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Effect of low velocity non-Darcy flow on pressure response in shale and tight oil reservoirs

Pengxiang Diwu[a], Tongjing Liu[a,*], Zhenjiang You[b,*], Baoyi Jiang[c], Jian Zhou[d]

[a] Enhanced Oil Recovery Institute, China University of Petroleum, Beijing 102249, PR China
[b] Australian School of Petroleum, The University of Adelaide, Adelaide, SA 5005, Australia
[c] China Huadian Institute of Science & Technology, Beijing 102249, PR China
[d] Beijing Jinshiliyuan Technology Co. Ltd., Beijing 102249, PR China

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ABSTRACT

Low velocity non-Darcy flow in shale and tight oil reservoirs is described by nonlinear or nonhomogeneous models. These models, especially for well shut-in period, are usually solved by numerical method, since the traditional pressure superposition principle is no longer applicable. The current paper presents a modified pressure superposition principle, accounting for the pseudo Threshold Pressure Gradient (TPG), and its mathematical proof. The proposed principle indicates that the total change of bottom hole pressure (BHP) in shut-in period is equal to the superposition of BHP change in a real well with pseudo TPG and that in a virtual well without pseudo TPG. The new principle is applied to the derivation of an analytical solution to the nonhomogeneous problem during the well shut-in period. Type curves calculated from the analytical solution show that the pseudo TPG leads to curve up-warping in switch-on period but down-warping in shut-in period, which agree with previous numerical results, and can be explained by the moving-boundary theory. Throughout the switch-on period, a closed moving-boundary is generated when the pressure gradient is less than the pseudo TPG. The boundary is closer to the well with higher pseudo TPG. However, during the shut-in period, a supply moving-boundary, which was generated during previous production or injection period, is earlier to be reached for virtual well with higher pseudo TPG. The flow is steady state afterwards. Matching of field data by the analytical solution results in the pseudo TPG in the investigation zone. The interpretation of the field case shows that pseudo TPG equals 0.104 MPa/m, generating a pressure drop as high as 6.35 MPa across the investigation zone during the well testing period.

1. Introduction

How to develop shale and tight oil reservoir efficiently has becoming more and more important for world energy supply. Fluid flow in shale and tight oil reservoirs is usually classified as low velocity non-Darcy flow. It has been studied intensively for decades [1–5,48]. Most of the previous works have demonstrated that this particular type of flow has significant impact on the well production and injection performance [6–7]. Theoretical calculation results show that the ultimate oil recovery from non-Darcy flow is approximately 48% of that from Darcy flow for a vertical well, and 80% for a multi-fractured horizontal well [8]. However, there is little research focused on the effects of low velocity non-Darcy flow on pressure response in well shut-in period.

The low velocity non-Darcy flow refers to the phenomenon that the flow velocity is lower than that predicted from Darcy's law at a low-pressure-gradient region. It results in a nonlinear section in the flow velocity-pressure gradient curve [9], as shown in Fig. 1 (blue section). Due to the wide range of the pores size distribution in shale or tight oil reservoirs, the threshold pressure gradient in smaller pores is relatively larger than that in larger pores. The fluid starts to flow through largest pores when the pressure gradient increases from zero until a certain value λ_{min}, defined as the minimum TPG (Fig. 1). As the pressure gradient continues to rise, the flow zone extends to smaller pore area. Finally, the pressure gradient reaches another certain value $\lambda_{\max}$, defined as the maximum TPG (Fig. 1), and the fluid flow occurs throughout the porous media. Further increase of the pressure gradient leads to linear relationship between pressure gradient and flow velocity (green section in Fig. 1). The extrapolation of this linear section intersects with the pressure gradient axis, at the so-called pseudo TPG, λ (Fig. 1) [10,11].

According to previous theoretical and laboratory studies, the existence of low velocity non-Darcy flow is due to non-Newtonian fluid [12], tight pores [13,49] and boundary layer [14]. Based on the

* Corresponding authors.
E-mail addresses: ltjcup@cup.edu.cn (T. Liu), zhenjiang.you@adelaide.edu.au (Z. You).

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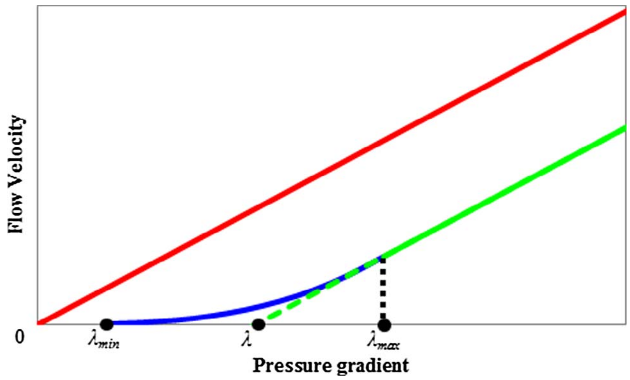

Fig. 1. Flow velocity versus pressure gradient for Darcy flow (red line) and low velocity non-Darcy flow (blue and green line). (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

definition of non-Newtonian fluid, the fluid viscosity is a function of the shear rate applied. The nonlinear section in the flow velocity-pressure gradient curve (blue section, Fig. 1) results from the viscosity variation [12]. However, the nonlinear relation takes place at low velocity only [15], and the same fluid yields different types of nonlinearity in different porous media. Therefore, it is generally acknowledged that low velocity non-Darcy flow is affected by the interaction forces between the fluid and tight pores, of course in small pressure gradients and low velocities. The interaction forces can be referred to as boundary layer effect. The fluid within a pore can be divided into two parts, i.e., boundary fluid and inner free fluid. The boundary fluid has relatively higher density and higher viscosity [8]. The smaller pore sizes lead to stronger rock-fluid interaction forces, which can show a significant influence on the flow in micro tubes with radii of 2.5 μm and 1 μm [16]. Even in nano-permeability shale gas reservoirs or coalbed, gas flow is considered low velocity non-Darcy flow due to the remarkable rock-gas interaction force resulting from extremely low permeability [17,18].

The low velocity non-Darcy flow phenomenon in laboratory or reservoir scale corresponds to the nonlinear section in Fig. 1. Therefore, many researchers have proposed modified Darcy's equation to address this deviation from Darcy's law. The main types of such models are listed in Table 1 below. Based on the knowledge of non-Newtonian fluid, a power-law equation was proposed by Dudgeon in 1966 [19]. However, this equation is over-simplified since it only accounts for fluid properties change, but not the interactions between the fluid and tight pores. In 1999, Prada and Civan developed the modified Darcy's law in the form of pseudo TPG [20]. This equation describes non-Darcy flow by pseudo TPG, including no-flow zone and linear-flow zone. Recently, more complex flow equations are derived, which can describe the nonlinear flow part [8,21–24]. For example, by matching the nonlinear part of experiment data, power functions are obtained [21,22]. Based on the assumption that the fluid in the pores can be divided into the boundary fluid and the inner free fluid, an exponential function is obtained [8]. If considering pore throat size distribution function, a linear function with multi-parameters is proposed [23]. In summary, these equations are in the form of power function, exponential function or linear function with multiple parameters.

However, these complex functions with multiple parameters lead to nonlinear or nonhomogeneous governing equations. The traditional pressure superposition principle, which is only valid for a linear system [24,25], is not applicable here to the derivation of analytical solutions [25–27]. Therefore, pressure response during well shut-in period in shale and tight oil reservoirs, governed by nonlinear or nonhomogeneous system, cannot be solved analytically from the pressure superposition principle. Unfortunately, some researchers still apply the traditional pressure superposition principle to the solution of mathematical model for well testing during the shut-in period. Their results show that it is the TPG that results in the slope of pressure derivative larger than zero after radial flow [28–31]. These results are highly doubtful and contradict with the numerical results reported in the literature [24,32], which show that pseudo TPG results in the slope of pressure derivative smaller than zero in late stage after radial flow. Therefore, until now it is believed that numerical methods are the only way to analyze pressure response in well shut-in period [33–35].

In this paper, we aim to fill the gap by developing a new pressure superposition principle to analytically analyze the pressure response of low velocity non-Darcy flow in shale and tight oil reservoirs, especially in well shut-in period. In Section 2, we propose a properly modified flow equation. The corresponding nonhomogeneous mathematical model for switch-on process is established and solved analytically. In Section 3, a modified pressure superposition principle for the above nonhomogeneous model is proved mathematically and its effects on type curves during well shut-in period are analyzed and explained physically by moving-boundary theory. Finally, in the field application presented in Section 4, a type curve of typical well is fitted and interpreted by the proposed modified pressure superposition principle.

2. Pressure responses during switch-on period

2.1. Flow equation

It is well known that Darcy's law is based on experimental observation, rather than physical mechanism how fluid flows through porous media. Darcy's law is in a simple and succinct form, which makes it easy to apply, not only in oil and gas reservoirs, but also in underground water flow. However, most of the flow equations shown in Table 1 have weak applicability, especially in reservoir scale, as they introduce more complexity to mathematical models and lose the above advantages of Darcy's law.

For shale and tight oil reservoirs, as defined in classical theory of flow in porous media [36], TPG is a function of pores construction, fluid properties and reactions on porous surface in general [12,37,38]. For specified porous medium and fluid type, TPG can be treated as a constant [39]. According to analyses in pore and field scales, the minimum TPG does not exist in low velocity non-Darcy flow [8,40], or it is negligible and has very small effect on pressure transient response [24].

Therefore, to analyze pressure responses in reservoir scale, the modified Darcy's equation with pseudo TPG [20] could balance the usability and veracity both in describing low velocity non-Darcy flow:

$$v = \begin{cases} -\frac{K}{\mu}(\nabla p - \lambda) & |\nabla p| \geqslant \lambda \\ 0 & |\nabla p| < \lambda \end{cases} \tag{1}$$

where v is flow velocity, cm/s, μ is fluid viscosity, mPa.s, K is effective permeability, D, ∇p and λ are pressure gradient and pseudo TPG respectively, atm/cm.

2.2. Mathematical model

Consider a cylindrical homogeneous reservoir with infinite boundary and a well in the center. The assumptions of the proposed mathematical model for radial flow towards wellbore include:

(1) Single-phase and slightly compressible liquid in the formation with isothermal radial flow;
(2) Wellbore storage and skin effect are considered;
(3) Initial reservoir pressure is p_i homogeneously;
(4) Gravity and capillary force are ignored;
(5) Fluid flows as low velocity non-Darcy flow, characterized by Eq. (1);
(6) Well production or injection rate is constant and equals q;
(7) Formation rock is slightly compressible.

The corresponding mathematical model of switch-on process, i.e.