NUMERICAL INVESTIGATION OF THE DEPENDENCE OF RESIDUAL OIL SATURATION ON GEOMETRY, WETTABILITY, INITIAL OIL SATURATION AND POROSITY

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This paper was prepared for presentation at the International Symposium of the Society of Core Analysts held in Avignon, France, 8-11 September, 2014

ABSTRACT

Oil/water drainage and imbibition processes have been numerically investigated for a set of sandstone samples including Berea, Fontainebleau and Bentheimer samples. The pore scale structures of the sandstone samples have been digitized using high resolution micro-CT. The primary drainage and first imbibition process was computed numerically with a pore scale simulator which is based on a two-phase lattice Boltzmann method including interactions with the solid pore wall. To cope with the large computational demand the simulations were run on high performance computing hardware. Residual oil saturation after imbibition S_{or} was calculated for complete water-wet rock surface (zero water contact angle) to investigate the effect of different geometries represented by different kinds of sandstone samples. The calculated results compare well with recently published high quality laboratory data. The change of S_{or} with variation of the degree of water wettability was investigated for the samples by changing the water contact angle on the pore surface. It was found that the weaker water wetness results in smaller S_{or} which is consistent with the experimental investigations recently reported in literature. The dependence of S_{or} on the initial oil saturation was calculated and the results are consistent with experimental data and published correlations. Finally the residual oil was calculated for several Fontainebleau samples with different porosity. It was found that S_{or} decreases with porosity and the variation of S_{or} agrees well with published experimental data.

INTRODUCTION

Oil/water drainage and imbibition processes in rocks are of fundamental interest to oil industry. For long time, the applied capillary pressure at different water saturations were measured experimentally [1 - 5]. Recently because of the emergence of advanced computerized tomography (CT) technology, high-performance computers and advanced computational methods, the numerical study of drainage and imbibition has become feasible. The rock geometry can be digitized into a 3D matrix data to represent solids and pores by CT. In order to calculate the transport of multiphase flow, either pore network model [PNM] or direct simulation can be used. PNM replaces real pore bodies and throat

shapes with geometric shapes such as ducts with circular, rectangular and triangular or more complex cross sections [6, 7]. The fluid transport and distribution are determined by employing (semi-)analytical solutions for the individual elements that are coupled together. We use a direct simulation method, the lattice-Boltzmann method (LBM) which directly simulates the fundamental equations of multiphase flow in pores with complicated boundaries [8 - 10] in a digitized rock sample. The LBM has emerged as an alternative numerical technique for simulating fluid flow. LBM solves a simplified kinetic equation. It can simulate the fluid equations accurately and efficiently, and still preserve some of the advantages of kinetic equations, including being suitable for parallel processing and accurately simulating flows with complicated wall geometries and interfaces. This study employs a LBM method to investigate the dependence of S_{or} on geometry, wettability, initial oil situation and porosity.

MATERIAL AND SIMULATION METHODS

Table 1. Rock samples used in the simulation and digital properties. Here Δx is the voxel length, L is the dimension of rock sample, ϕ is the porosity, K_a is the absolute permeability and FF is the formation factor.

Rock Type	Δx (μm)	L (Δx)	ϕ	K_a (md)	FF
Berea	2.2	600^3	0.192	208	19
Bentheimer	2.46	550^3	0.220	3048	14
Fontainebleau1	1.87	550^3	0.114	270	50.5
Fontainebleau2	2.23	500^3	0.0633	20.6	286
Fontainebleau3	2.3	500^3	0.0719	50.7	199
Fontainebleau4	2.2	500^3	0.0904	122	109
Fontainebleau5	2.34	500^3	0.150	826	27.4
Fontainebleau6	3.0	320x320x486	0.155	584	32.1
Fontainebleau7	2.3	500^3	0.221	2949	12.3
Fontainebleau8	2.38	500^3	0.228	3802	11.7

As listed in table 1, 10 sand stone samples were digitized using micro CT. The first 3 samples, Berea, Bentheimer and Fontainebleau rock samples, were used to investigate the dependence of S_{or} on rock geometry. In order to compare with recently published experimental data [1], we selected the samples that have approximately the same petrophysical properties with those used in the experiment. The other 7 samples are Fontainebleau with different porosity and were used to investigate the variation of S_{or} with porosity.

A LBM solver has been developed to simulate multiphase flow in the imbibition and drainage processes. The LBM solver uses a D3Q13 multiphase model [14] and was parallelized for multiple GPUs using CUDA and MPI. To cope with the large computational demand the simulations were run on high performance computing hardware. In the LBM the fluid wall interaction is modeled by wall wettability and fluid density fraction. The contact angle can be set by assigning certain wettability to the wall surface. A water wet surface may change to less water wet or even oil wet when oil stays

in contact with that surface long enough, such as the surfaces of pores occupied by oil in a reservoir or the oil-aged rock surfaces in experiments. In our LBM simulations only the intrinsic contact angle is assigned if the wall roughness is resolved. The receding and advancing contact angles are determined by the wall wettability and roughness through the fluid-wall interaction. If the wall roughness is not resolved, receding and advancing contact angles are input. In pore network modeling, the receding and advancing contact angles are always input parameters. In this study the wettability was varied between strongly and weakly water wet to model some experiments that we compare with our simulations. We developed special boundary conditions at the solid wall to model thin water- or oil-film flows that allow transport of fluids through those thin films. These boundary conditions prevent e.g.: unrealistic high values of trapped water in the drainage and allow snap-off effects through the films in imbibition. We use a digital porous plate experiment as described in [10]. The water pressure is kept constant throughout the simulation. In the drainage process the oil pressure increases step by step till the desired residual water saturation is reached. In the imbibition process the oil pressure decreases till it reaches the water pressure (only controlled spontaneous imbibition). The pressure difference between oil and water is called applied capillary pressure.

RESULTS AND DISCUSSIONS

Table 2. Comparison between simulation and experiment [1].

Rock Type		L (mm)	ϕ (%)	K_a (md)	FF	S_{oi}(%)	S_{or}(%)
Berea	Simulation	1.32	19.2	208	19.8	78.9	45.4
	Experiment	75	19.4	208	19.0	78.9	48.2
		6	17.6				45.2
Bentheimer	Simulation	1.35	22.0	3048	14.0	90.3	36.6
	Experiment	72	22.1	2676	11.9	90.4	35.1
		6	23.1				45.2
Fontainebleau1	Simulation	1.03	11.4	270	50.5	91.8	53.7
	Experiment	80	14.1	304	48.7	90.4	25.0
		6	12.0				37.2

The drainage and imbibition processes were calculated for three different rock samples. A zero contact angle was assigned to the water. The water saturation at the end of drainage in the simulation was matched with the experimental data in [1]. The petrophysical properties of rock sample and the calculated S_{or} for the experiments and the LBM simulations are listed in table 2. [1] reports two sets of results for plugs that were about 8 cm in length and 3.3 cm in diameter and min-plugs that were 6 mm in length and 5.9 in diameter. Our results for Berea and Bentheimer are between the two results and closer to the results of larger plugs. The simulation result of Fontainebleau is much larger than the experimental one. However it was found that the simulation results are consistent with more systematic experimental results reported in [5] as shown in Fig. 3. The result for Fontainebleau 1 is marked with a larger diamond in Fig. 3. It was pointed out in [5] that the observed smaller value of S_{or} for Fontainebleau rocks might result from gas

diffusion. Since the contact angle was the same in the simulations the difference of S_{or} resulted from different geometries characterized by the pore structure of the rocks.

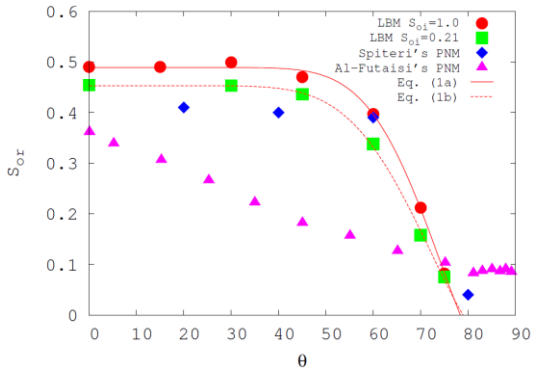

Fig. 1. Residual oil saturation as function of contact angle for a Berea sample.

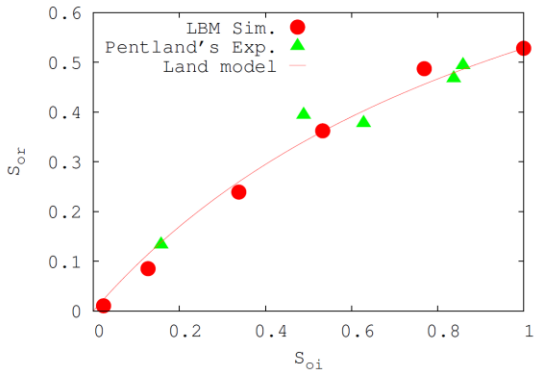

Fig. 2. Residual oil saturation as function of initial oil saturation for a Berea sample.

The variation of S_{or} with contact angle for the Berea sample is plotted in Fig. 1. The calculations have been done for two values of initial oil saturation S_{oi} = 1 and 0.79. In an ideal reservoir the rock can be completely drained while in a laboratory experiment the rock sample usually is partially drained due to time constraints [1, 2]. As shown in the plot the calculated results can be well fitted by the following formula:

$$S_{or} = 0.489 - 0.6481\sin^{13.5}(\theta), \quad (1a)$$

$$S_{or} = 0.453 - 0.5521\sin^{11.5}(\theta). \quad (1b)$$

The simulation results are close to the results of pore network modeling where the pore network was reconstructed from a Berea sandstone with porosity 0.183 and permeability 2287 md [6]. The PNM results from a different group for Bentheimer with porosity about 0.22 and permeability about 2800 md were also plotted and show a different behavior [7]. Our results are consistent with the recently published experimental data in [2] for Berea samples with porosity 0.2 - 0.21 and permeability 50 md. In the experiment the measured S_{or} varies from 0.48 to 0.27 when the rock surface changes from strongly water wet to weakly water wet.

The dependence of S_{or} on the initial oil saturation S_{oi} was investigated and the results agree well with experimental results for Berea samples as shown in Fig. 2 [3]. In order to reduce the end effects in the simulation the oil saturation was calculated by removing part of the sample that is located within 100 voxels from the inlet and outlet boundary condition. In the simulations zero contact angle was assumed. The calculated data also agree well with the Land correlation, a widely used empirical model in literature [11]:

$$S_{or} = \frac{S_{oi}}{1 + S_{oi}\left(\frac{1}{S_{or}^{\max}} - \frac{1}{1 - S_{wc}}\right)} \quad (2)$$

Here S_{wc} is the connate wetting phase saturation. It has been assumed S_{wc} = 0 in the simulation.

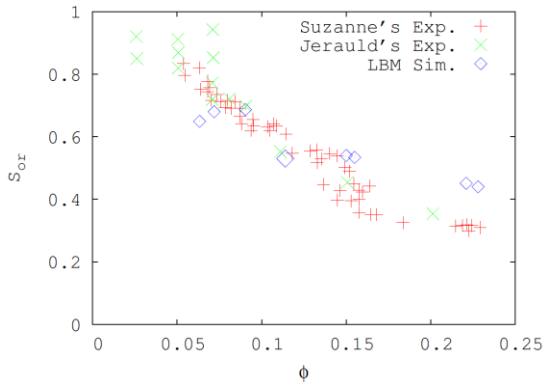

Fig. 3. Residual oil saturation as function of porosity for Fontainebleau.

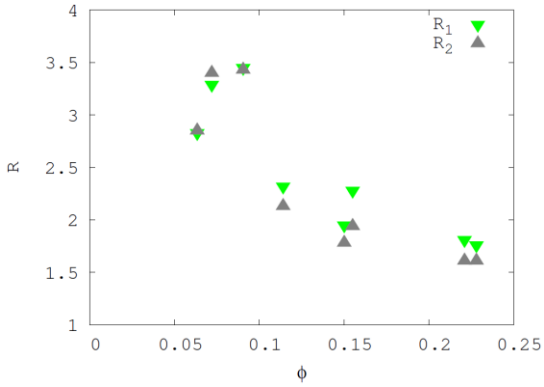

Fig. 4. Pore body to throat size ratio as function of porosity. Here R1 = $<r_{pore}>/<r_{throat}>$ and R2 = $<r_{pore}/r_{throat}>$. The brackets indicate an average.

Finally the dependence of S_{or} on porosity for Fontainebleau was investigated and the results are consistent with two experiments [4, 5] as shown in Fig. 3. Fontainebleau is mostly clay-free sandstone. The larger S_{or} at low porosity may result from larger pore body to throat size ratio. Aissaoui noticed that the pore throats sizes diminish with porosity [12]. We used a morphological approach [13] to compute pore body size distribution and a digital mercury injection experiment to compute pore throat distribution. As shown in Fig.4, the pore body to throat size ratio and S_{or} change with porosity in a similar manner. The correlation coefficients between S_{or} and R_1 and between S_{or} and R_2 are 0.94 and 0.93 respectively.

CONCLUSION

A lattice Boltzmann solver has been developed to investigate residual oil saturations after a drainage and imbibition cycle for different rock geometry, contact angles, initial oil saturations and porosities. The results are consistent with recently reported experiments. The residual oil changes slowly with contact angle for strong water wet surfaces. It decreases rapidly when the contact angle is around 60 degree which was also observed in high quality pore network modeling results. The dependence of residual oil on the initial oil saturation agrees well with the Land correlation. The residual oil in Fontainebleau decreases with porosity and is highly correlated with the pore body to throat size ratio.

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