SPE 110507

Impact of Self-Consistent Physically-Based Three-Phase Relative Permeability on Oil Recovery by Secondary Gas-flooding

Baharak Barzegar Alamdari, SPE, Tara LaForce, SPE, and Mohammad Piri, SPE, University of Wyoming

This paper was prepared for presentation at the 2007 SPE Annual Technical Conference and Exhibition held in Anaheim, California, U.S.A., 11–14 November 2007.

Abstract

We use a three-dimensional random pore-scale network model to simulate gas injection into oil and water after primary drainage. The model is based on the physics of multiphase flow observed in micromodel experiments. Important features of immiscible fluid flow at the pore scale, such as wetting and spreading layers and wettability alteration are implemented. The pore network simulator is utilized to model relative permeabilities, saturation paths, and capillary pressures. A random network that represents the pore space in Berea sandstone is used in this study. Three-phase relative permeabilities generated by the network model are dependent on the saturation path, which is not known *a priori.*

This paper includes numerical and analytical solutions for a series of secondary gas-floods with relative permeabilities generated using the network model. Analytical and simulated solutions such as these illuminate the large impact of correctly accounting for the effects of saturation history in relative permeabilities in gas injection. This knowledge is critical for the design of EOR schemes such as tertiary gas injection and WAG flooding. It is demonstrated that saturation history has a substantial impact on the relative permeabilities, and hence oil recovery. For the examples studied here, the physically-based relative permeabilities with correct saturation history exhibit an extremely rare solution structure. This is a strong indication that many of the complex solution structures frequently encountered in analytical solutions for three-phase flow may be the consequence of permeability models with little or no physical basis.

To the best of our knowledge, this is the first study to perform an analysis of the effect of physically-based relative permeabilities, using a description of the pore space and its connectivity that mimics *real* systems, on the saturation paths and secondary oil recovery by immiscible gas injection.

Introduction

Development decisions for oil fields are based on predictions of oil recovery under different putative development strategies, many of which are three-phase flow processes. These predictions use numerical simulation of multiphase fluid flow through a geological description of the reservoir. There has been an explosion of interest in assigning distributions of static properties – such as porosity and permeability – that faithfully represent the expected spatial heterogeneity and are consistent with a variety of different measurements of reservoir properties.

In comparison, multiphase properties, particularly relative permeability, are given less attention, and a single set of relative permeabilities is often assigned to a given rock type, or even to the whole field. For many improved oil recovery projects, accurate estimates of relative permeabilities are crucial, particularly for flow at low oil saturations in mixed-wet reservoirs and during reservoir blow-down and gas injection, where estimates of the oil relative permeability, that has a direct relation to recovery rate, may vary by orders of magnitude. Assigning a single relative permeability to whole regions of the field based on scant core data, or an empirical model [1, 2] with a shaky physical basis, may lead to errors comparable with mistaking or ignoring the gross-scale geological heterogeneity of the field.

Measurements of relative permeability are costly and time consuming and at low saturation the results are very uncertain [3, 4]. Furthermore, two independent fluid saturations are required to define a three-phase system and there is an infinite number of possible fluid arrangements, making a comprehensive suite of experimental measurements for all three-phase displacements impossible. This is mainly because the saturation path for a given grid block of the reservoir, for the process of interest, is not known *a priori*. In addition, the experiments are only performed on a small number of core samples, and thus cannot reproduce a representative variability in properties across the field. This is why numerical simulations of three-phase flow almost always rely on available empirical correlations to predict three-phase relative permeabilities from measured two-phase properties [1-2,5-6], despite the fact that they have little or no physical basis. The uncertainties associated with assigning multiphase flow properties often means that improved oil recovery projects are not carried out, with lost opportunity costs that may be hundreds of millions of dollars for a single field. This indicates that it is important to have a reliable physically-based tool that can provide plausible estimates of macroscopic properties.