Journal of Petroleum Science and Engineering 159 (2017) 588–602

Contents lists available at ScienceDirect

Journal of Petroleum Science and Engineering

journal homepage: www.elsevier.com/locate/petrol

Calibrating and interpreting implicit-texture models of foam flow through porous media of different permeabilities

O. Gassara[a], F. Douarche[a,*], B. Braconnier[b], B. Bourbiaux[a]

[a] *IFP Energies nouvelles, Geosciences Division, France*
[b] *IFP Energies nouvelles, Mechatronics and Numerics Division, France*

ARTICLE INFO

Keywords:
Enhanced oil recovery
Foam
Multiphase flow
Porous media
Capillary pressure
Permeability
Reservoir simulation

ABSTRACT

This paper proposes a robust methodology to calibrate steady-state models of foam flow through porous reservoirs from foam displacements on core samples. The underlying approach consists in linking foam mobility and foam lamellas density (or texture) at local equilibrium. This calibration methodology is applied to foam displacements at different qualities and velocities on a series of sandstones of different permeabilities. Its advantages lie in a deterministic non-iterative transcription of flow measurements into texture data, and in a separation of texture effects and shear-thinning (velocity) effects. They are discussed with respect to calibration methods that consist in a least-square fit of apparent viscosity data.

Scaling trends of foam parameters with porous medium permeability are then identified and discussed with the help of theoretical representations of foam flow in a confined medium. Although they remain to be further confirmed from other well-documented experimental data sets, these scaling laws can increase the reliability of reservoir simulators for the assessment of foam-based improved recovery processes in heterogeneous reservoirs.

1. Introduction

Since the sixties, foam-drive processes have been considered as a promising enhanced oil recovery (EOR) technique (Bond et al., 1958; Holm, 1970; Jonas et al., 1990; Heller et al., 1995; Sheng, 2013). Indeed, the injection of foam instead of gas alleviates gravity override and detrimental effects of heterogeneities and viscous instabilities on displacement efficiency.

Foam in porous media is defined as a dispersion of gas in liquid carrying surfactants, such that at least a fraction of the gas phase is discontinuous and the liquid phase is continuous and connected through wetting films and lamellas separating gas bubbles. Surfactants in foam context are used to stabilize the thin liquid lamellas and promote the foaming ability of the mixture. Foam is usually characterized by its texture, defined as the number of foam bubbles or lamellas per unit volume of gas, and also its quality f_g which is the ratio between the volumetric flux of foamed-gas and the total volumetric flux of gas and liquid.

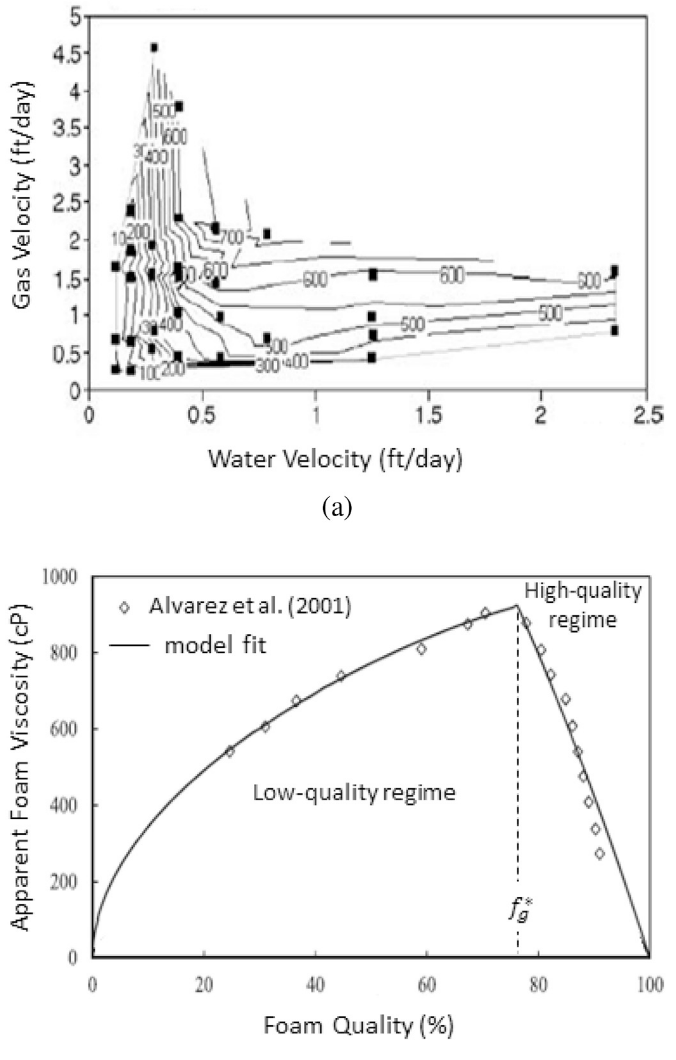
Foam reduces gas mobility compared to gas flowing as a continuous phase, whereas the mobility of liquid phase is presumed to remain unchanged (Bernard and Jacobs, 1965a; Lawson and Reisberg, 1980a; Friedmann et al., 1991). This reduced gas mobility can be seen as an increased effective gas viscosity, a decreased gas relative permeability, or also as a combination of the two effects (Hirasaki and Lawson, 1985; Falls et al., 1988; Kovscek et al., 1994, 1995). Rheological properties of foam are complicated since they depend on several parameters such as foam texture, which is the result of several pore-level scale mechanisms of lamellas generation and destruction, gas and liquid velocities (foam behaves as a shear-thinning fluid in porous media), permeability and porosity of the porous medium, surfactant formulation and concentration. Coarsely-textured foams are characterized by a small number of lamellas and are referred to as weak foams since they provide a moderate gas mobility reduction, whereas finely-textured foams, called strong foams, are characterized by a large number of lamellas and reduce gas mobility remarkably. The transition from weak foam to strong foam state is called foam generation which is usually thought to be governed by pressure gradient (or equivalently total velocity) (Rossen and Gauglitz, 1990; Dholkawala et al., 2007; Gauglitz et al., 2002; Lotfollahi et al., 2017).

The strong foam resulting from that generation process exhibits two different regimes: the low-quality regime, at which the steady-state pressure gradient is almost independent of water flow rate, and the high-quality regime at which the pressure gradient is nearly independent of gas velocity. These two regimes were first highlighted by Osterloh and

---

* Corresponding author.
E-mail address: frederic.douarche@ifpen.fr (F. Douarche).

https://doi.org/10.1016/j.petrol.2017.09.069
Received 16 June 2017; Received in revised form 11 September 2017; Accepted 26 September 2017



(a)

(b)

Fig. 1. (a) Contours of iso-steady-state pressure gradient as a function of gas and liquid velocities: vertical and horizontal contours represent the high- and low-quality regimes, respectively (adapted from Alvarez et al., 2001); (b) Apparent foam viscosity for a single scan of foam quality at constant total velocity (adapted from Lotfollahi et al., 2016).

Jante (1992) and later on by Alvarez et al. (2001) who represented the iso-value contours of the steady-state pressure gradient of strong foam as a function of gas and liquid volumetric fluxes as shown in Fig. 1(a). As any straight line drawn from the origin in this diagram represents a fixed foam quality, one can distinguish a specific value, called the optimal foam quality f_g^*, that divides the domain into two parts and provides the maximum pressure gradient that can be obtained for any given value of the total velocity. One can also clearly identify these two regimes from the evolution of the apparent foam viscosity μ_f with foam quality at constant total velocity, as reported in Fig. 1(b). μ_f is directly inferred from the pressure gradient ∇P by application of Darcy's law to foam considered as a single homogenous phase, that is $\mu_f = k|\nabla P|/u$, where k is the permeability of the porous medium and u the total velocity. In the low-quality regime, μ_f (or ∇P) increases with foam quality f_g until the optimal foam quality f_g^* for which the maximum value of the apparent foam viscosity is reached. For foam qualities higher than f_g^*, lamellas rupture occurs and μ_f (or ∇P) decreases, as reported in Fig. 1(b).

The two strong-foam regimes are dominated by different mechanisms: the low-quality regime is characterized by the mobilization of foam bubbles in proportion to foam quality (bubble size is nearly fixed), and the high-quality regime is characterized by lamellas coalescence as the liquid films in this regime become unstable. By conducting foam flow experiments in beadpacks, Khatib et al. (1988) found that the transition between these two regimes corresponds to a maximum or critical gas-liquid capillary pressure, denoted P_c^*, above which foam collapses. Since capillary pressure is related to water saturation, there is a limiting water saturation S_w^* corresponding to P_c^*. It has been shown that the magnitude of P_c^*, or equivalently S_w^*, varies with surfactant concentration, electrolyte concentration, gas flow rate and permeability (Khatib et al., 1988). The dependence of P_c^* to the permeability is not yet clearly elucidated. Nonetheless, predicting the evolution of foam apparent viscosity with the permeability of the porous medium is of primary importance in evaluating foam process at the scale of a reservoir with permeability heterogenities.

The objective of this work is twofold. The first main purpose is to set up and apply a novel methodology for calibrating an Implicit Texture (IT) foam flow model from experimental data expressed in terms of lamellas (texture) thanks to Population Balance (PB) modelling approach at steady state. A second purpose is to elucidate the scaling laws of the so-calibrated model with respect to the permeability of the porous medium.

Thus, this paper is organized as follows. Foam flow modelling in porous media and implicit texture foam flow models are introduced first. Then, after a summary of experimental data sets used in this work, the whole calibration methodology is detailed, starting with relative permeability data acquisition and going on with foam IT model calibration itself. A formal equivalence between IT model and PB model at steady state (Kam et al., 2007) underlies this methodology; it is developed in another paper under review (Gassara et al., 2017) and is summarized herein. Distinctive features of the methodology compared to usual calibrating procedures (Lotfollahi et al., 2016; Boeije and Rossen, 2015; Ma et al., 2013, 2014; Farajzadeh et al., 2015) include (a) the determination of a relation between foam-gas viscosity and foam texture (Hirasaki and Lawson, 1985; Bretherton, 1961) thanks to a deterministic processing of experimental apparent viscosity data, and (b) the sequential calibration of shear-thinning effects and texture effects. Next, the methodology is implemented to parameterize the IT model of foam flow data measured on three cores of different permeabilities. The last section is dedicated to the analysis of calibrated parameters evolution with core permeability according to different assumptions regarding lamellas stability, in order to elucidate scaling laws of IT model parameters in the context of heterogeneous reservoirs.

2. Foam modelling in porous media

We consider a model for a two-phase flow in a porous medium in the presence of foam. We distinguish two phases: an aqueous phase w and a gas phase g. This flow is modified by the presence of foam. Modelling foam requires the presence of a surfactant, which is transported by the water phase, and which is described by an additional mass balance equation. The surfactant is either mobile or adsorbed on the rock.

It has been shown that the transport of liquid is not affected by the presence of foam (Friedmann et al., 1991; Bernard and Jacobs, 1965b; Lawson and Reisberg, 1980b). On the opposite, the gas velocity is significantly reduced by the presence of foam. Thus, to describe the water and gas phases, we consider a black-oil model (Peaceman, 1977; Trangenstein and Bell, 1989) where the gas phase involves a modified velocity which will be denoted $\mathbf{u}_g^f$. The mass conservation equations read:

$$\begin{cases} \partial_t(\Phi\rho_w S_w) + \nabla\cdot(\rho_w \mathbf{u}_w) = q_w \\ \partial_t\left(\Phi\rho_w S_w C_w^s + (1-\Phi)\rho_r C_r^s\right) + \nabla\cdot\left(\rho_w \mathbf{u}_w C_w^s\right) = q_w C_w^s \\ \partial_t\left(\Phi\rho_g S_g\right) + \nabla\cdot\left(\rho_g \mathbf{u}_g^f\right) = q_g \end{cases} \tag{1}$$

where Φ is the rock porosity. For each phase denoted $i \in \{w, g\}$, S_i is the saturation, ρ_i the mass density and q_i the source/sink term per unit volume of porous medium. C_w^s stands for the flowing surfactant mass