Pore-scale Modeling and Simulation: Determining Petrophysical and Multiphase flow properties in Natural Porous Media

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Summary

A 3D natural Porous Media is reconstructed from several CT scanned images. Numerical simulation studies for multiphase flow are then performed at the pore-scale by solving the Navier-Stokes equation and using the level set method for the interface capturing. The purpose is to then predict the petro-physical properties such as the relative permeability, capillary pressure, and the resistivity index. Graphs of the relative permeability curves for a water and oil will be presented along with the resistivity index versus water saturation curves.

Introduction

The understanding of petro-physical and multiphase flow properties is necessary in order to be able to assess and exploit hydrocarbon reserves. These properties in turn, depend on 3D geometric and connectivity of the pore space, where fluids are stored and transmitted. The rock formations are typically heterogeneous, and the actual flow of liquid and gas phases occurs in the void space between rock grains, which are of the order of micrometers.

Observing the dynamic behavior and measuring the pertinent parameters at the subsurface is difficult and would involve numerous uncertainties. This is especially true when trying to understand the trapping mechanisms in unconventional systems (e.g. heavy oil waterfloods or trapping of oil at the edge of a SAGD steam chamber). Modeling and numerical simulation studies are performed to quantify the uncertainties. Moreover, by probing pore-scale structures, a better understanding of the role of pore structure on connectivity, conductivity, and permeability is obtained.

Theory

A pore-scale description of the multiphase flow of petroleum reservoir fluids through natural porous medium is very challenging. At the same time, the pore-scale description is a fundamental approach in hydrodynamics and so it is necessary in order to have a better understanding of the flow and transport at the pore-level. This will then make it possible to provide multiphase flow properties for large scale models and to make predictions on how the properties change with rock type, and wettability.

An important issue which arises is in the proper construction of a 3D computational model which can adequately describe the flow through the pore-space. At the initial stage, the geometry used in the model is constructed from a 3D computed tomography of a natural porous media (through 3D reconstruction of 2D scanned images). The real pore space is then meshed and the flow behavior is approximated through the discrete numerical model associated with the mesh.

Unlike traditional models that rely on space averaged properties and thus losing the meaning at pore-scale, a detailed solution of the flow behavior at the subsurface is considered by computing the solution to the Incompressible Navier-Stokes equation for fluid flow. We note however, that at the subsurface, the inertial terms are small and can be neglected and reduced to the Stokes' equations. For single phase flow, the incompressible Navier-Stokes equations are solved with given boundary conditions in order to obtain the velocity in the sample. In our problem we specify the pressure inlet and outlet conditions so that the driving force is the pressure difference. Once the velocity is (see Figure 2) obtained, Darcy law can be applied to give the absolute permeability.

For two-phase flows, the flow equations which model the different phases (oil and water) are then numerically solved within the 3D domain. In addition, the conservative level set method is invoked for the transport of the fluid interface separating the two phases and is given by

$$\frac{\partial \Phi}{\partial t} + \mathbf{u}.\nabla\Phi = \gamma\nabla.\left(\varepsilon\nabla\Phi - \Phi(1-\Phi)\frac{\nabla\Phi}{|\nabla\Phi|}\right).$$

$\mathbf{u}$ is the velocity of the fluid and Φ is the level set function where in the oil $\Phi = 0$ and in water $\Phi = 1$, and at the interface, represents the 0.5 contour i.e. $\Phi = 0.5$. The normal to the interface is then given by

$$\mathbf{n} = \frac{\nabla\Phi}{|\nabla\Phi|}.$$

The mass and momentum equations at constant density governing the equations for the flow are written explicitly as

$$\rho\frac{\partial \mathbf{u}}{\partial t} + \rho(\mathbf{u}.\nabla)\mathbf{u} = \nabla.[-\mathrm{p}\mathbf{I} + \mu\left(\nabla\mathbf{u} + \left(\nabla\mathbf{u}^T\right)\right) + \mathbf{F}_{\mathrm{st}} + \rho\mathbf{g}$$
$$\nabla.\mathbf{u} = 0$$

where p is the fluid pressure, $\mathbf{g}$ includes the effects of gravity, and the smooth density and viscosity jumps across the interface are given by

$$\rho = \rho_{\mathrm{oil}} + (\rho_{\mathrm{water}} - \rho_{\mathrm{oil}})\Phi$$
$$\mu = \mu_{\mathrm{oil}} + (\mu_{\mathrm{water}} - \mu_{\mathrm{oil}})\Phi.$$

The surface tension force $\mathbf{F}_{\mathrm{st}}$ acting on the oil-water interface is also given by

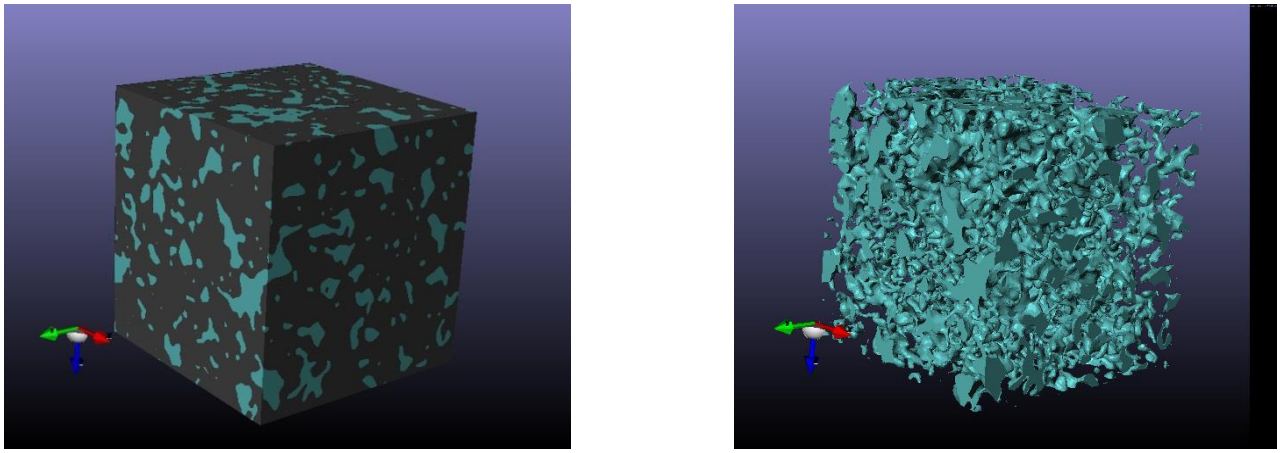
$$\mathbf{F}_{\mathrm{st}} = \nabla.\mathbf{T}$$
$$\mathbf{T} = \sigma(\mathbf{I} - (\mathbf{n}\mathbf{n}^{\boldsymbol{T}}))\delta$$

where $\mathbf{I}$ is the identity matrix, $\mathbf{n}$ is the interface normal, σ is surface tension coefficient and kronecker delta function δ is non-zero only at the fluid interface.

In the numerical simulation, we impose an initial interface where initially, the volume fraction of the water is 1 and of the oil is 0 (Figure 3). The level set equation then captures the evolution of the interface.

Examples

The pore flow behaviour of a digitised rock sample (consolidated sandstone) has been investigated Figure 1a, where the space between the grains constitute the pore network shown in Figure 1b. We perform a single phase flow simulation of the 40 µm × 40 µm × 40 µm sample where the equations governing the flow are modeled by the Stokes' equations (at the subsurface, the inertial terms are small and thus neglected). We then calculate the permeability of the sample to be 3 µD, and in Figure 2 flow channels where there is a permeable path are shown.



(a) (b)

Figure 1: Example of the pore sample reconstructed from 400 CT scanned images. (a) includes the rock structure as well, where (b) only shows the pore network of the same sample.

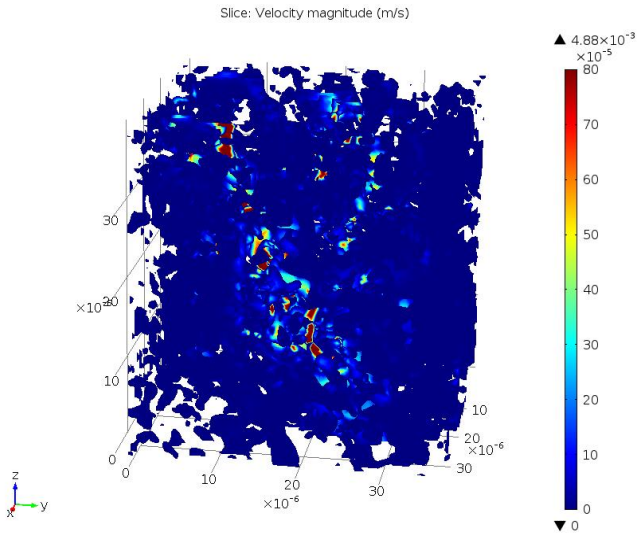


Figure 2: Velocity magnitude (m/s) of the flow in the pore sample. Shows the channels with a permeable path through the sample.

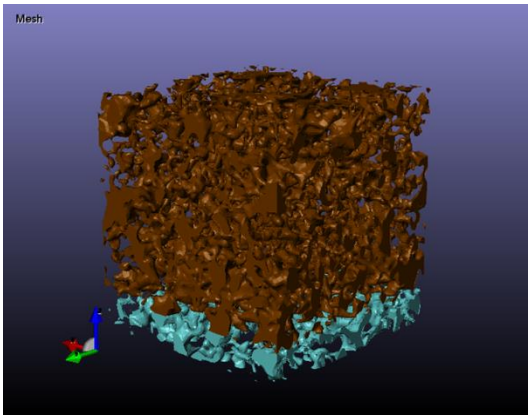


Figure 3: Porous media showing the initial interface between the oil and water.

Conclusion

We have demonstrated properties of a real porous medium through single phase flow numerical simulations. In addition, we have presented some first results for 3D two phase flow model based on the level set method for capturing the interface. We can simulate drainage and imbibition situations for different viscosity ratios, as well as predicting the phase relative permeabilities.

References

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