



Pore-Scale Simulation of Dispersion in Porous Media

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Abstract

Mixing of miscible gas with oil in a reservoir decreases the effective strength of the gas, which can adversely affect miscibility and recovery efficiency. The level of true mixing that occurs in a reservoir, however, is widely debated and often ignored in reservoir simulation where very large grid blocks are used. Large grid blocks create artificially large mixing that can cause errors in predicted oil recovery.

This paper examines the mixing that occurs in porous media by solving for single-phase flow in a connected network of pores. This work differs from network models in that we directly solve the Navier-Stokes equation and the convection-diffusion equation to determine the velocities and concentrations at any location within the pores. Flow in series and layered heterogeneous porous media are modeled by using many grains in different arrangements. We consider both slug, continuous, and partial injection as well as echo tests (single-well tracer tests) and transmission tests (interwell tracer tests). We match the concentrations from the pore-scale simulations to the analytical convection dispersion solution that includes both transverse and longitudinal dispersion coefficients.

The results show that for flow in series and in layers, echo and transmission longitudinal dispersivities become equal and reach an asymptotic value if complete mixing over a cross section perpendicular to flow has occurred. In practice, the asymptotic value of dispersivity may never be reached depending on pattern-scale heterogeneity and well spacing. Transverse dispersion coefficients also are scale dependent, but they decrease with traveled distance. We further demonstrate that the classical Perkins-Johnston relationship between longitudinal dispersion coefficient and fluid velocity

is obtained. We conclude that echo dispersivities are reliable indicators of true mixing in porous media.

Introduction

Oil recovery from miscible gas floods is highly dependent on the magnitude of mixing at the field or pattern scale.¹⁻⁴ Mixing acts to drive the composition route further into the two-phase region and away from the critical locus in multicontact miscible floods. Because the composition route moves further away from the critical locus and deeper into the two-phase region, the local displacement efficiency is reduced, in some cases, by nearly half of incremental oil recovery (recovery post waterflood).³⁻⁴ If reservoir mixing is large, good recovery efficiency may require operating at pressures well above the minimum miscibility pressure (MMP) or beyond the minimum enrichment for miscibility (MME).³⁻⁵

Numerical dispersion is also present in reservoir simulations, which can significantly increase mixing when large grid-block sizes are used. Methods that achieve low mixing, such as those used in streamline simulation, may reduce the level of mixing below that which is expected at reservoir scale. Streamline simulations may also not adequately include crossflow between streamlines. It is important to determine the appropriate level of dispersion at reservoir scale so that we can attempt to model it correctly.

Mixing in a reservoir is primarily caused by molecular diffusion of solute (or gas) from one stream line to the next within the pores. Mixing causes dilution of the gas, which can decrease oil recovery. Reservoir mixing is enhanced by any mechanism that increases the area of contact between the gas and the oil, thereby allowing the effects of diffusion to be magnified. This is in essence the cause of scale-dependent dispersion. The longer the distance traveled of a solute the greater the area exposed to diffusion and the longer time diffusion has to work. The contact area grows primarily because of variations in streamlines and their velocities around grains and through layers of various permeabilities (heterogeneity). Crossflow, such as that caused by gravity, can also allow for greater mixing when a fluid of different density than the reservoir oil is injected. Mixing can also be enhanced by the effects of other neighboring wells (fluid drift), and by differences in chemical potentials between components in different phases, that is, by phase mass transfer.