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Computing properties from 3-D imaging

Next-generation computed tomography (CT) scanning reveals the actual pore structure of shale reservoirs at the nanometer scale, and breakthrough algorithms compute the physical properties of shale from these 3-D images — all with unprecedented accuracy

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Analysis of reservoir rock samples has long been regarded as a cumbersome process requiring costly coring operations, increased drilling risk, and time-consuming physical lab experiments. Shales are particularly difficult to measure using physical methods as a result of the rocks' small pore sizes. But Ingrain, a startup oilfield service company, has achieved a technical breakthrough by applying advanced digital imaging and computing technologies to the process of physical core analysis. Ingrain's digital approach to measuring rock properties provides operators with the porosity, permeability, conductivity, and elastic properties of shales.

This non-destructive process accommodates all types of reservoir rocks, including those that are difficult or impossible to subject to physical lab experiments such as oil sands and shales. Without the constraints of a physical lab, the process can return accurate measurements from cores or drill cuttings within days — fast enough to aid critical drilling and production decisions.

Challenges to shale property measurement

Shales have some of the smallest pores found in any clastic or nonclastic reservoir rock. As a result, hydrocarbon flow in shale reservoirs occurs in pore structures that are orders of magnitude smaller than typical sandstone or carbonate reservoirs. This complexity makes it difficult to measure shale properties in physical lab experimentation. Until now, efforts at digital rock properties measurement in shales failed because rock samples were not being imaged at the nanometer level, or computations were being performed on simplified pore network models that didn't accurately characterize the detailed fabric of reservoir rocks.

Next-generation technology

The new process begins with a team of trained geologists evaluating rock samples and preparing them for imaging with industrial-grade CT scanners. Hundreds of 2-D scans of each rock sample are layered to create a high-resolution 3-D digital capture of the rock sample. Most conventional samples are imaged using a MicroXCT system that functions at resolutions up to one micron. For shale samples, Ingrain uses a NanoXCT, the only machine of its kind currently being used in the oil and gas industry. With the ability to produce accurate images of a sample's pore network at a resolution of .05 microns, the NanoXCT is particularly valuable in capturing the complex pore networks of unconventional reservoirs, including shales.

After imaging, geologists apply sophisticated image segmentation software to differentiate between the grains and pore space within the 3-D volume. The final result is a digital version of the actual fabric of the original physical rock, which Ingrain calls a "vRock." This vRock reveals the complete pore network at a level of detail that allows the company to accurately compute physical and fluid flow properties. The proprietary fluid flow computations are based on the lattice-Boltzman method, which allows for simulation of fluid flow in pore spaces of any complexity.

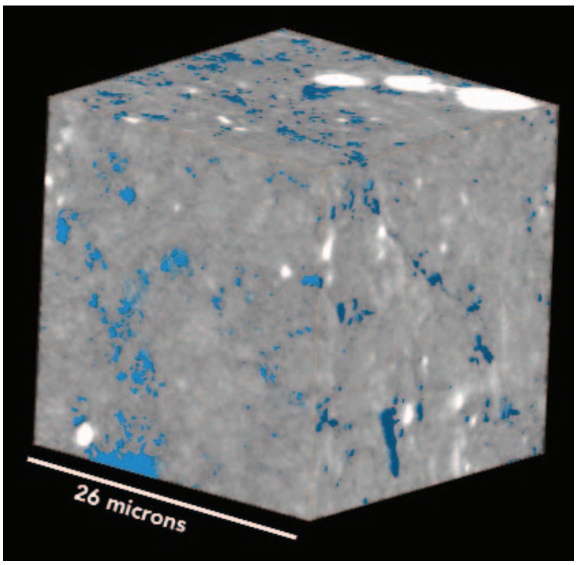

Figure 1. A three-dimensional rendition of a shale sample. The blue represents the pore structure. The gray areas represents the matrix, and the white spots are framboidal pyrites. (Images courtesy of Ingrain)

By unifying innovative technology with its proprietary segmentation methods and computational algorithms, the company provides operators with new insight into their reservoirs. Further, the speed of the process allows for large number of samples to be processed quickly, resulting in more measurements and the ability to better characterize the intricacies of the reservoirs at hand. This has high value in shale reservoirs, where inherent heterogeneities require large amounts of data to create accurate reservoir models.

When the process is complete and results are delivered, vRocks are stored for operators in a secure database. Software runs in a web browser, giving geoscientists the option of requesting multiple analyses on the same vRock to modify parameters and observe how the results change.

Improving decisions and reducing risk

The ability to measure shale properties introduces new elements of knowledge that can improve decision-making and reduce risk. For example, velocity measurements are typically used to predict pore pressure. But in shale formations, velocity is affected not only by pressure but also by the silt content of the shale (high silt content causes high velocity). In shale

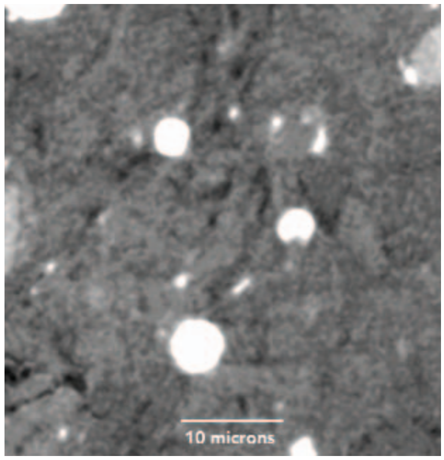

Figure 2. *A two-dimensional slice through a shale. The dark areas are the pores. The white spots are high density framboidal pyrites. The gray areas are siliceous minerals. The light gray areas are carbonate minerals.*

reservoirs where there is a risk of overpressure, this new analysis method can improve pore pressure prediction by measuring silt content in shales. Further, the solid hydrocarbon content of the shale can be quantified, which helps in interpreting well logs of shale sections.

Shales and other unconventional assets will continue to challenge operators simply because they require trial and adoption of new methods and technologies. By introducing a new level of insight and knowledge to the E&P process, Ingrain is empowering operators with the basic information required to overcome the challenges of shales, ultra-low permeability, and complex reservoirs.