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Effect of distinguishing apparent permeability on flowing gas composition, composition change and composition derivative in tight- and shale-gas reservoir

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ABSTRACT

Multi-flow mechanisms co-exist in tight- and shale-gas reservoirs such as slip flow, transition flow, and free molecular flow, thus apparent permeability is used to correct the flow deviation caused by the traditional Darcy's law. Strictly speaking, apparent permeability is also different for different gas components, which we call as multi-component permeability (MCP). In this paper, we use a compositional model incorporating extended Langmuir isotherm and slippage corrected MCP to study the effect of distinguishing apparent permeability for different components on the curves of wellhead flowing composition (WHFC) and its derivative. A fully implicit iterative numerical solution based on PEBI (Perpendicular Bisection) gridding generates 12 simulations to investigate WHFC, composition change (dc) and composition derivative (dc') with and without using MCP for a fractured vertical well in the reservoirs with different adsorption capacities. We find that MCP is an important factor for CH_4 component variance, especially CH_4 component variance is solely caused by MCP for reservoirs without adsorption gas, which shows that MCP can improve interpretation accuracy based on the measured composition. Another finding is that the behavior of WHFC is obviously different between reservoirs with and without adsorbed gas, which can be used to determine whether reservoirs contain adsorption gas or not.

1. Introduction

Because of the ultra-low permeability (less than 0.001 mD), small pore size (under 50 nm), and the existence of organic material in shale gas reservoirs, multi-storage mechanisms and multi-flow mechanisms coherently exist (Roy et al., 2003; Javadpour, 2009; Civan, 2010; Sakhaee-Pour and Bryant, 2011; Freeman et al., 2011). To describe multi-flow mechanisms, apparent permeability is often used as the correction of intrinsic permeability to correct traditional Darcy's law. Recently, Niu et al. (2014) consider the gas molecule accumulation effect near the pore wall, and proposes a permeability correlation model based on the corrected 2nd-order slip boundary condition for nano-scale flow in highly compacted shale reservoirs. The results show that the molecular accumulation effect has obvious negative effect on the apparent permeability. Swami et al. (2013) report that gas is stored via four storage mechanisms: gas in natural fractures, free gas in matrix pores, adsorbed gas on the pore walls, and gas dissolved in kerogen bulk in the shale.

Well test is a traditional way to estimate the well and reservoir parameters. Many researchers study the pressure transient response of wells in tight- and shale-gas reservoirs. Medeiros et al. (2010a) present a semi-analytical approach to compute transient pressure, and provide an alternative method to full numerical modeling of pressure-transient responses in heterogeneous formations. Guo et al. (2012) study shale gas well-test type curve using analytical solution incorporating desorption and diffusive flow in the matrix. Ozkan et al. (2011) propose a trilinear-flow model to predict the performances of multiple-fractured horizontal wells in tight sand and shale reservoirs, and studies productivity features of unconventional shale reservoirs.

The analysis of production data to determine reservoir characteristics, completion effectiveness, and hydrocarbons in place has become very popular in recent years. Ilk et al. (2010) provide guidelines for the analysis of production data, as well as identify common pitfalls and challenges. Medeiros et al. (2010b) use a semianalytical model to present production-decline characteristics in terms of transient-productivity index to discuss the analysis of production data from hydraulically fractured horizontal wells in shale reservoirs. Hasan et al. (2010) present two mathematical models to analyze production data from shale gas wells in their

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early life, and studies shale gas well-test type curves using analytical solution incorporating desorption and diffusive flow. Clarkson et al. (2012) extend the dynamic-slippage concept to shale-gas reservoirs to account for concentration-driven mechanism, and establish corresponding rate-transient methods for reservoirs exhibiting multi-mechanism flow. Clarkson et al. (2013) incorporate geomechanical modeling into production analysis procedures to account for stress-sensitivity of permeability.

Rate–time decline-curve analysis is a technique used in the evaluation of well performance, production forecasting, and prediction of original fluids in place. Ayala H. and Ye (2013) present the analytical decline equation that models production from gas wells producing at constant pressure under boundary-dominated flow to forecast boundary-dominated performance and predict original gas in place without pseudopressure or pseudotime transformations of production data. Another paper (Ye and Ayala, 2013) shows that original fluids-in-place prediction and gas-well-performance evaluations can be conducted simply by straight line analysis of boundary-dominated data in flow-rate vs. cumulative-production plots.

Because of the economic development and the long time of the transient flow regime in shale gas reservoirs, the traditional pressure-buildup test is not practical in the development of the ultra-low permeability reservoirs. There is more challenge for production-data analysis than for pressure-data analysis due to data resolution and data accuracy. Some researchers try to find new methods.

Compared to above researches, wellhead flowing composition (WHFC) change over time for the well in tight- and shale-gas reservoirs has not aroused enough attention. Freeman et al. (2011) firstly implement the dusty-gas model into a fluid flow modeling tool based on the TOUGH+ family code to study composition variance when the permeability is as low as 10^{-21} m^2 (about 10^{-6} mD). Later, Freeman et al. (2013) incorporate extended Langmuir adsorption isotherm into a compositional model based on the TOUGH+ family code. Recently, Zhang et al. (2014) develop a compositional flow model and find existence of a constant composition stage before the gas flow reaches the domain boundary, indicating the potential use of gas composition as another type of data to infer reservoir boundary and flow regimes.

This paper studies the effect of multi-component permeability (MCP) on BHP (Bottom Hole Pressure), composition change and composition derivative for a well in shale gas reservoirs by incorporating slip flow and multi-component adsorption into compositional model.

2. Component apparent permeability

Several flow regimes happen when gas flow in ultra-tight reservoirs, such as convective flow, slip flow, transition flow and free molecular flow, which can be classified by Knudsen number, as shown in Table 1.

Knudsen flow happens if $K_n > 10$ when collision between the gas molecules and the pore wall dominates. For $0.1 \le K_n \le 10$, it is considered as transition regime, the collision between the molecules and the collision between the molecules and the pore wall are roughly the same level. For $10^{-3} < K_n < 0.1$, the flow at the wall cannot be neglected, which means slip flow exists. For $K_n < 10^{-3}$, collision between molecules and the pore wall can be neglected, and the flow behavior can be described by Darcy's Law.

Table 1
Flow regimes classified by Knudsen number.

K_n value	> 10.0	Between 0.1 and 10	Between 10^{-3} and 0.1	$< 10^{-3}$
Flow regimes	Knudsen flow	Transition flow	Slip flow	Convective flow

K_n can be expressed as the free path of molecules as a function of a representative path (Loeb, 2004):

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

where 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 the following equation (Chung et al., 1988):

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

where 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:

$$R_h = 2\sqrt{2\tau}\sqrt{\frac{k_0}{\phi}} \tag{4}$$

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

Although there are many apparent permeability correlations, we use the correlation based on a unified Hagen–Poiseuille-type formulation (Beskok and Karniadakis, 1999; Civan, 2010). Under the slip flow condition, apparent permeability correlation used in this paper is

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

For component i, apparent permeability correlation is

$$k_i = k_0\left(1 + \frac{4K_{n,i}}{1+K_{n,i}}\right) \tag{6}$$

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

3. Mathematical model

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

$$\frac{\partial}{\partial t}\left(V\phi\rho_g y_i + V\rho_s V_{ads,i}\rho_{g,std}\right)_j = \sum_l T_{i,jl}\left(\frac{1}{\mu_g}\rho_g y_i \Delta\Phi_g\right)_{jl} - \rho_{g,std} y_i q_{g,std},$$
$$i = 1, \ldots, m \tag{7}$$

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, $\rho_{g,std}$ 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. $V_{ads,i}$ is the adsorbed volume of component i in m^3/kg, μ_g is the gas viscosity in Pa s, $\Delta\Phi_g$ is the difference in the gas potential between adjacent grids, $q_{g,std}$ is the gas production rate from reservoirs under standard condition in m^3/s.

The left term of Eq. (7) is the mass accumulation for the component i and includes both the free gas and the desorbed gas. The adsorbed volume $V_{ads,i}$ is represented by extended Langmuir