

THE NEAR-WELLBORE PRESSURE CALCULATION MODEL INCORPORATING THERMOCHEMICAL EFFECT

by

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The potential difference of hydraulic pressure, solute concentration and temperature between the drilling fluid and the formation fluid can induce the flow of solvent and cause changes in the pore pressure during drilling a tight formation, which may result in wellbore instability. According to the continuity equation of fluid, the pore pressure calculation model considering the effect of thermochemical coupling is established and the solution of the pore pressure in the Laplace domain is given. Using this model, the effects of the temperature, solute concentration and viscosity of drilling fluid on the pore pressure around the wellbore are simulated. The results show that, when the wellbore pressure is higher than the formation pressure and the solute concentration of the drilling fluid is larger than that of the formation fluid, the near-wellbore pore pressure will decrease first and then increase during drilling a tight formation, and increasing the drilling fluid temperature will decrease the pore pressure. Increasing the solute concentration of the drilling fluid can inhibit the increase of the pore pressure.

Key words: *tight reservoir, pore pressure, solute concentration, temperature, coupling effect*

Introduction

Except for rock mechanical properties, the near-wellbore pore pressure also will change with time during drilling a tight reservoir, resulting in a deterioration of wellbore instability. On the one hand, the tight reservoir has a certain permeability, which means that the hydraulic pressure will drive pore fluid to move into or out of the formation [1, 2]. On the other hand, the permeability of tight reservoir is extremely low and the solvent will flow into or out of the formation driven by chemical potential, as a similar effect of semipermeable membrane [3, 4]. In addition, the volume variation of formation fluid and rock caused by temperature change may also have some effect on the pore pressure around the wellbore. Therefore, many scholars have analyzed the thermal effects [5-8] and chemical effects [3, 4, 9-12] on the variation of near-wellbore pore pressure. Lomba [13] established a pore pressure diffusion equation by using the solute continuity equation and the relationship between the density and the pressure of formation fluid, ignoring the effect of temperature on pore pressure change. Combining the thermochemical constitutive equations of poroelastic medium and equations for solute and thermal diffusion, Araujo [14] and Araujo *et al.*, [15] established a pore pressure calculation model incorporating thermochemical coupling effect. However, the effects of temperature on the variation of solute concentration and fluid volume are neglected. Ghassemi *et al.* [16] and Zhou

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and Ghassemi [17] established a fully coupled thermochemical model, but the model is too complex. In this paper, a new calculation model of near-wellbore pore pressure is established by assuming that the formation fluid is slightly compressible, and that the thermal diffusion is faster than the solute diffusion which is faster than the hydraulic diffusion in tight reservoir. Using the model, the influence of drilling fluid performance on the near-wellbore pore pressure is simulated.

Pore pressure calculation model

Thermal diffusion equation

When a drilling fluid contacts with the formation, the heat diffusion will occur between the drilling fluid and the formation rock. Kurashige [5] established a thermal diffusion equation considering the heat diffusion caused by the flow of pore fluid. But the effect of the flow of pore fluid on the heat diffusion can be neglected because that the thermal diffusion is much faster than the flow of fluid in a tight reservoir. Therefore, the uniform thermal diffusion equation can be simplified [6]:

$$\frac{\partial T}{\partial t} = c^T \nabla^2 T \quad (1)$$

Solute diffusion equation

Driven by hydraulic pressure, chemical potential, and thermal difference the solvent of fluid may flow into or out of the formation, resulting in a variation of the solute concentration near the wellbore. Considering that the permeability of tight reservoir is very low, the influence of hydraulic pressure on the flow of solvent can be neglected. Under the combined effect of chemical potential and thermal difference, the variation of solute concentration can be determined by the diffusivity equation [16]:

$$\frac{\partial C}{\partial t} = \frac{D^S}{\phi} \nabla^2 C + \frac{\bar{C}^S D^T}{\phi} \nabla^2 T \quad (2)$$

Pore pressure calculation model

The flow of formation fluid is driven by hydraulic pressure, chemical potential and thermal difference, so the flux of formation fluid may be written [16]:

$$J_f = -\frac{k}{\mu} \left[\nabla P - \frac{\Re \rho R \bar{T}}{M^S \bar{C}^S (1 - \bar{C}^S)} \nabla C \right] + K^T \nabla T \quad (3)$$

Taking into account the slight compressibility of formation fluid, the relationship between density and pressure of formation fluid is [13]:

$$\rho = \rho_0 \exp[c_p (P - P_0)] \quad (4)$$

According to the continuity equation of fluid, the fluid density and flux have the following relationship:

$$\frac{\partial \rho}{\partial t} + \nabla(\rho J_f) = 0 \quad (5)$$

Substituting eq. (4) into eq. (5) yields:

$$\frac{\partial P}{\partial t} + \frac{1}{c_p} \nabla J_f + J_f \nabla P = 0 \quad (6)$$

Substituting eq. (3) into eq. (6):

$$\begin{aligned} \frac{\partial P}{\partial t} + \frac{1}{c_p} \nabla \left[-\frac{k}{\mu} \nabla P + \frac{k}{\mu} \frac{\Re \rho R \bar{T}}{M^s \bar{C}^s (1 - \bar{C}^s)} \nabla C + K^T \nabla T \right] + \\ + \left[-\frac{k}{\mu} \nabla P + \frac{k}{\mu} \frac{\Re \rho R \bar{T}}{M^s \bar{C}^s (1 - \bar{C}^s)} \nabla C + K^T \nabla T \right] \nabla P = 0 \end{aligned} \quad (7)$$

Neglecting the third item [13, 18] in eq. (7) then substituting eqs. (1) and (2), the pore pressure incorporating thermochemical effects can be calculated by the equation:

$$\frac{\partial P}{\partial t} = C^f \left(\frac{\partial P}{\partial r^2} + \frac{1}{r} \frac{\partial P}{\partial r} \right) + C^{Tf} \frac{\partial T}{\partial t} + C^{Cf} \frac{\partial C}{\partial t} \quad (8)$$

where

$$C^f = \frac{k}{\mu} \frac{1}{c_p} \quad (9)$$

$$C^{Cf} = -\frac{k}{\mu} \frac{1}{c_p} \frac{\Re \rho R \bar{T}}{M^s \bar{C}^s (1 - \bar{C}^s)} \frac{\phi}{D^s} \quad (10)$$

$$C^{Tf} = \frac{k}{\mu} \frac{1}{c_p} \frac{\Re \rho R \bar{T}}{M^s (1 - \bar{C}^s)} \frac{D^T}{D^s c^T} - \frac{1}{c_p} \frac{K^T}{c^T} \quad (11)$$

Solution in Laplace domain

Assuming that the wellbore pressure remains a constant during drilling a tight reservoir, the solution conditions for the pore pressure field are:

$$\begin{cases} P(r_w, t) = P_w \\ P(r, 0) = P_0 \\ P(\infty, t) = P_0 \end{cases} \quad (12)$$

If $\tilde{P}(r, t)$ is the Laplace transform of $\Delta P(r, t) = P(r, t) - P_0$, the Laplace conversion of eq. (8) can be written:

$$\frac{d^2 \tilde{P}}{dr^2} + \frac{1}{r} \frac{d\tilde{P}}{dr} - \frac{s}{C^f} \tilde{P} + \frac{s C^{Tf}}{C^f} \tilde{T} + \frac{s C^{Cf}}{C^f} \tilde{C} = 0 \quad (13)$$

where s is the Laplace transform variable.

The initial conditional and boundary conditions in eq. (12) after Laplace conversion are expressed:

$$\begin{cases} \tilde{P}(r_w, t) = \frac{1}{s} (P_w - P_0) \\ \tilde{P}(r, 0) = 0 \\ \tilde{P}(\infty, t) = 0 \end{cases} \quad (14)$$

Combining eqs. (1) and (2), the particular solution of eq. (13) in regard to the temperature and the solute concentration can be written [19]:

$$\tilde{P}^* = \frac{C^f c^T}{c^T - C^f} \left(\frac{C^{Tf}}{C^f} - \frac{C^{Cf}}{C^f} \frac{\bar{C}^s D^T}{D^s - \phi c^T} \right) \tilde{T} + \frac{D^s C^{Cf}}{D^s - \phi C^f} \left(\tilde{C} + \frac{\bar{C}^s D^T}{D^s - \phi c^T} \tilde{T} \right) \quad (15)$$

In eq. (15) the solutions of the temperature and the solute concentration in the Laplace domain are [15, 16, 19]:

$$\tilde{T}(r,t) = (T_w - T_0) \frac{1}{s} \frac{K_0(\sqrt{s/c^T r})}{K_0(\sqrt{s/c^T r_w})} \quad (16)$$

$$\tilde{C}(r,t) = \left[C_w - C_0 - \frac{\bar{C}^S D^T (T_w - T_0)}{c^T \phi - D^S} \right] \frac{1}{s} \frac{K_0(\sqrt{\phi s/D^S r})}{K_0(\sqrt{\phi s/D^S r_w})} + \frac{\bar{C}^S D^T (T_w - T_0)}{c^T \phi - D^S} \frac{1}{s} \frac{K_0(\sqrt{s/c^T r})}{K_0(\sqrt{s/c^T r_w})} \quad (17)$$

Therefore, the complete solution of eq. (13) can be determined by a combination of the particular solution eq. (15) and the solution of the homogeneous form of eq. (13) Taking into account the solution conditions of eq. (14), yields the solution of pore pressure in the Laplace domain:

$$\begin{aligned} \tilde{P}(r,t) = & \left[P_w - P_0 - \frac{C^{Cf} D^S}{D^S - \phi C^{Cf}} (C_w - C_0) \right] \frac{1}{s} \frac{K_0(\sqrt{s/C^f r})}{K_0(\sqrt{s/C^f r_w})} - \\ & - \left[\frac{C^{Tf} c^T}{c^T - C^f} + \left(\frac{c^T C^{Cf}}{c^T - C^f} - \frac{C^{Cf} D^S}{D^S - \phi C^{Cf}} \right) \frac{\bar{C}^S D^T}{c^T \phi - D^S} \right] (T_w - T_0) \frac{1}{s} \frac{K_0(\sqrt{s/C^f r})}{K_0(\sqrt{s/C^f r_w})} + \\ & + \left[\frac{C^{Tf} c^T}{c^T - C^f} + \frac{c^T C^{Cf}}{c^T - C^f} \frac{\bar{C}^S D^T}{c^T \phi - D^S} \right] (T_w - T_0) \frac{1}{s} \frac{K_0(\sqrt{s/c^T r})}{K_0(\sqrt{s/c^T r_w})} + \\ & + \frac{D^S C^{Cf}}{D^S - \phi C^{Cf}} \left[C_w - C_0 - \frac{\bar{C}^S D^T (T_w - T_0)}{c^T \phi - D^S} \right] \frac{1}{s} \frac{K_0(\sqrt{\phi s/D^S r})}{K_0(\sqrt{\phi s/D^S r_w})} + \end{aligned} \quad (18)$$

Example for analysis

According to the model, the performance of drilling fluid will affect the pore pressure with time. Next, the influence of temperature, solute concentration and viscosity on the pore pressure will be simulated by assuming that the solute of both drilling fluid and formation fluid is NaCl. The relevant parameters are shown as in tab. 1.

Because the drilling fluid temperature is lower than the formation temperature, the temperature near the wellbore will decrease with time after drilling fluid contacting with wellbore wall, as shown in fig. 1. The thermal diffusion is quite fast, and it takes only 10 minutes for the temperature at $2r_w$ to begin to decrease.

The formation water will flow into the drilling fluid driven by the chemical potential, so the solute concentration will gradually increase with time. Figure 2 indicates that solute diffusion is relatively slow and the solute concentration at $2r_w$ still keeps unchanged after 20 hours.

Figure 3 indicates that a drilling fluid with high solute concentration will decrease the pore pressure and a high wellbore pressure will increase the pore pressure around the wellbore. Because solute diffusion is faster than hydraulic diffusion, the pore pressure decreases first and then increases under the interaction of hydraulic pressure, chemical potential and thermal difference.

Table 1. Parameters for analysis

Parameters	Value	Unit
Wellbore radius	0.108	[m]
Initial temperature of formation	365	[K]
Temperature of drilling fluid	315	[K]
Thermal diffusivity	$1.6 \cdot 10^{-6}$	$[m^2s^{-1}]$
Solute mass fraction of formation fluid	0.05	
Solute mass fraction of drilling fluid	0.25	
Solute diffusivity	$2.0 \cdot 10^{-9}$	$[m^2s^{-1}]$
Coefficient of thermal diffusion	$6.0 \cdot 10^{-12}$	$[m^2s^{-1}K^{-1}]$
Porosity	0.08	
Wellbore pressure	30	[MPa]
Initial pore pressure	20	[MPa]
Formation permeability	$1.0 \cdot 10^{-7}$	$[um^2]$
Viscosity of formation fluid	0.3	[mPa·s]
Reflection coefficient	0.2	
Density of formation fluid	1111.1	$[kgm^{-3}]$
Thermal osmosis coefficient	$6.0 \cdot 10^{-11}$	$[m^2s^{-1}K^{-1}]$
Molar mass of solute	0.0585	$[kgmol^{-1}]$
Fluid compressibility	$4.35 \cdot 10^{-4}$	$[MPa^{-1}]$

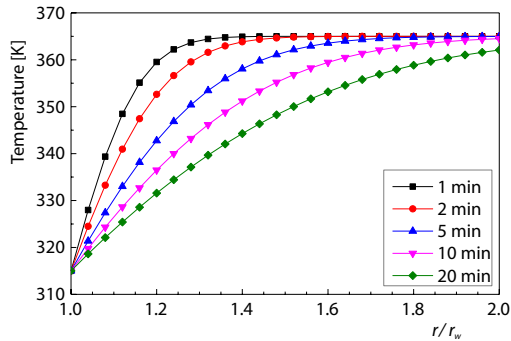


Figure 1. Variations of temperature profile with time

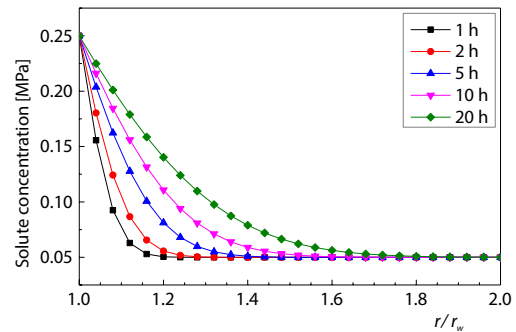


Figure 2. Variations of solute concentration profile with time

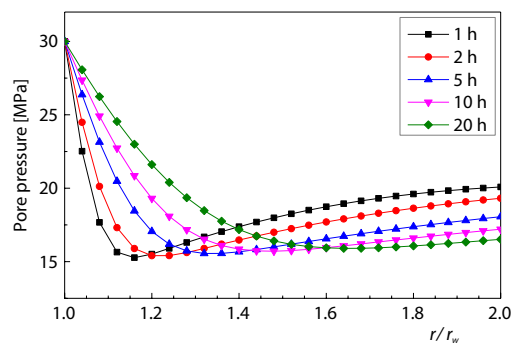


Figure 3. Variations of pore pressure profile with time

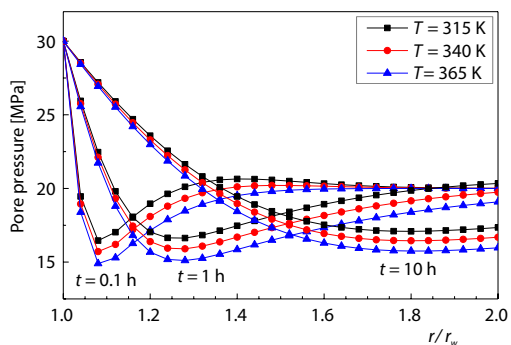


Figure 4. Effects of temperature on pore pressure profile

Changing the drilling fluid temperature and keeping the other parameters unchanged, the variations of pore pressure with the drilling time are shown as in fig. 4. Increasing the drilling fluid temperature will decrease the near-wellbore pore pressure when the solute concentration of drilling fluid is larger than that of formation fluid and the wellbore pressure is higher than formation pressure. In a short time, the temperature has a non-negligible effect on the pore pressure near the wellbore wall.

Figure 5 shows the variations of pore pressure with the solute concentration and temperature of drilling fluid after 1 hour. Both the temperature and the solute concentration of drilling fluid will affect the pore pressure profile, but the temperature has a relatively slight influence comparing to the solute concentration. When the solute concentration of drilling fluid and formation fluid are equal ($C_w = 0.05$), the near-wellbore pore pressure is mainly affected by hydraulic pressure.

If the drilling fluid temperature is 365 K and the solute mass fraction of drilling fluid is 0.05, the variation of pore pressure with the viscosity of formation fluid after 1 hour is shown as in fig. 6. The pore pressure decreases with the viscosity of formation fluid. Therefore, when the wellbore pressure is higher than the formation pressure, a formation fluid with high viscosity is beneficial to a steady the pore pressure around the wellbore.

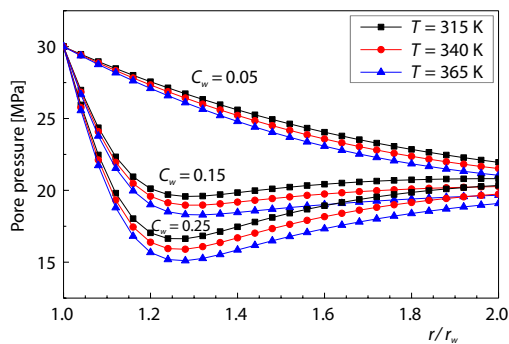


Figure 5. Effects of solute concentration on pore pressure profile after 1 hour

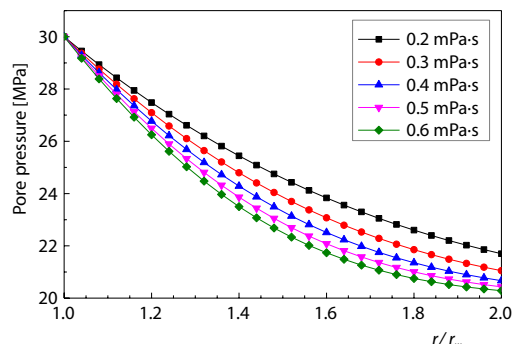


Figure 6. Effects of viscosity on pore pressure profile after 1 hour

In summary, the change of pore pressure during drilling a tight reservoir is a process of thermochemical coupling interaction. Besides the wellbore pressure, both the solute concentration and the temperature of drilling fluid will affect the near-wellbore pore pressure. When the wellbore pressure is higher than the formation pressure, increasing the solute concentration of drilling fluid is conducive to steady the pore pressure around the wellbore. When the solute concentration of drilling fluid is larger than in the formation and the wellbore pressure is higher than formation pressure, the pore pressure around the wellbore will decrease first and then increase.

Conclusion

According to the continuity equation of fluid and diffusion equations of thermal and solute, a thermochemical coupling model is established to calculate the pore pressure around the wellbore. Using this model, the effects of both the temperature and solute concentration of drilling fluid and the viscosity of formation fluid on the pore pressure around the wellbore of tight reservoir are analyzed. The model and analysis results in this paper can help drilling engineers to optimize the performance of drilling fluid for reducing the wellbore instability caused by pore pressure change.

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Nomenclature

C_0 – solute mass fraction of formation fluid, [-]	R – ideal gas constant, [$\text{m}^3\text{Pa mol}^{-1}\text{K}^{-1}$]
C_w – solute mass fraction of drilling fluid, [-]	\mathfrak{R} – reflection coefficient, [-]
\bar{C}^S – mean value of solute mass fraction, [-]	r – radial distance from wellbore axis, [m]
c^T – thermal diffusivity, [m^2s^{-1}]	\bar{T} – mean value of temperature, [K]
c_p – fluid compressibility, [MPa^{-1}]	T_w – temperature of drilling fluid, [K]
D^S – solute diffusivity, [m^2s^{-1}]	T_0 – initial temperature of formation, [K]
D^T – coefficient of thermal diffusion, [$\text{m}^2\text{s}^{-1}\text{K}^{-1}$]	t – time, [s]
K^T – thermal osmosis coefficient, [$\text{m}^2\text{s}^{-1}\text{K}^{-1}$]	
k – permeability, [um^2]	<i>Greek symbols</i>
M^S – molar mass of solute, [kgmol^{-1}]	μ – viscosity of formation fluid, [$\text{mPa}\cdot\text{s}$]
P_0 – initial pore pressure, [MPa]	ρ – density of formation fluid, [kgm^{-3}]
P_w – wellbore pressure, [MPa]	ϕ – porosity, [K]

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