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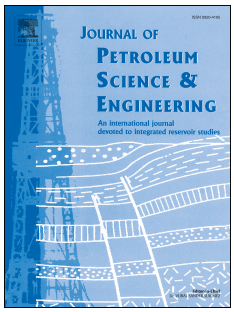

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A Mechanistic Model for Prediction of Three-Phase Flow in Petroleum Reservoirs

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Abstract

Multiphase flow in the porous media is of great interest for many engineering fields such as underground oil and gas reservoirs, environmental process (e.g. carbon dioxide (CO2) geological storage) and underground water resources remediation. Modelling of these process requires relative permeability (k_r) of each fluid as a function of the fluid saturation. The experimental measurement of the three-phase relative permeability is much more complex and time consuming process than the two-phase relative permeability. Hence, many correlations have been proposed in the oil industry for the calculation of the three-phase relative permeability using two-phase k_r data. However, most of the existing three-phase models ignore the physical mechanism underlying the multiphase flow in the porous media.

In this study, a novel mechanistic model is proposed to predict the three-phase relative permeability of the oil, water and gas in the petroleum reservoir (i.e. porous rock). The new idea is that the interaction between various fluids (i.e. oil, water and gas) and also the fluid saturation distribution are somehow considered in the estimation of the relative permeability. For this purpose, a new parameter named characteristic coefficient is introduced in the model. This parameter reflects the contribution of each fluid in controlling the flow of the other fluids. In other words, this factor is net impact of the various rock and fluid parameters (e.g. surface tension between fluids, wettability and saturation distribution) that all influence the flow in the porous media. This idea is taken from the glass-micro-model experiment that visualises the mechanism underlying the flow at the pore scale. Another feature of this method is that, at least one set of experimental three-phase k_r data is required to tune the characteristic coefficients. The estimated characteristic factors can then be employed to predict the three-phase relative permeability for the other saturation path.

The model is successfully validated against the experimentally measured three-phase relative permeability data.

Keywords: Porous media, Three-phase, Relative permeability, Petroleum

1- Introduction

The flow of immiscible fluids in the porous media is of great interest in many engineering process, such as underground hydrocarbon resources, storage of gas in geological formation due to environmental concern and contamination of underground water. The increasing demand for fossil fuel, on the one hand, and reduction of oil reserves in the world, on the other hand, have led many oil companies to develop enhanced oil recovery technique (EOR). Many of the EOR

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