1.1 Final Project Report

1.3.1 Pore scale simulation of multiphase flow in an evolving pore space

Project number and location (UiS, NORCE, IFE): 100162 (NORCE)
Project duration: Q1 2017 – Q4 2021
Project manager: Jan Ludvig Vinningland (NORCE)
PhD students and postdocs: N/A
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1.2 Executive summary

1.3 Introduction and background

(Project initiation, tasks involved, collaboration (national and international), user partner involvement if relevant)

1.4 Results

(Description and discussion, research-/user partner involvement)

1.4.1 Spontaneous imbibition simulations

A series of spontaneous imbibition simulation using a cylindrical sandstone sample have been performed. The geometry is shown in Figure 1 b), and the evolution in water saturation is shown in Figure 1 a). The simulations were executed on the Fram computing cluster[1] (fram.sigma2.no) using 320 processes in parallel. The system size is 5.3 x 5.3 x 2 mm, and the computational domain is 380 x 380 x 150 which yields a system of 21.7 million voxels, or 67 700 voxels in each process. For this system, 80 minutes of spontaneous imbibition required a total simulation time of about 21 days. Due to a time limit of 7 days, the simulation was split in three separate runs, as indicated by the colors in Figure 1 a). However, the simulation did not reach an end-point (steady-state) saturation.

[1] https://documentation.sigma2.no/hpc_machines/fram.html

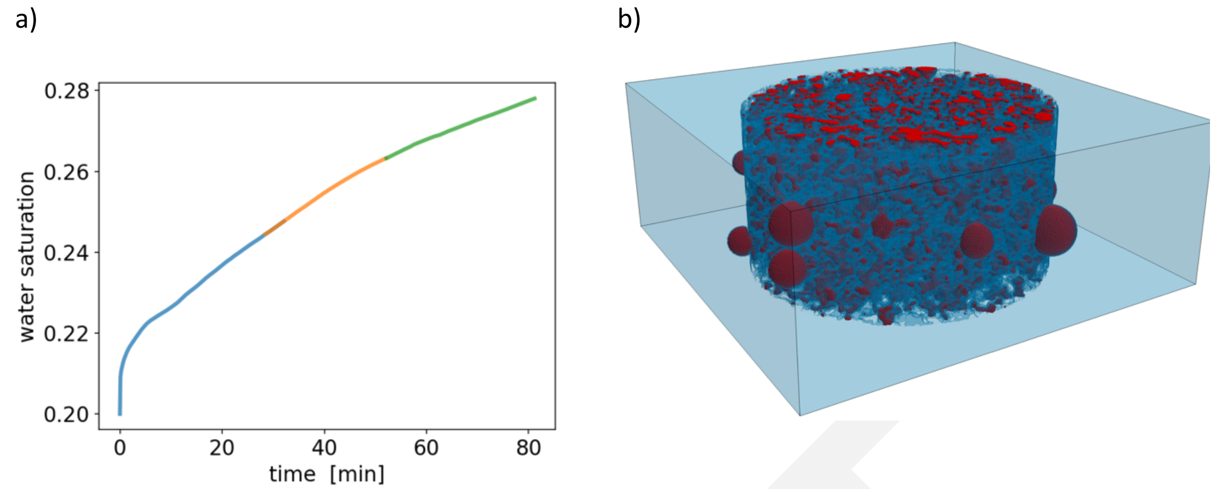

Figure 1: Spontaneous imbibition simulation

Figure 2 a) and c) shows, respectively, the radial distribution of water saturation and the change in water saturation ($\Delta S_w/\Delta t$) measured from the outer edge of the sample. As expected, we see that the water saturation dominantly changes along the edge, about 0.75 mm into the sample. Figure 2 b) shows the evolution in water saturation and capillary pressure, and it is evident that as oil is produced the capillary pressure decreases. Figure 2 d) shows the capillary pressure as function of water saturation.

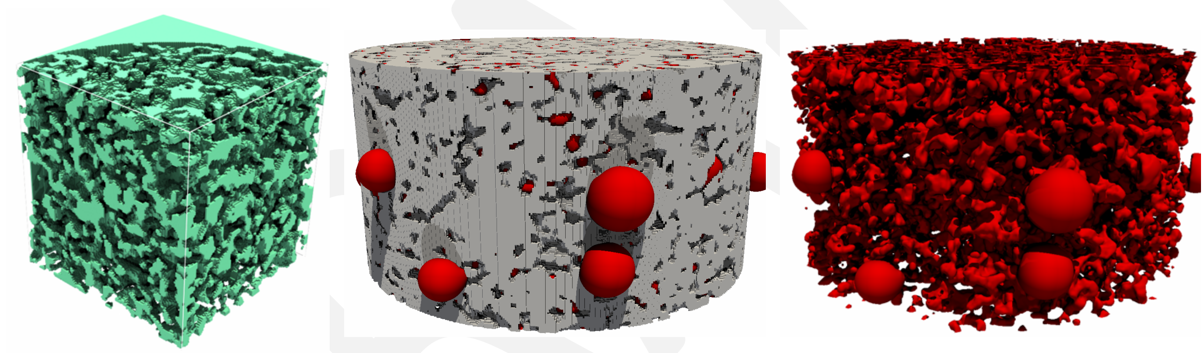
Figure 2: Spontaneous imbibition simulation in a cylindrical Bentheim sandstone sample of 4 mm in diameter with oil shown in red. The left figure shows pore space in green for one quadrant of the sample, the middle figure shows solid space in gray and oil in red after 50 minutes of imbibition, and the right figure shows the internal distribution of oil.

For the linear regime of S_w in Figure 2 c), a simple exponential approximation of $\Delta S_w/\Delta t$ is indicated in Figure 2 c). This demonstrates that pore-scale simulations can provide effective relations to be used at larger scales, e.g. in core scale simulations.

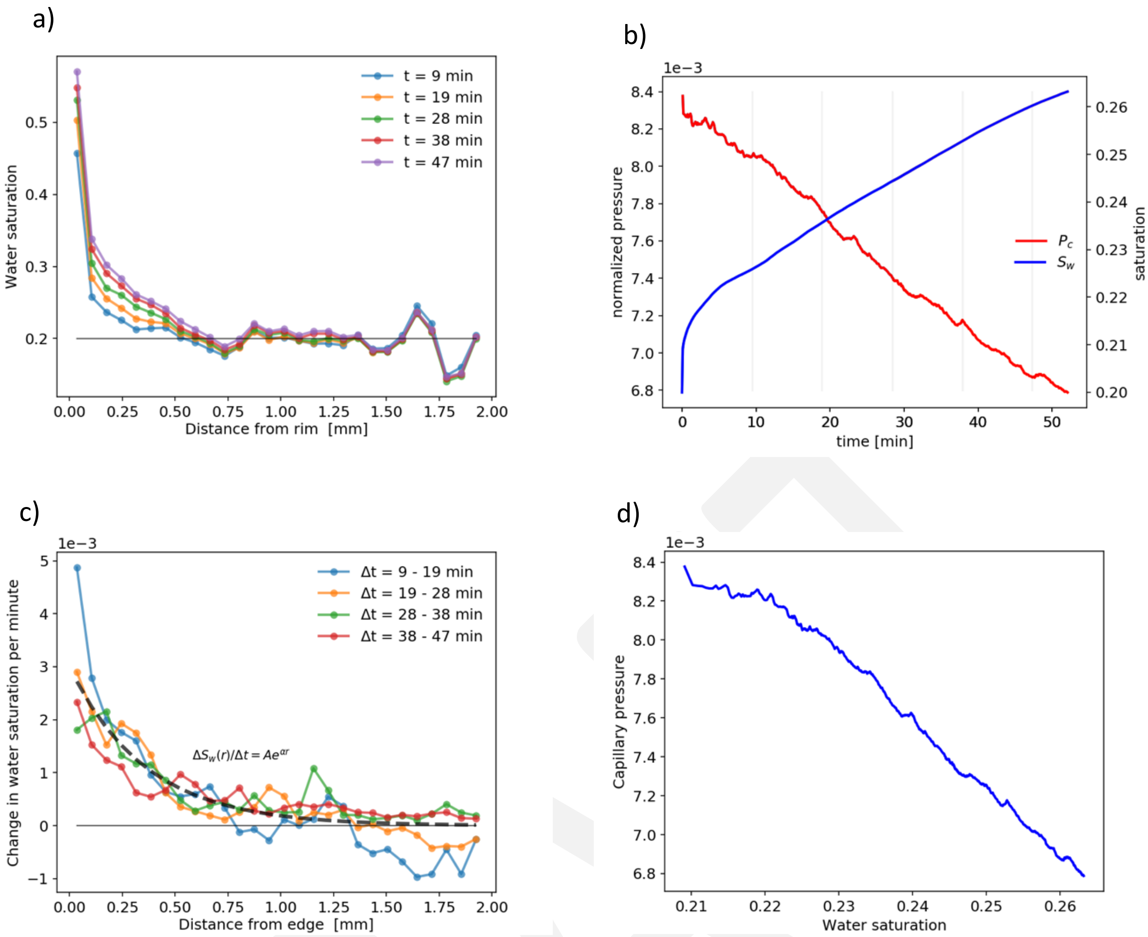

Figure 3: Results of a spontaneous imbibition simulation in a Bentheim sandstone sample 4 mm in diameter; a) shows the radial distribution of water saturation for different times; b) shows the evolution in water saturation together with the capillary pressure (the vertical lines indicate the times in a) and c)); c) shows the change in water saturation for different time-intervals at different radial positions; d) shows the capillary pressure as function of water saturation.

1.4.2 Relative permeability simulations

A series of relative permeability simulations are performed using a sandstone geometry initialized to three different wetting values: 1) oil-wet, 2) neutral-wet, and 3) water-wet. Periodic boundary conditions in the flow direction are achieved by reflecting the geometry. The initial oil-water configuration is shown in the left image in Figure 1; half of the sample with oil in the center and water close to the solid surface, and vice-versa for the other half.

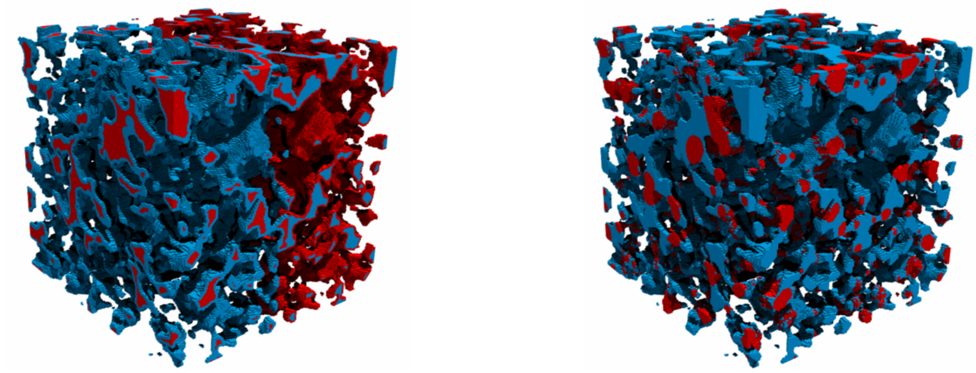

Figure 4: Snapshots from a relative permeability simulation using a water-wet sandstone sample of 200x200x200 voxels. The initial configuration is shown to the left, and the configuration after 1.5 pore volumes is shown to the right. The simulation is executed at the HPC cluster fram.sigma2.no hosted at UiT Arctic University of Tromsø.

Figure 5: Water- (left) and oil-distribution (right) after 1.5 pore volumes (same as in Figure 1, right)

In these simulations we have implemented a novel method for keeping the total flux fixed which yield very accurate constant flow conditions.

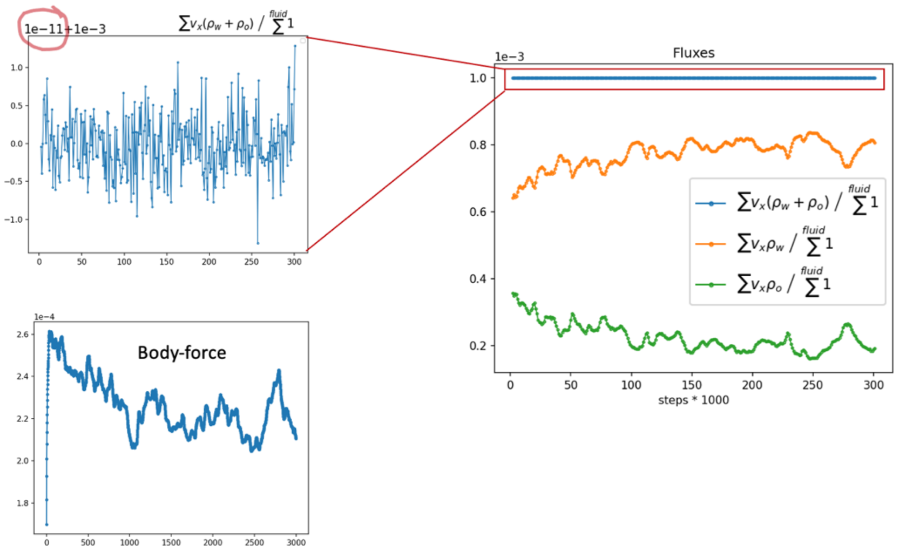

Figure 6: Demonstration of our novel method for constant flux conditions during relative permeability simulations with an accuracy of 10^{-11}. The body-force driving the flow is constantly varying to keep the flux constant.

Figure 4 shows the relative permeability curves for the oil-wet, neutral-wet, and oil-wet sandstone sample. An oil-water viscosity contrast of 5 is used in these simulations.

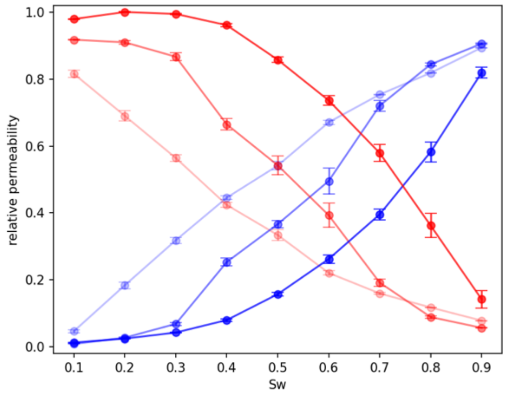

Figure 7: Relative permeability plots (red for oil, blue for water) for the sandstone sample at three different wetting values. Pale colors represent the oil wet sample, intermediate hue colors represent the neutral wet sample, and strong colors represent the water wet sample.

1.5 Conclusion(s)

1.6 Future work/plans

(Work in progress, journal papers in particular)

1.7 Dissemination of results

(Include testing/implementation by research-/user partners if relevant)

1.8 References