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Analysis of pressure falloff tests of non-Newtonian power-law fluids in naturally-fractured bounded reservoirs

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ABSTRACT

Application of non-Newtonian Power-law fluids (e.g. polymeric solutions) for production enhancement in petroleum reservoirs has increased over the last three decades. These fluids are often injected as viscous solutions to improve mobility ratio and enhance oil recovery during chemical flooding. As part of the flooding operation, surfactant (or micellar) solutions are first injected at the leading edge of the flood to reduce interfacial tension between water and oil. Subsequently, a slug of polymer solution is injected ahead of normal water to increase viscosity of the water, improve volumetric sweep efficiency and accelerate oil production. Analysis of pressure tests conducted pre and post injection, to evaluate mobility of these fluids, is more demanding than conventional techniques, which were developed strictly for Newtonian fluids. In naturally-fractured reservoirs, flow of non-Newtonian fluids is more complex due to fracture-matrix interaction which is usually resonated in the pressure footprints. Some models have been developed to aid interpretation of pressure tests, but boundary effects on down-hole measurements due to structural discontinuity and presence of an active aquifer, have not been thoroughly investigated.

This article presents an analytic technique for interpreting pressure falloff tests of non-Newtonian Power-law fluids in wells that are located near boundaries in dual-porosity reservoirs. First, dimensionless pressure solutions are obtained and Stehfest inversion algorithm is used to develop new type curves. Subsequently, long-time analytic solutions are presented and interpretation procedure is proposed using direct synthesis. Two examples, including real field data from a heavy oil reservoir in Colombian eastern plains basin, are used to validate and demonstrate application of this technique. Results agree with conventional type-curve matching procedure. The approach proposed in this study avoids the use of type curves, which is prone to human errors. It provides a better alternative for direct estimation of formation and flow properties from falloff data.

1. Introduction

The flow of non-Newtonian fluids through porous media has continued to attract interest among investigators. Recent advances in fluid flow through petroleum reservoirs have expanded existing knowledge in application of non-Newtonian fluids in enhanced oil recovery by polymer injection. Polymer flooding provides improved mobility control over conventional water flooding, thus offering better volumetric sweep efficiency [1,2]. Moreover, heavy (waxy) crude oil have been characterized as exhibiting non-Newtonian flow behavior [3–6]. Unlike Newtonian fluids (e.g. water), flow modeling of this class of fluids through porous formations is very complicated. Previously, the behavior of this special fluids have been investigated through experimental and theoretical studies [7–13]. Field application of non-Newtonian fluids in pressure falloff tests has been reported previously [14–16,2,17,18]. Pressure falloff data acquired during field-scale testing are important data used for evaluating

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formation properties. However, interpretation of these data is a major challenge and investigations are still evolving in this area of study.

When fluids flow through porous rocks, pressure behavior depends on fluid rheology, reservoir architecture, reservoir type and condition at the wellbore (Fig. 1). Theoretically, petroleum reservoirs are classified on the basis of geological complexity as homogeneous (single-porosity) and heterogeneous (dual-porosity or naturally-fractured systems and triple-porosity or vuggy systems) reservoirs. Well test analysis involving the flow of Newtonian fluids in single- and double-porosity reservoirs have been studied extensively [19–26]. For non-Newtonian fluids, only limited studies [27,15,28–36] have been conducted. None of these studies investigated the impact of reservoir boundaries (e.g. faults, aquifers etc.) on pressure behavior of these fluid systems under flowing condition in porous media. Procedure for analyses of pressure falloff data for such systems is important since most wells are drilled either close to a fault or near an active aquifer. Although field tests [14,18] have shown this trend, interpretation techniques are scarce; hence the need for further studies.

Fig. 2a illustrates the typical log–log plot of pressure derivative vs time for Newtonian and non-Newtonian fluids in single-porosity and dual-porosity reservoir systems. Recently, Ref. [37] presented models for radial flow of non-Newtonian Power-law fluids in a well located near boundaries in homogeneous (single-porosity) reservoirs. Models for interpreting transient tests of non-Newtonian fluids in dual-porosity bounded reservoirs are yet to be developed. Fig. 2b shows an actual log–log plot of pressure and pressure derivative field data obtained from a fully-penetrated heavy oil well in the Colombian Eastern plains basin [14]. This falloff data serves as the major motivation for this study. Initial attempt to match and interpret this data with non-Newtonian Power-law type curve developed for bounded and homogeneous reservoirs [37] was unsuccessful. Therefore, the data was re-evaluated and we observed two important features. Firstly, the data points that follow the early-time wellbore storage (WBS) and skin-dominated flow regime are discontinuous. For a single-porosity infinite-acting flow, data points would normally lie on line XX'. Instead, we noticed a 'trough' which is characteristic of naturally-fractured reservoirs (NFR). Fig. 2c shows another pressure falloff data obtained after conducting polymer injection in a Middle Eastern field [18]. In this case, no trough is present which suggests a homogeneous reservoir. Using single-porosity non-Newtonian fluid model, this data was successfully interpreted in another article by Ref. [37]. For NFRs, the line YY′ in the trough of the derivative plot has a unit slope [38,21]. This line is not the same as late-time unit-slope line which signals pseudo-steady state flow regime for boundary-dominated flow (BDF) in closed reservoir systems. As shown on the field data, the slope of this line is 0.86, which, for all practical purposes, can be approximated as 1 because the data on this line occur at early time (between 0.5 and 1.5 h) for short duration (1 h) and the variance between 0.86 and 1 could be due to data quality and/or non-Newtonian effect. Had the dual-porosity unit slope line occurred at late time, approximation of 0.86 as 1 would have been invalid. Secondly, the line XX′, which represents a single-porosity infinite-acting flow regime, is not horizontal (i.e. constant derivative value) as would be expected of a single-porosity derivative plot for Newtonian fluids. A similar observation is visible in Fig. 2c. The slanted line XX′ indicates a non-Newtonian fluid behavior whose flow index can be estimated from the slope of the line. It turns out that flow index is a function of the slope of the infinite-acting line (as shown in Section 3. of this article). In addition, the decline in pressure derivative at late time indicates a constant-pressure boundary.

As a result of the preceding analysis, we were motivated to hypothesize a dual-porosity reservoir system with constant-pressure boundary. Therefore, appropriate model (based on Warren and Root [26] model) was formulated to match and interpret this data. Dimensionless pressure solutions in Laplace domain were obtained for radial flow of non-Newtonian Power-law fluids in bounded dual-porosity reservoirs. These solutions were numerically inverted using Stehfest [39] algorithm and type curves were subsequently developed. Furthermore, a direct synthesis scheme is presented for estimating formation properties from long-time real-space analytic solutions. A type curve developed from this study perfectly matched the field data presented in Fig. 2b and direct synthesis technique was successfully used to interpret the data.

2. Equation for non-Newtonian fluid flow in NFRs

2.1. Model assumptions

Fig. 3 illustrates the well model adopted in this study. To simplify the problem, the following assumptions are made:

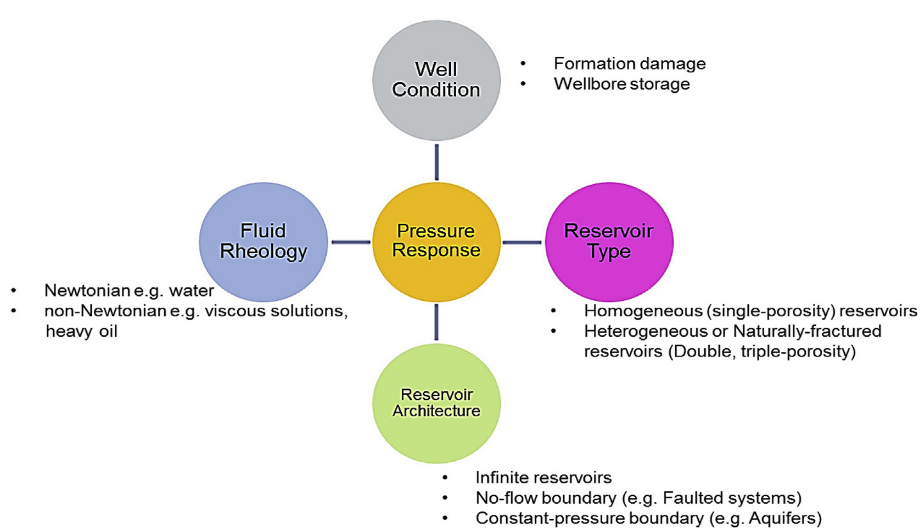

Fig. 1. Factors influencing pressure behavior of fluids flowing through porous rocks.