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Calculation of rock compressibility by using the characteristics of downstream pressure change in permeability experiment

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ABSTRACT

In petroleum exploration and production, knowledge of geomechanical properties of target reservoirs ensures producing hydrocarbon safely and economically, and protecting environmental friendly. Rock compressibility, one of the geomechanical properties, is an essential parameter in drilling and completion design. Because direct measurements of rock compressibility are time consuming and cost expensive, indirect measurements from other readily available experimental data are highly demanded. When direct measurements are unavailable or experimental data are unreliable due to lab and human errors, irregular core plug, and/or non-uniform deformation, obtaining rock compressibility from other methods is not only a good reference for the directly measured rock compressibility but also an important supplement to those indirect methods. In this study, a method with solid theoretical base is developed to determine rock compressibility using permeability experimental data. With that, core analysis can be more reliable and accurate. The combination of the proposed method with direct measurements can be employed to ensure the reliability of the experiment and to quantify the uncertainty resulting from lab and human errors.

1. Introduction

With the decline in conventional oil and gas production worldwide, petroleum exploration and production from unconventional oil and gas resources have gained great momentum throughout the world to fill the gap between ever increasing demand of energy and decreasing production of conventional reservoirs. Knowledge of geomechanical properties of target reservoirs ensures producing hydrocarbons from unconventional resources safely, environmental friendly, and economically. Rock compressibility is one of the key parameters in designing the drilling and completion of oil and gas wells, modeling the fluids flow in reservoir, and forecasting the well production. There are two categories of methods to obtain rock compressibility. One is direct measurement; another is indirect measurement. Direct measurement measures compressibility through uniaxial or triaxial stress experiment. Indirect measurement estimates compressibility from correlations or other measurements. The importance of rock compressibility is reflected by numerous investigations attempting to evaluate it accurately.

Carpenter and Spencer (1940) measured compressibility of consolidated oil-bearing sandstones collected from East Texas oil field at reservoir conditions. In the same manner as those reported in the Carpenter and Spencer's study, Hall (1953) conducted tests to measure compressibility of limestone and sandstone and developed a correlation to estimate rock compressibility through porosity. Moreover, he found that ignoring rock compressibility can lead to 30–40 percent overestimation of oil in place. Fatt (1958) found that rock compressibility is a function of pressure and cannot be correlated to porosity. Van der Knaap (1959) proved the nonlinear stress-volume relations of elastic porous media through theoretical and experimental analysis. Harville and Hawkins (1969) indicated that rock compressibility of geopressured gas reservoir is higher than that of normally pressured reservoir. Greenwald and Somerton (1981a) measured compressibility of Berea, Bandera, and Boise sandstones. Comparison of these compressibilities to those available in the literature indicated qualitative agreement for each of the sandstone types and for their relative behavior. Furthermore, Greenwald and Somerton (1981b) developed a semi-empirical model to calculated rock compressibility. The required variables for their model are initial porosity, clay content, a pore shape factor, a length and aspect ratio of representative cracks in the matrix grains, the volumetric density of these cracks, and the mineralogical composition of the sample along with the elastic moduli of the minerals present. Zimmerman et al. (1986) developed relations to evaluate rock

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Nomenclature

A	area of the cross section of the core plug
C_f	formation compressibility
C_g	gas isothermal compressibility
D	diameter of core
k	permeability
L	length of core
$m(p)$	gas pseudopressure
p	pressure
p_1	upstream reservoir pressure
p_2	downstream reservoir pressure
p_b	base pressure
p_c	confining pressure
Δp	pressure difference
q_g	gas rate
R	universal gas constant
s	slope of the pressure difference in a logarithm as a function of time
T	temperature
t	time
Δt	time period
V_1	volume of the upstream reservoir
V_2	volume of the downstream reservoir
V_p	pore volume of the core
v_x	gas velocity in x direction
x	distance from original point in x direction
Δx	incremental distance in x direction
z	gas z-factor
φ	porosity
ρ_g	gas density
μ	viscosity
μ_g	gas viscosity

compressibility from confining and pore pressures, and verified their relations through experimental measurements on Berea, Bandera, and Boise sandstones. Poston and Chen (1987) determined formation compressibility and gas in place in abnormally pressured reservoirs simultaneously using material balance. Chalaturnyk and Scott (1992) summarized different geomechanical test procedures and analyzed the results. Khatchikian (1996) proposed a method using the Gassman equation and reservoir parameters evaluated through log analysis to calculate rock compressibility. Yildiz (1998) predicted rock compressibility using production data. His method is the same as Poston and Chen's (1987) method. Macini and Mesini (1998) measured sandstone and carbonate compressibility by both static (deformation tests) and dynamics (acoustic tests) investigations. Their study showed that compressibility is not constant, but is a function of reservoir pressure. Marchina et al. (2004) measured compressibility of reservoir rocks of a heavy oil field under in-situ conditions. Li et al. (2004) presented a model to calculate rock compressibility using the elastic modulus and Poisson's ratio. Suman (2009) estimated rock compressibility under reservoir conditions at different depleted stages using sonic velocity derived from 4D seismic. Moghanloo and Javadpour (2014) modeled the pressure distribution in shale samples. They addressed the dynamic pressure change at the downstream by using a semi-analytic method of characteristics (MOC) solution. The comparison of the pressure profile and history plots indicated that their MOC solutions match the simulation results.

Because direct measurement of rock compressibility is time consuming and cost expensive. Estimation of rock compressibility from other readily available experimental data, such as sonic velocity and permeability experiment, is highly demanded. In this study, we developed a method to determine the rock compressibility using permeability experimental data. The combination of the proposed method with direct measurement can be employed to ensure the reliability of the direct measurement and to quantify the uncertainty resulting from lab and human errors, irregular core plug, and/or non-uniform deformation.

2. Methodology

The purpose of this study is to estimate rock compressibility from permeability experiment. To better understand the principle of the permeability experiment, it is imperative to derive the diffusivity equation that is used to model fluid flow through the rock. The following assumptions are made to derive the diffusivity equation of the test fluid flow in the core: 1) the core is homogeneous, 2) the properties of the rock are constant through the test, 3) the flow in the cylindrical core is laminar, and 4) the flow in the core is isothermal.

Fig. 1 shows the test fluid flowing through a core sample during the experiment. Nitrogen gas is used as test fluid in the experiments because the permeability of tight rock is low. Gas flows from the upstream reservoir on the left-side of the core, through the core, and out of the downstream reservoir on the right-side of the core.

For the gas flow through core sample, if we consider a control volume (from x to $x+\Delta x$), which is the volume that the gas flows in at x and out at $x+\Delta x$ during a certain time period Δt, we can obtain the governing diffusivity equation for linear gas flow inside the sample by combining the mass conservation law, Darcy's law, real gas law, and the gas pseudo-pressure concept (Al-Hussainy et al., 1966):

$$\frac{\partial^2[m(p)]}{\partial x^2} = \frac{\varphi\mu\left(C_g + C_f\right)}{k}\frac{\partial[m(p)]}{\partial t} \quad (1)$$

where $m(p) = \int_{p_b}^{p}\frac{2p}{\mu z}dp$ is the gas pseudo-pressure, p is the pore pressure inside the sample, φ is the porosity, C_g is the gas isothermal compressibility, C_f is the formation compressibility, μ is the gas viscosity, and k is the permeability.

In the downstream pressure build-up experiment, the sample is connected to an upstream reservoir and a downstream reservoir as shown in Fig. 2. At the beginning, the core plug is installed in a core holder, and then the core holder is pressurized by pumping mineral oil into the closed chamber. After that the test gas flows from upstream reservoir through core plug to downstream reservoir until the sample pore pressure, the upstream reservoir pressure, and the downstream reservoir pressure reach

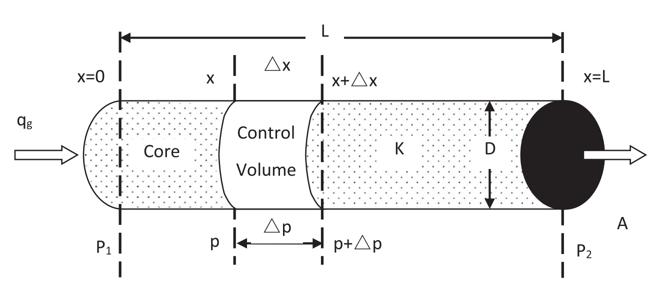

Fig. 1. Gas flows through core during permeability measurement.