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Numerical computation of elastic properties for porous rocks based on CT-scanned images using direct mapping method

Yanhui Han [1], Dandan Hu *, Luis Matzar

Halliburton, Houston, TX 77032, USA

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ABSTRACT

In recent years, computed tomography (CT) technologies have been applied to reconstruct reservoir rocks, in digital format, from CT-scanned images in oil-exploration- and production-related research and practice. The geometric, compositional, and mechanical properties of rock samples can be obtained from their digital counterparts through simple analysis or more involved computation. The geometric properties, such as size, distribution, and connectivity of pore space, and compositional properties, such as mineral and organic matter, can be determined rather accurately from digital rock without much difficulty. However, the computation of the mechanical properties for rock samples from their digital counterparts only became possible in very recent years because of the rapid rise of computer power. In this paper, idealized porous rock, synthetic rock, and real rock are employed to test the reliability of the predictions from numerical simulation. The meshing insensitivity of computing rock mechanical properties in digital rock is first demonstrated in a set of simple numerical simulations on idealized porous rocks, for which the computational meshes are generated arbitrarily and the numerical simulation results are compared against analytical solutions. For synthetic rock and Berea sandstone, the computational models are created through direct mapping of their CT-scanned images, and the numerical simulation results are checked with laboratory experimental data. This work confirms that the digital rock methodology has potential to become an accurate tool for measuring elastic mechanical properties for reservoir rocks.

1. Introduction

Reservoir rock is comprised of solid matrix and pore spaces. While its hydraulic properties, such as porosity and permeability, are determined by the distribution and connectivity of pore spaces, the mechanical properties of reservoir rock are associated with the compressibility of the compositional mineral grains in the solid matrix and the strength of the contacting bonds between grains. If viewed individually, the stiffness properties are the primary factor that controls the elastic deformation of rock mass for a given loading condition, the strength properties indicate the limit of stress state beyond which plastic yielding will occur, and the hydraulic properties characterize the fluid storage and transport capacity of reservoir rock. If viewed as a system, the fluid flow in the pore space and the mechanical response of the solid matrix actually interacts with each other in that the mechanical deformation changes the pore volume, thus imposing influence on the fluid pressure and, on the other hand, the pore pressure affects the effective stress and subsequently the deformation of the solid matrix (Biot, 1941; Detournay and Cheng, 1993). Example subjects to demonstrate their significance include reservoir compaction for stiffness properties, wellbore stability and sand production for strength properties, and well productivity for hydraulic properties. Evidently, determination of mechanical and hydraulic properties for reservoir rock is of critical importance in oil/gas exploration, development, and production.

Conventionally, the mechanical and hydraulic properties of reservoir rock are measured in laboratory experiments. Often-used experimental methods for measuring mechanical properties include unconfined compression tests, triaxial compression tests, direct shear tests, and Brazilian tensile tests. The steady-state flow air method is usually used to measure rock permeability. For rocks with ultra-low permeability (e.g., in the order of nanodarcies), the transient pulse decay or crushed rock (GRI) methods should be considered (Brace et al., 1968; Dicker and Smits, 1988; Luffel et al., 1993; Jones, 1997). A prerequisite condition of laboratory experiments is the availability of a reservoir rock specimen with size in the order of inches, which can be very challenging to acquire in deeply buried reservoirs.

In the drilling process, small rock cuttings are circulated to the surface with drilling fluid. These rock fragments carry valuable

* Corresponding author.
E-mail address: Dandan.Hu@halliburton.com (D. Hu).
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information about the host reservoir formation. The characteristics and properties of the host reservoir formation can be uncovered from rock fragments using appropriate technologies and tools; among them, digital rock technology (DRT) might be the most powerful technology developed in recent years, driven by oil and gas exploration in carbonates and shale (Rassenfoss, 2011). In DRT, X-ray scanning technologies and CT are combined to create three-dimensional (3D) images of rock sample in which the size, distribution, and connectivity of the pore spaces and the compositional minerals and organic matters in the solid matrix can all be clearly distinguished.

With simple analysis, the geometric and compositional properties of the rock sample can be obtained from the scanned images. With more involved extensive computation, the hydraulic and mechanical properties of the rock sample can be calculated from these images as well. For example, 3D images can be converted into an equivalent lattice Boltzmann model (LBM), with each voxel in the images represented by a lattice node in LBM lattice. The lattice nodes whose voxel is filled with solid phase in the image are marked as solid nodes in the LBM lattice, and nodes whose voxel is filled with pore space in the image are marked as fluid nodes in the LBM lattice. The permeability of the rock sample can be computed by performing a numerical LBM simulation of a simple flush test on the constructed lattice (Keehm and Mukerji, 2004). Similarly, the solid matrix in the images can be used to construct a computational mesh for computing the mechanical properties (Arns et al., 2002). The interaction between the fluid flow in the pore space and deformation/movement of the solid matrix can be captured by coupling fluid flow simulation with mechanical computation (Detournay and Cheng, 1993; Han and Cundall, 2011, 2013).

Besides its exceptional suitability to work on small rock fragments, DRT also has many other advantages compared to conventional laboratory experiments. For example, it provides faster and more cost-effective access to rock parameters, and it can be used to analyze the distribution and connectivity of pore space, fluids, minerals, and organic matter to repeatedly test the same sample with varying testing conditions to extend measured characteristics to temperature and pressure conditions that are difficult to achieve in the laboratory. Therefore, DRT is a powerful complementary tool to laboratory experiments and field tests.

Although use of DRT in the oil industry began several years ago, its applicability and reliability in practice is currently debatable. The most controversial topic is the representative elementary volume versus resolution. For fine-grained rock-like shale, the imaged sample must be very small (in the order of microns) to capture its detailed internal structure; however, it becomes questionable whether the properties measured in such a small sample could represent the real properties of the large-scale rock mass. It seems obvious that the eventual success of DRT will heavily rely on the successful development of trustworthy up-scaling methods/procedures to appropriately extend the properties/parameters measured in the small sample to a large-scale rock mass.

The CT-scanned imaging data can be used for site characterization, economic evaluation, and computer simulation. The construction of our digital rock laboratory targeted exploring the content and distribution of minerals and the internal structure and transport mechanisms of multiphase flow in unconventional reservoir formations. Two workflows are currently in development for computing material properties from imaging data. One workflow is used to calculate the hydraulic properties of the scanned rock sample using LBM, and the other is used to compute the mechanical properties of the rock sample using FLAC3D numerical geomechanics code software (Itasca Consulting Group, 2012). This paper presents the validation of the developed workflow through computing the elastic properties for idealized porous rock, synthetic rock, and Berea sandstone. (The verification and application of the LBM workflow will be reported separately.) Section 2 describes the workflow of image-based computing of mechanical properties. In Section 3, the computational accuracy of FLAC3D software is validated through computing the stiffness of blocks containing single and multiple spherical pores and comparing the calculation results with the corresponding analytical solutions. In Section 4, the developed workflow is applied to compute the elastic properties of Aloxite® synthetic rock and Berea sandstone. Section 5 concludes the work with comments and remarks.

2. Workflow description

A workflow was developed using the Avizo® and FLAC3D software platforms for computing mechanical properties of rock samples from 3D X-ray micro-CT images produced from our digital rock laboratory. In this workflow, the image segmentation of void and rock matrix from CT images is performed in the Avizo commercial software and then mapped into a mechanical model in FLAC3D software. Using FLAC3D software as a virtual laboratory, conventional geomechanics tests, such as unconfined compression tests, triaxial tests, direct shear tests, and Brazilian tensile tests, can be conducted on the constructed mechanical model to compute various mechanical properties. In brief, the developed workflow for computing mechanical properties from core plugs or rock cuttings can be divided into four stages—CT scan, segmentation, mesh generation, and computational simulation. Berea sandstone will be used as an example to explain the details of each stage.

For the CT scan, an Xradia VersaXRM-500 micro-CT microscope was used to explore the internal microstructures of the sandstone samples. In the micro-CT scan, X-rays are used to create cross-sections of a 3D object without destroying the original sample. The pixel sizes of the cross-sections are in the micrometer scale. In our setup, the X-ray source and detector are stationary during the scan while the sample rotates. The sandstone samples used for the micro-CT scan for the current manuscript were 1 in. (diameter) $\times$ 1 in. (height) core plugs, which were cut from the same location as the ones used for the experimental measurements. The highest resolution that can be achieved using micro-CT for a 1-in. core plug is approximately 28 μm. If higher resolution is desired, it is necessary to compromise the field of view. For the current study, the intent was to include the sandstone heterogeneity as much as possible, so the whole core plug was scanned with a resolution of 28 μm. The 3D slice number for the 1-in. core was 1000 (x-direction) $\times$ 1000 (y-direction) $\times$ 500 (z-direction), and a sub-volume was extracted of size $200 \times 200 \times 200$ for the image segmentation, mesh generation, and the mechanical property simulation.

In the segmentation stage, the $200 \times 200 \times 200$ cube of sandstone raw data from the micro-CT was segmented. The raw data were exported into Avizo Fire software, and the appropriate filter was applied to the data first. The filter used in this study was the “non-local Means filter;” this module implements the windowed non-local means algorithm for denoising scalar volume data. Other filters were tested, but it was concluded that the “non-local Means” worked best for our sandstone data. The image segmentation algorithm (Hu et al., 2012) used here is based on intensity multi-thresholding, which is performed in the Avizo “Edit New Label Field” module. The sandstone 3D images acquired from the micro-CT were very clear and sharp after the denoising treatment, so multi-thresholding segmentation worked very well to separate pore space and solid matrix. Also, different minerals in the solid phases could also be differentiated by this image segmentation treatment. The label file, which represents different phases of the