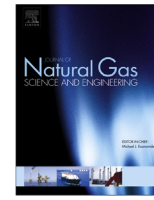
Journal of Natural Gas Science and Engineering 14 (2013) 55–65

Contents lists available at SciVerse ScienceDirect

Journal of Natural Gas Science and Engineering

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



A new method for production data analysis of tight and shale gas reservoirs during transient linear flow period

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ARTICLE INFO

Article history:
Received 5 April 2013
Accepted 20 May 2013
Available online 15 June 2013

Keywords:
Tight gas
Shale gas
Production data analysis
Correction factor
Transient flow
Permeability modulus

ABSTRACT

Pseudo-pressure has historically been used in analytical solutions of the diffusivity equation for analysis of real gas flow in conventional gas reservoirs. The accuracy of analytical solutions during the transient flow period is contingent on the validity of the assumption of constant hydraulic diffusivity which is implicit in the background formulations. However, the assumption of pseudo-pressure-independent hydraulic diffusivity during transient flow is not valid for the cases of high pressure drawdown at the wellbore. For tight and shale gas reservoirs, this dependency is more pronounced due to the complexities associated with non-Darcy flow, adsorption/desorption phenomena, stress-sensitivity of permeability and porosity, and condensation in porous media.

The current study focuses on rate transient analysis of tight and shale gas reservoirs during transient linear flow period for a single fractured well producing under constant well bottom-hole pressure. The results of the analytical solution of real gas flow in porous media are corrected for the effects of high pressure drawdown, non-static permeability, and condensate formation. The method proposed in this study includes three key elements: introducing a measure of nonlinearity (departure of dimensionless hydraulic diffusivity from linearity); differential and integral formulation of the correction factor (used to correct the slope of the square-root-of-time plot); implementing the iterative integral method for solution of flow equation; and evaluating the correction factor for constant-pressure production during transient linear flow period. The results show that the correction factor becomes more important for higher values of drawdown, permeability modulus, and condensate saturation.

1. Introduction

Development of production data analysis tools requires solutions of the flow equations in space and time domains. Flow equations are nonlinear partial differential equations (PDE) with pressure and saturation (multi-phase flow cases) as the unknown functions of space and time. The generally accepted solutions for the diffusivity equation (Van Everdingen and Hurst, 1949), flow of real gases (Aronofsky and Jenkins, 1954; Al-Hussainy et al., 1966), and multiphase flow in solution gas drive reservoirs (Raghavan, 1976; Bøe et al., 1989) are founded on the assumption of constant hydraulic diffusivity. If hydraulic diffusivity is a moderate function of pressure (in diffusivity equation) and/or pseudopressure (for real gases, stress-sensitive formations, and solution gas drive reservoirs) and/or pressure drawdown is not high, the assumption is acceptable. Otherwise, the analysis leads to considerable errors. In particular, for tight and shale gas reservoirs the assumption is violated due to the special flow and storage mechanisms. This calls for more elaborate solution methods and/or correction of the conventional solutions.

In this study, an iterative integral method is used to calculate a correction factor (which corrects the slope of the square-root-of-time plot obtained by the analytical solution) for constant pressure production during transient linear flow in dry gas and gas condensate reservoirs incorporating the effects of pressure drawdown at the wellbore, stress-sensitive permeability, and multiphase flow. This paper is organized as follows. The mechanisms affecting flow and storage of gas in tight and shale gas reservoirs and their impacts on well performance are discussed in Section 2. Transient linear flow is discussed in Section 3. Section 4 introduces the nonlinearity measure of dimensionless hydraulic diffusivity. The production data analysis tools for transient linear flow of gas are discussed in Section 5. Section 5 also explains the differential and integral formulation of the correction factor and discusses implementation of iterative integral method for evaluation of the correction factor. The results of the calculations for dry gas and gas

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http://dx.doi.org/10.1016/j.jngse.2013.05.005

condensate reservoirs are presented and discussed in Section 6. Finally, we end with Section 7, conclusions.

2. Tight and shale gas reservoirs

A tight gas reservoir is a reservoir that cannot be produced at economic flow rates nor recover economic volumes of natural gas unless the well is stimulated by a large hydraulic fracture treatment or produced by use of a horizontal wellbore or multilateral wellbores (Holditch, 2006). In tight gas reservoirs, natural gas is generated somewhere else (usually is a shale formation) and migrates to the tight reservoirs where it is trapped and stored in inter-particle, slot, and micro-fracture porosity (Aguilera, 2010). In shale gas reservoirs, however, natural gas is generated in the shale and remains within the shale (Spencer et al., 2011). Moving from conventional gas to tight gas to shale gas reservoirs, pore sizes steadily decrease, with shale gas reservoirs having pore sizes in the nano-scale and permeabilities measured in nanodarcies (Rahmanian et al., 2010).

Gas flow in tight and shale gas reservoirs is affected by special transport and retention mechanisms including non-Darcy flow at high flow rates (e.g. in hydraulic fractures), apparent gas permeability due to gas slippage on pore walls (e.g. in matrix), adsorption/desorption phenomena, stress-sensitivity of permeability and porosity, and condensation in porous media (in gas condensate reservoirs). In the following subsections, these mechanisms and their impacts on well performance in tight and shale gas reservoirs are reviewed.

2.1. Non-Darcy flow due to inertial effects

At high flow rates in porous media, pressure drop is not proportional to fluid velocity (non-Darcy flow). Firoozabadi and Katz (1979) summarize different authors' views on flow mechanisms at high flow rates. Some researchers (Fancher et al., 1933; Katz et al., 1959) connect non-Darcy flow to the turbulent flow by comparing flow of fluids through porous media and fluid flow in pipes. The Forchheimer number (Ma and Ruth, 1993; Zeng and Grigg, 2006) has also been used for identifying the beginning of non-Darcy flow in porous media. However, Geertsma (1974) believes that within the flow range normally experienced in oil and gas reservoirs, energy losses caused by actual turbulence can be ignored, and the observed departure from Darcy's law is the result of convective accelerations and decelerations of the fluid particles on their way through the pore space. Hassanizadeh and Gray (1987) used the general continuum approach to develop a nonlinear relationship between the pressure gradient and the flow velocity. They concluded that the nonlinear dependence of interfacial drag forces on the flow velocity can give rise to the nonlinear behavior of flow at high velocities. Regardless of the true mechanisms for non-Darcy flow, Forchheimer's nonlinear relationship (1901) or its variations are commonly used for non-Darcy flow at high flow rates. In terms of well performance analysis, non-Darcy flow increases pressure drop in the high-velocity region near wellbore, and within hydraulic fractures for fractured wells (Friedel and Voigt, 2006). This phenomenon may lead to underestimation of formation permeability if Darcy's law is used. Several researchers (Holditch and Morse, 1976; Umnuayponwiwat et al., 2000; Gil et al., 2003, to name a few) have studied the effects of non-Darcy flow on the performance of gas wells.

2.2. Non-Darcy flow due to slip-flow, transitional flow and diffusion

Apparent permeability of formations with comparable pore diameter to gas molecular size is different from intrinsic permeability, which is a property of the porous media. This effect can be explained by taking into account the phenomena of slip, which are related to mean free paths of the gas molecules and approximated by a linear function of the reciprocal mean pressure (Klinkenberg, 1941). The apparent gas permeability of a tight gas reservoir is related to the Knudsen number as the ratio of mean-free-path of molecules to the hydraulic (pore) radius (Civan, 2010; Civan et al., 2011). Swami et al. (2012) used different approaches for prediction of apparent gas permeability of tight gas reservoirs. They found that the apparent permeability becomes more important for reservoirs with nano-pores, that is mainly shale gas and some tight gas reservoirs. Wu et al. (1998) obtained analytical solutions for gas flow in porous media with Klinkenberg effects. Clarkson et al. (2012b) incorporated the dynamic slippage concept of Ertekin et al. (1986) in production data analysis of tight and shale gas reservoirs. In addition to the slip flow, other fundamental transport processes of gaseous molecules in porous media are identified as Knudsen diffusion, transition flow, viscous flow, adsorbed-phase diffusion, and condensate flow (Civan, 2011). These processes affect the apparent permeability of the formation.

2.3. Adsorption/desorption phenomena

Gas molecules under pressure have tendencies to adsorb physically on organic solid surfaces in coal and shale gas reservoirs due to the molecular interaction forces. Pressure disturbance during production changes the thermodynamic equilibrium conditions and leads to desorption of the gas molecules. There are two different groups of methods proposed for modeling the adsorption and desorption phenomena; equilibrium and non-equilibrium methods. The equilibrium methods consider no intermediate stages with adsorption or desorption, i.e. the adsorbed and the free phase systems are in immediate equilibrium. Equilibrium methods include Langmuir method, Dubinin Radushkevich/Astakhov equations, ideal adsorption model (Myers and Prausnitz, 1965), modified vacancy solution model (Clarkson, 2003), simplified local density model (Rangarajan et al., 1995), two-dimensional equations of state (Zhou et al., 1994). The non-equilibrium methods are used to model the time-dependency of the adsorption and desorption phenomena. The proposed non-equilibrium methods are absolute rate theory (Elliott and Ward, 1997; Rudzinski and Panczyk, 2002), sticking probability approach (Becker and Hartman, 1953; Ehrlich, 1956; Kisliuk, 1957), statistical rate theory (Ward, 1983; Rudzinski and Panczyk, 2002), and statistical rate theory of interfacial transport (Rudzinski and Panczyk, 2001).

Desorption of the gas molecules from the rock surface is accompanied by matrix shrinkage and permeability change. Palmer and Mansoori (1998) developed a theoretical model for incorporation of matrix shrinkage as a function of pressure in drawdown test. Clarkson et al. (2010) modified Palmer and Mansoori's model for matrix strain associated with multicomponent adsorption. Clarkson et al. (2007) incorporated the adsorption effects in production data analysis of CBM reservoirs by inclusion of desorption term in the total system compressibility calculation.

2.4. Non-static permeability

In all reservoirs, the changes in pressure and temperature induced by recovery operations are accompanied by changes of stress state (Settari et al., 2005). In stress-sensitive reservoirs, including tight oil and gas reservoirs, changes in the stress state of the system during production may reduce the absolute permeability, which in turn results in productivity loss. According to the theory of poro- and thermo-elasticity, supported by laboratory evidence, porosity and absolute permeability are functions of effective stress (Settari et al., 2005). Reservoir rocks may exhibit an