RP12

Study of Heterogeneity in Carbonate Rock Samples Using Digital Rock Physics

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SUMMARY

Carbonate reservoirs are considered extremely complex due to their texture heterogeneity. Using new approaches in Digital Rock Physics (DRP) is possible to compute core plug sample properties and study the heterogeneity from digital image data generated from X-ray computed tomography (CT) scan. Some numerical methods are effective to calculate and analyze these samples properties. However, there is a limitation when the simulations are run at the scale of the whole core plug, especially for fluid flow simulation, due to the large amount of calculation and consequent large computer memory requirement. Therefore, simulations are often done only in subsamples of the core plug. To get the dynamic properties of the whole core plug samples and study their heterogeneity, we propose a combined approach of DRP. Digital imaging processing is used to run digital core models for the calculation of porosity and permeability. The Lattice Boltzmann Method (LBM) is used to simulate fluid flow and calculate the absolute permeability. Experimental measurements are used to compare with simulated results of subsamples which are selected from the whole core plug sample. By comparing and analyzing the results of subsamples, the dynamic properties of the whole core samples are obtained and the heterogeneity is studied.

Introduction

Carbonate reservoirs are considered extremely complex when estimating oil and gas production due to their texture heterogeneity, mainly from the structure of the pore space. In order to address this problem, analysis for core samples is an effective way to obtain insights into the natural heterogeneities of reservoirs (Kusanagi *et al*. 2014). Using new approaches in Digital Rock Physics (DRP) is possible to compute core sample properties from digital image data generated from X-ray computed tomography (CT) scan. Some numerical methods are effective to calculate and analyze these sample properties. However, there is a limitation when the simulations are run at the scale of the whole core plug, especially for fluid flow simulation, due to the large amount of calculation and consequent large computer memory requirement (Sukop *et al*. 2013). Therefore, simulations of fluid flow are often done only in subsamples of the core plug. Consequently, to get the dynamic properties of the whole core plug samples, new accurate methods are needed.
In this study, we use DRP to estimate porosity and permeability in heterogeneous carbonate core plug samples, and study their heterogeneity. Digital imaging processing is used to run digital core models for the calculation of porosity and permeability. The Lattice Boltzmann Method (LBM) is used to simulate fluid flow and calculate the absolute permeability. Experimental measurements are used to compare with simulated results of subsamples. By comparing and analyzing the results of subsamples, the dynamic properties of the whole core plug samples are obtained and the heterogeneity is studied.

Procedure

In order to calculate the rock properties of porosity and permeability using DRP, we need to separate the grains and pore spaces in the acquired 3D digital images. First, we apply a local image histogram equalization procedure in order to enhance edges and fine details in the images. Then, we apply an automatic segmentation technique based on the Otsu algorithm to obtain the segmented image (only pore, value of 0 and grain, value of 1) (Otsu, 1979). Finally, we calculate the porosity by estimating the percentage of the pore volume from the segmented data. To estimate permeability, three consecutive subsamples of 4.096cm^3 volume are taken from the upper, middle and lower part of the core plug which has an approximate volume of 64cm^3. Then, we simulate the fluid flow and calculate the absolute permeability in 3 perpendicular directions using LBM in each subsample (see figure1).

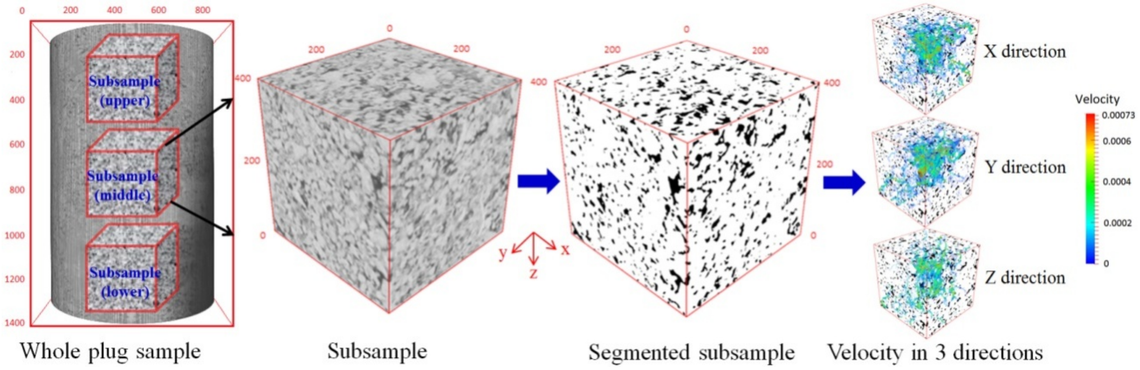

***Figure 1** Example of the digital subsamples from a whole core plug image (960X960X1400 voxels, resolution of 40µm/pixel): Three subsamples of 400X400X400 voxels are selected separately from the upper, the middle and the lower part of the whole plug sample to do the permeability simulation.*

Results and Analysis

From the Table below, it can be seen that, for all whole plugs there is difference between the calculated porosity and the experimental measurement (range of 1.03%-6.50%), this is perhaps because there may be many micropores in these rock samples, which couldn't be identified well due to the relative low resolution images (40µm/pixel). Only in S3, the difference is small (1.03%) because there are many clear pores (>0.1mm) which can be identified easily by DRP. These show that the micropores (which are below the image resolution) may have a great impact on the calculation of porosity as shown in samples S1, S2 and S5.

The experimental permeability measurements correspond to the axial direction of these core plugs (z direction). For all samples, the calculated permeability Kz of the three subsamples is different. It is to note that the minimum estimated Kz is always closer to the experimental permeability value. This result probably shows that fluid flow from one extreme to the other of the core plug has a variable velocity that is slowed at the lower part of the sample. Consequently, the fluid cannot move faster than the lower flow velocity and the measured permeability through the whole sample corresponds to the smallest fluid flow velocity according to Darcy's equation.

We also found that there is permeability anisotropy in these samples (Table 1). The calculated permeability in each direction for all subsamples of S3 is the highest of all. This might be due to the pores of S3 are clearly connected and play a major role in the fluid flow and permeability calculation in the images. For most of the subsamples, Kz is much higher than Kx or Ky, and Kx is close to Ky. These demonstrate that the permeability in the axial direction is higher than that in the radial direction for these samples. Only in the middle subsample of S1, Kz is lower than Kx and Ky. This result is probably due to that S1 is a rudstone with lots of stylolitics in the middle of the sample which have an impact on the fluid flow and permeability.

***Table 1** Calculated results and experimental results.*

Sample		S1	S2	S3	S4	S5
Calculated Porosity of Whole Plug ϕ_c (%)		25.20	20.40	28.40	25.80	19.30
Experimental Porosity of Whole Plug ϕ_e (%)		31.12	26.90	29.43	30.21	25.60
Porosity Difference (ϕ_e - ϕ_c) (%)		5.92	6.50	1.03	4.41	6.30
Calculated Permeability of Subsample (mD) (Upper)	Kx	108.36	22.50	997.60	149.20	17.50
	Ky	110.22	33.90	1430.70	65.80	8.60
	Kz	240.90	58.49	4676.91	417.06	59.24
Calculated Permeability of subsample (mD) (Middle)	Kx	150.09	6.00	829.60	35.50	38.70
	Ky	123.40	1.90	1222.40	64.03	21.30
	Kz	111.57	27.15	4560.77	727.70	58.69
Calculated Permeability of Subsample (mD) (Lower)	Kx	21.06	21.80	940.00	38.01	7.44
	Ky	47.80	18.86	983.40	38.98	13.37
	Kz	67.28	50.33	5368.45	163.39	62.46
Experimental Permeability of Whole Plug Ke (mD)		63.42	21.00	4263.45	134.47	56.1

Conclusions

We propose a combined approach of DRP to study the heterogeneity in carbonate rock samples. The simulated results show that 1) The pores below image resolution may have a great impact on the calculation of porosity and permeability; 2) The permeability anisotropy in these samples is clearly shown: the permeability in the axial direction is higher than that in the radial direction; 3) The low permeable part in the rock samples and the well connected bigger pores (resolved in the images) play a key role on the permeability calculation of the whole sample; 4) The heterogeneity of these rock samples is clearly affecting the permeability measurements, given as consequence an effective lowest value.

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