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Full Length Article

A new technique for permeability calculation of core samples from unconventional gas reservoirs

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ABSTRACT

Unconventional reservoirs and their outstanding characteristics have introduced a new field of research in reservoir engineering. The main challenge arises from the fact that in tight formations pore-throat size lays in the range of a few nanometers to a few dozens of nanometers, which makes the estimation of permeability a difficult task. When developing a permeability model for shale media, it is very important to accommodate for surface adsorption and transient flow effects, in addition to slippage effect and Knudsen diffusion, in order to achieve an accurate model. Prediction of fluid flow inside shale rock needs development of new models that take into account not only the diffusive flow but also the effect of high amount of gas adsorbed to the surface of the pores. In this work, we have proposed a new semi-empirical method for calculation of gas permeability inside tight formations. The method uses experimental data obtained from core plugs (canister data) and an analytical solution of continuity equation coupled with gas desorption in tight porous media. By matching the production data from core plugs, we have been able to calculate gas permeability by solving the analytical equation. We have been able to capture the effect of pore pressure on permeability by using production data at various core saturation pressures. We also compared our model with two previously proposed models. The results of this study show that the permeability calculated using our model is closer to experimental measurements of similar rock samples and comparable with other models.

1. Introduction

Shale resources have a key part in the United States' energy play. With over fifty percent of the total US oil production and over forty percent of the total US natural gas production, shale resources have proven to be a dependable source of energy. Advances in technologies such as hydraulic fracturing, natural fracture detection, and horizontal drilling make the production from such resources more feasible. Unlike conventional oil reservoirs, shale rocks consist of pores in nanometer-size range, which makes the study of such reservoirs both challenging and important. At nanometer-sized pores, fluid flow and behavior show large deviations compared to those of conventional reservoirs, which have pore sizes in the order of few hundred micrometers [1,2]. In order to accurately estimate the gas flow inside the shale reservoirs, an accurate estimation of permeability is vital. One of the most-used equations for prediction of permeability in oil reservoirs is Darcy's equation, which is derived on the basis of continuum equations. This equation, however, is not fully capable of describing the characteristics of a shale reservoir with nanometer-sized pores, and the permeability calculated using those methods leads to a large amount of error. Therefore, true modifications should be done to the original permeability model to account for phenomena such as surface adsorption. There have been several attempts to characterize the effect of small pore–throat size in calculation of permeability of shale gas reservoirs [3–10]. Javadpour [11] proposed a model for calculation of apparent permeability considering the Knudsen diffusion and slip flow in nanopores. The model states that the apparent permeability is not only a function of the porous media but also a function of the gas type and the physical conditions. He concludes that the Knudsen diffusion contributes to a higher extent when formulating the gas permeability in smaller pores. Florence et al. [12] developed a microflow model and validated the model using field data. They used a second-order correction for gas slippage which is used for ultra-low permeability formations. The model proposed is similar to the Klinkenberg model with suitable corrections and higher accuracy. Wasaki et al. [13] proposed a model for apparent permeability of single-phase liquids and gas flow. They assumed multiple transport mechanisms for multiscale flow of free phase and sorbed phase. The conclusion here was that at high reservoir

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Nomenclature

ρ_g	gas density (kg/m^3)
r	radial distance (m)
ν_r	radial direction velocity (m/s)
ν_z	vertical direction velocity (m/s)
D	desorption source 1/s
m(P)	pseudopressure (Pa)
P	pressure (Pa)
Z	compressibility factor
V	Langmuir isotherm (m^3/kg)
a	slope of Langmuir isotherm (m^3/kg.Pa)
V_m	Langmuir-isotherm volume (m^3/kg)
P_L	Langmuir-isotherm pressure (Pa)
P_a	atmospheric pressure (Pa)
P_s	sample initial saturation pressure (Pa)
c	compressibility 1/Pa
k	permeability (m^2)
M	molecular weight (kg/kmol)
$Q_{tb}(t_D)$	gas production at the bottom and the top of the core (m^3/s)
$Q_s(t_D)$	gas production at the side face of the core (m^3/s)
V_c	bulk volume of cylinder (m^3)
B_g	gas formation volume factor (m^3/std m^3)
k_{app}	apparent permeability (m^2)
D_f	fractal dimension of the pore surface

Greek letters

ϕ	porosity
μ	viscosity (Pa.s)
ρ_s	rock density (kg/m^3)
η	inverse of diffusivity coefficient (s/m^2)
ν	core aspect ratio
α	dimensionless sorption term
ω_m	Fourier-transform eigenvalue
λ_n	Hankel-transform eigenvalue
ρ_{ave}	average gas density (kg/m^3)
δ'	ratio of normalized molecular size to mean pore diameter
ϕ/τ	porosity-tortuosity factor

pressures, permeability is very much stress-dependent. However, at lower reservoir pressures the effect of sorbed-phase diffusion becomes more pronounced. Also, the effect of nanopore adsorption and heterogeneity on fluid flow and transport is investigated by the same author [14,15]. Although the models provide a good estimation of the permeability in shale rock media, yet dependable experimental measurements are required to validate those models. There have been several techniques to experimentally measure shale formation permeability [16–19]. On such techniques, the transient flow technique [20,21], the oscillating pulse method [22–24], the pulse decay method [25–28], and the Gas Research Institute (GRI) method [17,29,30] have garnered the most interest among the others. Kranz et al. [22] used the pore pressure oscillation method to measure the permeability and diffusivity of rock samples. At different loads and with the assumption of constant deformation rate, they have been able to calculate the permeability value and introduce the method for the first time as a reliable approach for calculation of permeability. Brace et al. [25] calculated the permeability using the pulse decay method, in which a small pressure pulse is introduced to the upstream of a core plug and the pressure decay is monitored. Using the dimensions of the sample and the compressibility and viscosity of the fluid, and also assuming the rock sample equivalent to a resistor in an electric circuit, the reservoir can be equivalent to a capacitor. Therefore, the pressure decay plot versus time yields to calculation of the permeability. Luffel et al. [17] for the first time introduced the GRI method for measurement of permeability of shale rock samples. In this method, the rock is crushed into small pieces (0.7 mm) and then put into the pulse pressure test with helium. They compared the permeability calculated by this method with other methods, which shows a good match. The advantage of such a method is being faster and cheaper with the drawback that it can only cover low overburden pressures.

Experimental methods have their own complexities and pure models have unavoidable uncertainties. Therefore, using a simpler experimental procedure together with a reliable model will provide researchers with a robust yet inexpensive method for calculation of formation permeability. Although the previous models provide a good estimation of gas permeability inside shale media, most of them focus only on Knudsen diffusion effect neglecting the important effect of surface adsorption and also the transient flow pseudopressures. In this work, we developed a semi-empirical method for calculation of gas permeability and tested the method on shale rock samples of Barnett shale formation. The experiments are originally performed for calculation of lost gas when sampling the formation rock using a canister. The samples are saturated with gas and then degasified inside a canister which measures the gas production amount. The main idea is to utilize canister data which is often used for lost gas calculation, as a tool for calculation of sample permeability. Having the data from core sample saturation and degasification and Langmuir adsorption curves, we have been able to match the core gas production data with our analytical model to solve it for permeability. The model is based on diffusive flow of gas inside core samples of shale rock which is coupled with the effect of surface adsorption and also takes into account the fact that assumption of pseudopressures inside the core leads to a higher accuracy in permeability calculation. The equations are previously developed by the author [31].

2. Core samples

The data used in this study is obtained from core samples from the Texas United Blakely #1 well located in the depth of 7222-ft of Lower Barnett Formation of Fort Worth basin, Wise County, Texas [32]. The core samples were saturated with pure methane gas at different saturation pressures and then put inside a canister. After a certain amount of time, which is referred to as gas loss duration, the released gas volume was measured until full desaturation. Using the data and the calculated Langmuir isotherms, we have been able to calculate the amount of lost gas and use it in our model.

3. Model

The model is developed based on the single-phase gas flow inside a core sample that is draining to all directions, considering the effect of pore surface adsorption/desorption and transient flow with pseudopressures [31]. For the case of a homogeneous cylinder core with finite dimensions, the continuity equation gives:

$$\frac{\partial(\phi\rho_g)}{\partial t} = \frac{1}{r}\frac{\partial(r\rho_g v_r)}{\partial r} + \frac{\partial(\rho_g v_z)}{\partial z} + \rho_g D \tag{1}$$

in which D is the amount desorbed gas from the core, which will be accounted for later using Langmuir isotherm.

Since the gas drawdown we would like to model lays on the transient flow regime, we have to account for property changes during pressure decline. Therefore, the pseudopressure is used as [33]:

$$m(P) = 2\int_{P_i}^{P} \frac{P}{\mu Z}dP \tag{2}$$