PORE-SCALE HETEROGENEITY ASSESSED BY THE LATTICE-BOLTZMANN METHOD

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ABSTRACT

A digital imaging technique is used to characterize pore-scale structures and to predict fluid flow at the scale. Heterogeneity at the pore-scale can be assessed by the micro-Computed Tomography (micro-CT), which provides complicated boundary conditions of porous media, and it can also be identified by the numerical flow simulation using the lattice-Boltzmann method (LBM) on the digital image. Both the LBM and the digital image are used to estimate the Representative Element Volume (REV) of the rock. Different types and sizes of pore-scale structures are evaluated in terms of the effects of heterogeneity and the porosity–permeability correlations. Numerical simulation on the digital image of porous media is useful to understand its heterogeneity and such digital experiments can add value to the laboratory measurements.

INTRODUCTION

Representative microscopic model of porous media is frequently employed to predict petrophysical properties of reservoir rocks. The microtomography has been used to characterize pore-scale structures and to simulate fluid flow at the scale [1]. Petrophysical analysis including in-situ saturation monitoring by conventional X-ray CT during a coreflood experiment can indicate the heterogeneity within a rock sample [2]; however, it is often difficult to understand the heterogeneity at the smaller-scale using only a core-scale measurement and its numerical simulation. Pore-scale heterogeneity can be assessed by the digital image and the numerical simulation using the LBM. The LBM provides a good approximation to solutions of the Navier-Stokes equations, using a parallel and efficient algorithm that readily accommodates complex boundaries such as porous media [3, 4]. These complicated boundary conditions are provided using the microtomography. Fluid flow at the pore-scale is simulated by the LBM in order to assess the pore-scale heterogeneity and to estimate the Representative Element Volume (REV). Different types and sizes of pore-scale structures are used to evaluate the effects of heterogeneity and to obtain the porosity–permeability correlation. Numerical simulation on the digital image of porous media is useful to understand its heterogeneity and it will be necessary for the accurate description.

The study shows how pore-scale structure and fluid flow at the scale are related. The lattice-Boltzmann method is briefly discussed first, followed by the description of the pore structure using the micro-CT, which can be used to examine the heterogeneity at the pore-scale. The paper also focuses on some correlations between pore structures and fluid flow by the LBM.

LATTICE-BOLTZMANN METHOD (LBM)

Many studies have shown that simple discrete particle models on a lattice can be used to solve complicated flow problems [4, 5]. The method is regarded as a simple microscopic particle model that can approach macroscopic dynamics based on the Boltzmann transport equation for the time rate of exchange of the particle distribution function in a particulate state. The model called the lattice-Boltzmann method (LBM) is a good approximation to the Navier-Stokes equations and a parallel and efficient algorithm to simulate single and multiphase fluid flows with complicated boundary conditions and multiphase interfaces as encountered in porous media [3]. The LBM, particularly LBGK (lattice-Bhatnagar-Gross -Krook) model, described in equation (1) is used to calculate permeability to examine the reconstructed structure quantitatively. A three-dimensional nineteen-velocity model, D3Q19, that includes a rest vector is used. The bounce-back scheme at walls is used to obtain no-slip velocity conditions and the flow field is computed using periodic boundary conditions.

$$f_i\left(\mathbf{x}+\mathbf{e}_i, t+1\right)-f_i\left(\mathbf{x}, t\right)=-\frac{1}{\tau}\left[f_i\left(\mathbf{x}, t\right)-f_i^{(eq)}\left(\mathbf{x}, t\right)\right] \quad (1)$$

where $f_i\left(\mathbf{x}, t\right)$ is the particle distribution function at space $\mathbf{x}$ and time t along the i-th direction (i=0,1,2,…,18 in our case). $\mathbf{e}_i$ is the local particle velocity and τ is the single time relaxation parameter. $f_i^{(eq)}$ is the local equilibrium state depending on the local density and velocity.

PORE STRUCTURE

Microtomography

Digital imaging techniques, such as micro-CT, have been used to provide void space information at a resolution of a few microns as shown in Figure 1. To examine reconstructed images of pore structures especially in terms of the transport properties, the LBM described above is used on the binalized pore-space images. The LBM, however, is limited by the size of the input structure due to the computational time. Therefore, permeability can only be computed on relatively small images.

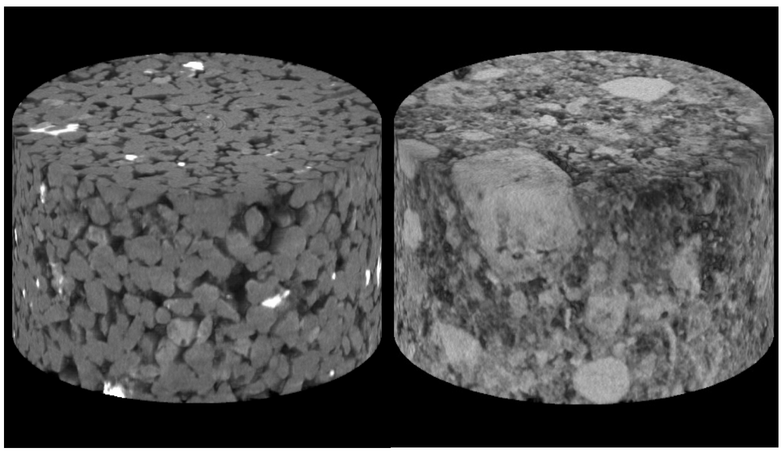


Figure 1. Micro-CT images with a resolution of 5.67 µm for a Berea sandstone (left) and a reservoir carbonate rock (right).

Representative Element Volume (REV)

Although the size of digital images is currently limited, the apparent Representative Element Volume (REV) of the rock samples at few mm scale can be assessed by the porosity and the permeability calculated by the LBM as shown in Figure 2. The largest cube (240^3, L=1.36mm) extracted from the cylindrical micro-CT image (diameter=2.9mm, height=1.45mm) is divided at several ratios in order to evaluate the REV in the image. Ranges of porosity and permeability variations become smaller as the size of objects is increased.

Subgrids of the micro-CT image are used to study the porosity–permeability correlation as shown in Figure 3. The larger the subgrid size is, the smaller the distribution of ϕ–k correlation is. There is a difference in porosities between the largest cube (240^3) and the laboratory experiment (marked in circle and star, respectively) since the micro-CT cannot capture smaller pores beyond the resolution of the image. However, the calculated permeability is not much affected by the resolution as the smaller pore space contributes very little to the transport properties. The figure also suggests a good ϕ–k correlation and demonstrates that the LBM provides a good prediction of permeability.

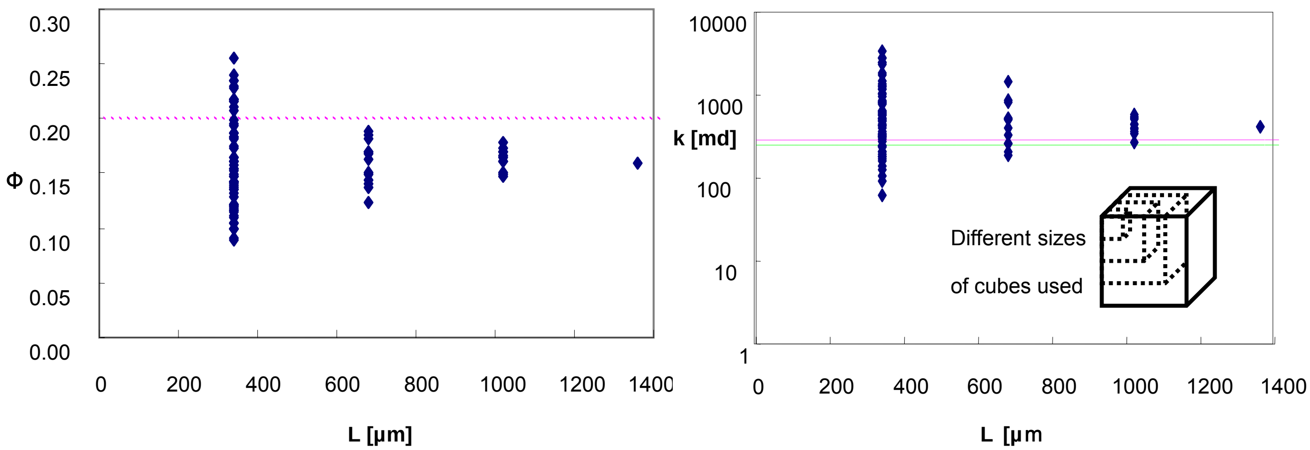


Figure 2. Distributions of porosity (left) and single-phase permeability (right) for the different subgrid sizes extracted from the pore-space image of Berea sandstone measured by the micro-CT. The smaller the subgrid size (L, μm) is, the wider the distribution is. Although the size of the image is limited due to the resolution of the micro-CT, larger than 1.2mm cube seems to be a representative element volume (REV) for the sample in terms of porosity and permeability. From a mercury intrusion measurement, the mean pore size is around 10μm.

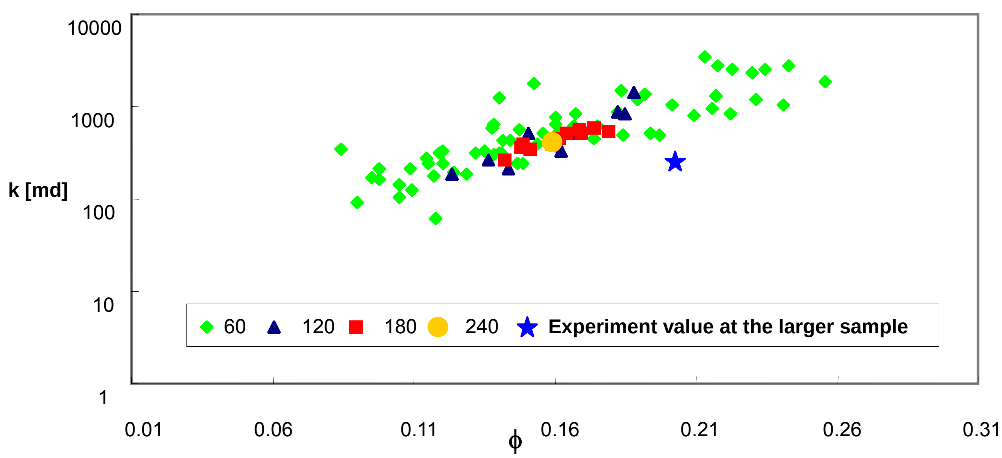


Figure 3. Distribution of ϕ–k correlation derived by the micro-CT image and the LBM for the Berea sandstone. Larger subgrid size (L=60→240) gives smaller ϕ–k distribution.

Pore-scale heterogeneity and its effect on fluid flow

The effects of pore-scale heterogeneity on the flow can be assessed by the LBM when smaller structures are used. Figure 4(a) shows ϕ–k correlations of two different types of pore structures generated artificially as a pore dominant geometry and a throat dominant geometry. The throat dominant geometry shown in Figure 4(c) has higher permeability than that of the pore dominant geometry in Figure 4(b) because the throat dominant geometry keeps good connectivity with lower aspect ratio. Figure 4(d) shows the permeability distribution for the micro-CT image of a Fontainebleau sandstone that indicates different pore geometries at the smaller scale could have similar porosities as marked in the oval. These pore structures can be used to assess multiphase fluid flow as shown in Figure 5. Wettability distribution at the pore-scale is also very important for the multiphase flow and it can be assigned in the flow simulation to see the effect of it [6].

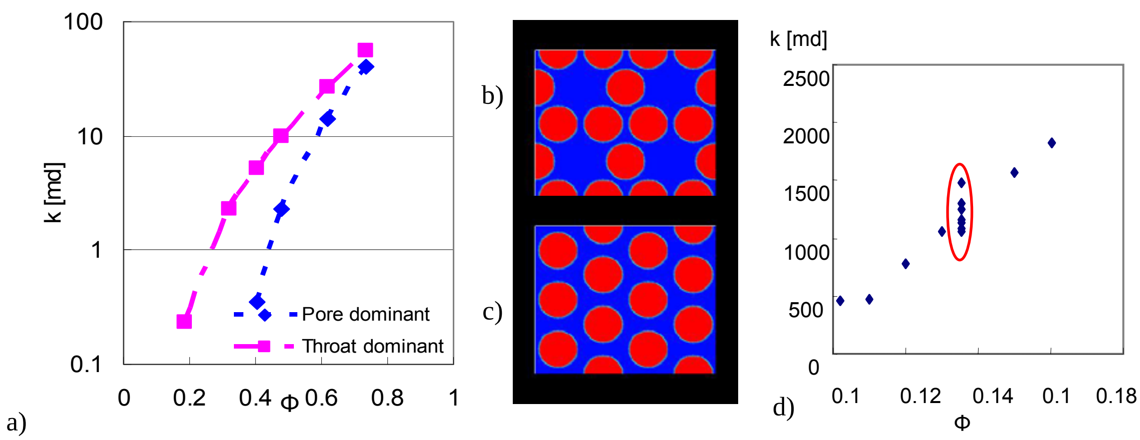


Figure 4. Pore-scale heterogeneity. a) ϕ–k correlations in different types of pore structures, which are the pore dominant structure (b) and the throat dominant structure (c) [grain in red and pore in blue]. d) ϕ–k correlation of a Fontainebleau sandstone using subgrids of the micro-CT image demonstrates the pore-scale heterogeneity of the permeability around the porosity of 0.14 (marked in red oval).

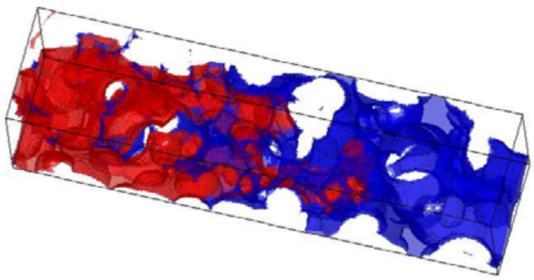
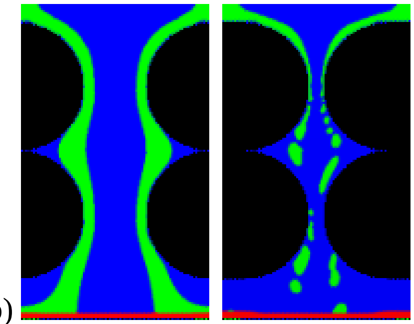
a)  b) 

Figure 5. Snapshots of fluid saturation distribution at the pore-scale during oil-water two-phase flow simulation. a) Fluid distribution in the 3D pore structure (oil in red and water in blue). b) Effects of pore structure (different aspect ratio) and fluid distribution on the multiphase flow in the simple 2D pore geometries (oil in green and water in blue with the structure in black). Larger aspect ratio on the right hampers the continuous oil flow.

CONCLUSIONS

Micro-CT imaging is used to characterize pore-scale structures and to predict fluid flow at the pore-scale. Pore-scale heterogeneities of different types of rocks, such as porosity, permeability and structure, are investigated by the numerical flow simulation using the lattice-Boltzmann method on the digital images. Representative Element Volume (REV) of the rock is also estimated on the 3D digital images in terms of porosity and permeability. The study shows multiphase flow at the pore-scale can be evaluated by the combination of the LBM and digital images, and it gives us the significant insight of pore-scale physics.

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