Advances In Unconventional Gas

Solutions to meet growing gas demand worldwide.

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1616 S. Voss, Suite 1000
Houston, Texas 77057-2627
713-993-9320
Fax: 713-840-8585
www.hartenergy.com

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BILL PIKE

Director of Custom Publishing
MONIQUE A. BARBEE

Contributing Editor
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Art Director
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About the cover: Halliburton fracture stimulated Devon Energy's Haygood No. 11H near Carthage, Texas. (Photo courtesy of Halliburton)

Tight Sand, Shale, Coal

As contribution grows, low-permeability reservoirs face common challenges.

By John Kennedy, Contributing Editor

Demand for natural gas will continue to grow at a faster pace than that for oil because it is a cleaner fuel. Though global conventional gas reserves are significant, the cost of moving gas from large sources to large markets still makes it, to some extent, a regional fuel.

The United States and Canada are two regions facing a growing gap between natural gas demand and conventional supply. Development of unconventional gas resources is most advanced in North America, where it has the potential to help fill that gap.

Fully exploiting the potential of unconventional gas resources will depend heavily on the application of advancing technology and new strategies.

A 2003 U.S. National Petroleum Council (NPC) study concluded that of the total gas resource in North America of 1,969 Tcf about 20% is contained in shale, low-permeability sands and coal seams. The study estimated recoverable reserves from tight gas sands at 175 Tcf, coal seams at 148 Tcf and gas shales at 51 Tcf.

According to the U.S. Energy Information Administration's (EIA) Annual Energy Outlook 2006, the contiguous U.S. states' non-associated onshore conventional gas production will fall from 4.8 Tcf in 2004 to 4.2 Tcf in 2030; associated dissolved natural gas reserves will slip during the period from 2.4 Tcf in 2004 to 2.3 Tcf.

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Devon's Bridgeport natural gas processing plant is one of the largest in the country, serving hundreds of gas wells in the rapidly expanding Barnett Shale field in north Texas. (Photo courtesy of Devon Energy)

However, the EIA expects production of the Lower 48's onshore unconventional resources to increase from 7.5 Tcf in 2004 to 9.5 Tcf in 2030, when it will represent about half of that total for the same area's production. The largest share of that unconventional production will come from low-permeability sands.

Common Technology Needs

Gas from shale, low-permeability sands and coal seams each offers a large, onshore resource target to multiple players. These tempting targets also pose special challenges.

Unconventional gas reservoirs are found in heterogeneous, complex and often poorly understood geologic systems. Understanding those systems is more difficult than understanding many conventional reservoirs and arguably more critical to economic success.

The defining characteristic of unconventional gas reservoirs – low permeability – makes effective stimulation and a large number of precisely placed wellbores keys to commercial production and recovery.

Though there are technologies more critical to one unconventional resource than others, the common characteristic of low permeability means many technology needs are common to all.

In a presentation at the Hart Unconventional Gas Conference in March, Kent Perry, director of exploration and production research with the Gas Technology Institute, listed 10 areas where improvement is needed to fully develop the potential of unconventional gas:

- reservoir characterization and imaging;
- stimulation;
- resource assessment;
- data mining;
- producibility models;
- produced water handling;
- extending well life;
- drilling cost reduction;
- horizontal well completion; and
- expert systems.

If one of these is most important, it is reservoir characterization, Perry said. Determining how much gas is available and at what depth as well as accurately defining the reservoir parameters are the foundation of a sound development strategy.

There is still much that is not known geologically, said Perry. "There are still a lot of unanswered questions about the size of these resources.

"Reservoir characterization is probably most critical in the case of gas shale. Coal seams might be considered the next most important in this regard. More is known about tight gas sands because they are the largest unconventional gas resource and have been studied for some time.

Some significant trends are under way, Perry said, including a shift "from horsepower to precision" in stimulation, significant reductions in drilling costs and the implementation of new development strategies.

The NPC report notes that as more unconventional gas resources are developed, the average permeability of the producing reservoirs will continue to decrease, requiring the industry to apply new technologies and best practices that enable wells to produce at economic rates.

The industry will be challenged to find methods to locate "sweet spots" in tight basin-centered gas fields, shale gas and coalbed methane reservoirs to reduce the number of marginally commercial wells being completed, according to the report.

In the United States, some help in pursuing the research and development needed to boost unconventional gas production will come from the Energy Policy Act of 2005. It provides research funds of $50 million annually for 10 years, and specifies that unconventional gas research will get $16.2 million.

Industry's traditional technology providers will perform most of the development.

Two Diversified Developers

Some operators are focused on one resource – gas shale, tight sand or coalbed methane. Other companies have developed large acreage positions and are aggressively developing more than one of these plays, sometimes all three.

XTO Energy Inc., for example, is active in tight sand reservoirs in East Texas, the Piceance Basin and elsewhere; in the Barnett Shale in the Fort Worth Basin; and in Powder River Basin coalbed methane development.

XTO's two big tight gas plays are the Freestone Trend in Texas and the Piceance Basin in Colorado.

"Freestone is one of the major drivers of our growth," said XTO President Keith Hutton.

The company entered the Barnett in 2004, and with an acquisition and expansion, became the second largest producer in the play. The company also has a significant position in other shale basins.

Its coalbed methane focus is on the Rocky Mountain region where per-well rates and reserves are "much better" than in other coalbed methane plays, Hutton said. The company entered San Juan in 1997, Raton in 2002, and the Powder River and Uintah basins in 2004.

Devon Energy Corp. is an aggressive developer of coalbed methane and shale gas. Its San Juan Basin success led Devon to other coalbed reservoirs. The company also helped the Barnett shale become such a successful play that it fueled interest by other operators and spurred exploration and development of other shale formations across North America.

Since 2002, when Devon boosted its position there by acquiring Mitchell Energy Corp., the company's Barnett Shale production has doubled.

The list of unconventional gas developers is long. Some have a narrow regional focus, others are pursuing a variety of low-permeability reservoirs.

> **"Unconventional gas development is a game of cost. You have to figure out what spacing to drill on and then how to cut your cost to drill."**
>
> Keith Hutton, XTO President

Think In New Ways

"Unconventional gas development is a game of cost," Hutton said. "You have to figure out what spacing to drill on and then how to cut your cost to drill."

Developers often face special environmental and regulatory challenges because of the need to drill many wells or dispose of large volumes of water.

It will take new ideas across a range of technologies to develop the remaining potential of gas shales, low-permeability sands and coal seams.

The Fruitland coalbeds and the Barnett Shale were not new places when they finally were targeted for development. They had been drilled through many times as operators looked for less complicated sandstone reservoirs above and below.

But, said Brad Foster, Devon's vice president and general manager for the central division, during the conference, "as University of Tulsa Petroleum Geology professor Parke A. Dickey said in 1958, 'sometimes, all it takes to reinvigorate an old place is a new idea.'"

Four things make unconventional gas plays work, he said:

- knowledge and expertise;
- technology and technology transfer;
- time to think and develop a strategy; and
- a healthy natural gas price. ■

Coalbed Methane

Water and fine-tuning technology to each zone are challenges for coalbed methane.

By John Kennedy, Contributing Editor

Devon drills in the Big George coal formation in the Powder River Basin. (Photo courtesy Devon Energy Corp.)

Coal is the world's most abundant hydrocarbon energy source. Volumes of methane-rich gas were generated and trapped when it was formed from plant material.

Until recent decades, this gas was known only as a hazard for underground coal miners. Now seen as a significant energy source in many parts of the world, development is most advanced in North America.

However, even there, serious exploitation of gas in coal seams is barely 20 years old and much of the resource remains undeveloped. Significant coal reserves extend from the northern reaches of Canada's Great Plains Coal Region in northern Alberta to the southern extent of the Gulf Coast Coal Region at the tip of Texas. More coal deposits are strung back northeast through the Black Warrior Basin to the upper end of the Appalachian Basin in western Pennsylvania.

Exploration costs are low, and improved dewatering techniques, horizontal wells with multi-seam completions and better control of fines have fueled coalbed methane's (CBM) growth development.

Despite the technical, economic and environmental challenges that remain, CBM reserves offer:

- low drilling costs, shallow depths;
- long life reserves, low decline rates and good production rates;
- large areas to explore, including bypassed opportunities; and
- advancing technology that can bring success in plays that failed earlier.

Still Much Potential

The growing club of coalbed methane producers in the United States includes large and small companies. Outside the United States, those involved in CBM projects tend to be major international companies with the resources needed to get development moving.

Section 29 tax credit incentives played a key role in the major companies' shift to natural gas in the 1990s and in establishing significant CBM production in the United States. Between 1990 and 1999, the companies using the credit increased their U.S. natural gas production by 26%, while other majors reduced their production by 14%.

During that period, growth in CBM production accounted for 57% of the overall growth in U.S. natural gas production, according to the U.S. Energy Information Administration (EIA).

The Gas Technology Institute (GTI) estimates total CBM resource in the continental U.S. to be 703 Tcf. Recoverable reserves are estimated at 63 Tcf from known resources, plus 110 Tcf from as-yet undiscovered resources. In addition, Alaska may have recoverable reserves of 57 Tcf from its total in-place resource of 1,045 Tcf.

Coalbed methane continues to be a significant source of gas in the United States, though production has reached somewhat of a plateau, said Vello Kuuskraa, president of Advanced Resources International (ARI).

"It is good to see that CBM production in the San Juan Basin continues to defy its expected demise," Kuuskraa said. "The real hope is to make deeper, lower permeability coals productive and economic, such as those in the Green River Basin and in the Piceance Basin. And advanced multi-seam completion technology for the thin multilayer mid-continent coals and the extensive Powder River coals is needed.

"If those technology barriers could be overcome there could be a second round of growth, but these are significant barriers."

Coalbed methane reserves in the

United States grew five-fold during 15 years, from 3.6 Tcf in 1989 to 18.3 Tcf in 2004, according to the EIA, accounting for almost 10% of U.S. dry natural gas reserves. Production in the United States has grown steadily, too, from 91 Bcf in 1989 to 1,720 Bcf in 2004, providing about 9% of U.S. dry gas production.

Together, Colorado and New Mexico, home of the San Juan Basin, account for about 60% of proved U.S. CBM reserves and production.

Fruitland coals alone, the San Juan Basin's most prolific reservoir, could contain between 50 Tcf and 100 Tcf of coal gas in place, said Barbara Wickman, Southern Ute Indian Tribe, Red Willow Production Co. at the Hart Unconventional Gas Conference last March.

Just Beginning

According to the Canadian Society of Unconventional Gas (CSUG), more than 3,000 CBM wells were drilled in 2005 and 3,500 more were planned for last year. Production was forecast to reach 700 MMcf/d by this year. The EIA recently cited predictions that Canadian CBM production could average more than 1,400 MMcf/d by 2010.

Most of Canada's CBM potential – and current activity – is in Alberta, where estimates put in-place reserves at 700 Tcf. An additional 80 Tcf is expected to be in place in British Columbia. Recoverable reserves, again mostly in Alberta, could be 75 Tcf.

In Alberta, where multiple coals underlie half of the province, according to CSUG, early activity is centered on:

- Horseshoe Canyon coals, the most mature development, with a 66-Tcf resource and current production of about 450 MMcf/d;
- Mannville coals, possibly a 300-Tcf resource, where the first commercial projects are under way and horizontal wells are encouraging; and
- Ardley coals, with an estimated 53 Tcf in place, where there is little current production but active evaluation.

"As the impact of CBM development on the province's water resources is evaluated, we may see the Ardley begin to be developed," said Michael Gatens, chairman of the board for Quicksilver Resources Canada Inc. "That success will grow over the next 2 to 5 years."

Other targets in Alberta also have potential, said Gatens, including those down south along the Crows Nest Pass area; in the traditional coal-mining areas in the north; in northeast British Columbia; even in Nova Scotia.

China and Russia

China is the largest consumer and producer of coal in the world, according to the EIA. BP, Chevron and others are developing CBM production in cooperation with China United Coalbed Methane Corp. (CUCM), which will participate in a number of ventures in northern, northwestern and northeast areas of China, according to a report by news agency *Xinhua.*

According to the report, a spokesman for the corporation indicated it has 26 contracts for CBM exploitation with foreign companies. The spokesman said CUCM produced 20 million cu m in 2005, and output was expected to hit 150 million cu m last year. In 2005, there were 330 CBM wells completed, more than the total of the previous decade, he said.

Russia, too, has large coal reserves. A report by L.A. Puchcov, S.V. Slastunov and G.G. Karkashadze of the Moscow State Mining University estimates the methane resource of Russian coal basins at 49 trillion cu m, including Kuzbass, 13.085; Pechora, 1.942; Eastern Donbass, 0.097; South Yakutia, 0.920; Ziryansk, 0.099; Tunguska, 20.0; Lensk, 6.0; and Taymir, 5.5.

According to the report, the Vorkutinskaya, Severnaya, Komsomolskaya and Zapaliarnaya mines in the Pechora coal basin have the highest methane content, with 380 million cu m, 362 million cu m, 292 million cu m and 298 million cu m per square km, respectively.

San Juan Players

"The San Juan Basin dwarfs everything" in CBM development, said Keith Hutton, president of XTO Energy Inc. "It has the best wells and the best economics."

Active primarily in the Rocky Mountain region because per-well rates and reserves are "much better," XTO's CBM production was about 160 MMcf/d in September, a rate it expects to double in the next 2 to 3 years. XTO first entered the San Juan Basin in 1997 and CBM production in the San Juan, Uinta and Power River basins now accounts for about 12% of the company's production.

Economics can be good for CBM even with the 2-year dewatering period, Hutton said. The wells XTO is drilling in San Juan toward the outer edge of the basin average 1 Bcf of reserves and cost between $400,000 and 500,000 to drill. That compares with Raton Basin wells at $500,000 to 700,000 to drill, also with 1 Bcf of reserves. In Uintah, wells cost between $700,000 and $1 million to drill and typically have reserves of 1.5 Bcf.

Powder River Basin is the cheapest at $150,000 per well and reserves of 500 MMcf per well, Hutton said.

Marathon Oil Corp. holds 390,000 net acres in the Wyoming portion of the basin. In mid-2005, it operated 3,100 coalbed natural gas wells. Average net daily production was 69 MMcf/d during 2004.

The Williams Cos. Inc. also is active in the San Juan Basin, operating more than 3,300 wells producing about 225 MMcf/d.

According to ConocoPhillips, as of March 31, the bulk of its CBM production was from the Fruitland Coal where net gas production averaged 470 MMcf/d in 2005. The company has an ongoing program to drill new wells, work over existing wells, add compression and install artificial lift.

Anadarko Petroleum Corp. operates multiple full-scale CBM properties as well as active pilot programs and continues to

Fenced off wellhead is tied in for production. (Photo from Canadian Society for Unconventional Gas courtesy MGV Energy.)

evaluate new CBM exploration opportunities across the Rocky Mountain region, according to the company. In mid-2006, it was focused on the Big George coal at the company's County Line property and the Atlantic Rim field in Wyoming, and the Helper and Drunkard's Wash fields in Utah.

In the second quarter, Anadarko's gross production reached 145 MMcf/d, compared with 131 MMcf/d in the first quarter, primarily because of dewatering of the Big George coals in the County Line field. Its Atlantic Rim development had sales of 5.9 MMcf/d during the quarter.

The company also has completed the Powder River Basin Water Pipeline to transport produced water from CBM wells to the Madison aquifer at Salt Creek. The line will reduce water-handling expenses and establishes a predictable cost structure for future water handling, according to Anadarko. The 48-mile (77-km) 24-in. line will handle between 400,000 b/d and 450,000 b/d of water.

Bill Barrett Corp. is also targeting the Big George. At the end of 2005, it had 53,040 net undeveloped acres, 20 MMcfe/d net production and 26 Bcfe of proved reserves, according to the company.

Nance Petroleum Corp. has an active coalbed gas development program under way in the Hanging Woman Basin, a sub-basin in the northern Power River Basin on the Wyoming-Montana state line.

Beyond San Juan

Black Warrior Basin extends from Alabama into northeastern Mississippi and contains Lower Pennsylvanian coals. *Oil and Gas Investor's* "Alabama Hat Trick," which appeared in last March's issue, reported that "since 1994, Black Warrior CBM wells have consistently produced in the vicinity of 310 MMcf/d and 325 MMcf/d of gas, combined. Operators have been able to pull off this decline-busting feat through steady drilling, adding hundreds of wells a year at average costs of around $350,000 each and recoveries of up to 400 MMcf of gas each."

Dominion Exploration & Production Inc. entered the Black Warrior in 1993 and early last year was producing a gross 60 MMcf/d, according to *Oil and Gas Investor*. By then it had drilled 1,000 wells in the play.

In Appalachia, Range Resources Corp.'s CBM now covers about 400,000 acres and production has reached 20 MMcfe/d. At the end of 2005, about 1,000 CBM wells had been drilled, with 3,000 remaining in inventory. Success with an infill-drilling pilot in the Nora field in Virginia could significantly boost the number of undrilled locations, according to the company.

Coast to Coast in Canada

Quicksilver Resources Canada established the Horseshoe Canyon play, the first commercial Canadian CBM production, in 2001. Half way through last year, "We're on schedule with our Horseshoe Canyon development drilling and in maintaining production," Gatens said.

By third quarter, the production decline had been offset with new production, and an increase of 15% was expected by year-end. Quicksilver-operated properties now produce about 90 MMcf/d to 100 MMcf/d, most coming from Horseshoe Canyon coal seams and associated sands; the company's net is about 50 MMcf/d to 55 MMcf/d.

Most of Quicksilver's budget for last year is for Horseshoe Canyon, but it is during this time that major new facilities construction will be needed, Gatens said. Now, the focus will be primarily on development drilling and well tie-in.

Quicksilver is in the process of evaluating the few horizontal wells it has drilled in Manville and is continuing to evaluate older vertical pilot wells.

In late 2005, Trident Exploration Corp. announced plans for commercial development of the Corbett Mannville CBM joint venture, expecting to reach a production of 150 MMcf/d by 2011. Trident is a joint venture between Nexen Inc. and Red Willow Exploration Co.

On the other side of the continent, Stealth Ventures Ltd.'s CBM project in the Stellarton sub-basin in Pictou County, Nova Scotia, contains an estimated 500 Bcf of natural gas in place in coal seams at depths between 1,313ft and 3,937ft (400m and 1,200m). Individual seam thicknesses range from 3ft to 10ft (1m to 3m) and total net coal thickness is as much as 394ft (120m.) The coals have gas contents in the tested coals between 100 scf per ton to 330 scf per ton, according to Stealth.

In June, Stealth began testing its Cumberland property, installing downhole pumping equipment and flow testing the 1,411-ft (430-m) open hole at Coal Mine Brook No. 3, the first completion test. The Cumberland subbasin is estimated to contain more than 1 Tcf of gas in place in coal seams at depths between 2,000ft and 8,000ft (610m and 2,440m).

China Projects

Chevron was the first multinational oil company to sign a contract with China's CBM development firm, according to Chevron. The company has interests in four onshore production-sharing contracts in the Ordos basin with CBM and conventional natural gas potential.

Far East Energy Corp. is exploring and developing CBM projects through its agreements with ConocoPhillips and CUCM. Far East's China projects could contain between 18.3 Tcf and 24.9 Tcf of gas in place with recovery as high as 50%. Shanxi has an estimated 6.55 Tcf to 9.8 Tcf of recoverable CBM resources, Enhong 1.10 Tcf and Laochang 1.55 Tcf. Enhong and Laochang coals range between 55ft and 62ft (17m and 19m) thick and tests show gas content between 200 cu ft and 500 cu ft of gas per ton.

In April, Far East began drilling its third horizontal well in the Shanxi Province project.

Adapt Technology to Each Setting

The high porosity of coal seams allows them to hold a lot of gas, but low permeability makes getting it out a challenge. Coal's natural fractures – cleats – are filled with water that exerts pressure on the coal and holds gas in place. When the water is produced, the pressure within the fractures decreases and gas desorbs from the coal. Once desorbed, the gas moves into and through fracture networks to wells.

Gas content generally increases by coal type as well as with coal bed depth and reservoir pressure; the deeper the coal bed, the less water is present.

With the easiest production developed, CBM producers face thinner coal seams, said Kent Perry, director of E&P research with the Gas Technology Institute. In the past, some seams were tens of feet thick; now there are many that are between 1ft and 2ft (0.3m and 0.6m) thick.

"Fracturing is almost everything in many coal plays," Hutton said.

Some water fracs are used, especially in the Powder River Basin. In other areas, large sand fracs are required along with some type of coal fines stabilization.

It's also important to draw down the pressure as low as possible and dewater effectively. "Because dewatering may take as much as 2 to 3 years, it does take some staying power to play the coalbed-methane game," he said.

To tailor technology to the development plan, it's best to "let the rocks talk to you," then use both practical observations and science, such as micro-seismic data and reservoir modeling, to help establish the best way to drill, complete and stimulate wells, Kuuskraa said.

"Adaptation of technology to each setting is a fundamental objective," he said. "And the more information you have on the reservoir, the better the adaptation."

Another top priority is to continue improving horizontal well and stimulation technologies in ways that do not create well damage. In many unconventional gas settings, for the first 6 months, the well is still cleaning up and may never reach its productive potential.

"Past use of heavy cements, high-weight drilling fluids plus gels and polymers in lower temperature settings are some of the reasons that wells never cleaned up," Kuuskraa said.

More Deliverability, Less Cost

The first CBM projects were developed with fracture-stimulated vertical wells. Then expansions began to be drilled with horizontal wells and from multi-well pads, and completed as single leg multi-seam or multilateral horizontal wells. In the process, the four surface locations typically needed for a site evolved to a single surface location that could develop four sites.

Equipment evolved, too. Today, for example, Quicksilver drills its wells with fit-for-purpose shallow gas single rigs or coiled tubing rigs.

"Both are working well, and we are approaching an average of 1 day or less per well for drilling," Gatens said.

In the Horseshoe Canyon play, efforts to reduce the surface impact of operations have resulted in a well footprint that can be as small as 10ft by 10ft (3m by 3m), according to CSUG. In "minimal disturbance drilling," no soil is stripped, and no location or built-up access road is constructed. Pipelines are plowed in.

Nitrogen fracs are typical in the Horseshoe Canyon formation where multiple seams must be stimulated and gas flows commingled to achieve economic production rates. Coiled tubing units allow multiple seams to be treated in a short time; individual coal seams are perforated and selectively fractured using gaseous nitrogen.

Regulators and Communities

The more wells that must be drilled, the greater the environmental issues and more important the need for a good relationship among operators, landowners and communities.

In the San Juan Basin, regulatory requirements are especially complex because of the many agencies and governments involved, including the U.S. Environmental Protection Agency, Bureau of Indian Affairs and Bureau of Land Management (BLM) at the federal level, as well as state and native-American tribal governments.

Regulatory issues include produced water disposal, compressor noise and air quality as well as the protection of cultural sites and ranching/farming/wildlife surface use. Spacing, for example, is an issue with tribes, the BLM and states.

Water production in San Juan can range from 0 b/d to 1,000 b/d of water; between 5 b/d and 200 b/d of water is common. Some agencies oppose pits, and the volumes are too large to evaporate or flow downstream, so most operators lay water pipe with gathering lines and inject into their own wells, Wickman said.

The regulatory environment in Canada is on a par with that in Michigan, California or New York, said Gatens, and some requirements are quite stringent.

Another complication is that a typical resident landowner does not own the mineral rights. The Alberta government has tried to develop practices that allow development of the resource for all taxpayers, while facilitating the relationship between industry and landowners, Gatens said.

Carbon Dioxide Injection: Two Benefits

Another feature of coal seams is their high affinity for carbon dioxide (CO_2). When coal seams with adsorbed methane are exposed to the CO_2, the molecules replace the adsorbed methane molecules.

This feature is the focus of growing attention because coal seam gas production could be enhanced with CO_2 while the reservoir also serves the goal of CO_2 sequestration.

With the increasing attention to CO_2, there is also new interest in the use of CO_2–based frac fluids. When used to stimulate a coal bed, the CO_2 releases more methane, but stays locked in the coal seam.

However, the diffusion of methane-CO_2 mixtures of variable concentrations in the cleat and pore systems is not fully understood, according to GTI, and more research and development on this process are needed.

	Reserves, Bcf		Production, Bcf	
	1999	2004	1999	2004
United States	13,229	18,390	1,252	1,720
Alabama	1,060	1,900	108	121
Colorado	4,826	5,787	432	520
New Mexico	4,080	5,166	582	528
Utah		934		82
Wyoming		2,085		320
Eastern states (Pennsylvania, Virginia, West Virginia)		1,620		72
Western states (Kansas, Montana, Oklahoma)		898		77
Other*	3,263		130	

Source: US Energy Information Administration. *Prior to 2000, Other States includes Kansas, Montana, Oklahoma, Pennsylvania, Utah, Virginia, West Virginia, and Wyoming.

U.S. Coalbed Methane Reserves and Production

Two Looks at Technology Needs

In preparing its Technological Roadmap for Unconventional Gas Resources, GTI's survey of operators turned up a number of top priorities. Many were common to all unconventional gas sources, but some are unique development challenges.

For example, participants cited 3-D characterization of the lateral continuity of reservoir beds, and other reservoir properties as especially important for CBM operators. Because coal seams must be dewatered, water is a special issue with CBM development. CBM producers would welcome downhole water separation and injection, ways to produce less water and improved surface water treatment.

"It's rare in any area to not have water issues, either produced water handling or a supply of fresh water for drilling and completion," Perry said. "Water issues need more work and continued research."

Projects in new areas also face special challenges, according to the GTI report. Coal seam permeability, which governs the dewatering and degassing processes, cannot be determined prior to drilling with any degree of reliability, for example. In addition, well placement in thinner coal seams is difficult.

Another report resulted from a series of three workshops sponsored by the U.S. Department of Energy's National Energy Technology Laboratory. Issued in November, *Technology Needs for U.S. Unconventional Gas Development* cited these major areas in which CBM technology needs improvement:

- *multizone well completion*—Improved construction of fishbone well patterns and directional control within thin coal formations;
- *smaller well footprint*—Ability to drill and produce from small surface locations and with greater well spacing;
- *rapid technology transfer*—Rapid dissemination of best field practices;
- *produced water technology*—The ability to change produced water from waste to resource;
- *improved gas recovery per well*—More effective well stimulation techniques and new technologies; and
- *technology integration/development planning*—A systematic approach to field development that integrates all technology. ■

Effective Multizone Stimulation and Controlling Fines

Keys to successful coalbed-methane production.

New fracturing fluids and additives have been developed specifically for coalbed methane (CBM) and unconventional gas reservoirs:

- For cross-linked gel fracturing, Delta Frac® CBM has been optimized for lower temperatures to provide further reduction in permeability damage based on regained permeability testing.
- HpH Foamer™ surfactant, a new foaming agent designed to reverse its foam character upon flowback has been incorporated into a new CBM foam fracturing system. This system reduces the damage conventional foamers can have on production in CBM wells.
- For water fracturing, a new CBM system, Water Frac™ CBM, has been developed incorporating a low-damage friction reducer. Additives including GasPerm 1000™ agent and SandWedge® enhancer provide high-value solutions to help achieve ultimate well performance in CBM reservoirs.
- CoalStim℠ service has recently achieved success in primary stimulation of horizontal laterals and use as a pre-pad and primary fracturing fluid.

CoalStim Service

An operating company exploring for and producing coalbed methane from vertical wells in the eastern United States has increased its anticipated 5-year cumulative CBM production by 40%, and its estimated ultimate recovery (EUR) by 57% in three wells selected for a pilot study. The production improvement was seen in wells that were in the third phase of the CBM well lifecycle. The five phases of CBM wells are:

- regional resources reconnaissance;
- local asset evaluation;
- early development;
- mature development; and
- declining production.

The wells in the study were treated with CoalStim post-fracture service, which has been used to reverse production declines in more than 1,000 CBM wells in the western United States. In some cases, entire fields have been treated with treatment payout being as short as 9 days.

The service helps remove wellbore damage and coal fines blockage with a powerful back flush and can restrict the mobility of formation fines (coal, shales, clays). The service degrades polymer left from

Case	CBM Refrac 1	CBM Refrac 2	CBM Refrac 3
Gas produced 9 months after initial stimulation (Mcf)	463,747	88,406	72,452
Delta gas 9 months after refrac (Mcf)	179,071	408,818	268,294
at $2.50 per Mcf	$447,677.50	$1,022,045.00	$670,735.00
Rate of Interest of refrac after 9 months (approximate)	3.37:1	9.22:1	5.71:1
Time to pay out of stimulation treatment	3 weeks	3 weeks	1.33 months

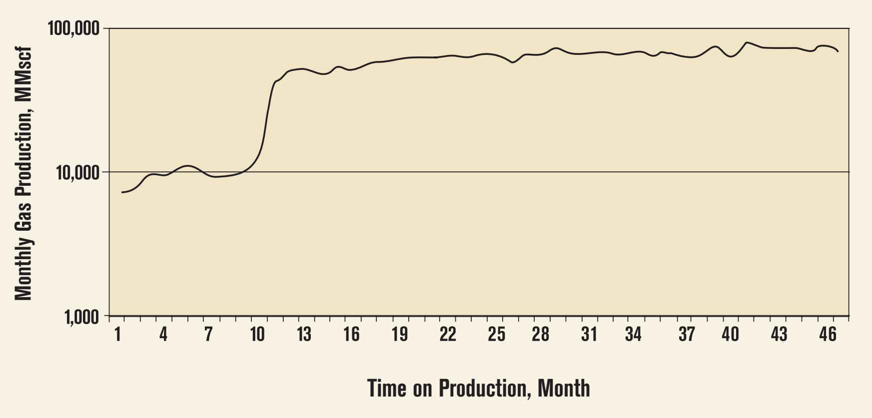


Figure 1. Production results from three San Juan Basin coalbed methane wells that were refractured using SandWedge service.

SandWedge service combines advanced proppant coating capability with a treatment design and proppant selection specific for each application.

fracturing operations and helps dissolve precipitates or carbonate scales.

CoalStim agents initially act as "clot busters," helping break apart the internal bridges and agglomerates. Then, the agents act as "clot formers," making coal particle surfaces tacky. The tacky particles form clots that adhere to formation features and proppant grains away from the fluid flow paths.

The result is a highly conductive flow path from the coal matrix to fractures, then to the wellbore.

The thin CoalStim carrier fluid is pumped under high pressure into the damaged fractures, then the well is shut-in to allow the chemical process to alter the surface of the fines. Finally, pump pressure is released to allow fluid in the well to rush out, flushing solids out of the wellbore area.

Material that had previously blocked the wellbore is held immobile at the extremes of the fracture so gas can now more easily enter the wellbore.

When an operator producing from a mature CBM basin implemented the CoalStim process to help extend the life of a field, a typical treatment response was a 17 $^1/_2$ % increase in gas production rate. During the long life of a typical CBM well, such an increase can add up to a significant increase in cash flow and production.

Average payout for these treatments was 9 days.

A 30-well program using the CoalStim service resulted in an average incremental production of 66 MMcf of gas with an average treatment payout of 32 days, even at the low gas prices at the time. Two-thirds of the wells treated showed increases in production of at least 7%.

SandWedge Service Helps Achieve More Production Longer

Halliburton's SandWedge agent can be a useful tool in CBM stimulation. It combines advanced proppant coating capability with a treatment design and proppant selection specific for each application. The following case history illustrates its effectiveness in rejuvenating CBM wells. Three CBM wells in the San Juan Basin (Four Corners area) were refractured using SandWedge service. The wells were studied in terms of the effect of SandWedge agent on advancing dewatering and overall production. All three wells responded significantly and provided fast payouts of the refracs. The production chart in Figure 1 is for well two. Notice there is no production decline.

Cobra Frac Service Provides Excellent CBM Results

Halliburton's Cobra Frac service is especially effective in CBM development. It enables efficiently stimulating multiple zones in a single trip by straddling each individual productive stringer (Figures 2 and 3). These example jobs highlight its capabilities.

Colorado—In southeastern Colorado, CBM trapped in multiple seams has plagued operators for decades. Typical well depth is 3,500ft (1,068m) with up to 20 seams trapping gas. Until recently, the most popular technique, a "velocity over accuracy" approach, did not bring the best results. Now, the Cobra Frac service team is fracturing multiple seams in a single day, bringing more methane to market quicker and with less environmental impact.

England—In the United Kingdom, the objective was to complete an exploration program in multiple coal seams (10 to 14 per well) in a cost-effective and timely manner in a highly populated area. Using the Cobra Frac technology, five wells were completed with 53 individual fracture treatments, placing 3 million lb of

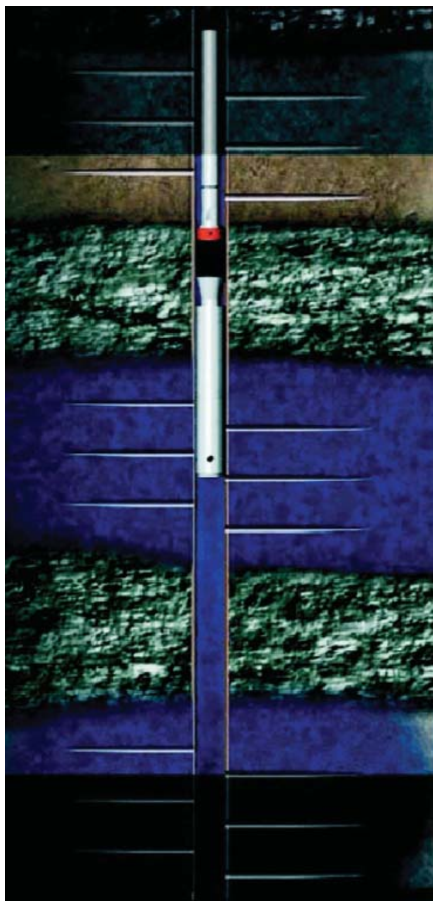


Figure 2. Cobra Frac service enables stimulating multiple thin zones in a single trip.

sand accurately in all targeted seams.

Alabama—The goal was to stimulate production from three individual zones in a 1,950-ft (595-m) CBM well. Total thickness of the three formations – the Mary Lee, Blue Creek and Pratt Coal groups – is only 30ft (9m) and is distributed over 800ft (244m) of wellbore. Production after treatment was expected to be 200,000 scf/d. The zones were perforated with the goal of treating between 2-ft and 10-ft (0.6-m and 3-m) intervals. Using 2 $^7/_8$-in. coiled tubing, the Cobra Frac process was used to place 80,000 lb of proppant into the Mary Lee and Blue Creek coal groups. The process also broke down each set of perforations in the Pratt Group.

Cobra Frac service could not be applied to the Pratt Group since each perforated interval communicated with open perforations above and could not be isolated. After the Pratt Group was stimulated by placing 70,000 lb of proppant down the 5 $^1/_2$-in. casing, it came in at 500,000 scf/d against 125psi backpressure.

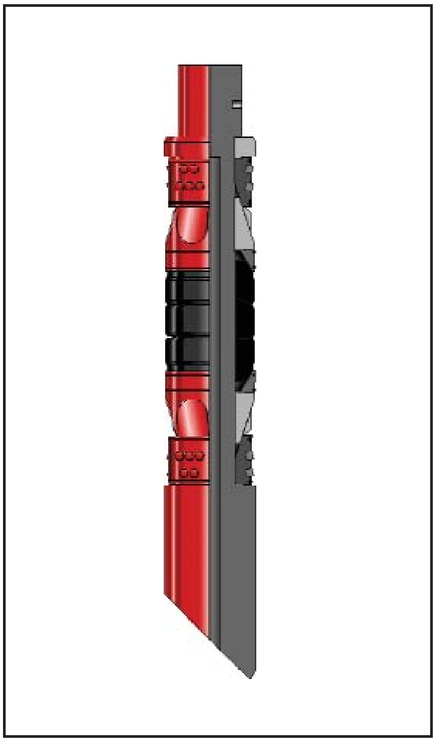


Figure 4. The Fas Drill composite plug helps reduce drill out time in multizone treatments.

Conventional treatment	Cobra Frac
Three to nine stages per well	Four to 18 stages per well
Treated down casing	Treated down 2 $^3/_8$-in. coiled tubing
Zones isolated with bridge plug	Zones isolated with straddle bottomhole assembly
Sequence: Perf/frac/set bridge plug (two trips per zone)	Sequence: Perf every zone/frac each pay with one trip in well
Average effective stimulation of net pay: 60%	Average effective stimulation of net pay: 76%
Higher completion cost	Completion cost reduced by 2%
Lower production because of less effective stimulation	Increased production, though conventionally treated wells had twice the net pay

Figure 3. Cobra Frac service compared with conventional fracturing process.

Composite Bridge Plug

Success in CBM development depends on efficient hydraulic fracturing of multiple coal seams. The seams may be commingled and fractured together or isolated to perform staged fracturing treatments.

Halliburton's Fas Drill is a composite epoxy-glass fracture plug designed for completing multiple coal seams with staged zonal treatments (Figure 4). It provides flow back capabilities after treatment and reduces drill out time.

The Fas Drill bridge plug is used much like a conventional permanent bridge plug and is available in standard and high-pressure/high-temperature models. In addition to multizone stimulation in coalbeds, the tool can isolate a lower zone during squeeze cementing operations on land-based or offshore rigs, in vertical or deviated wells.

Fas Drill bridge plugs can be set on tubing, drillpipe or with electric wire line. It can be drilled out with conventional three-cone, PDC or junk-mill bits.

To re-frac an old well in northwest Virginia to boost production from the upper coals without damaging the P-3 coal, a Fas Drill bridge plug was set to protect the lower coal. Cobra Frac service was used to treat the upper coals using coiled tubing. Then the Fas Drill plug was drilled out. After a successful treatment, the well showed a sustained production increase expected to last for several years. ■

Success in CBM development depends on efficient hydraulic fracturing of multiple coal seams. The seams may be commingled and fractured together or isolated to perform staged fracturing treatments.

Low-permeability Gas Sands

Precisely placed wellbores and tailored stimulation are keys to success.

By John Kennedy, Contributing Editor

Exploitation of low-permeability sands is most advanced in the United States where "tight" sands are the largest unconventional gas resource. According to the 2003 National Petroleum Council study, recoverable gas reserves in low-permeability sands in the United States is 175 Tcf.

Production from tight gas sands averages 3.2 Tcf/year, representing about 15% of U.S. gas production, according to the Gas Technology Institute (GTI). The U.S. Energy Information Administration forecasts tight gas production will reach 6.8 Tcf by 2025.

"U.S. gas shale development has been growing at a healthy pace, but tight gas is still the '600-pound gorilla' of unconventional gas resources," said Vello Kuuskraa, president of Advanced Resources International. And its contribution continues to grow.

"We estimate tight gas production, not including gas shale or CBM, at nearly 15 billion cu ft per day (Bcf/d) last year," he said.

The accepted definition of a tight gas reservoir is one with a matrix porosity of 10% or less and less than 0.1 milliDarcy permeability.

Production has come from a variety of sources, including East Texas, North Louisiana, the San Juan Basin and along the Gulf Coast. Big plays in the Rockies include Green River, Wind River and Piceance basins.

The Piceance Basin in Colorado has seen especially rapid growth, although from a modest base, Kuuskraa said. Extensive infill drilling and use of multiple stimulations have contributed significantly to the increase in tight gas production from 0.2 Bcf/d 5 years ago to nearly 0.8 Bcf/d last year, he said. New transportation infrastructure has helped bring this new gas to market, supporting a four-fold increase in well completions during the period.

U.S. Sources

Half of U.S. tight sand gas production comes from Texas and 30% from the Rocky Mountain region. Most of the rest is produced in the Permian and Anadarko basins; less than 2% now comes from the Appalachian Basin.

According to last March's special report, "Tight Gas," published by *Oil and Gas Investor*, since 2000, East Texas gas production from unconventional reservoirs has grown by 12.5%, more than double the growth rate of conventional production. By the end of 2005, tight gas plays had cumulative production of 8.7 Tcf of gas, according to the report.

In East Texas and North Louisiana, tight gas sand pays include Travis Peak, Cotton Valley, "regular" Bossier (at 12,000ft to 15,000ft or 3,660m and 4,575m) and Deep Bossier (deeper than 15,000ft).

"The really exciting new tight gas play in East Texas is the Deep Bossier, which is just starting," Kuuskraa said. "The recently drilled wells in this deep tight play appear to have recoveries that range from 5 Bcf to 25 Bcf per well."

Setting aside the Deep Bossier, the average East Texas tight sand well produces 1 $^1/_2$ Bcf to 2 Bcf during its productive life, and the top 10% of the wells will average 5 Bcf to 6 Bcf, he said.

Tight gas reservoirs are a significant share of the Appalachian Basin's remaining resource base, according to the *Oil and Gas Investor* report. A major Mississippian reservoir is Ohio's and West Virginia's Berea sandstone. More than 12,400 wells have been drilled into the Berea in Ohio, where the sands are found at depths to 6,000ft (1,830m). A typical well can recover up to 400 MMcf of gas, according to the report.

In an area that covers parts of southern New York, northwest Pennsylvania and eastern Ohio and Kentucky, the U.S. Geological Survey has estimated that several tens of trillions of cubic feet of recoverable gas still remain in the Clinton and Medina reservoirs.

In the western United States, more than half of the tight gas resource is on federal lands, where U.S. Bureau of Land Management and the U.S. Forest Service place significant restrictions on development.

The impact of those restrictions on supply was indicated by a study ARI completed for the U.S. Department of Energy (DOE). The study concluded that a 10% improvement in permitting, wildlife mapping, drilling exceptions and length of drilling season could increase the available natural gas resource in the region by about 14 Tcf.

Some Key Players

About 65% of XTO Energy Inc.'s gas production is from tight sands in the East Texas Basin, San Juan Basin and Rocky Mountains, said company president Keith Hutton. XTO's two big tight gas plays are the Freestone Trend in Texas and the Piceance Basin in Colorado.

In the third quarter of last year, the company was running 23 rigs in the Freestone play and production was about 570 MMcf/d. "We can increase that by 10% to 20% a year for the next 3 years," Hutton said.

Compressor header for gas-gathering in the Freestone Trend. (Photo courtesy of XTO Energy Inc.)

XTO's cumulative production in the play is about 600 Bcf and it has booked about 2.5 Tcf of reserves.

"That puts us about half way done. There is still probably 3 Tcf to be added," he said.

The Piceance Basin, where XTO will earn 50% of a 70,000-acre farm out from ExxonMobil by drilling four wells, is XTO's next big tight gas push, Hutton said. In early September, the first well was being completed in the 4,000-ft (1,220-m) gas column and the second well was under way. All four are expected to be at total depth between 14,000ft and 15,000ft (4,270m and 4,575m) by the first quarter this year.

"In the first well, we had good shows and good sand," Hutton said. "If half of XTO's acreage is successful, net reserves would be about 2 Tcf."

Development wells are expected to cost between $3 million and $4 million to drill, and recover between 3 Bcf and 4 Bcf per well with initial producing rates between 3 MMcf/d and 4 MMcf/d. Exxon's offset wells in the Piceance Creek unit have reportedly been producing at initial rates between 3 MMcf/d and 6 MMcf/d. Exxon and others in the Piceance are developing on 20-acre spacing.

In Southwestern Energy Co.'s **Overton** field in East Texas, tight gas production was only 2 MMcf/d in March 2001, but by late 2005, the production rate was about 107 MMcf/d, according to the *Oil and Gas Investor* report.

Anadarko has been working to produce natural gas from tight sands since the early 1980s. It began in the Golden Trend of Oklahoma and transferred those techniques first to the **Bossier** field in East Texas then to deeper zones in the **Vernon** field of North Louisiana. Recently, it has added areas including West Texas, Wyoming and the **Wild River** field in Canada. Anadarko's net gas production from tight gas formations averaged 521 MMcf/d in 2005, according to the company.

The East Texas Bossier play, where Anadarko has been operating since the mid-1990s, is one of its more mature tight gas plays, with more than 750 wells. It expects to ultimately recover 2.4 Tcf from its 200,000 net acres and has a 5-year drilling inventory. Net production in the middle of last year was about 190 MMcf/d.

Anadarko's Wild River/Cecilia drilling program continues in the company's most active development area in Canada. With between five and seven zones at depths between 9,500ft and 11,000ft (2,898m and 3,355m), the company had a 243-well inventory in the middle of last year.

With a 1.9 million-net acre leasehold position in Appalachia, Range Resources Corp. is targeting substantial reserves in shallow tight gas sands, as well as CBM and shale gas. During first quarter last year, its Appalachian division drilled 149 (106 net) wells in its tight sandstone and CBM properties. Last year, the company planned to drill or participate in about 800 wells compared with 600 wells in 2005.

At the end of 2005, Range Resources' proved reserves in Appalachia were 838 Bcfe; daily net production for the year was about 94 MMcfe.

Identify and Define

The best unconventional gas strategy depends on the type of resource and the basin.

"Each basin and resource has its unique set of technical challenges," Kuuskraa said. "Reservoir characterization techniques that can show 'this part of the basin is high in quality, while this part is low in quality' is the No. 1 technology need."

A key part of that analysis is detecting natural fractures that can connect permeability with horizontal wells.

"That doesn't always work in all basins," Kuuskraa said. "In some basins, natural fractures have served as fluid flow paths and brought minerals into the matrix, reducing permeability.

"It's not a panacea, but it is generally desirable to find naturally fractured settings."

Identification of gas-bearing zones by surface seismic imaging and seismic attribute analyses has had reasonable success in conventional reservoirs but has seen limited success in tight sands. The same holds true for identification of pay zones and estimation of gas saturation by well logging and petrophysical analysis techniques.

Finding and identifying gas-filled porosity in formations containing large amounts of clay is still less than perfect. Depending on the nature of the clay and its volume, those formations can look "wet" on a traditional log and thus be bypassed.

"We just don't have enough data on clay mineralogy, including its cation exchange capacity, for the important tight gas basins," Kuuskraa said.

More Skill, Less Brute Force

Stimulation is the key to making tight gas sand development economically viable. The evolution of stimulation techniques has been driven by new technology and an expanding range of options that can be tailored to individual reservoirs. More cost-effective multiple stimulations in horizontal wells is an important objective; existing technology works, but it is still relatively expensive.

"The key to tight gas plays is to figure out how to frac them," Hutton said. "Usually, you know the sands are there. The challenge is to maximize the flow rate for the lowest cost."

"Stimulation has evolved from horsepower to precision," said Kent Perry, director of exploration and production research with GTI. In the 1960s, an experiment with nuclear stimulation showed that technique "was not practical for a lot of reasons," he said.

Hydraulic fracturing then became the tool for developing low-permeability reservoirs. In the Denver-Julesburg Basin in Colorado, for example, the strategy was to drill one well on 640-acre spacing and perform a massive hydraulic frac in an attempt to drain a significant portion of that rock.

Stimulating tight sand reservoirs with cross-linked polymer fluids and large sand volumes often was too expensive. In the 1990s, the less-costly slick-water fracturing technique that used large volumes of water and low concentrations of proppant made more prospects economical. Then the development of multi-stage fracturing made it possible to more efficiently treat several zones.

> **"Stimulation has evolved from horsepower to precision."**
>
> Kent Perry, Director of Exploration and Production Research, GTI

As more was learned about fractures, it became clear that the ability to reach all the rock with 640-acre spacing was limited.

"Fractures were short and taller, and more complex," Perry said.

The key to success is to get a wellbore into the vicinity of the rock that is to be produced. With the limited ability to reach out with a frac treatment, the sands have to be reached with a wellbore instead.

An example is the Jonah field in Wyoming, Perry said. Spacing as low as 10 acres per well is being considered to adequately drain the gas from that reservoir. With horizontal drilling and

In East Texas, XTO has been using water fracs since 1998. It took a while before service companies routinely recommended this technology, but it is widely used now in many different basins.

Water fracs make it possible to treat more stages for the same cost as treating one interval with a gel frac, Hutton said. At a cost of $100,000 for water frac and $300,000 for a gel frac, three stages can be treated with the water frac for the cost of one gel frac.

"Also, a large gel frac can screen out a well," Hutton said. "It can hurt the well, but a water frac will not."

In East Texas, where the gas column is about 4,500ft (1,373m), XTO can do as many as nine stages and still keep well cost about $2.5 million for wells that average 3 Bcf of reserves.

Halliburton performs fracturing service on Quicksilver Resource's well in the Barnett Shale formation. (Photo courtesy of Halliburton)

microhole wellbores, it is practical to access reservoirs with small well spacing.

"We hit it with a hammer in the 1960s," he said. "Now, we are using a much lighter touch."

Still, hydraulic fracturing of low-permeability zones is complex. Tight gas sands have a wide geographic spread and vary in depositional environments, subsurface stress regimes and reservoir properties. Predicting and characterizing natural fractures in low-permeability sandstones is difficult; a fracture design that is successful in one field may not be in another.

Introducing a water-based fracturing fluid into a low-permeability reservoir can lower the effective frac half-length because of phase trapping associated with the retention of the water-based fluid in the formation. The problem is magnified by the water-wet nature of most tight gas reservoirs where no liquid hydrocarbon saturation has been present.

Retention of this increased water saturation in the pore system can restrict the flow of methane. Use of water in reservoirs with low saturation may also reduce permeability and associated gas flow by permanently increasing water saturation.

Another significant issue in tight sands reservoirs is permeability reduction resulting from physical and chemical reactions between the reservoir rock and the drilling and fracturing fluids.

Better fracturing technology has made possible increased production from tight sands during the past two decades, but several challenges remain to be met, according to a GTI report on unconventional gas technology needs. For example, because hydraulic fractures normally grow parallel to the open natural fractures, they intersect only a few of the open fractures, limiting flow rates.

Challenges of the Deep

The Deep Bossier play in East Texas poses special challenges, Kuuskraa said, because it involves deep, expensive wells drilled to depths of 20,000ft (6,100m).

The "regular" Bossier and the Deep Bossier are similar to the offshore Gulf of Mexico "shelf" and the "slope," he said. The Deep Bossier – the slope – deepens rapidly and is a "much more complicated geological animal."

The cost of drilling Deep Bossier wells makes stimulation technology critical, and because of the high pressure and temperature, it is necessary to use fluids that will not dehydrate and proppants that will not be crushed, for example. The treatment must be placed against an over-pressured formation.

There have been very big wells and very big disappointments to date, Kuuskraa said. "Deep Bossier is an emerging play that is still being defined. It is pushing the limits of unconventional gas development," he said.

Rigs and Tools

To put a wellbore near more gas accumulations means more wellbores, which means cost and surface footprint rise to the top of the list of challenges.

The good news is that since each accumulation is relatively small, a large wellbore is not needed. So, one way to cut cost is with a fit-for-purpose coiled tubing drilling rig designed to drill smaller holes faster with little surface disturbance.

An example of that technology, Perry said, is a very mobile rig that routinely drilled 3,000-ft (915-m) wells in a single day in the Niobrara in Colorado and Kansas.

For this rig's operation, no location is built, and usually no built-up road is needed. Only one small pit is required if cuttings are to be buried on site, or they can be hauled away. Since most wells are drilled with fresh water, little cuttings treatment is needed.

A fit-for-purpose rig for unconventional gas development should be able to handle 1 in. through 2 5/8 in. coiled tubing, have a 5,000-ft (1,525-m) depth capability and a zero discharge mud system, according to GTI. It should also be rated to handle 7 5/8 in. casing.

"As boreholes become smaller, and the reach of the wellbore needs to be extended, a new portfolio of tools is required," Perry said.

The DOE has its microhole drilling work aimed at those needs, but more needs to be done in developing those tools, especially those for formation evaluation.

"As we continue to move away from brute force toward more precision approaches to development, we need to develop smaller tools for logging while drilling, steering and data transmission."

The coiled tubing rig, for example, can drill vertical wells efficiently in the Niobrara in Kansas and Colorado. Operators also would like to be able to use that rig to drill between 1,000ft and 1,500ft (305m and 458m) horizontally, but it is difficult to get the weight on the bit needed to effectively drill.

"The ability to drill horizontally with coiled tubing is an area that needs development," Perry said.

	Freestone	Barnett	CBM
Depth, 1,000ft	13 to 15	5 to 9	2 to 4
Cost, $ million	2 to 3	1.6 to 2.2	0.4 to 0.8
Rate, MMcf/d or b/d of oil	1 to 7	2 to 7	0.4 to 1.1
Reserves, Bcf or million boe	2 to 4	2 to 6	0.5 to 2.5
Rate of return, %	80 to 100	50 to 100	50 to 100

Based on Nymex prices of $8/Mcf and $50/bbl. Source: XTO Energy Inc. presentation to Hart Unconventional Gas Conference, March 2006 XTO's unconventional gas economics

XTO's unconventional gas economics.

Technology Priorities

Many of these challenges that stem from the need to drill an increased number of wells are closely related:

- understanding the resource, ability to drain the rock, designing the best drainage patterns and spacing;
- efficient drilling; and
- minimizing the environmental impact that could result from increased number of wells.

Minimizing wellbore damage is also critical to the economic performance of unconventional gas wells. Advancing drilling and completion technology in ways that reduce wellbore damage is one of the biggest challenges.

Technologies exist for breaking up wellbore damage, helping restore and enhance the permeability of the perforations and surrounding area, including the creation of pulsating pressure waves within the wellbore and formation fluids.

According to GTI's Technological Roadmap for Unconventional Gas Resources, participants in the survey of technology needs cited two high-priority needs related to stimulation and completion of all types of unconventional gas reservoirs: developing best practices and quantifying/preventing formation damage; and understanding the rock-fluid interaction.

Important needs related to stimulation and completion, though not described as a top priority, are:

- improved understanding of the natural stress field;
- development of appropriate fracture models;
- improved diagnostics;
- candidate selection and evaluation of re-stimulation; and
- effective horizontal well stimulation.

During production, the real-time continuous monitoring of flow rate, pressure and other parameters is deemed a top priority. Also important are extending well life by re-stimulation, more efficient water handling and a more accurate estimate pressure depletion and drainage volume.

A top priority in reservoir characterization for tight sands is improved reservoir imaging for thin and deep pays as well as natural fracture assessment and prediction. Improved models for calculating original gas-in-place and producible gas, and 3-D characterization of lateral continuity of bed and other reservoir properties are also needed, according to the operators surveyed.

Other top priorities include improved direct imaging of thin reservoirs and depositional models on a play and basin scale. Needed in the logging/petrophysics area, according to participants in the survey, are better resolution, characterization and accurate flow predictions of thin bedded pay, natural fracture/cleat characterization and behind pipe logging to identify bypassed pays. ■

Technologies Optimize Tight Gas Sands

Fracture face damage control, accurate fracture placement and reliable tools help get the most from tight gas sands.

Ultra-low-permeability formations are especially prone to fracture face damage because of imbibition of fracturing fluids. When the fracturing fluid initiates and extends the fracture and then carries proppant into it, water is drawn into the formation, sometimes several feet into the rock porosity. This movement of water into the formation is because of the capillary effect and can be a significant cause of low hydrocarbon production.

New GasPerm 1000SM service provides important benefits to help get production from unconventional gas reservoirs online faster and at higher rates:

- helps reduce damage because of phase trapping;
- enhances mobilization of liquid hydrocarbons including condensate;
- helps increase regained permeability to gas following treatment;
- improves load recovery;
- GasPerm 1000™ additive can replace methanol for water block applications; and
- it improves environmental and safety performance over existing alternatives.

Operators are already receiving positive results from applying GasPerm 1000 service. For example, a Cotton Valley tight gas sand well was fracture stimulated using Halliburton's suite of products designed to help improve water frac results. The GasPerm 1000 service included a version of SandWedge® enhancer especially formulated for water fracs and OptiKleen-WF™ agent. Results show more than 14 times the wellhead pressure and almost twice the initial production (Figure 1).

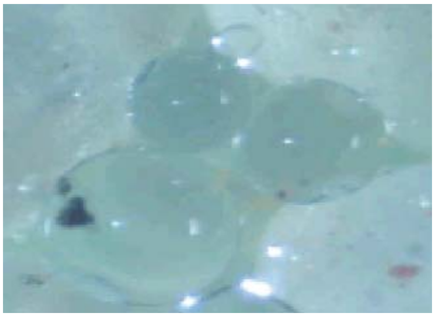


Figure 1. Photomicrograph shows the effects of phase trapping that can occur during a fracturing treatment. This process is especially pronounced with water fracs in ultra-tight gas formations. The discontinuous phase reduces the gas permeability. GasPerm 1000 service has helped enable the trapped phase such as imbibed water flow freely from the rock matrix and fracture system resulting in significantly improved permeability to gas.

OptiKleen-WF™ viscosity-reducing agent

In fracturing unconventional gas reservoirs, friction reducers have been shown to cause fracture face damage and have demonstrated damaging effects to fracture conductivity. Proprietary OptiKleen-WF viscosity-reducing agent has been developed to enhance fluid load recovery and reduce damage that can be created by long chain polymers. It helps return the viscosity of solutions containing treating agents, such as friction reducer, to that of water. It can help maximize the effectiveness of water-fracturing treatments by:

- improving load recovery and productivity;
- minimizing friction-reducer polymer damage;
- preventing polymer adsorption to the fracture face; and
- reduces fluid viscosity.

CobraMax® V Service

The CobraMax V service process is used for unperforated, cemented casing completions in vertical wells (Figure 2). The process is performed with a coiled-tubing-deployed Hydra-Jet™ bottom-hole assembly (BHA). There are no packers or mechanical devices to set. Depth correlation is accomplished by setting a wireline bridge plug below the deepest interval to be stimulated. The bridge plug is tagged with the coiled tubing, and the referenced depth is input into the depth encoders on the coil unit. The BHA is moved to the first target and perforating is accomplished by hydrajetting via the coil. The annulus is closed in to break down the perforations, and the fracture treatment is pumped

Figure 2. CobraMax V service extends the benefits of coiled tubing fracturing to larger, higher rate treatments.

through the annulus. The coiled tubing is moved above the treatment interval and then acts as a deadstring for fracture diagnostics. A final proppant stage of un-crosslinked, high concentration proppant is pumped to induce a near-wellbore proppant pack that further improves near-wellbore conductivity and acts as a diversion for treatments further uphole. When all intervals have been treated, the well is cleaned out with the coil unit, and the well can be jetted or flowed to recover treatment fluid. Up to 22 individual intervals have been fracture-stimulated in a single completion.

CobraMax V service was successfully deployed in Chevron's Lost Hills asset with significant reduction in overall cost/barrel of oil equivalent based on 180-day cumulative production over conventional 'perf-and-plug' limited-entry fracturing method (37.6% higher cumulative production reported). Since the initial test of the method, the process has been used on more than 40 of Chevron's well completions averaging 17 fracs per well with 2.2 million lb of proppant per well in the Lost Hills alone.

CobraMax® H Service

The same CobraMax process used to treat vertical wells is especially beneficial for horizontal wells where flow convergence from the fracture into the wellbore can cause significant loss in production (Figure 3). The proppant pack as a final stage of each fracture treatment helps ensure maximum conductivity in the near-wellbore region where flow convergence issues are the most extreme.

Horizontal well fractures are especially vulnerable to conductivity loss in the near-wellbore area because of fines migration, proppant flowback and the limited flow area exposed by the small perforated interval connecting to the fractures. A small amount of fines plugging near the perforations will create a significant choke point to production. Conductivity endurance products can be combined with the CobraMax H service process to deliver the highest possible sustained production from each completion.

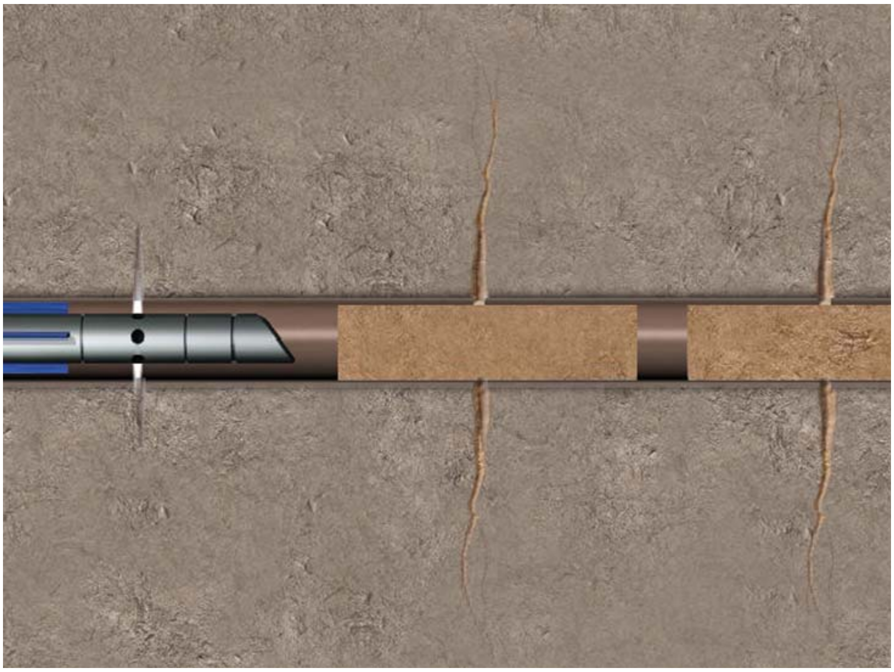


Figure 3. CobraMax H service successfully addresses the flow convergence issues in fractured horizontals.

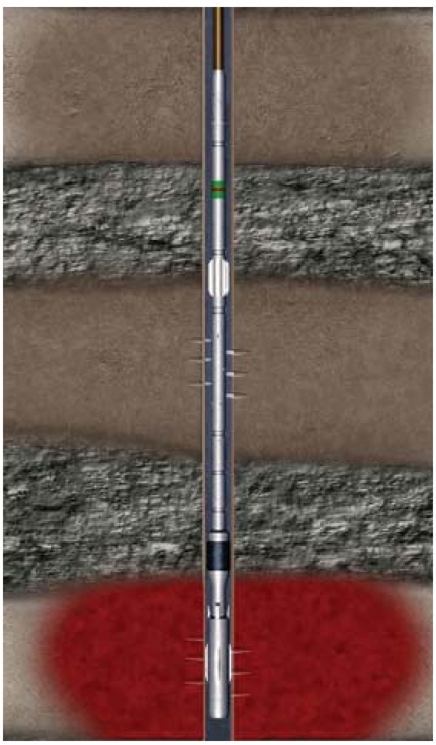


Figure 4. CobraJet Frac service diversion is accomplished by using a compression set packer.

CobraJet Frac® Service

The CobraJet Frac* process also uses a coiled tubing deployed BHA (Figure 4). This process is similar to CobraMax service in that the Hydra-Jet perforating is accomplished by pumping through the coiled tubing and the fracture treatment is pumped though the annulus. In this process, however, diversion from previously stimulated intervals down hole is accomplished using a compression set packer. CobraJet Frac service offers the same dead-string advantages as CobraMax service. One advantage of Cobrajet Frac service is the time savings between treatments. The packer isolation method is often quicker than the process of setting proppant plugs in the wellbore and often does not require a cleanout at the end of the completion.

RapidFrac-MZ℠ Service

RapidFrac-MZ* service is a multiple-zone stimulation process that uses select-fire perforating guns that remain in the casing while fracturing is accomplished down the casing. A series of select-fire guns is run into the well, and the lowermost interval is perforated (Figure 5). The guns are then positioned

**Technology licensed from ExxonMobil Upstream Research Co.*

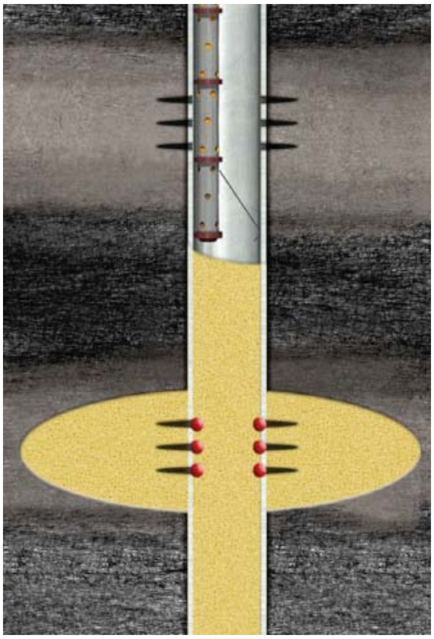


Figure 5. RapidFrac-MZ service provides speed of operation and is well suited for water fracs.

at the next interval uphole while the fracturing treatment is pumped on the first interval down the casing. As a final fracturing stage, ball sealers are injected to seal-off the first interval. When the pressure rises, indicating the first interval is sealed, the second zone is perforated without shutting down the pumps, and the second fracture treatment is initiated while the guns are moved uphole to the third interval. Usually, only six select-fire guns are run in a single run into the wellbore; therefore, the spent guns are retrieved after the sixth interval is stimulated.

If more than six treatments are required, a composite bridge plug and new select-fire guns are run into the well. The bridge plug is set above the sixth zone via wireline, and the seventh interval is perforated. The process is repeated as before for zones seven through 12, if desired.

The process promises speed because of the idea that there is essentially no downtime between fracture treatments. However, premature screenouts can cause complications, so the process is best suited for water fracs.

Delta Stim™ Sleeves

For multi-zone fracturing applications in horizontal and vertical wells, the Delta Stim sleeves can be used not only to provide an effective means of replacing conventional perforating and isolating individual frac treatments, but also can to selectively close off fractures that may have communicated with water producing intervals. The sleeves are typically cemented in the wellbore as part of the casing string with acid soluble cement. Acid can be used to facilitate formation breakdown.

Delta Stim sleeves offer a distinct advantage to convention processes for acid fracturing treatments as well as treating reservoirs with potential for producing hydrogen sulfide that would complicate hydrajetting practices.

Magnum Stimulation Valve™ Assembly

Magnum Stimulation Valve assemblies are run as part of the completion casing and cemented in place between frac targets. They are full open and present no restrictions inside the casing string. These are flapper valves actuated mechanically using slickline, wireline or coiled tubing to shift a sleeve that allows the flapper to be released to provide isolation of fluid flow from above (Figure 6).

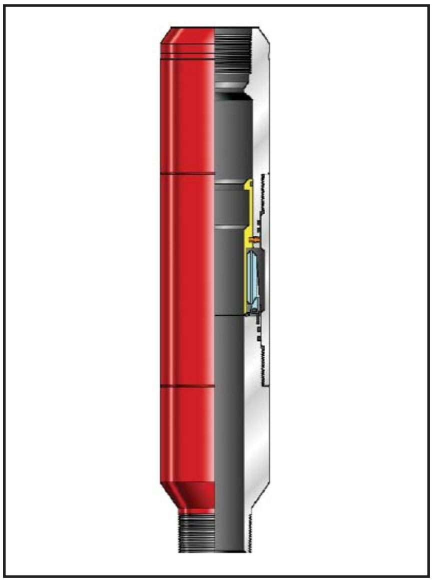


Figure 6. Magnum Stimulation Valve assemblies present no restrictions inside the casing string.

Reliable Well Construction

In many wells, unsuccessful installation of liners and failure of liner tops result from a variety of causes, including;

- a lack of integrity in the liner top cement;
- pre-setting of the liner hanger and packer;
- failure to get the liner to depth; and
- failure of tools such as darts, plugs and running/setting tools.

Current technology for running and setting mechanical equipment poses several risks, including multiple slips, tortuous flow paths, exposed hydraulic ports, many potential leak paths and reduced radial clearance.

These risks, however, can be minimized – in many cases eliminated – by applying new technology.

The VersaFlex® liner hanger system, for example, combines expandable solid liner hanger technology as well as Halliburton's complete range of cementing products and services (Figure 7). The system expands the capability and enhances the reliability of conventional liner installations.

The system's heart, the VersaFlex integral liner hanger/packer, is made up of an integral tieback receptacle above or below (depending on system size) an expandable solid hanger body. Elastomeric elements bonded to the hanger body are compressed in the annulus as the hanger body is expanded. This virtually eliminates the liner hanger/casing annulus and provides liner top pressure integrity as well as high tensile and compressive load capacity.

The VersaFlex liner system provides:

- *Simplicity*—no moving parts, slips, or cages to suspend the liner in the support casing, eliminating the risk of pre-setting the liner hanger/packer;
- *Reliability*—multiple redundant elastomeric elements maintain pressure integrity while virtually eliminating gas migration paths in the liner top;
- *Integrity*—the reduced outer diameter (OD) of the hanger body allows for higher circulation rates during

Figure 7. VersaFlex liner hanger system running.

cementing to improve cement integrity and minimize cement pack-off potential;

- *Versatility*—VersaFlex systems will soon be available in virtually all common liner/casing configurations; and
- *Adaptability*—the liner hanger/packer can be combined with existing Halliburton completion products to provide a superior liner top completion solution.

While hangers with slips and cones provide a trap for cuttings and debris to pack off and increase equivalent circulating density, the slick OD of the VersaFlex system significantly reduces the risk of lost circulation.

The system also avoids a stuck setting tool, the most common causes of which are debris entering the setting tool/extension sleeve gap, and incorrect tool assembly. In the VersaFlex system, the liner top is completely sealed to keep out fines, cuttings and other well debris. In addition, the hanger and setting tool assembly will not make up if incorrectly assembled.

To avoid presetting the hanger or packer by catching the slips or packer elements and by the surge effect when running in the hole, the system can only be set by following the proper setting sequence. There are no exposed hydraulic ports.

Anadarko Petroleum Corp. recently chose the system for a 13,549-ft (4,132-m) well being drilled in Madison County, Texas. The liner was run in the hole without any problems until it got stuck at 13,386ft (4,083m). Freeing it required a total pull of 465,000 lb (260,000 lb over pick-up weight). During pumping, the hole packed off several times, creating a maximum pressure of 4,500psi on the drillpipe.

Only when the pump rate was increased to 10.5 bbl/min and the liner was rotated at 80 rpm with torque between 8,500 ft-lb and 14,500 ft-lb did the liner begin to move. It took 25 hours of washing and reaming to achieve total depth.

After setting the hanger, a 300,000-lb pull test and 4,200-psi positive pressure test with no pressure loss confirmed the hanger was set.

Anadarko representatives on location were quoted as saying, "No one else's equipment could have stood up to that kind of abuse and still set or tested."

Anadarko has since utilized the VersaFlex liner system in several of their wells.

A Versatile Retrievable Packer

The Halliburton Versa-Set® wireline or tubing-set packer is a single-bore retrievable packer ideal for medium-to high-pressure environments (Figure 8). It is used for testing, injection and zone stimulation, and can serve as a production packer, temporary bridge plug or tubing anchor in a pumping application.

The packer is a useful tool in any well that requires it to be lubricated into the well under pressure with a plug in place, minimizing damage to sensitive formations. It can be released, moved and reset mechanically on tubing. Rated at

Figure 8. Versa-Set Packer

10,000psi with full-bore inner diameter for most tubing/casing combinations, it easily converts to wireline set or mechanical set in the field.

An opposing slip design holds in both directions and is operated with a simple quarter-turn J-slot. A temporary plug may be installed at the top of packer. Mechanically re-settable, it has an internal bypass and emergency shear release.

Restoring Permeability

Halliburton's Pulsonix® service uses alternating bursts of fluid to create pulsating pressure waves within the wellbore and formation fluids. These pressure waves can break up many types of near-wellbore damage, helping restore and enhance the permeability of the perforations and the surrounding area.

Fluidic oscillation helps remove damage instead of breaking through it, cleaning the entire interval, not just the open sections.

Pulsonix TF service, the next-generation process for treating near-wellbore and perforation damage, uses tuned frequency (TF) technology to customize amplitudes and frequencies for each application. The service incorporates Halliburton's coiled tubing expertise with its proven fluidic oscillator technology (Figure 9).

Pulsonix TF service is applicable for a variety of vertical and horizontal wells, both openhole and cased hole. It performs well in removing deposits – scale, formation fines, paraffin, asphaltene, emulsions and more – from the near-wellbore area, perforations and screens.

It minimizes location time because it can clean out fill and stimulate the well in one trip. It is not limited by stand off requirements like jetting nozzles and can be run with other tools.

The technology provides significant advantages over the original service. A wider range of rates can better match the bottomhole assembly and gain the benefits of flow capacity, and the amplitude is stronger for more effective action.

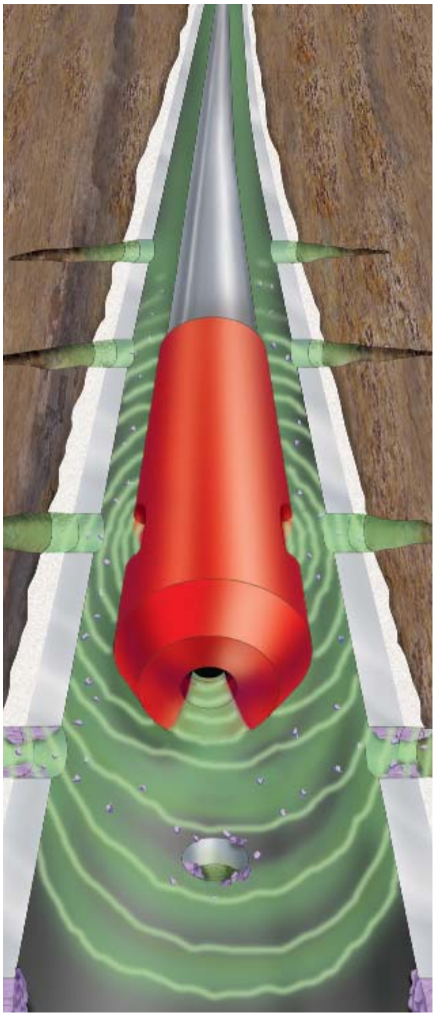


Figure 9. New Pulsonix TF tool is equipped with side and bottom parts for more direct impingement on perforations.

Side and bottom ports enable more direct impingement on perforations than the original service and the process can function at lower flow rates. The service can be used:

- to enhance placement and effectiveness of treatment fluids;
- for primary stimulation of high-permeability formations;
- for preparation prior to stimulation treatments, gravel packing or frac packing;
- to clean out fill from openhole or casing;
- to change injection profiles; and
- for correct placement of treating chemicals. ■

Gas Shale

Better 3-D interpretation, tighter spacing and more efficient drilling are needed.

Gas-in-place in shale formations in a dozen U.S. basins could total between 500 Tcf and 600 Tcf. Early last year, more than 35,000 wells were producing an estimated 600 Bcf per year, according to the 2006 edition of "Shale Gas," a special *Oil and Gas Investor* report.

Production comes from shale reservoirs in the Michigan, Illinois, Appalachian, San Juan and Fort Worth basins.

"Currently, the hottest play going in unconventional gas is pursuit of shale gas reservoirs," said Vello Kuuskraa, president of Advanced Resources International (ARI).

The hottest shale gas play is the Barnett in the Forth Worth Basin, where horizontal drilling and multiple-zone stimulation techniques have fueled the growth from about 0.2 Bcf/d 5 years ago to more than 1.3 Bcf/d in 2005.

"We believe this gas play could reach 3 Bcf/d down the road," Kuuskraa said.

These technologies and their success in the Barnett have also spurred other shale plays, he said, including the Fayetteville in Arkansas, the Barnett and Woodford in West Texas and the Caney and Woodford in the Arkoma Basin of Oklahoma. Interest has also been renewed in the Devonian shale of the Appalachian Basin where gas shale drilling is up by 50% during the past year.

In *Oil and Gas Investor*'s January 2007 "Shale Gas" report, John White, U.S. exploration and production analyst for Natexis Bleichroeder Inc., said 64 public companies were involved in eight shale-gas plays in the United States. Among the most active are:

- Chesapeake Energy Corp.;
- Southwestern Energy Co.;
- Range Resources;
- Carrizo Oil and Gas;
- Brigham Exploration;
- Abraxas;
- EnCana Corp.;
- EOG Resources Inc.;
- Devon Energy Corp.;
- Quicksilver Resources Inc. and others.

The Big One…And Why

Development of the Barnett shale, contained mainly in Wise and Denton counties in North Texas, began with experimental drilling and completion techniques during the 1980s and early 1990s.

By early last year, the Newark East Barnett shale field had about 4,200 wells and 135 active rigs, according to a presentation by Brad Foster, vice president and general manager, central division for Devon Energy Corp. during the Hart Unconventional Gas Conference last March. Cumulative production stood at 1.7 Tcf, and the play had the potential to expand to a 10-county area, he said.

There are two key reasons the Barnett became the biggest shale play, Foster said. Compared with other productive U.S. gas shales – the Ohio, Antrim, New Albany and Lewis – the Barnett is over pressured with a gradient of about 0.52 psi/ft, and it contains much more gas in place, an estimated 142 Bcf/sq mile.

Recovery from near-term development is expected to be between 10% and 12%; improved recovery techniques might recover an additional 5% to 10% of gas-in-place.

The core producing area of the Barnett has the following characteristics:

- fractures are closed and calcite filled;
- porosity is 3% to 5% primary;
- permeability is less than 0.001 milliDarcies;
- Reservoir thickness is 400ft to 600ft (122m and 183m);
- well depth is between 6,000ft and 9,000ft (1,830m and 2,745m); and
- reserves are greater than 1 Bcf per well (vertical).

Midway in the third quarter of last year, Devon had 26 rigs running in the play, up from 18 early in the year. It was scheduled to drill about 325 wells last year as planned, most of which are horizontal. In 2005, Devon drilled 217 wells, 244 of which were horizontal. Devon's cumulative production reached 1 Tcf in 2005 and by the middle of last year, was 1.1 Tcf.

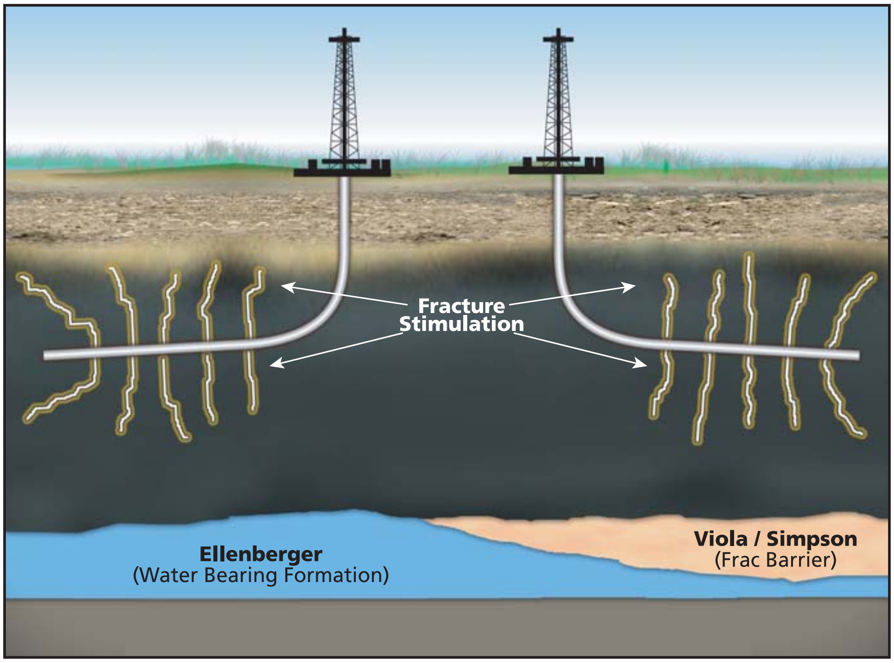
A 20-acre infill well pilot program in Devon's core acreage has boosted expected recovery from 1.8 Bcfe per well to 2 Bcfe per well. Ultimately, the company expects to drill infill wells on its core and non-core acreage.

Devon's recent purchase of Chief Holdings LLC added significant reserves and acreage. Plans for the Chief acreage include drilling about 800 wells during the next 5 years and ultimately recovering more than 2 Tcfe of gas.

"Four things made Chief work for us," Foster said. "We have extensive knowledge and expertise in the Barnett and a lot of proprietary seismic interpretation technologies. We also have a unique experience with our 20-acre infill wells. And finally, we have an advanced production optimization capability."

Average recovery of gas-in-place from Devon's acreage in the core area is now 16%, up from 9% to 10% in 2002. Every four percentage-point increase in recovery adds 1 Tcf of recoverable reserves for Devon, Foster said.

XTO Energy Inc. entered the Barnett in 2004 with an acquisition, and by September 2006, was producing about 270 MMcf/d and had 21 rigs running, 7 in its non-core acreage. It has about



Horizontal wells can avoid water even when the shale is not protected by the frac barrier. Horizontal wells also are exposed to more pay zone and are able to produce more gas than vertical wells. (Graphic courtesy of Devon Energy)

200,000 net acres, about 90,000 in the core area. XTO is targeting a recovery of more than 20% in the core area of the Barnett where its spacing is 50 acres.

"Back in the day of $2 gas and vertical wells, the Barnett shale was mediocre," said Keith Hutton, XTO president. "That started to change when gas prices went up and operators began to drill horizontal wells."

Vertical wells in the Barnett produced between 500,000 cu ft/d and 700,000 cu ft/d and had typical reserves of 1 Bcf; many horizontal wells had initial flow rates of 3 MMcf/d to 5 MMcf/d and reserves of 3 Bcf.

Hutton estimates the company has 1.2 Tcf of reserves in the Barnett, a number expected to grow by the end of last year.

"That will probably grow by 15% to 20% over the next 2 years," he said.

Most of XTO's non-core acreage is in areas where the Barnett is 200ft (61m) or thicker. "We believe you can frac the wells into water if the layers are any thinner than that," he said.

The Barnett Shale is one of EOG Resources Inc.'s key developments, said Phil Delozier, vice president of business development, during the Unconventional Gas Conference. At that time, the company had 10 rigs running in Johnson County and three in western counties; it planned to have 22 rigs running by the end of the year. The company's average production from the Barnett in 2005 was about 50 MMcf/d, but reached 100 MMcf/d by the end of the year.

Delozier called EOG's northeast Johnson county area "monster" well territory and its western Johnson county area, where wells provide a 100% rate of return, "routine." Early last year, with four Johnson county pilots under way, EOG was implementing 500-ft (153-m) spacing throughout the county and was ready to begin a 500-ft Erath county pilot.

Early last year, EOG's Barnett Shale economic model was based on a direct well cost of $1.8 million and 1.9 Bcf of net reserves for western Johnson County, and a well cost of $2.9 million and net reserves/well of 2.9 Bcf for northeast Johnson County.

Chesapeake Energy Corp.'s Barnett Shale average daily net production was about 140 MMcfe in the middle of last year; the company expected it to reach 200 MMcfe by year-end and 250 MMcfe by end 2007. Most of its acreage is in Johnson and Tarrant counties.

Chesapeake had 2,100 net potential locations and was operating 12 rigs in the middle of last year, expecting to have 24 rigs at work by year-end capable of drilling 350 to 400 gross wells per year. From the 2,100-net potential locations, Chesapeake estimates it has 3.4 Tcfe of unproved reserve potential in addition to 0.6 Bcfe of proved reserves.

Range Resources Inc.'s shale plays are producing about 24 MMcfe/d from more than 350,000 acres. In the Barnett, the company plans to complete 40 wells in the second half of the year and have six rigs running by year-end, according to company information.

In the West Texas Barnett play, Range has a 3-D seismic shoot under way and an initial well planned for early this year.

Early last year, Reichmann Petroleum Corp. extended drilling contracts on three rigs in the Fort Worth Basin Barnett for 1 year with an option to extend the contracts for an additional year. Reichmann planned to drill more than 30 wells in the play last year.

Emerging Fayetteville

The Fayetteville shale in the Arkansas side of the Arkoma Basin is Mississippian-age shale, the geological equivalent of the Caney Shale in Oklahoma and the Barnett Shale in north Texas, according to Southwestern Energy Co., the major participant in the play.

The extensive shale ranges in thickness from 50ft to 325ft (15m to 99m), and is found at depths from 1,500ft to 6,500ft (458m to 1,983m). Southwestern has drilled productive wells as far apart as 120 miles (193 km) in an east/west direction and 20 miles (32 km) apart in the north/south direction, said Richard Lane, Southwestern Energy Co. president. In the middle of last year, Southwestern had 10 drilling rigs running in its Fayetteville area.

Basin average Fayetteville porosity is between 2% and 8%, according to Southwestern, compared with 6% to 8% in the Newark East field in the Barnett play. Permeability is similar for both shales at 100 nanoDarcies to 400 nanoDarcies.

The key difference between the two is that the Fayetteville is not overpressured.

In the third quarter, Southwestern was on track with its 2006 plan to drill between 175 and 200 wells in the Fayetteville, almost all of them horizontal. The company has a two-fold drilling strategy, Lane said. In areas where production is building and infrastructure is in place, infill wells are being drilled to further boost production. The other prong of the strategy is to step out with new pilots.

"By the end of 2006, this strategy will give us a good spatial sampling of the play on our acreage," Lane said. "We've seen a good production response as we drill and complete more wells and improve the process."

Gross production from the play topped 50 MMcf/d by late summer, compared with 20 MMcf/d in May.

Southwestern expects its horizontal wells to have an ultimate recovery between 1.3 Bcf and 1.5 Bcf per well. The newer slick-water completions are coming in above that curve, Lane said, but more production history is needed to fully evaluate those completions. Recovery is expected to be in the low 20%-range.

Chesapeake believes at least 300,000 of its 1.1 million net acres in the Fayetteville will be commercial. If so, it would have up to 4,600 net potential drilling locations with an estimated recovery between 1.2 Bcfe and 1.5 Bcfe per well. In the middle of last year, it had three rigs running and could have between 10 and 15 by year-end.

XTO is also in the Fayetteville with about 200,000 acres. The company will begin drilling this year, and it owns interest in wells now being drilled by others. If drilled on 100-acre spacing, XTO reserves could be between 1 Tcf and 2 Tcf.

Other Basins

Oil and Gas Investor's 2006 "Shale Gas" report also highlights participants in other plays around the United States. Talisman Energy Inc. has a significant position in the Appalachian Basin's Devonian/Ohio play. Edge Petroleum Corp., Noble Energy Corp. and Murphy Oil Co. are active in the Black Warrior Basin in Alabama and Mississippi. Newfield Exploration Co. and Petrohawk Energy Corp. are active in the Caney/Woodford in the Arkoma Basin, according to the report.

Penn Virginia Corp. has a position in the New Albany Shale play in the Illinois Basin. Questar Corp. is in the Baxter play in the Vermillion Basin of northern Colorado and Southern Wyoming.

In the Devonian Shale play in Pennsylvania, Range Resources has drilled 13 wells, with several yet to be completed. Three of the vertical wells have been on production for an average of 5 months, and reserves appear to be in the range of 600,000 cu ft to 1 MMcf per well, according to the company. It plans to have 10 vertical wells frac'd and on production early in the fourth quarter 2006.

Chesapeake is evaluating horizontal vs. vertical wells on its acreage in the West Texas counties of Reeves, Pecos, Brewster and Culberson, where shales are up to four times thicker than the Barnett, have two to four times as much gas-in-place and have similar porosity, permeability and organic content, according to the company. West Texas shales, however, are twice as deep as the Barnett, and recovery factors are not yet known. At mid-2006, Chesapeake had three commercial wells on production on its West Texas acreage – four being completed and two being drilled.

XTO has about 30,000 acres in the Woodford shale in Oklahoma where it will drill one or two wells in 2006. It expects between 2 Bcf and 3 Bcf/well and a well cost between $3 million and $4 million.

The 2006 Oil and Gas Investor report said the Palo-Duro Bend Shale in the south Texas Panhandle, 500ft to 1,000ft (153m to 305m) thick at depths of 7,000ft to 10,500ft (2,135m to 3,203m), is similar in ways to the Barnett Shale and could "be as big as the Barnett."

Production from the Antrim Shale in Michigan has declined for several years. The wells are between 400ft and 2,000ft (122m and 610m) deep, cost about $170,000 to drill, and complete and produce between 400 MMcf and 800 MMcf during their life.

In Western Canada, Stealth Ventures Ltd. announced in October 2005 that it acquired rights in three Saskatchewan Exploration Permits, covering slightly more than 1 million acres of primarily shallow gas prospective lands, including shale gas. In mid-2006, the company began its shallow shale gas-drilling program in Alberta and Saskatchewan. In Alberta, Stealth completed drilling a second well that was cored through two target intervals identified by the first well in the same area.

At Foam Lake, Saskatchewan, six test wells have been drilled and cased in the ongoing drilling program. Stealth has a 50% interest in the program, which was expected to have 16 wells by the fourth quarter. The company intends to evaluate several producing zones, including the Upper and Lower Colorado Group, for shallow and shale gas.

Stimulation Trends

Fit-for-purpose fracs have significantly improved shale gas economics, driving the acceleration of activity in the Barnett, for example.

"The light sand frac really kicked the Barnett off," Foster said. "It was the first technology breakthrough."

Gas is produced from shale through desorption from organic components in the shale and the release of free gas residing in pore spaces in interbedded sand and siltstone layers.

Understanding the reservoir is the

first step in creating a development strategy. During the past 2 years, 3-D seismic has been acquired over much of the Barnett and most operators have proprietary interpretation technology.

"We're doing things with 3-D data to try to understand the shale play better," Lane said. "It goes past the normal mapping of reflection data and deeper into the attributes."

In addition to its shift to horizontal wells, Southwestern has been experimenting with completion techniques. More than 30 recent wells have been treated with slick water, or hybrid slick water that use cross-linked fluids, instead of nitrogen-foam-based treatments.

"On a rate time plot, these completions are better performers than previous wells," Lane said. "We are hoping for higher recoveries from this type of stimulation."

Credit for the improvement likely goes to the ability of the water-based treatment to contact more rock, he said.

Southwestern is also testing multi-stage completion technologies that would make it possible to complete horizontal wells quicker and more efficiently. The company has experimented with different perforating schemes as well as acid soluble cement.

Southwestern also continues to analyze microseismic data to determine the type of fracture geometries being created. Interpretation of microseismic information has led to better understanding of fracture geometry and subsequent job design modifications.

There is another key to success in the Barnett, Hutton said, where XTO has 3-D over all its acreage.

"You also need 3-D seismic to identify karsts and salts that can serve as conduits for water when drilled into," he said.

Drilling and Completion Trends

Compared with vertical completions, horizontal wells produce more gas sooner and have higher ultimate recovery. Horizontal wells began to be a factor in the Barnett in 2002 and are now general practice.

At the Hart Unconventional Gas Conference, Steve Drake of Netherland-Sewell and Associates Inc. said the 3,000 vertical wells in the Barnett core area typically will produce 800,000 cu ft/d initially, and 0.6 Bcf to 1.5 Bcf during a 35-year life. In contrast, the typical initial potential of 750 horizontal wells was 1.3 MMcf/d to 3 MMcf/d, and they are expected to produce 1.3 Bcf to 2.7 Bcf during a 30-year life.

In Devon's 29-well 20-acre infill pilot program in the Barnett, vertical wells left a portion of the reservoir untouched. In the program, a horizontal well drilled between vertical wells develops four 20-acre areas at a time with one horizontal well. Offsetting the existing wells boosted recovery in the core area to about 2 Bcf per well.

In Johnson County, Devon has reduced the average number of days to drill a Barnett Shale well from 33 in 2005 to 18.

Southwestern's strategy is to purchase and operate its own drilling rigs. In late summer, it had six company-owned and operated rigs running in the Fayetteville play.

"We're seeing improved efficiencies from that decision. Not only do we have better equipment, but it is custom built for the play," Lane said.

The rigs are a "super single" design that uses 45-ft (14-m) joints. The automated pipe-handling system does not rack pipe in the derrick during trips; instead, a joint is picked up from the pipe rack and added to the string.

Technical Issues, Resource Constraints

In the case of the Barnett, Devon cites these challenges facing expansion:

- in the oil prone Barnett, the lower frac barrier is water-bearing;
- there are limestone facies in the Lower Barnett;
- increased drilling depths are required;
- urban encroachment is a growing issue;
- production decline is steep; and
- fault zones transport water into Barnett.

In areas outside the core area, Upper and Lower frac barriers are absent, the effect of faulting is unknown and pressures are normal, and the Barnett section thins. There also is a lack of infrastructure.

Technology advancement needs are across the board. It is important to find more ways to reduce the footprint of operations, use resources such as fresh water and lower the impact on local communities. More efficient multilateral completion techniques would be welcome, as would more cost-effective frac techniques.

There is potential for a quantum leap in completion efficiency by condensing the drilling and completion cycle time.

Priority technology needs for gas shale development are the ability to quantify and prevent formation damage and understand rock-fluid interaction, according to operators surveyed for the Gas Technology Institute's Technology Roadmap for Unconventional Gas Resources. A better understanding of production mechanisms is needed, according to the report. Also at the top of the list was public domain gas desorption and thermal maturity data. ■

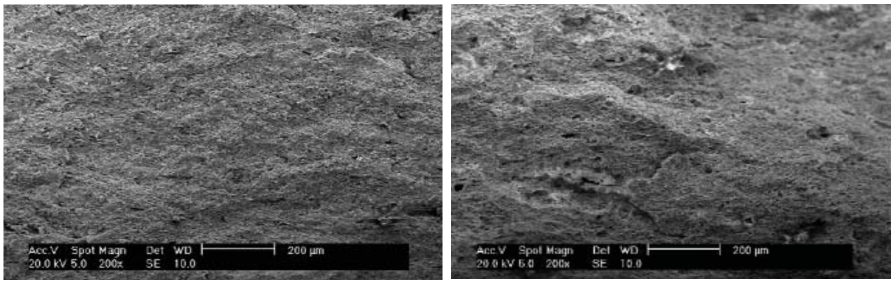
	Barnett	Ohio*	Antrim*	New Albany*	Lewis*
Depth, ft	7,200 to 9,000	2,000 to 5,000	600 to 2,200	500 to 2,000	3,000 to 6,000
Thickness, ft	400 to 500	300 to 1,000	160	180	500 to 1,900
Scf/ton	100 to 150	60 to 100	40 to 100	40 to 80	1 to 45
Reservoir pressure, psi	3,000 to 4,000	500 to 2,000	400	300 to 600	1,000 to 1,500
Gas in place, Bcf/sq mile	142.5	5 to 10	6 to 15	7 to 10	8 to 50

*Source: Hill & Nelson, 2000, from a presentation by Devon Energy Corp.

U.S. Productive Gas Shales

Developing Gas Shale Reserves

Lifecycle-based approach works best for gas shale reserve development.



New Shale Frac-RF frac fluid is proving highly effective in stimulating shale formations. SEM pictures of the shale fracture face before (left) and after exposure to reactive fluids show a remarkable amount of surface disruption. This can result in improved production following a fracturing treatment.

Shale is a fine-grained sedimentary rock characterized by thin layers that break with an irregular curving fracture parallel to the bedding planes. Shale is typically deposited in slow-moving water and is often found in lake and lagoon deposits, river deltas, offshore beach sands and on floodplains.

Shale usually contains free as well as adsorbed gas. If the predominant production mechanism is by desorption, then a stimulation treatment should be designed to maximize total fracture surface area. If most of the gas is free gas stored in the micro-porosity and natural fractures, a high-conductivity prop frac would likely be more effective.

ShaleStim℠ Process Provides Effective, Holistic Approach

The low permeability of shale has driven stimulation design toward large-volume water fracs, the most economical and practical way to stimulate gas shales. Volumes in excess of 100,000 bbl have been pumped on a single zone.

Pumping this amount of water into a gas-bearing formation, however, is not without risk. Halliburton's ShaleStim process helps address some of the negative consequences associated with large-volume water fracs. The service is tailored to the specific shale production mechanism and composition. The process follows the lifecycle of the reservoir, which includes these phases:

- *Phase 1*—Regional Resource Reconnaissance (Reservoir Assessment). Initial look at reservoir potential and extent. Evaluate the shale. Quantify reservoir quality.
- *Phase 2*—Local Asset Evaluation (Start-up Exploration). Experimental development of drilling and completion techniques. Trial investigation of fracture design and production prediction.
- *Phase 3*—Early Development (Mass Production). Rapid development with optimized design. Database development and benchmarking.
- *Phase 4*—Mature Development (Reserve Harvesting). Cash flow cycle. Reservoir production history matching. Adjusting reservoir model. Database imaging.
- *Phase 5*—Declining Phase (Maintenance and Remediation). Identification of remedial candidates. Re-stimulation. Decline curve shifting.

ShaleStim service consists of a family of products and services to help operators enhance asset value throughout the shale reservoir lifecycle.

- *ShaleEval℠* service—Shale evaluation including total organic carbon (TOC) content, shale maturity (vitrinite reflectance Ro), gas content (scf/ton), free and adsorbed gas content, fracture flow tests, x-ray, SEM and acid solubility analysis.
- *ShaleLog℠ service*—Log identification of sweet spots (TOC, scf/ton, brittleness, GIP, IP and EUR).
- *ShaleFrac℠ service*—Shale-specific hydraulic fracture stimulation technologies.
- *ShaleClean℠ service*—Primary stimulation and remedial chemistry designed to restore or enhance productivity.

Production decline from fractured shale appears to have three distinct flow periods, each governed by multiple reservoir and completion factors. In the early period, frac spacing in the stimulated area and frac permeability are key criteria. During a middle flow period, fracture areal extent is important, along with frac permeability. In the later period, un-fractured area (drainage area), matrix permeability and frac spacing in the non-stimulated area all have an impact.

Though proppant transport in thin fluids is not well understood, prop nodes, bed fluidization and the ability to move high-density prop deposits through narrow slots and right angle turns have been demonstrated in lab experiments.

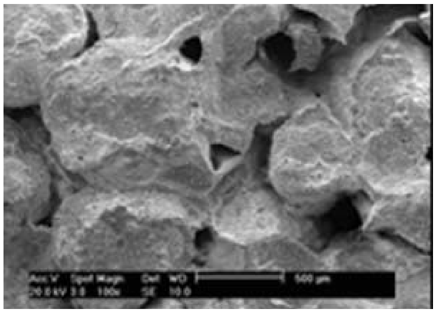
ShaleFrac service is useful because shale is not characterized by single bi-wing fractures but contains many parallel and orthogonal fracture wings. Empirical models have been generated for the Barnett Shale using microseismic image data.

Each ShaleClean service treatment has several elements. Surface reactive fluid enhances the overall surface area conductivity; surface modification agents help reduce fines migration, enhance fracture conductivity and help remove treatment water. A microemulsion also helps treatment water removal. Conductivity enhancement/endurance prop additives improve and maintain fracture network conductivity during the production cycle.

ShaleClean agent is a primary water frac clean up and remedial treatment chemical used to mitigate the impact of foreign chemicals and solids injected during a large-volume water frac. These foreign materials can cause reactions between the fluids injected, the rock face and the reservoir fluids. Scale, sludge and emulsions can form. Other problems can occur, including formation degradation, prop pack loss of conductivity and fines migration. Fresh water also can introduce bacteria capable of thriving at downhole conditions.

ShaleFrac-RF service

The use of reactive fluids is a relatively new concept in shale stimulation. The concept evolved from the use of acid slugs to increase injection rates. The unexpected pressure drop that occurs when acid hits the shale formation raised a question about shale acid solubility. Most shales in the Mid-Continent area have a solubility of 8% to 20%. Multiple treatments have been done using between 20,000 gal and 200,000 gal of reactive fluid dispersed through the water frac volume.



Diagenesis can greatly reduce fracture conductivity. Coating the proppant with SandWedge enhancer can help control this process.

Reported initial production has been double that of treatments without reactive fluids.

SandWedge® enhancer

SandWedge enhancer, part of Halliburton's Conductivity Endurance technology, is now available in a special formulation designed for water fracs. This on-the-fly proppant coating technology provides several benefits for water frac treatments:

- increases conductivity.
- increases load recovery;
- controls the effects of diagenesis; and
- helps increase production.

SurgiFrac® service provides fracture control

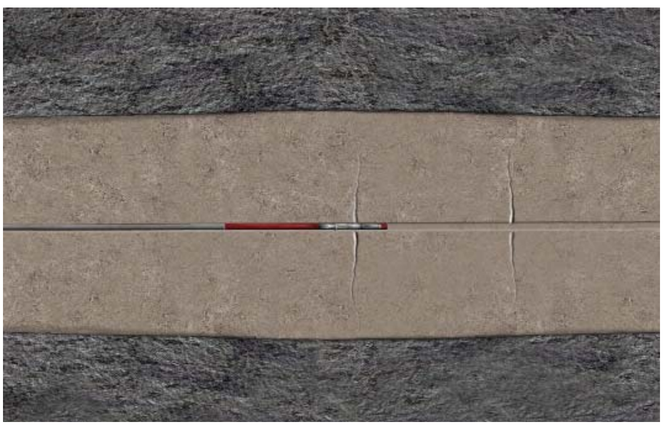
Horizontal completions are the choice for many shale wells; however, in some situations, horizontal completions are less productive than fractured vertical wells. Low-permeability zones often contain multiple layers of varying porosity and permeability. Unexpected vertical permeability barriers often exist that are too thin to be detected by conventional well logs.

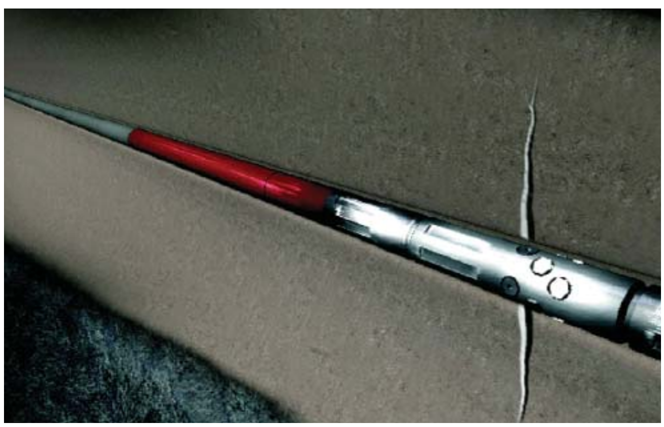
Uncontrolled generation of hydraulically induced fractures can result in a poor distribution of the fractures along an openhole lateral. For best results, a fracture treatment should produce a limited number of discrete fractures widely separated and well distributed along the horizontal.

Fractures also should be created only where they are needed. Multiple fractures close to each other will improve the initial stimulation response but usually provide little additional cumulative production after a year or two following treatment.

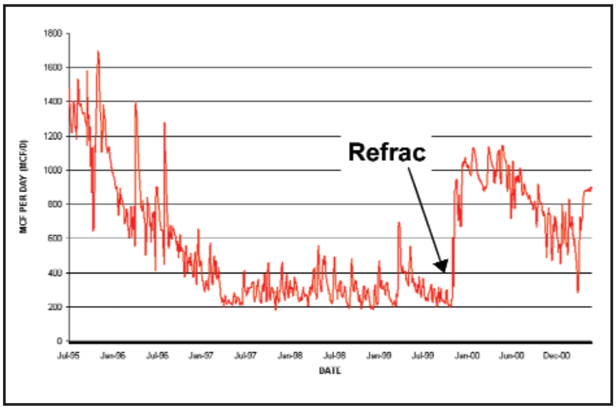
Now, there is a stimulation process that is consistently effective in low- to medium-permeability horizontal completions. Field performance of Halliburton's SurgiFrac service has shown it can provide precise control of fracture initiation and propagation in gas shale. The SurgiFrac service provides important benefits:

- helps increase production by re-entering openhole horizontal wellbores with coiled tubing or jointed pipe and accurately placing fractures in bypassed and underperforming zones quickly and cost effectively;





SurgiFrac service combines proven hydrajetting technology and fracturing techniques to enable placing multiple fractures with surgical precision in horizontal wellbores with no downhole sealing devices. Operators are achieving significant increases using this method.



Example of the effect of refracturing a shale well on production rate.

- optimizes reservoir drainage by precise location of fractures with a customized treatment;
- adds new production more quickly than with conventional fracturing by creating multiple fractures in the wellbore with no sealing (packers, etc.) required between zones; and
- reduces fracturing treatment costs by lowering tortuosity, resulting in less equipment and lower viscosity fluids.

As with single wellbore horizontal completions, a growing number of marginally economic Level 1 and Level 2 multilateral completions are not living up to their potential. Conventional methods that are effective usually pose too high a risk of well problems or are too costly for low-return reservoir conditions.

In openhole multilateral Level 1 wells in Texas and Louisiana, however, SurgiFrac service was used to create six to 14 independent fractures in each of several dual and triple lateral wells, some of which were sand fractured and others were acid fractured. Consistently high production rates proved that if permeability is low, the SurgiFrac process can stimulate wells that could not be stimulated with conventional techniques.

Case histories

In Canada, SurgiFrac service provided a six-fold production increase, turning a well with the lowest pre-treatment production rate of three wells into the best performer. To stimulate production from the three horizontal completions in a low-permeability carbonate reservoir, conventional treatments and the SurgiFrac process were used. Well depths ranged from 11,000ft to 12,500ft (3,355m to 3,813m) and laterals varied in length from 2,200ft to 4,600ft (671m to 1,403m). Reservoir pressure was between 3,219psi and 4,650psi.

Wells 1 and 2 had the best potential. They were treated using coiled tubing and a tool with a jetting sub to place acid treatments. Production increases, however, were disappointing.

Well 3 had the lowest pre-stimulation production rate and the least potential, even though it had the longest openhole lateral. After Well 2 experienced such a short-lived production increase, it appeared the only way to make Well 3 economical was to create deep fractures that could connect with natural fracture networks that were not near the borehole.

SurgiFrac service used 1 3/4 in. coiled tubing to pump three stages averaging 5,000 gal of gelled 28% hydrochloric acid (HCl) down the tubing through the special service tool. Carbon dioxide pumped through the annulus formed a foam down hole that enhanced acid retardation and helped limit fluid loss.

The result was longer fractures.

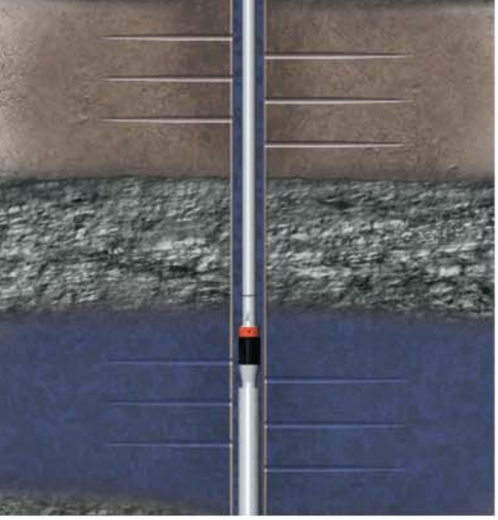
Although only three fractures were placed along the lateral, production increased from 0.83 MMscf/d to 5.9 MMscf/d. The well exhibited a slower decline than Well 2, indicating the treatment was successful in reaching the distant fracture network.

Other field results highlight SurgiFrac's versatility and effectiveness:

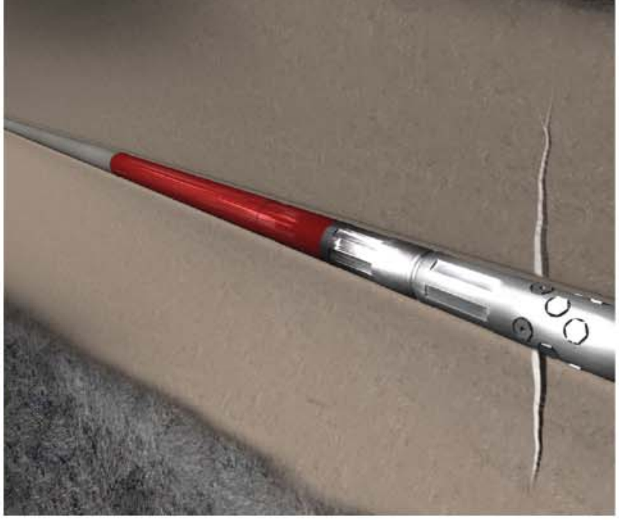
- production increased 800% after the service was deployed with coiled tubing in a 4 3/4-in., 1,600-ft (488-m) openhole horizontal section and eight fractures were placed in 5 hours;
- in the first treatment of an openhole multilateral completion, a workover rig and a bent sub were used with the SurgiFrac assembly to place six small-to-moderate size fractures in each of two 800-ft (244-m) laterals using 28% HCl as a stimulation fluid and avoiding a nearby water zone. An initial five-fold increase stabilized at a four-fold increase several weeks after the treatment;
- in South Texas, a gas well with an 1,800-ft (549-m) horizontal perforated liner was treated with 40,000 gal at 18 bbl/min down casing, boosting production by 75% compared with a conventional acid frac;
- in Southeast New Mexico, an old well in a mature waterflood with a 1,600-ft (488-m), 4 3/4-in. openhole lateral in low-permeability carbonate was producing 3 b/d of oil before being fracture-acidized with SurgiFrac service, creating eight distinct fractures. Initial production after treatment was 50 b/d of oil and production a month later was 30 b/d of oil;
- offshore Brazil, SurgiFrac boosted production from an offshore, openhole horizontal well with a pre-perforated liner by five-fold after three proppant fractures were placed using bauxite and resin coated bauxite (16 to 20 mesh) in concentrations reaching 14 lb/gal.

Refracturing shale wells

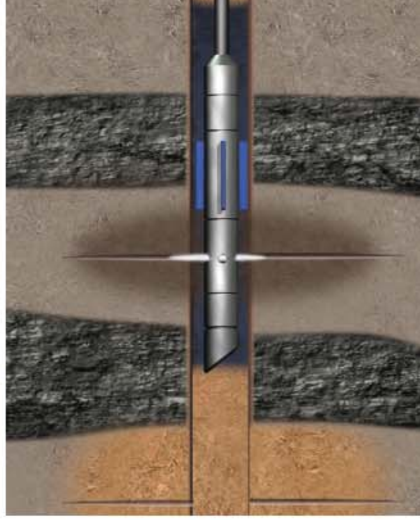
It has been established that only 10% of GIP is recovered with the initial completion. Refracturing the shale can increase the recovery rate by an additional 8% to 10%. Simple reperforation of the original interval and pumping a job volume at least 25% larger than the previous frac has produced positive results in vertical shale wells. ■



Cobra Frac® service



SurgiFrac® service



CobraMax® service

What is reliability worth?

Reaching more unconventional reserves with pinpoint accuracy.

Halliburton's highly reliable, exclusive **Pinpoint Stimulation** technology places multiple treatments in vertical and horizontal wells, for both cased- *and* openhole completions.

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