Shale Gas Revolution

Around the globe, companies are aggressively pursuing shale resource plays, hoping to find the next Barnett Shale. But developing and producing from these enigmatic resources require more than just finding organic-rich shales and hydraulically fracturing them. As the shale gas revolution gains momentum globally, exploration companies are discovering that an integrated approach is essential to success. Learning from past experiences and continually improving methodologies may not guarantee success, but its likelihood is greatly improved.

From the advent of the modern oil and gas industry, petroleum geologists have followed a conventional route for exploration: look for hydrocarbon source rocks, find reservoir quality rocks where hydrocarbons can accumulate, identify a trapping mechanism and then drill a well. But a revolution is taking place in the E&P industry. Rocks that in the past were of little interest, other than as potential source rocks, are today being actively pursued as potential reservoirs. When considering unconventional resource plays, the focus is on finding organic shales.

The Barnett Shale of central Texas, USA, is recognized as the play that initiated the recent interest in developing shales as producing reservoirs. This development represents a fundamental shift in the way exploration companies consider resource plays. The two main enabling technologies that have made shale plays economical are extended-reach horizontal drilling and multistage hydraulic fracture stimulation. However, operators have discovered that there is much more to producing gas from source rocks than drilling horizontal wells and hydraulically fracturing them.

Engineers and geologists studying shale gas resources find that having a greater understanding of a reservoir can lead to process adaptation and refinement of techniques. It is important to integrate data from many sources and at many scales to optimally drill, complete and stimulate wells to produce hydrocarbons from their source rocks.

This article reviews lessons learned from 30 years of shale development and looks at some of the tools used to analyze shales. Taking an integrated approach to developing its Fayetteville Shale play, one operator was rewarded for its efforts, as evidenced by increased gas production and improved operational efficiencies. In another example, a large production log study, using data from six major shale basins in the US, uncovered results that may impact drilling and stimulation practices.

Shale Reservoir Characteristics

Shales are fine-grained rocks that form from the compaction of silt and clay-sized particles.1 Sixty percent of the Earth’s sedimentary crust consists of shale, and it is the primary source rock for most of the conventional hydrocarbon deposits in the world.2 Because shales are formed from mud, they are often referred to as mudstones. Shales are differentiated from other claystones and mudstones in that they are laminated—finely layered—and fissile, which means they can be

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1. Geologists generally consider sedimentary particles smaller than 4 microns to be clay sized. Silt particles range from about 4 to 62.5 microns.
broken or split into sheets along their lamina-
tions (left). Depending on their maturity and
mineralogy, they may also be easily fractured.

For all their abundance, few shale deposits
can be developed as hydrocarbon resource plays.
The targets for gas shale exploration are organic-
rich sediments that were deposited in such a
manner as to preserve a significant fraction of
the original organic matter that eventually serves
as the feedstock for hydrocarbon generation.

Organic-rich shale formations form under spe-
cific conditions—high levels of organic matter
and low levels of oxygen—differentiating them
from other shale deposits. These conditions were
prevalent during various geologic ages, including
the Devonian Period when the climate was warm,
sea levels were high and much of the Earth was
covered by tropical seas. But the Devonian Period
was not the only time when thick deposits of
organic-rich sediments formed. Organic-rich
shales from the Precambrian Period through
modern times have been identified (below left).4

However, to meet thermal maturity criteria, most
gas shale plays focus on sediments from a geologic
time range that begins in the Ordovician and
extends through the Pennsylvanian Period.

Organic matter, which consists mostly of
remains of plants and animals, settles to the bot-
tom of lakes or oceans and becomes food for other
animals and bacteria. However, in anoxic environ-
ments, anaerobic bacteria, which are less effi-
cient consumers than their aerobic counterparts,
are the only bacteria able to consume organic
matter. Thus, the sediments may retain much of
their original organic material. Today, the Black
Sea is a close analog for conditions needed to cre-
ate shale resource plays—anoxic conditions allow
sediments to accumulate with high concentra-
tions of organic matter (next page, top right).4

As more material accumulates and underlying
ooze becomes compacted, the sediments are bur-
ied deeper and subjected to increased pressure
and temperature. Laminations also develop. In
deep marine environments, these processes can
take place very slowly and encompass very long
periods of time; accumulations of a few centime-
ters may take thousands of years. The weight of
the overlying sediments expels fluids and com-
pacts the mudstone, which are steps in the pro-
cess of lithification. The organic material slowly
and partially cooks and is transformed into ker-
ogen, an insoluble material from which hydrocar-
bons, both oil and gas, can be generated.

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<table>
<thead>
<tr>
<th>Million years ago</th>
<th>Period</th>
<th>North America</th>
<th>South America</th>
<th>Europe</th>
<th>Siberia and Central Asia</th>
<th>Africa</th>
<th>Australia and Asia</th>
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<tr>
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<td></td>
<td>Archeozoic</td>
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<td>● ● ● ● ● ● ●</td>
<td>● ● ● ●</td>
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Global distribution of organic marine shales by geologic period. Tectonics, geography and climatic
conditions contribute to the deposition of organic-rich sediments. Organic-rich marine shales are
found across the globe. (Black circles represent the number of occurrences for each age.)
Exploration companies have focused on marine sediments that have sufficient thermal maturity to
convert kerogen into hydrocarbons to develop as resource plays. Lacustrine shales from shallow,
freshwater deposits (not shown) are also targets of exploration but have not yet proved to be as
productive as their marine counterparts. (Adapted from Tourtelot, reference 4.)
Different organic material generates different kerogen types.\(^3\) When exposed to heat and pressure, each kerogen type is more prone to generate specific products: oil, wet gas, dry gas and non-hydrocarbons. During the processes of burial and maturation, kerogen passes through a range of temperatures and pressures. First is the oil window, in which liquid petroleum may be generated from oil-prone kerogen, or wet gas from gas-prone kerogen (middle right). This stage of maturation is referred to as catagenesis. With deeper burial, the kerogen passes into the dry gas window. Through the process of metagenesis, gas is generated by the conversion of remaining kerogen and the transformation of heavier hydrocarbons created during catagenesis. Shales that are rich in organic materials and that have been subjected to temperatures and pressures in the dry gas window are prime targets for gas shale exploration.

However, just because sediments pass through the maturation stages does not necessarily mean they are reservoir quality rock. Using geochemical, petrophysical and geomechanical properties derived from a variety of sources, geologists and engineers determine the feasibility of proceeding with gas shale exploration.

**Geochemical Analysis**

To identify shales that have production potential, geologists look for specific geochemical properties, which are typically derived from core data. Some of the properties can be measured with downhole sensors; however, petrophysicists refine and characterize downhole measurements by calibrating log data to core data. Geochemical properties needed to adequately characterize shale resources include total organic carbon (TOC), gas volume and capacity, thermal maturity, permeability and mineralogy.

**TOC**—An organic shale, by definition, must have organic carbon, and the TOC governs the resource potential of a shale. Rocks with higher TOC values are organically richer. Exploration targets have TOC values in the general range of 2% to 10% (bottom right). Rocks with TOC above 10% are usually too immature for development.

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3. Some geologists also believe that if the sediments are deposited faster than oxic fauna can consume them, high levels of organic matter can be preserved in sediments that are not oxygen poor.


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Modern analog for organic-rich shales. Decay of organic material is a bacterial process that occurs under aerobic conditions; limited anaerobic bacterial activity can also occur under anoxic conditions. The Black Sea is stratified with an upper oxidized layer and a lower anoxic zone. Freshwater (green arrows) flows from in rivers, and denser seawater (blue arrow) flows in from the Mediterranean Sea via the Bosporus Strait. Because of the different salinities and densities, mixing is limited to the uppermost 100 to 150 m (330 to 490 ft). The mixing between surface water and bottom water is strongly restricted; the water at the bottom is exchanged only once in a thousand years. Black, organic-rich sediments accumulate on the bottom. Anaerobic bacteria strip oxygen from sulfates and give off hydrogen sulfide \([\text{H}_2\text{S}]\) as a waste product. The hydrogen sulfide may react with iron in the sediments to form pyrite \([\text{FeS}_2]\), which is frequently observed in organic-rich shale deposits. (Adapted from Lueschen, reference 5.)

Maturation stages in hydrocarbon generation. The processes of burial, conversion of organic matter and generation of hydrocarbons can be summarized in three steps. Diagenesis: characterized by low-temperature—below 50°C (122°F)—conversion of organic matter to kerogen. Bacteria may digest and convert some of the organic matter into biogenic methane. Catagenesis: generally occurs as further burial results in more pressure and increased heat in the range of 50°C to 150°C (122°F to 302°F), which causes chemical bonds to break within the shale and the kerogen. Metagenesis: the final stage, in which heat and chemical changes transform kerogen to carbon. During this stage, late methane, or dry gas, evolves, along with other gases, including CO\(_2\), N\(_2\) and H\(_2\)S. Hydrocarbons produced in earlier stages eventually convert to methane, as well. Temperatures range from about 150°C to 200°C (302°F to 392°F) and higher.

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**The relationship between total organic carbon and resource potential.**

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**Table 2**

<table>
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<th>Total Organic Carbon, Weight %</th>
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<tr>
<td>&lt; 0.5</td>
<td>Very poor</td>
</tr>
<tr>
<td>0.5 to 1</td>
<td>Poor</td>
</tr>
<tr>
<td>1 to 2</td>
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<td>&gt; 10</td>
<td>Unknown</td>
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</table>
The total carbon in a shale sample includes both inorganic and organic carbon. To quantify organic carbon, engineers use a combustion technique. A small portion of the rock sample is first treated with phosphoric acid to remove inorganic carbon. Sediments are dried and then combusted at 1,350°C [2,462°F] in an oxygen-rich environment. The organic carbon is oxidized to form CO₂, which flows through a nondispersive infrared detection cell tuned to respond to CO₂. The measured gas volumes are converted to a TOC measurement and recorded as a weight percent of the rock.

TOC values may vary greatly across a reservoir section. But because it is not feasible to acquire and then analyze cores over long intervals, petrophysicists commonly use downhole data from geochemical and conventional logging suites to quantify the volume of kerogen in the rock and then compute TOC values from these data. To validate the models used to measure TOC, scientists calibrate petrophysical data to TOC, scientists calibrate petrophysical data to core-derived values.

Gas volume and capacity—Gas is adsorbed on the surface of the kerogen in the shale and is also freely distributed in the primary and secondary porosity. The total gas in place (GIP) is the combination of adsorbed and free gas. Depending on the initial pressure of the reservoir, as free gas is produced and the pore pressure falls, adsorbed gas will be liberated, or desorb, from the surface of the kerogen. However, recent research indicates that desorption is also a function of the shale pore size, which scientists must consider when estimating resource potential.

Scientists sometimes use canister desorption tests to determine the total GIP from cores. Immediately upon retrieval, freshly cut core samples are sealed in canisters and sent to the laboratory for testing. The gas is removed from the canister, volumetrically measured and compositionally analyzed as a function of time. A plot of gas produced over time can be used to estimate the GIP for the core sample at reservoir conditions. This analysis is sensitive to the amount of time it takes to retrieve the core from downhole.

To determine adsorbed gas volume for shales, engineers use pressure relationships that estimate the sorptive potential of the rock. Samples are pulverized to maximize surface area and then heated to drive off any adsorbed gas. Samples are then exposed to methane at increasingly high pressure while held at a constant temperature. The volume of gas adsorbed by the rock sample, presented in units of standard cubic feet/ton (scf/ton), is described by a Langmuir isotherm curve (below). Once an isotherm is established, the storage capacity of the rock can be determined by referencing the pore pressure of the formation, which is representative of the in situ reservoir pressure.

Engineers use the Langmuir isotherms from core data to compute the adsorbed gas from log-derived TOC data. They compute free gas volumes from log-derived effective porosity and gas saturation, after subtracting the computed pore volume occupied by the adsorbed gas. Proper evaluation requires geochemical and petrophysical input including clay content and type, matrix density, formation water and bound water resistivities, effective porosity and gas saturation.

**Thermal maturity**—Thermal maturity is a function of depositional history. As kerogen is exposed to progressively higher temperatures over time, vitrinite—cell-wall material and woody plant tissue preserved in the rock—undergoes irreversible alteration and develops increased reflectance. The measurement of vitrinite reflectance ($R_o$) was originally developed to rank coal maturity.

$R_o$ is determined by microscope measurements of the reflectivity of at least 30 grains of vitrinite from a rock sample: Values typically range from 0% to 3%. Measurements in excess of 1.5% are a sign of dry gas–generating source rocks, a positive indicator for gas shales. $R_o$ ranges of 0.6% to 0.8% indicate oil and ranges of 0.8% to 1.1% indicate wet gas. Initially, oil and condensate were considered negative indicators for shale development; however, some operators have had success producing oil and condensate from shale, and lower $R_o$ values can be considered a positive indicator in these cases. A reflectance value below 0.6% is indicative of kerogen that is immature, not having been exposed to sufficient thermal conditions over adequate time for conversion of the organic material to hydrocarbons.
Permeability—One of the most difficult properties to quantify when characterizing shales is permeability to gas, which can range from 0.001 to 0.0000001 md. Permeability is a function of effective porosity, hydrocarbon saturation and mineralogy. Conventional reservoirs have permeabilities in the hundreds of millidarcies, several orders of magnitude greater than that observed in shales. Engineers measure permeability of conventional rocks by forcing fluid through cores and measuring the volume and rate of fluids as they pass through the sample. Shale permeabilities in the nanodarcy range preclude this conventional approach.

TerraTek developed the TRA tight rock analysis pyrolysis technique to quantify ultralow permeability in unconventional formations. In addition to permeability, the TRA technique provides bulk and grain density, total and effective porosity, water and hydrocarbon saturation, gas-filled porosity, bound hydrocarbon saturation and clay-bound water volume.

Reservoir permeability can also be estimated from short duration nitrogen-injection falloff tests. These tests provide system permeability and take into account not only the matrix permeability but also the influence of natural fractures.

Mineralogy—Shales can have complex mixtures of minerals, and the relative concentrations of the constituents have the potential to make or break a potential resource play. Core samples can provide a wealth of information about the geochemistry and mineralogy, but are limited to the specific location where the sample was retrieved. Mineralogy is more often determined from petrophysical data acquired from downhole logging tools, which are calibrated to core data.

Petrophysical Data
The primary data used for petrophysical analysis of shale formations are the same as those used for conventional reservoir analysis—gamma ray, resistivity, porosity and acoustic—with the addition of neutron capture spectroscopy data. Just as conventional oil and gas wells have key indicators for production, shales with hydrocarbon production potential display specific characteristics that set them apart from shales with little or no potential (above right).

Petrophysical analysis of shales begins with one of the most basic measurements: the gamma ray log. It may provide one of the first indications of the presence of organic-rich shale. Organic matter commonly contains higher levels of naturally occurring radioactive materials—thorium, potassium and uranium—than do conventional reservoir minerals. Because they have a higher concentration of organic matter than other sediments, organic-rich shales often exhibit gamma-ray counts in excess of 150 gAPI. Petrophysicists use high gamma ray counts to identify organic-rich shale formations; however, some formations of Cretaceous, Mesozoic and Tertiary age may not display this artifact.

Triple-combo toolstrings, such as the Platform Express integrated wireline logging tool, provide resistivity and porosity measurements. They also provide petrophysical characteristics to help log analysts identify potential gas-bearing shales. For instance, the resistivity measurements in gas-bearing shales are usually higher than those in surrounding shales that have no gas potential.
Porosity measurements also have distinct characteristics in gas-bearing shales. In general, conventional shales exhibit a uniform separation between the density porosity and neutron porosity measurements. Organic-rich shales with hydrocarbon production potential, however, exhibit more variability, higher density porosity and lower neutron porosity. This response is partly a result of the presence of gas in the rock, which lowers the hydrogen index and the resulting neutron porosity. A lower neutron porosity may also occur in organic shales because of the lower clay-mineral content in organic shales compared with typical shales.

As for the density porosity measurement, the constituent materials that make up shales generally have higher bulk densities than those of conventional reservoir rocks such as sandstone or limestone. In contrast, kerogen has a much lower bulk density (1.2 g/cm³) than sandstone or limestone, and its presence can lead to a higher computed porosity. To accurately compute the density porosity of a shale, engineers must know the grain density of the rock in question. The grain density is primarily derived from the ECS elemental capture spectroscopy tool. The ECS tool also provides a kerogen estimation for correcting the grain density.

Formation evaluation to characterize unconventional reservoirs depends heavily on understanding the mineralogy of rocks. The characterization can be done by analyzing cores, but this method is neither efficient nor cost-effective over long depth intervals. Continuous measurements from logging tools such as the ECS tool provide elemental yields that lead to the estimation of weight percent for various minerals that are common to organic shales.

The primary outputs from the spectroscopy tool include silicon [Si], calcium [Ca], iron [Fe], sulfur [S], titanium [Ti], gadolinium [Gd] and potassium [K]. Schlumberger engineers use SpectroLith lithology processing of spectra from neutron-induced gamma ray spectroscopy tools to compute the mineralogy and geochemical data. They then calibrate SpectroLith outputs with empirical relationships derived from an extensive core chemistry and mineralogy database. Matrix grain density can be determined from these data and used for the porosity computation. Certain types and quantities of minerals may indicate rocks that break or fracture more easily. Log analysts use this information to identify intervals for placing both vertical and horizontal wellbores and initiating hydraulic fracturing. Spectroscopy data can also be acquired while drilling using the EcoScope multifunction logging-while-drilling service.

Along with mineralogy data, spectroscopy measurements provide information on clay types. Engineers use clay type to predict sensitivity to fracturing fluids and to understand the fracturing characteristics of the formation. Contact with water will cause some clays to swell, which inhibits gas production and creates numerous operational issues. Smectite is the most common swelling clay. Fluid sensitivity may be inferred from clay typing, but tests on cores from the reservoir provide the most accurate information.

In addition to indicating fluid sensitivity, clay type is an indicator of rocks that are ductile, thus do not fracture easily. Ductile shales are more likely to embed proppant. Other shale types may be brittle and are more easily fractured. The presence of illite is preferred for hydraulic fracturing because it is often indicative of brittle rocks that are not reactive with water. The presence of smectite usually indicates ductile clay.

Acoustic measurements, especially those that provide mechanical properties for anisotropic shale media, are also a significant need for understanding the long-term productivity of shale gas wells. The Sonic Scanner acoustic scanning platform provides data that are used to enhance mechanical earth models and optimize drilling and stimulation. Mechanical properties that can be derived from acoustic tools include bulk modulus, Poisson's ratio, Young's modulus, yield strength, shear modulus and compressive strength. These values are computed from compressional-, shear- and Stoneley-wave measurements.

In highly laminated, argillaceous shales, the Young's modulus and Poisson's ratio are a function of the orientation of the measurement relative to that of the formation bedding planes. These anisotropic mechanical properties influence the closure stress and therefore the hydraulic fracture height. Sonic Scanner data are used to estimate anisotropic mechanical properties and thus provide a realistic determination of the in situ rock stresses.

When a large difference occurs between the vertically and horizontally measured Young's moduli, the closure stress will be higher than that in isotropic rocks. These anisotropic intervals are normally associated with rocks that have higher clay volume as well as with expandable clays. These clay-rich rocks are poor candidates for both horizontal well placement and hydraulic fracture stimulation. Stresses in these intervals will be higher, and it will be more difficult to retain fracture conductivity during production because the proppant is more likely to embed into the ductile formation.

Sonic porosity is another acoustic measurement that is beneficial in shale analysis. For shales, sonic porosity is usually much lower than neutron porosity. This is a function of the high clay-bound water volume that is common in shales. When the sonic porosity is much higher than the neutron porosity, this may indicate that gas, rather than water, is present in the pore spaces. When the sonic and neutron porosity values are similar, the shale may be oil prone.

Log analysts also use wireline borehole image logs, such as those from the FMI fullbore formation microimager tool, to identify the presence of natural and drilling-induced fractures and to define their orientation and concentration. Interpreters can determine from these data whether the natural fractures are closed (mineralized) or open. Engineers use this information to optimize lateral placement and select perforation cluster locations along a horizontal wellbore. By analyzing drilling-induced fractures, they can also infer the state of near-wellbore stresses.

Although there are methods for acquiring petrophysical data in lateral wellbores, most wells are drilled vertically and logged with a full suite of tools prior to drilling the lateral section. Data can be acquired using LWD tools, which have the added benefit of allowing directional drillers to optimally steer the bit into potential sweet spots. The geoVISION imaging-while-drilling service can provide resistivity along with images for bed- and fracture identification; the SonicScope multipole sonic-while-drilling tool can provide acoustic measurements.

The measurements from these various tools can be combined in an integrated display such as the shale montage log provided by Schlumberger. The formation properties are presented using a common platform, and geologists can directly compare the quality of the rocks (next page). Free and adsorbed gas are computed and presented in units of scf/ton, a common unit of measurement in coal mining operations. Some operators prefer adsorbed, free and total gas to be presented in Bcf/mi². Gas resource concentration presented in a Bcf/section helps quantify the total potential for a prospective shale reservoir.
Shale montage log. Water saturation and porosity are computed from conventional resistivity (Track 2) and porosity (Track 3) logging tools. The ECS tool provides mineralogy (Track 5) and matrix density (Track 4) for improved porosity computation and differentiates TOC from porosity (pink shading). The grain density of the rocks can also be computed and used to correct the density porosity (Track 4). Data from core samples provide Langmuir isotherms for gas storage capacity and confirm computed data to ensure model-based outputs such as matrix and bulk density, water saturation, total porosity and TOC (circles, Tracks 4, 6 and 7) are valid. Fluid saturations, corrected for lithology, are presented in Track 6. Geologists use total GIP, adsorbed gas and free gas (Track 8), to determine the potential for the reservoir. Additional features of the shale montage log are the numerical outputs in Tracks 4, 6, 7 and 8, which allow the geologist to read values directly from the log. For example, at XX,350 ft, the effective permeability (red numbers, Track 7) is 313 nD and the cumulative free gas volume (blue numbers, Track 8) is 32 scf/ton. In this interval, contrary to most organic shales, the gamma ray (Track 1) is not reading in excess of 150 gAPI.
The integrated product, in addition to characterizing the petrophysical and geomechanical properties of the reservoir, helps engineers determine the depth to land the lateral for horizontal drilling (below). The preferred strategy is to drill in the minimum horizontal stress direction, which is perpendicular to the maximum horizontal stress.

Quality Rocks
A study in 2007 concluded that fewer than 30% of Barnett Shale wells would be profitable at commodity pricing levels that existed at that time. Much of the data were taken from wells that were completed while operators were still learning how to properly exploit shales. Production log (PL) data from several Barnett Shale wells indicated that 30% of the perforations provided 70% of the total gas flow, and in some wells, 50% of the perforations were not flowing at the time of logging. Taking into account all the basins, the PL study showed that approximately 30% of perforation clusters were not contributing to production. These statistics illustrate that, when log data are lacking, drilling blindly and hydraulically fracturing geometrically staged intervals may not be the optimal strategy.

Prior to drilling, geologists and engineers should identify layers that have superior reservoir and geomechanical characteristics, then drill and complete within these high-quality intervals. Shale resource plays typically cover large geographic area and their log characteristics may not change much laterally across the basin. However, subtle, and sometimes not so subtle, lateral heterogeneity within these sequences results in areas with characteristics that promote better production and hydraulic fracture stimulation. These sweet spots include zones with high gas potential—good reservoir quality (RQ)—and those that can be optimally stimulated—good completion quality (CQ). Geologists build detailed models to simulate the reservoir and attempt to identify the parts of the reservoir with the best RQ and CQ. These models can be refined as wells are drilled and more data become available.

Geologic features, especially naturally occurring fractures, influence well productivity. Knowledge of fracture density and orientation and in situ stress properties can help engineers make decisions on well placement and spacing, as well as optimize a fracture stimulation program. Conventional reservoirs can be drained across long distances, but recovery from resource plays depends on optimal well spacing and maximizing the fracture stimulated volume.

The local stress regime is important for both drilling and stimulation. Stresses along the wellbore are a function of tectonic forces, depth and formation thickness in addition to changes resulting from previous stimulation and production of nearby wells. For optimal wellbore stability, drilling should be oriented in the direction of minimum principal stress. It is important to understand how the reservoir, including existing natural fracture networks, will react as it is stressed during drilling, stimulation and production. Changes in the reservoir from production and induced stresses will influence stimulation stage organization, perforation placement and well spacing decisions. This type of information can be quantified in geomechanical studies.

Geomechanics is a branch of engineering that applies solid mechanics, mathematics and physics to predict how rocks respond to external forces. Following the lead from mining and civil engineering—disciplines that have long used geomechanics to predict and avoid catastrophic consequences—drilling and production engineers are more frequently applying these concepts to reservoir development. These practices call for measuring and estimating stress and examining how materials respond to stress.

A region’s initial state of stress results from its tectonic and sedimentary history. Stresses are also induced by a variety of processes common to oilfield operations, including the effects of drilling and changes in fluid pressure caused by injection and production. All of these effects can be simulated using 3D and 4D earth models, allowing engineers to predict behavior of the reservoir in response to drilling, stimulation and future production.

Geophysicists and engineers at Schlumberger have built a mechanical earth model in the Petrel seismic-to-simulation software that integrates data from ECLIPSE reservoir simulation software. Engineers use these models for well planning and to determine initial stress states. By coupling the ECLIPSE 3D simulation with the VISAGE Modeler, geophysicists can create a 4D model, which simulates changes in the magnitude and orientation of downhole stresses that
occur over time (above). The full production history for a single well, multiple wells or an entire field can be simulated and visualized using the combination of ECLIPSE and VISAGE software.

The identification of potential drilling, stimulation and production hazards is another crucial piece of information gleaned from seismic data. Existing faults can be especially troublesome when an operator is hydraulically fracturing a shale interval. A fault can effectively dominate the fracture growth and redirect all the energy of the treatment into the fault system and out of the target zone. Subsequent fracture stages may grow into previously stimulated faults, adding little to the total stimulated volume. Faults also serve as conduits that direct the hydraulic fracture treatments into zones that produce water, which can potentially kill or greatly reduce gas production.

Based on knowledge gained from 30 years of Barnett Shale development, engineers have learned to account for several considerations when developing resource plays. These include knowing the present-day maximum horizontal stress direction to determine optimal wellbore direction; quantifying natural fracture density, nature and orientation relative to the maximum horizontal stress direction; having sufficient knowledge of geomechanics to design completions that promote maximum hydraulic fracture surface area and complexity; and understanding the fracture-to-fracture interference from both multiple stages and multiple wells. Completion engineers must balance the cost of stimulation and drilling against the addition of wells or fracture stimulation stages. These decisions are greatly aided by the 3D and 4D models.

Hydraulic Fracturing
Success in developing the Barnett Shale has been attributed in part to the use of cost-effective slickwater fracture treatments. However, slickwater is not the only type of treatment utilized during development and may not be the correct fluid choice for some shale types. Gelled, gas-assisted and hybrid fracture stimulations have all been tested in the Barnett Shale as well as in other shale plays.

There is no single solution for all shale reservoirs. For instance, although slickwater has been an effective technique in the Barnett Shale, the lower sand-carrying capacity of these systems, as compared with gelled systems, and the propensity for proppant settling can limit flow capacity for induced fractures. The limited contact or loss of conductivity within the stimulated area can also cause production rates to plummet.

14. Slickwater fracturing fluids are composed of water and a polymer (usually polyacrylamide) for lowering the friction pressure when pumping the fluid through tubulars.
16. Hybrid fracture stimulation often begins with low-viscosity fluids to create a complex network. At the end of the stimulation, fluids capable of carrying heavy concentrations of proppant are used to open the near-wellbore region.
Another concern with slickwater fracturing is shale fluid sensitivity because some clay types have a tendency to swell when they come into contact with water. Gas and foam fluids seem to offer an ideal alternative to slickwater and gelled systems; however, they are not extensively used because of their higher cost, limited availability and the fact that they are traditionally deployed for smaller jobs. The conundrum faced by operators is to find the best system for the specific shale while minimizing the expense of trial and error.

Recently, scientists at the Schlumberger Novosibirsk Technology Center in Russia developed a novel approach to hydraulic fracture design. The HiWAY flow-channel hydraulic fracturing technique (see “Open-Channel Fracturing—A Fast Track to Production,” page 4), developed after years of modeling and testing, has been successfully applied in a number of environments. Initial results in Eagle Ford Shale test wells have shown increased production rates of 32% to 37% compared with those from similar nearby wells. The often marginal economics of resource plays can be greatly enhanced by such improvements in production.

Another common practice in shale fracturing programs is to divide the lateral wellbore into equally spaced segments (above left). This process ignores the vertical and lateral heterogeneity of the formation and has resulted in cases of significant waste of fracturing capital. However, completion engineers can design programs using data acquired during drilling to improve the stimulation program.

Pathway to Success
In large part because of success in the Barnett Shale, E&P activity in North America has been dominated by gas shale exploration for the past decade. Initially, however, operators were not certain that success in the Barnett Shale could be replicated with other shale plays. The Fayetteville Shale, which was discovered by Southwestern Energy Company, was one of the first reservoirs where operators attempted to expand gas shale horizons beyond the Barnett Shale. The company’s success led to a rush to develop shale resources elsewhere.

The Fayetteville Shale is located in the northern Arkoma basin and southern Ozark region in the central US (left). The Southwestern Energy acreage is located in north central Arkansas, USA. The company’s acreage (red box) includes formations with complex structure as a result of regional rifting and uplift.

^ Microseismic monitoring of multiple-stage hydraulic fracturing across a lateral. Analysis of microseismic data, as in this StimMAP hydraulic fracture stimulation diagnostics presentation, can provide operators with information about the effectiveness of hydraulic fracturing treatments. In this example, five stages were pumped from the treating well (red line) while monitored from a second well (green line with location of geophones shown as green circles). The first stage (yellow dots) at the toe of the lateral creates a complex fracture network; however, the second stage (blue dots) overlaps the stimulated volume from the first stage. The third and fifth stages (red and magenta dots) develop complex fractures. The fourth stage (cyan dots) has a preferential direction that leaves some of the formation untouched. It is important to identify these variations in fracture quality to optimize future stimulation designs, well placement and well spacing. Tools such as StimMAP LIVE real-time microseismic fracture monitoring service may allow completion engineers the opportunity to adjust operations during the execution of the job to improve the effectiveness of the treatment.

^ Fayetteville Shale, Arkoma basin. Southwestern Energy developed a Fayetteville Shale play located in north central Arkansas, USA. The company’s acreage (red box) includes formations with complex structure as a result of regional rifting and uplift.
followed by compressional tectonics during the Ouachita orogeny of the Late Paleozoic era. The rifting generated large, northeast-striking normal faults, whereas the later tectonic events are characterized by north-striking thrust faults. The present-day maximum horizontal stress orientation, a product of later relaxation, is northeast to southwest.

The reservoir is subdivided into upper, middle and lower Fayetteville intervals. The upper Fayetteville has streaks of high gas-filled porosity and abundant natural fractures, which can be stimulated at low treatment pressures. The middle Fayetteville has relatively high concentrations of illite and smectite clays and is characterized by higher fracture gradients and lower effective porosity. The lower Fayetteville is subdivided into three zones; the middle layer is the main target interval of the three because of its low clay content and high gas-filled porosity. Natural fractures, both open and mineralized, are present throughout the lower Fayetteville interval.

Because of a wide range of well production performance, Southwestern Energy initiated a multidisciplinary study to characterize the Fayetteville Shale and identify the main production controls. The study covered three areas of about 10 mi² [26 km²] each. A 3D earth model, built using the Petrel seismic-to-simulation software, was a crucial component in the analysis. To build the model, geologists systematically integrated data from a number of sources including petrophysics, seismic surveys, geomechanics and fracture models (above). In addition, a single-phase fluid model was used with the ECLIPSE reservoir simulation shale gas module. The 3D model included a dual porosity option for history-matching and production forecasting.

To build the 3D earth model, geologists started by constructing a geologic model, following a workflow that used data from core samples—X-ray diffraction, scanning electron microscope, thin sections, vitrinite reflectance, pyrolysis and TRA data. Next, they added calibrated log data that included triple-combo openhole logs, geochemical logs, Sonic Scanner and DSI dipole shear sonic imager logs and FMI wellbore images, which were acquired from vertical pilot wells. Geochemical data from the ECS tool provided key mineralogic information and were calibrated with core data.

Living earth model workflow and input. Engineers and geologists build the 3D earth model by integrating data from multiple sources. They use geologic data from cores and well logs along with seismic data to construct a static model. Reservoir simulation software is used to populate the model with data from vertical and horizontal wells. Engineers create well spacing plans and design hydraulic stimulation programs to maximize production. Microseismic data can be used to validate the model and improve future fracture stimulation and well planning. The reservoir model is updated as new data become available.
Parameters commonly associated with shale resource evaluation, such as Langmuir isotherms, TOC, initial GIP and adsorbed versus free gas, were measured and then extrapolated from a single-well scale to a basinwide scale using 3D surface seismic surveys. Because lateral changes in petrophysical properties across shale basins are usually subtle, this extrapolation was accomplished without sacrificing the variability of the finer resolution data. Geologists were also able to correlate specific lithologies to natural fractures. Using production logs, engineers could correlate lithofacies to intervals with natural fractures that exhibited higher flow rates of gas after fracture stimulation.

Engineers next developed a structural model using seismic data that was further refined using log-derived geomechanical data. Downhole data included fracture gradient, Poisson’s ratio, Young’s modulus and natural fracture density. A fracture model based on discrete fracture networks was created from image logs, which were calibrated with core data and microseismic events. Engineers took a multiple pseudo-3D hydraulic fracture model approach to predict fracture characteristics for each stage of each well in the study. They modeled half-length, fracture height, fracture conductivity variations and elements of fracture geometries and then used these data in the reservoir simulation model. Natural fracture orientations, based on interpretations from image logs, were included in the model.

Engineers further developed the structural model by populating it with reservoir properties from the geologic model. The properties that were used are similar to those of conventional reservoirs and include porosity, permeability and hydrocarbon saturation. However, for shale plays, the porosity is calibrated to core data and may come from the average of several different sources. Permeability may be derived from core data, although the ultralow permeabilities of shales make a direct measurement practically impossible. Thus, engineers applied a core-derived porosity-permeability transform to downhole log data to compute permeability.

The 3D earth model included flow simulation as well. Developing a flow simulation model for ultratight rocks requires knowledge of the stress regime because the orientation of the grids used in the model can affect the computed results. In the case of the Fayetteville Shale simulation, the grid cells were created with one side parallel to the maximum horizontal stress direction and the other side parallel to the horizontal well paths. This information was provided by the structural model, which indicated that the present-day maximum horizontal stress direction is northeast to southwest.

The Bigger Picture

By integrating these various data, engineers created the full 3D earth model, which helped them characterize the Fayetteville Shale reservoir (left). The model was used to develop better drilling and completion programs, as, for example, when it was used to analyze and improve hydraulic fracture stimulations.

Hydraulic fracturing can be the most expensive process in the completion and development of resource plays, and it has the greatest impact on effectively producing the well. Completion engineers concluded, based on results of post-stimulation production logs, that there was a direct correlation between in situ stresses and hydrocarbon production (next page, top right). Thus, knowledge of the stress gradient along the lateral wellbore provided completion engineers with a tool for optimizing stimulation programs. In addition, knowing the horizontal stress orientation assisted drilling engineers in selecting better wellbore trajectories for drilling laterals. Borehole stability is improved when drilling in the direction of minimum horizontal stress.

Because some wells had lateral lengths in excess of 5,000 ft [1,500 m], significant variations in reservoir properties were encountered along the lateral wellbores. The 3D earth model provided engineers with more-accurate design parameters for the fracture stimulation program than would have been possible by projecting properties of a vertical borehole section some distance away. Following each stimulation treatment, the fracture model was updated using production history-matching.

As the study progressed, engineers observed that fracture height growth varied in different parts of the basin. In the early stages of development, microseismic data indicated that fracture stimulation extended from the lower Fayetteville Shale into the uppermost Fayetteville Shale interval. However, they discovered that some wells did not produce as expected because the stimulation was not reaching the upper layer.
Reservoir engineers attributed the differences in fracture growth to areas with higher clay content in the middle Fayetteville Shale interval. The presence of more clay resulted in higher in situ stresses, which inhibited fractures from growing into the upper layers. Engineers identified these anomalies by analyzing the 3D earth model.

Tangible results from the optimization process, which included drilling and stimulating longer lateral sections, performing optimized fracture stimulations and increasing operational efficiencies, were evident in the continuous improvements seen from 2007 to 2011 (below). The number of days to drill a well decreased by more than 52% even as the lateral length of the average well increased by more than 84%. Average production increased dramatically, almost sevenfold, but well costs remained virtually unchanged during the period.

Resource plays are capital intensive, but because they typically cover large geographic areas, operators benefit from economies of scale and operating flexibility. Identifying and developing the sweet spots significantly improve the economics and ROI. The ultimate measure of success is production: In October 2011, Southwestern Energy reported gathering approximately 2.0 Bcf/d [56.6 million m^3/d] in gas production from the Fayetteville Shale play.

![Production contribution obtained from PL analysis. The lateral well (blue line) passed through low (red) and high (blue) in situ stress intervals. The hydraulic fracture stimulation consisted of five stages with three perforation clusters per stage (green ovals). Poststimulation PL data were then acquired. The red lines extending below each perforation cluster represent gas production normalized to the maximum contributor. The length of each red line represents normalized flow. The first two stages (dashed red ovals), at the toe of the well, were in the high stress zones. Only 16% of the flow came from these stages. The other 84% of production came from the three stages (dashed yellow ovals) located in the intervals of lower stress. Engineers can use this type of information to identify sweet spots and avoid expensive fracture treatments in zones with low production potential.](image)

|^ Production contribution obtained from PL analysis. The lateral well (blue line) passed through low (red) and high (blue) in situ stress intervals. The hydraulic fracture stimulation consisted of five stages with three perforation clusters per stage (green ovals). Poststimulation PL data were then acquired. The red lines extending below each perforation cluster represent gas production normalized to the maximum contributor. The length of each red line represents normalized flow. The first two stages (dashed red ovals), at the toe of the well, were in the high stress zones. Only 16% of the flow came from these stages. The other 84% of production came from the three stages (dashed yellow ovals) located in the intervals of lower stress. Engineers can use this type of information to identify sweet spots and avoid expensive fracture treatments in zones with low production potential.|

![^Continuous process improvement. Over a four-and-a-half year period, from 2007 to 2011, Southwestern Energy reduced days to drill (dark blue) by 52%, even though the lateral length was increased by more than 84% (pink). Well costs (dark red) were flat to slightly lower during the period but the company’s finding and development costs (F&D, light blue) were significantly reduced during the period. Production (gold) and reserves (green) greatly increased during the study period. (Data for 2011 are for the first six months of the year.)](image)|
Postfracture Evaluation

The final, and often neglected, component in optimizing production from resource plays is production analysis. Considerable effort goes into determining reservoir qualities and developing complex models to identify zones within the reservoir with the greatest potential. Drilling engineers analyze wellbore properties and use geosteering to direct the well into the areas perceived to have the best RQ and CQ. Completion engineers design stimulation programs to maximize production by concentrating on rocks with the best CQ. These efforts can identify most likely candidates for production, but they rarely address small-scale variations that exist within the resource. PL data provide empirical proof of production and offer the potential for identifying reservoir characteristics that differentiate zones with the greatest potential (below).

A recent large-scale study from six US gas shale basins demonstrated the benefits of PL data for resource play development. The study attempted to highlight characteristics that engineers could incorporate in development workflows to improve overall efficiency. One disturbing finding was that in only 20% of the wells were all the perforation clusters contributing to production. In two Arkoma basin Woodford Shale horizontal wells, only half of the clusters were producing gas.

Shale resources are viewed by some as large monolithic structures; however, heterogeneity caused by variations in rock properties occurs vertically at extremely small scales in these reservoirs. Furthermore, the presence of natural fractures can introduce large variations in rock mechanical properties within a small area. If this variability is not accounted for in stimulation design, wells may not achieve expected results.

Engineers may be able to use PL data to correlate gas production with differences in rock or geomechanical properties. Wellbore geometry and completion practices that may affect production can be observed in PL data as well. The PL study, which included data from more than 100 wells, assessed various common practices used in shale gas wells and evaluated their effects on production.

Wellbore trajectory—Initially, most horizontal shale wells were drilled uphill with deviations that exceeded 90 degrees. This was done to facilitate gravity drainage of fracture fluids to the heel of the lateral and help unload the fluids more quickly. In some shale plays, this practice has been replaced by drilling laterals on structure, regardless of trajectory. However, the ideal trajectory is more than 90 degrees with minimal sumps and doglegs while remaining in the target zone. One trend evident from the data is that wells with high flow rates can effectively unload the fracture fluids regardless of trajectory and can overcome detrimental effects related to wellbore geometry.

Fracture staging—Well productivity improves with the number of fracture stages. An increase in the number of stages often correlates with longer laterals, thus contact with more of the reservoir. However, the study indicated that stimulating shorter sections of the lateral has a positive impact on production, even when the data are normalized for increased lateral lengths. Thus, while the length of laterals has increased over the last few years, the segment lengths that are stimulated per stage have decreased.

The study analyzed the effects of fracture stage spacing—the distance between stages. Engineers observed that for most shale plays, spacing in the range of 100 ft [30 m] resulted in the best production. They concluded that any increase in stress associated with previous stimulation treatments did not adversely affect the productivity of subsequent stages when this spacing was utilized. An exception to this finding was in the Barnett Shale, where there was no clear correlation between stage spacing and productivity. Engineers attributed this difference to the structural environment of the Fort Worth basin.

Because natural fractures in the Barnett Shale tend to run orthogonal to the hydraulically induced fractures, a complex fracture network can be achieved during stimulation. Therefore, closely spaced stages provide less benefit compared with those of other shale plays. This finding illustrates the importance of understanding the geologic setting of a reservoir and its impact on completion quality. The practical result is that an

<table>
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<th>Well A</th>
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<tr>
<td>1,000</td>
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<tr>
<td>3,000</td>
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<table>
<thead>
<tr>
<th>Well B</th>
<th>Rate for each cluster, bbl/d equivalent</th>
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<tbody>
<tr>
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<td></td>
</tr>
<tr>
<td>15,000</td>
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<td>TVD, ft</td>
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<tr>
<td>Measured depth, ft</td>
<td>8,200 8,600 9,000 9,400 9,800 10,200 10,600 11,000</td>
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^Production log comparison. These PL logs are from two different Woodford Shale wells in the Arkoma basin. The red and gold vertical lines along the well trajectory indicate perforation cluster locations. Red shading represents gas in the wellbore; blue shading indicates water. The PL data from Well A (top) show variable production with only three clusters contributing significantly to the total gas produced and three clusters producing most of the water (measured rates for individual clusters shown in top track). Three clusters (gold lines) are not contributing anything. Production in Well B (bottom) is more uniform. Most clusters are contributing equivalent amounts, although the first and last clusters (gold lines) are not contributing. Although water is present at the toe, no water production is indicated in Well B. (Adapted from Miller et al, reference 11.)
optimized stimulation methodology in one basin may not transfer to another.

The PL study also analyzed fracture stage designs by comparing theoretical production to measured production. Theoretical production was defined as the production rate if all stages produced equally. The study found that for every two wells completed, with an average of eight stages per well, there was at least one stage that contributed nothing. In addition, multiple perforation clusters were not contributing at the theoretical level. Again, these findings had basin-specific attributes. The percentage of stages producing at least half of their theoretical rate ranged from 18% for the Marcellus Shale in the northeast US to 33% for the Haynesville-Bossier Shale in north Louisiana and east Texas.

Perforation cluster—Analysis of perforation cluster productivity provided few clear trends, and results were often basin specific. Whereas the Barnett Shale was effectively stimulated with a single cluster per stage, Woodford Shale wells with four clusters per stage outperformed those with eight clusters per stage. Apart from these basin-specific characteristics, the results illustrate that it is very difficult to effectively stimulate multiple perforation clusters per stage. For example, almost half of the clusters in the wells with six perforation clusters per stage were not contributing at the time of production logging. This contrasts with an average of 20% of the clusters not contributing when only two perforation clusters were included per stimulation treatment. The current trend is toward fewer perforation clusters per stage.

Along with the number of perforation clusters, the spacing of the clusters also affects production. The cluster spacing for the wells in the study ranged from 36 to 421 ft [11 to 128 m]. The results suggest that a cluster spacing of less than 125 ft [38 m] produces superior results. Operators have recognized the apparent correlation between cluster spacing and productivity, and more recently, developed shale plays are utilizing closer cluster spacing. As before, however, this trend did not hold true for the Barnett Shale, where acceptable results were achieved even with spacings in excess of 175 ft [53 m].

Applying the lessons—The analyses indicate some findings are basin specific, others are well specific, and some indicate that there is no established trend. PL data provide information about what is happening in the well at the time of logging, but geologists and engineers may be able to correlate the differences in production with lateral variations in reservoir characteristics. For example, image logs can provide information about lateral variations, such as fractures, mineralogy and changes of the stress regime. However, these data are infrequently available after the initial information-gathering phase of development in shale plays as operators focus on operational efficiencies and cost reduction. This makes it difficult to correlate PL results to formation properties.

In one horizontal well, engineers ran an FMI tool in open hole and PL logs after completion and stimulation (above). Geologists derived microresistivity logs from the FMI image data from which they could qualitatively determine mineralogy. Low resistivity often corresponds to high clay content and high resistivity corresponds to better quality rocks. Lower clay content rocks have lower in situ stress and higher Young’s modulus, and they are more likely to retain fracture conductivity during production. Of five fracture stages in the well, the three stages that were performed in zones identified as low clay content outperformed the two in clay-rich rocks. Engineers can optimize staging, isolation of high stress intervals, cluster placement and proppant scheduling when these data are available.

Evolution or Revolution?
To develop resource plays, the oil and gas industry faces challenges that go beyond technology, and these challenges should not be minimized. There are political, environmental and perceptual issues that have little to do with drilling and producing hydrocarbons from the shale formations that are found around the globe. The industry focuses primarily on the technical elements, although the others are crucial considerations.

E&P companies have proved that, after three decades of development, resource plays are viable targets for exploration. Rocks that were once considered practically worthless from a production standpoint are now supplying the US with abundant supplies of natural gas. In an environment with low natural gas prices brought on by the success of organic shale development, operators will need to continue using innovation, technology and engineered solutions to improve profitability while developing resource plays.

What has been demonstrated over the last decade is that the revolution that began in the Barnett Shale has not stopped there. As technology evolves, the revolution is poised to become a global endeavor (see, “Shale Gas: A Global Resource,” page 28).

—TS