The Effects of Thermal Alterations on Formation Permeability and Porosity

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Abstract: An enhanced oil recovery (EOR) project becomes more attractive if porosity and the residual oil saturation at the end of the primary recovery phase are higher. In addition, greater permeability values contribute to an increase in efficiency of the EOR scheme. It is well known that during thermal intervention, the reservoir permeability and porosity are subject to alterations. However, few studies report the extent of such alterations and their consequences. This study investigates the effects of permeability and porosity during a thermal oil recovery scheme. A 1-D numerical model is used to solve the heat conduction/convection problem, with the inclusion of thermal changes in both permeability and porosity. Numerical results show that permeability decreases and porosity increases with the increase of temperature for a particular time period. This is contrary to the commonly held belief that permeability and porosity function of temperature should have the same trend. The model also shows that pore volume increases with the increase of temperature for a particular time period, which leads to increased oil recovery. These findings show that the cumulative effect of oil recovery is more favorable than expected through conventional analysis that does not consider thermal alterations of permeability and porosity.

Keywords: cumulative oil production, rock expansion, temperature effects, thermal operation

INTRODUCTION

The efficiency of an EOR method is defined as a measure of its ability to provide better hydrocarbon recovery at an economically appealing production rate than by natural depletion. It depends on reservoir characteristics and the

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nature of the displacing and displaced fluids. The reservoir characteristics include average depth, structure, degree of heterogeneity, and petrophysical properties, such as porosity, permeability, capillary pressure, and wettability. The effect of capillary forces on recovery efficiency depends on the rate of production. Capillary forces often have a detrimental effect, being responsible for the trapping of oil within the pores. This trapping is a function of the ratio viscous forces to capillary forces ($u\mu/\sigma\cos\theta$) where u is the velocity of the front. Thermal operation is a process where hot water or steam is injected into a number of wells, while the oil is produced from adjacent wells (Figure 1).

For generating hot water or steam, solar energy can be used for sustainability with direct solar heating system. This technique has been demonstrated by Khan et al. (2007). In some hot water or steam flood, the produced gas has some residual heating value that can be utilized to heat the water (Kaye et al., 1982; Chu, 1983). This heat can be used to preheat the water (Figure 1). The flue gas passes through a small furnace to burn before releasing to atmosphere. Finally, the chemical heat energy and furnace heat is used to further preheat the water. This process not only lowers the hot water or steam generation cost but also reduces the amount of air pollutants released to the surroundings. This process will improve the economics of a thermal operation process.

Ideally, hot water or steam forms a saturated zone around the injection well. The temperature of this zone is nearly equal to injected hot water or steam. As the hot water or steam moves away from the well, its temperature drops as it continues to expand in response to pressure drop. At some distances from the well, the steam condenses and forms a hot water bank. In the steam zone, oil is displaced by steam distillation and gas (steam) drive. In the hot water zone, physical changes in the characteristics of oil and reservoir rock take place and result in oil recovery. These changes include thermal
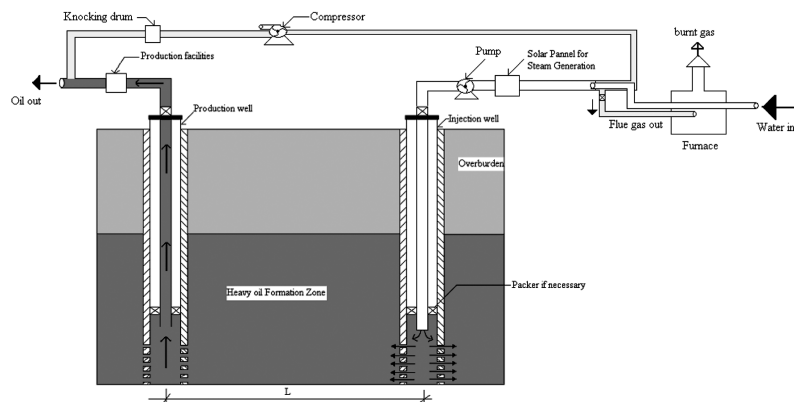

Figure 1. Injection and production wells in an oil field reservoir.

expansion of rock and oil, as well as change in in situ pressure. Significant research has been conducted on tracking the changes in fluid property changes due to heat loss in the reservoir formation. This focus is due to the fact that fluid properties are more susceptible to thermal alterations. The changes of rock properties, such as rock expansion, permeability, and wettability, are also significant but are rarely included in conventional analysis. Canbolat et al. (2004) conducted an experiment to investigate steam-assisted gravity drainage mechanisms with CO_2 and n-butane. They found that the steam condensation temperature and the steam-oil ratio decreased as the amount of carbon dioxide increased. Their findings also showed that the cumulative oil recovery, as well as the recovery rate, decreases due to lower temperatures and more viscous oil. They concluded that thermal operation is effective for producing heavy oil-saturated limestone.

THEORETICAL ANALYSIS

Consider a porous medium with uniform cross-sectional area as depicted in Figure 2. A constant rate of heat generation per unit volume Q_g is maintained. The boundary of the porous cell is maintained at a uniform temperature T_i. The partial differential equations have a familiar form because the system has been averaged over representative elementary volumes (REV). The Boussinesq approximation is used to model the natural convection. It is considered that a constant density for natural convection flows, except in the buoyancy force term that drives the natural convection. The porous media is considered as homogeneous and isotropic in its physical properties. The thermal conductivity of fluid and solid is assumed to be constant with respect to temperature.
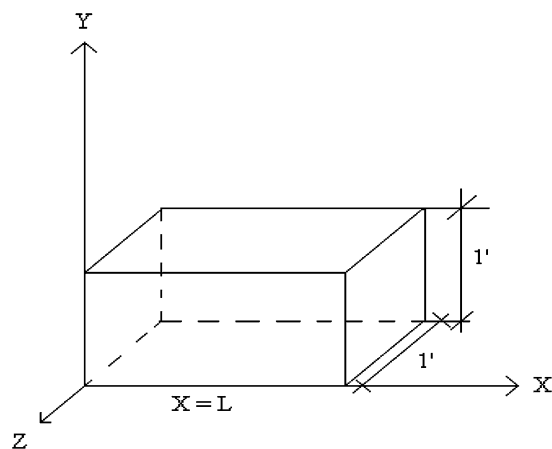

Figure 2. Porous media representing the media.

For an incompressible flow, the continuity equation can be written as

$$\frac{\partial u}{\partial x} = 0 \tag{1}$$

The momentum equation (Chan and Banerjee, 1981; Kaviany, 2002) subject to the above conditions for describing the motion of fluid phase in the system is

$$\frac{\rho_f}{\phi}\frac{\partial u}{\partial t} + \frac{\rho_f u}{\phi^2}\frac{\partial u}{\partial x} = -\frac{\partial p}{\partial x} + \rho_f g - \frac{\mu}{K_i}u + \mu\frac{\partial^2 u}{\partial x^2} \tag{2}$$

Substituting Eq. (1) into Eq. (2) becomes:

$$\frac{\partial p}{\partial x} = \rho_f g - \frac{\mu}{K_i}u - \frac{\rho_f}{\phi}\frac{\partial u}{\partial t}. \tag{3a}$$

It is assumed that the axis x is horizontal and therefore,

$$\frac{\partial p}{\partial x} = -\frac{\mu}{K_i}u - \frac{\rho_f}{\phi}\frac{\partial u}{\partial t} \tag{3b}$$

Now, the initial reservoir temperature T_i can be defined as the average solid phase temperature T_s and fluid injection temperature T_f. These two temperatures represent the thermal state of each phase in the same REV. Here, T_s and T_f are different. So the heat transfer within the medium can be represented by an energy balance equation (Chan and Banerjee, 1981; Kaviany, 2002) for the two phases as:

$$-\frac{\partial}{\partial x}k_s\frac{\partial T_s}{\partial x} = -(1-\phi)(\rho c_p)_s\frac{\partial T_s}{\partial t} + h(T_s - T_f) \tag{4a}$$

$$-\frac{\partial}{\partial x}k_f\frac{\partial T_f}{\partial x} + (\rho c_p)_f\frac{\partial (uT_f)}{\partial x} = -\phi(\rho c_p)_f\frac{\partial T_f}{\partial t} + h(T_f - T_s) \tag{4b}$$

When the reservoir becomes a thermally equilibrium condition, i.e., when T_s and T_f will be the same, then the total given heat Q_g will be equal to total heat loss rate in the formation per unit length. Hagoort (2004) pointed out that Q_g is a function of temperature, length, and time. However, to simplify the problem, $Q_g(T, s, t)$ is considered as constant with respect to temperature, length, and time. Consider that the thermal conductivity of solid rock matrix and fluid remains the same where there is no chemical and physical bond change as energy conversion. Now combine Eqs. (4a) and (4b) for a common equilibrium temperature T, which leads to the form of Eq. (5).

$$\{\phi\rho_f c_{pf} + (1-\phi)\rho_s c_{ps}\}\frac{\partial T}{\partial t} + \rho_f c_{pf}u\frac{\partial T}{\partial x} - (k_s + k_f)\frac{\partial^2 T}{\partial x^2} = 0 \tag{5}$$

where

$$\rho_f c_{pf} = \rho_w c_{pw} S_w + \rho_o c_{po} S_o + \rho_g c_{pg} S_g \tag{6}$$

$$k_f = k_w + k_0 + k_g \tag{7}$$

$$\rho_f = \rho_w S_w + \rho_o S_o + \rho_g S_g \tag{8}$$

and

$$S_w + S_o + S_g = 1 \tag{9}$$

$$P_{cow} = P_o - P_w \tag{10}$$

$$P_{cgo} = P_g - P_o \tag{11}$$

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 from heat capacity data at a constant pressure. Equation (12), as given by Green and Willhite (1998), provides one with an expression of 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_f (in °F).

$$Q_g = M(T_f - T_s) \tag{12}$$

where

$$M = (1 - \phi)\rho_s c_{ps} + \phi S_o \rho_o c_{po} + \phi S_w \rho_w c_{pw} + \phi S_g \rho_g c_{pg} \tag{13}$$

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

$$c_{pw} = \frac{H_{wTf} - H_{wr}}{T_f - T_r} \tag{14}$$

$$c_{po} = \frac{H_{oTf} - H_{oTi}}{T_f - T_i} \tag{15}$$

$$c_{ps} = \frac{H_{sTf} - H_{sTi}}{T_f - T_i} \tag{16}$$

$$c_{pg} = \frac{H_{gTf} - H_{gTr}}{T_f - T_r} \tag{17}$$

In order to render Eq. (5) dimensionless, the following considerations have been taken into care:

$$T^* = \frac{T}{T_i}, \ \partial T^* = \frac{1}{T_i} \partial T; \ t^* = \frac{u_i t}{L}, \ \partial t^* = \frac{u_i}{L} \partial t;$$

$$x^* = \frac{x}{L}, \ \partial x^* = \frac{x}{L}, \ \partial x^* = \frac{1}{L} \partial x; \ L^* = \frac{L}{L_{res}} \text{ and } u^* = \frac{u}{u_i}.$$

Here L_{res} is the distance between production and injection well which is 200 ft.

Equation (13) can be used into Eq. (5) which can be written as:

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

$$\frac{\partial T}{\partial t} + \frac{\rho_f c_{pf}}{M} u \frac{\partial T}{\partial x} - \frac{(k_s + k_f)}{M} \frac{\partial^2 T}{\partial x^2} = 0 \qquad (18)$$

Using the dimensionless analysis, Eq. (18) can be written as:

$$\frac{T_i u_i}{L} \frac{\partial T^*}{\partial t^*} + \frac{\rho_f c_{pf}}{M} (u^* u_i) \frac{T_i}{L} \frac{\partial T^*}{\partial x^*} - \frac{(k_s + k_f)}{M} \frac{T_i}{L^2} \frac{\partial^2 T^*}{\partial x^{*2}} = 0$$

The equation reduces to:

$$\frac{\partial T^*}{\partial t^*} + \frac{\rho_f c_{pf}}{M} (u^*) \frac{\partial T^*}{\partial x^*} - \frac{(k_s + k_f)}{M L u_i} \frac{\partial^2 T^*}{\partial x^{*2}} = 0 \qquad (19)$$

Equation (19) has been used to find out the temperature distribution along x-direction.

Permeability Alteration

For a fractured porous media, it is assumed that the Boussinesq approximation (Ghorayeb and Firoozabadi, 2000; Islam and Nandakumar, 1990) is valid in the range of temperature and pressure so that the density ρ is constant except in the buoyancy term ($\rho g z$) where it varies linearly with the temperature T_f. So this approximation is invoked to model the permeability variation with respect to heat transfer in the formation which is

$$\rho_r = \rho_f \{1 - \beta(T_r - T_f)\} \qquad (20)$$

The fluid velocity in the media can be described by using Darcy's law:

$$u = -\frac{K_{(T,t)}}{\phi \mu} \left(\frac{\partial p}{\partial x} + \rho_f [1 - \beta(T_r - T_f)] g \right) \qquad (21)$$

Substituting $T_s = T_f = T$ in Eq. (19) becomes:

$$K_{(T,t)} = \frac{-\phi\mu u}{\dfrac{\partial p}{\partial x} + \rho_f\{1 - \beta(T_r - T)\}g} \tag{22}$$

Furthermore, the relative permeability can be defined as the ratio of effective permeability to absolute permeability. Therefore, from the definition, one can write

$$K_r = \frac{K_{eff}}{K_{abs}} \tag{23}$$

Porosity Alteration

Kühn et al. (2002) used the Kozeny-Carman equation (Carman, 1956), which links permeability to the effective pore radius and the formation factor to produce a general permeability-porosity relationship (Pape et al., 1999) as a three-term power series of porosity.

$$K_{(T,t)} = A\phi + B\phi^p + C(10\phi)^q \tag{24}$$

where the exponents p and q depend on the fractal dimension. The coefficients A, B, and C need to be calibrated for each type of reservoir sandstone or chemical pore-space modification. For average sandstone (porosity range 2: 40%), Pape et al. (1999) found coefficients and exponents

$$K_{(T,t)} = 31\phi + 7,463\phi^2 + 191(10\phi)^{10} \tag{25}$$

To investigate the effects of temperature on porosity, a steady state situation is considered, where velocity does not change for a particular time interval. So, for a constant time period, Eq. (25) can be differentiated with respect to temperature and can be written as:

$$\frac{\partial K}{\partial T} = 31\frac{\partial\phi}{\partial T} + 14,926\phi\frac{\partial\phi}{\partial T} + 191 \times 10^{11}\phi^9\frac{\partial\phi}{\partial T}$$

$$\frac{\partial K}{\partial T} = (31 + 14,926\phi + 191 \times 10^{11}\phi^9)\frac{\partial\phi}{\partial T} \tag{26}$$

Combining Eqs. (3) and (22) yields:

$$K_{(T,t)} = \frac{-\phi\mu_T u}{\rho_f g - \dfrac{\mu}{K_i}u - \dfrac{\rho_f}{\phi}\dfrac{\partial u}{\partial t} + \rho_f\{1 - \beta(T_r - T)\}g}$$

$$K_{(T,t)} = \frac{-\phi\mu_T u}{2\rho_f g - \dfrac{\mu}{K_i}u - \dfrac{\rho_f}{\phi}\dfrac{\partial u}{\partial t} - \rho_f\beta g T_r + \rho_f\beta g T} \tag{27}$$

For a constant time, permeability can be differentiated with respect to temperature T, and Eq. (27) becomes:

$$\frac{\partial K}{\partial T} = \frac{-\frac{\partial \phi}{\partial T}\mu_T u(2\rho_f g - \mu u/K_i - \rho_f/\phi \partial u/\partial t - \rho_f \beta g T_r + \rho_f \beta g T)}{\left[2\rho_f g - \frac{\mu}{K_i}u - \frac{\rho_f}{\phi}\frac{\partial u}{\partial t} - \rho_f \beta g T_r + \rho_f \beta g T\right]^2}$$

$$- \frac{(-\phi\mu u) \times \left(-\frac{\rho_f \partial u/\partial t}{\phi^2}\frac{\partial \phi}{\partial T} + \rho_f \beta g\right)}{\left[2\rho_f g - \frac{\mu}{K_i}u - \frac{\rho_f}{\phi}\frac{\partial u}{\partial t} - \rho_f \beta g T_r + \rho_f \beta g T\right]^2}$$

$$\frac{\partial K}{\partial T} = \frac{-\frac{\partial \phi}{\partial T}\mu u}{\left[2\rho_f g - \frac{\mu}{K_i}u - \frac{\rho_f}{\phi}\frac{\partial u}{\partial t} - \rho_f \beta g T_r + \rho_f \beta g T\right]}$$

$$+ \frac{(\phi\mu u) \times \left(-\frac{\rho_f \partial u/\partial t}{\phi^2}\frac{\partial \phi}{\partial T} + \rho_f \beta g\right)}{\left[2\rho_f g - \frac{\mu}{K_i}u - \frac{\rho_f}{\phi}\frac{\partial u}{\partial t} - \rho_f \beta g T_r + \rho_f \beta g T\right]^2} \tag{28}$$

Substituting Eq. (28) into Eq. (26) yields:

$$\frac{(\phi\mu u) \times \left(-\frac{\rho_f \partial u/\partial t}{\phi^2}\frac{\partial \phi}{\partial T} + \rho_f \beta g\right)}{\left[2\rho_f g - \frac{\mu}{K_i}u - \frac{\rho_f}{\phi}\frac{\partial u}{\partial t} - \rho_f \beta g T_r + \rho_f \beta g T\right]^2}$$

$$- \frac{\mu u\frac{\partial \phi}{\partial T}}{\left[2\rho_f g - \frac{\mu u}{K_i} - \frac{\rho_f}{\phi}\frac{\partial u}{\partial t} - \rho_f \beta g T_r + \rho_f \beta g T\right]}$$

$$= (31 + 14{,}926\phi + 191 \times 10^{11}\phi^9)\frac{\partial \phi}{\partial T}$$

Let us assume

$$A_1 = 2\rho_f g - \frac{\mu}{K_i}u - \frac{\rho_f}{\phi}\frac{\partial u}{\partial t} - \rho_f \beta g T_r + \rho_f \beta g T$$

Substituting the value of A_1 in the above equation,

$$\frac{(\phi\mu u) \times \left(-\dfrac{\rho_f \partial u/\partial t}{\phi^2}\dfrac{\partial\phi}{\partial T} + \rho_f\beta g\right)}{A_1^2} - \frac{\mu u\dfrac{\partial\phi}{\partial T}}{A_1}$$

$$= (31 + 14{,}926\phi + 191 \times 10^{11}\phi^9)\frac{\partial\phi}{\partial T}$$

$$\left(31 + 14{,}926\phi + 191 \times 10^{11}\phi^9 + \frac{\mu\rho_f u}{\phi A_1^2}\frac{\partial u}{\partial t} + \frac{\mu u}{A_1}\right)\frac{\partial\phi}{\partial T} = \frac{\phi\mu\rho_f u\beta g}{A_1^2}$$

Again let

$$A_2 = \left(31 + 14{,}926\phi + 191 \times 10^{11}\phi^9 + \frac{\mu\rho_f u}{\phi A_1^2}\frac{\partial u}{\partial t} + \frac{\mu u}{A_1}\right)$$

Putting the value of A_2 in the above equation,

$$\frac{\partial\phi}{\partial T} = \frac{\phi\mu\rho_f u\beta g}{A_1^2 \times A_2} \tag{29}$$

Pore Volume Change

Equation (29) represents the variation of porosity with temperature. Now, in order to develop the change of pore volume due to heat transfer through porous media, one can determine this from the definition of porosity. So the relation between porosity and pore volume can be written as:

$$V_{pore} = \phi V_{bulk}$$

$$\frac{\partial V_{pore}}{\partial T} = V_{bulk}\frac{\partial\phi}{\partial T} \tag{30}$$

Cumulative Oil Recovery

The general form of material balance equation can be written as:

$$
\begin{matrix}
\text{Underground} \\ \text{withdrawal} \\ (rb)
\end{matrix}
=
\begin{matrix}
\text{Expansion} \\ \text{of oil} \\ (rb)
\end{matrix}
+
\begin{matrix}
\text{Original} \\ \text{dissolved} \\ \text{gas } (rb)
\end{matrix}
+
\begin{matrix}
\text{Expansion} \\ \text{of gas cap} \\ \text{gas } (rb)
\end{matrix}
+
\begin{matrix}
\text{Connate} \\ \text{water} \\ \text{expansion} \\ (rb)
\end{matrix}
+
\begin{matrix}
\text{Change} \\ \text{of pore} \\ \text{volume} \\ (rb)
\end{matrix}
\tag{31}
$$

a) *Underground withdrawal*

$$\text{Underground withdrawal} = N_P(B_0 + (R_p - R_S)B_g)$$

b) *Expansion of oil*

$$\text{Expansion of oil} = N(B_0 - B_{0i})$$

c) *Original dissolved gas*

$$\text{Original dissolved gas} = N(R_{Si} - R_S)B_g$$

d) *Expansion of gas cap gas*

$$\text{Expansion of gas cap gas} = mNB_{0i}\left(\frac{B_g}{B_{gi}} - 1\right)$$

e) *Change in pore volume*

Change in pore volume, i.e., rock volume

$$= (1 + m)\frac{NB_{0i}(C_w S_{wi} + C_f)}{(1 - S_{wi})}\Delta P$$

If we consider there is no water influx, then material balance equation becomes:

$$N_P\{B_0 + (R_P - R_S)B_g\} = N(B_0 - B_{0i}) + N(R_{Si} - R_S)B_g$$

$$+ mNB_{0i}(B_g/B_{gi} - 1)$$

$$+ (1 + m)\frac{NB_{0i}(C_w S_{wi} + C_f)}{(1 - S_{wi})}\Delta P$$

$$N_P = \frac{N}{\{B_0 + (R_P - R_S)B_g\}}\{B_0 - B_{0i} + (R_{Si} - R_S)B_g$$

$$+ mB_{0i}\left(\frac{B_g}{B_{gi}} - 1\right) + (1 + m)\frac{B_{0i}(C_W S_{Wi} + C_f)}{1 - S_{wi}}\Delta P\}$$

We know that initial oil in place N can be defined as:

$$N = \frac{V\phi(1 - S_{wi})}{B_{0i}}$$

So the above equation can be written as:

$$N_P = \frac{V\phi(1 - S_{wi})}{\{B_0 + (R_P - R_S)B_g\}}\left\{\frac{B_0 - B_{0i} + (R_{Si} - R_S)B_g}{B_{0i}}\right.$$

$$\left. + m\left(\frac{B_g}{B_{gi}} - 1\right) + (1 + m)\frac{(C_W S_{Wi} + C_f)}{1 - S_{wi}}\Delta P\right\}$$

Let

$$A_3 = \frac{V(1 - S_{wi})}{\{B_0 + (R_P - R_S)B_g\}} \left\{ \frac{B_0 - B_{0i} + (R_{Si} - R_S)B_g}{B_{0i}} + m \left(\frac{B_g}{B_{gi}} - 1 \right) \right.$$

$$\left. + (1 + m)\frac{(C_W S_{Wi} + C_f)}{1 - S_{wi}} \Delta P \right\}$$

So

$$N_P = \phi A_3 \tag{32}$$

Initial and Boundary Conditions

The initial conditions are specified as follows:

$$T(x \rightarrow L, t = 0) = T_i = T_s \text{ and } T(x = 0, t = 0) = T_i = T_s$$

The boundary conditions are as follows:

$$q_{inj} = \text{Constant at } T(x = 0, t) \text{ and } T = T_i, \text{ at } x = L$$

$$T_{injection} = T_f \text{ at } T(x = 0, t) \text{ and } T = T_i, \text{ at } x = L$$

NUMERICAL SIMULATION

The variation of permeability, porosity, and pore volume can be solved using a momentum balance equation. Cumulative oil production can be solved using a material balance equation with calculated porosity values. Temperature variation along x-direction for a constant time period has been considered to find out the rock parameters. Change of temperature with respect to distance between injection and production well is calculated from an energy balance equation of the system. Darcy and Boussinesq's approximation model has been used to simulate all the parameters presented in the theory.

To solve the problems, the Gauss-Seidel iteration explicit discretization method has been used. Equation (20) has been solved for the variation of permeability with different temperatures along x-direction using a momentum equation (Eq. (3)) at different time steps. The following parameter values, such as $A_{yz} = 200$ ft^2, $A = 0.267$ (7" ϕ), ft^2, $g = 32.4$ ft/sec^2, $K_i = 100$ md, $L = 200$ ft, $q_{inj} = 500$ sbl/day, $T = 150°F \sim 500°F$, $T_r = 500°F$, $T_i = 150°F$, $u = 0.1217t$ ft/sec, $V_{bulk} = 200$ ft^3, $\phi = 25\%$, $\mu_f = 10,000$ cp, $\rho_g = 1.0433$ lb$_m$/ft^3, $\rho_0 = 50.0$ lb$_m$/ft^3, $\rho_w = 62.4$ lb$_m$/ft^3, $S_g = 20\%$, $S_0 = 50\%$, $S_w = 30\%$, $\beta = 0.0005$ 1/°F have been considered to simulate the model. Here, t is in hours. Similarly, Eqs. (26) and (27) have been solved to find out the variation of porosity and pore volume with temperature for different time steps. To simulate the porosity with temperature, Eq. (29) has been used. Here $\Delta t = 1.0$ hr has been considered.

For cumulative oil production, $C_f = 0.0000086$, psi^{-1}; $C_w = 0.000003$, psi^{-1}; $m = 0.4$; $S_{wi} = 0.3$; $R_P = 0.0$, scf/stb; $B_{gi} = 0.0006$, rb/stb at 4,000 psi; $B_g = 0.00087$, rb/stb at 3,330 psi; $R_{Si} = 620$, scf/stb at 4,000 psi; $B_{0i} = 1.2417$, rb/stb at 4,000 psi; $B_0 = 1.2511$, rb/stb at 3,330 psi; $\Delta P = P_i - P = 670.0$ psi, $R_S = 510$, scf/stb at 3,330 psi; $V = 200$ ft^3 have been considered in numerical simulation.

For temperature distribution along x-direction, $u_i = 0.1217$ ft/sec; $\Delta x = 0.001$ ft; $\Delta t = 0.0000005$; $\Delta t/(\Delta x)^2 = 0.5$; $T_{injection} = T_f = 500°$F, and $T_{boundary} = T_{production} = T_i = 150°$F have been considered in numerical simulation. Equation (19) has been used for numerical simulation.

These phenomena describe the effects of enhanced oil recovery due to heat loss in the formation during thermal operation. A change of thermal expansion of rock is influenced in the oil recovery. After certain expansion, i.e., when the reservoir will reach its steady state temperature $T_i = T_f$, then the rock expansion will stop and hence the recovery of oil due to this criterion will not further effect the recovery. It should be mentioned here that other properties have not been considered during this calculation.

RESULTS AND DISCUSSION

Figures 3–8 show the rock properties change for different temperatures. Figure 3 shows the variation of permeability with temperature along the x-direction. This is for the 1–5-hr time interval. Permeability decreases with the increase of temperature for every time step. As times goes up, permeability change is more steep, i.e., the permeability changes more rapidly with temperature at longer time.

Figure 4 shows the variation of permeability with temperature along the x-direction. This is for time 6–10-hr time interval. Permeability decreases with the increase of temperature for every time step. As time is increased, permeability changes are steeper.

Figures 5 and 6 show the variation of porosity with temperature along the x-direction. This is for time intervals of 1–5 hr and 6–10 hr, respectively. Porosity decreases with the increase of temperature for every time step. As times elapses, porosity changes are more pronounced.

Fluid expansion is more predominant than rock expansion within the pore space. Due to this, when fluid moves from pore space toward a production well, both the rock and the void space decompress, increasing respective volumes. However, the rock decompression is much less pronounced than fluid decompression, leading to an overall increase in porosity.

Figures 7 and 8 show the variation of pore volume with temperature along the x-direction. This is for time intervals of 1–5 hr and 6–10 hr, respectively. Pore volume increases with the increase of temperature for every time step. As times goes up, pore volume change is more steep, i.e., the pore volume changes more rapidly with temperature at longer times. Normally, the
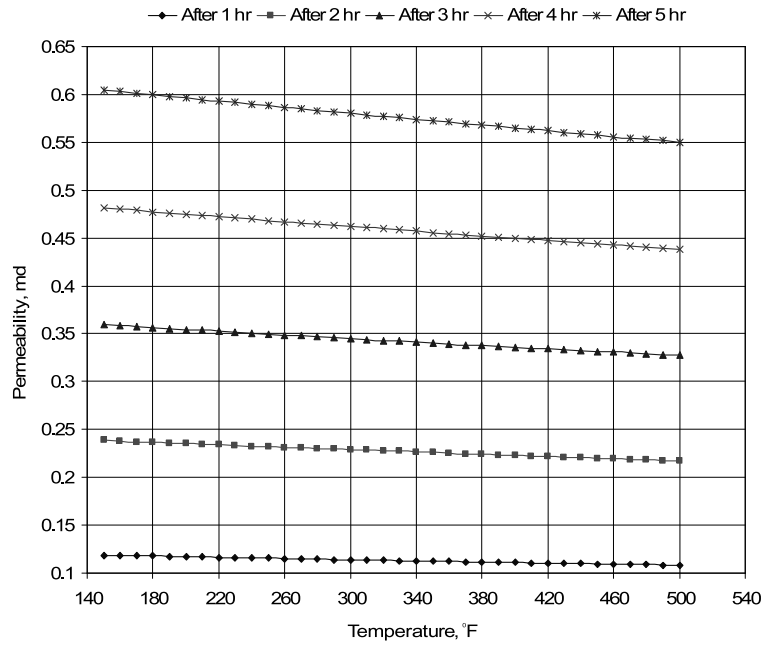
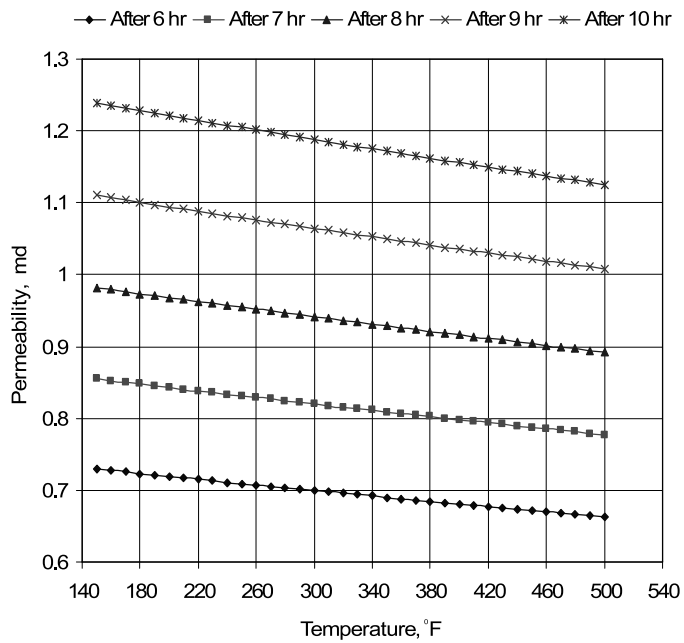*Figure 3.* Variation of permeability with temperature after 1–5 hr.

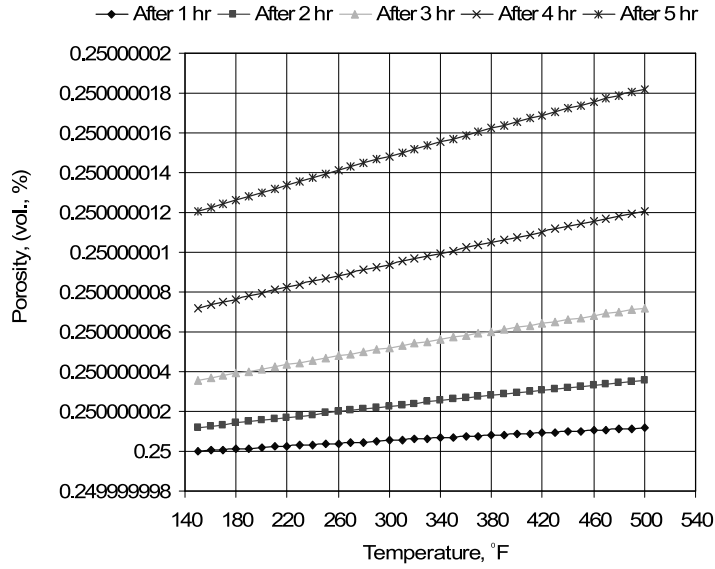*Figure 4.* Variation of permeability with temperature after 6–10 hr.

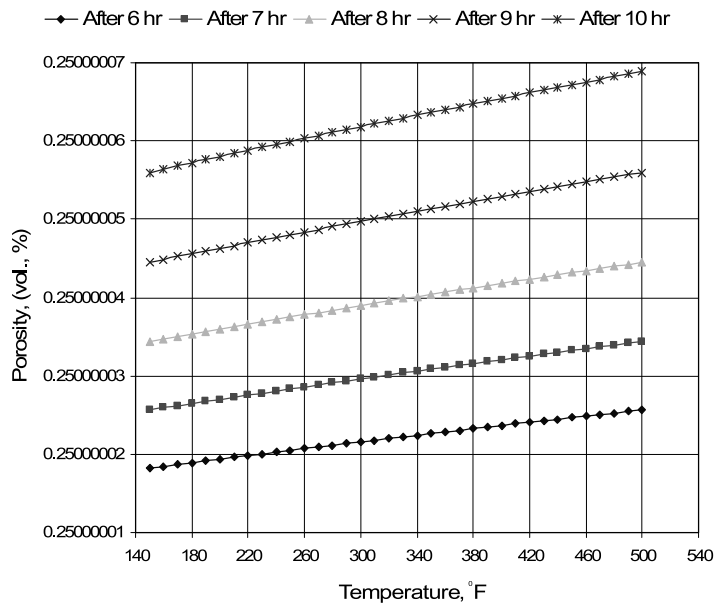***Figure 5.*** Variation of porosity with temperature after 1–5 hr.

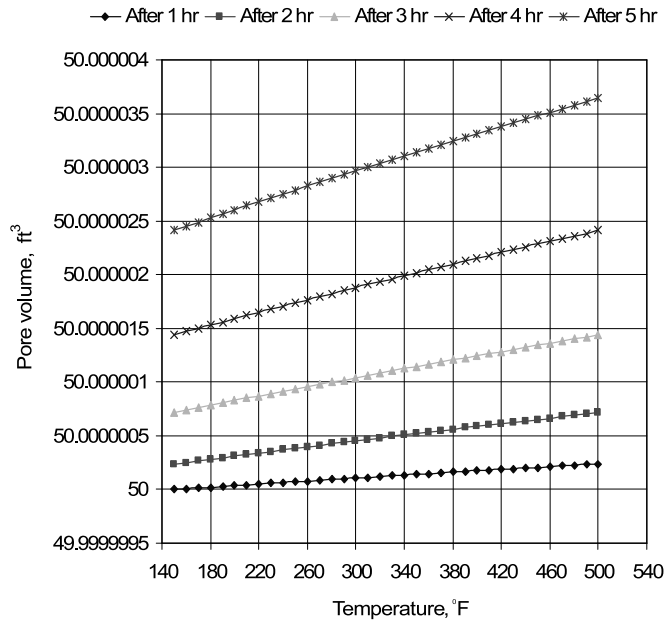***Figure 6.*** Variation of porosity with temperature after 6–10 hr.

Figure 7. Variation of pore volume with temperature after 1–5 hr.
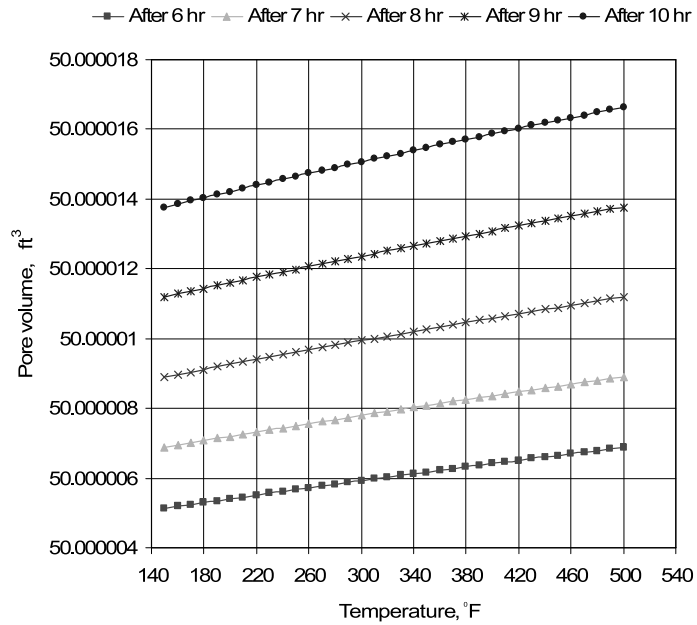

Figure 8. Variation of pore volume with temperature after 6–10 hr.

pore volume value decreases with the increase of temperature. However, this finding shows the opposite nature of pore volume change. Fluid expansion is more predominant than rock expansion within the pore space. Due to this, when fluid moves from pore space toward production well, the rock and void space loses the pressure which increases the pore volume of the rock matrix.

Figures 9 and 10 show the cumulative oil production due to the change of pore volume during thermal operation. These figures show the variation of pore volume with temperature along the x-direction. This is for time intervals of 1–5 hr and 6–10 hr, respectively. This cumulative oil production is only due to the change of rock matrix when only temperature is considered as a criterion for oil production. Cumulative oil production increases with the increase of temperature for every time step. As times goes up, the change is steeper, i.e., the oil recovery goes up rapidly with temperature at a longer time. In cumulative oil production, the effect of temperature is not significant during the later stage of production. This is a nominal addition of cumulative oil production during thermal operation. The other factors, such as fluid expansion, pressure change, and water influx, are the most dominant factors for oil recovery. The previous section discusses the reason behind such behavior.

Figure 11 shows the dimensionless temperature distribution with dimensionless distance along the x-direction. The temperature profile reaches its
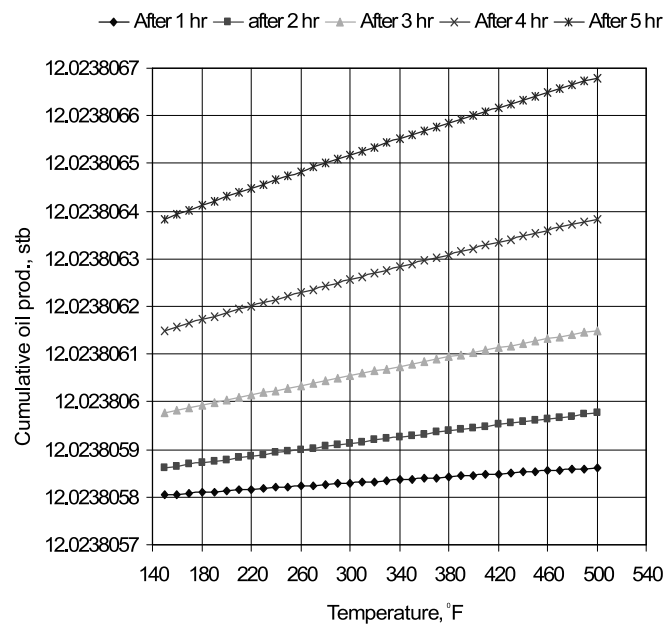

Figure 9. Variation of cumulative oil production with temperature after 1–5 hr.
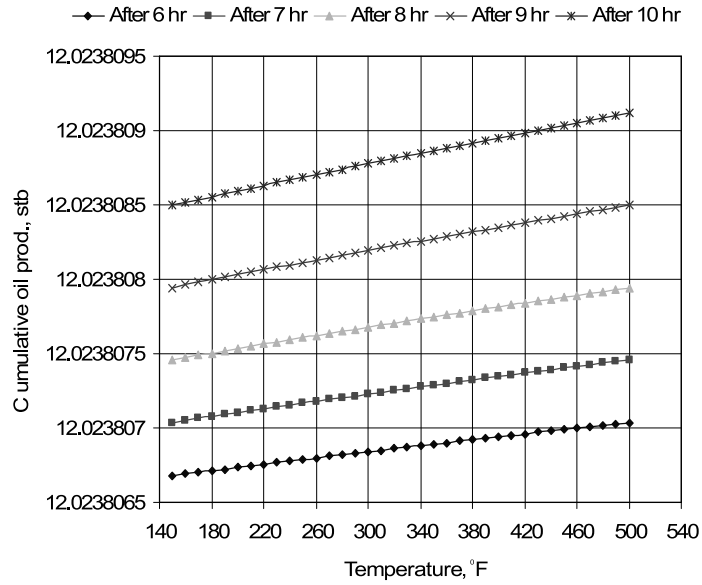
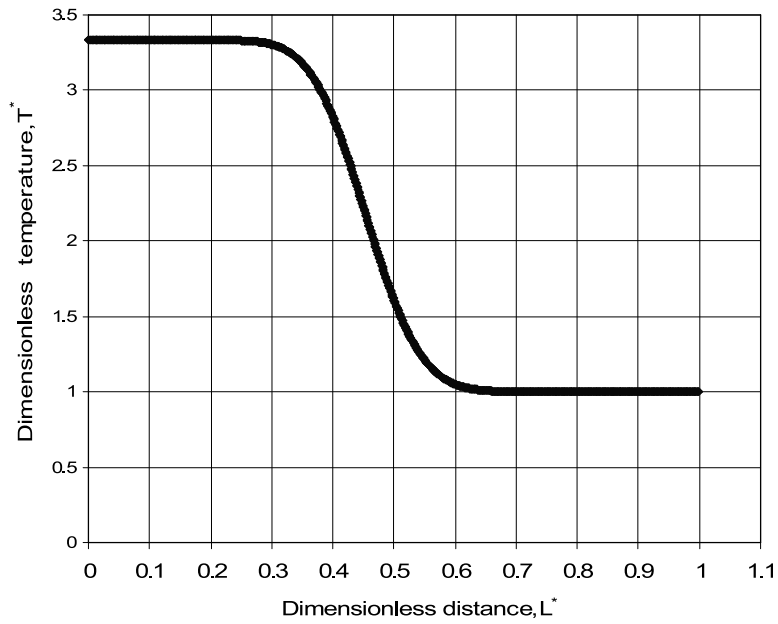***Figure 10.*** Variation of cumulative oil production with temperature after 6–10 hr.

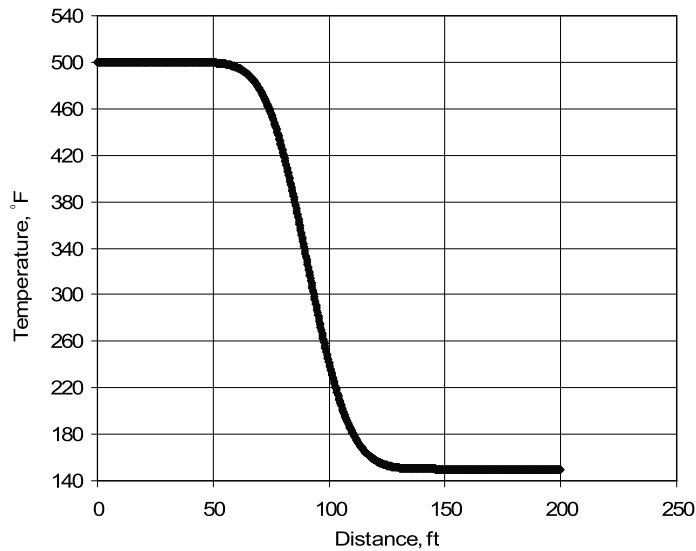***Figure 11.*** Variation of temperature along *x*-direction.

Figure 12. Variation of temperature along *x*-direction.

steady state when dimensionless distance becomes 0.912, i.e., temperature reaches its boundary with the reservoir.

Figure 12 shows the temperature distribution along the *x*-direction. The temperature profile reaches its steady state when dimensionless distance becomes 165.8 ft, i.e., temperature reaches its boundary with the reservoir.

CONCLUSIONS

A series of numerical runs was conducted in order to determine the role of thermal alterations on porosity and permeability of rock. Based on this numerical simulation study, the following conclusions can be reached.

1. Permeability decreases with an increase of temperature during thermal operation in an oil recovery scheme. During a thermal injection scheme, permeability increases with time.
2. Porosity increases with increase of temperature. During a thermal injection scheme, porosity increases with time.
3. The net result of an increase in temperature is an overall increase in cumulative oil production. The amount of incremental oil production is found to be greater in case the combined effects of thermal alterations on porosity and permeability are included than in conventional analysis, which ignores thermal alterations.

ACKNOWLEDGMENTS

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NOMENCLATURE

A_{yz}	Cross-sectional area of rock perpendicular to the flow of heat, ft^2
A	Cross-sectional area of injection and production well, ft^2
B_g	Gas formation volume factor, rb/stb
B_{gi}	Gas formation volume factor at initial pressure, P_i, rb/stb
B_0	Oil formation volume factor at reduced pressure, P, rb/stb
B_{0i}	Oil formation volume factor at initial pressure, P_i, rb/stb
C_f	Reservoir fluid compressibility, psi^{-1}
C_w	Reservoir water compressibility, psi^{-1}
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 hot water or steam, Btu/lb$_m$ − °F
E	Activation energy for viscous flow, Btu/mol
g	Gravitational acceleration in x direction, ft/sec^2
h	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 hot water or steam at temperature T_f, Btu/lb$_m$
H_{gTr}	Enthalpy of hot water or steam at temperature T_r, Btu/lb$_m$
K_i	Initial reservoir permeability, md
$K_{(T,t)}$	Reservoir permeability varies with temperature and time, md
k_f	Thermal conductivity of fluid, Btu/hr − ft − °F
k_o	Thermal conductivity of oil, Btu/hr − ft − °F
k_s	Thermal conductivity of solid rock matrix, Btu/hr − ft − °F
k_w	Thermal conductivity of water, Btu/hr − ft − °F
k_g	Thermal conductivity of hot water or steam, Btu/hr − ft − °F
L	Distance between production and injection well along x direction, ft
L^*	Dimensionless length of the reservoir
m	Initial hydrocarbon volume of the gas cap/initial hydrocarbon volume of oil
M	Average volumetric heat capacity of the fluid-saturated rock, Btu/ft^3 − °F
N	Initial oil in place = $V\phi(1 - S_{wi})/B_{0i}$, stb
N_P	Cumulative oil production, stb
p	Pressure of the system, psia
P_{cow}	Capillary pressure of water oil interface, psia

P_{cgo}	Capillary pressure of gas oil interface, psia
P_o	Pressure of oil, psia
P_w	Pressure of water, psia
P_g	Pressure of gas, psia
ΔP	$P_i - P =$ Pressure drop in the reservoir, psi
Q_g	Constant rate of heat generation per unit volume, Btu/ft^3
q_{inj}	$Au =$ injection volume flow rate of hot water or steam, sbl/day
q_{prod}	$Au =$ production volume flow rate of oil, sbl/day
R	Universal gas constant, Btu/mol $-$ °F
R_P	Cumulative gas-oil ratio $=$ cumulative gas production/cumulative oil production, scf/stb
R_S	Solution gas-oil ratio, scf/stb
R_{Si}	Initial solution gas-oil ratio, scf/stb
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
V	Total reservoir volume, ft^3
V_{pore}	Pore volume of rock matrix, ft^3
V_{bulk}	Bulk volume of rock matrix, ft^3
x^*	Dimensionless distance
ϕ	Porosity of the rock, volume fraction
μ_r	Dynamic viscosity of reservoir fluid at a reference temperature T_r, cp
μ_T	Dynamic viscosity of reservoir fluid at temperature T, cp
β	Coefficient of thermal expansion, 1/°F
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 hot water or steam, lb$_m$/ft^3