Journal of Unconventional Oil and Gas Resources 11 (2015) 53–59

Contents lists available at ScienceDirect

Journal of Unconventional Oil and Gas Resources

journal homepage: www.elsevier.com/locate/juogr

Effect of distinguishing apparent permeability for different components on BHP and produced gas composition in tight- and shale-gas reservoir

Longjun Zhang [a], Daolun Li [a,b,*], Detang Lu [a]

[a] Department of Modern Mechanics, University of Science and Technology of China, Hefei, China
[b] Hefei University of Technology, Hefei 230026, China

ARTICLE INFO

Article history:
Received 11 January 2014
Revised 4 December 2014
Accepted 18 May 2015
Available online 27 May 2015

Keywords:
Shale gas
Tight gas
Slip flow
Compositional modeling
Apparent permeability
Multi-component

ABSTRACT

With increasing interests and demand in natural gas, it is important to understand and predict the flow processes in unconventional tight- and shale-gas reservoirs. Because the permeability is very low and the pore throat size is very small in tight- and shale gas reservoirs, gas flow mechanisms are different from that in conventional reservoirs. Slip flow, for example, often happens. Generally, apparent permeability is used to correct flow deviation from conventional flow. In this paper, apparent permeability is distinguished for different components in the reservoir, and incorporated into a compositional model to study the effect of distinguishing apparent permeability on the BHP (Bottom Hole Pressure) and gas composition. Several comparison simulation scenarios are performed to show the significance of distinguishing permeability for different gas components. The results show output predicted without distinguishing apparent permeability for gas components make larger deviation at higher production rate, lower permeability and more content of heavier component, and the interpretation by this method can under estimate formation permeability by 14%. Therefore, distinguishing the apparent permeability for different components is very important and would lead to more accurate results of BHP and gas composition which are very important factors for gas recovery.

Introduction

Shale gas production has grown rapidly recently. According to Energy Information Administration, shale gas production accounts for 39% of total dry natural gas production in U.S. in 2012. In shale gas and tight gas reservoirs, the permeability is very low (usually under 0.1 mD) and the pore size is very small (under 50 nm) (Nelson, 2009). Several physical flow mechanisms can happen during gas flowing in such kind of porous media, such as slip flow, Knudsen diffusion and the conventional Darcy flow (Javadpour, 2009).

Many modeling works on gas flow through shale and tight reservoir have been done. Javadpour (2009) incorporated the slip flow and Knudsen diffusion into apparent permeability which is found that one or two orders of magnitude difference from the original permeability could happen in the shale. Civan (2010) proposed a revised formulation of apparent permeability in terms of Knudsen number based on a unified Hagen–Poiseuille-type formulation (Beskok and Karniadakis, 1999). The revised formulation is able to describe all flow regimes defined by Knudsen number. Freeman et al. (2011) incorporated the dusty-gas model into TOUGH+ family code to simulate Knudsen diffusion in shale and illustrated a methodology which uses measurements of gas composition to determine the permeability in tight reservoirs. Clarkson et al. (2012) used the dynamic slippage concept to analyze the production data in shale gas reservoir. Swami et al. (2013) and Li et al. (2013) incorporated slip flow and Knudsen diffusion into a numerical model for shale gas reservoirs separately.

However, all the works above did not distinguish the apparent permeability for different gas component neither did any of them investigated gas flow through shale on a compositional base. In our previous work (Zhang et al., 2014), we incorporated slip flow and multicomponent adsorption into compositional model to study flow behavior in shale gas and tight gas reservoirs, while used the same apparent permeability for all gas components. In this work, we distinguish the apparent permeability for different gas components and incorporate the new apparent permeability formulation into our compositional model. Then the significance of distinguishing apparent permeability for each component is studied by simulating gas flow in shale under several scenarios.

* Corresponding author at: Hefei University of Technology, Hefei, 230026, China
E-mail addresses: zlj0000@mail.ustc.edu.cn (L. Zhang), ldaol@mail.ustc.edu.cn (D. Li), dtlu@ustc.edu.cn (D. Lu).

http://dx.doi.org/10.1016/j.juogr.2015.05.004
2213-3976/

Apparent permeability

Several flow regimes happens when gas flow in shale reservoirs, such as convective flow which is typically described by Darcy's law, slip flow, transition flow and free molecular flow. According to Chambre and Schaaf (1961), the flow regimes can be classified by Knudsen number K_n, as shown in Table 1. K_n can be expressed as the free path of molecules as a fraction of a representative path (mean hydraulic radius, for example) (Loeb, 2004):

$$K_n = \frac{\lambda}{R_h} \tag{1}$$

Here λ is the mean free path of gas molecules given by the following equation:

$$\lambda = \frac{1}{\sqrt{2}\pi N\sigma^2} \tag{2}$$

where σ is the diameter of the molecule and N is the number of molecules per cubic centimeter. They can be expressed by following equation:

$$N = N_A\rho \quad \sigma = 0.809V_c^{1/3}$$

(Chung et al., 1988) here N_A means the Avogadro's constant ($6.02214129 \times 10^{23}$ mol^{-1}), ρ is the gas density in mole per cm^3 and calculated by Peng–Robinson EOS(Walas, 1985), V_c is the critical volume in cm^3 per mole.

R_h is the mean hydraulic radius of flow tubes in porous media and is given by the following equation:

$$R_h = 2\sqrt{2\tau}\sqrt{\frac{k_0}{\phi}} \tag{3}$$

where τ is the tortuosity, ϕ is the porosity of porous media, and k_0 is the intrinsic permeability.

All the flow regimes can be described in terms of apparent permeability based on a unified Hagen–Poiseuille-type formulation (Beskok and Karniadakis, 1999; Civan, 2010):

$$k = k_0(1+\alpha K_n)\left(1+\frac{4K_n}{1-bK_n}\right) \tag{4}$$

where α is the dimensionless rarefaction coefficient and b is the slip coefficient. Beskok and Karniadakis (1999) indicate that $\alpha = 0$ and $b = -1$ under the slip flow condition. Therefore under slip flow regime, Eq. (4) becomes:

$$k = k_0\left(1+\frac{4K_n}{1+K_n}\right) \tag{5}$$

The apparent permeability expressed by this equation will be incorporated into the mathematical model which is described in the following text.

Mathematical model

A mass balance equation for each gas component i in the shale reservoir is established:

$$\frac{\partial}{\partial t}(V\phi\rho_g y_i + V\rho_s V_{\mathrm{ads},i}\rho_{g,\mathrm{std}}) = \sum_l\left(T_{ri}\frac{1}{\mu_g}\rho_g y_i\Delta\Phi_g\right)_l - \rho_{g,\mathrm{std}}y_i q_{g,\mathrm{std}}, \quad i = 1,\ldots,n \tag{6}$$

where V is the volume in m^3, ϕ is porosity, y_i is the mole fraction of component i, n is the total number of the components, ρ_s is the rock density in kg/m^3, $\rho_{g,\mathrm{std}}$ is the gas density under standard condition in mol/m^3, and ρ_g is the gas density under formation condition in mol/m^3. $V_{\mathrm{ads},i}$ is the adsorbed volume of component i in m^3/kg, T_{ri} is the transmissibility between the adjacent grids of component i, The symbol l represents adjacent grids, μ_g is the gas viscosity, $\Delta\Phi_g$ is the difference in the gas potential between adjacent grids, $q_{g,\mathrm{std}}$ is the gas production rate under standard condition in m^3/s.

The left term of Eq. (6) is the mass accumulation for the component i and includes both the mass in the free gas phase and the sorbed mass on the solid phase. The adsorbed volume $V_{\mathrm{ads},i}$ is represented by extended Langmuir isotherm which is widely accepted by petroleum industry.

$$V_{\mathrm{ads},i} = V_{L,i}\frac{y_i P}{P_{L,i}(1+\sum_{j=1}^{n} y_j\frac{P}{P_{L,j}})}, i = 1,\ldots,n$$

where $V_{L,i}$ is the Langmuir volume, $P_{L,i}$ is the Langmuir pressure. They are measured from the pure gas i. ρ_g and $\rho_{g,\mathrm{std}}$ are calculated using the Peng–Robinson EOS (Walas, 1985).

The first right term refers to the advection in which incorporated slip flow in transmissibility T_{ri} for component i. $T_{ri} = \frac{k_i A}{\Delta L}$, k_i is the apparent permeability of component i.

$$k_i = k_0\left(1+\frac{4K_{n,i}}{1+K_{n,i}}\right) \tag{7}$$

here $K_{n,i} = \frac{\lambda_i}{R_h}$, $\lambda_i = \frac{1}{\sqrt{2}\pi N\sigma_i^2}$, σ_i is the diameter of gas component i.

The gas viscosity μ_g is calculated by Lohrenz–Bray–Clark correlation(Lohrenz et al., 1964). The gas potential between adjacent grids m and n $\Delta\Phi_g$ is described as: $\Delta\Phi_g = \Phi_m - \Phi_n = p_m - p_n - (\rho_m Z_m - \rho_n Z_n)g$, Z is the grid depth.

The second right term refers to the mass of gas production or injection of reservoir. The well production rate $q_{g,\mathrm{std}}$ of a well contains a fracture is described by infinite conductivity model:

$$\frac{\sum_l(T\lambda_g\rho_g\Delta\Phi_g)_l}{\rho_{g,std}} - \frac{C}{\Delta t}(p_{wf}^{T_{n+1}} - p_{wf}^{T_n}) = q_{g,std} \tag{8}$$

here p_{wf} is the bottom-hole flowing pressure in Pa, C is wellbore storage in m^3/MPa, T_{n+1} and T_n is the time step of $n+1$ and n.

The mathematical model is discretized based on PEBI (PErpendicular BIsection) grid (Zha, 2009; Zhang et al., 2013) by finite volume method and solved implicitly using the matrix solver GMRES.

Model validation

We use the commercial simulator ECLIPSE 300, which is developed by Schlumberger and widely accepted in petroleum industry, to verify our code. Because ECIPSE 300 has no function of slip flow, we divide the validation into two parts. In the first part, we used the ECLIPSE coal bed methane (CBM) model to validate the compositional flow with multi-component sorption without slip flow. In the second one, we calculated a series of transmissibility multipliers using apparent permeability modifier under different pressure conditions. These transmissibility multipliers were used to "mimic" slip flow in ECLIPSE and therefore verify the correct implementation of our code with slip flow. To enable ECLIPSE to

Table 1
Flow regimes classified by Chambre and Schaaf (1961).

K_n	Larger than 10.0	Between 0.1 and 10	Between 10^{-3} and 0.1	Less than 10^{-3}
Flow regimes	Free molecular flow	Transition flow	Slip flow	Convective flow