formation. The formation velocity is considered as a linear function of time, $u^* = at^*$.

NUMERICAL SIMULATION

The dimensionless temperature profiles are obtained by solving Eqs. (13) and (14) simultaneously when fluid and rock matrix temperatures are different. Equation (17) is solved for the temperature profile when fluid and rock matrix temperatures are the same. These dimensionless temperature profiles with respect to dimensionless space and time are obtained numerically with the finite difference method. Equations (13) and (14) are expressed as

$$T_{si}^{*n+1} = a_1 T_{si}^{*n} + a_2 T_{s(i+1)}^{*n} + a_2 T_{s(i-1)}^{*n} + a_3 T_f^{*n} \tag{19}$$

$$T_{fi}^{*n+1} = b_1 T_{fi}^{*n} + b_2 T_{f(i+1)}^{*n} + b_3 T_{f(i-1)}^{*n} + b_4 T_{si}^{*n}, \tag{20}$$

where

$$a_1 = 1 - 2a_2 - a_3, a_2 = -a_4 h, a_3 = a_5 \Delta t^*,$$

$$a_4 = -k_s/M_1 Lu_i, a_5 = h_c L/M_1 u_i$$

$$b_1 = 1 + 2b_5 h - b_4, b_2 = b_6 - b_5 h, b_3 = -b_6 - b_5 h, b_4 = b_8 \Delta t^*,$$

$$b_5 = -k_f/M_2 Lu_i, b_6 = b_7 \Delta x^* t^* h/2, b_7 = a/\varphi,$$

$$b_8 = h_c L/M_2 u_i, h = \Delta t^*/(\Delta x^*)^2.$$

Equation (17) can be written as

$$T_i^{*n+1} = c_1 T_i^{*n} + c_2 T_{i+1}^{*n} + c_3 T_{i-1}^{*n}, \qquad (21)$$

where

$$c_1 = 1 - 2c_4, c_2 = c_5 + c_4, c_3 = c_4 - c_5, c_4 = -c_7 h,$$

$$c_5 = -c_6 h t^* \Delta x^*/2, c_6 = a\rho_f c_{pf}/M, c_7 = -(k_s + k_f)/MLu_i.$$

RESULTS AND DISCUSSION

The computations are carried out for a reservoir of $L = 500$ ft. The steam is injected through a 7-inch well diameter. The properties of the rock and fluids are given in Table 1. It is assumed that $\Delta x = 0.02$, $\Delta t^* = 0.0001$.

The variations in temperatures are obtained for two cases. At first, it is assumed that the fluid and rock temperatures are the same. In the second case, variations in the fluid and rock temperatures are obtained separately. The computations are carried out for different fluid velocities. It is assumed that the velocity coefficients are $a = 0.04108$, 0.035, 0.03, 0.025, 0.02, 0.01, 0.001, and 0.0001. It is also assumed that $u_i = 0.1217$ ft/sec.

Temperature Variation With Distance and Time for Fluid Velocity

The variation of dimensionless temperature along the length of the reservoir is depicted in Figure 1 for $a = 0.04108$ and 0.0001, respectively, when $u_i = 0.1217$ ft/sec for different time steps and $T_s = T_f$ (case I). At the beginning of

Table 1. Fluid and rock property values for numerical computation

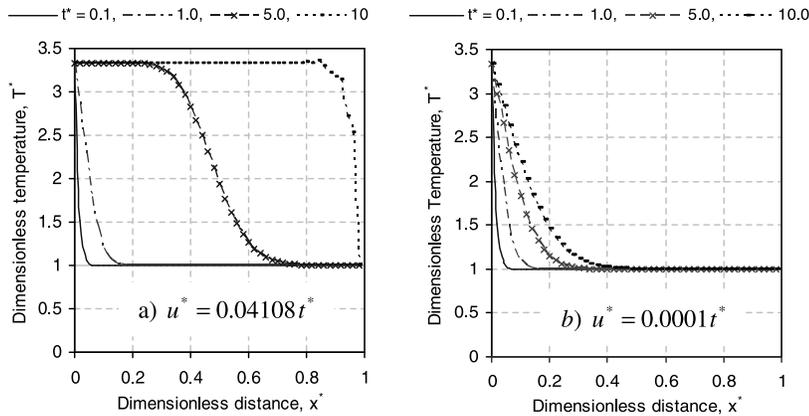| Fluid and rock properties	Fluid and rock properties
$c_{pg} = 7.1 \ [Btu/lb_m - {}^\circ F]$	$S_g = 20\% \ [vol/vol]$
$c_{po} = 0.5 \ [Btu/lb_m - {}^\circ F]$	$S_o = 60\% \ [vol/vol]$
$c_{ps} = 0.21 \ [Btu/lb_m - {}^\circ F]$	$S_w = 20\% \ [vol/vol]$
$c_{pw} = 1.0 \ [Btu/lb_m - {}^\circ F]$	$T_{steam} = 500 \ [{}^\circ F]$
$h_c = 13.74 \ [Btu/hr - ft^2 - {}^\circ F]$	$T_i = 150 \ [{}^\circ F]$
$k_g = 0.0023 \ [Btu/hr - ft - {}^\circ F]$	$\rho_g = 1.0433 \ [lb_m/ft^3]$
$K_i = 100.0 \ [md]$	$\rho_o = 50.0 \ [lb_m/ft^3]$
$k_o = 0.22408 \ [Btu/hr - ft - {}^\circ F]$	$\rho_s = 167.0 \ [lb_m/ft^3]$
$k_s = 1.5 \ [Btu/hr - ft - {}^\circ F]$	$\rho_w = 62.5 \ [lb_m/ft^3]$
$k_w = 0.606 \ [Btu/hr - ft - {}^\circ F]$	$\phi = 25\% \ [vol/vol]$
$p_i = 4000 \ [psia]$	$\mu_f = 10000 \ [cp]$

Figure 1. Temperature variation as a function of distance for Case I.

the steam injection, the reservoir formation heats up only around the injection wellbore. For low velocity, reservoir temperature goes up gradually with time. However, if the fluid velocity goes up, the overall reservoir temperature goes up faster with time. Temperature distribution along the x direction can be separated into three zones: the steam zone, the hot water zone, and the unaffected zone. For low velocity, the steam zone is steeper, the hot water zone is only a little wider, and the unaffected zone is almost 50% of the reservoir, whereas for high velocity, the steam zone and hot water zone become gradually wider with time.

The temperature profile is depicted in Figure 2 when $T_s \neq T_f$ (case II). The same trend is shown in this situation. The difference between the rock
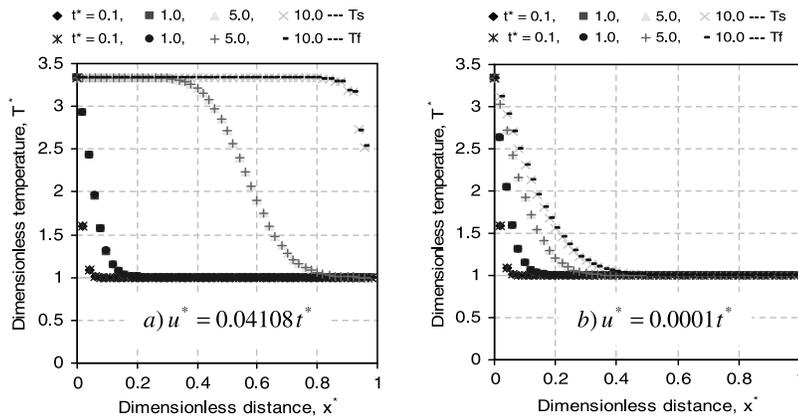

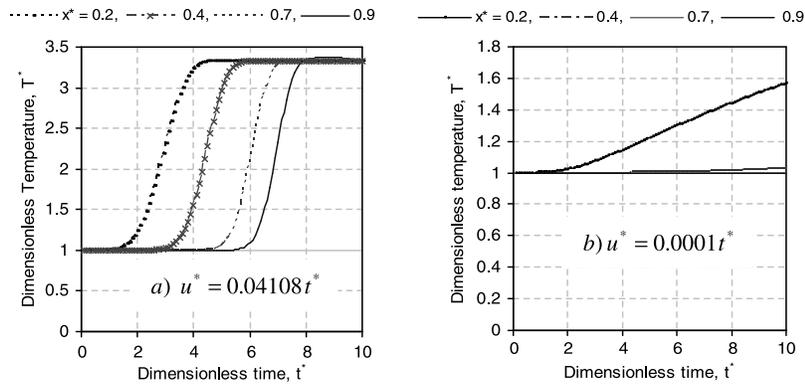**Figure 2.** Temperature variation as a function of distance for Case II.

Figure 3. Temperature variation as a function of time for Case I.

and fluid temperature is very small, in the range of 10^{-3}. The profile of temperature shows that the reservoir temperature is going up in this case.

The variation of dimensionless temperature with time is shown in Figure 3 for $a = 0.04108$ and 0.0001 and $u_i = 0.1217$ ft/sec at different distances when $T_s = T_f$. When fluid velocity is low, reservoir temperature does not propagate evenly for a long time after its 50% distance. However, temperature increases gradually around the wellbore. If the fluid velocity is increased, the propagation is higher and temperature goes up rapidly with time and reaches its maximum temperature after a longer time.

The temperature profile is depicted in Figure 4 when $T_s \neq T_f$. Almost the same trend is shown in this situation. The difference between the rock and fluid temperature is very small, in the range of 10^{-3}. The profile of
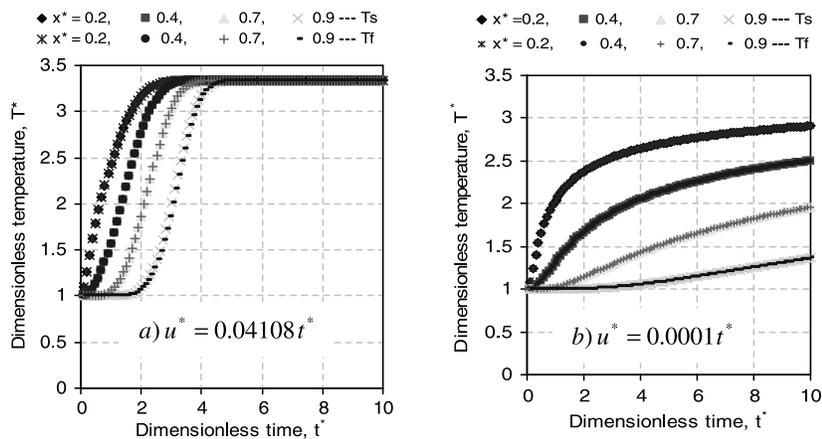

Figure 4. Temperature variation as a function of time for Case II.

temperature shows that the reservoir temperature is going up and rises faster with time for both situations in comparison with the first case.

Effects of Fluid Velocity on Temperature With Time and Distance

The variation of dimensionless temperature along the length of the reservoir is presented in Figure 5 for different fluid velocities. This is for the same fluid and rock temperature. Here, $u_i = 0.1217$ ft/sec is assumed. At the beginning of the steam injection, formation velocity has less impact on temperature distribution and does not heat up very far away from the injection well. However, as time goes on the reservoir formation gradually heats up and goes deeper into the formation. If formation velocity goes down, the temperature profile cannot propagate further.

Figure 6 represents the same conditions when $T_s \neq T_f$. The pattern of the graph is almost the same as in the first case. This indicates that if fluid and rock temperatures are different, this criterion has less impact on temperature propagation. However, this consideration makes the propagation somewhat faster and more in line with the first case. This phenomenon indicates that the fluid convection effects are less important than conduction.

The variation of dimensionless temperature with dimensionless time of the reservoir is presented in Figure 7 for different fluid velocities. This is for the same fluid and rock temperature. Here, $u_i = 0.1217$ ft/sec is assumed. It is very clear that fluid velocity has a strong influence on temperature
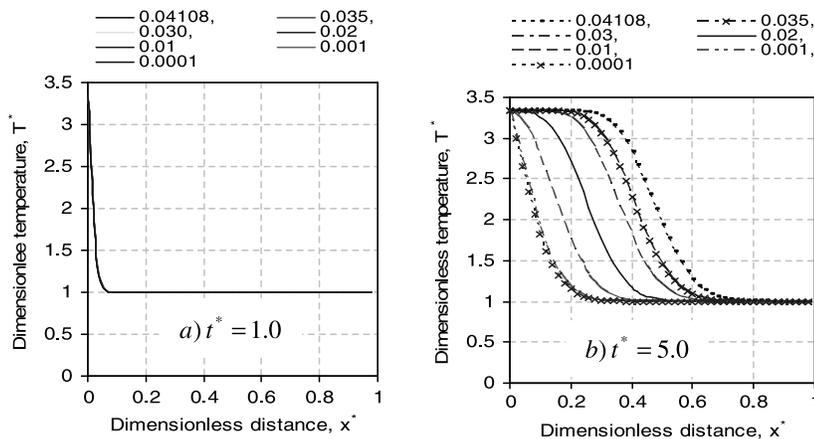

Figure 5. Temperature variations for different fluid velocities as a function of distance for Case I.
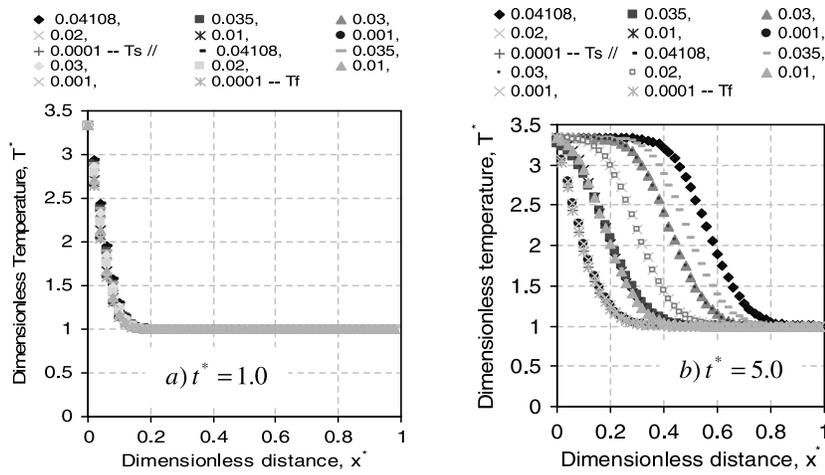
Figure 6. Temperature variations for different fluid velocities as a function of distance for Case II.

propagation. The reservoir heats up quickly with time and reaches its injected steam temperature depending on the time and velocity of fluid. When the velocity of the fluid decreases, the reservoir does not heat up as fast and remains almost the same as the initial reservoir temperature for low fluid velocity. At the beginning of the steam injection, formation velocity has less
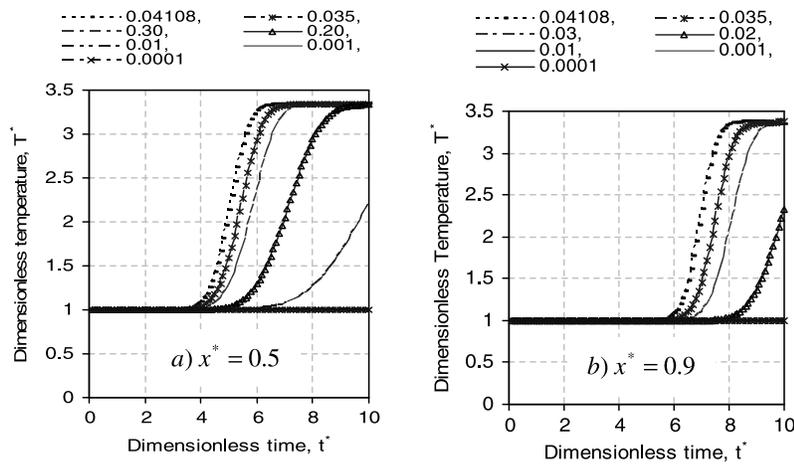

Figure 7. Temperature variations for different fluid velocities as a function of time for Case I.
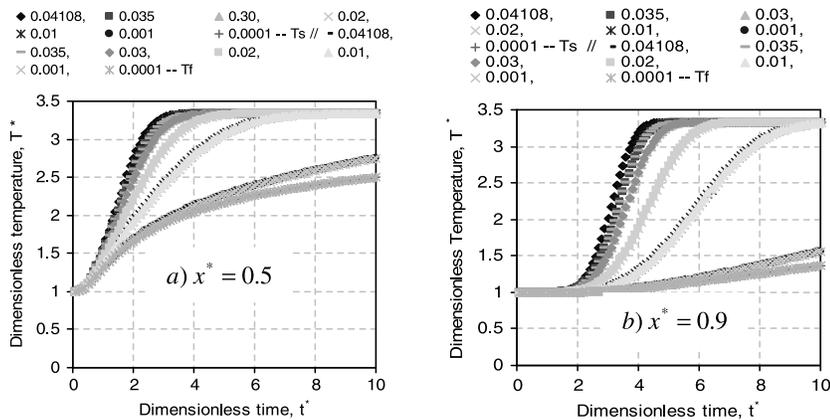
Figure 8. Temperature variations for different fluid velocities as a function of time for Case II.

impact on temperature distribution and does not heat up very far away from the injection well. However, as time passes the reservoir formation heats up gradually and goes deeper into the formation. If formation velocity goes down, the temperature profile cannot propagate further.

Figure 8 represents the same conditions when $T_s \neq T_f$. Fluid velocity has more of an effect on the temperature profile in this case compared with the other case. The reservoir heats up faster in less time than in case II. The temperature propagates gradually with time, even at low fluid velocity. The difference between the rock and fluid temperatures is not very significant throughout these fluid velocity changes.

CONCLUSIONS

The energy balance equation for temperature distribution in porous media has been solved using a convection and conduction heat transfer concept in which there is an option of considering different fluid and rock temperatures. A simultaneous iteration process is used when fluid and rock temperatures are different. Convection does not play a dominant role in the temperature profile due to the very slow motion of fluid inside the media; conduction does play a dominant role. This study shows that temperature distribution is sensitive to time. This distribution is responsive to formation fluid velocity because of the effect of injection velocity. It is also sensitive to steam or hot water injection rate or velocity. The temperature distributions along the x direction and with time were also been investigated. The shape of the temperature profile is dependent on fluid and steam velocity.

ACKNOWLEDGMENTS

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NOMENCLATURE

c_{pf}	specific heat capacity of injected fluid, Btu/lb$_m$-°F
c_{po}	specific heat capacity of oil, Btu/lb$_m$-°F
c_{ps}	specific heat capacity of solid rock matrix, Btu/lb$_m$-°F
c_{pw}	specific heat capacity of water, Btu/lb$_m$-°F
c_{pg}	specific heat capacity of steam, Btu/lb$_m$-°F
g	gravitational acceleration in x direction, ft/sec^2
h_c	convection heat transfer coefficient, Btu/hr-ft^2-°F
H_{oTf}	enthalpy of oil at temperature T_f, Btu/lb$_m$
H_{oTi}	enthalpy of oil at temperature T_i, Btu/lb$_m$
H_{sTf}	enthalpy of rock at temperature T_f, Btu/lb$_m$
H_{sTi}	enthalpy of rock at temperature T_i, Btu/lb$_m$
H_{wTf}	enthalpy of water at temperature T_f, Btu/lb$_m$
H_{wTr}	enthalpy of water at temperature T_r, Btu/lb$_m$
H_{gTf}	enthalpy of steam at temperature T_f, Btu/lb$_m$
H$_{gTr}$	enthalpy of steam at temperature T_r, Btu/lb$_m$
K_i	permeability, md
k_f	thermal conductivity of fluid, Btu/lb$_m$-ft-°F
k_o	thermal conductivity of oil, Btu/lb$_m$-ft-°F
k_s	thermal conductivity of solid rock matrix, Btu/lb$_m$-ft-°F
k_w	thermal conductivity of water, Btu/lb$_m$-ft-°F
k_g	thermal conductivity of steam, Btu/lb$_m$-ft-°F
L	distance between production and injection well along x direction, ft
L^*	dimensionless length of the reservoir
M	average volumetric heat capacity of the fluid-saturated rock, Btu/ft^3-°F
Q_g	constant rate of heat generation per unit volume, Btu/ft^3
$q_{inj} = Au$	injection volume flow rate of steam, sbl/day
$q_{prod} = Au$	production volume flow rate of oil, sbl/day
S_{wi}	initial water saturation
S_w	water saturation, volume fraction
S_g	gas saturation, volume fraction
S_o	oil saturation, volume fraction
t	time, hr
T	temperature, °F
T_f	temperature of injected fluid, °F
T_i	initial reservoir temperature, °F
T_r	reference temperature of injected fluid, °F
T_s	average temperature of solid rock matrix, °F
t^*	dimensionless time
T^*	dimensionless temperature

u filtration velocity in x direction, ft/sec
u^* dimensionless velocity
x^* dimensionless distance
φ porosity of the rock, volume fraction
ρ reference density, lb_m/ft^3
ρ_f density of fluid, lb_m/ft^3
ρ_o density of oil, lb_m/ft^3
ρ_s density of solid rock matrix, lb_m/ft^3
ρ_w density of water, lb_m/ft^3
ρ_g density of steam, lb_m/ft^3