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Rheological Effects in Two-phase Microflow

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***Abstract* -** Comprehensive characterization of rock and pore-scale phenomena are of the vital importance for oil and gas industry. The key traditional characterization methods include measurements of porosity, absolute and relative permeabilities. Such measurements are costly in terms of both time and money and also the results sometimes fail repeatability tests. We present results of numerical modelling of two-phase pore-scale flow within rock at variable saturations and capillary numbers. Two-phase flow is described in the frame of density functional hydrodynamics. The effects of non-Newtonian rheology are considered. To account for the non-Newtonian phenomena, mean phase seepage velocities are calculated instead of relative permeabilities.

***Keywords*:** Pore-scale hydrodynamics, Multiphase flow, Rheology, Relative permeability, Density functional hydrodynamics.

1. Introduction

In oilfield development planning, the importance of having reliable workflow for estimating the potential oil recovery factor is hard to overemphasize. The common experimental approach includes performing several steps, which could be very complex and time-consuming. Also there are either uncontrolled parameters in an input or debatable interpretation of the output. Even absolute permeability and porosity measurements performed on core plugs face certain difficulties; e.g., a lengthy cleaning/saturation stage for each experiment is required, which can lead to changing in rock properties such as wettability or even structural changes caused by fluids or pressure gradients. The relative permeability measurements are by far more difficult. They require a long series of runs with different ratios of phases in a two-phase flow and different pressure gradients (or flow rates). Some of the parameters cannot be controlled directly. For example, there is no direct way to measure saturation of phases within the core.

As opposed to the experimental measurements, numerical modelling is able to resolve the said problems and brings new possibilities. Numerical simulation is repeatable, non-destructive, and able to reproduce very complex multiphase flow scenarios in a fully controllable way. At the same time, the simulation model can be calibrated with experiment to make sure it runs properly and produces reliable results.

Here we present a new simulation method and workflow for modelling fluids behaviour within rock at the micro-scale. Our approach can be used to predict the transport properties and oil recovery factor in unconventional reservoirs. The key part of the suggested method is the direct hydrodynamics (DHD) simulator that is based on the density functional theory (DFT) in the hydrodynamics of complex compositional systems. It is known from the middle 1990s as a numerical method for direct simulation of multiphase compositional fluid flows in complex geometries (Dinariev, 1995). The simulator was benchmarked against multiple analytical solutions and experimental data. In the DHD, many of the multiphase phenomena are taken into account and modelled directly. Among them are interfacial tension between fluid phases and between fluid and solid, topological changes of interfaces, moving contact lines, changes of phase properties and phase transitions, different types of fluid rheology, presence of surfactants, and mobile solid phases (Demianov et al., 2009, 2011).

2. Digital Rock Workflow

Direct pore-scale simulation enters the so-called Digital Rock (DR) approach that can be used as a de-risking tool at early stages of oil recovery planning by predicting multiphase transport characteristics of rock samples (Koroteev et al., 2013). Usually, the DR workflow combines three numerical approaches described in the next subsections.

2. 1. Pore-Scale DR Model Construction

X-ray micro computed tomography (μCT) is used to obtain a three-dimensional digital model of core samples in a non-destructive and non-invasive way. This method was developed during the last two decades (Coles et al., 1998; Wildenschild et al., 2002). Typical μCT scanned image resolution is up to 1 μm/pixel, with a whole model size being between a few millimetres to a few centimetres. The scanning equipment allows getting the DR model containing the total of 10^8–10^{10} cells in several hours. Under these limitations, μCT already provides the capability to resolve pore space of many types of carbonate and sandstone cores. The most recent progress in scanning technology has improved resolution from micrometres to tens of nanometres, which allows resolving difficult types of rocks that have a large amount of microporosity.

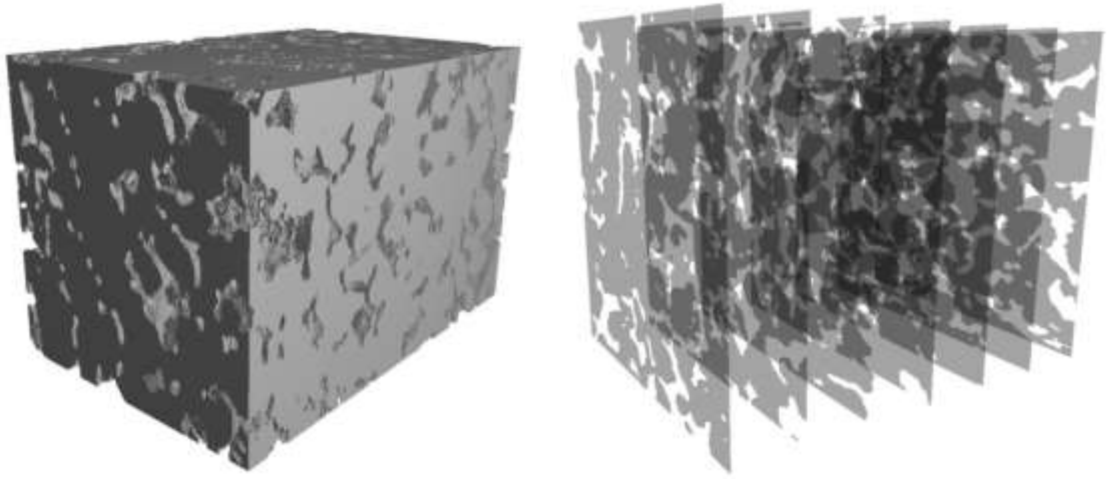
a) b)

Fig. 1. Binarized 3D DR model of a Berea sandstone sample showing a 3D view (a) and a set of semi-transparent 2D sections of the model (b).

Although X-ray μCT reveals a strong contrast in signal attenuation between rock minerals and air, it is insufficient to resolve mineral composition. However, atomic force microscopy can be used to build a reliable correlation between signal gradients on greyscale scans and mineral composition. Then reconstruction of probable minerals distribution becomes possible, which yields information about distribution of wetting properties. Alternatively, wetting properties of rock can be measured by calorimetry.

In this work we use a Berea sandstone DR model obtained from X-ray μCT. The model dimensions are 1.2 mm x 0.8 mm x 0.8 mm, approximated by 450x300x300 cubic cells (Fig. 1). The distribution of wetting properties with contact angles less than 60 degrees was constructed to reflect the water-wet nature of the core.

2. 2. Density Functional Hydrodynamics

The detailed theoretical background of DFT in hydrodynamics is explained by Demianov et al. (2009, 2011). The DFT-based multiphase compositional hydrodynamic simulator, the DHD, describes a continuously multiphase, multicomponent mixture in a uniform way by solving the same system of hydrodynamic equations (mass, momentum, and energy) in bulk and interfacial regions. Combining classical hydrodynamic and thermodynamic principles, this method is able to describe bulk phases and their interfaces as a continuous distribution of molar densities of mixture components. Herewith, bulk properties of phases and properties related to fluid-fluid or fluid-solid surfaces are specified in a physically meaningful way.

Incorporating the description of moving contact lines and dynamic changes of interface topology consistently, DHD provides the way for accurate multiphase flow modelling in complex geometries, which is important in core analysis. DHD also models wettability and adsorption, different rheology of phases, effects of surfactants, solvents, polymers, and solid phase sedimentation and transport in flow, including elastic or/and plastic properties of solid phase (Demianov et al., 2009, 2011). All these capabilities make this method very perspective for complex fluid analysis in the oil and gas industry, especially for de-risking complex enhanced oil recovery (EOR) scenarios (Koroteev et al., 2013), laboratory experiments simulation, and studying processes related to changing of the core properties.

2. 3. Fluid Model in DHD

To make flow simulation possible, fluid properties—such as composition, density, phase behaviour, rheological model, and interfacial tensions—all have to be characterized using experimental data or reliable correlations. In DHD, the bulk fluid behaviour is specified by Helmholtz energy. In contrast to the equation-of-state (EOS) method, which is often fitted for a range of pressure and temperature but for a strictly specified mixture composition, Helmholtz energy is specified for a narrower range of pressure and temperature but covers a range of compositions. In most cases, the physical size of DR models is usually in the range of millimetres to a few centimetres, and the time scale of the pore-scale flow processes is up to only a few seconds. So variations in thermo-baric conditions are expected to be rather small. But the local mixture composition, on the contrary, can change dramatically depending on a particular scenario.

On the other hand, if Helmholtz energy is known in the required range of parameters, it is possible to calculate pressure unequivocally (i.e., to obtain EOS); however, the opposite is not true without providing additional information. Also if Helmholtz energy is obtained from a conventional EOS (like van der Waals or Peng–Robinson equation), it may appears inconvenient for numerical simulation due to the presence of highly complicated terms involving exponents and logarithmic functions.

In order to overcome the said issues, the following approach was developed. A computationally efficient Helmholtz energy approximation, which usually contains only polynomial and rational functions, is fitted to describe the existing bulk fluid experimental data. Wetting properties at solid boundaries are specified by the distribution of surface Helmholtz energy density.

3. Simulation Results

Using the DR workflow discussed in Section 2, we have simulated flow of two immiscible phases through a Berea sandstone core sample. The DR model is shown in Fig.1. The model has relatively high porosity and permeability (ϕ = 0.25; k_x = 1.4 D). The flow was arranged in the lateral direction of the model (X-axis). An aqueous phase has mass density and shear viscosity close to that of water (ρ_w = 1000 kg/m^3; ν_w = 1 cP) and wets the rock; surface tension between the aqueous phase and the rock was distributed in the range Θ = 0.01÷0.03 N/m. Another phase with mass density ρ_{hc} = 730 kg/m^3 and shear viscosity ν_{hc} = 0.92 cP has properties close to a light hydrocarbon (HC) fluid. Interfacial tension between the two liquid phases is σ = 0.029 N/m. Initial distributions of phases within the pore volume were obtained as a final state in binodal decomposition of homogeneous mixture with specified mole fractions of components in the absence of external forces. As a result, the phases appeared to be distributed in equilibrium with the present water-wet (i.e., wettability is favourable for the aqueous phase) boundary conditions. Fig. 2 shows examples of phase distribution at two different combinations of phase saturations. It is notable that the aqueous phase fills mostly the small pores, while the HC phase forms drops in bigger pores.

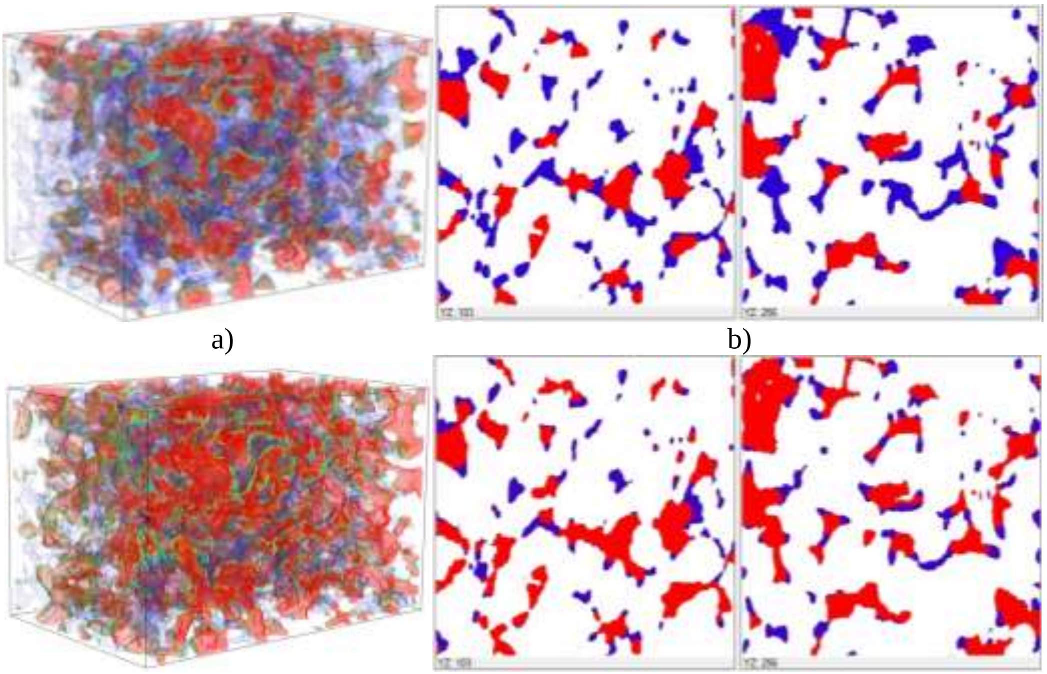
a) b)
c) d)

Fig. 2. Distribution of phases at different mixture compositions shown in 3D view and 2D slices taken in *YZ* plane: a, b) saturation of aqueous phase $S_w = 0.5$; c, d) $S_w = 0.3$. Aqueous phase is shown in blue and HC phase in red. In 3D view, the rock is fully transparent and liquid phases are semitransparent.

Calculated equilibrium distributions of phases were used to calculate two-phase transport properties of the DR model. Periodic boundary conditions were applied in the lateral (X-axis) direction to simulate quasi steady-state two-phase flow. Because the model was not originally periodic, it was rendered periodic by adding identical grate-like structures at both lateral ends. The concept of such grates originates from the laboratory setups in which incoming mixture flux is distributed over the core’s face by means of similar devices. The geometrical parameters of the grates were adjusted to minimize the influence of the grates on the model's transport properties. The fluid flow was arranged by using bulk force applied in the X-direction. Because two-phase flow in complex geometry has no steady-state regime in a strict meaning of the word (i.e., it has only quasi steady-state), time-averaging on the length of 0.001÷0.1 s has been applied to obtain flow parameters. For example, the seepage velocity was calculated using the expression in Eq. (1). Usually, the seepage velocity is used to obtain effective absolute and relative permeability under the assumptions of Darcy’s law, which is shown in Eq. (2):

$$u_{Ax} = \frac{1}{T}\int_T \frac{\int_{V_A} v_x dV}{\int_{V_A} dV} dt \qquad (1)$$

$$u_{Ax} = \frac{k_x \, k_{A\,rel} \, \Delta P}{\mu \, L}, \qquad (2)$$

where $k_{A\,rel}$ is the relative permeability function of saturation of phase A, and ΔP is the pressure drop over the model with length L. The internal integration in Eq. (1) is performed over the volume of each phase. Calculated seepage velocities at different initial saturations are shown for both phases in Fig. 3. Corresponding capillary numbers ($Ca = u\nu/\sigma$) are 10^{-4} for a pressure gradient of 5 bar/m and 10^{-3} for a pressure gradient of 50 bar/m.

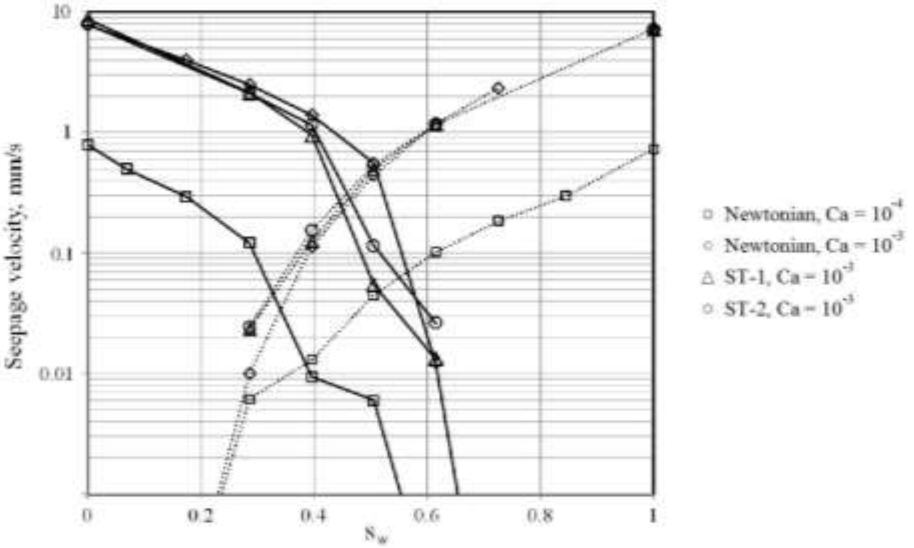

Fig. 3. Steady-state seepage velocities of the aqueous phase (dashed lines) and the HC phase (solid lines).

Fluids with non-Newtonian rheological features are of interest in the oil and gas industry. For example, some oils, EOR fluids (polymer gels or suspensions), or muds can have non-Newtonian rheology. Many of them have high viscosity (1–100 cP and higher) and distinctive shear-thinning or shear-thickening rheology. To demonstrate effects of non-Newtonian rheology, we repeated the simulations described above under the condition that one of the phases, namely the HC phase, has shear-thinning rheology. This rheology is characterized by the concept of effective viscosity with the Ostwald-de Waele law that states non-linear dependency between viscous stress τ and shear rate $\dot{\gamma}$:

$$\tau = \mu\dot{\gamma} \tag{3}$$

$$\mu = \begin{cases} \mu_0, & \dot{\gamma} \le \Gamma_0 \\ k\,\dot{\gamma}^{n-1}, & \dot{\gamma} > \Gamma_0 \end{cases}. \tag{4}$$

The parameters for non-Newtonian rheology, which are listed in Table. 1, were used to provide viscosity of ~1 cP at an effective shear rate range 1÷2×10^4 s^{-1}.

Table 1. Ostwald–de Waele law parameters for non-Newtonian fluid characterization.

	ST-1	ST-2
k, Pa · s^n	0.05	0.007
n	0.6	0.8
Γ_0, s^{-1}	10^{-6}	10^{-11}
μ_0, Pa · s	2.5	~1.1

Similar to the previous scenarios, two quasi-steady phase seepage velocities were calculated. The results are shown in Fig. 3. They provide the comparison of this new case with the previous Newtonian results. The results are close within one-phase mobility regions, because the effective viscosity has been specifically chosen to be close to the value in the Newtonian case. At the intermediate saturation values, when both phases are mobile and have to share the available pore space, the deviation appears that cannot be taken into account within the conventional framework of relative permeability. Although the difference between Newtonian and shear-thinning rheology appears only in a narrow range of saturations and has absolute value less than 5% of the single-phase transport velocity, the significant impact of the rheology reveals itself when the flow structure and composition are studied.

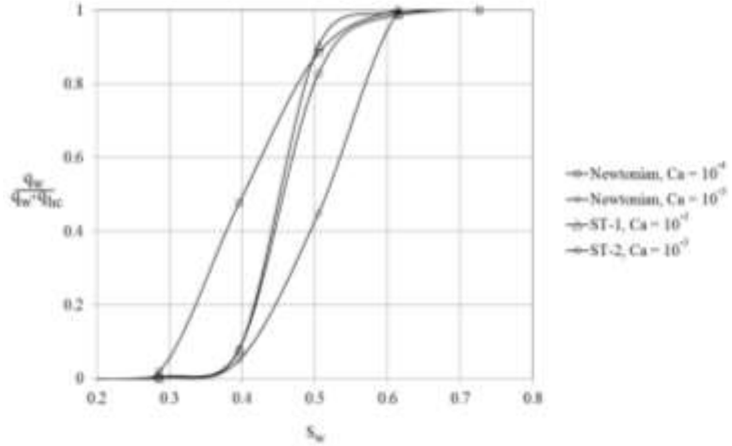

Fig. 4. Two-phase flow. Fraction of water in flow, which is given by Eq. (5).

Because in the oil and gas industry the flow rate and the fraction of hydrocarbons in the outflowing mixture are used to evaluate the production well efficiency, we employ the concept of water cut given by Eq. (5) to make our analysis more representative:

$$\mathrm{WC} = \frac{u_w S_w}{u_w S_w + u_{hc} S_{hc}} \tag{5}$$

$$\mathrm{R} = \frac{s_{hc}^{*} - s_{w}^{*}}{s_{hc}^{*}} \tag{6}$$

Table 2. Oil displacement ratio at various velocity thresholds.

Ca	Rheology	Velocity threshold			
		1%	0.1%	10 μm/s	1 μm/s
		R			
10^{-4}	Newtonian	0.17	0.51	0.05	0.32
10^{-3}	Newtonian	0.38	0.54	0.47	0.47
	non-New., ST-1	0.24	0.46	0.49	0.47
	non-New., ST-2	0.32	0.46	0.49	0.47

Also it is worthwhile to estimate the so-called oil recovery factor or displacement ratio R (Eq. 6), which is calculated using the concept of mobility threshold s^* for each phase. The important step is to choose a reasonable threshold velocity value at which the phase is immobile. We performed analysis with several threshold values as shown in Table. 2; the thresholds are given as both absolute values and percentage of the maximum velocity.

The presented simulations show that in the case of complex fluid transport through heterogeneous media, the resulting dynamic properties cannot be represented as a simple superposition of porous media characteristics and fluid properties. Using the said superposition could be misleading and not present a clear picture about all the features of the process. It is more reliable to study combined media-fluid system interaction and transport properties at an effective range of flow rates and saturation.

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