Digital rock physics provides new insight into shale reservoir quality

Advanced imaging, rigorous physics, and high-speed computation combine to reveal reservoir properties of organic-rich shales.

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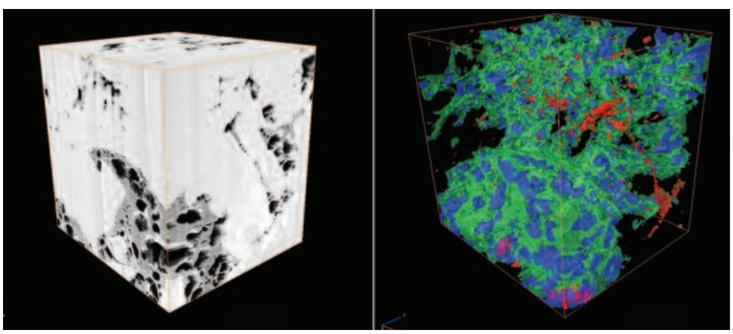
The great majority of whole core samples recovered in the US today come from shale reservoirs. A primary reason for so much shale coring is that petrophysical models require rigorous core calibration to provide reliable data for reservoir quality, hydrocarbons in place, and hydraulic fracturing potential.

However, the uncertainty in interpreting shale well log data is sometimes matched or exceeded by the uncertainty observed in traditional methods of analyzing core samples. Most commercial core analysis methods are 50+ years old and were developed originally for sandstones and carbonates exceeding 1 millidarcy in permeability. High-quality, organic-rich shale, on the other hand, is usually lower than 0.001 millidarcy. This extremely low permeability creates substantial challenges for existing methods and has contributed to the rapid rise of a new approach to reservoir evaluation called digital rock physics (DRP).

The DRP process

DRP analysis of shales usually is performed in three stages. Each stage provides visual and quantitative information that can be used to select a smaller but representative volume for the next stage of analysis. Stage 1 is performed on whole cores, Stage 2 uses plug-size samples, and Stage 3 is an ultra high-resolution 3-D pore-scale analysis.



The image on the left shows the outer surface of a 3-D FIB-SEM volume from an organic-rich shale. The image on the right shows a transparency view of the distribution of connected pores (blue), isolated pores (red), and organic matter (green).

In Stage 1, whole cores are analyzed using calibrated X-ray computed tomography (CT) imaging at a resolution of about 500 CT slices per linear foot of whole core. These detailed images are obtained while the fragile shale is sealed and protected inside the aluminum core barrel liner. This process is substantially reducing the need to "slab" or saw-cut the core along its length in order to photograph and describe it.

The X-ray energy data are used to determine both bulk density (RhoB) and effective atomic number (Zeff) for each CT slice. Zeff is analogous to the photoelectric wireline measurement and provides key information about lithology. Together, the bulk density and Zeff logs provide quantitative measures to assist in discriminating lithology, porosity, and rock facies.

In Stage 2, plug-size samples are taken at multiple depths based on the high-resolution RhoB and Zeff data from Stage 1. Micro-CT analysis provides information on fine-scale laminations and fracturing at a resolution of 10-40 microns. Image analysis from 2-D scanning electron microscope (SEM) data provides porosity and kerogen volume fraction at a resolution of a few nanometers and also is used as a screening process to ensure representative samples for the subsequent 3-D special core analysis laboratory (SCAL) computations. An X-ray energy dispersive spectrum method provides elemental composition, which is used to compute mineralogy. This method has the advantage of giving both volume and geometric distribution of minerals.

The 3-D SCAL analysis begins with nanometer-scale pore and matrix imaging. This process uses a focused ion beam SEM (FIB-SEM) system. The system acquires an SEM image of an ion-beam polished surface, then uses the ion beam to slice away a few nanometers of rock and takes another SEM image. This is repeated several hundred times for each sample. All of the individual images are aligned and combined into a single 3-D volume. Image processing and segmentation allow separation of the solid mineral, organic material, and pore space into unique 3-D objects. This resultant 3-D digital rock volume is termed a "vRock" and is used for subsequent SCAL computation work. Absolute permeability is computed on each vRock using a numerical method known as Lattice-Boltzmann.

Results and discussion

Pores in shale resource plays often are described as belonging to one of three classes: intergranular, intragranular, or organic matter. From work on hundreds of samples from many different shale formations, it appears that organic matter porosity (porosity associated with the diagenesis of kerogen) is especially critical in establishing unconventional reservoir permeability. On the other hand, samples with primarily intergranular porosity appear to have lower permeability for a given level of porosity.

Based on pore-scale images from a wide range of organic shales, it can be seen that organic material is present in a variety of forms or textures. Three primary forms – nonporous, spongy, and pendular – are commonly observed.

This can be illustrated in a ternary diagram where the bottom-right corner represents nonporous organic components (likely kerogen) that fill all of the available nonmineral space, leaving virtually no porosity or fluid flow path. The bottom-left corner represents porous or "spongy" organic material commonly encountered in thermally mature gas shales. The top corner of the diagram represents pendular organic material that appears to fill the small intergranular and grain contact regions, leaving open pore space in the larger voids.

The appearance of the pendular organic matter, potentially a migrant bitumen product, suggests that it may behave as a viscous liquid at reservoir conditions. If it is mobile under reservoir conditions, laboratory measurements at ambient conditions could underestimate permeability. There also are combinations of these primary kerogen textures. The pendular style of organic material appears to be more common in samples from oil-window shales, whereas spongy organics are more common in gas-window shales. E&P