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The impacts of microcosmic flow in nanoscale shale matrix pores on the gas production of a hydraulically fractured shale-gas well

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Special nanoscale storage mechanisms and pore radii create complex shale gas transport mechanisms. Shale gas reservoir production performance evaluations are challenging due to difficulties associated with microcosmic flow mechanisms, such as Knudsen diffusion, surface diffusion, adsorption and desorption. A thorough understanding of the effects of these transport mechanisms on shale gas production can help to develop new and improved shale gas production prediction models. This paper derives a unified apparent permeability equation based on the Knudsen number and four flow regimes, incorporating viscous, slip, transition and free molecule flows. The new apparent-permeability model also considers the surface diffusion, adsorption layer and tortuous diffusion path. Fully coupled differential equations were developed for a hydraulic fracture and matrix system based on these microcosmic transport mechanisms and using the finite difference method. A sensitivity analysis was performed to investigate the impacts of several parameters on production, including the nanopore radii, Langmuir parameters and bottom-hole flow pressure. The simulation results demonstrate that the microcosmic flow mechanisms significantly impact shale gas production. Gas production increases as the Langmuir parameters increase, but the rate of the increase decreases over time. Knudsen diffusion and surface diffusion become more prominent as the pore radius and reservoir pressure decrease. The adsorption layer cannot be ignored at sufficiently small pore radii.

1. Introduction

Shale gas reservoirs have gained significant interest in North America and other countries. Shale gas is stored as a free, adsorbed and dissolved gas in organic-rich kerogen with well-developed, interconnected nanometer pores. Shale gas transport mechanisms incorporate the physics of viscous flow, slippage, Knudsen diffusion, surface diffusion, gas desorption and adsorption. Therefore, these mechanisms are characterized by complex flow regimes, including microcosmic molecular flow in nanoscale pores and macroscopic viscous flow in hydraulic fractures. The nanopore level gas flow state will vary as collisions between gas molecules and pore walls become more frequent due to decreasing nanopore radii. Shale gas transport is microcosmic flow at this scale, which invalidates the classic Darcy flow approach. Numerous researchers have studied nanoscale shale gas transport, and various permeability models have been proposed to characterize complex nanopore flow behaviors. Beskok and Karniadakis (1999) derived an apparent permeability equation to describe capillary fluid flow. The equation is appropriate for any flow regime involving non-slippage flow, Knudsen flow, slip flow and free molecular flow. Michel et al. (2011) extended the model to include arbitrary pore size distributions based on actual gas flow conditions. Javadpour (2009) derived an apparent permeability model that included the direct summation of the Knudsen diffusion and slippage effect. Swami et al. (2013) studied and compared various apparent permeability models. Xiong et al. (2012) discussed the impacts of the adsorption layer, Knudsen diffusion and surface diffusion on apparent permeability. Singh et al. (2014) proposed an analytical apparent permeability model without empirical parameters. This model can be used to quantify the impacts of pore size, pore geometry, temperature, gas properties and average reservoir pressure on the apparent permeability. Guo et al. (2015) presented a new apparent permeability formula based on convection and Knudsen diffusion and compared it with experimental data. Shi et al. (2013) studied shale matrix pore size distributions and developed a new

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diffusion-slip flow model to predict shale gas production. Wua et al. (2015) developed a unified mathematical model for describing shale gas multi-transport mechanisms in nanopores. Sakhaee-Pour and Bryant (2011) found that the formation permeability is non-linearly related to decreasing pore pressure during gas well production, which would slow the declining shale gas production rate.

Various mathematical models have been proposed to describe macroscopic and microscopic flow in multiscale media. Mi et al. (2014) differentiated four types of diffusion based on the Knudsen number and created a mathematical model to characterize several microcosmic flow mechanisms, including Knudsen diffusion, slippage, gas adsorption, desorption and diffusion from kerogen. Sun et al. (2013) established a shale gas seepage model in a matrix and natural fracture system based on a dual-porosity model. The new model accounted for Knudsen diffusion, viscous flow and molecular diffusion, and the Langmuir isothermal equation was adopted to estimate the shale gas adsorption content on the matrix surface. Swami et al. (2012) introduced a mathematical model that incorporated Knudsen diffusion, slippage, gas desorption and gas diffusion from kerogen. Freeman (2010, Freeman et al. 2012) presented a multicomponent gas flow model comprised of convective transmission, Knudsen diffusion and molecular diffusion mechanisms in porous media at the micron and nanometer scales. Shabro et al. (2011, 2012) established a shale gas production simulation model that incorporated slippage, advective flow, Knudsen diffusion and Langmuir desorption effects. The model was used to quantitatively analyze convection, Knudsen diffusion and desorption effects as they related to the mass flux. Civan (2013) produced a shale-gas reservoir flow model after hydraulic fracturing. However, the shale gas production model did not fully incorporate nanoscale gas migration, including adsorption, desorption, pore restriction and gas property corrections. Swami et al. (2013) believed that shale gas was stored as free gas in natural fractures and matrix pores, adsorbed gas on nanopore surfaces and dissolved gas in bulk kerogen. They developed a dual porosity model with a corrected shale matrix permeability that could characterize the microscale transport mechanisms. Song et al. (2015) proposed a multiscale shale gas flow model that incorporated steady gas seepage in hydraulically fractured vertical and horizontal wells and derived a volume flux equation. Deng et al. (2014) also established a multiscale shale gas flow model based on steady seepage. The model included Knudsen diffusion, slippage and desorption effects. A sensitivity analysis was performed to investigate the effects of Knudsen diffusion and hydraulic fracturing parameters on the shale gas productivity.

Numerous studies have analyzed shale gas storage and transport mechanisms, often developing theoretical models. However, the factors influencing the apparent permeability are often over simplified. Shale gas matrix permeability corrections are not sufficiently comprehensive, and the impacts of these microflow parameters on fractured shale gas well performance are rarely quantitatively analyzed. This paper develops a more comprehensive apparent permeability model to correct shale matrix permeability based on a variety of classic models and derivation methods. Matrix and hydraulic fracture transport models were created and a sensitivity analysis was performed to observe the impacts of microflow mechanisms on multistage fractured horizontal well production.

2. Shale gas transport mechanisms in matrix pores

As shown in Fig. 1, nanopore gas transport mechanisms mainly incorporate viscous flow, slip flow, Knudsen diffusion and surface diffusion for single component gases. Viscous flow is the result of intermolecular collisions, and slip flow will occur when gas molecule and pore wall collisions become significant. Knudsen diffusion is caused by collisions between gas molecules and pore walls. Surface diffusion results from a concentration gradient, which is caused by gas adsorption and desorption.

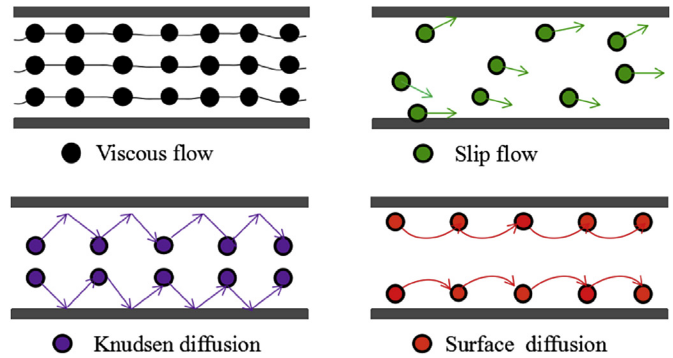

Fig. 1. Gas transport mechanisms in shale nanopores.

2.1. Nanopore gas flow regimes

Darcy's equation is used to represent fluid flow in conventional gas reservoirs, while nanoscale gas flow behaviors are more complex in shale reservoirs, especially as pore radii decrease. The collisions between gas molecules and pore walls become more frequent, which causes the flow state to transition from Darcy flow into other states. Therefore, it is necessary to identify gas flow regimes based on the Knudsen number K_n.

K_n is defined as:

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

where λ is the mean free path of a gas molecule (m) and r is the pore radius (m).

The mean free path of a gas molecule can be defined as:

$$\lambda = \sqrt{\frac{\pi RT}{2M_g}}\frac{\mu}{p} \tag{2}$$

where p is the reservoir pressure (MPa), R is a gas constant (8.314×10^3 J/kmol/K), M_g is the molecular mass (kg/mol), μ is the gas viscosity (mPa·s) and T is the reservoir temperature (K).

We first propose mass flux equations for different flow regimes and then derive a corresponding apparent permeability model.

(1) Viscous flow

Collisions between gas molecules and pore walls are negligible when $Kn \leq 0.001$ because the pore radii are sufficiently large compared with a gas molecule's mean free path. Gas flow in shale pores behaves as viscous flow without slippage effects. Therefore, the mass flux can be characterized by Darcy's equation, which is driven by a pressure gradient in the flow region:

$$J_V = -\left(\frac{\rho_g K_D}{\mu}\right)\nabla p \tag{3}$$

where J_V is the mass flux of the viscous flow (kg/s/m^2), ρ_g is the gas density (kg/m^3) and K_D is the Darcy permeability (m^2), which can be calculated by Eq. (4).