International Journal of Rock Mechanics & Mining Sciences 48 (2011) 1135–1144

Contents lists available at SciVerse ScienceDirect

International Journal of Rock Mechanics & Mining Sciences

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

Measuring low permeabilities of gas-sands and shales using a pressure transmission technique

Yasser M. Metwally [a,b,*], Carl H. Sondergeld [c]

[a] University of Houston, Houston, TX, USA
[b] Faculty of Science, Tanta University, Tanta, Egypt
[c] University of Oklahoma, Norman, OK, USA

ARTICLE INFO

Article history:
Received 30 July 2010
Received in revised form
14 December 2010
Accepted 17 August 2011
Available online 13 September 2011

Keywords:
Gas-shale
Matrix permeability
Fracture permeability
Pressure decay

ABSTRACT

Liquid and gas permeability measurements for tight gas-sand and shales were done using a pressure transmission technique in specially designed apparatus in which confining pressure, pore pressure, and temperature are independently controlled. Downstream pressure changes were measured after increasing and maintaining upstream pressure constant. The initial pressure difference changes only after the pressure pulse propagates across the sample. For low permeability samples, the downstream pressure increase is delayed but the measurement senses a greater sample volume. On the other hand, conventional pulse decay techniques provide a more rapid response but are sensitive to local sample permeability heterogeneity. Permeability measured for the rocks studied varies from 1.18×10^{-15} to 3.95×10^{-21} m^2. The measured permeability anisotropy ratio in gas shale varies from 20% to 31%. The magnitudes of permeability anisotropy remain almost constant, but the absolute permeability values decrease by a factor of 10 with a 29.79 MPa effective pressure. All samples showed a nonlinear reduction in permeability with increasing effective pressure. The rate of reduction is markedly different from sample to sample and with flow direction. This reduction can be described by a cubic k–σ law and explained by preferential flow through microcracks.

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1. Introduction

Many geo-engineering projects such as mining, tunneling, reservoir productivity [1], hydraulic-fracturing [2], and nuclear waste disposal [3], are affected by the mechanical and hydraulic properties. Recently, unconventional reservoirs such as gas shales, coalbed methane, and tight-gas sand, have become significant produces of domestic natural gas and offer tremendous potential for future gas reserves and production. Recent success in tight-gas shales has renewed interest in understanding gas flow in these reservoirs and how to measure permeability in these tight rocks. Similar to conventional hydrocarbon systems, gas shales are characterized by complex geological and petrophysical systems as well as heterogeneities at all scales. Permeability is important for predicting flow and reservoir modeling of gas shales.

Permeability is a measure of the rate of fluid flow through a porous material under a pressure gradient. Intrinsic permeability (k [m^2], where 1 m^2 is essentially equivalent to 10^{12} Darcies) is usually determined by measuring the steady state flow rate through a sample under a constant pressure gradient using Darcy's law

$$k=\frac{Q\mu}{A}\left(\frac{dP}{dx}\right)^{-1} \tag{1}$$

where Q is the volume of fluid discharge per unit time (m^3/s), A is the cross-section area (m^2), μ is the dynamic viscosity of fluid (Pa s), and dP/dx is the pressure gradient (MPa/m) in the flow direction x.

Generally, it is not practical to determine the permeability of tight rocks, especially shale, using steady-state methods. These rocks require long times to establish a steady-state flow. Song et al. [4] used one-dimensional fluid diffusion induced into the core sample (granite) by a constant flow rate pump to measure both the steady state permeability and specific storage of the sample. Brace et al. [5] measured permeability in granite using a pressure–decay transient technique, this reduced the test time making permeability measurements possible. This method depends on measuring the decay in pressure imposed at one end of the sample rather than the flow rate or velocity of fluid through the sample. In this configuration, laminar flow of a compressible fluid through a saturated isotropic porous and compressible medium in one dimension can be described as follows:

$$\frac{\partial^2 P}{\partial x^2}=\frac{S_s}{K}\frac{\partial P}{\partial t} \tag{2}$$

* Corresponding author at: University of Houston, Earth Science, 5530 Imperial Grove Dr., Houston, Texas 77066, USA. Tel.: +1 405 445 8452.
E-mail address: ykhoris@yahoo.com (Y.M. Metwally).

1365-1609/$ - see front matter Published by Elsevier Ltd.
doi:10.1016/j.ijrmms.2011.08.004

where P is the pressure (MPa), t is the time after the pressure is applied (s), K is the hydraulic conductivity, which depends on the fluid properties and sample permeability, and is expressed as

$$K = \frac{k\rho g}{\mu} \tag{3}$$

where k is the permeability (m^2), ρ is the density of the fluid (kg/m^3), g is the gravitational acceleration (m/s^2), μ is the viscosity of the fluid (Pa s), and S_s is the specific storage of the sample, which can be specified according to Ref. [6] as

$$S_s = (\beta_{eff} - \beta_s) + \phi_e(\beta_f - \beta_s) \tag{4}$$

where β_f is the static compressibility of the fluid (MPa^{-1}), β_{eff} is the effective compressibility of the rock (MPa^{-1}), β_s is the compressibility of the solid matrix (MPa^{-1}), and ϕ_e is the connected porosity of the sample (fraction). Fig. 1 shows the general configuration of pressure decay permeability test. Solutions of Eq. (2) exist for various boundary conditions. The solution provided by Ref. [5] assumed both β_{eff} and β_s are very small as compared to β_f, and the porosity is very small as well, i.e., there is no compressive storage in the rock sample. This may be reasonable for some crystalline rocks, but may be a poor assumption for sedimentary rocks that have significant porosity and compressive storage such as shale. Several authors [7–10] presented and examined a general analytical solution for Eq. (2) taking the compressive storage into account, which requires independent measurements of the porosity and bulk compressibility of the sample. Their model is valid to use with any combinations between upstream and downstream reservoir volumes. While for very low permeability samples ($< 10^{-20}\,m^2$ scale) and because of time, small reservoir volumes are usually used; i.e., storage capacity of reservoirs is within the same order as sample storage capacity. In this case, Kamath et al. [11] indicated that the permeability calculated based on a simplified form of the solution given in Ref. [7] will show a greater sensitivity to sample heterogeneity and can lead to erroneous interpretations. In addition, the permeability will be underestimated if the experimental fluids are adsorptive to the experimental samples [12]. It is widely known that the clay minerals and organic matter, which are the main components of shale, have net negative electrical charges on their high surface areas, make shale samples vulnerable to absorb fluid even the inert gases such as helium.

To overcome these problems, the current study implemented a technique that senses much more of the sample. This technique is based on creating an infinite storage capacity for the upstream reservoir by keeping its pressure constant. That implies that the initial pressure difference decays only after the pressure change is sensed at the other end of the sample. While it takes longer for the pressure to increase in downstream, the measurement senses across sample. The constant pressure mode used for the upstream reservoir will illuminate the permeability error that associated with neglecting absorption phenomena, absolute upstream reservoir volume and leaking. In addition, the current technique provides an advantage over methods that neglect the reservoir condition, such as mercury intrusion, or that neglect the directional dependence of shale permeability, such as using crushed samples, as in Ref. [13]. Detailed description of the current techniques and preliminary results will be discussed in the subsequent sections.

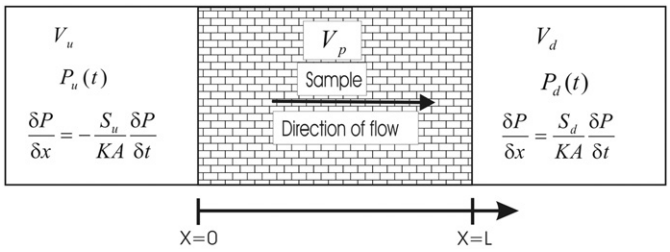

Fig. 1. Schematic diagram for a general pressure decay permeability test with pressure gradient in the upstream and downstream reservoirs. Upstream is indicated by subscript u while d indicates the downstream (after Ref. [10]).

2. Methodology

2.1. Theoretical approach

Hsieh et al. [7] and Dicker and Smits [9] presented a general analytical solution for the dimensionless pressure difference between the two reservoirs as a function of time:

$$\delta P_D = 2\sum_{n=1}^{\infty} e^{-\theta_n^2 t_D)} \frac{\alpha(\gamma^2+\theta_n^2)-(-1)^n\gamma[\theta_n^2(\gamma^2+\theta_n^2)]^{1/2}}{\theta_n^4+\theta_n^2(\alpha+\alpha^2+\gamma+\gamma^2)+\alpha\gamma(\alpha+\alpha^2+\gamma+\gamma^2)} \tag{5}$$

where θ_n are the roots to the transcendental equation

$$\tan\theta = \frac{(\alpha+\gamma)\theta}{\theta^2-\alpha\gamma} \tag{6}$$

where α is the ratio of the sample pore volume V_p to the upstream reservoir volume, V_u

$$\alpha = \frac{V_p}{V_u} \tag{7}$$

γ is the ratio of the sample pore volume to the downstream reservoir volume, V_d

$$\gamma = \frac{V_p}{V_d} \tag{8}$$

δP_D is the normalized dimensionless pressure difference:

$$\delta P_D = \frac{\delta P(t)}{\delta P(t=0)} \tag{9}$$

and t_D is the dimensionless time, given by

$$t_D = \frac{kt}{\beta_f\phi_e\mu L^2} \tag{10}$$

where L is the specimen length (m). The compressibility of the rock matrix is ignored because in all cases it is much less than the fluid compressibility, especially the gas compressibility. If the upstream reservoir has infinite storage capacity (Fig. 2B), then α will be zero and Eq. (4) will reduce to

$$\delta P_D = 2\sum_{n=1}^{\infty} e^{-\theta_n^2 t_D} \frac{(-1)^{n+1}\gamma[\theta_n^2(\gamma^2+\theta_n^2)]^{1/2}}{\theta_n^4+\theta_n^2(\gamma+\gamma^2)} \tag{11}$$

Note, in case of upstream constant pressure the absorption has no effect on the $\delta P(t)$ curve because $\delta P(t)$ depends only on the rate of fluid leaving the sample and the downstream storage capacity. Assuming the mass flow rate of fluid entering the sample is equal to that leaving the sample at the same instant (Darcy's law assumption), Eq. (11) can be reduced to a single exponential, i.e. n is equal to one. Thus, θ is the root of the equation

$$\tan\theta = \frac{\gamma}{\theta} \tag{12}$$

Eq. (11) can then be approximated by

$$\delta P(t) = f_1 \exp\left(\frac{-\theta^2 kt}{\beta_f\phi_e\mu L^2}\right) \tag{13}$$

where

$$f_1 = \frac{2\gamma\theta\delta P_O(\gamma^2+\theta^2)^{1/2}}{\theta^4+\theta^2(\gamma+\gamma^2)} \tag{14}$$