Recent Advances in Imaging and Computational Rock Physics and Applications

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Abstract

The need for rock physics information is exploding as we aspire to improve geo-steering, recovery, wellbore management and reservoir simulation. The most reliable source of this information is experimentation. However, physical measurements on rock fragments are slow and cumbersome, and often impossible to conduct or conduct well. Even when available, such data are sparse - required are properties not for tens but for thousands or tens of thousands of samples.

The only way to obtain such massive data is through the emerging computational rock physics. This methodology includes 2D and 3D high resolution (below micron and even down to nanometers) and fast (minutes) imaging of the pore spaces of cores, plugs, or cuttings. These images are used to (a) accurately and fast (minutes) compute bulk properties of rock and (b) simulate pore scale processes also very fast (tens of minutes).

This technology was developed and implemented and today can be delivered with reliability in large-scale. We have implemented cutting edge codes to deliver porosity (including micro porosity in carbonates); absolute and relative permeability, the latter accounting for interfacial tension, wettability, and viscosity contrasts; electrical; and elastic properties. Soon to come are capillary pressure and formation damage simulations.

Introduction

Accurate hydrodynamic characterization of porous media is paramount to understanding many large-scale fluid flow phenomena that govern the overall performance of a reservoir system. The ultimate hydrodynamic behavior is completely dominated by the pore level flow phenomena at work. The characterization of this pore scale behavior has traditionally been done with specific, and limited, resource and/or time consuming laboratory measurement processes. The primary measurement vehicle has been core sample analysis, whereby an extracted core is prepared and subjected to laboratory measurements that, in the best light, yield important parameters for the core (and therefore the site under examination). Common parameters such as porosity (the total volume of pore space in a given sample) and permeability (how fluids migrate in the given sample) are two important properties produced in the laboratory. An item missing in all these measurement processes is a complete picture of the overall structure of the pore-space. An accurate representation of the pore-space can lead to detailed simulation and analysis of the processes in rock.

Furthermore, if we understand the physical laws at work at the microscopic level, simulations of fluids moving through such pore space representation can be accurately performed. Until now, the total end-to-end process of acquiring an accurate pore scale representation and fluid dynamic modeling in it has not been possible or practical to implement and provided as a service.

Method and Examples

We have recently finished designing and implementing a digital procedure and we are now in the process of perfecting its application to real rock. This ambitious task is especially relevant to carbonates, whose pore structure is notoriously complex and prone to rapid diagenetic alterations. Figure 1 shows an outcome of such computational experiment simulating two-phase flow of water and oil through a carbonate sample from the Middle East.

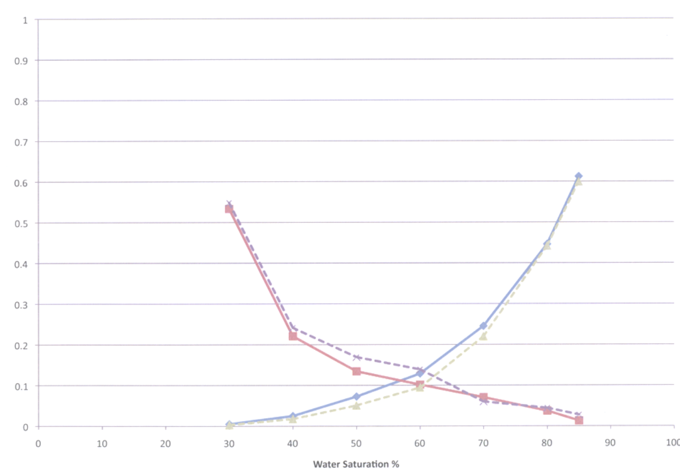

Figure 1: Relative permeability for water (ascending curves) and oil (descending curves) versus water saturation calculated on a 3D image of Middle East carbonate. Solid curves are for the viscosity of oil twice that of water. Dashed curves are for the viscosity ratio 4. The surface tension is 30 dynes/cm.

This simulation was based on the Lattice-Boltzmann method (LBM), a method that enables us to reproduce viscous flow governed by the Navier-Stokes equations in a realistic pore space, as imaged on real rock, without any unwarranted idealization of the pore-space geometry. LBM can handle steady-state as well as transient processes, the latter important for drainage and imbibition simulations. Multiphase LBM takes into account difference in the viscosities of the phases, wettability and interfacial surface tension.

This feature is especially remarkable – it allows us to vary the conditions of a digital experiment that reflect potential conditions in a reservoir, including temperature and chemical variations as well as interfacial conditions altered, for example, by surfactants. Such experiments are hardly possible in a physical laboratory.

The digital technology enables us to tackle several problems unsolvable within the traditional physical experimentation framework. Among such problems is scaling -- one of the outstanding problems in geology in general and petroleum engineering specifically. The question is how to best link information, especially physical measurements that are obtained at very different scales, to understand the nature and forecast outcomes of natural phenomena.

This is the case for earthquakes – we still do not understand the physical meaning of the frequency-magnitude relation with the event size varying from a meter to hundreds of kilometers. In the petroleum applications we still do not have a rigorous and systematic workflow that begins to link data obtained from cuttings, plugs and core, well logs, cross well seismic, seismic, reservoir simulation, and geology.

Digital rock physics may help us address this problem. Consider Figure 2 where laboratory permeability-porosity data point obtained on Berea sandstone is matched by a digital experiment on a small fragment of this rock. Let us uniformly subdivide this small digital sample into 8 and then 27 subsamples and perform digital permeability-porosity experiments on these subsamples.

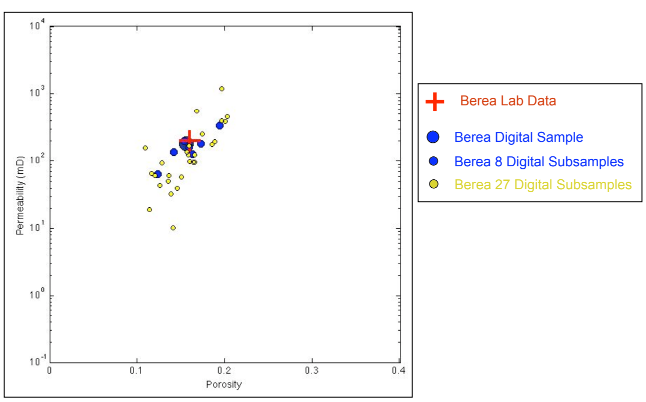

Figure 2: Permeability versus porosity for Berea sandstone. The legend explains the symbols.

We observe that the data from these subsamples form a permeability-porosity trend. In other words, although both porosity and permeability vary among the subsamples, they form a physically meaningful and reasonably tight trend, which includes the physical data point.

This result may mean that the relations between rock properties that we observe at a microscopic scale hold at mesoscopic and macroscopic scales. Figure 3 where we compile more digital and physical permeability-porosity data obtained on core plugs, small digital samples, and their subsamples facilitates this hypothesis.

Same may be true not only for permeability but for other rock properties, such as electrical resistivity and formation factor, which is the ratio of the resistivity of porous rock fully saturated by brine to that of the brine (Figure 4).

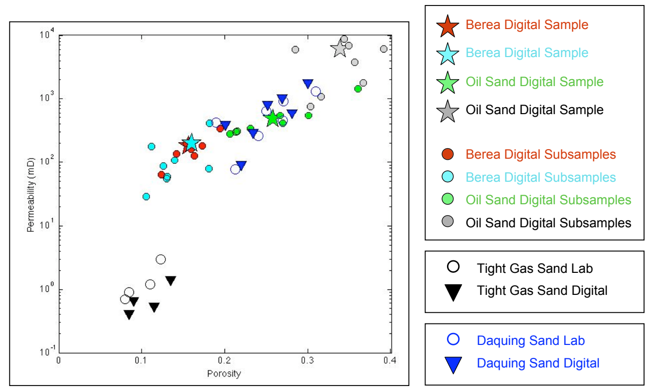

Figure 3: Permeability versus porosity for various physical and digital sandstone samples. The legend explains the symbols.

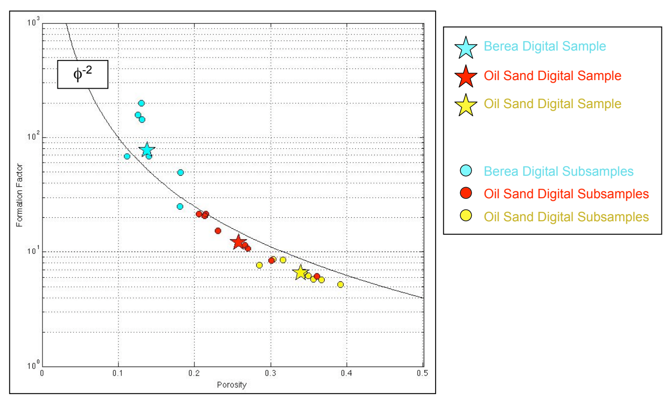

Figure 4: Electrical formation factor versus porosity obtained on digital sandstone samples and their subsamples and compared to one of accepted experimentally-derived formation factor versus porosity curves.

Yet another example of such trends that persist at different scales is for the elastic moduli of rock. In Figure 5 we compare laboratory dynamic moduli elastic data for room-dry Fontainebleau sandstone samples to digital data from microscopic subsamples of these rock fragments. Not only the digital data match the physical measurements but these data also form a trend that conforms with the physical trend at the core plug scale.

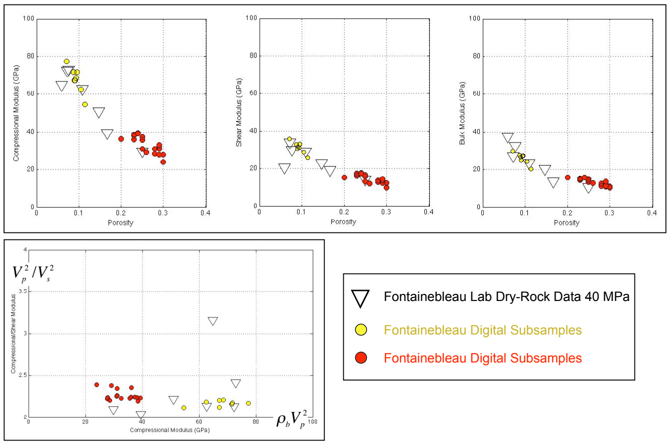

Figure 5: Elastic moduli versus porosity for Fontainebleau sandstone obtained physically at the core plug scale and digitally at the microscopic scale.

Conclusions

We conclude that the heterogeneity of natural rock that persists at many scales calls into question the practical utility of data obtained on a given sample, which is, in effect, a point in the space occupied by the rock. For example, we contest the validity of such data in an application such as of remote sensing which samples different and differently sized volumes within a formation.

The examples presented here indicate that under certain circumstances, trends formed by pairs of data points obtained on an internally heterogeneous dataset form a trend that is valid over a range of scales. Such a trend is stationary with respect to position and scale, and thus can be applied to a remotely sensed quantity (e.g., porosity) to arrive at another desired property (e.g., permeability) at the scale of practical measurement.

Acknowledgments

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References

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