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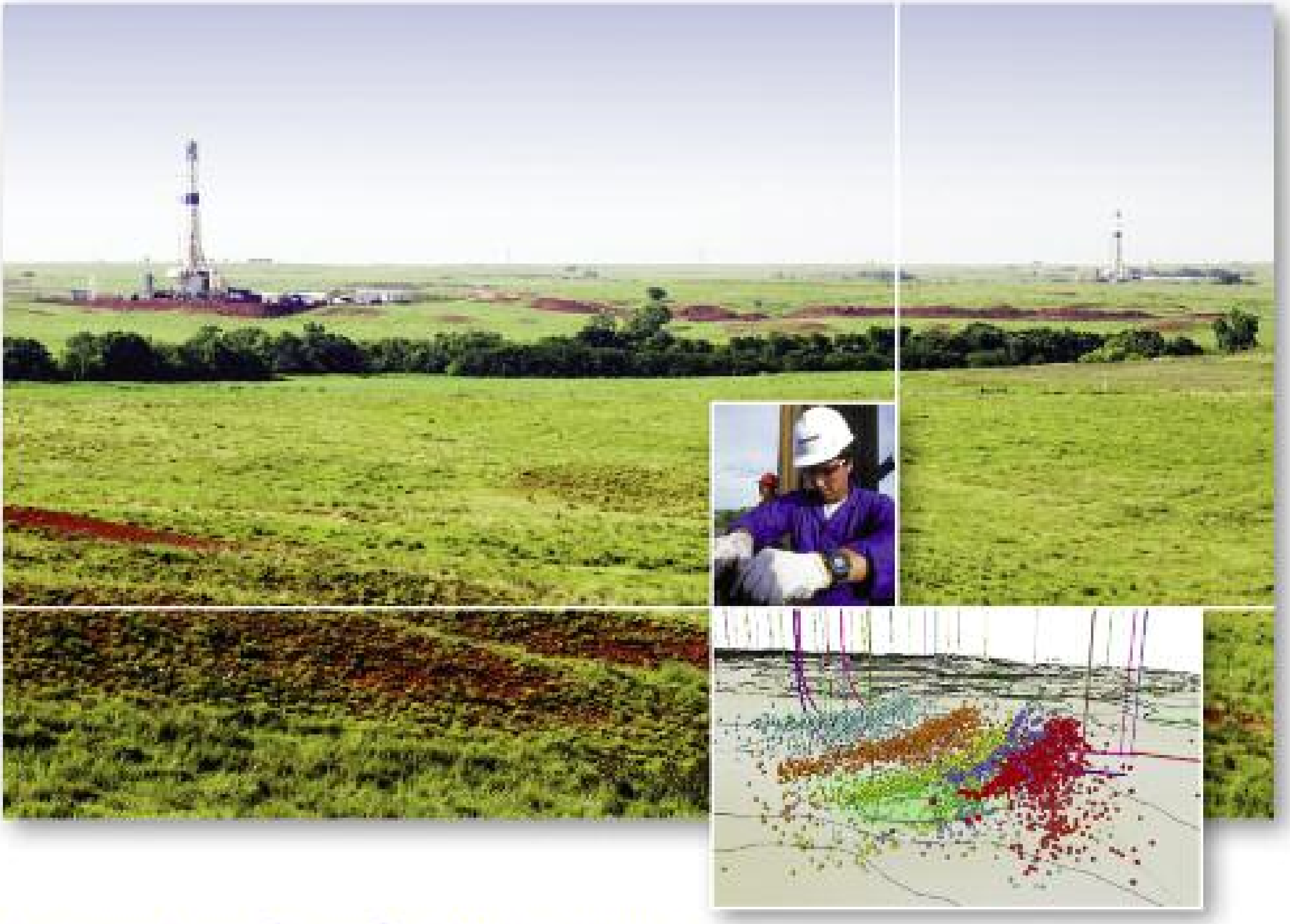

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More Natural Gas On the Way

Hats off to the oilfield service sector that is enabling E&P firms to find and produce more natural gas from tight sands, shales and coalbed methane. It's an exciting time for the industry.

Production from shale reservoirs is grabbing the headlines thanks to the Haynesville and Marcellus shales in particular. But U.S. shale output could double in the next decade and supply up to 25% of U.S. gas needs, according to Terry Ruder, vice chairman of the Natural Gas Supply Association, and also senior vice president of marketing and midstream at Devon Energy Corp.

Ruder told a Federal Energy Regulatory Commission conference in November that shale plays currently produce 6- to 8 billion cubic feet of gas per day, or 10% to 12% of U.S. demand. But that production could more than double to 15- to 20 Bcf per day within a decade, he said. Americans use about 60 Bcf of gas per day currently.

"What we've seen so far from shales is just the tip of the iceberg," he said.

Indeed, shale plays are "disruptive plays," says Richard Nehring of Nehring Associates in Colorado Springs, Colorado, because they will have such a large impact on U.S. gas supply—and maybe on prices—for many years to come.

The FERC believes in the story. "U.S. conventional gas production fell 24% between 1998 and 2007, from 37 Bcf a day to 28.5 Bcf a day. Just over half of U.S. daily gas production can now be considered to come from conventional sources compared to 72% some 10 years ago," a FERC report says.

"Gas production from unconventional gas sources (shale, tight sands, coalbed methane and deep gas) grew at an average annual rate of 6.4% between 1998 and 2007, from 14 Bcf a day to 25 Bcf a day, and could soon become the dominant source of gas production in the U.S.," FERC says.

—*Leslie Haines, Editor-in-chief,* Oil and Gas Investor

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Shale Gas Plays: Boom or Bust in 2009?

By Gretchen Weis, Contributing editor

With lower gas prices and a credit squeeze for some companies, how do these shale players see 2009 taking shape?

From the Woodford, Fayetteville and Barnett to the Haynesville and Marcellus, leasing and drilling activity has been booming. But the $64,000-question today is, will these shale plays go from boom in 2008 to bust in 2009?

Hardly, but current commodity prices and a virtual lock-down on access to working capital are redefining drilling and development priorities for the year ahead.

Given the price-sensitive nature of unconventional gas commercialization, it's no surprise that liquidity will call the shots in the shales in 2009. We talked with several small- to mid-cap companies about their successful shale programs in 2008 and about the challenges and opportunities they see ahead in 2009.

PetroQuest Energy

A $500-million company, PetroQuest Energy Inc. (NYSE: PQ) saw tremendous success in Oklahoma's Woodford shale in 2008. Entering Oklahoma to target Hartshorne coalbed-methane opportunities in early 2004, PetroQuest now holds interests in more than 45,000 net acres in tier-one Woodford shale acreage. The company has an average 50% to 60% ownership interest in the Woodford and operates the majority of its acreage.

Today, about 30% of the company's production comes from the Woodford, which is flowing at approximately 30 million cubic feet per day (MMcf per day), and growing.

PetroQuest also holds an average 10% working interest in 18,000 net acres operated by others in the Fayetteville shale in Arkansas, with net daily production of 6 MMcf there—a level that is continuing to expand as more partner wells are brought on-stream.

"Despite lower commodity prices and a slowdown in spend during fourth-quarter 2008, PetroQuest expects to see year-end reserve growth of 20% to 30% through the drill bit," says Charlie Goodson, chairman, president and chief executive officer.

The company estimates it will have spent about $100 million in 2008, or 40% of its capital budget, on drilling and development in the Woodford by year-end, which included drilling 20 operated horizontal wells. It had three rigs drilling earlier in the year, but expected to cut back to one rig by yearend 2008.

At press time, PetroQuest had yet to announce a capex plan for 2009, but intends to execute its drilling and development plans within cash flow.

"We will begin 2009 activities with one rig operating, to reflect current market conditions," Goodson says. "But 2009 will also be front-end loaded with high drilling costs. We need to see those costs come down to reflect the current price environment."

PetroQuest drilled longer, more cost-effective lateral wells in 2008 to lower finding and development costs. Completion costs for these super-laterals remain high, but so is the expected production payout from these long, horizontal wells. Thus, the company hopes to see shale production growth in 2009, even if it drills fewer wells than in 2008.

"With the pricing outlook and equity markets slammed shut, companies are going to batten down the hatches and live within cash flow in 2009," he says. Analysts predict that PetroQuest's current Gulf of Mexico/Gulf Coast inventory should provide the cash flow needed to fund the company's Woodford and East Texas programs in the year ahead.

Other weapons in PetroQuest's liquidity arsenal: The company enjoys the $40-million-plus cash benefit from spinning off its midstream pipeline assets in Oklahoma to MarkWest Energy Partners LP in July 2008.

And, accomplishing the near-to-impossible in October, PetroQuest expanded its credit facility by $55 million to $150 million borrowing capacity. In addition, it expanded its banking group from three to five banks and extended its debt maturity until 2012.

"The fact that we were able to accomplish this without modifying our financial covenants during a virtually nonexistent credit market speaks volumes for our 2008 reserve growth and diversification strategy," notes Todd Zehnder, PetroQuest's executive vice president, chief financial officer and treasurer.

Zehnder points out that increased shale volumes shifted PetroQuest's production profile to a nearly 50-50 split between the Gulf of Mexico and Midcontinent, and opened the door to increased hedging activities.

"As our production stream diversified over the past several years, we became more comfortable with the percentage of production we were willing to hedge," he says. "We have committed virtually all of our operated Woodford production to a five-year, firm-transportation commitment to serve a large utility in the Midwest."

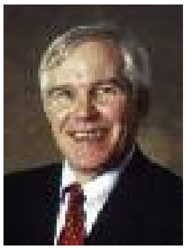
PetroQuest will start 2009 with approximately 15 billion cubic feet equivalent (Bcfe) of total corporate gas volumes already hedged with a floor of $8.43 per thousand cubic feet (Mcf).

In addition, the company looks forward to the completion of the Boardwalk Pipeline expansion, which will provide additional outbound capacity for PetroQuest's Fayetteville volumes and is likely to benefit pricing for Woodford volumes as well.

"Financial discipline will be more highly rewarded in the shales in the 2009 environment," Goodson says. "We are well-positioned to ride this out, and we have the flexibility to ramp back up quickly when commodity prices turn back around."

Any plans for growth through acquisition in the year ahead? "While we certainly have plenty of assets and activity on our plate, that's not to say we won't take a look at opportunities," Goodson says. "Some private companies may not have access to the capital or equipment they need to continue to hold their leases. We've preserved our balance sheet in case it becomes cheaper to buy reserves than drill for them in the coming year."

Newfield Exploration



David Trice

Newfield Exploration Co. (NYSE: NFX) was the first to enter the Woodford, beginning in 2003. With 165,000 net acres, 85% of which are held by production, it is today one of the largest players in the region, operating more than 225 horizontal wells. Its Woodford shale production was expected to hit approximately 250 MMcf per day gross by year-end 2008, or 138 million net.

The company backed off earlier projected capital spending plans for 2009 by more than $450 million, with $1.55 billion now earmarked for 2009 for domestic and international projects, but the Woodford remains Newfield's crown jewel and primary focus in the year ahead.

The company plans to put $500 million of its capital to work in the Woodford in 2009, comparable to 2008 spending levels in this play.

"Cash will be king in 2009," vows David Trice, chairman, president and chief executive officer. "Our highest priority in the year ahead will be to drill our best projects while living within cash flow. The Woodford remains the most active play in Oklahoma and its development represents our largest capital expenditure."

Trice describes Newfield's Woodford activities. "We ran between 10 and 12 operated rigs in the Woodford in 2008, which allowed us to drill about 100 operated horizontal wells there. We had hoped to increase to 17 operated rigs in 2009, but current market conditions called for scaling back plans.

"We hope to have 14 operated rigs in place by midyear 2009 for a 38% projected growth rate in Woodford production volumes."

Having completed its first dual-lateral well in 2008, Newfield plans for super-extended lateral drilling (8,000

Newfield Exploration Co. projects 38% growth in its Woodford shale production in 2009. (Photo courtesy Newfield)

to 10,000 feet) in the year ahead, hoping to boost volumes while lowering development costs.

"With the majority of our acreage HBP [held by production], we have control over where and when we drill," Trice says. "That gives us the flexibility to adjust our budget to align with market conditions and preserve liquidity to weather whatever comes over the next few quarters."

Newfield ended 2008 with approximately 60% of its 2009 natural gas production hedged at attractive prices, with exposure across 13 separate counterparties. For the first half of 2009, total corporate production is hedged primarily in fixed-price swaps averaging $8.40 per million Btu. For second-half 2009, approximately 50% of gas production is hedged at similar price points.

In an effort to minimize the risk of basis differentials, Newfield has entered in three separate 10-year, firm-transportation agreements totaling up to 650 MMcf per day of expected Woodford production.

According to Trice, Newfield expects to enter 2009 with about $800 million of liquidity.

"We don't like the environment, but we like the way Newfield is positioned to face the current market," Trice says. "The Woodford will continue to be an important part of Newfield's playbook over the next decade."

GMX Resources

GMX Resources Inc. (NASDAQ: GMXR) is a pure-play natural gas exploration and production company headquartered in Oklahoma City, Oklahoma. It's had a presence in East Texas for 11 years and drilled into the Haynesville/Bossier shale for the first time in 2006.

With a market cap of more than $700 million, the company raised $125 million through a bond offering in February 2008 and held an equity offering in July, netting $134 million to beef up cash flow and nearly double its Haynesville acreage—with an average cost of less than $5,000 per acre.

With services and supplies tight, the company also pre-funded drilling and pipeline materials this past year to support an aggressive Haynesville program.

GMX expected to end 2008 holding approximately 38,455 net Haynesville acres, operating 81% of those. According to chairman, president and CEO Ken Kenworthy Jr., GMX holds the most Haynesville acreage per million shares of any other publicly traded operator in the play.

GMX drilled or participated in 18 vertical test wells in the Haynesville in 2006 and completed its first horizontal well in November 2008. Initial production from the eight-stage frac in this horizontal well flowed 7.7 MMcf a day. Through GMX's activities in the Cotton Valley sands, a significant portion of its Haynesville acreage is held by production.

GMX plans to ramp-up considerably in the Haynesville/Bossier Shale in 2009.

"We'll be shifting our focus in the year ahead from the Cotton Valley to target 88% of our $400-million 2009 capex budget for horizontal drilling activities in the Haynesville," says Kenworthy.

"As we continue to set records with our increasing production volumes, we believe we can fund our 2009 plans out of projected cash flows, plus some additional borrowings from our existing credit facility." The company will enter 2009 with a net available credit line of $160 million.

GMX expects to kick off 2009 with four rigs in the Haynesville/Bossier Shale and hopes to expand to eight or nine rigs as the year progresses. "We've ordered four new fit-for-purpose rigs for three-year terms, to be delivered throughout 2009 for horizontal well development in the Haynesville," Kenworthy says.

"Current plans are to drill 45 net wells in the Haynesville in 2009 for an estimated projected production of approximately 30 Bcfe, net. That would represent a more than 100% increase in overall corporate production growth in 2009."

The final 2009 well count will depend on rig delivery schedules, internal cash flows, and frac proppant and other service equipment availability, among other factors.

Like most other producers, GMX has an actively managed hedging strategy to reduce risk on a commodity price basis. Approximately 72% of 2009 proved developed producing production is hedged.

"As production increases in 2009, we'll continue to evaluate our hedging strategy and may consider put options."

GMX owns the Endeavor Pipeline Co., a gathering and compression system in the region with interconnects to a number of major trunklines heading north, east, south and west. "We want to be an early mover to access end markets with Haynesville volumes and will be seeking midstream relationships and joint ventures with other producers in the area to leverage our infrastructure investment in the Endeavor system," Kenworthy says.

In addition to its aggressive Haynesville development plans, GMX remains open to other possible growth opportunities in the region in 2009.

"A number of competitors may have to limit their budgets and cut back on Haynesville activities depending on their ability to access capital. We may find people interested in partnering to be able to save leases held by production," Kenworthy explains.

"Depending on market conditions, we'd like to remain open to looking at growth opportunities on a case-by-case basis, including more lease acquisitions as prices in the Haynesville start to come back down to earth.

"Our size and liquidity will allow us to move quickly to respond to market shifts and opportunities in the year ahead," Kenworthy says.

Quick Takes

We asked these executives what they think are the biggest challenges ahead for the shales in 2009.

For PetroQuest's Charlie Goodson, it's the specter of severe recession. "We look out at the broader economy over the next few quarters and wonder, have we hit bottom yet? Is there an end in sight? If the country slips into a deep, extended recession, how will that impact the consumption of natural gas in 2009 and beyond?"

Ken Kenworthy of GMX Resources agrees. "The biggest challenge ahead for everyone is the health of the overall global economy, which could impact the health of the banks lending capital to this industry."

Rex Energy's Ben Hulburt hopes that access to water treatment facilities doesn't slow things down in the Marcellus in 2009. "Pennsylvania has very few water treatment and disposal facilities available, and they are virtually all at full capacity to help support the expected drilling ramp-up coming to the Marcellus," he says.

"Each horizontal well can produce anywhere from 2- to 2.5 million gallons of water that must be treated and disposed of properly. The industry is testing new technologies for environmentally safe water treatment, but clearly, access to water treatment capabilities will be key to Marcellus development until more facilities are built."

Hulburt also notes that Appalachian Basin production currently enjoys pricing premiums, which might erode as the Rex East pipeline hits the region in mid-2009. •

Cubic Energy


Calvin Wallen

Cubic Energy Inc. (AMEX: QBC) is a Dallas micro-cap that acquired Cotton Valley acreage in northwestern Louisiana in 2004. It was among the first to discover Bossier and Haynesville shale pay zones underneath its 6,300 net acres in fall 2007.

Cubic drilled five vertical wells in 2008 to prove up reserves and hold Haynesville leases by production. Initial flow rates from these vertical wells have been in the 1- to 1.2-million-a-day range, but the company expects those flows to settle back to around 300,000 cubic feet a day.

"We entered northwest Louisiana four years ago with the intent on developing the Cotton Valley and hit paydirt in the Haynesville shale," explains Calvin Wallen, president, chief executive officer and chairman.

"Even though the industry is facing a brutal climate right now, people still seem to be gung ho on the Haynesville. They are seeing a better bang for their buck there."

Cubic Energy holds acreage in several sweet spots: the southern track south-southwest of Shreveport, as well as the North Johnson branch of the Haynesville. Based on Cubic's well flows and the proximity of other nearby production, Cubic agrees with industry estimates there are

Cubic Energy Inc. drilled five vertical Haynesville wells in Louisiana in 2008 to hold acreage. (Photo courtesy Cubic Energy Inc.)

55- to 65 Bcf of recoverable reserves per square mile in the Haynesville/Bossier Shale.

In addition, the company owns two compressor sites, two tap points and has pipelines and rights-of-way in place on its acreage.

"Cubic owns two small donut holes of acreage surrounded by larger, extremely active players. With attractive, recoverable reserves in place, we felt it was time to execute our exit strategy," Wallen says.

Cubic has always been on the progressive path to form a public company, acquire acreage, prove up value and then liquidate. The current environment wasn't a factor when the company hired RBC Richardson Barr in the fall of 2008 to explore a strategic sale of its Haynesville/Bossier shale holdings.

"With cash so tight right now, we're open to a stock deal. With everyone's stock taking a beating in the market, we see a stock deal as a win-win for both parties," Wallen says. "We hope to have a transaction finalized sometime in the first quarter of 2009."

Following the liquidation of Cubic, Wallen plans to pursue other non-shale projects with his team at Tauren Exploration, one of his privately held companies.

Rex Energy in the Marcellus

The Marcellus shale is a hometown, backyard play for Rex Energy Corp. (NASDAQ: REXX), based in State College, Pennsylvania. With a market cap of approximately $200 million, Rex is the largest oil producer in the Illinois Basin and also focuses activities throughout Appalachia and the Permian Basin.

In 2008, Rex spent approximately $66 million, or 48% of its capital budget, in the Marcellus, with more than $50 million of that spent on an aggressive leasing program. By year-end 2008, Rex held approximately 65,000 to 70,000 net acres, and will operate the majority of the properties.

The company operated one rig and drilled seven vertical test wells in the Marcellus in 2008, but has not disclosed reserve estimates to date. "The good news is that we sure don't have to worry that there's no gas down here," says Ben Hulburt, president and CEO.

Rex Energy has a $115-million capital budget in place for 2009 and hopes to earmark $56 million, or roughly 49% of its working capital, on horizontal drilling in the Marcellus in the year ahead.

"In 2008, we focused on land acquisition throughout the Marcellus," Hulburt explains. "In 2009, it's going to be all about drilling and development.

"We'll continue to operate one rig going forward and focus on drilling between five to 10 horizontal wells, depending on market conditions and our results."

Since the majority of Rex's leases were acquired in the past 12 months with five-year time horizons, Hulburt believes the company has plenty of time to drill and develop its Marcellus holdings to hold acreage by production.

Horizontal drilling plans for 2009 will begin in Westmoreland County in the southwestern corner of the state, where Rex has two pipeline taps in place and plans to install a third tap in the next year.

"In Westmoreland County, we've got enough available market capacity to bring wells online as they are completed and flowing," Hulburt says. The company expects to shift its focus to drill horizontal wells in the Clearfield and Centre areas in the second half of 2009.

Ben Hulburt

Despite current market conditions, Hulburt believes Rex Energy's liquidity and strong balance sheet will provide the capital needed to continue its push into the Marcellus in 2009. It expected to end 2008 with $70- to $80 million in revenues. Most importantly, the company currently has zero long-term debt.

Rex anticipates dipping into its $90-million, three-year credit facility to support capital plans in 2009. In addition, the company may divest all of its Texas and New Mexico Permian Basin assets in first-quarter of 2009. Proceeds from such a sale would be refocused predominantly on Marcellus development.

"We're very excited to be so well-positioned in the Marcellus—it's right in our backyard," Hulburt notes.

"As a Pennsylvania-based company, our knowledge of the political and regulatory landscape will serve us well. We expect the Marcellus to be as big an asset base for us as the Illinois Basin has been on the oil side." ■

This rig drills in the Marcellus shale for Rex Energy Corp. (Photo courtesy Rex Energy Corp.)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Q&A

Haynesville Tech Primer

Bill Clark, marketing and sales manager, U.S. Central GeoMarket for Schlumberger in Houston, answers our questions about developing the Haynesville shale.

Investor Bill, in general, what are the new lessons you and the operators have been learning about horizontal drilling/completing/frac'ing in the shales?

Clark Drilling and completion efficiencies in horizontal shale reservoirs have increased significantly. Improved techniques for placing bridge plugs and perforating have reduced the down-time between stimulation treatments. Methods such as Zipper-Fracs, where one frac crew and one perforating crew are used to complete two adjacent laterals concurrently, allow operators to complete wells faster with lower resource requirements.

In shales, the evolution has been to perform more stimulation treatments per lateral through perforation clusters that are spaced closer together. As more shales have been developed, the benefit of larger proppant volumes, whether due to higher stresses, as is the case for the Haynesville, or because of proppant embedment, as commonly occurs in high clay-volume rocks such as the Marcellus, has become clear.

Investor Which best practices from other shales may be applicable in the emerging Haynesville? Which may not?

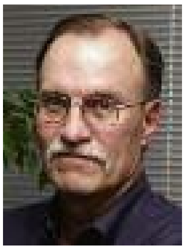
Clark The Haynesville, like all other shale reservoirs to date, is an ultra-low permeability reservoir that requires very large hydraulic fractures to expose as much rock as possible to a pressure drop to maximize production. But it has greater depth and higher fracture closure stress.

Investor What will that mean?

Clark It necessitates greater attention to the conductivity of the hydraulic fracs than is required in most shales. Therefore, viscous fluids are used to place higher concentrations of high-strength proppants, both ceramics and resin-coated sands. The characteristics of the Haynesville vary across the basin, but openhole shale-gas evaluation logs are able to qualify and quantify the key characteristics of the reservoir.

Investor Is microseismic going to be a key to this play?

Clark Yes. Similar to other shale plays, microseismic fracture mapping will play an important role in evaluating the hydraulic frac geometry and complexity.



Bill Clark

Investor Is the Haynesville going to need a different approach than other shales such as Barnett or Fayetteville? Why?

Clark The high Haynesville reservoir temperature is a challenge for directional drillers because we are bumping up against the upper temperature limit of most of the drilling and measurement tools.

And, because of the greater depth and higher fracture closure stresses encountered in the Haynesville, larger volumes of higher-strength proppant are required as compared to other shale reservoirs. Closure stresses of 10,000 psi are not uncommon in the Haynesville. This is up to three times greater than the stresses seen in the Barnett.

Investor What problems does that cause?

Clark Poorly-propped fractures are less likely to remain conductive when the wells are placed on production. This also infers that engineered production-management techniques to minimize the stress placed on the proppant pack will be required. The higher temperature and pressure also leads to the Haynesville being mostly a free-gas play with adsorbed gas being only a small contribution to the total production.

Investor Is the technology needed for the Louisana portion of the Haynesville slightly different as it crosses the border to East Texas and the Bossier/Haynesville?

Clark As I said, the quality of the reservoir varies as you move across the basin. Therefore, robust well log and core petrophysical evaluations need to be used to understand how the reservoir quality and corresponding key completion drivers change spatially. Once these are identified, then you can change the completion program. For example, mineralogy changes impact the stresses applied to the proppant in the hydraulic fractures. This also impacts the stress contrast through the various intervals and corresponding hydraulic fracture height growth. So, identifying spatial changes in mineralogy will impact the types of proppant, the types of fracturing fluid, and the pump rate used during the well completions. ■

In the Maverick Basin, TXCO's on the hunt

By **Gary Clouser,** Contributing Editor

TXCO Resources Inc., the largest landholder in the Maverick Basin in south Texas, is methodically developing its emerging Pearsall shale play. The company estimates net gas resources of at least 8 trillion cubic feet.

The Pearsall shale gas play has produced gas for many years, but it had a reputation as a hit-or-miss target. Initial production from the formation occurred in the 1970s. A few good wells intersected natural fractures and had high flow rates, but additional drilling did not intersect fractures, uncertainty ensued, and development ceased. Now, San Antonio-based TXCO and its partners are using horizontal drilling and advanced fracturing and completion techniques perfected in the Barnett shale as they try to make the Pearsall into a predictable resource play across virtually the whole basin.

Results have been encouraging during Phase I of separate farm-in agreements the company has with EnCana Oil & Gas (USA) Inc. and Anadarko Petroleum Corp. as the partners evaluate the play's long-term viability.

TXCO says its Pearsall shale gas project consists of 848,000 gross (341,000 net) acres covering 1,325 gross (533 net) sections. The company estimates gas in place in the play could be 80- to 120 billion cubic feet per section.

At a recovery rate of just 20%, that would result in estimated recoverable gas of 16- to 24 Bcf per section, or square mile. The company thus estimates the potential net gas asset of its Pearsall play is 8- to 12 Tcf—a staggering and transformative amount for a company of its size.

TXCO says it has more than 1,000 prospective Pearsall drilling locations.

Early Results

One well, known as the Myers well, drilled by TXCO under the EnCana agreement, was placed on production in late September 2008 at 2.8 million cubic feet a day. It averaged 1.5 MMcf a day for the first month-and-a-half of production even though it was curtailed by the low-pressure pipeline system into which it is producing. This was the third and final well drilled under Phase I of the farm-in agreement. In late October, TXCO spud the first Phase II well on the EnCana acreage.

"We intend to 'microseismic monitor' the frac on this well as we did our Myers well," TXCO president Gary Grinsfelder told investors during the company's third-quarter earnings conference call in November.

The microseismic technique allows the partners to closely follow the progress of a fracture stimulation treatment as it occurs, which can lead to higher production rates and reserves, he explained. Under Phase II with EnCana, TXCO will drill four additional Pearsall wells before July 1, 2009.

On its Anadarko farm-in, TXCO was flowing back gas with frac fluid after completing a four-stage frac in a slimhole test well. "We continue to be delayed in fracing, due to the short supply of high-strength proppant necessary to properly frac the high-pressure Pearsall formation," Grinsfelder said.

Proppants are fluids laced with granular material. The man-made, sand-sized particles are mixed with fracturing fluids to hold fractures open after a hydraulic frac treatment.

TXCO also says it intends to drill four additional wells within the next year under Phase II with Anadarko. St. Mary Land & Exploration Co. is also participating with TXCO under the agreement, which required two Pearsall and two Eagleford test wells in Phase I.

The Eagleford is a separate shale with resource-play potential that lies above the Pearsall across much of South Texas.

Steady Pace

"We are particularly excited about the results of our Pearsall gas shale play and the Eagleford shale play,"

The Eagleford Shale

Petrohawk Energy Corp. in October unveiled a significant natural gas discovery in the Eagleford Shale, some 20 miles east of TXCO's acreage. Its shale well was placed on production at 9.1 million cubic feet equivalent per day. The company says it has leased more than 100,000 net acres in what it believes to be "the most prospective areas for commercial production from the Eagle Ford shale." This new field is in La Salle County, Texas.

At press time, the Houston-based company was drilling the lateral on a second confirmation well and a third well was expected to spud. Petrohawk is the operator and owns 90% working interest in the project, with 10% owned by industry partners.

Chief operating officer Dick Stoneburner says the discovery "folds perfectly into our portfolio of unconventional resource assets. Petrohawk's staff has extensive experience in the acquisition and development of horizontal plays as exhibited by our results in the Haynesville and Fayetteville shale plays. Leveraging that expertise to uncover new opportunities like the Eagleford shale adds significantly to our playbook."

The company expects drilling and completion costs for development wells to range between $5- and $7 million. For 2009, it has dedicated one rig to run continuously for Eagleford development with a budget of $82 million for the play.

Petrohawk reported in November that it leased an additional 50,000 net acres to bump up its total to 150,000 net. The position extends from La Salle County eastward into neighboring McMullen County.

Hill Vaden, analyst for Wood Mackenzie, says: "We understand Petrohawk's Eagle Ford shale is black and brittle, with high amounts of silica and calcite-filled natural fractures similar to the Barnett. It's not as over-pressured as Haynesville, but is higher in organic content. The gas is not sour, like some gas from the Edwards Trend, but does have a higher-than-normal Btu content. Petrohawk believes it has leased a unique section of the shale and warns against extrapolating its data to other counties."

TXCO and its partners also are drilling the Eagleford. The company has so far successfully tested three Eagleford wells. TXCO has 783,400 gross (497,300 net) acres in its Eagleford project area. It estimates 80- to 110 Bcf of gas per section, or 16- to 22 Bcf per section with a 20% recovery factor. Thus, TXCO's potential net asset in the Eagleford could be 7- to 10 Tcf of gas equivalent •

TXCO chief executive officer James Sigmon says. "We and our partners, EnCana, Anadarko and St. Mary, are in the planning stages to delineate our acreage positions by drilling additional horizontal wells. We now expect to add additional activity…into 2009.

"…we will continue to concentrate on the Pearsall and Eagleford shale plays, which potentially could have a large impact on the company's reserves and production. Pending board approval, we intend to reduce our 2009 capex to drill within our available cash flow," Sigmon told analysts in a November conference call.

"The company is accelerating its Pearsall and Eagleford shale plays by electing to move to Phase II in both the EnCana and Anadarko farm-ins. The Pearsall shale gas resource play is one of our key growth catalysts."

Although analysts and investors have questioned the company's slow and methodical pace, Sigmon says TXCO has advanced its knowledge about exploiting the resource, while it has increased its net interest by more than 150,000 acres.

"We find ourselves with this newly arriving shale in a great position, with a large acreage position to go forward, and we're finding what we believe to be the keys to unlock the potential for this formation."

If the play develops as TXCO expects, Sigmon says it will have to lay extensions to its system pipeline. "Remember, it's a very large acreage position, and our 90-plus miles of pipeline system that we own ourselves, just covers a portion of that acreage. We will probably have to be laying 10 or 20 miles worth of 12- or 20-inch line going down to the heart of it as we develop the field."

Grinsfelder says the Pearsall gas is typically very dry so it doesn't have much need for treatment. "Normally after transportation and compression costs and all the things that are involved, we're looking at 93% to 94% of Houston Ship Channel-type pricing."

Jeff Bookout, chief operating officer, said in a September presentation that TXCO "is going through an evolution to find the correct completion techniques required to unlock the Pearsall potential under our leasehold. The Myers well gives us an extremely valuable data point on which to build going forward, as we currently have two additional Pearsall wells drilling horizontally. As our geoscientists and engineers get a chance to study the Myers completion, we should have a much better understanding of how the Pearsall shale responds to stimulation.

"We are currently in a learning mode with this vast resource that we have under our control, and each data point we acquire puts us one step closer to unlocking the Pearsall."

TXCO is currently developing other major plays in the Maverick Basin, including the Eagleford shale, the Glen Rose Porosity oil play and San Miguel heavy oil sands.

Robert Clarke, analyst for Wood Mackenzie, says the Maverick Basin has historically been under-explored due to its small scale and complex reservoirs—even though it is adjacent to the well-known and heavily explored Gulf Coast Basin.

"Without the current advancements in 3-D seismic processing and directional drilling, the Pearsall shale would likely remain too challenging to explore. Previous operational problems and low commodity prices led to under-development in the basin, a trait very uncharacteristic of the Gulf Coast region.

"The Pearsall blanket shale deposit occurs across the entire basin. TXCO was originally brought into the Maverick Basin because of this play, and the company now holds shale acreage in the northern and central portions of the basin, together with EnCana and with Anadarko, it recently acquired acreage in the southern section."

Pearsall Potential*

Original gas in place	80- to 120 Bcf/section
Est. recovery factor	20%
Est. recoverable gas	16- to 24 Bcf/section
Project acres	848,300 gross (341,000 net)
Project sections	1,325 gross (533 net)
Potential net gas	**8- to 12 Tcf**

*Internal estimates

Source: TXCO Resources Inc.

Editor's note: Is it Eagleford or Eagle Ford shale? The answer depends on who is providing the information. TXCO and Apache Corp. refer to it as Eagleford; Petrohawk Energy says it is Eagle Ford. We asked Wood Mackenzie's Hill Vaden, who said: "I don't think there's consensus on Eagleford being one or two words. It appears to depend on operator and target." ■

The Mighty Marcellus

By Stuart Smoller, Contributing editor

Despite a tough economy and a cautious industry, this super-giant gas field in the Appalachian Basin remains highly promising. Water and environmental issues must be addressed.

Ever since geoscientists at Penn State and State University of New York (SUNY) said a black shale in northern Appalachia, the Marcellus, could boost proven U.S. natural gas reserves by many trillions of cubic feet, industry excitement has mounted. To realize the vast potential depends on how well E&P companies use horizontal drilling and fracturing techniques to maximize production. But the prize could be enormous: the Marcellus shale stretches from southern New York through western Pennsylvania into eastern Ohio and across West Virginia.

Penn State professor Terry Engelder and SUNY professor Gary Lash say the Marcellus shale conservatively holds 168 trillion cubic feet equivalent (Tcfe) of gas in place, but this figure might be as high as 516 Tcfe. This compares to the U.S., Mexico and Canada currently producing roughly 30 Tcf of gas annually.

Engelder says the technology exists to recover 50 Tcfe of gas from the Marcellus, making it a super-giant gas field. This volume would be enough to supply the entire U.S. for about two years, with a wellhead value of about $1 trillion.

One key challenge is to delineate this huge play, which covers about 1,100 miles from West Virginia to New York. "As a company and an industry, we will be attempting to determine which areas will be most productive and what drilling and completion methods are most effective," says Range Resources Corp.'s president and chief executive John Pinkerton.

"While existing technologies from the Barnett shale and other similar plays in North America are being employed in the Marcellus shale play, these technologies will need to be tailored to specific geological conditions present within the various regions of this play."

In those areas that have already entered the development phase and where infrastructure exists, drilling and production can increase significantly, he says. Areas of the play that are untested or lack infrastructure could be delayed for several years.

Here is a look at the plans of some key players who are starting to develop this vast resource.

Range Resources Corp.

John Pinkerton

Range Resources has drilled some 100 wells in the Marcellus shale in Pennsylvania, New York and West Virginia, which gives it substantial insight into the potential of this emerging resource. In late 2008, it had three rigs drilling with plans to increase that to eight for 2009.

Range's last seven horizontal wells had an average peak initial rate of 4.9 million cubic feet (MMcf) per day.

Over the past 30 years, Range has quietly accumulated a lease position in the Appalachian Basin of 2.3 million net acres. Of this, approximately 900,000 net acres are in the fairway of the Marcellus. Based on current recovery rates, Range estimates there is from 15- to 22 Tcfe of net unrisked resource potential associated with its acreage—or enough to grow its current proved reserve base ten-fold.

"Range acquired a significant portion of its acreage prior to the run-up in lease prices precipitated by the recent land grab, and to date our Marcellus acreage costs average $404 per acre," says CEO Pinkerton.

"We have drilled approximately 100 vertical and horizontal wells to the Marcellus over the past four years, but a number of these wells have been shut-in awaiting processing and pipeline infrastructure. With the opening of the Houston, Pennsylvania, gas processing plant by MarkWest Energy LLP in October 2008, our Marcellus production currently exceeds 30 MMcfe per day."

Significantly, MarkWest has already started building two additional processing plants to stay ahead of Range's drilling and completions teams.

Range Resources Corp. has drilled nearly 100 wells in the Marcellus shale. (Photo courtesy Range Resources Corp.)

"We do not foresee any delays in hooking up wells drilled in 2009, and therefore expect to exit 2009 with Marcellus production in the 80- to-100-MMcfe-range, coming from both dry gas and wet gas areas," says Pinkerton.

At press time, the 2009 budget was estimated to be about $1 billion. "We anticipate entering the development mode in the Marcellus during 2009, drilling approximately 50 horizontals and another 25-plus verticals."

Range has been drilling on 80-acre spacing; however, optimum spacing isn't known yet, so in 2009, it will test 40-acre spacing. If this is successful, Range anticipates being able to drill up to 14 wells from a single pad, vs. the current design of six wells per pad.

"Not only does this enable us to more effectively drain an area and increase the recovery factor, but it substantially reduces surface disturbance and leaves a smaller environmental footprint," says Pinkerton. In addition, it reduces drill time and costs as drilling equipment can remain in one place for multiple wells, versus the time-consuming task of moving equipment and rigging up and down at multiple drill sites.

Atlas Energy Resources

As of October 2008, Atlas Energy Resources LLC had completed 98 wells to the Marcellus shale, of which 90 (some of which have been online for two years) have normalized production approaching 25 MMcf per day into a pipeline, according to Atlas president and chief operating officer Richard D. Weber. The remaining eight wells were to be turned into the sales line by the end of 2008.

Atlas has developed a robust geologic database from its Marcellus shale wells in southwestern Pennsylvania and has significantly enhanced its vertical completion and production techniques that include perforation schemes, multistage fracs, pumping rates, fluid volumes, and flow-back rates.

Other Challenges

Excitement about the Marcellus shale play has led to ambitious leasing and drilling plans by many companies, which brings up the need for new efforts to protect the environment and work with the many landowners involved.

Looking to 2009, Atlas Energy Resources president and CEO Rich Weber sees some challenges ahead regarding well permitting and water-sourcing issues. His company is working with the Pennsylvania Department of Environmental Protection to strike a balance between the enormous potential of this promising energy resource and sound environmental practice.

Some water-disposal issues that need to be addressed, he says, are water treatment and recycling.

In southwestern and central Pennsylvania, people are more used to the extensive drilling activities that have gone on for approximately 150 years. But in the northeastern portion of the state, more effort is needed in the way of community outreach to educate the population that is not as used to these activities, says Weber.

Range Resources Corp. CEO John Pinkerton agrees. "With 900,000 net acres in the trend's fairway, we have a multi-decade drilling inventory, even if our drilling pace accelerates. And given the current credit situation, we and many of our competitors have dramatically slowed our leasing efforts, choosing instead to direct our capital toward drilling," he says.

With most of the industry pulling back on leasing, the result has been a sharp decline in lease-bonus payments here in the Marcellus shale and in other shale plays around the country.

"Our goal is to continue acquiring Marcellus leases in high-graded development areas. We believe our lease and surface owner relations are very good. In terms of community relations, we understand that large-scale shale gas drilling is new to the Appalachian region. As a result, we have undertaken an educational campaign to reach out to citizens and help them understand the drilling process and what they can expect if they see a rig move into their area."

Range Resources plans to meet with citizens at local fairs and festivals, in addition to talking to township supervisors, addressing local Lion's clubs, distributing literature, and tapping into the press to help tell the story. It will also publish information on its website. •

Richard Weber

The company's last 13 vertical Marcellus wells averaged initial rates of 1.3 MMcf per day, which is 30% higher than Atlas's prior average vertical Marcellus well. One vertical well in Fayette County, Pennsylvania, had an initial rate of 3.6 MMcf per day and it has produced 132 MMcf in its first 60 days.

With results like that, no wonder Atlas intends to drill 100 vertical and 25 horizontal wells in the Marcellus in 2009.

A typical vertical well costs between $1.3- and $1.8 million, whereas horizontal well costs will run between $4.5- and $5.5 million, says Weber.

Atlas has posted much higher IP (initial potential) rates on vertical Marcellus wells using a two-stage frac design, and has averaged 24-hour IP rates of 2.1 MMcfe per day, more than double the company's historical average from its previous 90 wells. The two-stage frac also exhibits a shallower decline rate than a well with a single-stage frac.

Assuming these results continue—which is not assured—the company expects to realize sizable increased reserves and production per vertical well. The incremental cost of the two-stage design over a single-stage design is approximately $125,000 per well.

In November 2008, Atlas reported successfully casing its second horizontal well to the Marcellus, with a lateral leg of approximately 3,000 feet. The company planned to complete this well, in Washington County, with an eight-stage frac. Atlas has spudded its third and fourth horizontal wells. For the remainder of 2009, it plans to drill 12 additional horizontal Marcellus wells, in which it will have a 100% working interest.

Atlas has all permits and equipment in place for its Marcellus program. In addition to two rigs on contract that are capable of drilling the lateral section of its horizontal wells, Atlas, through a 50%-owned affiliate, will take delivery in the second quarter of 2009 of a third, built-for-purpose, horizontal rig. (The company uses its fleet of contracted shallow rigs to drill the vertical section of horizontal Marcellus wells.)

As of last fall, Atlas had obtained 70 vertical and 10 horizontal drilling permits and had more than 130 being prepared for submission to the Pennsylvania Department of Environmental Protection.

Atlas controls 555,000 acres in the Marcellus shale fairway, which includes 271,000 acres in its focus area of southwestern Pennsylvania. Since the beginning of 2007, Atlas has acquired 217,000 acres, primarily in southwestern Pennsylvania, at a fully loaded cost of $235 per acre.

Atlas has delineated most of this acreage, and the company estimates its potential net recoverable reserves attributable to this area is between 4- and 6 Tcf.

Enhancing the economics, all of its current production is pipeline quality gas that does not need to be treated. Through its affiliate, Atlas Pipeline Partners LP, Atlas con-


7,500 shale
frac stages
in the U.S.
3,500 shale
frac stages
in Canada.
No one fracs
more shale than
BJ Services.

trols a gathering system capable of delivering 120 MMcf per day into four different interstate pipelines. It plans to more than double this gathering capacity by the end of 2009.

Southwestern Energy Co.

Southwestern Energy Co. currently has about 110,000 net acres in Pennsylvania under which it believes the Marcellus shale is prospective. It has drilled its first four wells in Bradford and Susquehanna counties; the company's first horizontal well was to be completed in fourth-quarter 2008.

At press time, the company was still formulating its budget for 2009. "We continue to be encouraged regarding the technical merits of the play, but activity will be measured due to the uncertainty in the regulatory arena, permitting, water handling, and the lack of a pooling statute.

"Long term, the Marcellus has the potential to be a viable play across a significant geographical area generating significant economic benefits for all parties involved," says Jeff Sherrick, senior vice president of exploitation.

One of the keys to success in the Marcellus shale, according to Sherrick, will be to execute a socially responsible development plan. To effectively produce gas from shale requires fracturing, which requires access to water—to date this has been a limiting factor for industry activity in the trend.

But Southwestern experienced a similar challenge in the early development of the Fayetteville shale in Arkansas a couple of years ago. "Working closely with the Arkansas Department of Environmental Quality (ADEQ), together we developed a very successful program of building water-supply ponds for frac jobs across the 860,000 acres we are developing in the Fayetteville shale, and today these same ponds are providing wildlife habitats and recreation to the landowners, " he says.

"The topography in Pennsylvania where we are active is very similar and we believe our water needs for the Marcellus program can be met by jointly developing a similar program with the Pennsylvania Department of Environmental Protection and the local water authorities," adds Sherrick.

The Marcellus, like most shale reservoirs, will require horizontal wells to economically develop the resource. A significant challenge that needs to be resolved is pooling of land into units to allow for effective development using horizontal drilling techniques. In order to drill wells that stretch out horizontally 4,000 to 6,000 feet from the surface location, several tracts of land must be pooled into a unit to share in the ownership.

"Many states have pooling provisions to address this issue and we believe this would greatly enhance the future development of the Marcellus shale. Pooling will also enhance the number of locations companies can utilize for multi-well drilling pads, with several horizontal wells drilled from the same surface location. Southwestern Energy has very successfully used multi-well, pad drilling in the Fayetteville shale to minimize our environmental footprint in Arkansas, and with the adoption of pooling we will be able to apply similar techniques across more of our acreage during development of the Marcellus shale," says Sherrick.

Penn Virginia Corp.

Penn Virginia's Jim Dean, vice president for investor relations, says the company will commence drilling in the Marcellus shale in the second half of 2009 at the earliest. This is largely due to a number of Penn Virginia's other shale and resource plays competing for capital and other resources.

Other factors that are influencing Penn Virginia's timing in the Marcellus include a desire to further analyze its recent acreage additions and to decide where to drill. Issues with commodity prices and in the capital markets likely reinforce the timing, as this activity is higher-risk, exploratory drilling.

"We are likely to focus on other established developmental plays earlier in 2009 prior to turning to the Marcellus shale and other exploration plays later in the year or in the following year. These plays include the Lower Bossier (Haynesville) shale in East Texas, the Granite Wash play in the Anadarko Basin, the Selma Chalk in Mississippi, and horizontal coalbed-methane in Appalachia," says Dean.

"We are encouraged by the results of others in Pennsylvania for the Marcellus shale and hope that we are able to add another winning developmental play to our growing portfolio."

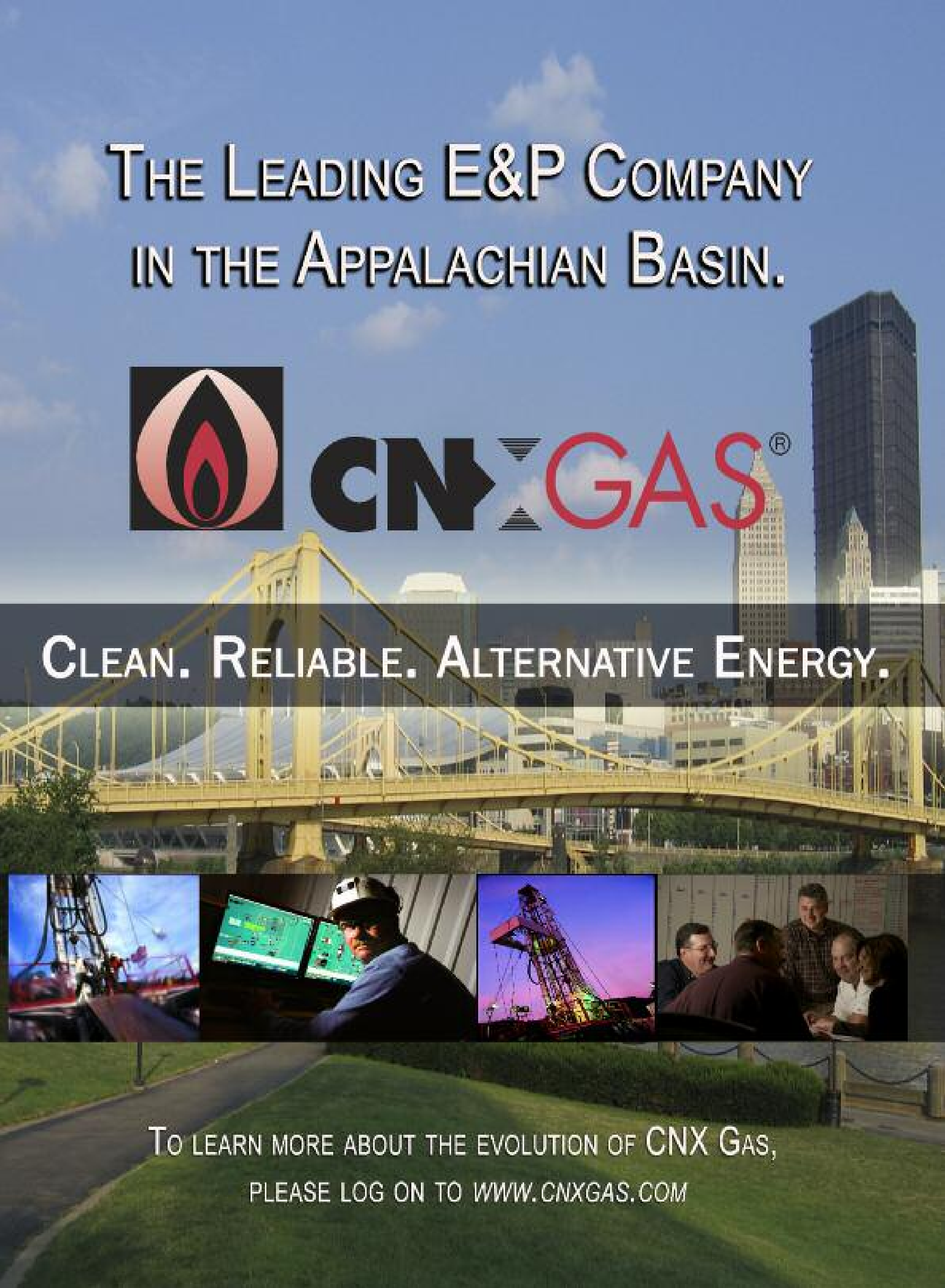
Carrizo and Avista join forces

Carrizo Oil & Gas Inc., and Avista Capital Partners announced in November a joint venture to pursue growth opportunities in the Marcellus shale. Under the terms of the agreement, each has committed to contribute up to $150 million in cash and properties to acquire and develop acreage in the Marcellus shale play, including the dedication of all of their respective current Marcellus leasehold. The joint venture controls approximately 155,000 net acres in the play.

Carrizo, which is already active in the Barnett shale, will operate the joint venture properties and provide all geotechnical, land and accounting support. Avista has agreed to fund 100% of the joint venture's next $71.5 million of expenditures, currently projected to be spent over the course of the next eight to 12 months.

After this initial cash contribution has been funded by Avista, the parties will share all costs of joint venture operations in accordance with their participating interests, which are expected to be 50/50 thereafter.

Carrizo's undivided interest in the joint venture, including land and drilling expenditures, future net oil and gas revenues, and future oil and gas reserves, will be reflected in the company's consolidated financial statements. S.P. (Chip) Johnson IV, Carrizo's CEO, views the Marcellus shale as "one of the company's potential core growth areas and a source of future shareholder value." ■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Q&A

Gene Powell: Barnett Guru

Michael (Gene) Powell has been an operator and investor in the oil and gas business for 44 years. He started the Powell Barnett Shale Newsletter in 2003. Now, he is known as the go-to guy for the latest news and statistics about the play, which covers 21 counties in north Texas. We spoke with him to get the latest update on this, the grand-daddy of natural gas shale plays, which has spawned a surge in U.S. gas production.

Investor What is the current daily production in the Barnett, and how does that compare to 2007?

Powell Production in the Barnett shale in the Fort Worth Basin continues to increase as more wells are brought into production, more than offsetting the hyperbolic decline of existing wells. As of August 2008 (the latest available figures), daily production was 4.68 billion cubic feet of gas, compared to 3.5 Bcf a day in December 2007. Some 1.12 trillion cubic feet of gas was produced in 2007, and we project 1.55 Tcf to be produced in 2008, once all the data are in.

Investor How many producing wells are there now?

Powell As of September 1, 2008, there were 11,317 wells that had produced from the Barnett shale with 10,932 producers active in August 2008. This compares to 8,960 wells as of December 2007.

Investor What is the total accumulated production?

Powell Total production to September 1, 2008, was 4.66 Tcf and 13,542,748 barrels of oil from 21 counties in the Fort Worth Basin. This comprises 15 Texas Railroad Commission fields, including the Newark East (Barnett shale) and Cleburne West (Barnett shale) fields, among others.

The Barnett shale in the Fort Worth Basin should pass 5 Tcf in total production in 2008. By the way, all this production data includes wells in the RRC pending files.

Investor What are the latest projections for daily production for 2009? And, is that being adjusted because of the decline in natural gas prices?

Powell Projecting daily production in 2009 depends a great deal on the price of gas. If it drops below $5 per MMBtu for several months, we would anticipate some wells will be either shut-in or curtailed, as well as some frac jobs on wells with pipe set being delayed. At that point, the decline of the production would overcome new well production—and we would see an overall decline in daily production.

Gene Powell

With normal seasonal price ranges, we expect a slightly slower increase in daily production in the first half of 2009 due to fewer drilling rigs running, but we see it picking up in the second half of 2009.

Investor What amount of gas production is not hooked up yet that is waiting on pipelines?

Powell The major bottlenecks that were being experienced early on in the development have been relieved with new midstream gathering and compression systems. The major cause of wells waiting on pipeline is mostly in the inner city, with local regulators creating more red tape and trying to assume control of the pipeline development that in the past has been the jurisdiction of state and federal law. This has caused an estimated 250 wells to be shut-in, representing initial peak production of at least 500 million cubic feet of gas per day. This "road-block" tactic by local authorities is depriving mineral owners of royalty and the county, schools and cities from ad valorem tax revenue.

The status of current midstream pipelines is a downstream bottleneck affecting a northern Tarrant County, 36-inch line which should be relieved by spring 2009, at least doubling capacity to about 900 million cubic feet of gas per day.

Photo by Michael Ives

A 36-inch line, just south of Spinks Airport in Tarrant County, is relieving some upstream pressure in central Tarrant County on some smaller lines as it marches west. The new Boardwalk Pipeline will be coming online this spring, opening new eastern markets for Barnett shale gas, which should result in higher net prices.

Barnett Shale Production – August 2008

Company	No. Wells	No. Active Wells	MCFGPD
Devon	3,426	3,388	1,257,084
Chesapeake	1,060	1,016	754,800
XTO	1,176	1,117	684,530
EOG	939	905	637,771
Quicksilver	528	500	234,495
EnCana	717	699	218,216
All Producers	**11,317**	**10,932**	**4.68 BCFGPD**

Source: IHS Enerdeq August 2008

Investor Where do you stand on the debate of when Barnett production will peak?

Powell Based on the current drilling pace, we expect the Barnett shale in the Fort Worth Basin to peak at approximately 8 Bcf a day before 2018, based on all the industry increasing by the same amount as projected by Devon Energy Corp. president John Richels.

In August 2008, several executives producing in the Barnett expressed their views. Devon's John Richels sees it doubling in less than 10 years. This is based on projecting Devon's production to increase from 1.1 Bcf a day to 2.0 Bcf a day in less than 10 years.

Chesapeake Energy Corp. expects the Barnett to peak at 6- to 6.5 Bcf a day by 2012. Mark Papa, the chief executive officer of EOG Resources Inc., said he sees production in the Barnett shale peaking at about 5 Bcf a day in 2009.

Investor Do you foresee continued mergers and acquisitions in the play, or is that slowing down?

Powell We will continue to see some of the major companies currently in the Barnett shale acquiring smaller companies to increase their lease and production position, especially in Tarrant and Johnson counties. There has been some slowdown due to fewer companies being available for sale that have significant production, but the national financial crisis may change that, with some smaller companies not having sufficient production revenue to meet their lease drilling commitments.

Investor You have begun observing the Fayetteville and other shale plays. How do you see them developing compared to the Barnett?

Powell Without a further decrease in natural gas prices, we see the Fayetteville shale continuing to develop at its current pace. The Haynesville shale in northern Louisiana and far East Texas will develop on a more rapid pace as demonstrated by the increase in drilling rigs and new leases. Ceramic proppant availability could slow down progress there.

The Marcellus shale in the northeastern U.S. will develop at a slower pace due to lack of infrastructure and service companies, and regulations. In area, it has the largest projected gas reserves, but more development is needed in horizontal drilling technology in the much softer shale there.

It took 27 years for the Barnett to develop to where it is today. Each shale has its own properties and, although the Barnett may be used as a starting point, each shale must develop its own technology to maximize gas recovery.

Investor What do you think it means that the Exxon joint venture (DDJET) sold to Harding (and later to Chesapeake), but that BP entered the Haynesville? Do you foresee more JVs between majors and independents?

Powell The DDJET JV was a very small project with few wells, as compared to other operators in the Barnett shale. It can hardly be considered as Barnett shale participation by a company as large as Exxon, since much of the acreage was outside the core area of Tarrant and Johnson counties, and the leasing agent was a very small independent company. Chesapeake has been active in bringing in 25% partners in various shale plays, including with BP. We foresee more JVs of that type between the majors and independents with large acreage positions.

Investor What about Barnett leasing trends?

Powell The less-frenetic pace of the leasing activity does not mean all leasing activity has slowed in the Barnett shale. The national financial crisis and falling gas prices have greatly reduced leasing in the Barnett shale at high lease-signing bonuses once topping out at a reported $32,500 per acre.

Recent reports from neighborhood associations and home-owner groups indicate most leases are being offered in the range of $3,000- to $5,000 per-acre signing bonus with a 25% royalty.

There are exceptions. Some selected neighborhoods are being signed for $13,250 per acre to $22,500 per acre by XTO Energy, through its leasing agent, Holland Acquisitions, in Tarrant County.

This time of low gas prices and financial instability in our country will be used to catch our breath and begin filling out those drilling units, so the wells may be drilled before the leases begin to expire. ■

Smarter Technology Reduces Drill Time

By Laurel Ziemba, Contributing Editor

CNX Gas and Scientific Drilling Inc. partnered in the Mountaineer coalbed-methane area to develop better horizontal well design and new fit-for-purpose tools that allow for much faster drilling times.

In the early 1980s, CNX Gas was a business unit of Consol Energy, operating primarily in southwest Virginia. Because the Pocahontas #3 coal seam there produced such gaseous coal, Consol's gas operation was charged with degassing the seam prior to mine-through to improve the mine's safety and productivity. Not until 2005 did circumstances coalesce and the idea of CNX Gas as a stand-alone company become a reality.

In 2003, management considered the prospect of expanding into northern Appalachia, but it was faced with a unique challenge. While the vertical fracturing technique employed in Virginia worked well in the geology in that state, it proved unsuccessful in northern Appalachia.

"We were pulling gob gas off of the Loveridge and Blacksville #2 coal mines (much like we were at the Buchanan mine in Virginia), but we couldn't apply the same vertical fracturing technique employed in Virginia due to the geology in northern West Virginia and southwestern Pennsylvania," says Sam McLaughlin, vice president of Northern Appalachia for CNX Gas. For this reason, Consol engineers began experimenting with horizontal drilling. From 2003 to 2005 they experimented with the design of about nine horizontal wells, attempting different patterns and techniques, no two of which were the same.

Their specific challenge was this: The permeability and cleat system of the Pittsburgh #8 coal seam did not allow for vertical fracing, because the fracture didn't penetrate the coal seam. Therefore, minimal gas migrated to the production hole. The Pittsburgh #8 seam is sandwiched between very soft shale strata—the fracturing liquid that was pumped in migrated to the softer shale rather than staying in the coal seam. This forced CNX Gas to approach the seam horizontally.

This is CNX Gas Corp.'s new Mountaineer headquarters in Pennsylvania. (Photos courtesy CNX gas)

The separation of CNX Gas from Consol was the catalyst for the creation of Mountaineer CBM Operations in northern Appalachia. At this time, a dedicated CNX Gas management team focused on aggressively degassing the more than two billion tons of coal held by Consol in the region. The intent was to provide a "second front" to the already successful Virginia CBM operations. In 2005, Mountaineer started out with five employees and was producing 2.2 million cubic feet per day from the experimental wells.

The original horizontal well design had an access well, which began vertically and turned horizontally to intercept an already-drilled production well. After a successful intercept, drilling would continue with three laterals of roughly 4,000 feet each in a pattern that resembled a turkey foot. The drainage pattern was thought to be 640 acres. The rate of return on a well was also analyzed in meticulous detail because it was now imperative that these wells generate an after-tax rate of return of 15%, assuming gas was priced at $5 per Mcf.

The first rig dedicated to Mountaineer arrived in May 2006. Directional drillers were also interviewed. "We had one directional driller who we thought had the potential to be a very good partner," says McLaughlin, now general manager, Mountaineer Operations. "Later, we also found out about Scientific Drilling Inc (SDI)."

CNX Gas engineers were ensuring that the horizontal wells were oriented to cross the largest number of natural fractures while always drilling up-dip in the coal, in order to have the associated water flow downhill to the production well, where it could be easily removed.

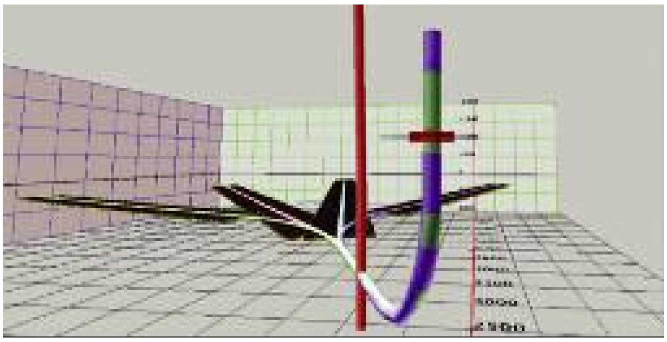
The early wells were being drilled at a 50% intercept rate to the production well. It was taking 24 to 28 days to drill them, which was not acceptable. The company consistently found that after the laterals were drilled past the 3,000-foot mark, problems occurred that ranged from not being able to stay in the seam, to issues involving rate of penetration and steerability.

It was time to try something new, and CNX Gas engineers rose to the occasion with a new well design, dubbed the asymmetrical quad. Instead of drilling three legs 4,000 feet into the coal seam, they would shorten the legs and add one. "We really thought we were onto something and we were right," says McLaughlin. "With this design, things were starting to gel. Drilling time dropped and productivity increased dramatically."

Even more significant changes were in the works. The year 2007 turned out to be a watershed for Mountaineer. Management began telling the story of Mountaineer as a business unit, which meant that operations managers had to deliver solid results. The drilling program increased by 280%. The 15 wells CNX Gas scheduled for Mountaineer in 2006 was ramped up to a target 62 in 2007, and the employees increased from eight to 35.

CNX Gas also started to evaluate potential directional drilling companies, which led to a historic partnership. Scientific Drilling was aware of the target of 62 wells and was interested in partnering to attain that goal. Management teams from both companies were brought together and as a result, one Scientific Drilling crew was brought onboard. Today, they are on 50% of CNX Gas rigs.

McLaughlin remembers Scientific Drilling making a full commitment to partner with CNX Gas. The company rented apartments and looked for warehouse space in the area, and it invested in research and development technology for CNX Gas. "They brought their employees in from all over the country just to train them on our drill sites in case we were going to ask for an additional crew. They anticipated our needs and our growth. They were open-minded and experimented with new technology," says McLaughlin. "Did their CEO have the foresight to see what Mountaineer would shortly become? Maybe."



Drilling time dropped significantly by using this asymmetrical quad design.

Specialized Tools

The key to Scientific Drilling's success is that they build their own tools, according to McLaughlin. While most other drillers rent their tools from another vendor, Scientific Drilling specifically designed their tools around the CNX Gas Mountaineer operation. They provided CNX Gas with specialized service and even had their CEO make a special trip to northern Appalachian headquarters to meet with the CNX Gas management team. It was during that same trip that a pivotal idea was born.

At this particular meeting, the chairman and CEO of Scientific Drilling asked a very important question: "What can Scientific Drilling do for CNX Gas that they are not currently doing?" The reply from Geoff Fanning, drilling manager, was simple: "Gamma at the bit technology."

Traditionally, a gamma ray was used anywhere from 20 to 40 feet from the bit. Fanning's request identified a need to move the gamma to as close as five feet from the bit. Until this point, no one could make that happen because of the size of the drill steel used by CNX Gas, which is 3¾-inch in the motor and 4¾-inch in the wellbore.

At this point "Smart Motor" technology was born, and the gamma would soon move to just five feet away from the bit. The Scientific Drilling management team focused its entire team's effort to make this happen. McLaughlin and Fanning traveled to California to see the technology first hand. "We were sold," recalls McLaughlin. It wasn't long before the gamma at the bit was put into use at Mountaineer and proved to be a huge success.

The Technology

Since coalbed-methane horizontal drilling rates are generally very fast, electromagnetic-measurement-while-drilling (EMWD) systems are the preferred telemetry system, because of the additional data transmitted while drilling. An EMWD system typically transmits data three to four times faster than a conventional mud-pulsed MWD system, and can reduce time required by up to 70% when taking surveys during connections. EMWD

After a successful test in June 2008, Scientific Drilling is building SmartMotor tools for use in all of CNX Gas' CBM horizontal wells.

systems have no moving parts, can operate with no returns and with aerated mud (i.e., gas, nitrogen, air) and can handle just about any kind of lost circulation material. In addition, EMWD systems are able to utilize bi-directional communications, which is a key to developing additional sensors near the drill bit.

The primary logging-while-drilling (LWD) tool used in coalbed-methane (CBM) horizontal drilling is the radial and focused natural gamma ray tool. Both types of gamma ray tools used in CBM applications are Scintillation Crystal Detectors. The focused gamma ray sensor has a specially configured shield around the gamma crystal to only allow gamma rays to enter from one direction. This "gamma window" is oriented with the bend of the drill motor so that the drilling operator can know the orientation of the gamma crystal window at any time, because it is the same as the bend of the drill motor. This capability is very beneficial to CBM steering operations.

Placing the gamma ray sensors and accelerometer sensors for inclination in the body of a positive displacement drill motor adds considerable value to the CBM projects. Another advantage is the enhancement of depth of investigation, because the sensor payload rides on a carriage on the top of the drilling motor. These new tools communicate to the MWD system using a "short-hop" electromagnetic signal received by the MWD system.

Until now this specialized equipment was not available in a size that could be used to drill a 4¾-inch wellbore size. The first test of the new 3¾-inch Smart Motor occurred on June 10, 2008, just prior to the promised nine-month development plan that came out of the CNX Gas and Scientific Drilling management meeting on September 12, 2007. The results of the field trials have been extremely successful. SDI has since commercially released the Smart Motor and is currently building a fleet of these systems for all the CNX Gas horizontal CBM rigs on this project, as well as adding additional capacity for other similar operations.

What does this mean for CNX Gas? First, the company realized an immediate impact in efficiency. It can now drill horizontally 3,000 feet into the coal seam in 24 hours—a dramatic decrease in drilling time which lowers the cost of the well and improves the economics. Recently, Mountaineer, with a Scientific Drilling crew, drilled a horizontal CBM well in less than eight days. This technology also opens up narrower seams for drilling, increasing potential reserves.

What if the SDI management team was to ask the same question today? McLaughlin would reply: "Cost. Operationally they are top-shelf. But they could work on shaving their costs—not because it's a deficiency, but because cost control should be a main focus for every operation in every company." He adds that CNX Gas is constantly working to shave costs and to remain the lowest-cost producer in the eastern United States. "At CNX Gas, we are always looking for ways to improve. Nothing to us is routine."

The Future

The drilling team is currently looking at 3-D modeling, which will help to cut costs on the Consol coal-side as it pertains to cut-through wells. "They are a technologically aggressive company—a great team to partner with," says McLaughlin. "We're a perfect fit because both companies are open to exploring new technologies and to continuous improvement." Mountaineer plans to increase its complex quad-lateral well-drilling program in 2009. Part of that program will be to drill laterals in new coal seams and unaccessed acreage to prove and produce additional reserves to help CNX Gas reach its strategic vision of 100 Bcf by 2010.

This technology also ultimately helps CNX Gas to be a safer company. The less time spent drilling the well, the less exposure employees and contractors have to potential incidents. Their exposure to accidents is minimized by minimizing their time and exposure at the well-site. ■

This is one of the nearly 100 horizontal CBM wells drilled in 2008 in the Mountaineer area.

The Pierre Shale Bonus

By Gary Clouser, Contributing Editor

Pioneer Natural Resources expects proved reserves from the Pierre to exceed 200 billion cubic feet by 2010.

When Pioneer Natural Resources Co. acquired coalbed-methane producer Evergreen Resources in 2004, the deal signaled Pioneer's long-term commitment to investment in Colorado's Raton Basin. But at the time, no mention was made about the possible commercial viability of the Pierre shale as a potential additional source of gas on the acreage.

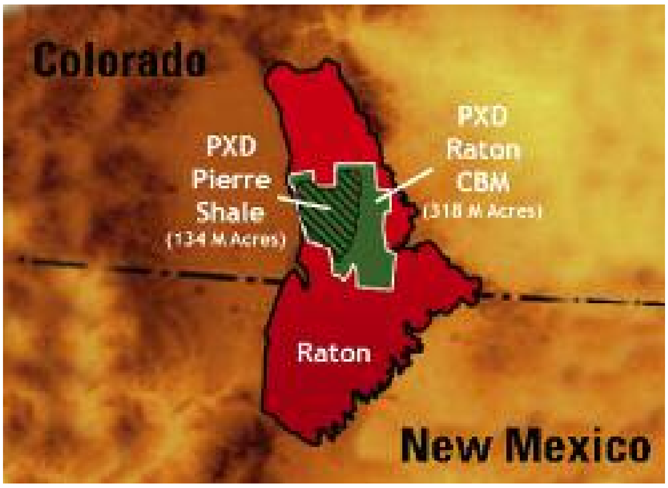
Since then, Pioneer has dramatically increased its net production from the Raton Basin, from 135 million cubic feet per day in 2004 to approximately 200 MMcf per day in the first half of 2008. This increase was primarily related to CBM volumes, with the Pierre shale just recently starting to become a more significant contributor. This strong growth performance has solidified Pioneer's position as the top gas producer in the Raton Basin.

In April 2008, Pioneer publicly unveiled its discovery of Pierre shale as a gas play that it intends to exploit. The company said it had been working on this play for almost two years.

What is the potential? Jay Still, executive vice president of domestic operations for Pioneer, told *Oil and Gas Investor* in October that the total amount of gas in place is 21 trillion cubic feet (Tcf). At a conservative recovery rate of just 20%, this would mean that the recoverable resource from Pioneer's interest in the Pierre shale would be more than 2 Tcf, Still said. At a daily production rate of 200 MMcf, this would equate to about 30% of the company's total production.

By year-end 2008, the company expected to have 20 producing shale wells, and to have drilled nine such wells during the year. However, Still says, projections for 2009 activity "are up the air," because of the extreme price volatility of oil and gas at year-end 2008. He notes that in the Pierre shale, the break-even price for natural gas would be $3.50 to $4 per thousand cubic feet.

Looking back on the Evergreen Resources acquisition, Still says the commercial viability of the Pierre shale has been a bonus. The company knew when it made the acquisition that dating back to the mid-1980s, there had been some limited testing of this shale, but nothing indicated a commercially viable play. "We knew there was some activity, but we gave it no value," Still remembers.



"At that time (2004), coalbed methane was new to us and we were totally focused on learning coalbed methane technology," Still says. About a year and a half into the CBM exploitation, while working on a water disposal well, a company geologist told management that the shale looked interesting and was worth further investigation. By then (now 2006), particularly because of the success of the Barnett shale play, shale was the buzz throughout the industry.

Vast potential

Pioneer's Pierre shale play covers 134,000 acres on held-by-production leases, meaning shale plays are on land the company controls through its CBM operations. Pioneer has recorded proved reserves from the shale asset of 18 Bcf as of December 31, 2007. That was significant because previously, Pioneer had considered the Pierre play a resource to which it had not attributed any booked reserve value.

Other Emerging Rockies shales

Research and consulting firm Wood Mackenzie, in a recent study of emerging shale plays in the Rockies, profiled seven shales. They include the Gothic, Cody, Cane Creek, Baxter, Mancos, Lewis and Pierre shales.

"The region holds a number of shale gas plays that have either been overlooked or were produced with other tight gas plays," says Connie Lin, upstream research analyst for Wood Mackenzie.

The seven plays are located in six basins across the region and are in various stages of exploration. Vertical depths range from 3,000 to 16,000 feet, and the typical play has multiple pay zones. Initial production rates are highly variable and have reached as high as 12 million cubic feet per day in the Cane Creek play. Well costs and completion methods are still being modified as companies learn more.

By definition, shale gas is an unconventional, continuous natural gas reservoir contained within fine-grained rocks, dominated by shale. These plays tend to have long-lived wells, which produce at low rates for up to 30 years. Recoveries are typically up to 20% of the gas in place.

Deutsche Bank E&P analyst Shannon Nome also identified those Rockies plays as particularly worth watching. Here, in part, is what Nome and others say about shale plays, other than the Pierre.

If natural gas prices hold up, there will be more news in 2009 about these Rocky Mountain shales.

Gothic and Cody "Bill Barrett Corp. is the main operator in the Gothic and Cody shales," said Nome in a recent report. "In the Paradox Basin Gothic shale, the company is partnered with Williams and is currently shooting 3-D seismic to identify horizontal test-well locations. Another potential pay zone that lies above the Gothic is the Hovenweep shale.

"In the Cody shale, Bill Barrett and partner Devon Energy Corp. are assessing test well results and 3-D seismic. Should the company develop the Cody shale, it will be required to build infrastructure in the Montana Thrust Belt."

Fred Barrett, chairman and CEO of Bill Barrett Corp., also commented on the Gothic shale in November: "Our company is very excited about the initial results from the first two horizontal Gothic shale gas wells at the Yellow Jacket prospect in southwest Colorado. The Koskie well produced for 17 days, averaging 4.5 million cubic feet per day of gas over the final 10 days and completed the testing period at a rate of 5.7 MMcf per day. The second horizontal well, the Neely well located 14 miles north of the Koskie discovery, is currently testing early in the flowback stage at 3.1 MMcf a day.

"Due to the encouraging results from the wells drilled to date, in 2009 we will operate a continuous program to evaluate the area and will begin construction of infrastructure. This is a widespread but shallow (5,500 to 6,500 feet) resource play where the company has built a 397,000-gross-acre position over the past four years."

Baxter The Baxter Shale is an overpressured reservoir in the Vermillion Basin, which is located within the Greater Green River Basin. It has one of the largest gas-in-place resources of any U.S. shale, estimated to be 440 Bcf per square mile. "However, Questar Corp., Kodiak Oil & Gas and its partner Devon Energy have not been able to fully exploit the shale due to the high well cost and low IPs (initial potentials). We expect further drilling tests from Kodiak and Devon in the Baxter over the next 12 to 18 months," Nome wrote.

Wexpro Co., a subsidiary of Salt Lake City-based Questar Corp., reported in October that it completed a horizontal Baxter producer in the Vermillion Basin about 42 miles southeast of Rock Springs, Wyoming, in Canyon Creek Field. Gas flowed at an initial rate of 3.3 Mmcf per day.

Lewis The Lewis shale, a sandy siltstone with four pay intervals, is commingled with the deeper Mesaverde and Dakota formations in the San Juan Basin and the shallower Almond formation in the Greater Green River Basin. Says Nome: "Operators typically complete the Lewis as a secondary zone. In the San Juan Basin, the main players are ConocoPhillips, BP, Chevron and XTO Energy. Within the Greater Green River Basin, Continental Resources, BP and Anadarko Petroleum are assumed to be testing the Lewis shale, due to their large positions in Wamsutter."

Cane Creek "While perhaps the most unknown of the six, the Cane Creek shale stands out as the highest-performing play based on recent well results," said Nome.

"The formation consists of stacked shales interbedded with sandstones and carbonates. The total organic content of Cane Creek can be up to 28%. The formation is estimated to have resources of several Tcf. Delta Petroleum, the play's only known operator, is in the process of drilling horizontal completions which should improve recoveries." •

The company now expects proved reserves from the Pierre shale to reach 70 Bcf by the end of 2008 and to exceed 200 Bcf by the end of 2010

Initial production per well is expected to average 750 Mcf per day, with estimated ultimate recovery per well forecast at 0.75 billion cubic feet.

Based on 80-acre well spacing, Pioneer believes it has approximately 1,200 potential drilling locations in the Pierre shale.

Future wells will be tied into Pioneer's extensive existing CBM infrastructure and drilled from both existing and new well pads, utilizing the company's integrated well service model and benefiting from related drilling efficiencies.

The Cretaceous Pierre shale occurs at depths of 4,000 to 6,000 feet in the Raton Basin. The gross overall thickness of the shale ranges from 2,200 to 2,800 feet, and completions to date have primarily focused on the lowest of five intervals, with commercial pay of 200 to 300 feet.

The company has also successfully tested the two zones above and confirmed that they can contribute additional production and reserves.

In April 2008, Pioneer told analysts that its finding and development costs are expected to average $10 to $15 per barrel of oil equivalent (BOE), with an average before-tax internal rate of return of approximately 40%—at an average gas price of $8 per thousand cubic feet.

To date, Pioneer has drilled vertical wells in the Pierre, with such wells costing about $1 million. Each fracture treatment adds $200,000. The company initiated horizontal drilling in third-quarter 2008 to assess upside in the play. If successful, it expects the returns from this play to become even better.

Pioneer is enhancing its gathering and compression facilities in the area. Current plans include increased drilling in the Raton CBM field and Pierre shale during 2009. To accommodate longer-term production growth in the Raton Basin, the company added firm pipeline capacity to transport 75 MMcf per day from the Raton Basin to the West Coast gas markets beginning in 2011.

In its 10Q report issued in August 2008, Pioneer said: "The company remains encouraged by the drilling and testing results to date from the initial Pierre shale zone."

Tim Dove, president and chief operating officer, also stated at the time, "We believe with the contribution from the Pierre shale, we can increment the longer-term Raton production growth rate to 10% to 15%.

"The fact that we are now adding firm transportation to take Raton gas to the West Coast confirms our confidence in this growth forecast. It will also allow us to reduce our dependence on pricing and differentials in the Rockies and Midcontinent markets." ■

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British Columbia New Hub for Unconventional Plays

By **Ann Priestman,** Editor, *Hart's Unconventional Natural Gas Report*

New shale plays in Canada are taking the spotlight away from conventional gas and coalbed methane activity.

Wasn't it just a year or two ago that Horseshoe, Mannville and Ardley were the buzz words surrounding the hot coalbed-methane plays in Alberta? Today it is the shale and tight-gas plays of the Montney, Horn River, Muskwa, Peace River, Utica and Bakken that have sparked exploration efforts in Canadian unconventional resources. Alberta is out and British Columbia has come to the fore.

A report by ICF International predicts that by 2020, 60% of U.S. gas production and 43% of Canadian gas will come from unconventional plays. Approximately 300,000 unconventional wells will need to be drilled with an outlay of $560 billion.

Mike Dawson of the Canadian Society for Unconventional Gas (CSUG) says, "Horizontal drilling technology has provided significant opportunities to develop new hydrocarbons in basins across all of Canada."

According to Dawson, CBM development is still chugging along, but it is just not making headlines the way the Montney and Horn River shales are. There have been more than 2000 CBM wells drilled in 2008 in Alberta.

Dawson describes two business models to develop unconventional resources. First, drill deep wells that rely on technology like horizontal drilling, are expensive to drill and require C$1 million a day or more for the economics to work, with larger companies such as EnCana Corp. being the main drivers of activity. The second model spotlights smaller companies active in the Colorado Group in Alberta that are drilling cheaper vertical wells, fracture-stimulating four or five zones and commingling the gas.

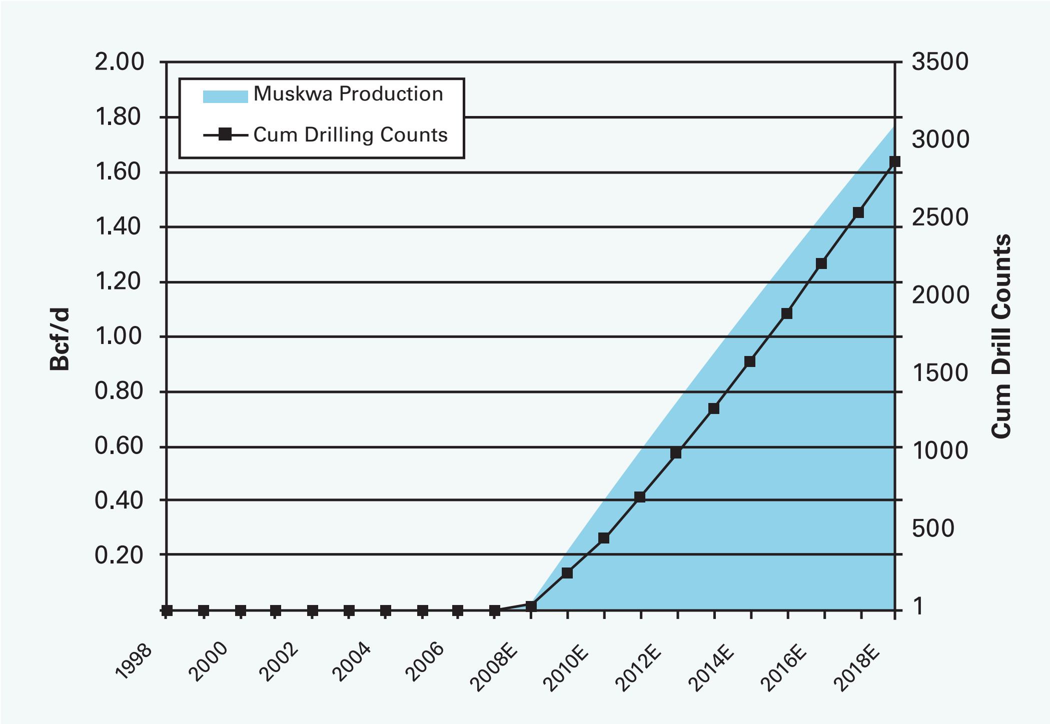
Either way, it appears Canadian activity is set to rise. Regulators approved 2,315 oil and gas well permits in October 2008, up 10% from a year earlier, pushing the 10-month tally to 18,730 licenses (including test and evaluation wells)—and edging 3% ahead of the comparable 2007 count. Alberta has dragged down the gas sector, however, issuing 7,639 permits over the 10 months, its poorest showing in six years. Saskatchewan permits surged 22% to 1,299 gas-targeted wells. British Columbia gained 10% to 899 permits.

Richard Neufeld, B.C. Minister of Energy, Mines and Petroleum Resources, estimates B.C.'s shale gas potential between 250- and 1,000 trillion cubic feet (Tcf), with an unknown recoverability factor. The province pocketed C$114 million from its November 2008 sale of leases and drilling licenses, pushing the 2008 total to about C$2.57 billion, well above C$1.05 billion in 2007.

The Petroleum Services Association of Canada forecasts B.C. will increase well completions 20% to 1,150 wells.

Horn River

The main focus is the Horn River Basin, which covers more than 3 million acres. However, a second depositional environment exists in the Cordova Embayment to the east where operators are aggressively acquiring land. The Muskwa shale is the most notable target with depths ranging from 2,500 to 3,000 meters, similar to the Fayetteville and Woodford shales, but not as deep as the Haynesville. The shale in the Horn River is thicker than the Barnett with higher storage capacity resulting in higher OGIP (original gas in place) per section. The British Columbia government expects the Horn River to contain



Source: GeoScout, Tristone Capital

up to 250 Tcf of original gas-in-place.

While the B.C. royalty framework is favorable, there are challenges, including winter access, lack of infrastructure, high capital costs and the basis differential.

Initial well production ranges from 2- to 8.8 million cubic feet (MMcf) per day, according to a recent Tristone Capital Inc. study. The study estimates ultimate gas recovery of 4- to 6 Bcf per section.

Current estimates indicate recoverable resources in the Horn River shale play of 37 Tcf, which could increase to more than 50 Tcf if the play becomes economic over most of the leased acreage, according to a Wood Mackenzie analysis.

The Montney shale is ahead of the Horn River play because it has year-round access for drilling. In addition, the first commercial production of coalbed methane from the Hudson Hope area is expected to start this year.

In 2004, the B.C. government commissioned a study of the Horn River shale to encourage exploration, jump-starting the unconventional rush. The net profit royalty system introduced in 2008 will reduce royalty payments in the early stages of unconventional development, with royalties calculated on a sliding scale ranging from 2% of revenue at the start of production until all capital costs have been recovered, rising to 35% of profit after capital costs plus 105% have been generated.

The province has also provided both deep drilling and directional drilling incentives, and improved its corporate tax structure. Additionally, it put C$120 million into an infrastructure partnership with industry to build roads and bridges to make exploration in remote areas possible.

Montney Shale

The Montney shale is in the east-central part of British Columbia where companies are stimulating horizontal wells, perforating and fracturing 6-11 zones, which cost approximately $100,000- to $120,000 per frac interval. It can thus cost more than $1 million for fracturing each well, says Tristone Capital.

The company's study expects estimated ultimate gas recovery to increase to 7 Bcf per well from 5 Bcf as technology develops. The report also says drilling should increase production to 1 Bcf a day by the end of 2009, from the 600 million cubic feet a day seen in early 2008.

EnCana is the most active operator with approximately 400 wells, completing 530 frac intervals. At Cutback Ridge EnCana is producing about 290 million cubic feet (MMcf) between its Cadomin tight-gas play and the Montney shale. Using innovative drilling and frac technologies helps the company reduce the costs to drill, stimulate and complete each horizontal well interval by 79%. A frac that used to take 30 days now takes two.

Logistics challenge Horn River developers but EnCana is responding by bringing in fracturing sand and pipe by rail and it owns a road in the area. The province's infrastructure program should help in the future.

In 2003, ARC Energy Trust began breaking open the Upper Montney formation in northeastern B.C. Development surged two years later after ARC completed the play's first multiple-stage frac of a horizontal well at a cost of $7.9 million. With five fracs along 1,500 horizontal meters, the well is still producing 1.6 MMcf a day. ARC recently drilled a 1,900-meter horizontal well, fraced it eight times, spent $5 million and achieved initial production of 8 MMcf a day. It reports finding and development costs of about $10 per BOE at its Dawson project, a netback of about $40 per BOE, and total production potential of about 5 Bcf for each well.

Without pipelines, the gas riches of the Montney and Horn River will merely sit in the ground. But a solution could be in the offing, with the National Energy Board expected to rule in the first quarter of 2009 on an application by TransCanada to allow rolled-in tariff rates for British Columbia and Alberta pipelines. That requires shifting TransCanada's Nova Gas Transmission network in Alberta from provincial to federal jurisdiction. ■