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Research paper

Structural characterization and numerical simulations of flow properties of standard and reservoir carbonate rocks using micro-tomography

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ABSTRACT

With advances in imaging techniques and computational power, Digital Rock Physics (DRP) is becoming an increasingly popular tool to characterize reservoir samples and determine their internal structure and flow properties. In this work, we present the details for imaging, segmentation, as well as numerical simulation of single-phase flow through a standard homogenous Silurian dolomite core plug sample as well as a heterogeneous sample from a carbonate reservoir. We develop a procedure that integrates experimental results into the segmentation step to calibrate the porosity. We also look into using two different numerical tools for the simulation; namely Avizo Fire Xlab Hydro that solves the Stokes' equations via the finite volume method and Palabos that solves the same equations using the Lattice Boltzmann Method.

Representative Elementary Volume (REV) and isotropy studies are conducted on the two samples and we show how DRP can be a useful tool to characterize rock properties that are time consuming and costly to obtain experimentally.

1. Introduction

Understanding the mechanism of fluid flow within subsurface reservoirs is fundamental to many engineering processes such as oil extraction, enhanced oil recovery and geological sequestration of CO_2. The most important property pertaining to fluid flow is permeability as defined by Darcy's law. Empirical models that relate hydrodynamic properties to geophysical properties such as the Kozeny – Carman equation provide an overly simplistic method to predict permeability (Carman, 1937). Even though this correlation works best for homogenous samples such as synthetic materials and sandstones, it was developed with the assumption that porous media can be represented as a bundle of capillary tubes with identical radius and cross-sectional area (Nooruddin and Hossain, 2011), which means its applicability for heterogeneous carbonates is still unknown (Hebert et al., 2015). The heterogeneity of geological carbonate rocks is attributed to the reactive nature of their components, thus leading to diagenetic alterations of their porous microstructure following deposition. Despite the challenges posed by their heterogeneity, studying carbonates is important as they constitute 50% of the world's hydrocarbon reserves (Arns et al., 2005) as well as 70% of the Middle East's oil reservoirs (Sheng, 2013).

Due to the unreliability of empirical models, current industrial practice in the oil and gas industry requires huge expenditure in logging and core analyses to characterize reservoirs and provide information prior to creating geological models to make informed decisions regarding field development. The main experiments conducted fall under the conventional core analysis (CCA) and the special core analysis (SCAL); the former to determine properties such as porosity, saturation and permeability and the latter to measure relative permeability and capillary pressure. However, lab experiments to measure flow properties can be time-consuming as they require the fluids flowing through the core plugs to reach equilibrium (Andersen, 2014). Additionally, multiple core plugs are usually needed for multiple experiments. Therefore, there's an increased interest in studying numerical methods for determining reservoir properties.

Initial attempts made to numerically model flow in porous media focused on network models that idealized the porous media. These models consisted of a lattice of tubes to characterize pore throats and nodes to portray the pores (Aker et al., 1998; Øren et al., 1998; Lovoll, 2005; Joekar Niasar et al., 2009). Though they helped develop an understanding of flow in general, they were oversimplified and were not accurate representations of subsurface porous media. Other types of models were conducted in fictitious porous media generated to have statistical properties equivalent to those of 2D thin sections from real core

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plugs (Adler et al., 1990; Hazlett, 1997; Sallès et al., 1993; Yeong and Torquato, 1998; Bodla et al., 2014). Such stochastic reconstructions were found to underestimate the connectivity of the pore space – thus permeability – when compared with micro-tomographic images (Biswal et al., 1999).

Recent advances in imaging techniques and computational capabilities make it now possible to directly simulate fluid flow within the segmented 3D images of porous rock microstructures that are taken directly as the computational domain instead of simulating on statistically reconstructed or idealized porous media. This novel technique of determining rock properties from high-resolution images of rock cores is known as Digital Rock Physics (DRP) (Andrä et al., 2013a; Andrä et al., 2013b; Fredrich et al., 2006). In their work, Andra et al. (Andrä et al., 2013a, b), delineated the basic steps for DRP as image acquisition, image processing, and numerically solving field equations using known physical properties of different phases in order to compute multiple properties such as absolute permeability, electrical resistivity, and elastic moduli. One main advantage is that these properties can all be obtained from the same set of images.

Many DRP research teams (Arns et al., 2005; Andrä et al., 2013a,b; Auzerais et al., 1996; Arns et al., 2004), numerically simulated flow through 3D images of rocks using the mesoscopic Lattice Boltzmann method (LBM). LBM models fluid as fictive particles that can only move in discrete directions in two main steps; streaming and collision. It solves for the incompressible Navier-Stokes equations (Wiki) using the Bhatnagar-Gross-Krook (BGK) collision operator. The LBM method is generally used due to its direct translation of the 3D image into a numerical grid without the need for discretizing or meshing required for conventional Computational Fluid Dynamics (CFD) methods as was presented by Bird et al. (2014), who ran the simulation on the commercial software COMSOL after segmenting the image on Avizo (FEI Visual Sciences Group).

However, some limitations do exist while running numerical simulations on grids based on x-ray micro-computed tomography (μ-CT) images. Numerical simulations are restricted to small sample sizes containing a few thousand pores even with high-end computing facilities. Also, sub-micron pores cannot be captured at a resolution lower than the resolution of the μ-CT, and as is known with all imaging techniques, there's a trade-off between resolution and volume studied.

In this work, we present the details for imaging, segmentation, as well as numerical simulation of single-phase flow through a standard homogenous Silurian dolomite core plug sample as well as a heterogeneous sample from a carbonate reservoir. We develop a procedure that integrates experimental results into the segmentation step of DRP for calibration, thus fortifying the consequent simulation steps. We also look into using two different numerical tools for the simulation; namely Avizo Fire Xlab Hydro (FEI Visual Sciences Group) that solves the Stokes' equations via the finite volume method (FVM) and Palabos (Palabos) that solves the same equations using LBM. Also, Representative Elementary Volume (REV) studies as well as isotropy studies are conducted on the two samples for both porosity and absolute permeability. The numerical simulations helped determine characteristics of the samples that would have required multiple core plugs in the lab such as permeability in the y and x directions. This work helps establish DRP as a useful tool to study properties of porous media.

2. Material and methods

2.1. Image acquisition

Two rock samples were studied in this work; one was a standard Silurian dolomite sample purchased from Kocurek Industries Inc (Kocurek) and the other was from an actual carbonate reservoir. The core plugs were of standard size – 1.5 inch (3.81 cm). Table 1 summarizes the experimental data obtained for porosity and permeability using conventional gas injection tests. Porosity was determined by measuring the change in helium pressure and applying Boyle's law, while permeability was determined by measuring the pressure drop at different flow rates and using Darcy's law.

Table 1
Experimental data for samples.

	Helium porosity	Permeability (D)
Silurian dolomite plug	0.142	0.279
Carbonate plug	0.12	1.970

Despite there being various tomographic techniques that enable the non-invasive imaging of material, the x-ray μ-CT is the most widely used in the field of structural geology and rock mechanics (Fusseis et al., 2014). The μ-CT works by probing the sample with x-rays from a source and recording the transmission radiography using a charged-coupled device (CCD) camera. A series of radiographs is then gathered at different viewing angles by rotating the sample and then processed with a reconstruction algorithm to generate the tomogram (Madonna et al., 2012). The grey levels in a μ-CT image correspond to x-ray attenuation, which is a function of x-ray energy, composition of the sample and its bulk density.

Imaging of the Silurian dolomite was performed using Ingrain's Versa 500 CT in their Abu Dhabi facility (Ingrain). A cylindrical microplug of size 0.5 inch (1.27 cm) in diameter and 1 inch (2.54 cm) in length was drilled from the standard 1.5 inch (3.81 cm) diameter core plug. The image output was an 8-bit file of size 1004 by 1024 by 1996 scanned at a resolution of 13.24 μm as shown in Fig. 1a. A rectangular subvolume was extracted from the center of the sample as can be seen in Figure 1(b) for the REV and isotropy studies.

Images of a microplug taken from a 1.5 inch (3.81 cm) carbonate sample provided by the oil company were received as an 8-bit image file of size 1600^3 voxels at a resolution of 8 μm per voxel as shown in Fig. 2. The pre-processing steps included resampling the image dataset and applying a non-local means filter to denoise the image while preserving the microfeatures as shown in Fig. 3. Resampling was done to change the voxel size to 16 μm per voxel so it would be the same order of magnitude as the Silurian dolomite, lowering the computational needs of the simulations as the dataset size reduced to 800^3. A study was conducted in section 4.2 on the subsequent effects of the resampling. REV and isotropy studies were then done on the complete resampled subvolume.

2.2. Image segmentation

The main purpose of segmentation is to separate images into discrete phases (one for the void space and the other for the rock matrix). As can be seen from Fig. 4, both histograms are bimodal with frequency peaks at two distinct grayscales. The pores are denoted by the darkest components along the greyscale spectrum. To determine the thresholding value that would separate the pores from the solid matrix, a systematic study was conducted where the effective porosity of a large cube was numerically determined for different thresholding values, then the threshold value was varied and the image-based effective porosity was computed. The subvolumes used for this step was a 600^3 voxel sized cube taken from the center of the dolomite rectangular subvolume and the complete 800^3 voxel size for carbonate. The greyscale value threshold selected was based on the experimental results as can be seen in Fig. 5.

2.3. Computational details

Many researches (Andrä et al., 2013a, b), worked on in-house codes to solve for fluid flow using the Lattice Boltzmann Method (LBM), a method common for mesoscopic scale simulations based on kinetic theory. Bird et al. (2014). segmented their image on Avizo and then ran it on COMSOL after meshing it. Prior to determining the results for the REV and isotropy studies, a comparison was done (Section 4.1) between simulations run directly on Avizo Xlab module (FEI) and the open-source