

MODELING THE SOLUTION GAS DRIVE PROCESS IN HEAVY OILS

Primary heavy oil recovery relies on the Solution Gas Drive mechanism, which has been the object of many recent research efforts. Current models are unreliable, and it is likely that they do not represent important physical effects. Here, we introduce a Darcy scale model in which the relative permeability of the gas phase is replaced by a new expression for the gas phase velocity based on the relative strength of viscous, gravity and capillary effects.

Первоначальная добыча тяжелых нефтей основывается на механизме вытеснения их растворенным газом, который в последнее время стал объектом многочисленных научных исследований. Существующие на настоящий момент модели не надежны и, вполне вероятно, не отражают важных физических феноменов. В работе предлагается масштабная модель Дарси, в которой относительная фазовая проницаемость газовой фазы заменена новым выражением для скорости газовой фазы, учитывающим влияние вязкости, плотности и капиллярного эффекта.

Introduction.

Cold production involved in primary oil recovery is deemed the most economical production mechanism. Yet it needs a pressure support which can be provided, for example, by a strong aquifer, by a gas cap or by an over pressurized reservoir. This pressure support can also be provided by the gas in solution in oil, forming a dispersed phase as the pressure drops below the bubble point pressure. The bubbles expanding during depletion will «push» the oil out of the reservoir. This is called a Solution Gas Drive (SGD) process.

The SGD mechanism is often modeled by laboratory depletion experiments. In such experiments, long sample of rock is initially saturated with live oil, a high pressure mixture of lighter and heavier species. By slowly decreasing the pressure at one end of the core, oil and gas are produced in variable proportions. Usually, the pressure decreases at a set rate over the duration of the experiment. When experiments are modeled by

commercial simulators, several difficulties arise. The main one is that relative permeabilities have to be adjusted as a function of the rate of decrease of the pressure or depletion rate. In other words, relative permeabilities matched for one depletion rate do not match the results for the other depletion rate. This is a classical difficulty in heavy oil modeling.

In order to address these difficulties, we introduce in this paper a model with new physical effects related to capillarity and viscosity. In a few words, the new model assumes the existence of relatively large gas bubbles and relates their ability to move to the relative strength of viscous and gravity effects and of the capillary effects. The motivation for the use of this number is that gas bubbles in the porous medium grow until they become larger than pore throats. They are then considerably slowed down or even blocked by capillary effects. Only when the viscous forces on the bubble are large enough does the bubble move.

The model.

Thermodynamics and mass conservation. Thermodynamic equilibrium between the dissolved gas phase (made of light species only) and the liquid phase is obtained when the mass fraction of light species dissolved in the liquid is $x = x_{eq}$, where the equilibrium mass fraction x_{eq} is related to the pressure P by Henry's law $x_{eq} = KP$, where K is a constant. More sophisticated thermodynamic models K may depend itself on temperature and pressure.

We use a simple perfect gas equation $\rho_g = C_g P$, where $C_g = M_g / RT$ to relate the gas density to the pressure. The liquid is incompressible. Initial conditions for the model are usually a high initial pressure P_{ini} , and a certain initial dissolved mass x_{ini} . The pressure at which the mixture is predicted to start boiling is the *bubble point pressure*, given by $P_{bubble} = Kx_{ini}$. It is also customary to define a standard pressure $P_{std} = 1$ bar, and a standard gas density at the standard pressure $\square_{g, std}$. The Ratio of saturation is then defined as $R_s = \square_l x_{ini} / \square_{g, std}$. Three mass conservation equations may be written

$$\phi \partial_t (\rho_g S) + \partial_z (u_g \rho_g) = R(x - x_{eq}), \quad (1)$$

$$\phi \partial_t (\rho_l (1 - S)x) + \partial_z (u_l \rho_l x) = -R(x - x_{eq}), \quad (2)$$

$$\phi \partial_t [\rho_l (1 - S)(1 - x)] + \partial_z [u_l \rho_l (1 - x)] = 0. \quad (3)$$

In these equations, S is the fraction of the pore volume filled with the gas phase. The term $R(x - x_{eq})$ represents mass transferred from the liquid to the gas phase. It is proportional to the supersaturation $(x - x_{eq})$, and the factor R depends on the speed of growth of bubbles by diffusion. For an isolated bubble $R = (48 \square_l \square_g D N^{2/3} S^{1/3} (1 - S))$, N is the number of bubbles per unit volume, D is the diffusion coefficient for the light species in the liquid.

Liquid and gas mobility models. The velocities are given in usual reservoir scale models by Darcy's law. For the liquid this law takes the form

$$u_l = -\frac{k k_{rl}(S)}{\mu_l(x)} (\partial_z P + \rho_l g).$$

In this equation, k is the rock permeability, k_{rl} the relative permeability and $\mu_l(x)$ the liquid viscosity which depends on the mass fraction of dissolved gas. In classical models the relative permeability is derived from the match of the experimental data. However in what follows we shall attempt to represent the experiments using the straight line permeability, $k_{rl} = 1 - S$.

For the gas we introduce a new model of motion. We consider that bubbles smaller than the pore throats have negligible motion: either they are attached to the solid matrix or they are so small and sparse that their contribution to the gas flux is negligible. Bubbles larger than the pores are slowed down by capillary effects. We consider that these bubbles are predominantly blocked until they become large enough to start moving as discussed by Valavanides et al. (1998). The balance between capillary forces and viscous forces may be viewed as follows. Consider a bubble or «ganglion» of size r , larger than the typical pore size. The pressure that opposes bubble motion is the capillary pressure $2 \square_l r_{pore}$. The force that drives the bubble is the pressure gradient in the liquid and the force of gravity in the gas. The pressure gradient force is larger than the capillary force when

$$r \left\| \nabla P - \rho_g g \right\| > K_{mobility} \frac{\sigma}{r_p}.$$

The two forces may be compared through a number N_f (force number) and the bubbles are entrained by liquid motion when $r \gg r_c$ while when $r \ll r_c$ the bubbles are blocked:

$$r_c = \frac{K_{radius\ crit} r_p}{N_f} \quad \text{and} \quad N_f = \frac{\left\| \nabla P - \rho_g g \right\| r_p^2}{\sigma}.$$

We model the gas velocity by

$$u_g = -K_{v\ bubble} \frac{kS}{\mu_l(x)} (\partial_z P + \rho_g g).$$

When the bubbles are entrained by the liquid, their velocity may actually be larger than the velocity of the surrounding liquid, thus the coefficient K_{bubble} . As ganglia become even larger, they eventually merge to form a connected gas phase. In a connected gas phase, the gas is much more mobile as its motion is not impeded by the liquid. This connected gas phase occurs when the gas saturation is above a percolation threshold S_c

that depends on the rock characteristics. The gas velocity then takes the classical form

$$u_g = -\frac{kS}{\mu_g}(\partial_z P + \rho_g g).$$

Again we simplify the model by assuming a straight line relative permeability, $k_{rg} = S$. The model may be summarized by the schematic view on fig.1.

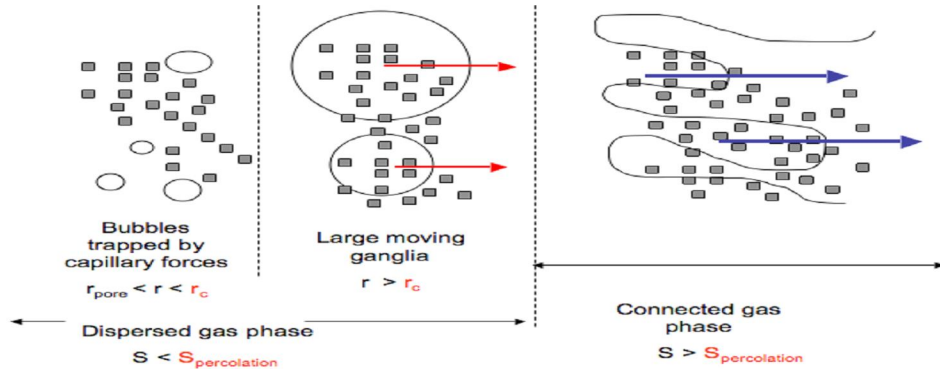


Fig.1. Schematic view of the bubble mobility model

Finally, we consider a smooth transition between the various regimes, using sigmoid functions for the transitions. We need the smooth transition because all the bubbles do not become mobile simultaneously: instead, statistical effects make a fraction of the bubble move at any time. The resulting gas velocity is

$$u_g = -\frac{kS}{\mu_g} \left\{ K_{bubble} \frac{\mu_g}{\mu_l} f(r, r_c) \Phi(S, S_c) + [1 - \Phi(S, S_c)] \right\} (\partial_z P + \rho_g g)$$

where Φ is a smooth function that varies between 0 and 1 around the percolation threshold and the function f is given by

$$f(r, r_c) = \frac{r^2}{r^2 + r_c^2}.$$

Ganglia coalescence model. In order to model the growth of the ganglia size, we develop a model of bubble coalescence through an evolution equation for the number of bubbles. The number of bubbles in a Representative Elementary Volume of the porous medium located at z , at time t is $N(z, t)$ and obeys the equation

$$\partial_t N + \partial_z (u_g N) = -4SN/t_c,$$

where t_c is a characteristic coalescence time given by,

$$t_c = K_{coalesc} \frac{\mu_p r_p}{\sigma} \left(\frac{r}{r_p} \right)^3.$$

More details on the model can be found in Zaleski et al. (2005) and Chraïbi et al. (2006).

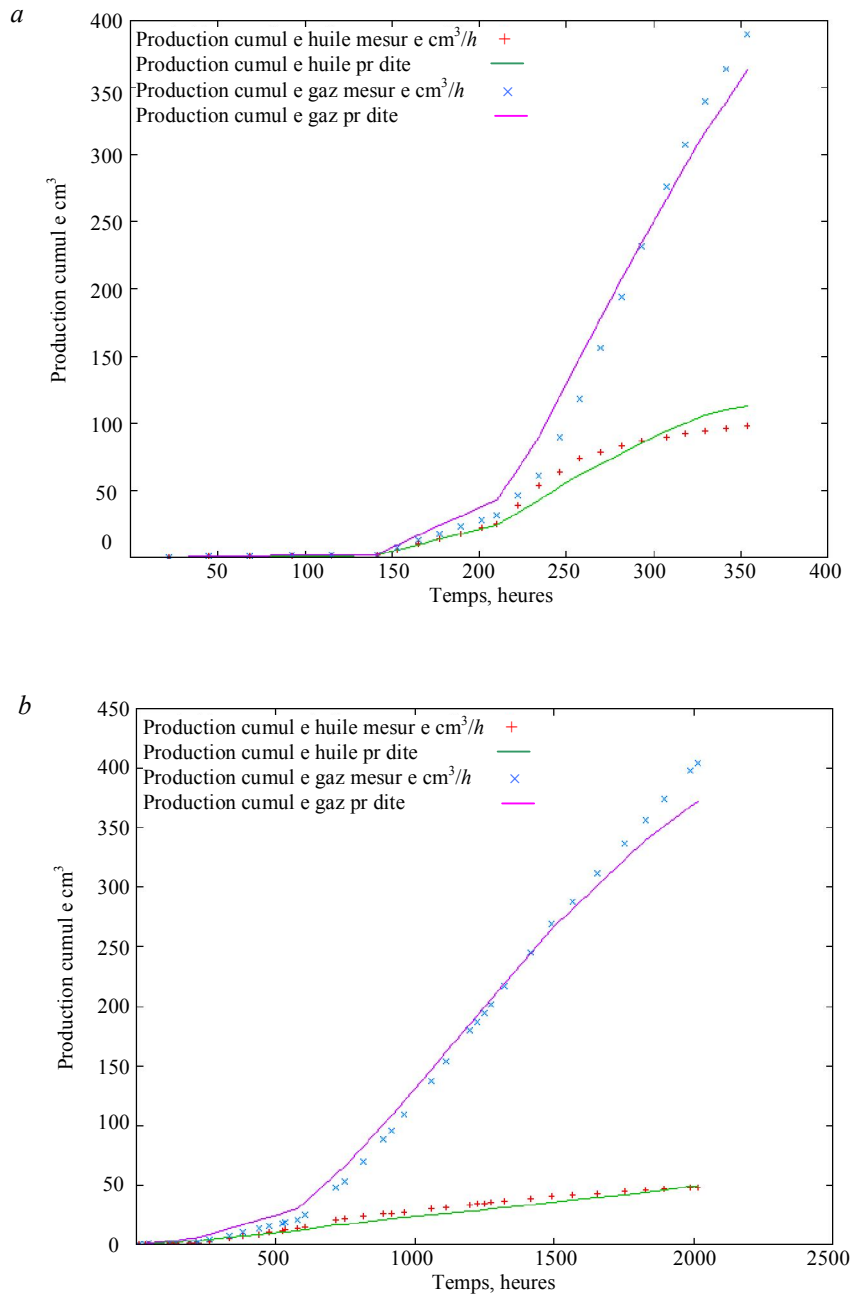


Fig.2. Predicted and measured oil and gas productions for the 8 bar/day experiment (a) and the 0,8 bar/day experiment (b) with the following tuning parameters $K_{v\ bubble} = 15$, $K_{radius\ crit} = 0,1$, $K_{coalesc} = 0,05$ and $S_c = 0,4$

Results.

The model is computed using the IMPES method (IMPlicit Pressure Explicit Saturation). Parameters are given in Table 1 at the end of the paper and follow those of the 8 bars per day and 0,8 bars per day experiments of Bayon, Cordelier and Nectoux (2002). Some of the physical parameters are measured independently, while others are un-

known, such as the initial bubble radius and the initial number of bubbles. Finally four parameters: $K_{v\ bubble}$, $K_{coalesc}$, $K_{radius\ crit}$ and S_c are purely model parameters. Fig.2 shows the results on the productions. Good agreement is obtained for both experiments even if the fast depletion results could be improved. Work is in progress to improve the model to better reproduce both depletion rates.

Experimental parameters:

Length of core h , m	0,9
Mean porosity	0,172
Mean permeability, mD	630
Oil viscosity at bubble point, cp	308
Dead oil viscosity at final pressure, cp	2130
Saturation pressure P_{bubble} , bar	52
$R_s = x_{ini} \square / \square_{g, std}$, Std·m ³ /Std·m ³	15,5
Oil density, g/cm ³	0,984
Diffusion coefficient D , m ² /s	1,2 10 ⁻¹⁰
Number of bubbles N , 1/mm ³	20
Initial bubble radius r_{bi} , microns	0,01
Surface tension, kg/s ⁻²	0,028
Approximate depletion rate, bars/day	8/0,8

Conclusion and discussion.

We have presented a new model for liquid-gas two-phase flow in porous media that takes into account the dynamics of bubble ganglia. The model is markedly different from the classical models as it does not rely on arbitrary

fitting functions such as relative permeability curves. The parameters are independent of depletion rates. However the agreement with experimental results is still tentative. Progress is reported towards the goal of predicting oil and gas productions for the same set of parameters independently of the depletion rate.

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