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Digital Rock Physics Provide Critical Insights To Characterize Eagle Ford

By Joel Walls and Steven Sinclair

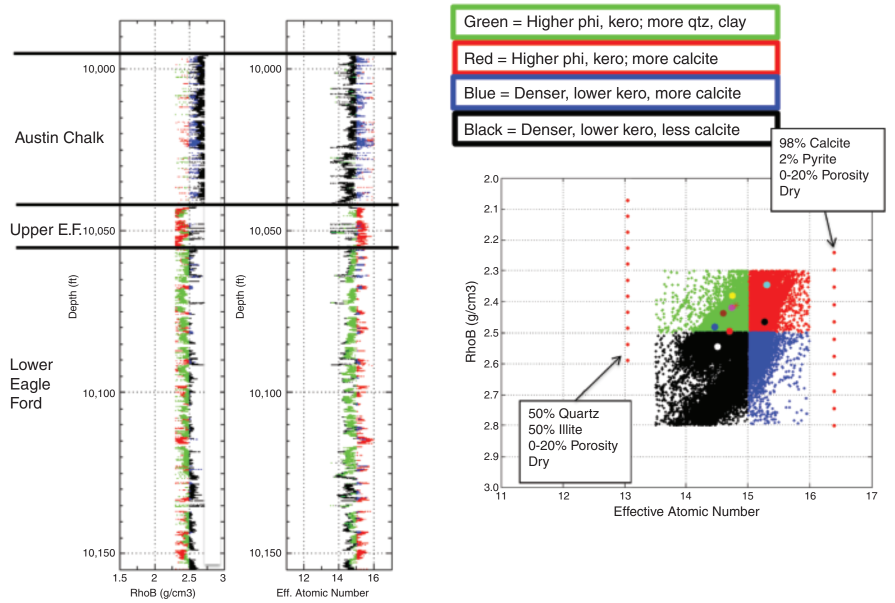
HOUSTON–Much of the understanding about how shale reservoirs store and flow hydrocarbons has come from high resolution imaging of very small pores, especially within the shale's kerogen component.

Pioneering work by the University of Texas at Austin's Bureau of Economic Geology revealed the nature of porosity in shales in 2009 when Robert Loucks and his colleagues presented images of Barnett Shale pores obtained with a revolutionary new technology called focused ion beam scanning electron microscopy (FIB-SEM). For the first time, geologists could see that shale porosity was unlike anything ever observed. Loucks' remarkable images clearly showed that the pores were not only very small (1-5 millionths of an inch wide) but that virtually all the porosity in the Barnett was in the kerogen, not between solid mineral grains as is the case in most other oil and gas reservoirs. These important findings have been confirmed by researchers at the University of Oklahoma and Indiana University.

Of course, geologists and engineers need to know much more about shales than only pore size and shape. The most important information deals with the extent to which porosity is connected–so that it can provide flow paths for oil and gas–as well as the permeability, or ease with which the hydrocarbons can flow.

FIGURE 1

Bulk Density and Zeff



Bulk density and effective atomic number from CoreHD data are used for lithology and facies discrimination, and to aid in upscaling. This data is from well B.

These needs can be met with another cutting edge technology called digital rock physics (DRP). DRP computes connected porosity, disconnected porosity and directional permeability from three-dimensional pore space images that are created by the latest generation FIB-SEM apparatus. Digital rock physics technology that employs unique and proprietary fluid flow algorithms has been used by one operator to derisk exploratory drilling in the Eagle Ford Shale of South Texas.

The Eagle Ford Shale was "discovered" only a few years ago, but exploration, drilling and production activity has accelerated quickly and the play has emerged as one of the hottest unconventional resource developments in the country, thanks largely to distinct gas condensate and oil windows within the formation.

Effective Characterization

Core samples were tested from two wells in the Eagle Ford Shale. Well A is in the early oil window of the Eagle Ford's northern edge. Well B, near Hawkville Field, is in the late oil window. While Eagle Ford Shale pore sizes typically amount to a few millionths of an inch (from tens to hundreds of nanometers), gas and oil molecules are much smaller. DRP proved an effective and expeditious method to characterize this very tight formation and provided data that otherwise might have been difficult or impossible to obtain from conventional core laboratory methods.

The principal objective was to quantify the relationships between porosity and matrix permeability for the key producing facies within the depth zone of interest. Such trends, combined with facies identification from whole core X-ray CT scanning, facilitate upscaling and well-to-well correlation. A secondary objective was to explore, and attempt to quantify, the links between rock layers (how the original shale was deposited) and pore types, which relate to overall reservoir quality.

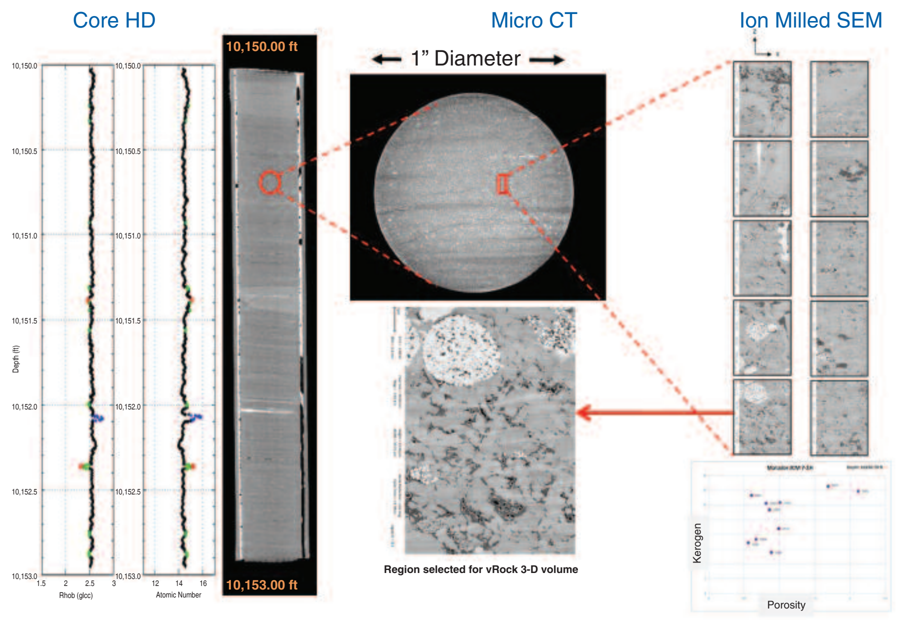
The first step of the DRP process began with a proprietary method for high-definition calibrated whole core X-ray CT scanning at high resolution (about 500 CT slices for each linear foot of whole core), followed by computing "core logs" for bulk density (RhoB) and effective atomic number (Zeff). These bulk density and Zeff logs measured on whole core help discriminate lithology, porosity, rock facies, and depositional sequences.

Figure 1 shows how the RhoB and Zeff data can be used to separate the well into multiple facies, determine which reservoir is likely to be high quality, and to aid in upscaling. These data are from Eagle Ford well B. In this formation, the data's lowest density and lowest effective atomic number quadrant (green data points) probably represents higher porosity and/or higher kerogen content zones.

Plug samples were taken at multiple depths based on whole core scanning and information from the operator about principal zones of interest. Plug sample

FIGURE 2

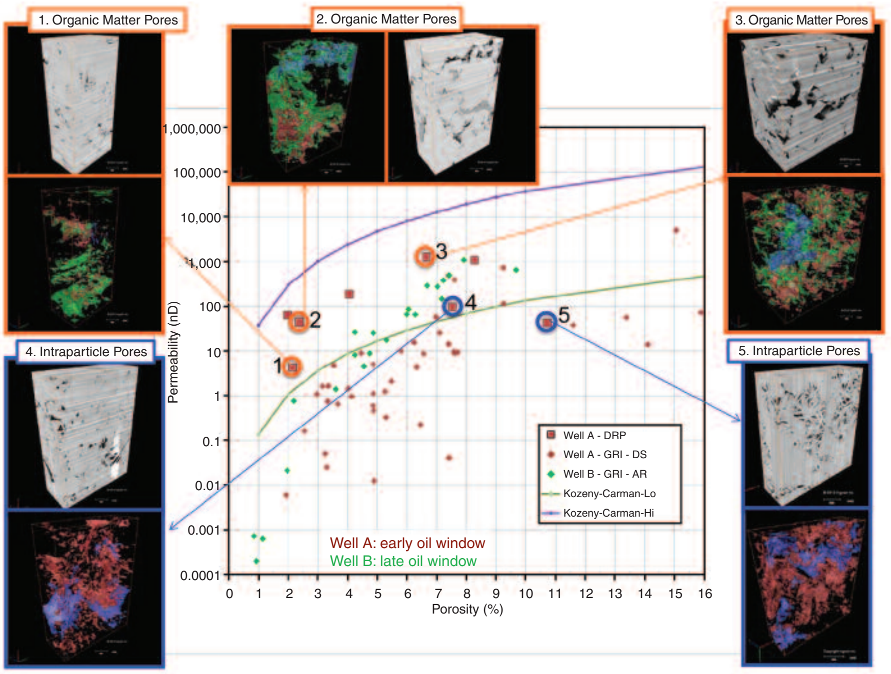
Plug Sample Selection and Analysis



Plug sample selection and analysis process uses a combination of CoreHD CT whole core analysis, micro-CT scanning, and quantitative analysis of ion beam polished SEM data (well B).

FIGURE 3

Special Core Analysis from 3-D FIB-SEM Imaging and vRock Computation



Organic matter (kerogen) dominated samples have better permeability than samples with equivalent "conventional" porosity between solid grains. Special core analysis from 3-D FIB-SEM imaging and vRock computation can help relate facies and shale pore types to porosity-permeability trends. These trends then can be integrated with facies logs from CoreHD to improve net/gross, reserves, and producibility estimates.

analysis primarily was used to quantify porosity and kerogen content and to monitor variation throughout the sample. Figure 2 shows the plug sample selection and analysis process using a combination of high-definition CT calibrated whole core analysis, micro-CT scanning and quantitative analysis of ion beam polished SEM data (well B). Plug sample analysis also was used as a screening process to ensure representative samples for the subsequent 3-D special core analysis (SCAL).

Eagle Ford Core Analysis

The 3-D SCAL analysis began with ultrahigh magnification, FIB-SEM pore and mineral matrix imaging. Next was segmentation, image processing, and creation of digital reservoir rocks using a proprietary technique for determining fluid transport properties from computer tomographic images of rock formation samples. This analysis included connected and isolated porosity, kerogen volume fraction and distribution, and absolute permeability in X, Y and Z directions. Other shale data also can be obtained, such as two-phase relative permeability and capillary pressure curves.

In this project, a major objective of core analysis from 3-D FIB-SEM imaging and digital reservoir rock computation was to understand the relationships between porosity and permeability for each of the primary producing facies, and to help relate facies and shale pore types to porosity-permeability trends. This information (as illustrated in Figure 3) is an important component in shale reservoir characterization. These trends can be integrated with facies logs from high-definition CT calibrated whole core analysis to improve estimates regarding net/gross, reserves and producibility. DRP also will reveal details of the shale pore types and show which ones are associated with higher permeability.

In Figure 3, it appears that organic matter porosity–porosity associated with kerogen–is especially critical to good reservoir permeability, with organic matter-dominated samples demonstrating better permeability than samples with equivalent conventional porosity between solid grains. On the other hand, those samples with more intra-granular porosity appear to have lower permeability for a given porosity. DRP results (shown in large square symbols) indicate that where kerogen is sufficient and it demonstrates associated porosity, there is also ample permeability for oil production from multistage, hydraulically fractured wells.

Conventional core analysis methods tend to show lower permeability than the

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STEVEN SINCLAIR

Steven Sinclair is senior geoscience adviser at Matador Resources Co. He joined ARCO Oil & Gas in 1980, initially working on new ventures in Appalachia and the Mid-Continent. Two overseas tours as chief geologist in Indonesia and Malaysia for ARCO and its successor, BP, exposed him to basin modeling, geochemistry, field development through integrated 3-D interpretation and reservoir modeling, and petroleum systems and resource/risk assessment. After BP closed its Malaysian operation, Sinclair joined EOG Resources to work unconventional resources, coalbed methane and tight fractured reservoirs. At Matador Resources, he is involved in unconventional projects in the Haynesville, Eagle Ford, Woodford and Meade Peak shales. Sinclair holds a B.S. in geology from Texas A&M University and an M.S. from the Center for Tectonophysics at Texas A&M.

DRP results in the lower porosity range, but the trends appear to converge at higher porosity. Conventional permeability data are shown by small, diamond-shaped symbols. This difference in porosity-permeability trends between the two methods will be the subject of further study.

This experimental study to conduct DRP analysis on whole core and plug samples from two wells in the Eagle Ford Shale formation has yielded a number of observations, including:

- Density and Zeff from high-resolution X-ray CT scans of whole cores provide detailed information on layering and facies in the Eagle Ford Shale.
- Key facies changes can be observed readily from the high-definition CT whole core data, while the core is preserved in sealed aluminum tubes.
- Plug sample locations can be selected based on key facies and lithology variations from whole core scans.
- Pore types are mainly organic matter and intragranular.
- At higher porosity, organic matter-dominated samples have better permeability than comparable porosity samples with intragranular porosity. ❒