U.S. Shale Gas

An Unconventional Resource. Unconventional Challenges.

WHITE PAPER

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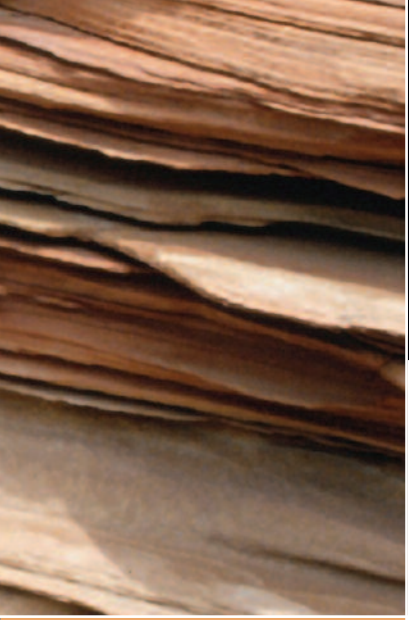

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Executive Summary

Current increasing demand and lagging supply mean high prices for both oil and gas, making exploitation of North American unconventional gas plays suddenly far more lucrative for producers. One of the most important such plays to emerge has been U.S. shale gas, with current recoverable reserves conservatively estimated at 500 to 1,000 trillion cubic feet.

Hydraulic fracturing and horizontal drilling are the key enabling technologies that first made recovery of shale gas economically viable with their introduction in the Barnett Shale of Texas during the 1990s. However, a comparison of the currently hottest shale plays makes it clear that, after two decades of development and several iterations of the learning curve, best practices are application-dependent and must evolve locally.

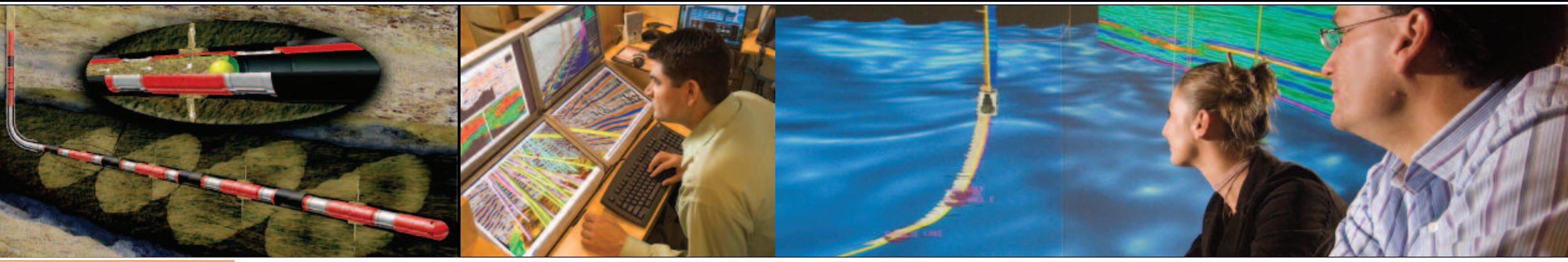
That said, a review of current trends in these hot plays indicates that, in many cases, the impact of high-drilling density required to develop continuous gas accumulations can be minimized through early and better identification of the accumulation type and size, well-designed access and transportation networks, and cooperative planning and construction efforts, when possible.

U.S. Shale Gas Geographic Potential

Across the U.S., from the West Coast to the Northeast, some 19 geographic basins are recognized sources of shale gas, where an estimated 35,000 wells were drilled in 2006. Presently, significant commercial gas shale production occurs in the Barnett Shale in the Fort Worth Basin, Lewis Shale in the San Juan Basin, Antrim Shale in the Michigan Basin, Marcellus Shale and others in the Appalachian Basin, and New Albany Shale in the Illinois Basin.

But it wasn't always so.

Lacking an efficient means of production, U.S. shale gas reserves were largely ignored so long as market conditions made reserves more costly to produce than conventional sources. In fact, one of the first recognized major shale gas plays, the Barnett Shale of Texas, was under investigation as early as 1981, but not until 1995 was the hydraulic fracturing technology available that successfully brought in the gas at commercial rates. Then, five of the initial six wells each began producing more than two million cubic feet of gas per day and, soon after, introduction of horizontal drilling began to extend the basin where today two percent of all the gas consumed daily in the U.S. is produced.



Evolution of a Shale Play

Typically, exploitation of a shale play proceeds through three distinct phases, from the discovery stage, through drilling and reservoir evaluation, to production.

Discovery and planning is the stage during which all of the initial reservoir knowledge is gathered. Extensive analysis including coring establishes the economic viability of the play during this phase, and helps determine the techniques to be used to optimize the development. The effectiveness of planning accomplished in the discovery stage depends largely upon knowledge of the reservoir.

Drilling and reservoir evaluation is the operational phase. During this stage, the focus is on applying the planned techniques most efficiently to maximize reservoir contact and lower cost per unit. It is in this stage of development that the issues concerning infrastructure and practical efficiencies are addressed. And this is the present state of several currently hot shale plays.

Production phase focuses on optimizing reservoir drainage, which in U.S. shale gas plays typically requires stimulation, usually by hydraulic fracturing. The efficiency of these completion operations can have significant impact during the production phase; with proper fracturing and placement of proppants, some shale wells have been producing for decades.

The Problem with Shale

Despite its geographic abundance and enormous production potential, gas shale presents a number of challenges – starting with the lack of an agreed-upon definition of what, exactly, comprises shale.

Shale makes up more than half the earth's sedimentary rock but includes a wide variety of vastly differing formations. Within the industry, the generally homogenous, fine-grained rock can be defined in terms of its geology, geochemistry, geo-mechanics and production mechanism – all of which differ from a conventional reservoir, and can differ from shale to shale, and even within the same shale. Little wonder there is no industry-standard definition.

Nevertheless, all shale is characterized by low permeability, and in all gas-producing shales, organic carbon in the shale is the source. Many have substantial gas stored in the free state, with additional gas storage capacity in intergranular porosity and/or fractures. Other gas shales grade into tight sands, and many tight sands have gas stored in the adsorbed state.

Since these various conditions determine the production mechanism of the various shales, knowledge of local reservoir characteristics is of vital importance in keeping development costs under control and optimizing production over the life of the reservoir.

Every Shale is Different

Due to the unique nature of shale, every basin, play, well and pay zone may require a unique treatment. Briefly comparing the characteristics of some of the current hottest plays can help illustrate the impact of these differences throughout development.

The Barnett Shale: Setting the Standard

With current assets still exceeding an estimated 10 trillion cubic feet, the spectacular success in the Barnett in 1995 established the economic potential of U.S. shale gas production and set the standard for subsequent development in other basins.

Horizontal drilling and hydraulic fracturing are the key enabling technologies that first made recovery of Barnett shale gas economically viable in the mid-1990s. Today, completion and drilling techniques are well established there, and drilling efficiencies continue to improve even as laterals extend to increasing lengths. A typical lateral is 2,500 feet to 3,000 feet. Use of water-based muds is standard, as is cementing with acid soluble cement. A typical Barnett completion is Tubing Conveyed Perforating toe then fracturing in stages using pump-down plugs and guns.

In addition to drilling longer laterals, current trends in the Barnett are toward bigger frac jobs and more stages. Infills are being drilled and testing of spacing is down to 10 acres, while re-fracturing of the first horizontal wells from 2003 and 2004 has commenced; both infills and refracs are expected to improve Estimated Ultimate Recovery from 11 percent to 18 percent. In addition, pad drilling, especially in urban areas, and recycling of water are growing trends in the Barnett, as elsewhere.

The Woodford Shale – Oklahoma

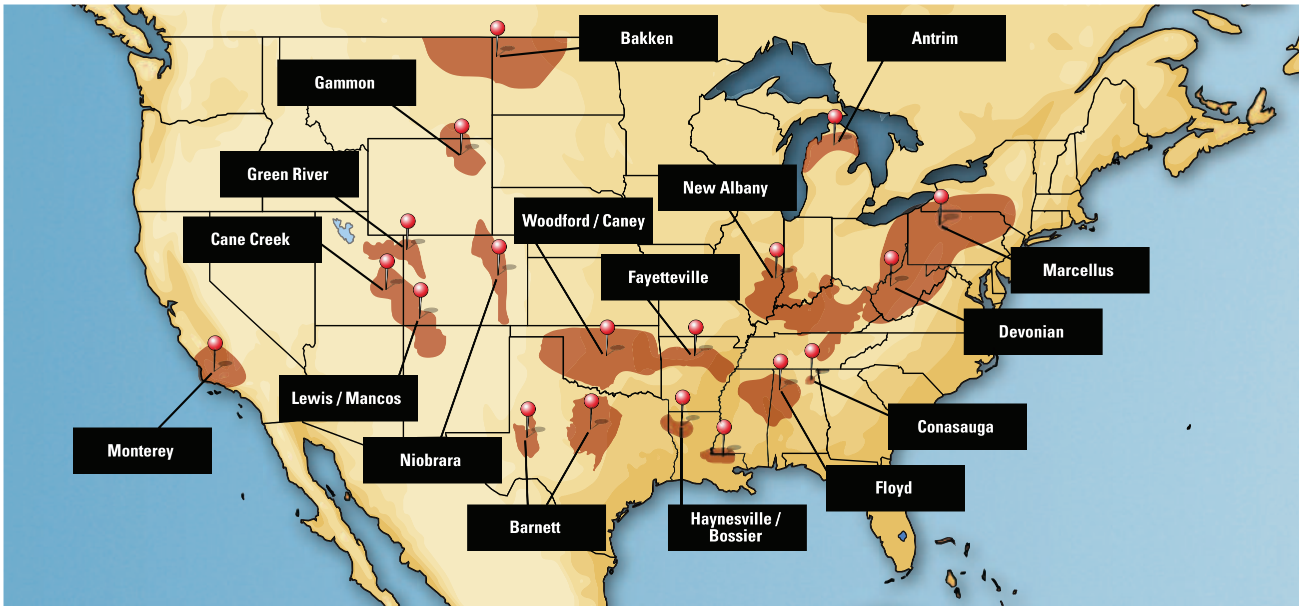
Woodford shale stratigraphy and organic content are well understood, but due to their complexity compared to the Barnett shale, the formations are more difficult to drill and fracture. Because shales have the most elements and chemostratigraphic information to work with, they are more easily analyzed than most sandstone and carbonate reservoirs and can be Chemosteered with unprecedented resolution using LaserStrat® services.

As in the Barnett, horizontal wells are drilled, although oil-based mud is used in the Woodford and the formation is harder to drill. In addition to containing chert and pyrite, the Woodford play is more faulted, making it easy to drill out of the interval; sometimes crossing several faults in a single wellbore is required. Halliburton geosteering techniques in combination with logging while drilling tools can minimize this risk.

Like the Barnett shale, higher silica rocks are predominant in the best zones for fracturing in the Woodford play, although the Woodford has deeper and higher frac gradients.

ZoneSeal® cement has significantly improved the success rate of frac jobs here, although acid and/or sand slugs are sometimes required to gain entry.

Due to heavy faulting, 3-D seismic is extremely important, as the Woodford trends toward longer laterals exceeding 3,000 feet with bigger frac jobs and more stages. Testing infill pilots has begun, as well as some simultaneous-frac jobs. Pad drilling also will increase as the Woodford continues expanding to the Ardmore Basin and to West Central Oklahoma in Canadian County.



The Haynesville Shale – East Texas / Northwestern Louisiana

Still in the early discovery stage, the Haynesville shale environment already has proved especially challenging. Compared to the Barnett, the Haynesville is extremely laminated, and the reservoir changes over intervals as small as four inches to one foot. In addition, at depths of 10,500 to 13,500 feet, this play is deeper than typical shales creating hostile conditions. Average well depths are 11,800 feet with bottomhole temperatures averaging 300°F and wellhead treating pressures that exceed 10,000 psi. As a result, wells in the Haynesville require almost twice the amount of hydraulic horsepower, higher treating pressures and more advanced fluid chemistry than the Barnett and Woodford shales.

The high-temperature range, from 260°F to 380°F, creates additional problems in Haynesville's horizontal wells, requiring rugged, high-temperature/high-pressure logging evaluation, Toolpusher™ and LWD tools. For these conditions, the availability of SOLAR™ tools from Sperry Drilling Services has proved a plus, particularly as logistics issues begin to emerge.

Already, there are issues with availability of casing and proppant supplies as producers increase demand under pressure to complete wells before their leases expire. The majority of Haynesville leases are held for just three years, and with acreage leasing for up to $25,000 per acre, producers are concerned about their ability to drill in time.

Durable high-horsepower pumping equipment will be required to effectively fracture stimulate the Haynesville. Halliburton is positioned to provide the maximum horsepower necessary in these types of formations. Additionally, Halliburton's pump reliability is well established in the industry. The formation depth and high-fracture gradient demand long pump times at pressures above 12,000 psi. In these deep wells, with fracture gradients of one psi/ft, and low Young's modulus, there is also concern about the ability to sustain production with adequate fracture conductivity.

Currently, Haynesville wells are being drilled with oil-based muds, and as the trend continues toward increased activity, environmental issues will come to the fore. The estimated 115-plus rigs that will be drilling this play will require large volumes of water for fracturing, making water conservation and disposal a primary issue.

The Bakken Shale – Williston Basin

The Bakken differs from other shale plays in that it is an oil reservoir, a dolomite layered between two shales, with depths ranging from around 8,000 to 10,000 feet. Oil, gas and natural gas liquids are produced.

Each succeeding member of the Bakken formation – lower shale, middle sandstone and upper shale member – is geographically larger than the one below. Both the upper and lower shales, which are the petroleum source rocks, present fairly consistent lithology, while the middle sandstone member varies in thickness, lithology and petrophysical properties.

Currently, Bakken oil wells are completed either openhole or with uncemented liners, and the use of isolation tools such as Halliburton Delta Stim® sleeves and Swellpacker® systems is extensive. The Bakken is not as naturally fractured as the Barnett and, therefore, requires more traditional frac geometries with both longitudinal and transverse fractures. Diversion methods are used throughout hydraulic frac treatments, which primarily use gelled water frac fluids, although there is a growing trend toward the use of Intermediate Strength Proppant. Compared to the Barnett, rate treatments in the Bakken typically are lower – from 30 to 50 bpm – with openhole completions requiring higher rates.

Recently, the Bakken has seen an increase in activity, and the trend is, again, toward longer laterals – up to 10,000 feet for single laterals in some cases. In addition, some operators are drilling below the lower Bakken shale and fracturing upwards.

The Fayetteville Shale – Arkoma Basin

With productive wells penetrating the Fayetteville shale at depths between a few hundred and 7,000 feet, this play is somewhat shallower than the Barnett. Mediocre production from early vertical wells stalled development in the vertically fractured Fayetteville, and only with recent introduction of horizontal drilling and hydraulic fracturing has drilling activity increased. As a result, at present there is less oilfield infrastructure in place in the Fayetteville than in other hot plays.

In the most active Central Fayetteville Shale, horizontal wells are drilled using oil-based mud in most cases, and water-based mud in others. Most wells now are cemented, but the current trend is toward using tools such as Halliburton's Delta Stim® sleeves and Swellpacker® systems technology in openhole completions. In addition, 3-D seismic will gain importance as longer laterals of 3,000-plus feet are drilled and more stages are required for fracing. With growing numbers of wells and a need for more infrastructure, pad drilling is another trend emerging in the Fayetteville.

The Marcellus Shale – Appalachian Basin

Currently the hottest play in the 54,000-square mile Appalachian Basin, the Marcellus formation is not a new discovery. Prior to 2000, this low-density, vertically fractured shale formation was explored with a number of successful vertical gas wells, many of which have produced – slowly but surely – for decades. However, not until the 2000 introduction of techniques pioneered in the Barnett shale, did Marcellus wells begin to yield significantly improved production rates.

The Marcellus shale ranges in depth from 4,000 to 8,500 feet, with gas currently produced from hydraulically fractured horizontal wellbores. Horizontal lateral lengths exceed 2,000 feet, and, typically, completions involve multistage fracturing with more than three stages per well.

To date, the heavy leasing activity has occurred primarily in one small geographic area where the thick shale can be drilled at minimum depths. As a result, the Marcellus play is still in the exploration stage, with trends toward inevitably deeper wells, longer laterals and more stages.

Summary

As these brief comparisons suggest, at every step of development in every shale gas play, best practices are application-dependent and must evolve to meet specific, local challenges. As techniques are refined and local best practices emerge, it remains to be seen if the rising star of the Barnett play will be eclipsed by these other up-and-coming shale gas plays.

Conclusions

Unconventional Resources Require Unconventional Solutions

As a source of abundant, high-quality natural gas, the potential of U.S. shale gas has only begun to be realized. While the challenges to producers may be significant— and significantly different from play to play—they are not insurmountable, providing the right technology and experience are on hand.

While conventional horizontal directional drilling technologies have been used to drill shale gas wells, in almost every case, the rock around the wellbore must be hydraulically fractured before the well can produce significant amounts of gas, and the cost of fracturing horizontal wells can be as much as 25 percent of the total cost of the well.

To keep development costs under control, there will be a need for improved exploration, production efficiencies and best practices that combine current knowledge and new approaches.

In most cases, multiwell drilling can afford improved efficiencies in hydraulic frac stimulation operations, enhancing the percentage of recoverable gas to boost production rates over the economic threshold, while pad drilling of several multilateral wells from a single pad will further improve the economies-of-scale and help reduce location costs while generating a minimal environmental footprint.

The unconventional challenges of shale gas drilling demand higher levels of service intensity. Halliburton is uniquely positioned to respond with integrated solutions for more productive and cost effective shale exploitation.

For more information contact us at:
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