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Start with the rock

Developing an understanding of gas shale plays and how they work is essential to successful development.

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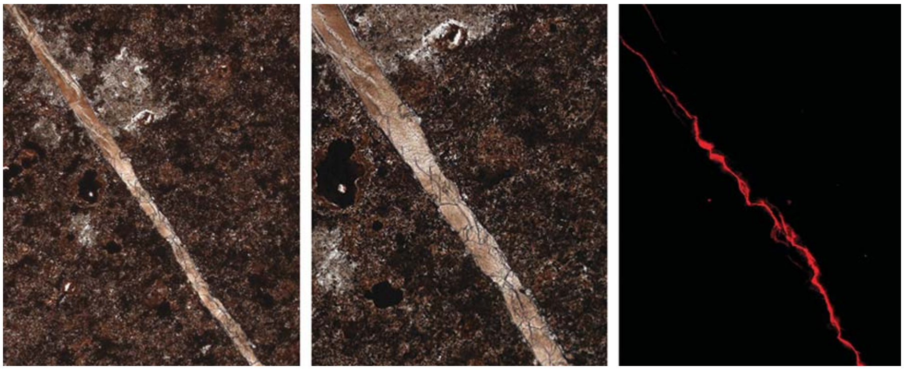

Thin section photomicrograph of a mineralized natural fracture in a gas shale. Images on the left are taken under white light. Image on the right is taken with ultraviolet light. (Image courtesy of Core Lab)

It seems like perfect supply and demand. On the supply side, 70% of the Earth's crust is composed of shale. On the demand side, power generation and industrial applications will nudge domestic consumption of natural gas higher every year for the next 20 years. Bringing these two insights together through gas shale exploitation seems like a strategically located, economical and secure contribution to the domestic energy mix for US operators. But what do we really know about gas shale? Even those who have mastered these plays will admit that the specific innermost machinations of the gas shale offer more learning curve ahead of us than behind.

The first successful commercial gas shale was drilled in New York state, 40 years before the Civil War. Interest in these plays has ebbed and flowed with the market from the 1920s when pioneering souls developed the Devonian shales of the Appalachian Basin to be the largest known gas field in the world to the early '70s when the federal government created formal encouragement for such unconventional production. Michigan's Antrim was the first place government incentives, process improvements and a favorable price environment spurred truly successful recent gas shale activity in the United States.

In the early '80s, gas shales got a massive wave of traction when George Mitchell's investments in fracturing the Mississippian-age Barnett Shale began delivering. Until Mitchell's successes, his efforts in North Texas received more raised eyebrows than expectations. But today players like Devon, EOG Resources, XTO and many others are scrambling to acquire land in what has come to cover 18 Texas counties and upwards of 7,000 sq miles (18,000 sq km). And everybody is looking for "the next Barnett Shale" from West Virginia to the West Coast.

But it's not for the weak. Gas shale plays are demanding. To identify premium gas shale properties, understand the risk horizon and truly optimize completion takes a profound understanding of the rock properties and an extensive modeling of rock behavior in the context of the reservoir.

Better investigation and investment

Since low permeability makes economically viable production the big question, assumptions regarding rock properties and optimal completion methodologies make or break these wells — and their investors. So understanding the economics of a gas shale well means replacing assumptions with information and modeling on every front, from the pore system to reservoir-specific knowledge management.

Six critical analyses comprise a truly comprehensive look at gas shale characterization and risk:

- Gas content and storage;
- Geochemical;
- Geological;
- Geomechanical;
- Petrophysical; and
- Behavioral (Modeling stimulation and production).

Yet data aren't enough. Identifying and quantifying productive intervals in these wells demands integrating and interpreting the data collectively to answer specific questions involving risk.

The first step is asking, "What, exactly, am I working with here?" While certainly not as diverse as a conventional reservoir, significant heterogeneity exists in a gas shale. Kerogen, organic composition, thermal activity, clay contents and fracture characteristics all contribute to economic viability and can differ hugely in a matter of a surprisingly short distance.

Heterogeneities exist even within the same shale and well bore, warranting different fracture treatment design considerations at the tip of the fracture than near the well bore, for example. So exhaustive rock property characterization is the foundation on which all good gas shale decisions are built. Nothing happens until you know the rock.

Early on, assessments must be made of gas content and storage, including transmissibility, composition and physical properties of the sorbed and free-phase gases as well as gas recovery factors. This should be followed by a chemical analysis that ranges from total organic carbon to fluid ion analysis. Next, a total geological evaluation of the depositional environment should follow, covering facies, rock type, mineralogy and pore structure. And, critical to understanding completion options, a comprehensive description and evaluation of fracture networks is needed.

At this point it's time to move to the geomechanical properties, determining compressional and shear wave velocities at net overburden pressure to get a solid grasp of the rock's predicted behavior on a micro-level. Geomechanical parameters such as Young's Modulus, Poisson's Ratio and the like will also shed light on attributes of the rock and reservoir for modeling and optimization purposes and for the determination of better drilling trajectories, choosing the best mud weight and so forth.

Then, finally, it's time to calibrate rock and log data to form a better foundation for fracture optimization decisions. This is done through a thorough petrophysical evaluation — everything from porosity and permeability to grain and bulk density. The end product will be a 3-D fracture stimulation model, used to make the most of available data. Only when all of these comprehensive data are in place and in proper context can you move to the challenge of determining fracture stimulation and optimization.

Fracture design and optimization

With a solid understanding of rock properties and a calibrated petrophysical model that puts the data into context, you now have much of the decision-making framework you need to minimize financial risk: proper fracture design, optimal fluid, fracture half-length and producing conductivity. All of these decisions can be determined from rock properties and petrophysical modeling.

Three-dimensional models can be constructed to create enough "what if" scenarios to enable a real vision of subsurface risk, experimenting with alternative production scenarios by swapping out various treatments, fracture geometries and fluids. And adding financial metrics to the mix puts even more teeth into the modeling process. A petrophysicist or production engineer is hard-pressed to find new insights from a single number representing a reservoir attribute. But calling upon a complete and integrated data set of rock properties can drive modeling efforts toward truly useful conclusions.

At this point, the critical processes to consider are 3-D modeling of frac design, treatment identification, maintaining performance awareness in real-time and a post-frac evaluation. Two major challenges affect gas shale optimization. The first, obviously, is fracture design and geometry. But notably for these clay-rich plays is the second question: expeditious clean-up of the fracturing fluid. While always important, optimizing this step through measured rock property data and effective modeling is critical to assessing reservoir damage.

What makes gas shale modeling so interesting is the production nascence. For any good reservoir characterization effort, data is only part of the picture. Truly informed and repeatable well optimization methodologies demand production history and analysis for any given play — information that may not exist. And thus the assumption trap, human nature compelling us to draw connections that may or may not be valid or unique; endorsing a particular fracturing technique based on a past success without true understanding of why it worked last time, for example. But technology can help.

Software exists enabling the contrast and comparison of gas shale play types between different basins, in various wells within the same basin or field or in different reservoirs in the same well bore. Thickness. Absorbed gas. Total organic content (TOC). Each of these metrics can warrant different stimulation and completion decisions. And any tools or techniques that help differentiate gas shale characteristics, behavior and results will bring us that much closer to improved gas shale efficiency and economics.

Gathering collective intelligence

Investing in the data and expertise to stimulate and optimize these plays is simply a matter of commitment and due diligence. But developing an industry-wide understanding of previous gas shale completions is trickier, a function of well quantity and knowledge capture. With that in mind, a joint industry project (JIP) was formed by Core Lab's Integrated Reservoir Solutions division last year. This project provides operators with measured geological, petrophysical, geomechanical, geochemical and production properties of domestic gas shales. "This project will provide our participants with critical data and interpretations to assess the key technical parameters required for successful exploration and exploitation of existing and emerging gas shale plays," said Randy Miller, president of the Integrated Reservoir Solutions Division.

Companies participating in the Gas Shale JIP are asked to core three wells, which undergo characterization and evaluation at a laboratory equipped for comprehensive data collection, interpretation and modeling. In the lab, these data are integrated with well logs, stimulation designs and production test information. After a proprietary period in which the operator can capitalize on the data, that well information is then released to other study participants through a searchable database. Statistical analysis software can then be used to search for analogs that can fast-track appraisal and exploitation of "unknown or newly discovered" gas shales.

With dozens of study participants, the Gas Shale JIP is boosting the industry's collective understanding of how these plays work. It's providing a platform for domestic efforts and likely for global gas shale exploitation in the future. And in the process, participants are accessing specialized resources that improve formation evaluation and optimize stimulation and production of those wells.

Enthusiasm for gas shales continues apace; new and notable plays are emerging in the Palo Duro and Arkoma Basins, and basins across much of the country are improving track records. So developing an understanding of these rocks and how they work will continues to pay. And just as technology stands to improve conventional production, with the characterization of each new gas shale well we come closer to putting one of our most abundant geological resources to work toward one of our most pressing energy needs. E&P