2014 Unconventional Yearbook

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The Top 20 US Resource Plays


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2014 Unconventional Yearbook

2014 UNCONVENTIONAL YEARBOOK

In an extension of Hart Energy's unconventional resources playbook series, known for its in-depth coverage of the most compelling shale plays in North America, the 2014 Unconventional Yearbook presents the most important facts and figures on the Top 20 US resource plays. This fourth in an annual series of yearbooks provides an overview of current activity with snapshots of the regional plays, profiles of key players, a review of technology, a look at midstream activity, economic analysis and data, and a bibliography. Like the playbooks, this yearbook includes a full-color map. To learn more, visit ***ugcenter.com/subscribe***.

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On the cover, Hart Energy photos clockwise from top left: Drilling the Niobrara shale play *(photo by Tom Fox)*, workers in the Tuscaloosa Marine shale *(photo by Mieko Mahi)*, a rig in the Marmaton of western Oklahoma *(photo by Tom Fox)*, and a new refrigeration plant for the Eagle Ford *(photo by Mieko Mahi)*.
Cover design by Natasha Pittman

(Photo by Mieko Mahi, Hart Energy)

A Geologic Review of the Top 20 US Resource Plays

Steve Thornhill, Contributing Editor

The US is on track to become the world's No. 1 oil-producing country in 2014.

These are exciting times in the oil patch as unconventional production opportunities abound across North America. According to the International Energy Agency, the US is poised to become the world's No. 1 oil-producing country in 2014. The lion's share of the new oil production is coming from just three diverse unconventional play areas: the Bakken in North Dakota and Eastern Montana, the Eagle Ford in South Texas, and the Permian basin in West Texas. The trend began in 1981 with the Barnett play and Mitchell Energy's tenacious resolve to obtain economic production from the shale. It took the industry innovator 16 years and many attempts to unlock the Barnett production secrets. Finally in 1997 Mitchell made its technological breakthrough, and the rest is history. Thanks in large part to Mitchell Energy's pioneering efforts, the industry is now busy unlocking production secrets to multiple geologically diverse North American unconventional oil and gas plays.

The following 20 snapshots are of current unconventional plays scattered across North America. These emerging plays are, for the most part, either oil or gas liquids.

Facing page: Floor hands on Helmerich & Payne Rig #398 drill Bumble Bee 1H, targeting the Eagle Ford shale, for Halcón Resources Corp. in Brazos County, Texas.

Bakken Formation

The Upper Devonian/Lower Mississippian Bakken shale oil play in Montana and North Dakota's Williston basin continues to astound both geologists and engineers alike. The Bakken formation blankets about 200,000 sq miles at a depth of approximately 10,000 ft, extending into Canada's Saskatchewan and southwestern Manitoba provinces. Stratigraphically, the

(Photo by Lowell Georgia, Hart Energy)

Cyclone Rig #28 drills a horizontal Bakken well for Continental Resources Inc. in Dunn County, N.D.

Bakken consists of three members, including upper and lower organically rich black shale members and a highly friable mixed silt/sand/carbonate middle member. Operators typically drill to the middle member and then kick out horizontally through the petroleum-rich friable silty/sandy dolomitic layer. Laterals can extend for 2 miles or more, with multistage hydraulic fracturing applied throughout the lateral length.

The Bakken is such an exceptional producer because the upper and lower shales not only act as petroleum source rock but also as confining layers. When the kerogen in the upper and lower shale layers, through heat and pressure, expels its hydrocarbons into the confined and friable middle layer, it also undergoes a volumetric increase, with enough confined energy to fracture its containing rock. This natural fracturing takes place along the formation's weakness zones – its bedding planes. In addition, since it is a closed system of highly friable rock, it is particularly susceptible to induced hydraulic fracturing radiating out from the wellbore.

More good news regarding the Bakken is that operators are learning newer, better, and more economic Bakken completion methods. Today, 10,000-ft laterals with 50 or more staged fractures are the norm. Though Bakken wells remain comparatively expensive, initial productions (IPs) – such as those of two recent wells reporting 3,000 boe/d and 3,317 boe/d (a record), respectively – go a long way in paying for those Bakken drilling and completion costs.

Barnett Combo

The Mississippian Barnett shale play, like the Energizer Bunny, just keeps on going, this time by reinventing itself. The shale blankets about 5,000 sq miles, much of which is in the Dallas/Fort Worth area, at a depth ranging from 7,500 ft to 10,000 ft and with a thickness of 1,400 ft to 1,700 ft in the Fort Worth basin's oil-rich Barnett Combo play area. Overall, the Barnett is best described as an extremely hard and brittle yet friable, organically rich black marine shale source rock. Operators typically drill horizontally through the friable shale with lateral extensions based on area geology and operator lease holdings. The wells are stimulated with multistage hydraulic fracturing applied throughout the lateral length.

Top 12 IP Wells in the Three Forks

Flow	Operator	Well #	County, State	Section, Survey	Comp. Date
3,957.33 boe/d (2,559 Bo, 2.15 MMcf)	Oasis Petroleum North America	5300 44-12T Andy	Williams, N.D.	12-153n-100w	May 2013
3,606 boe/d (3,106 Bo, 3 MMcf)	Whiting Oil & Gas Corp.	21-18TFH Heckler	Stark, N.D.	18-140n-99w	March 2011
3,043 boe/d *	Kodiak Oil & Gas Corp.	9-5-6-5H Koala	McKenzie, N.D.	5-151n-99w	April 2011
3,031 boe/d (3,030 Bo, 118 Mcf)	Encore Operating LP	14X-35H Charlson	McKenzie, N.D.	35-154n-95	Oct. 2008
2,939 boe/d (2,446 Bo, 2,96 MMcf)	Whiting Oil & Gas Corp.	34-12TFH Smith	Billings, N.D.	12-140n-100w	Sept. 2011
2,926 boe/d (2,429 Bo, 2.98 MMcf/d)	Helis Oil & Gas Co.	5-17-16H Andrecovich	McKenzie, N.D.	17-149n-95w	Sept. 2010
2,724 boe/d (2,186 Bo, 3.23 MMcf/d)	Helis Oil & Gas Co.	15-18H Moberg	McKenzie, N.D.	18-149n-95w	June 2012
2,700 boe/d **	XTO Energy Inc.	43X-4 Jorgenson	Dunn, N.D.	21-154-95w	Dec. 2009
2,473 boe/d (2,148 Bo, 1.952 MMcf/d)	Whiting Oil & Gas Corp.	34-24TFH Schnitzler	Roosevelt, Mont.	24-30n-56e	May 2012
2,472 boe/d (1,872 Bo, 3.61 Mcf/d)	Brigham Oil & Gas Co.	11-1TFH Rising Sun	McKenzie , N.D.	1-151n-96w	May 2011
2,356 boe/d ***	Brigham Oil & Gas Co.	2H State 36-1	Williams, N.D.	36-155n-100w	Sept. 2010
2,327 boe/d *	Kodiak Oil & Gas Corp.	9-5-6-12H3 Koala	McKenzie, N.D.	6-151n-99w	April 2010

Conversion: 6,000 cf of gas = 1 boe

**Kodiak Oil & Gas Corp.*
***XTO Energy Inc.*
****Brigham Oil & Gas Co.*

(Source: Table compiled by Larry Prado, Hart Energy, with data from IHS Inc.)

Mitchell Energy has long been recognized as the pioneer with respect to unconventional production, with the late George Mitchell tenaciously drilling one uneconomic well after another into the Barnett until he finally realized success. As is often the case in the oil patch, the reward for his persistence was a flood of operators pouring into the area leasing everything in sight. Mitchell knew that there was an oil component to his Bar-

nett gas play, but at the time, economics dictated that he focus on the gas-prone play areas. The play has now come full circle, and the Barnett oil window in Montague, Cook, Clay, and Jack counties is the focus of attention.

EOG Resources published production results from some of its 2011 and 2012 horizontal Barnett wells. The 2011 wells made 412 boe/d to 705 boe/d, and the 2012 well made 870 boe/d, representing a 23% improvement from the best well of 2011.

Brown Dense (Lower Smackover)

The Late Jurassic-age Brown Dense is an organic-rich, fine-grained carbonate rock interval that ranges in thickness from 300 ft to 500 ft and constitutes the lower-most member of the prolific Smackover formation. The Smackover is located in an east-west band running through northern Louisiana and Arkansas. Within this area, the Brown Dense lies at depths between 8,000 ft and 10,000 ft and is a source rock for the Smackover formation.

Like so many source rock intervals, the Brown Dense is only considered tight when compared to a normal reservoir rock. However, the Brown Dense has better porosity and permeability than its name implies, and operators are learning that with modern hydraulic fracturing the Brown Dense can become very economic. Combining horizontal drilling with staged hydraulic fracturing can make the formation very productive.

Southwestern Energy published production results recently from both vertical and horizontal wells. The vertical well made 214 b/d and 1,237 Mcf/d, while the horizontal well with a 4,300-ft lateral and 19 staged fractures made 421 b/d and 3,900 Mcf/d.

Chainman Formation

The Chainman formation is an organic-rich, dark gray to black silty marine shale interbedded in some areas with thin sandstones and carbonates. The formation ranges in thickness from approximately 299 ft to more than 6,000 ft; however, it is commonly less than 3,000 ft thick. The Chainman, named after the Chainman Mine, is located in Utah's Antler and Oquirrh subbasins of the Eastern Great basin, and it spreads into southeastern Nevada where it thins to a few hundred feet. The Chainman is considered the Eastern Great basin's primary source rock. Many geologists also feel that it is a world-class source rock and perhaps the leading source rock in the world. The Chainman area currently being tested lies at depths of 4,000 ft to 7,000 ft. However, some of the potentially best targets lie at depths between 10,000 ft and 25,000 ft.

Current completion information is lacking. However, historical data reveal incredible promise. A 1983 Chainman well drilled in Nevada flowed more than 4,000 b/d for more than five years from a depth of 4,400 ft. Thirty years later the well is still producing oil and has yielded 12 MMbbl to date.

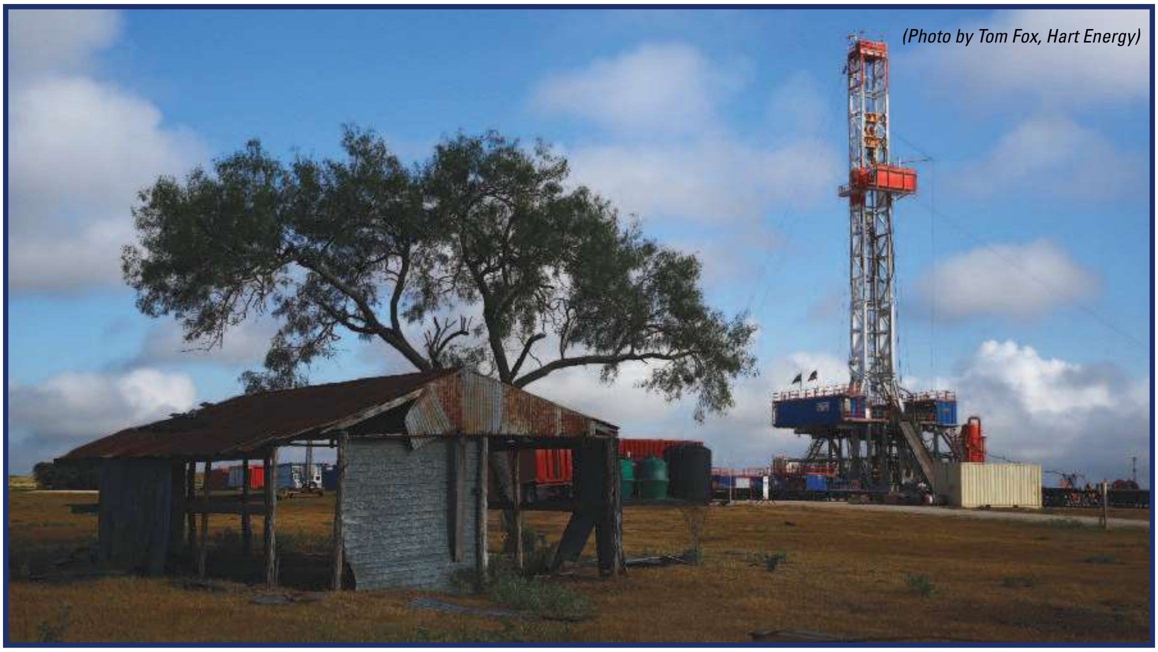
Eagle Ford Formation

The Late Cretaceous South Texas Eagle Ford shale extends in a crescent-shaped swath from the Texas-Mexico border in the south to Fayette County, Texas, to the north. Across the Rio Grande River in Mexico, the Eagle Ford is part of the Agua Nueva formation. Toward the Gulf Coast, the formation deepens to more than 17,000 ft and then plunges much deeper as it goes off the buried Cretaceous shelf margin edge, which extends in a general line through the middle of Webb County at the Rio Grande River northeast through Colorado County.

The East Texas Eagle Ford formation makes a formal outcrop appearance in its namesake Dallas suburb, Eagle Ford. From Dallas and Waco, the formation trends eastward across the East Texas basin until it pinches out against the overlying Austin Chalk formation in a north-south trending line along the western flank of the Sabine uplift. In addition, the Eagle Ford reappears in the subsurface off the eastern flank of the Sabine uplift in Louisiana.

What has been causing so much excitement during these days of severely depressed gas prices is that as the formation goes from deep to shallow, it goes from producing dry gas in the deeper eastern Eagle Ford to wet gas as it gets progressively shallower toward the west. Finally in the west, a shallow band is reached that produces oil.

While most operators have been following the Eagle Ford in South Texas, operators in East Texas have been quietly playing an Eagle Ford offshoot called the Eaglebine play. The play, located in Madison, Leon, Grimes, and Robertson counties, uses horizontal


(Photo by Tom Fox, Hart Energy)

Patterson UTI Energy's Rig 246 drills ahead on the Riedesel 01-02H pad site for Pioneer Natural Resources Co. in the Eagle Ford shale play near Yorktown, Texas.

drilling combined with hydraulic fracturing in a heretofore overly tight transition zone, located just underneath the Eagle Ford, to make some extremely prolific oil wells.

Fayetteville Formation

The Mississippian Fayetteville formation is organic-rich, black marine shale. The shale is located in the Arkansas portion of the Arkoma basin, covering approximately 4,000 sq miles, stretching in an east-west 50-mile-wide swath through northern Arkansas. The Fayetteville formation ranges in thickness from 50 ft to 550 ft and lies at depths between 1,500 ft and 7,001 ft beneath the surface. It is suspected to be a major Arkoma basin hydrocarbon source rock.

The Fayetteville play got its start in 2004 when Southwestern Energy became aware that the formation was similar to the Barnett shale. This awareness led to the first successful horizontally drilled and fractured Fayetteville well.

Southwestern Energy, still a major Fayetteville player in early 2013, was completing wells at an average cost per well of US $2.3 million. The horizontally drilled natural gas wells had an average lateral length of 5,165 ft. Unfortunately, the Fayetteville play activity has slowed considerably through 2013 because of low natural gas prices.

Frontier Formation

The Late Cretaceous-age Frontier formation is an organic-rich, gray to black shale, interfingered with thin coal, gray sandstone, and bentonite beds. The formation is located in southwestern Wyoming, north-


(Photo by Lowell Georgia, Hart Energy)

Right: Rig hands on Nomac Drilling Inc.'s Rig #25 in the midst of Fayetteville drilling operations for Chesapeake Energy in White County, Ark.

ern Utah, southeastern Idaho, southern Montana, and northwestern Colorado in a number of sedimentary basins including the Green River, Powder River, Wind River, and Bighorn basins. The formation varies in thickness from 600 ft to 3,999 ft and lies at depths of 9,000 ft to more than 18,000 ft below sea level.

As of May 2013, SM Energy had drilled three horizontal Powder River basin wells in the Frontier with 30-day IP rates between 927 boe/d and 1,734 boe/d.

Granite Wash Play

The Anadarko basin Granite Wash play spans a 6,870-sq-mile area along the southern Anadarko basin boundary, extending approximately 160 miles from western Oklahoma into the Texas Panhandle.

The Granite Wash is well known in the Anadarko basin, where it has been a bailout zone for decades when an operator's primary exploration target came in dry. However, due to the formation's inherent heterogeneity, operators have learned that drilling it horizontally will produce economic wells – in fact, some spectacularly economic wells that pay out in months.

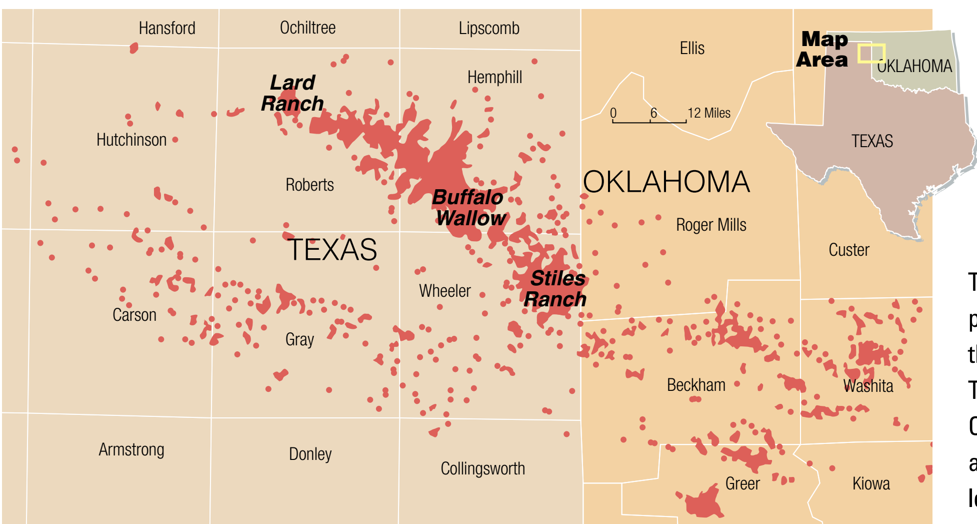
Though the formation is known for its heterogeneity, sweet spots with high porosities and permeabilities along with pay zones as thick as 2,999 ft go a long way in making up for the formation's heterogeneous nature.

So what exactly is "granite wash"? Being a grab-bag term, granite wash is locally shed (washed down) rock debris and sediments from adjoining mountains. Though it is called "Granite Wash," there are actually three different rock types composing the Anadarko basin's Granite Wash play. The first two granite wash types are both carbonates, with the oldest being limestone and chert, followed by dolomite. Only the third granite wash type is actually composed of igneous rock. All three granite wash types originated locally from adjoining mountainous areas. Eventually, over the last 300 million years, the adjoining tall mountains eroded, filling up the adjoining basins with sedimentary, carbonate, and igneous rock.

Due to the Granite Wash's heterogeneity, it is an ideal candidate for horizontal drilling. However, individual granite wash accumulations can vary dramatically in aerial extent. It should never be taken for granted that one can drill a lateral and expect to stay within the areal confines of the original granite wash accumulation.

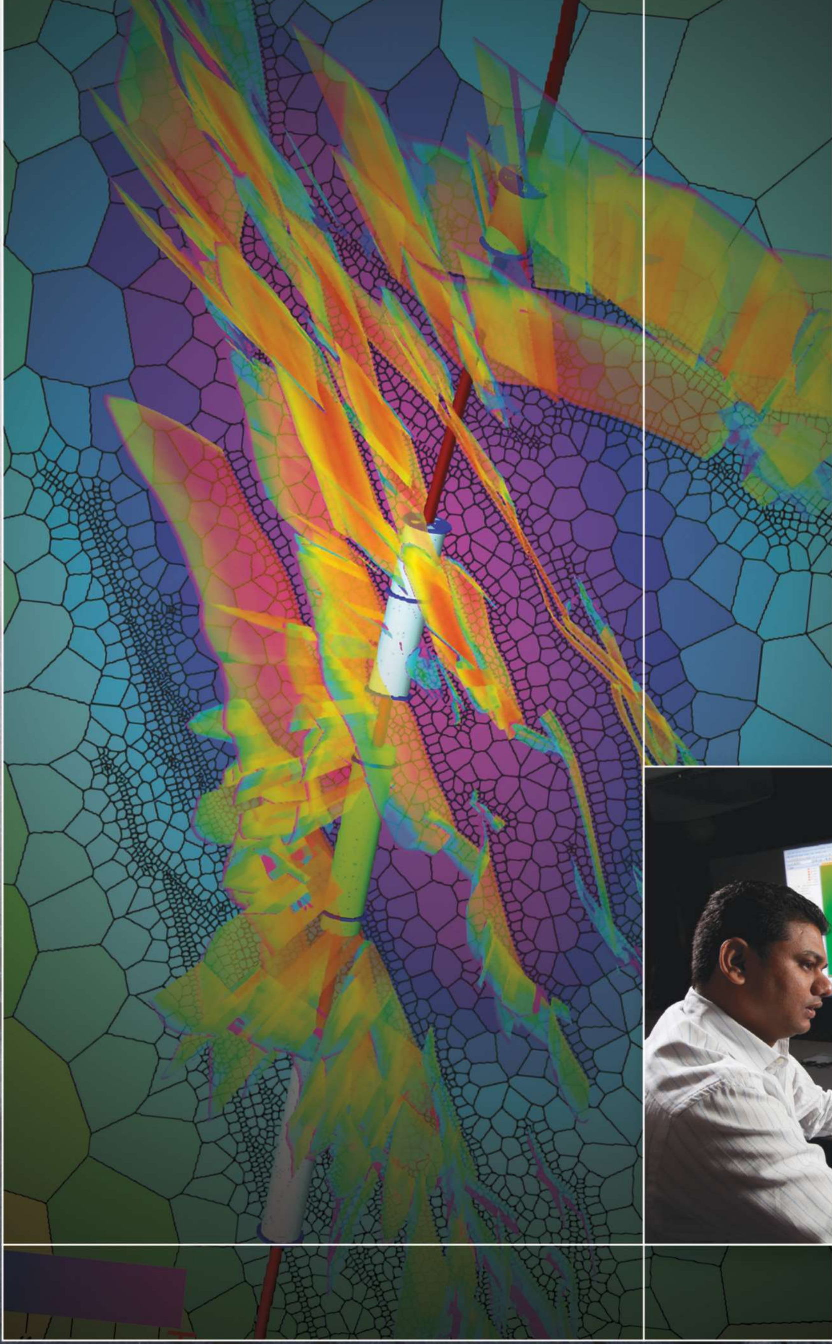
Haynesville Formation

The Upper Jurassic-age Haynesville formation is a heterogeneous, organically rich black marine mudstone varying from calcareous to argillaceous with higher-than-average porosity for a shale, though it still has low permeability. The formation underlies much of southwestern Arkansas, northwestern Louisiana, and East Texas, covering approximately 9,000 sq miles. As is common with geological formation names, there has been controversy as to whether the formation is the Haynesville and/or the Bossier shale. The controversy arises because of different names given to the same for-



(Source: Oil and Gas Investor*, adapted from the Oklahoma Geological Survey)*

The Granite Wash play runs across the Panhandle of Texas into Oklahoma, covering a swath 160 miles long and 30 miles wide.



Right: Atlas Energy Inc.'s Cardine #5H and #7H horizontal wells undergo fracturing in Westmoreland County, Pa., in the Marcellus shale play.

mation in Texas and Louisiana. Most geologists agree that the East Texas Lower Bossier shale interval correlates with the Louisiana Haynesville. As for the Upper Bossier, it has more sand than the Lower Bossier and is located more to the southwest of the Haynesville trend. Putting naming controversy aside, the Haynesville/Lower Bossier formation ranges in thickness from approximately 200 ft to more than 299 ft, lies at depths between 10,500 ft and 13,000 ft, and is overpressured with a pressure gradient between 0.72 psi/ft and 0.90psi/ft. Since 2008, the Haynesville has been known for its unconventional gas potential and also is suspected to be the main source rock for the overlying Cotton Valley formation.

Haynesville horizontal wells are typically completed with 4,000-ft to 5,000-ft laterals followed by staged hydraulic fracturing. Haynesville completions commonly make 2 MMcf/d or greater IPs. The main thing holding the play back is low gas prices.

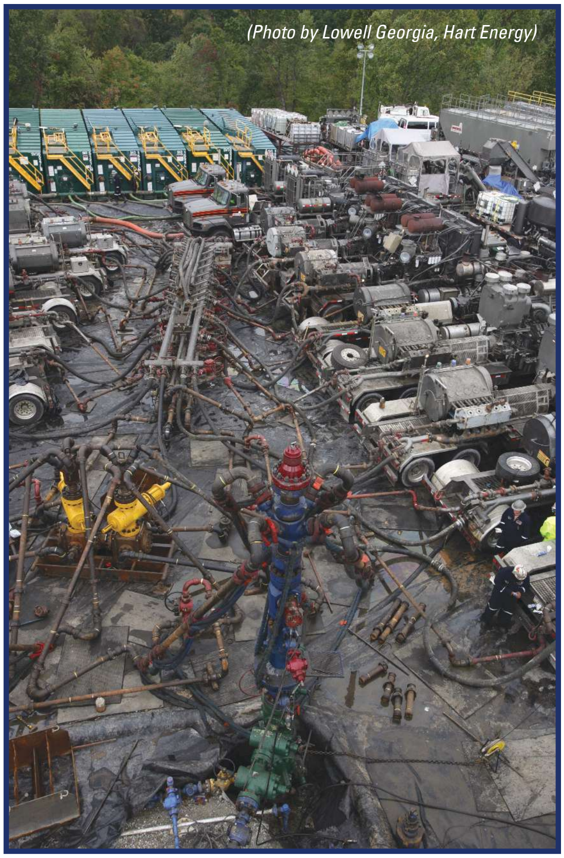
Marcellus Shale

The Appalachian basin's Devonian-age Marcellus shale is organically rich, highly friable black marine shale that covers a subsurface area extending from New York's Finger Lakes region in the east to eastern Ohio in the west. The shale covers a total area of approximately 102,000 sq miles and extends north into Canada and south into Pennsylvania, running southwest through Pennsylvania into eastern Kentucky and Tennessee.

The Marcellus shale's productivity, while having typical low porosity and permeability, is enhanced with a system of natural fractures running through the rock. Researchers have discovered two vertical systems defined as systems J1 and J2. System J1 is an east-northeast-trending closely spaced fracture system. System J2 runs in a northwest direction perpendicular to J1 with less closely spaced fractures.

Marcellus shale depths range from 2,000 ft to more than 11,000 ft. Thickness ranges from less than 49 ft in eastern Ohio to approximately 900 ft in New Jersey, while net pay ranges in thickness from 25 ft to 300 ft.

There have been some spectacular wells reportedly drilled in the Marcellus. In early 2013, Cabot Oil & Gas reported 30 wells with average 24-hour IP rates of 20 MMcf/d and average 30-day IP rates of 16.6 MMcf/d. One well with 35 staged fractures


(Photo by Lowell Georgia, Hart Energy)

had a 41.4 MMcf/d IP. To make the Marcellus even sweeter, the play area is crisscrossed with existing gas pipelines.

Marmaton Formation

The Pennsylvanian-age Marmaton formation produces from the Texas-Oklahoma southern Anadarko basin northward into Kansas. Where the Marmaton is found away from the main Granite Wash in the southern Anadarko basin, it is identified as a granite wash turbidite tight gas sand with gross thicknesses varying from 80 ft to more than 600 ft. Moving northward through Oklahoma into southern Kansas, the Marmaton is a naturally fractured limestone with thin shale interbeds and is found at an approximate depth of 6,500 ft.

Until recently, due to tight rock issues, limestone Marmaton production tended to be hit or miss with occasional sweet spots providing sound economic production. That changed when operators began drilling the formation horizontally and applying staged hydraulic fracturing to the already naturally fractured rock.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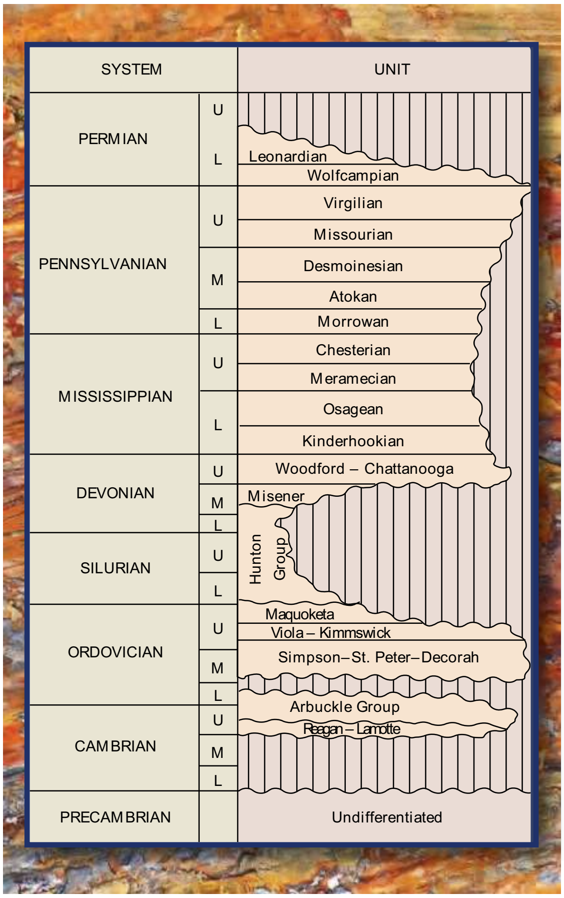
Unit Petroleum is the largest carbonate Marmaton producer. Unit was going with 4,500-ft laterals stimulated with 16-stage fractures and achieving average 30-day IPs of 300 boe/d. Now Unit is attempting longer laterals, with a recent one being a 9,500-ft lateral stimulated with 32 staged fractures that had a 30-day IP of 960 boe/d.

Mississippi Lime/Chat

In the Anadarko basin the Mississippi Lime goes from a few feet to more than 400 ft in thickness with hydrocarbons sourced from the underlying Woodford formation. Hydrocarbons are typically produced at depths ranging from 3,500 ft to 22,000 ft, with reservoirs below depths of 13,500 ft producing gas.

The Mississippi Chat overlies areas of the Mississippi Lime and is an extremely heterogeneous and often compartmentalized erosionally altered rock that can have porosities greater than 50%. However, it typically has low permeability, but fortunately it is normally naturally fractured. The Mississippi Chat play has been pursued since the 1950s by operators drilling vertical wells. Operators have since found that by drilling horizontally and fracturing, the Chat will produce very economic oil volumes. But, like the underlying Mississippi Lime, the formation produces a great deal of water with its hydrocarbons. Therefore, an operator producing from the Mississippi Chat must commit to drilling water disposal wells too. However, even with the water disposal issues, between the shallower depths and the very friable formation, the Mississippi Lime is still relatively inexpensive to develop.

The 2012 edition of the *Shale Shaker* reported an average production of 306 Mcf/d and 25 b/d from 241 producing horizontal Mississippi Chat/Lime wells.



(Source: US Geological Survey)

A stratigraphic map of common formations in north-central Oklahoma and south-central Kansas.

Monterey Formation

The Miocene-age Monterey shale is simply too big to ignore. In recent reports, the US Geological Survey stated that the lower 48 states have 23.9 Bbbl of technically recoverable shale oil reserves. Of those 23.9 Bbbl, more than half (15.4 Bbbl) are expected to be recoverable from California's Monterey/Santos shales.

Unlike the majority of the shale plays, the Monterey is a very young source rock having been deposited just 17 million years ago during the Miocene. The Monterey covers approximately 1,750 sq miles at depths between 6,001 ft and 1 5,000 ft. In the San Joaquin basin it can be as much as 7,999 ft thick, with average thicknesses between 1,000 ft and 2,000 ft generally encountered. While the formation consists predominately of organic-rich and highly friable silt, there also are areas that have a less brittle carbonate matrix. In addition, operators often must deal with an enormously complex subsurface structural and stratigraphic environment.

Venoco, a long-time Monterey operator, has divided the Monterey into three distinct rock structure types:


(Image courtesy of ExxonMobil Corp.)

The Heritage platform hosts one of the most powerful drilling rigs ever built on a fixed offshore platform. ExxonMobil ordered the rig to drill extended-reach wells to the Monterey formation.

- The Monterey is found in fracture-dominated areas. Venoco gave the South Ellwood field as an example. The field averaged a 410 b/d IP on more than 28 wells. For such a field Venoco recommended large acid stimulations;
- In matrix-dominated areas, with higher-than-average porosity and permeability, the SE Lost Hills field was used as an example. The field averaged an IP of 65 b/d on more than 600 wells. Hydraulic fracturing with proppants was the recommended stimulation; and
- In dual-porosity areas, with both fracture and matrix porosity, the Elk Hills field was given as an example. The Elk Hills field averaged an IP of 265 b/d, producing from both vertical and horizontal wells that were typically stimulated with large acid fractures.

It is clear that as with many shale plays, there is a complex and potentially expensive learning curve to be climbed before the Monterey's potential can be realized. Added to the play's potential technical difficulties, environmental and agricultural interests already are piling on regulatory and legal production barriers.

New Albany Formation

The Upper Devonian/Lower Mississippian New Albany formation is an organic-rich, dark brown, black, and green marine shale interbedded to minor extent with dolomite and sandstone interbeds. The formation underlies the Illinois basin in southern Illinois, southern Indiana, and western Kentucky covering approximately 60,000 sq miles. The New Albany formation is approximately 100 ft thick around the basin edges and thickens to nearly 499 ft in the basin's depocenter along the Illinois-Kentucky border. The shale is found at depths of 600 ft to 5,000 ft, depending on the basin area. In 2001, technically recoverable gas reserves were estimated between 1.9 Tcf and 19.2 Tcf with 160 Tcf of gas in place. Though the New Albany formation is known for its gas potential, geochemistry has shown that it is the primary source rock for all Illinois basin hydrocarbons including oil.

New Albany players are predominately using horizontal drilling to take advantage of the natural fractures associated with the formation. Hydraulic fracturing using water is often a problem because of swelling clays existing in the shale. Nitrogen fracturing can be used. In addition, New Albany hydrocarbon

production also produces large formation water volumes that must be treated prior to disposal. As operators successfully climb the learning curve, New Albany production is expected to get better and better.

Niobrara Chalk/Shale Formation

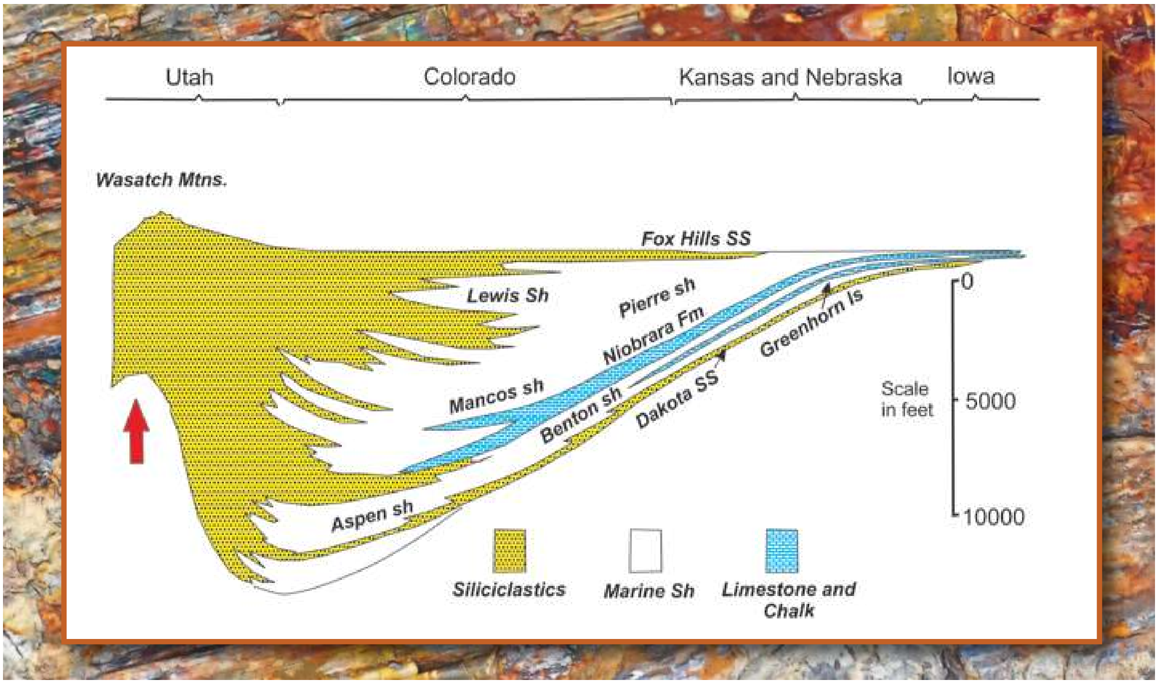
Approximately 90 million years ago during the Upper Cretaceous, the Western Inland Seaway ran in a generally north-south direction from what is now the Arctic Ocean in northwestern Canada to the ancestral Gulf of Mexico. The Niobrara formation, an organic-rich shale/marl/chalk/limestone formation, with its lithology dependent on its basin location, remains as stratigraphic evidence of the Western Inland Seaway.

Today's Niobrara formation, like other unconventional plays, is both a hydrocarbon source and reservoir rock, with the Niobrara B chalk member being the normal target. The Niobrara B member is a friable oil-prone, source/reservoir rock with gross thicknesses ranging from 200 ft to 1,499 ft and net pay thicknesses of 20 ft to 40 ft. Until recently, Niobrara wells relied on drilling into areas with elevated porosity and permeability, natural fractures, or both. It has taken the combination of both horizontal drilling and hydraulic fracturing to reliably coax economic hydrocarbon volumes from the tight rock.

Examples of Niobrara production can be seen with two recently drilled wells. One well, with laterals extending more than 8,999 ft combined with 40-stage hydraulic fractures along the length of the lateral, achieved a 30-day IP of 795 boe/d, of which 76% was oil. The second well, with a shorter 4,498-ft lateral and staged hydraulic fracturing, achieved a 30-day IP of 458 boe/d. A third Niobrara well making recent news had an IP of 16 MMcf/d (2,759 boe/d) exceeding 1 Bcf of gas during its first 100 days of production.

Sunniland Formation

The Lower Cretaceous-age Sunniland formation is an organic-rich, heterogeneous carbonate and anhydrite succession with the carbonate facies generated from marine algal deposition. It consists of upper and lower Sunniland members, with the lower member being the source rock for the upper member. The formation underlies the South Florida basin, which is located in southwestern Florida and covers approximately 80,000 sq miles both onshore and offshore. While the entire lower Cretaceous-age section has an average thickness of 3,501 ft, the Sunniland formation is approximately 250 ft thick. The basin's depocenter lies northwest of the Florida Keys under the present-day Florida Bay. The Sunniland produces from depths between 10,000

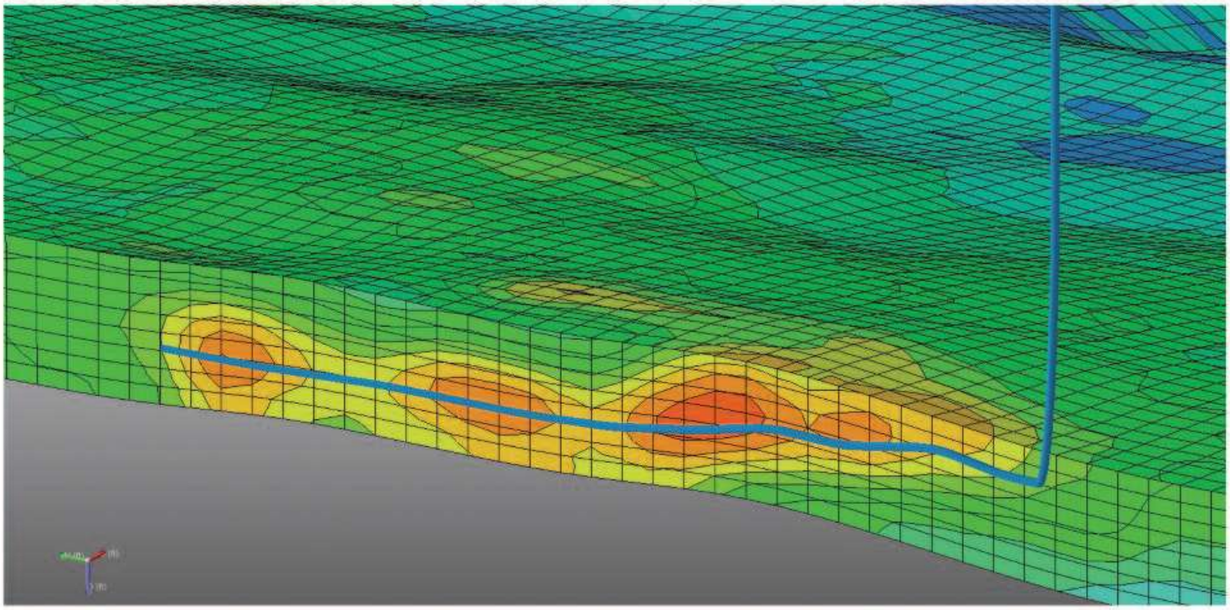


A generalized cross section across the Western Interior Cretaceous basin is shown. The Niobrara is Upper Cretaceous in age. Limestone and chalk beds are present over the eastern two-thirds of the basin.

(Image modified from Kauffman, 1977)

Make Every Frac Count

Geoscience solutions for unconventional resources



The benefits of integrated geoscience and drilling technologies include proper positioning of frac zones within targeted reservoirs to maximize production.

Success in the exploration and development of unconventional source rock plays (shale, carbonate gas and oil, tight gas, etc.) depends largely on thorough integration of geoscience and drilling technologies.

The CGG and Baker Hughes Shale Science Alliance has developed a fit-for-purpose integrated solution to successfully explore and develop unconventional resources. Our scientific approach supports efficient well placement and optimized hydraulic fracturing by estimating rock brittleness and stress derived from seismic data that is calibrated with formation evaluation and geological data to provide predictive models for well trajectory planning and completion (frac) modeling analysis and design.

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BAKER HUGHES | Shale Science Alliance | CGG ft and 12,999 ft with a median production depth of 11,800 ft. Oil produced from the Sunniland is a high-sulfur crude but with little associated gas.

Tuscaloosa Marine Shale Formation

The Middle Cretaceous-age Tuscaloosa Marine shale (TMS) formation is an organically rich, gray to black, finely bedded, and sandy marine shale. The TMS stretches in an east-to-west band averaging 55 miles wide and 250 miles long across southern Louisiana and southwestern Mississippi and covering approximately 14,000 sq miles. The TMS formation is approximately 499 ft thick in southwestern Mississippi and more than 800 ft thick in southeastern Louisiana. It has a net pay thickness ranging from less than 20 ft on either end of the swath to greater than 140 ft near the swath's middle located on the southern Mississippi-Louisiana border. The formation lies at a depth between 11,001 ft in the north to more than 15,000 ft in the south.


(Photo by Mieko Mahi, Hart Energy)

Ensign Energy Services Inc.'s Rig 753 works on the lateral for Goodrich's Crosby 12H-1 in the TMS.

Currently, the play's problem is that it is comparatively untested and very expensive with well costs exceeding US $12 million. One operator has drilled several wells in the Tuscaloosa, and all have costs equal to or exceeding US $12 million. The first well averaged 300 b/d, while the second did better at 670 b/d. The Tuscaloosa should see future activity increase once operators learn ways to reduce costs and improve production.

Utica Shale

The Appalachian basin's Ordovician-age Utica shale is an organic-rich, highly friable, black, carbonate-rich marine mudstone underlying the Marcellus shale by 3,000 ft to 7,001 ft and covering an area extending from eastern New York westward to central Ohio. The shale extends north into Canada as far as Quebec and south into Pennsylvania running southwest through Pennsylvania into West Virginia and eastern Kentucky and covering a total area larger than the 102,000 sq miles covered by the overlying Marcellus shale. The Utica shale, while typically having a lower total organic carbon (TOC) than the Marcellus, is generally thicker and has a natural fracture system running through the rock. In addition, the oil-prone TOC zone in Ohio, sourced from Type II kerogen, extends into the underlying Point Pleasant formation, which consists of carbonates interbedded with black shales.

Utica shale depth ranges from surface outcropping in Utica, N.Y., to a depth of more than 12,000 ft in southwestern Pennsylvania and West Virginia. The play ranges in thickness from as thin as 75 ft at the basin margins to more than 499 ft, with it generally thinning from east to west.

Numerous companies are pursuing Utica production, drilling horizontal wells anywhere from 2,001 ft to more than 7,500 ft in length with multistage fracturing. Production examples include a well with a 3,973-ft stage-fractured lateral that had a 30-day IP rate of 1,256 boe/d. Another well that was drilled with a 5,020-ft 17-stage fractured lateral made 400 b/d and 386 Mcf/d.

Wolfcamp Formation (Wolfbone, Wolfberry, and Wolfcamp Plays)

The Permian basin is broken up into several sub-basins. The two largest sub-basins are the Delaware and Midland basins. They both have different depositional

(Photo by Mieko Mahi, Hart Energy)

A Basic Energy workover rig cleans out and prepares to perforate the toe stage of Newfield Exploration's Casados 4H 21X targeting the Woodford shale in Stephens County, Okla.

thicknesses and slightly different depositional histories, because the two basins subsided at different rates.

The Early Permian Delaware basin Wolfcamp formation achieved thicknesses in excess of 2,001 ft. The formation is a multilithological source rock made up of both siliciclastic and redeposited deep-basin carbonate sediments. The formation is divided into upper and lower zones and is found at subsurface depths ranging from 11,001 ft to 12,001 ft. Both zones are each about 1,001-ft thick, with the upper zone being the oilier of the two. Delaware basin operators have been comingling the Wolfcamp with the overlying Bone Spring formation, resulting in the Wolfbone play. The Wolfbone play, at a depth of approximately 11,001 ft, is a vertical well play that simultaneously produces from both the Wolfcamp and the overlying Bone Spring formation. Wolfbone wells generally have a completion zone thickness of approximately 1,250 ft and are overpressured.

The Midland basin Wolfcamp formation achieved a thickness of 1,001 ft. Like the Delaware basin Wolfcamp, it is a multilithological source rock with a similar sedimentary history. The formation in the Midland basin is generally found from depths of 7,700 ft to 11,700 ft depending on the basin area.

In the northern Midland basin, operators are combining the overlying Spraberry formation with the Wolfcamp. The resulting Wolfberry play, at depths ranging from 9,500 ft to 9,800 ft, is a vertical well play that produces simultaneously from both the Wolfcamp and the overlying Spraberry formation with the Spraberry being equivalent to the Delaware basin Bone Spring formation. The southern Midland basin Wolfcamp play, found at depths ranging from 9,501 ft to 11,699 ft, is a horizontal play with an approximate 1,001-ft thickness.

Woodford Formation

The Late Devonian/Early Mississippian-age Woodford formation, or its geological time equivalent, is a petroleum source rock that covers much of the midcontinent from Nevada, Idaho, and western Montana down into Texas and eastward through the Midwest reaching into New York and Pennsylvania. With the introduction of horizontal drilling and staged hydraulic fracturing, operators are drilling economic Woodford wells in the Anadarko and Ardmore basins. Devon kicked off the Cana Woodford play in Oklahoma's Canadian County with a successful horizontal Woodford well in 2007.

The play has since spread southeast from its origin into the western Ardmore basin where operators have been calling it the South Central Oklahoma Oil Play (SCOOP). The Woodford is made up of organic-rich siltstone and silty black shale layers reaching thicknesses of 899 ft. Though found at a depth ranging from 6,001 ft to 11,001 ft, it has been typically produced from depths between 7,500 ft and 8,500 ft, where the formation thickness can vary between 49 ft and 299 ft or more.

As is the case with many shale plays, lateral lengths have increased as the play has unfolded, and fracture programs have been modified to optimize the formation's unique properties. In 2013, lateral lengths ranging from 7,001 ft to more than 8,999 ft were not uncommon, and fracture programs have been constantly adjusted as operators learn more about the rock and as the rock changes laterally. This relentless fine-tuning is paying off. In 2Q 2013, Devon Energy announced a daily 10-well average production rate of 840 boe/d from its Woodford wells. ■

(Image courtesy of BHP Billiton)

US Unconventional Development Sets Standards, Records

Kelly Gilleland, Contributing Editor

The potential and challenges of the top 20 US established and emerging plays keep operators busy.

Editor's note: Data in this article are current as of Nov. 1, 2013.

Turn on the news any day anywhere in the US, and you will find a story about shale. It's creating jobs. It's boosting revenues. Every field and every play is touted as "potentially the biggest" find out there. We are in awe of the possibilities of shale and unconventional resources, and players large and small are betting the farm on tapping into those vast yet cagey reserves.

Growing supplies of shale gas and gas liquids have put US natural gas production at its highest level ever, up by more than 30% in the last seven years, and US oil production rose by 1 MMb/d in 2012, the largest annual increase in US history. Those are jaw-dropping figures, enough to make every investor salivate and every explorationist pack his/her geologic toolkit and head out for the shale hills.

The shale game welcomes all players, from multinational majors to the smaller companies that have been working an area for years, knowing there are riches in their own backyards if they could just figure out how to get to them. And therein lies the problem – what works in one shale play doesn't always produce the same results in another. New technologies and unique approaches are required. And, of course, shale exploration is not a simple process – cooperation is required at every level, from the land owner to the local and state regulators all the way up to the highest levels in Washington.

And with any frontier phenomenon comes fear of the unknown. The public perception of unconventional exploration and development is well publicized. Concerns abound that the energy industry might be using innovative technologies that could have unforeseen negative effects.

Still, the promise of shale riches has activated the can-do, problem-solving spirit of the oil and gas industry in a way that hasn't been seen since the wildcatting days of the first US oil discovery, at Titusville, Pa., in 1859 – ironically, located in an area that contains the prolific Marcellus shale.

Below is a brief overview of activity in 20 of the established and emerging US plays, followed by specifics on how the industry's top operators are developing shale and other unconventional resources to transform America's energy landscape.

THE PLAYS

Bakken/Three Forks

Located in the Williston basin stretching between Montana and North Dakota and extending into Canada, the Bakken shale continues to hold its spot as one of the hottest – and largest – plays in North America. As exploration efforts progress, reserves estimates continue to rise. In 2008, the US Geological Survey (USGS) put undiscovered, technically recoverable oil reserves at 3.65 Bbbl; by April 2013, that amount had doubled, now standing at 7.4 Bbbl technically recoverable. Gas estimates have nearly tripled in that same time period, from 1.7 Bcf to an

Facing page: BHP Billiton is using new H&P Flex 5 rigs in its Eagle Ford operations.

Top 12 IP Wells in Bakken Shale

Flow	Operator	Well #	County, State	Section, Survey	Comp. Date
7,088 boe/d (4,815 Bo, 13.16 MMcf/d)	Whiting Oil & Gas	21-4H Tarpon-Federal	McKenzie , N.D.	4-152n-97w	Nov. 2011
7,013 boe/d (6,800 Bo, 1,28 MMcf/d)	Burlington Resources Co.	34-34H Llano	McKenzie , N.D.	34-153n-95w	June 2012
6.755 boe/d (5,130 Bo, 9.57 MMcf/d)	Burlington Resources Co.	24-34H Brazos	McKenzie , N.D.	34-153n-95w	June 2012
5,330 boe/d (4,661 Bo, 4.01 MMcf/d)	Brigham Exploration Co.	2-H Sorenson 29-32	Mountrail, N.D.	20-155n-92w	Mar. 2011
5,237.67 boe/d (4,341 Bo, 5.38 MMcf/d)	Oasis Petroleum North America LLC	13-30B Casey 5200	McKenzie, N.D.	30-152n-100w	July 2012
5,200 boe/d (3,731 Bo, 8.8 MMcf/d)*	Newfield Exploration Co.	152-96-4-2H Wisness-Federal	McKenzie, N.D.	4-152n-96w	July 2011
5,133 boe/d (4,335 Bo, 4.79 MMcf/d)	Brigham Exploration Co.	1-H Sorenson 29-32	Mountrail, N.D.	29-155n-92w	Mar. 2010
5,061 boe/d (4,438 Bo, 3.73 MMcf/d)	Brigham Exploration Co.	1-H Clifford Bakke 26-35	Mountrail, N.D.	26-155n-92w	Oct. 2010
5,035 boe/d**	Brigham Exploration Co.	1-H Jack Cvancara	Mountrail, N.D.	19-155n-92w	May 2010
4,864 boe/d (4,174 Bo, 4.14 MMcf/d)	Oasis Petroleum North America	5300 44-12B Ashlin	Williams, N.D.	12-153n-100w	Jan. 2013
4,761 boe/d***	Whiting Oil & Gas Corp.	11-27H Maki	Mountrail, N.D.	19-155n-92w	May 2010
4,675 boe/d**	Brigham Exploration Co.	1-H Domaskin 30-31	Mountrail, N.D.	30-155n-92w	Jan. 2010

Conversion: 1 bbl condensate = 6,000 cf of gas
**Source: Newfield Exploration Co.: 24-hour average*
***Source: Brigham Exploration Co.*
**** Source: Whiting Oil & Gas Corp.*

(Source: Table compiled by Larry Prado, Hart Energy, with data from IHS Inc.)

estimated 6.4 Bcf technically recoverable in the Bakken petroleum system.

At 14,700 sq miles, the self-sourced Bakken is the largest continuous crude oil accumulation in the US. The Three Forks formation underlies the Bakken and accounts for about one half of the estimated undiscovered, technically recoverable oil, according to USGS reports. Prior to 2008, the underlying Three Forks formation was "generally thought to be unproductive" and was not assessed for reserves potential, but the 4,000-plus wells drilled in the Williston basin since 2008 have resulted in a new understanding of the reservoir and its resource potential.

Operators are targeting not only the Middle Bakken and Three Forks-1 zones, but they are now excited about the prospects of the Upper Bakken and Three Forks-4. Continental Resources remains the largest acreage holder in the Bakken, with 1.2 million net acres under lease. The company is especially encouraged by testing in the underlying Three Forks formation that indicates "unique reserves in areas with little faulting or structure," and said that, while there are some areas in the Three Forks where

production interference could occur with more severe faulting and natural fracturing, these areas do not appear to be widespread.

An Exxon report points out that six years ago production from the Bakken region registered at a modest 6,000 b/d. Thanks to enhanced technologies, production in the Bakken has increased 100-fold, and largely due to Bakken exploration efforts, "for the first time since the mid-1980s, crude production in the United States is increasing."

Barnett

America's largest onshore gas field, the Barnett shale play in Texas' Fort Worth and Permian basins, covers 3.2 million acres and is said to contain 86 Tcf of undeveloped technically recoverable gas, according to the results of a two-year study released in September by the Bureau of Economic Geology at the University of Texas at Austin. This estimate doubles the US Energy Information Administration's 2011 estimate of 43 Tcf undeveloped technically recoverable reserves.

The Barnett contains the prolific Newark East gas field that accounts for more than a quarter of Texas' natural gas production. Since its discovery in 1981, more than 16,000 wells have been drilled in the Barnett shale, resulting in production of nearly 9 Tcf of natural gas.

Despite these high expectations, rig counts continue to taper off in the Barnett, with only 34 active rigs in the shale play in November 2013, according to industry estimates. Daily production rate in the play has now declined on a year-over-year basis for nine straight months, with the decline rate reaching double digits the last three months for which data


(Photo by Lowell Georgia, Hart Energy)

Casing is stacked on a pipe rack in the Barnett shale.

are available (April, May, June), as reported by Hart Energy Research & Consulting's *North American Shale Quarterly*.

The Barnett was discovered by Mitchell Energy in 1981. When Devon Energy purchased Mitchell in 2002, Devon became the largest single acreage holder in the Barnett, with 615,000 net acres and five currently active rigs. The company boasted that continuing efforts to optimize production resulted in net production that averaged 1.4 Bcf/d of natural gas equivalent during 2Q 2013 from the Barnett, and liquids production increased to 56,000 b/d, a 34% increase compared to 2Q 2012. In mid-October, Devon announced it would combine pipelines and processing plants with another big Barnett player, Crosstex Energy Inc., and form a new Dallas-based company to handle midstream activities in the Barnett as well as in other unconventional plays where Devon is active. The new company will operate about 7,300 miles of gathering lines and transportation pipelines, 13 processing plants, six fractionation plants, and other storage and transportation facilities.

A 2011 study by the Perryman Group stated that Barnett shale-related activity has created more than 119,000 jobs in Texas and "is expected to continue to generate economic stimulus for local area and state economies for decades to come."

Brown Dense

Located in southern Arkansas and northern Louisiana, the Lower Smackover Brown Dense formation is an Upper Jurassic reservoir ranging in vertical depths from 8,000 ft to 11,000 ft and thicknesses from 300 ft to 550 ft. Found across the southern US from Florida to Texas, the Brown Dense is believed to be the source rock for the Upper Smackover, which has been producing for more than 90 years. Below the Brown Dense is the Lower Smackover formation.

The play is still in the early stages of horizontal exploration. The largest acreage holder in the Brown Dense, Houston-based Southwestern Energy, holds 507,000 net acres and has drilled eight wells to date – five of the eight were successful, but production rates so far are moderate. The company said that the Brown Dense shows indications of the "right mix of reservoir depth, thickness, porosity, matrix permeability, sealing formations, thermal maturity, and oil characteristics" and planned three additional wells before year-end 2013.

Chainman

The Eastern Great basin province of Nevada, Utah, Idaho, and Arizona is home to the Chainman formation. Oil from the Chainman has been typed to several producing fields in Nevada, and thickness of the formation ranges from more than 6,000 ft in the foreland basin trough and Oquirrh basin of northwestern Utah to a few hundred feet in southeastern Nevada and southwestern Utah. At some surface localities more than 5,000 ft is exposed; some well logs show 3,000 ft or more of section, but thicknesses are commonly less than 3,000 ft. The US Geological Survey puts the potential reserves at 1.5 Bbbl of oil and 1.8 Tcf of natural gas.

However, that oil is frustratingly difficult to access, as the federal Bureau of Land Management (BLM) continues to block large-scale energy development in Nevada, argues the Nevada Policy Research Institute's (NPRI's) deputy policy director, Geoffrey Lawrence. In early 2012, the BLM was scheduled to auction off 75 Nevada oil and gas leases covering 133,000 acres but reduced the auction down to 42 leases covering only 72,000 acres at the last minute due to concerns that oil and gas exploration might disrupt the habitat of the sage-grouse, a bird heading toward endangered status.

"In other words, eastern Nevada could be sitting on one of the most energy-rich rock formations in the entire world," Lawrence said. "One oil developer told Las Vegas reporters, 'You have the richest, largest organic mature rock source anyplace in the world except Saudi Arabia or Kuwait...There is no doubt, I can assure you 100%, you are sitting on some of the greatest wealth in this country and the world.'"

NPRI also points to a recent analysis from Dr. Timothy J. Considine, a professor of energy economics at the University of Wyoming, showing that development of the Chainman shale on federally owned lands could result in US $5.2 billion in economic impact over the next decade while creating 21,797 new jobs.

Considine's study asserts that most of Nevada's oil production comes from two fields: the Grant

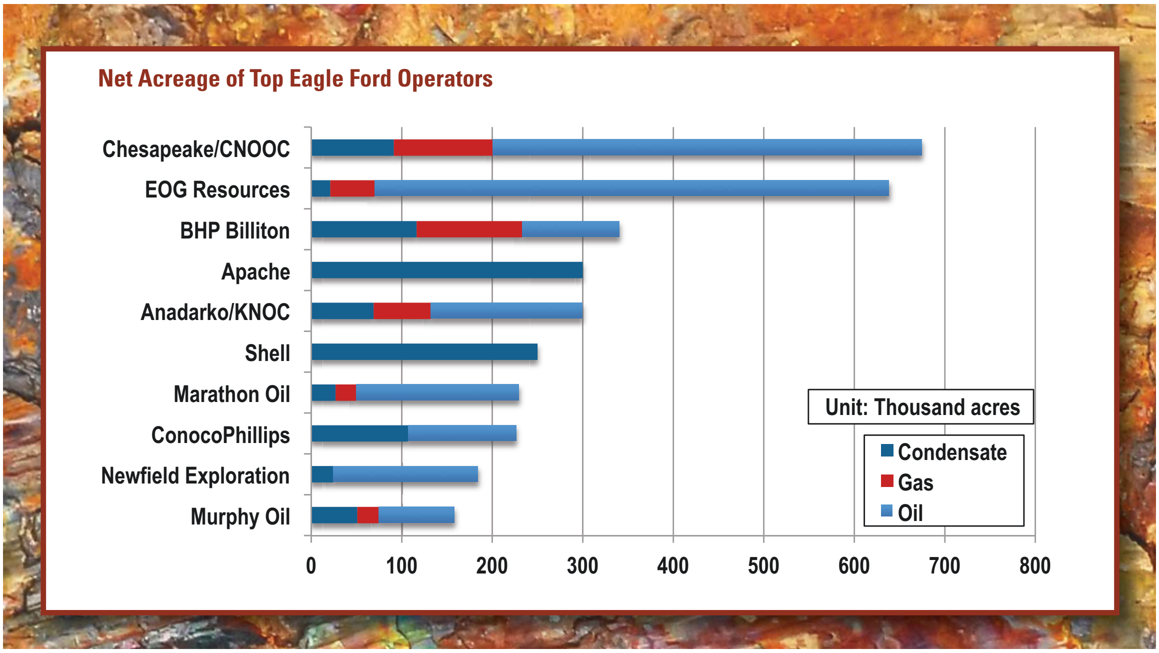
Canyon southwest of Ely, Nev., and the Cobble Canyon structure in the western part of the state, southeast of Carson City. "Royal Dutch Shell owns a well in Grant Canyon that has produced 21 MMbbl of oil since it was completed in 1983, well more than the 13 MMbbl anticipated by geologists based upon the pore space and other physical attributes of the surrounding rocks," Considine said. "The belief is that this well is being recharged by oil from the deeper Chainman shale, which extends down from Alaska. The Chainman shale is believed to have some of the richest shale rock characteristics of oil in the country and possibly the world. The problem is that the major oil pockets might be located at 10,000 ft to 25,000 ft underground, which dramatically increases drilling costs."

According to industry reports so far, no wells have definitively validated the Chainman shale as an economic play. A few years ago, Cabot Oil and Gas drilled a rank wildcat in Nevada that encountered the Chainman shallower in the section than anticipated, and the well was subsequently abandoned. "Our play in Nevada is made up of three distinct areas," said Cabot Chairman Dan Dinges in a 2010 statement. "We will take what we learned and shoot some additional seismic before we attempt the next well as there is no imminent lease expiration."

Still, red tape and bureaucracy on federal lands are stalling efforts to explore this potential gold mine, "despite numerous investors eager to purchase its oil and gas leases," Lawrence said. "Developing the Chainman shale would yield a net positive for public revenues — channeling more than $100 million in direct taxes to state coffers and another $100 million to federal coffers. This is not to mention the indirect tax revenue that could be received when newly employed individuals begin paying sales, property, and other taxes. Or the benefit of lower oil and natural gas prices for Nevadans."

Eagle Ford

One of the largest and most active shale plays in North America, it has been estimated that the Eagle Ford could contain as much as 27 Bboe. However, even those prospects can't hold the attention of some major players, as evidenced by mega-major Shell announcing its exit from the Eagle Ford — where the company has been active since 2006 — as soon as it can sell its 106,000 acre holdings. Shell's withdrawal has explorers nodding in agreement that the economics of Eagle Ford exploration may be best suited to the larger independents, despite the tricky subsurface features usually best explored by multinational majors. Even so, independents



(Source: Hart Energy Research & Consulting)

like Chesapeake Energy, Marathon Oil, and Murphy have all culled acreage in the play in 2013 to focus on the most prospective areas to keep economics in line until those multibillion barrels are actually proved up.

The source rock in the Eagle Ford exhibits three distinct windows for oil, condensate, and dry gas. More than 3,200 wells were drilled in 2013 alone. The Eagle Ford formation has been one of the most actively drilled in the past few years, with two large independents – a Chesapeake/CNOOC partnership and EOG Resources – dominating the acreage holdings. However, the list of operators in the play is a "who's who" of unconventional exploration, each with its own take on how to best extract the prolific hydrocarbons. In light of recent findings, Hart Energy's analysts have materially downgraded the mid- to long-term outlook on the play. "Whereas we had previously forecasted production to peak at 2.75 MMboe/d in 2023, we now expect a peak of 2.13 MMboe/d in 2019. We currently project cumulative production during the 2013 to 2030 horizon in the play to total 12.5 Bboe," Hart Energy Research & Consulting's *North American Shale Quarterly* service reported.

Fayetteville

Sited primarily in the Arkoma basin in northern Arkansas, the Fayetteville shale play covers an estimated 3.2 million acres and targets dry gas. The Fayetteville shale layer is located at depths between 1,500 ft and 6,500 ft with thickness varying from 50 ft to 550 ft. The US Department of Energy stated in 2009 that Fayetteville had 41.6 Tcfe of recoverable gas resources.

The Fayetteville shale play is very focused, with Southwestern Energy, BHP Billiton, and ExxonMobil subsidiary XTO Energy holding the biggest chunks of available acreage and operating the majority of the play's current production.


(Photo by Lowell Georgia, Hart Energy)

Schlumberger prepares to frac a Fayetteville well for Southwestern Energy subsidiary Seeco Inc. near Rose Bud, Ark.

BHP Billiton has put exploration in the play on hold, moving its two rigs out of the state in early 2013, but said it continues to invest in other wells where it sees value. According to Southwestern Energy, the Fayetteville shale is the "geologic equivalent of the Barnett shale" currently producing in North Texas, and the company has dedicated eight rigs allocated to Fayetteville plays to drill continuously in the shale.

The University of Arkansas reported that the most active area of natural gas development is from Arkansas's western Conway County through eastern White County. "Development further to the east is anticipated to proceed very slowly because the shale is considerably deeper, making gas extraction less economical," the report stated.

The shale game welcomes all players, from multinational majors to the smaller companies that have been working an area for years, knowing there are riches in their own backyards if they could just figure out how to get to them.

"At the end of 2007, there were approximately 2 million acres under lease to production companies in the play," the Arkansas report continued. "It is anticipated that thousands of wells will be drilled during the next several years. This activity will include construction and installation of roads and pipelines, as well as drilling fluid disposal pits and infrastructure to handle hundreds of millions of gallons of fracturing fluids."

The US Energy Information Agency said the Fayetteville shale gas play is still in early days, but gas prices and complex geology seem to be the factors hampering the play's current state of exploration. The US Geological Survey (USGS) reported that the Fayetteville shale "underlies some of the most beautiful and ecologically sensitive regions of the state," which may further inhibit exploration efforts. In anticipation of increased drilling activity, the USGS in 2011 proposed to develop a full 3-D description of the hydrogeologic units throughout northern Arkansas in order to characterize groundwater flow using advanced modeling software and visualization tools into the Fayetteville formation. That study appears to be on hold waiting for industry participation and additional outside funding.

Frontier

The Frontier formation stretches across Wyoming, Colorado, Montana, Idaho, and Utah, but the play is still in the infancy of shale hydrocarbon extraction evaluations. The formation is primarily sited in southwestern Wyoming and ranges in thickness from about 600 ft to as much as 1,000 ft.

Oil and Gas Investor reported that Chesapeake recently drilled a successful short-lateral Frontier formation well with an estimated ultimate recovery (EUR) of 600,000 boe, and Anadarko, with some 350,000 acres in the Powder River basin, reported "exciting exploration results" from about 20 Powder River wells in its 2Q 2013 conference call. "The zones we're playing are the Shannon and Frontier, and we're also looking at the Niobrara and Mowry," Charles Meloy, Anadarko's executive vice president of US onshore E&P, said during the late-July 2013 call. "The rates look really good, about 500 to 600 barrels a day, although it's too early to know EURs." The company is putting plans together for development programs in the two areas for 2014.

Granite Wash

The Anadarko basin is home to the Granite Wash, a tight sand play that is benefiting from the use of the same horizontal drilling technologies now being used in shale formations. Stretching from the Texas Panhandle into western Oklahoma, the Granite Wash is actually made up of a number of oil and gas producing formations covering an area 160 miles long by 30 miles wide, with the producing formations at depths varying from 11,000 ft to 16,000 ft. The actual producing formations of the Granite Wash range in thickness from 10 ft to as much as 4,000 ft.

Since 1993, the Granite Wash has produced 17.2 MMbbl of oil and roughly 1.4 billion Mcf of natural gas, according to Railroad Commission of Texas estimates. Production has been steadily increasing in Granite Wash fields since 2004, with more than 1.8 MMbbl of oil and 250 MMcf of gas as of August 2012.

A rig hand guides a stand of drillpipe to the rack during drilling operations on the #7-9H Britt horizontal Granite Wash well in Wheeler County, Texas.

Complicated lithologies such as those found in the Granite Wash have spurred several service companies to come up with solutions that enable more efficient and productive exploration. Halliburton has said that because of its varied mineralogy, the Granite Wash defies categorization. "Parts of its deposits are conventional, producing significant amounts of gas and liquids with little technological intervention," the company said. "However, much of the Granite Wash is extremely unconventional with poor reservoir characteristics and enormous volumes of gas in place. Extended laterals and smaller annuli challenge the probability of achieving a successful cement job. The tight clearances increase equivalent circulating density, reduce displacement efficiency, impede wellbore cleaning, and increase the probability of fluid intermixing and channeling. Without wellbore architecture integrity, long-term production with lower operating costs is jeopardized."

Haynesville

The Haynesville shale play is considered one of the largest dry gas plays in the country, with an estimated 75 Tcf of technically recoverable gas in place. Located in Texas and Louisiana, the Haynesville covers approximately 9,000 sq miles, and the depth of the shale ranges between 10,500 ft and 13,500 ft with a thickness of 200 ft to 300 ft, according to the US Energy Information Administration.

Chesapeake Energy, the largest acreage holder in the Haynesville and the company that claims discovery of the Haynesville shale play, stated in 2008, "Based on its geoscientific, petrophysical, and engineering research during the past two years and the results of three horizontal and four vertical wells it has drilled, Chesapeake believes the Haynesville shale play could potentially have a larger impact on the company than any other play in which it has participated to date." In 2009, the company began curtailing production from the field due to low natural gas prices. The company has since sold some of its assets in the play to pay down debt.

Marcellus

The largest gas play in the country is the Marcellus shale, covering 60 million acres across the Appalachian basin, spanning across New York, Pennsylvania, Ohio, Maryland, Kentucky, and West Virginia. The Oct. 22, 2013, US Energy Information Administration report showed that Marcellus production has reached 12 Bcf/d, exceeding growth predictions that did not expect that production rate for several more years. Most of the play's gas is produced in West Virginia and Pennsylvania. Ohio wells primarily produce oil from the Marcellus, and New York ceased all drilling operations in 2008 after environmentally based lawsuits questioned the safety of fracturing operations. The moratorium remains in place as the industry awaits enactment of new regulations from the New York Department of Environmental Conservation.

The Marcellus shale's gross thickness ranges from less than 20 ft along the Lake Erie shoreline to more than 250 ft in northeastern Pennsylvania. The formation appears to be targeted between 2,000 ft and 8,000 ft, and recoverable gas resource estimates vary from 260 Tcf to 490 Tcf. Parts of the Marcellus are sandwiched between the Utica shale below and the Upper Devonian shale above, potentially creating a triple stacked play formation.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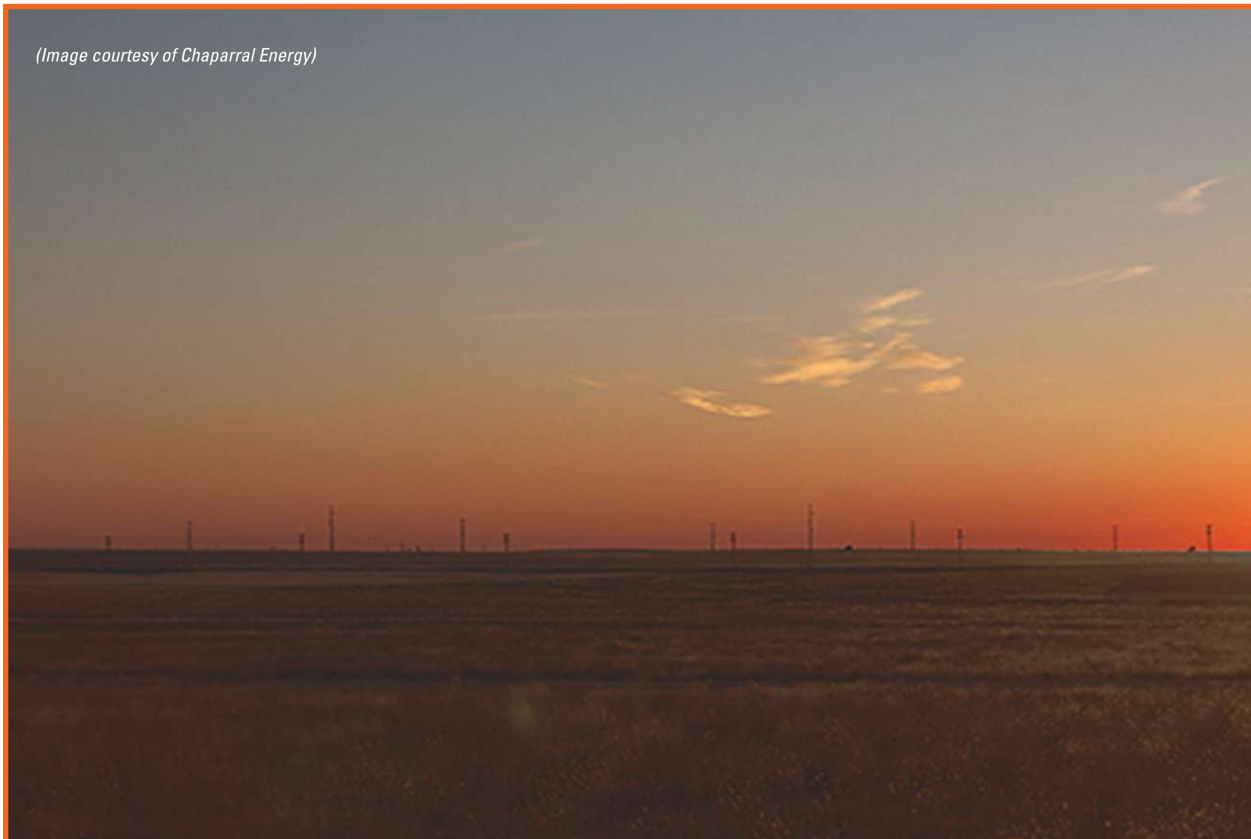
The Marcellus shale is recognized among the lowest cost domestic shale plays, and it is ideally located near major demand markets in the northeast US. However, the play has become a political hot potato, with many politicians basing their election platforms either for or against Marcellus exploration. New York Governor Andrew Cuomo promised to make a decision on the current drilling moratorium in New York sometime before the 2014 election. Pennsylvania Governor Tom Corbett announced his reelection campaign in early November 2013, touting the high number of jobs shale exploration has brought to his state as one of his successes. Meanwhile, citizens are still being bombarded with a barrage of conflicting information regarding horizontal drilling, fracturing operations, potential increases in radiation from drilling activities, and even the threat of manmade earthquakes. Several exploration companies have become frustrated with the political climate and have scaled back operations or pulled out altogether. The Marcellus and the underlying Utica remain two of the most controversial shale development plays in the nation.

Marmaton Wash

Not to be confused with the Pennsylvanian-age carbonate limestone called the Oswego elsewhere, the oil-bearing limestone known as the Marmaton Wash is gaining increased exposure for its shale prospects. Stretching across the Anadarko basin in a 125-mile arc from the Texas Panhandle into western Oklahoma, the Marmaton Wash is home to more than 400 vertical wells, many of which produce high-quality, 38°API crude.

More than 400 vertical wells produced from the primary porosity that intermittently developed in the play's five distinct shelf limestone cycles with average recoveries of 45 Mboe per well. Volumetric analysis of this entire system indicated very low drainage areas due to very low recovery factors. Further analysis of this cyclic sequence of brittle rock concluded a system that was highly charged with oil. Due to the relative tight nature of these limestones, conventional vertical drilling resulted in low recoveries of the trapped oil, tapping mostly the low primary porosity with occasional drainage of encountered fractured porosity. As this fracture



(Image courtesy of Chaparral Energy)

Night falls on Chaparral Energy's Anderson Rig 2HX-27 in the Marmaton.

system was uncovered, and with the advent of unconventional horizontal drilling, the exposure of more fractures along the wellbore face has proven to be highly lucrative. Recoveries of these horizontal wells are averaging 160 Mboe per well and in some cases exceeding 200 Mboe per well, which is 85% to 88% oil with associated highly rich gas. Rates of return have been in the 40% to 70% range.

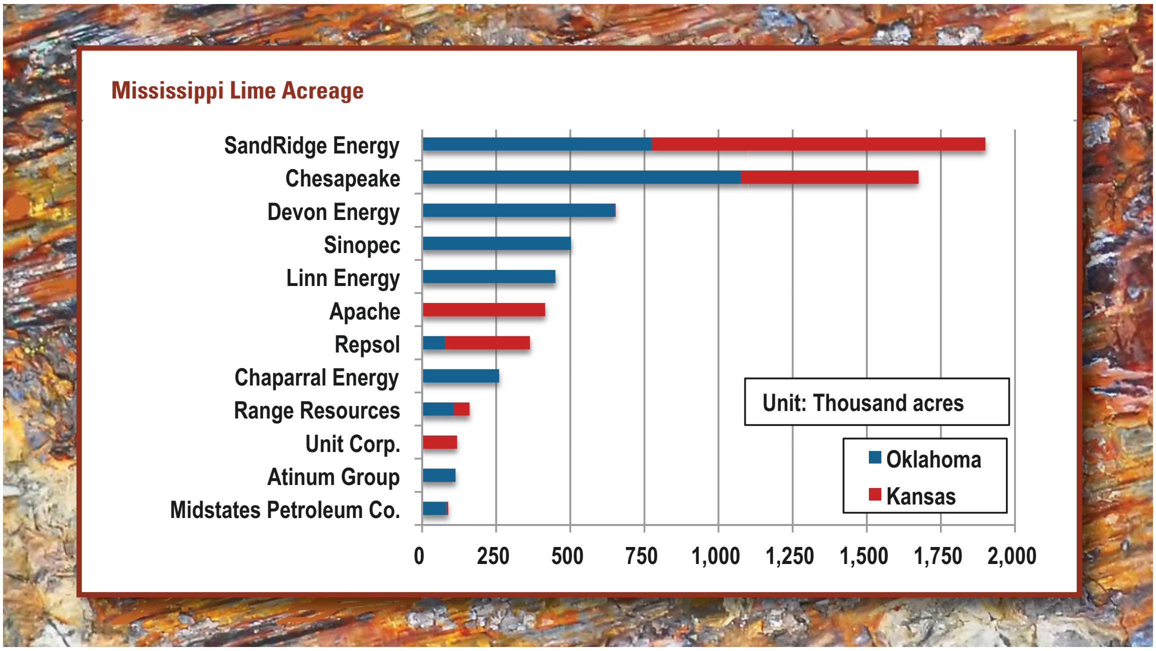
Mississippi Lime

The 17-million-acre Mississippi Lime play across Oklahoma, Kansas, and Nebraska is not a true shale play but conventional tight oil from porous chert and limestone, gaining new life as horizontal drilling technologies advance. More than 14,000 vertical wells drilled since the 1950s through the formation have provided much information on the play, which has been touted by some as "the next Bakken." Well depths are fairly shallow, averaging between 3,000 ft and 6,000 ft vertical depth.

What makes the Mississippi Lime play somewhat unique – and attractive – is that it is very low-tech, Hart Energy's *E&P* magazine reported. Some sections of the formation are naturally fractured, lowering exploration costs. The formation is very low-pressure, and porosity is better than in many tight formations. Infrastructure is already in place in many cases. Formation thicknesses run up to 1,700 ft. "At the same time, it is very cost-effective to drill into the formation with well costs ranging around US $2.8 million to $3.5 million," according to *E&P*.

However, produced water is a real issue in the play. When fractured, unusually high volumes of associated water are produced, making transportation, disposal, treatment, and reuse critical factors in Mississippi Lime exploration. The water issue is so troubling that it prompted the first "Mississippi Lime Production and Produced Water Congress" in Oklahoma City in June 2013, bringing operators together to discuss tactics and strategies for optimizing production technology, enabling high oil cuts, and dealing with excess water.

Hart Energy researchers predict production in the play will reach a peak of 509 MMboe/d in 2023. However, particularly in the Kansas portion of the play, some companies have scaled back operations,



(Source: Hart Energy Research & Consulting)

put exploration plans on hold, or even pulled out altogether after disappointing results. Shell Oil is one company reportedly putting its 45 producing wells and 600,000 acres in Kansas on the sales list, stating the play does not fit with its corporate strategic criteria. Chesapeake sold some of its assets in the Mississippi Lime to Sinopec to raise capital to pay down debt.

Monterey

Although the Monterey formation has been projected to hold as much as two-thirds of America's shale oil resources, the complicated geology continues to perplex explorationists. Spanning across 1,700 sq miles in both the San Joaquin and Los Angeles sedimentary basins, the US Energy Information Administration puts the Monterey at 15.24 Bbbl of technically recoverable oil. Depth of the shale ranges from 8,000 ft to 14,000 ft with thicknesses anywhere from a couple hundred feet up to 3,000 ft. However, the complications of the lithology are legendary and are exacerbated further by the amount of quartz found in the formation.

The oil can be sweet or sour, and natural fracturing is so prevalent that hydraulic methods are not always viewed as necessary – but that double-edged sword cuts both ways, as the amount of natural fracturization and tectonic faulting also can lead to lost circulation and stability issues downhole.

California's regulatory climate also has put a damper on exuberant exploration of the Monterey shale play. In September 2013, California legislators passed Senate Bill 4, which institutes "strong environmental protections and transparency requirements for hydraulic fracturing and other well stimulation operations" and goes into effect in January 2015. Although California Governor Jerry Brown was reportedly quick to comment to Bloomberg reporters, "I think we ought to give science a chance before deciding on a ban on fracing," the proposed environmental study of the effects of fracturing in the state is slated to last as long as 18 months.

New Albany

The New Albany shale play is located in the Illinois basin and southern Illinois, southwest Indiana, and northwest Kentucky, and the US Energy Information Administration puts technically recoverable gas reserves at 11 billion Tcf. The New Albany shale has more than 100 years of production history, but there is still some debate about the amount of oil in place and whether it is economically recoverable from the shale formation given the basin's complex geology.

The New Albany is unique in its "organic-matter content, high radioactivity, and paucity of fossils, especially benthic forms," the US Department of Energy said. "A typical shale formation has 100 API units of radiation; the New Albany Shale has in some cases up to 200 to 400 API units above the normal shale background." This radioactive component has spurred environmental groups to call for a ban on horizontal activity in the New Albany formation. So far moratoriums are in effect in a few individual counties, but a statewide moratorium has not been issued in Illinois, the primary location of New Albany shale drilling interest at this time.

Still, something intriguing is happening in the New Albany shale that has explorationists taking notice. The Illinois Department of Natural Resources (IDNR) began accepting online registration on Oct. 3, 2013, from firms and individuals interested in applying for a permit for high-volume horizontal hydraulic fracturing in Illinois, and the government intends to make public the names of the companies that apply for these fracing permits. However, no applications for high-volume horizontal fracing permits will be accepted until after the Illinois General Assembly approves pending rules on fracturing operations. The registration is required under provisions of Illinois' new Hydraulic Fracturing Regulatory Act, the IDNR stated.

Niobrara

The Niobrara shale formation can be found in several basins in the Rocky Mountain region of the western US, including the Denver-Julesburg (DJ), Powder River, Piceance, Douglas Creek Arch, North Park, San Juan, Raton, and Greater Green River basins. The Niobrara Petroleum System is comprised of a network of natural fractures and faults, making the play's sweet spots difficult to predict. All sedimentary basins in Colorado include the Niobrara, and the formation continues to produce commercial quantities of both oil and gas.

Estimated ultimate recovery rates (EURs) vary throughout the various basins in which the Niobrara is present. Operators such as Noble Energy, the top DJ basin operator, report EURs in the 335 Mboe to 345 Mboe range throughout its Wattenberg field leasehold. The company's extended-reach laterals wells have much-improved EURs ranging between 750 Mboe and 1,000 Mboe. Thanks to new discoveries in the Niobrara, Colorado's oil production hit a 50-year high in 2012 – 48 MMbbl – and the state reported that enthusiasm for the play, despite the tricky geology, is still on the rise.

The Cretaceous-age Sunniland trend stretches onshore from Florida's Fort Myers to Miami. In the South Florida basin, it is home to some of the state's most intriguing hydrocarbon production.

Rig counts in the play are averaging 300-plus, according to the US Energy Information Administration. Wells in the Deep Niobrara can be 10,000 ft to 12,000 ft deep with laterals averaging 4,000 ft to 7,000 ft, making well costs in the US $10 million range. Pad drilling is becoming more commonplace in the play, with multiple wells from a single pad location.

Noble Energy has estimated its Niobrara reserves at 2.1 Bboe and will spend $10 billion in the next five years on developing the play. Anadarko said its Niobrara reserves are 1.5 Bboe and planned to spend $1 billion in 2013 on the play. The company recently announced a strategic acreage exchange in the Wattenberg field that is expected to enhance operating efficiencies and concentrate core acreage position near the company's operated infrastructure. However, as has been the case in other shale plays, the smaller independents claim the spotlight when it comes to big discoveries. In October 2013, WPX, a former Williams subsidiary, announced it has discovered both the top and the second highest producing wells in the Niobrara.

Sunniland

The Cretaceous-age Sunniland trend stretches onshore from Florida's Fort Myers to Miami. In the South Florida basin, it is home to some of the state's most intriguing hydrocarbon production. To date, all discoveries have been via conventional vertical wells, although some directional drilling has been undertaken. The trend is 150 miles long and 20 miles wide and is divided into two zones: the Upper Sunniland, which has produced more than 120 MMbbl of heavy sour crude so far; and the Lower Sunniland, the shale formation found at around 20,000-ft depths that is now garnering attention as a potential unconventional resource.

Production from the Upper Sunniland formation began in the 1940s and peaked in the mid-1970s at around 17,000 b/d. Current production in the basin has declined to a few thousand barrels per day, but recent horizontal wells drilled into Upper Sunniland are spurring renewed interest. One of the more encouraging horizontals had a 30-day average initial production (IP) of 1,200 b/d and has produced 200,000 bbl in its first 10 months, explained Sunrise E&P Co., a privately held New Orleans-based firm taking a serious look at the formation's future potential.

Sunrise reported that, although hundreds of successful completions have been made in the Upper Sunniland limestone, only one completion attempt in the Lower Sunniland shale has ever been made – by Humble Oil (now ExxonMobil), which perforated 20 ft of the Lower Sunniland shale in the late 1960s and established conventional production in a vertical well with no fracture stimulation. That slightly overpressured well had an IP of 118 b/d of oil and has produced about 300,000 bbl during the past 40 years with no water.

The largest leaseholder in the Sunniland is Collier Resources, which manages more than 800,000 mineral acres. The company leases its mineral rights to explorationists and monitors oil production and development operations at its three oil fields.

Legislation in Florida now allows hydraulic fracturing, but to date no permits have been formally requested or issued. Recent reports indicate that Florida officials are still undecided about whether fracturing will be allowed if or when an impending request to fracture is made. Several bills have made it to the discussion phase but none provides a definitive answer on the state's position to date.

Tuscaloosa Marine

The Tuscaloosa Marine shale is located in the Texas-Louisiana Salt basin and spans southwestern Mississippi, southeastern Louisiana, and a portion of southern Florida. It is estimated to hold potential reserves of about 7 Bbbl of oil, according to the Louisiana Department of Natural Resources. The extreme depths at which the Tuscaloosa can be found has kept explorers from tapping into what some speculate might be comparable quantities to those found in the Eagle Ford, but technological improvements such as multistage fracturing might make this deep play more attractive and economically viable.

To highlight his state's welcoming stance toward shale exploration, Mississippi Governor Phil Bryant signed legislation in April 2013 that dramatically reduced the state's tax rate for oil and natural gas companies that use horizontal drilling as part of his "Energy Works: Mississippi's Energy Roadmap" plan.

The bill reduced the severance tax from 6% to 1.3% for oil and gas extracted from horizontally drilled wells for a period of 30 months or until the payout of the well. The legislation applies to all qualified horizontally drilled wells between July 1, 2013, and June 30, 2018.

While there are several geologic formations in Mississippi with significant potential for oil and gas production using horizontal drilling, the emerging Tuscaloosa Marine shale development in southwest Mississippi is the one most likely to lure investment and interest in the short term, the governor's office predicts. "The Tuscaloosa Marine shale will be one of the most active shale plays in the United States. Several companies are currently undergoing preliminary drilling tests in the play, working to refine the extraction techniques appropriate for the Tuscaloosa Marine shale."

Although the depths required to reach the formation can be formidable, one of the things that makes the Tuscaloosa Marine shale attractive is that it is an oil play. Early wells have shown production to be weighted up to 95% light, sweet crude. And, if commercial quantities are able to be extracted from this play, the good news is that it is located close to the infrastructure, refining, and processing facilities so abundant on the Gulf Coast.


(Photo by Mieko Mahi, Hart Energy)

Roughnecks on Ensign Rig 753 work on the Crosby 21H-1 in Wilkinson County, Miss. The crew moved to Crosby after drilling Goodrich's first operated TMS horizontal, Denkmann 33H-1, just east, in Amite County.

Utica

The Utica shale is located under the Marcellus shale in multiple states in the northeastern US. In the Appalachian basin, the Utica can be found in Pennsylvania, Ohio, West Virginia, and New York, as well as in parts of Kentucky, Maryland, Tennessee, and Virginia. The Utica also shows up in the Michigan basin in Michigan, Indiana, and parts of Canada.

The Utica shale is generally considered a gas-prone play, although the western portion of the formation yields both NGL and oil. The bulk of the shale's development is focused in eastern Ohio. Activity is concentrated in the wet gas-to-oil window where the total organic carbon is usually very high and liquids-prone, according to Hart Energy's *North American Shale Quarterly* report. As of November 2013, 600 Utica wells have been drilled in Ohio, and permits have been approved for 963 wells.

The US Geological Survey estimated that "the Utica holds about 38 Tcf of undiscovered, technically recoverable natural gas (at the mean estimate) according to the first assessment of this continuous (unconventional) natural gas accumulation. The Utica shale has a mean of 940 MMbbl of unconventional oil resources and a mean of 208 MMbbl of unconventional NGL, 8 Tcf of recoverable gas, and 940 MMbbl of oil."

If the play is as productive as predicted, infrastructure may quickly become a problem, although processing plants and pipelines are in the works in several locations in anticipation of large-scale production.

Wolfcamp

The Permian basin is the gift that keeps on giving. One of the world's earliest producing basins, the Permian has now added unconventional targets to its repertoire, including the Wolfcamp Horizontal located in both of the main sub-basins of the Permian (the Midland and Delaware). Unconventional reservoirs account for more than 24% of the Permian's total basin production, and liquids comprise 78% of that unconventional production, according to Hart Energy Research & Consulting's *North American Shale Quarterly* report.

In the Midland sub-basin, operators are drilling into the Upper Spraberry at 7,000 ft and extending down into the Wolfcamp at 10,500 ft. This stacked play has seen some of the highest activity levels among Permian tight oil plays, and recent reports suggest that deeper sequences beyond 11,000 ft in the Pennsylvanian Strawn and Atoka, even Mississippian, are being targeted. Also of stacked nature, the Wolffork is a vertical play that extends across several counties in the southern region of the Midland sub-basin at depths between 6,000 ft and 8,300 ft. This play refers to production from both the Wolfcamp and the shallower Clear Fork reservoir, developed by vertical wells treated with multistage fracturing techniques. Another section of the Wolfcamp in the Midland basin is sometimes referred to as the "Wolfcamp University," named after University of Texas land leases. The Wolfcamp encompasses three zones at depths from 5,000 ft to 8,300 ft. All key operators in the Permian basin are targeting the Midland Wolfcamp sequence in some form or another, the *North American Shale Quarterly* reported.

The Delaware sub-basin's Wolfcamp play is located in the state-border area of southeast New Mexico and West Texas. These areas have significant conventional production from operators with large, legacy acreage positions. On the Delaware side, the Wolfcamp is targeted with horizontal wells in such areas as the Sage Draw field in Eddy County, N.M.

The largest acreage holder in the Wolfcamp, Pioneer Natural Resources, said the Wolfcamp could be the world's second largest play in the world in terms of recoverable reserves – estimated second only to Saudi Arabia's 100-Bboe Ghawar field – with recoverable reserves that could reach 50 Bboe. As Pioneer CEO Scott Sheffield said on CNBC in 3Q 2013 after the discovery of a new producing zone, the Wolfcamp D, "We have the best well in the Permian basin. It came in over 3,000 barrels per day. We dominate the field. Now we have the Wolfcamp A, the Wolfcamp B, and the Wolfcamp D. I think our 50 Bbbl number is going to end up being low over time. We are definitely the 100-lb gorilla in the Spraberry-Wolfcamp field."

Woodford

The Woodford shale is found in Colorado, Kansas, Oklahoma, and Texas. The Woodford covers nearly the entire state of Oklahoma and shows up in at least three basins, the Ardmore (called Woodford Central, where it might cover an estimated 1,800 sq miles), the Arkoma (Woodford Western, extending approximately 2,900 sq miles), and the Anadarko. The Anadarko Woodford produces crude oil, natural gas, and natural gas condensate, and is an ultra-low permeability reservoir with multiple layers, faults and fractures that require 3-D seismic and geological analyses to develop optimum lateral orientation, and complex completion strategies and fracture stimulate to obtain commercial production.

The Woodford shale produces both light, sweet oil and NGL. In areas with optimal thermal maturity and kerogen type, the Woodford has served as a source rock for oil and gas reservoirs that have been producing for almost a century. According to a 2010 US Geological Survey report, mean undiscovered resources from all the Woodford shale areas are estimated at around 25 Tcf of natural gas and 726 MMbbl of NGL.

Service giant Halliburton has been working hard to crack the code of the Woodford and has said the reservoir is "far more complex than other Devonian black shales found in North America." These complexities affect drilling and completion design, production practices, and well productivity, and "can have a major impact on horizontal drilling, slowing penetration rates and quickly destroying bits," the company said.

Woodford shale production in Oklahoma began in the 1930s, but the first horizontal wells were not drilled until 2004 when gas prices became more economically favorable and completion techniques improved. Currently, almost 2,000 wells are in production, approximately 475 vertical and more than 1,500 horizontal.

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KEY PLAYERS

Anadarko Petroleum Co.

• Niobrara 1.25 million net acres; Eagle Ford 200,000 net acres; Marcellus 260,000 net acres
• Produces enough energy to heat or cool more than 10 million American homes each day

Anadarko Petroleum is the largest acreage holder in the Niobrara play, where the company has been active for more than 30 years. The company holds Niobrara acreage in both the Denver-Julesburg (DJ) and Powder River basins and stated that its Wattenberg horizontal program in the DJ basin could hold net resources of 1 Bboe to 1.5 Bboe. In addition to unconventional exploration, the company undertakes traditional vertical wells, EOR projects, and coalbed methane extraction and also operates or has access to extensive midstream assets including pipelines and processing. Anadarko produces enough energy from its Rocky Mountain operations to heat or cool more than 10 million average American homes each day.

In late 2013, the company finalized a property exchange with Noble Energy in the Wattenberg field to consolidate individual acreage positions and cut costs. Each company exchanged approximately 50,000 net acres, a move that served to add 8,000 boe/d to Anadarko's current production levels. Anadarko said it plans to drill 350 to 400 new horizontal wells in the Wattenberg horizontal program in 2014 and expand infrastructure throughout the field. "We anticipate increasing activity on our core Wattenberg acreage, where we are generating rates of return that exceed 100%," said Chuck Meloy, Anadarko's executive vice president of US onshore E&P.

In the Marcellus, the company has invested more than US $6 billion since becoming active in the play in 2006. The company holds more than 260,000 net acres in Pennsylvania. Since 2006, Anadarko and its partners have produced approximately 350 Bcf of natural gas. Anadarko is producing more than 2 Bcf/d of natural gas (gross).

The company also is one of the largest producers in the Eagle Ford, where its net sales continue to rise. Total liquids sales volumes averaged almost 32,000 b/d, representing a 62% increase in liquids sales volumes compared to 2Q 2012. The company operates around nine rigs in the area and was on target to drill a planned 325 wells in the play in 2013.

In 3Q 2013, Anadarko completed its first two Wolfcamp shale wells with encouraging results. The Permian basin wells tested 1,600 boe/d and 1,000 boe/d, respectively, and the company is evaluating its next move in this play.

The company also is active in East Texas/Haynesville, where it reported sales are up more than 87% compared to 2012.

Apache Corp.

• Granite Wash 418,000 net acres; Mississippi Lime 580,000 net acres; Cline shale 520,000 net acres
• Leading acreage holder in Oklahoma's Granite Wash

Apache Corp. is the leading acreage holder in Oklahoma's emerging unconventional play, the Granite Wash. The company has more than 418,000 net acres in the Granite Wash and has identified more than 22,800 potential well locations within this area. Apache is not shy about trying new technologies and boasts the use of a new drillbit technology and cementing procedures in its Granite Wash wells. The company planned to drill a total of 100 wells in the play before year-end 2013. Flow rates from the company's first six wells drilled and producing for 30 days in 2013 averaged 1,495 boe/d, and after processing for NGL the 30-day initial production rate averaged 291 bbl of crude oil, 469 bbl of NGL, and 4.4 MMcf of natural gas.

"We're realizing more robust production from the Granite Wash than we expected a year ago," said Rob Johnston, vice president of Apache's central region. "We have decreased costs by 15% from a year


SURFACE CONDITIONS
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(Image courtesy of Apache Corp.)

Drilling continues at the Stiles Ranch in the Granite Wash basin.

ago, representing savings of US $1.3 million to $2 million per well, depending on the formation's depth and reservoir characteristics. We expect to be able to capture additional cost savings in the year ahead, as we incorporate more lessons learned from being the most active driller in the play and analyzing data from the 120-plus Granite Wash wells we've operated as well as results from other operators in the area. The more we drill, the more we learn and the better the economics of the Granite Wash play get."

Depositional thickness of the Granite Wash play averages an estimated 2,700 ft. Because Granite Wash reservoirs are sandier than shale-based formations, the possibility exists for more prolific flows, predictable operations, and repeatability than conventional oil and gas plays, Johnson said.

Apache more than doubled its holding in the Anadarko basin when it acquired Cordillera Energy Partners III LLC for $2.85 billion in cash and stock in 2012.

West Texas' Wolfcamp shale also may prove to be a winner for Apache, where 971 potential well locations already have been mapped and where Apache believes there is an estimated 347 net MMboe recoverable. Apache also is experimenting in the Cline shale, where the company has put together a 520,000 net acre position, planned to drill 30 wells during 2013, and had identified more than 2,300 drilling locations with estimated resource potential of 640 MMboe.

In Kansas and Nebraska, Apache has leased more than 580,000 net acres in the Mississippian Lime play, and in the Williston basin Apache holds 300,000 net acres in the Bakken/Three Forks play in Montana. Both areas are under evaluation.

Apache also is working to set itself apart from its shale play competition by using operating strategies across its properties. As an example, Apache has partnered with Halliburton and Schlumberger to find ways to use natural gas to power hydraulic fracturing, one of the most energy-intensive processes employed in the industry. Only 1% of drilling rigs and zero full fracture spreads are powered by natural gas.

The reason why is clear, Mike Bahorich, Apache's executive vice president of technology, said. The industry uses upward of 700 MMgal/year of diesel to pump sand and water during fracture stimulation. Converting the process to using field gas could save 70% in operating costs for fuel.

"By using field gas, the US would import 17 million fewer barrels of oil each year to make the diesel to fuel these fracs," Bahorich said. Using an engine modified by Caterpiller to handle a dual-fuel setup, Apache, Halliburton, and Schlumberger have had several successful tests in Oklahoma in the Granite Wash using up to eight engines running on the dual-fuel kits. A full complement of 12 engines was scheduled to be used in December 2013 at a fracture near Elk City, Okla.

Apache also holds acreage in the Eagle Ford shale, but the Eagle Ford is not proven in that part of Texas yet, a company spokesman said. Apache and others are in the evaluation process in this region.

BHP Billiton

• Fayetteville 487,000 net acres; Haynesville 268,000 net acres; Eagle Ford 341,000 net acres
• Will sell more than half of its Permian acreage in both the Delaware and Midland sub-basins

BHP Billiton made its move into the US shale game in 2011 after purchasing Fayetteville assets from Chesapeake Energy and an acquisition of Petrohawk Energy that included significant acreage positions in the West Texas Permian basin and the Eagle Ford shale play in south Texas. BHP Billiton said it will sell more than half of its Permian acreage in both the Delaware and Midland sub-basins to concentrate on a more focused area for appraisal.

For sale is 165,000 net acres in the Delaware basin offering "thousands of feet of stacked pay that includes multiple intervals within the Avalon, Bone Spring, and Wolfcamp," and 85,000 net acres in the Midland sub-basin, where "newly drilled horizontal wells and permits to drill horizontal wells in the Wolfcamp, Strawn, Fusselman, and Spraberry surround the company's acreage," according to the website of BHP's agent, Scotia Waterous (USA) Inc. Six exploration wells have been drilled by BHP and predecessor companies, shortcutting the development process in the acreage for sale, the agency said.

While natural gas prices remain low, BHP has reduced its rig count to zero in the dry gas Fayetteville shale in Arkansas but is running five rigs in the gas-prone Haynesville/Bossier shale in Louisiana and East Texas and 19 rigs in the liquids-rich Eagle Ford shale in South Texas. The company also is actively appraising for potential development in the Permian basin in West Texas. A significant increase in the number of producing wells in the Eagle Ford contributed to a 29% increase in the company's onshore US liquids production from 2Q 2013. US onshore development activities continue to focus on the Black Hawk region of the Eagle Ford. BHP holds acreage in two Eagle Ford fields: the Black Hawk and Hawkville.


(Image courtesy of BHP Billiton)

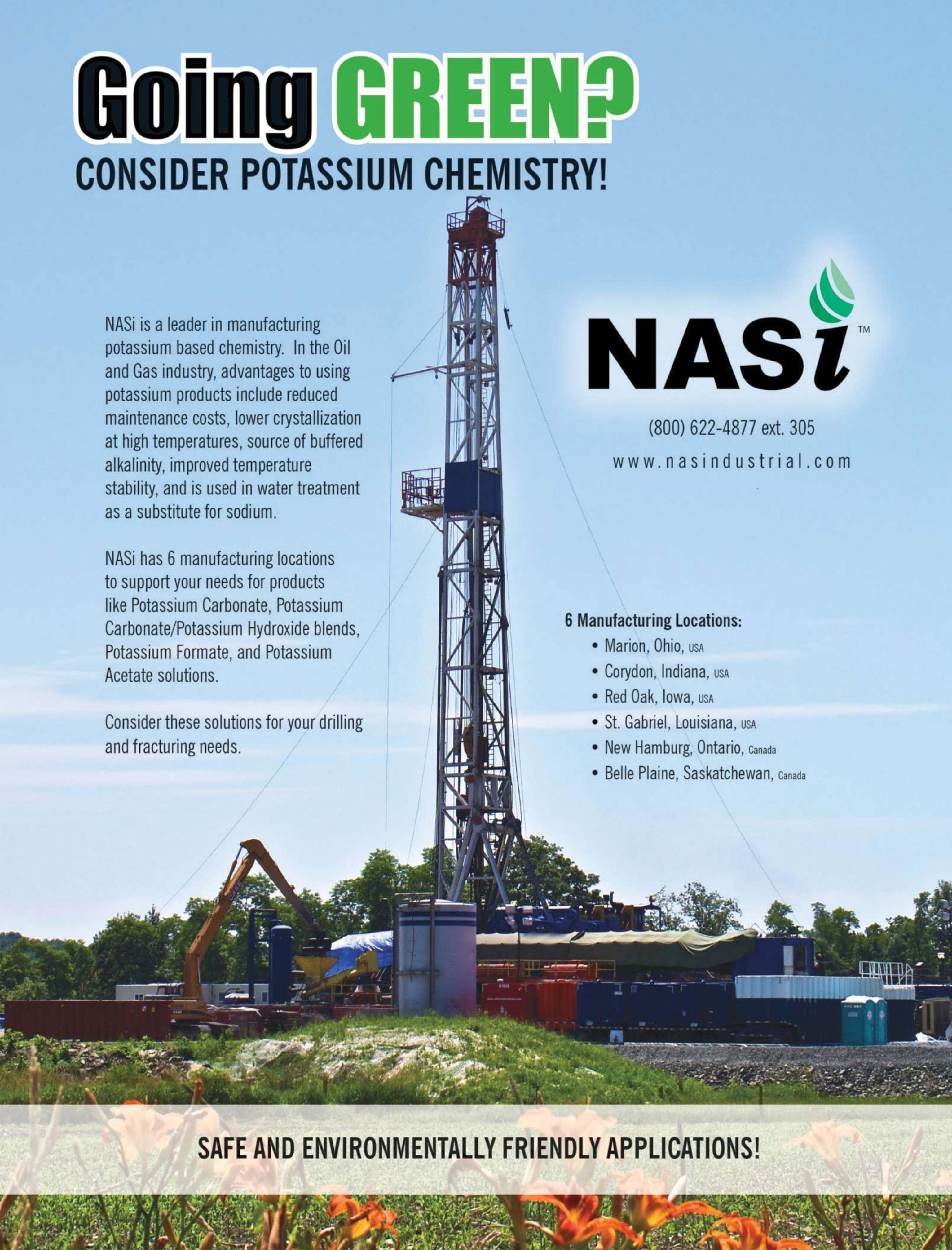
BHP Billiton is one of the largest foreign investors in US shale.

Bill Barrett Corp.

• Frontier 68,000 net acres; Niobrara 76,000 net acres
• Plans to drill its first extended-reach lateral in the DJ in 1Q 2014

Bill Barrett Corp. holds about 68,000 net acres in the Powder River Deep and has drilled two wells into the Frontier formation. Both wells were successful and drilled to a true vertical depth around 12,800 ft with 4,100-ft laterals and about 18 fracture stages. Delineation plans are under way. The company explained that while the prospectivity of each of the lower formations varies across its acreage position, competitors have had success in lower formations, which Bill Barrett believes it can replicate. "We think this is a great play, with the potential to offer scale and profitable returns," Jennifer Martin, vice president of investor relations, said.

The company also is active in the Denver-Julesburg (DJ) basin targeting the Niobrara B bench, C bench, and Codell formations through horizontal drilling, where it said its proved reserves were up 80% in 2012 compared to 2011, and the company predicts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a "notable increase" when its reserves figures are announced again at the end of January 2014. Bill Barrett met its goal of obtaining permits to scale its operations to four continuously active rigs and has modified its drilling and completions technologies to better suit the tricky geologic environment. "The Niobrara is prospective across the northeast Wattenberg," and for the remainder of 2013, Bill Barrett focused on delineating its position and drilling extended-reach wells to test what it hopes is "sizeable economic upside through multiple horizons, downspacing, and new technologies," the company said.

Bill Barrett Corp. holds about 68,000 net acres in the Powder River Deep and has drilled two wells into the Frontier formation.

Bill Barrett was on track to drill 65 DJ/Wattenberg wells in 2013, 15 of which would target the Niobrara C. The company also plans to drill its first extended-reach lateral in the DJ basin in 1Q 2014.

BreitBurn Energy Partners

• Sunniland 33,322 net acres; New Albany 50,000 net acres
• Spent about $30 million on its Florida wells in 2013

BreitBurn Energy Partners operates five Florida fields with 19 actively producing wells. Production is from the Cretaceous Sunniland trend of the South Florida basin, and each well is producing oil without associated gas. The company holds estimated proved reserves of approximately 10.4 MMbbl, and average daily production from its Florida fields was approximately 1.9 Mb/d in 2012. Production from the Raccoon Point field accounts for more than half of BreitBurn's Florida production. In 2012, the company drilled four productive wells in Florida. During the second half of 2013, the company spudded three Sunniland wells that are still drilling ahead. The company spent about US $30 million on its Florida wells in 2013.

The company also operates 254 producing wells in southern Indiana and northern Kentucky's New Albany shale play with proved reserves of 0.6 MMboe or 3.4 Bcf. BreitBurn's estimated proved reserves in Indiana and Kentucky on Dec. 31, 2012, were 0.6 MMboe or 3.4 Bcf, and capital spending in Indiana and Kentucky for 2012 was less than $1 million and included two optimization projects. BreitBurn's operations in the New Albany play include 21 miles of high-pressure gas pipeline that interconnects with the Texas Gas Transmission interstate pipeline.

Chaparral Energy

• Marmaton Wash 60,000 net acres; Mississippi Lime 133,000 net acres
• New acreage effectively doubles company's holdings

Chaparral Energy became the largest acreage holder in the Oklahoma-Texas Panhandle Marmaton Wash play when it announced its purchase of all of Cabot Oil & Gas' acreage in the area for US $160.1 million. Acquiring the 66,000 new acres effectively doubled Chaparral's holdings in this unconventional play and added 2,000 boe/d to Chaparral's books.

Production from the purchased assets is approximately 81% oil with proved reserves estimated to be 8.4 MMboe and unproven reserves estimated to be 24 MMboe on the effective date of Oct. 1, 2013.

The Cabot acquisition increases Chaparral's growth potential through the addition of approximately 450 drilling locations targeting the Marmaton Lime formation, which typically generates recoveries of an average of 160 Mboe per well and a rate of return in the 40% to 70% range, the company said.

"In addition, this area offers significant upside associated with drilling numerous horizons in this stacked-pay environment," Chaparral President Mark Fischer said. "The purchase includes significant infrastructure, including saltwater disposal wells and electricity, which will generate operating efficiencies and economies of scale by supplementing Chaparral's existing footprint."

Cabot completed five Marmaton wells during 2Q 2013, each with an average of 21 fracture stages, resulting in an average initial production rate of


Packers Plus

Employees connect a valve on piping for the Thomas 2H-26 tank battery in the western Oklahoma/Texas Panhandle Marmaton Wash.

more than 800 boe/d. Chaparral, on its existing acreage, drilled or had plans to drill 15 horizontal wells in the Marmaton formation in 2013. With the expanded acreage position, Chaparral expects to operate an average of four to five rigs in the play in 2014.

The company also holds a significant acreage position in the Mississippi Lime in northern Oklahoma and expected to drill or participate in 40 horizontal wells in 2013. Chaparral averaged two to three operated rigs in this play during 2013 and expects to maintain a three-rig program in 2014.

"Both of these two plays are similar in depth, costs, and economics, but recoverable reserves are different with the Mississippi Lime, producing approximately 40% to 45% oil and with recoveries in the 350 Mboe range per well," Fischer said.

Chesapeake Energy

• Marcellus 1.8 million net acres; Mississippi Lime (with Sinopec) 2 million net acres; Utica 1.2 million net acres

• Second largest oil producer in the Eagle Ford shale

Chesapeake Energy can be found in a wide variety of unconventional plays across the US, both as a solo operator and as a joint venture partner. In the Eagle Ford shale, Chesapeake is the second largest oil producer and claims it has "the fastest gross operated oil growth rate" in the play. The company owns approximately 380,000 net acres and has identified more than 3,400 core drilling locations. In July 2013, Chesapeake sold 55,000 net acres of its Eagle Ford properties to EXCO Operating Co. including approximately 120 producing wells averaging 6,100 boe/d.

In the Marcellus shale, Chesapeake holds 100,000 net acres with 1,000 potential drilling locations sited in what it has deemed its core area. In the Northern Marcellus in Pennsylvania, the company operates an average of five rigs at any given time and said production, which is all natural gas in this sector of the play, has been temporarily constrained by downstream factors. At the end of September 2013, Chesapeake had 128 wells waiting on pipeline connection or in various stages of completion in the

northern Marcellus. However, relief is in sight, as new capacity expansion projects were placed in service in the last few months of 2013 on several key pipelines. The company has contracted for approximately one-third of the estimated 1.4 Bcf/d of new pipeline capacity expected to be online in 4Q 2013, which the company believes will benefit both its production volumes and gas price realizations.

The southern Marcellus shale of Pennsylvania and West Virginia holds wet gas production for Chesapeake, with a ratio of around 13% oil, 17% NGL, and 70% natural gas. During 3Q 2013, the company operated an average of three rigs and connected 30 gross wells to sales, and the average peak daily production rate of the 30 wells that began first production during 3Q 2013 was approximately 6.7 MMcfe/d. Again, downstream constraints kept 62 wells waiting on pipeline connections or in various stages of completion as of Sept. 30, 2013.

Utica shale net production for the company averaged approximately 164 MMcfe/d (312 gross operated MMcfe/d) during 3Q 2013, representing an increase of 91% sequentially from 2Q 2013. During 3Q 2013, Chesapeake operated an average of 11 rigs and, as of Sept. 30, 2013, had drilled a total of 377 wells in the Utica, which included 169 producing wells and 208 wells waiting on pipeline connections or in various stages of completion.

The company also is active in the Barnett shale, which is dubbed "the granddaddy of US shale plays," and last disclosed 225,000 net acres in the formation. As another huge gas play with massive potential, the Barnett already has produced more than 4.8 Tcf of natural gas and is expected to produce an additional 40 Tcf of natural gas resources. Chesapeake has remained active in the play since 2005, when it became the first operator to drill on an international airport at the Dallas/Fort Worth International Airport.

In 2008, the company announced its discovery of the Haynesville shale, which many have said has the potential to become the largest natural gas play in the US with technically recoverable resources estimated at 251 Tcf.

In July 2013, the company said it had sold 9,600 net acres of its Haynesville holdings in Louisiana to EXCO Operating Co., including 11 units operated by Chesapeake and 42 units operated by EXCO. Average net daily production from the Haynesville properties included in the transaction was approximately 114 MMcf of natural gas equivalent.

In the western US, Chesapeake has holdings in the Niobrara shale with a small independent, RKI E&P. Chesapeake began drilling the deep-basin Niobrara in 2009, and most of the acreage is held by 26 federal units in place or Niobrara production, with more than 90 wells drilled. However, the company is focusing on a 140,000-acre development program using pad drilling in southern Converse County, a location that holds "the sweet spot Niobrara and Frontier" formations, Ronni Irani, RKI CEO, told *Oil and Gas Investor*. "That's where Chesapeake's rigs are now focused. Wells here consistently [have] initial production between 1,200 boe/d and 1,800 boe/d with 70% oil and liquids."

Chesapeake also is one of the largest leasehold owners in the Mississippi Lime unconventional play, with nearly 2 million net acres, the majority of which are in northern Oklahoma and Kansas. The company also is active in Oklahoma's Granite Wash play.

Doug Lawler, Chesapeake's CEO, said, "Although we have reduced our drilling and completion activities in the second half of 2013 and we are planning for a lower capex budget next year, we expect to continue delivering organic production growth in 2014. We anticipate our growth will be led by an increase in oil production from the Eagle Ford shale and an increase in natural gas and NGL production from the Utica and Marcellus shales, which will benefit from new gas processing and pipeline takeaway capacity."

Chevron

• Utica 491,000 acres; Marcellus 714,000 net acres; Wolfcamp 320,000 acres in the Midland basin, 1.1 million acres in the Delaware basin

• One of the largest leaseholders in Pennsylvania and Ohio

Chevron is actively pursuing shale gas in the US as well as overseas. The company entered the Marcellus shale only about two years ago, when it acquired Atlas Energy and other properties in the region for about US $4 billion. It now is one of the largest leaseholders in Pennsylvania and Ohio, with more than 700,000 net acres of leases in the Marcellus shale and a robust drilling program to grow its Marcellus production. The company operates about 10 drilling rigs in the play at any given time and has drilled more than 100 development wells.

Chevron also has a strong position in the Utica shale, an undeveloped formation beneath the Marcellus. In 2012, the company acquired regional seismic data in eastern Ohio to identify core areas and began drilling four exploratory wells. In Michigan, the company recently began drilling its first well to test the Collingwood/Utica shale formation, where it holds an additional 459,000 acres. In 1Q 2013, drilling began on a Collingwood/Utica shale exploratory well to further evaluate this opportunity.

In East Texas, the company continued development of the multiple stacked reservoirs in the area, including the Travis Peak, Cotton Valley, Bossier, and Haynesville zones. In 2010, Chevron completed a pilot drilling program in the Haynesville shale that identified 2 Tcf of potentially recoverable natural gas, and two years later the company's Haynesville shale appraisal continued with two wells drilled in Panola and Nacogdoches counties. To further evaluate the Haynesville and other rock layers in the area, Chevron conducted a 3-D seismic survey; the data are being interpreted to improve the company's understanding of the reservoirs in the area.

The Wolfcamp shale is found in both the Delaware basin and the Midland basin, and Chevron holds sizable chunks of acreage in both. The company is one of the largest acreage holders in the Delaware basin, with approximately 1.1 million total acres located in West Texas and southeast New Mexico, including 350,000 acres that were added in New Mexico in late 2012. The company runs three rigs in the area and has participated in more than 100 wells in the last three years, defining multiple

liquids-rich unconventional plays and demonstrating production in the Avalon shale, Bone Spring sands and shale, Wolfcamp shale, and Delaware Mountain Group.

In the Midland basin, the Wolfcamp tight oil play continues to be developed using vertical drilling and multistage fracture stimulation. Chevron holds more than 320,000 total acres where the company has an average nonoperated working interest of about 70% in more than 1,100 wells, with average net daily oil-equivalent production of more than 18,000 bbl. The company keeps seven rigs busy in this play.

The Wolfcamp shale is found in both the Delaware basin and the Midland basin, and Chevron holds sizable chunks of acreage in both.

The company also is continuing a managed development of 100% owned and operated natural gas properties consisting of approximately 72,000 total acres located in northwestern Colorado's Piceance basin, where the Niobrara shale has been identified as an additional potential resource. The company said it "continues to evaluate this opportunity."

ConocoPhillips

• Bakken/Three Forks 626,000 net acres; Greater Anadarko basin 1.3 million net acres
• Increased the size of its fracture jobs and is pilot-testing 80-acre well spacing in the Eagle Ford

At a recent analyst event, the company's executive vice president of E&P, Matt Fox, was asked why ConocoPhillips doesn't accelerate activities in the Eagle Ford, where 3Q 2013 production averaged 126,000 boe/d, up 66% compared with 3Q 2012.

"The flexibility exists to do that in the Eagle Ford," Fox said, adding, "We're focused on a few different things there to establish what the optimum rate of development is. We want to make sure that we are operating efficiently and safely, so that comes in as an important factor. We want to move toward pad drilling. We want to make sure we don't get out in front of infrastructure constraints in the Eagle Ford.

"We want to make sure that we're taking advantage of the learning curve because we're continuing to see learning curve improvements, and we want to take advantage of that before we ramp up," Fox continued. "And, we want to get results from the many pilot tests we're running in the Eagle Ford, too, so that we're making sure that we're investing the capital as efficiently as we can. These opportunities are not going away, so we think that our strategy is the right strategy for us."

This attention to detail is what is making ConocoPhillips a success in unconventional exploration, according to the company. With a backlog of 77 wells waiting on facilities in various stages of completion and 11 rigs operating full time, ConocoPhillips also is taking the time to look at other levels in the Eagle Ford for potential. In addition, the company has increased the size of its fracture jobs and is pilot-testing 80-acre well spacing in the Eagle Ford, which may result in more drilling locations.

"We're still very excited about the Eagle Ford position, and we're going to see significant growth and very high margin growth from the Eagle Ford for several years to come," Fox said.

In the Bakken, production averaged 34,000 boe/d in 3Q 2013, up 31% compared to 3Q 2012. "Our focus during the third quarter was on reducing the time from drilling a well to bringing it on production. This continues to be our focus and will become even more important as we shift to pad drilling. At the end of the third quarter, we had 11 operated rigs running in the Bakken, nine of which were pad drilling," Fox said.

The company also is experimenting with 320-acre spacing to determine optimum spacing and what level of communication exists between the Middle Bakken and the Three Forks for fracturing. When asked if ConocoPhillips had plans to increase its Bakken rig count, Fox said, "No, I don't think so. I think that that's the right level for now, but one of the beauties of these unconventional plays is that you do have flexibility. It's just a question of

The *Polar Adventure* tanker lifts crude oil in Valdez, Alaska.

making sure that we are exercising that flexibility at the right time and with the right information."

In the Denver-Julesburg basin ConocoPhillips is targeting the Niobrara formation, where in 2013, it had one rig in operation and had drilled 11 wells resulting in five horizontal producers. Continued area appraisal and extended production tests are required to determine full-field development potential, but the company should be ready to make development decisions by year-end 2014, Fox said.

"The same really applies in the Permian," he said. "We're testing our portfolio there, making sure that we understand which of the different prospective horizons – the Avalon, the Bone Springs, the various Wolfcamp horizons – offer the best potential and are the right places to start that development. By year-end 2014, we'll have a really good sense of how that's going to develop."

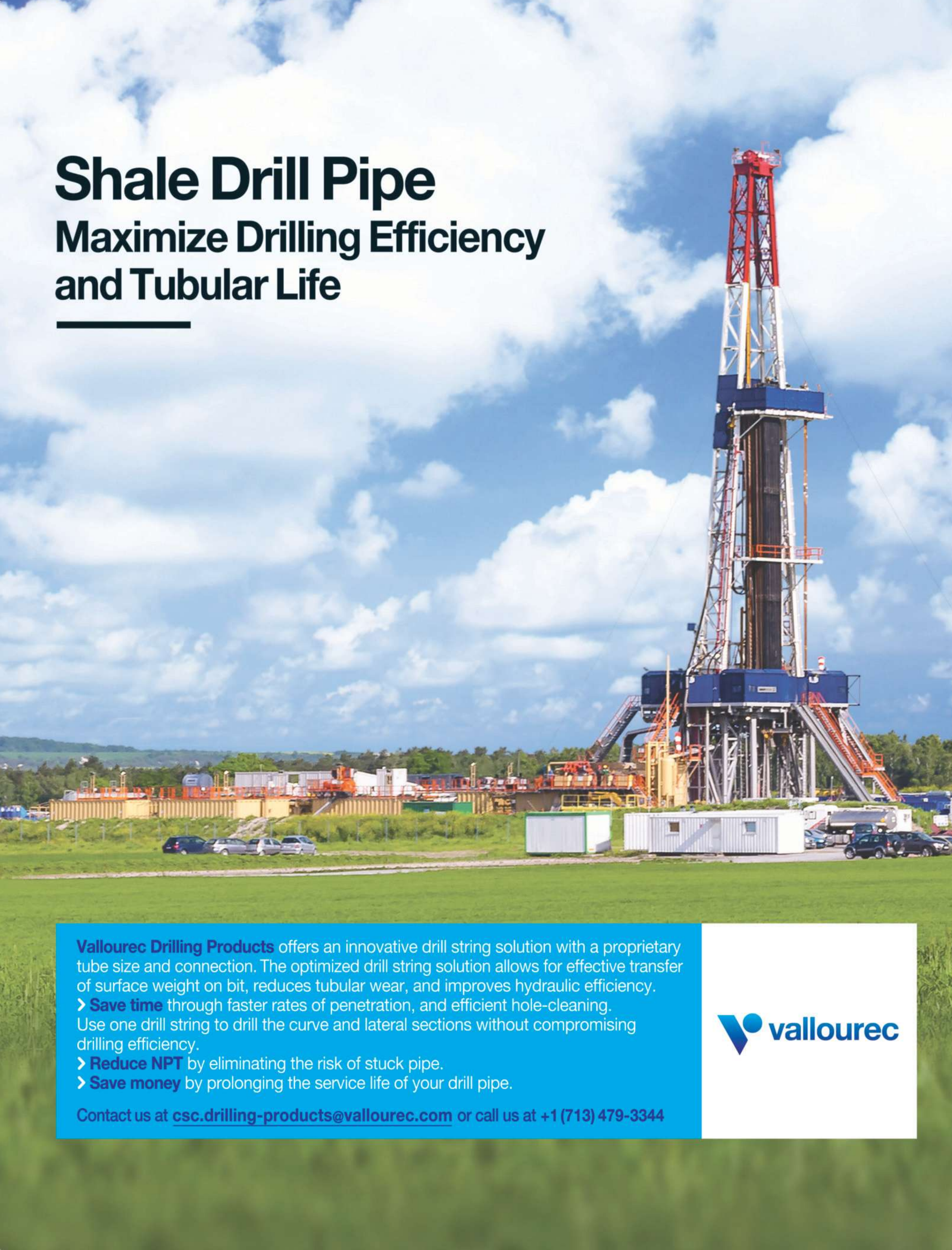
ConocoPhillips also is active in the Bossier trend in east Texas, where it produces natural gas from approximately 90 wells net. In north-central Texas' Barnett shale, the company said it is "carefully controlling the pace of activities with emphasis on liquids-rich segments of the Barnett shale play."

"We focus on getting positions in the best parts of these plays, then we methodically drill and test to assess commerciality," Fox said. "Since we are not motivated by growth alone, we can take our time to test and deploy the technologies that work best in each of these plays, which we believe is important to ensuring that we do not overcapitalize them."

CONSOL Energy Inc.

• Marcellus 620,000 acres (partially operated by Noble Energy); Utica 40,000 net core acres
• Plans to drill on the Pittsburgh International Airport property

Over the past few years, CONSOL Energy has transformed itself from a pure-play coalbed methane


Shale Drill Pipe
Maximize Drilling Efficiency and Tubular Life
Vallourec Drilling Products offers an innovative drill string solution with a proprietary tube size and connection. The optimized drill string solution allows for effective transfer of surface weight on bit, reduces tubular wear, and improves hydraulic efficiency.
› Save time through faster rates of penetration, and efficient hole-cleaning.
Use one drill string to drill the curve and lateral sections without compromising drilling efficiency.
› Reduce NPT by eliminating the risk of stuck pipe.
› Save money by prolonging the service life of your drill pipe.
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(CBM) producer to a full-fledged E&P company. CONSOL boasts that its vast experience drilling 4,000 CBM wells and 9,000 conventional wells gives the company the expertise needed to achieve a leadership position in the unconventional natural gas arena.

The company is not afraid to join up with others when the circumstances favor collaboration. In 2011, the company formed a strategic partnership with Hess Corp. to explore for and develop oil, liquids, and gas on 200,000 acres of Utica shale in Ohio.

CONSOL expects to spend US $600 million to continue development in the Marcellus, which includes drilling capital of $415 million.

In the prolific Marcellus shale, CONSOL joined forces with Noble Energy to explore in Pennsylvania and West Virginia. Noble Energy operates 170,000 acres in the wet gas regions of Pennsylvania and West Virginia, while CONSOL operates 430,000 acres in the dry gas regions. CONSOL expects to spend US $600 million to continue development in the Marcellus, which includes drilling capital of $415 million. Both companies plan to drill 126 gross horizontal wells in the Marcellus, including about 90 gross wells in the liquids-rich area of the play.

Much of CONSOL's Marcellus acreage is located in areas with pipeline-grade gas, allowing it to be piped directly to market without processing.

"Our gas production growth is beginning to accelerate as we and our Marcellus shale partner expand the rig count," said J. Brett Harvey, CONSOL chairman and CEO. "We now have a record eight rigs drilling in the Marcellus shale. For 2014, we and Noble Energy expect to be operating at least this many rigs, which will, we believe, enable us to achieve our 2014 production guidance of 210 Bcfe to 225 Bcfe, which represents a 22% to 30% growth rate over expected 2013 production."

The company also has plans to drill on the Pittsburgh International Airport property, a somewhat controversial move that the company believes is justified by the potential underneath. Their proposed plan outlines six well pad locations from which 47 Marcellus wells will be drilled, with the future potential to drill Upper Devonian wells too. The company projects that construction of the well sites, centralized impoundments, and pipelines will begin in 2Q 2014. Drilling activity is expected to begin in July 2014 with two vertical rigs. Upon the start of horizontal rig operations, the vertical rig count will be reduced to one, and both units will run for the duration of the project through 2018.

Seismic testing at the Pittsburgh International Airport began in early November 2013. Survey and recording crews planned to gather data during a one- to two-week period that would parallel approximately 33 miles of surrounding roadways. CONSOL also engaged a consultant to conduct a sound study, which entailed recording sound levels at a range of lengths from several of its current Marcellus locations during various stages of development. This process has been completed, and early results indicate that drilling activities will meet the township ordinance and will not have a significant impact.

Continental Resources

• Bakken/Three Forks 1.2 million net acres; Woodford 428,192 net acres; Niobrara 111,000 net acres
• Largest acreage holder in the Bakken shale play

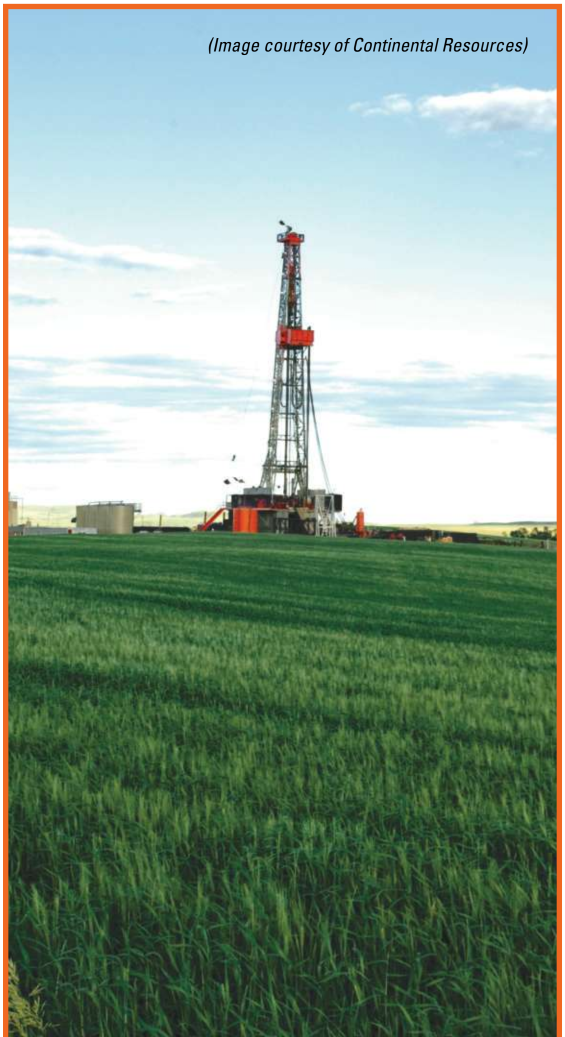
Continental Resources is the largest acreage holder in the Bakken shale play, with 1.2 million net acres under lease. It was the first to drill a commercially successful well in the North Dakota Bakken that was both horizontally drilled and fracture-stimulated – the Robert Heuer 1-17R in Divide County in 2004. Continental was the first to drill a horizontal well in the Three Forks zone in 2008, and the first to perform a 1,280-ft-long lateral multistage fracture operation. The company also was the first to successfully complete a well that paired both the Middle Bakken and Three Forks formations in 2010.

In 3Q 2013, the company averaged net Bakken production of 94,500 boe/d, up 7% from production in 2Q 2013. In 3Q 2013, the company operated 20 rigs throughout its leasehold position and planned

to continue this rig count throughout 2013. In early 2013, the company set a goal of lowering completed costs per well to US \$8.2 million; it met that goal in early 2013 and is now shooting for \$8 million per well. The company completed 20 Lower Three Forks wells in 2013.

Continental's next big play is sited in the Woodford shale of Oklahoma. In 2012, the company divided its Woodford assets into two projects referred to as the South Central Oklahoma Oil Province (SCOOP) and Northwest Cana. SCOOP wells generally produce crude and NGL, while Northwest Cana wells produce primarily dry gas, requiring different strategies in the two areas.

The company was running 12 rigs in the play with plans to increase to 15 by year-end 2013. Continental said its internal reserve models estimate that wells in the SCOOP crude oil fairway may produce an estimate ultimate recovery (EUR) and yield of approximately 626 Mboe per well (75% liquids). Wells in the SCOOP condensate fairway may produce an EUR and yield of approximately 1,190 Mboe per well (61% liquids), with the "possible upside of encountering additional pay from a variety of conventional and potential unconventional reservoirs overlying and underlying the Woodford formation," according to the company's 2012 annual report. The report also noted there are "more than 60 different conventional reservoirs known to produce in the SCOOP area."


(Image courtesy of Continental Resources)

Continental Resources has 20 rigs operating in the Bakken/Three Forks shale.

Northwest Cana, on the other hand, is on hold until gas prices improve. "No significant drilling or development plans are expected to take place in the Northwest Cana play in 2013 due to the pricing environment for natural gas," the company said. The Arkoma Woodford acreage activity also will lie dormant, waiting on better economic conditions to stimulate more exploration.

In 2014, the company will add eight more rigs to its program and has set its sights on 400 net well completions, representing a 22% increase from the 329 net budgeted for in 2013, with the focus firmly set on continued density drilling tests in the Bakken, further testing of the lower Three Forks formation, and delineating the SCOOP.

"Achieving our 2014 goals will be an excellent 'Year 2' in our five-year plan to triple production and proved reserves," said Harold G. Hamm, Continental chairman and CEO. "We remain focused on our industry leadership in oil production growth, low well costs, and capital efficiency. We're on track to achieve our five-year growth plan."

Devon Energy

• Barnett 613,000 net acres; Woodford 940,000 net acres; Permian basin 1.3 million acres
• Second largest gas producer in Texas and the largest producer in the Barnett

Since acquiring Mitchell Energy in 2002, Devon Energy has drilled more than 5,000 wells into the Barnett shale, and the company's wells account for

more than 20% of the field's overall production. The use of fracturing technology has helped the company increase its Barnett production from 200 MMcf/d of natural gas equivalent in 2002 to about 1.4 Bcf/d in 2013, making the company the second largest gas producer in Texas and the largest producer in the Barnett. In 2Q 2013, Devon announced it had achieved a 34% increase in liquids productions compared to 2Q 2012. The company accounts for more than 20% of the Barnett's overall daily hydrocarbon production.

Devon spent US $500 million in the Barnett alone in 2013 and was on target to drill 150 horizontal wells with its five continuously active rigs by year-end 2013.

The company also is focusing on the potential of the US Midcontinent. The company is in the early stages of derisking its 650,000 net acres in the Mississippian-Woodford trend acreage in north-central Oklahoma, which is prospective for both the Mississippi Lime and Woodford shale targets. The company is integrating data from 3-D seismic, production, logs, and core samples to enhance overall well performance and expects to run 14 operated rigs on acreage where it has the benefit of 3-D seismic. This rig count will keep the company on pace to participate in approximately 350 wells for 2013. In 2Q 2013, Devon began producing from 36 operated wells in this emerging light oil play, including 10 wells in the Woodford oil shale where 24-hour initial production (IP) rates averaged 840 boe/d. Given the strength of the Woodford oil shale results and the fact that Woodford wells secure acreage for the Mississippi Lime formation as well, the company is focusing its activity on Woodford wells. Net production was on target to approach 15,000 boe/d by year-end 2013 for the Mississippi Lime and Woodford oil shale combined.

According to the company, the Cana Woodford shale in western Oklahoma's Anadarko basin is "a leading growth area for Devon and has rapidly emerged as one of the most economic shale plays in North America." The company has the largest position in the play, holding more than 50% of the prime acreage. The Cana Woodford shale is especially attractive because of the liquids-rich nature of the gas. Some areas of the play can yield upwards of 300 bbl of oil and NGL per 1 MMcf of natural gas


(Image courtesy of Devon Energy)

A Devon Energy rig drills horizontally for oil in the Mississippian-Woodford trend in northern Oklahoma.

produced, the company said. In addition to the high NGL content, the Cana Woodford offers a significant condensate component that further enhances drilling economics. With more than 11 Tcf equivalent of risked resource potential and with approximately 5,400 risked locations remaining, the company predicts the Cana will provide many years of highly economic production and reserve growth.

Devon also maintains a position in the Arkoma Woodford shale located in southeast Oklahoma, where it holds a working interest in 414 producing wells. However, additional exploration activity in the Arkoma Woodford is not planned for the near future, the company said.

Another condensate and liquids-rich play for the company is the Granite Wash in the Texas panhandle, which the company said provides some of the best economics in the company's portfolio. In 2005, Devon initiated a vertical drilling program targeting the multiple stacked conglomerate sandstones of the Granite Wash formation. Through this successful vertical program, optimum horizontal targets were identified leading to the company's first operated horizontal in 2006. The company spent \$210 million in 2013 to evaluate additional untapped potential of the Granite Wash.

The Permian basin has been a legacy asset for Devon and continues to offer exploration and low-risk development opportunities from many geologic reservoirs and play types, including the oil-rich Wolfberry, Bone Spring, Wolfcamp shale, Delaware, Cline shale, and various conventional formations. Driving oil growth for Devon in the Permian was strong performance from the company's Wolfcamp shale position in the Midland basin. The company brought 19 Wolfcamp shale wells online during 2Q 2013 with 30-day IP rates as high as 1,000 boe/d. With 27 operated rigs running, Devon expected to drill more than 300 wells in the Permian by year-end 2013.

In the Powder River basin, the company reported oil production increasing 34% to 11,000 b/d in 3Q 2013 compared to 3Q 2012.

"In 3Q 2013, we tied in two Frontier wells with initial 30-day production rates averaging 740 boe/d, of which more than 85% was light oil," Devon said in its quarterly earnings call. "We also are excited about two additional high-rate oil wells that we brought online early in 4Q 2013 targeting the Frontier formation. The 24-hour IP rate of these two wells each averaged in excess of 1,400 boe/d, with light oil comprising almost 90% of the production. In addition, we are currently completing our first two long-lateral wells in the Powder River basin and should have those results by our next call."

The company has identified approximately 600 risked locations in its Powder River acreage, currently operates four rigs in the Rockies, drilled 18 wells in 2013, and planned seven more by year-end 2013.

Devon has exited the Tuscaloosa Marine shale and Utica plays and put its Utica acreage on the market, but no agreements or transactions have been announced, a company spokesperson said.

Encana Corp.

• Tuscaloosa Marine 294,000 net acres; Utica 429,000 net acres; Mississippi Lime 324,000 net acres
• Holds 184,000 net acres and 216 producing wells from the Haynesville and planned to drill up to 24 wells in 2013

After CEO Doug Suttles was established at Encana in summer 2013, the company went into reorganization and cost-savings mode. Prior to Suttles' posting, the company already had been mulling selling assets to help the bottom line. There is some speculation that Suttles' new operating strategy, which he promised to announce before year-end 2013, may cut exploration activities in potentially lucrative but expensive venues such as unconventional shale and tight oil and gas plays.

The company has interests in several unconventional plays. In the Collingwood/Utica shale in Michigan, Encana holds 429,000 net acres and drilled three horizontal wells averaging 6,800 ft each in 2012. As of this writing, no further drilling in the area had yet taken place, although one well was planned in early 2013 to meet commitments to retain acreage in the southern area of the play.

The company also planned minimum work in 2013 in the Niobrara liquids play located in the Denver-Julesburg basin in northern Colorado to continue evaluations of the play's potential and to hang on to existing acreage. In the Mississippi Lime, located in Oklahoma and Kansas, Encana also is evaluating results of 12 horizontal wells drilled in 2012. The company said the Kansas wells performed "lower than expected," but the Oklahoma acreage is still under evaluation.

The Tuscaloosa Marine shale in Louisiana and Mississippi is showing more signs of life for the company. In 2011, the company established a significant land position in the play and drilled seven horizontal wells in 2012. Four more wells were drilled in 2013, two of which were put online. The company is looking to enhance repeatability in the play and has identified more than 1,100 possible well locations for future drilling.

Encana quietly began assembling a sizable land position in the Haynesville shale in 2005 after identifying it as an exciting opportunity. The Haynesville shale is one of the most promising natural gas resource plays in North America. The company holds 184,000 net acres and 216 producing wells from the formation and planned to drill up to 24 wells in 2013.

EOG Resources

• Barnett 430,000 net acres; Eagle Ford 639,000 net acres; Marcellus 170,000 net acres
• One of the top oil producers in the Bakken/Three Forks

Can't get crude to market? EOG built a rail spur and loading facility in the Bakken. Need a lot of sand for fracturing operations? EOG bought a few sand mines and supplies its own sand. This has helped make EOG Resources the top crude oil producer in the Bakken/Three Forks, the Barnett, and the Eagle Ford shale plays and one of the top oil producers in the Bakken/Three Forks. The company is working hard to hang on to those bragging rights.

(Photo by Tim Singley)

EOG Resources expects operations in the Eagle Ford to continue providing long-term growth opportunities.

Since discovering the prolific Eagle Ford in South Texas in 2010, the company reported it has more than doubled the initial crude oil production rates from its wells in both the western and eastern parts of the play. At the end of 2Q 2013, EOG's Eagle Ford stake was producing 173,000 boe/d net.

Improved drilling efficiencies and completion technology also have enhanced well productivity in EOG's Bakken/Three Forks operations. During 2Q 2013, the company's North Dakota drilling focused on testing 160-acre spacing, which was so successful that the company increased its drilling inventory in the Bakken/Three Forks from seven to 12 years, the company said.

EOG also remains active in the Delaware basin's Leonard and Wolfcamp shale formations, although the plays are constrained by a lack of natural gas processing infrastructure, an issue that the company hints is "being addressed." In Reeves County, Texas, EOG recently drilled its best Delaware basin Wolfcamp well to date. The company has a 100% working interest in the Phillips State 56 #301H, which was completed to sales at 870 b/d of oil with 570 b/d of NGL and 3.7 MMcf/d of natural gas.

"We expect EOG's three high rate-of-return oil plays – the Eagle Ford, Bakken/Three Fork, and Delaware basin – to provide us with years of drilling inventory as well as significant growth opportunities," Mark Papa, EOG's executive chairman, said. "These plays just get bigger and better."

The company also is keeping its hand in the Marcellus shale, where it said it would drill four wells in 2013 to retain its acreage. In the Haynesville shale, EOG is keeping a watchful eye on natural gas prices and said it will defer a major exploration program until economics are more favorable.

The company has expanded its activities in the Midcontinent area with a focus on growth and extension of its Western Anadarko basin core area. In 2012, the company continued its successful horizontal exploitation of the Cleveland and Marmaton tight-gas sandstones, drilling 35 wells. Since 2002, EOG has drilled more than 270 net wells in the plays and holds approximately 125,000 net acres throughout the trend. In 2013, approximately 35 net wells were planned to further exploit these liquids-rich plays.

EV Energy Partners / EnerVest

• 712,000 net acres in the Utica shale
• Built one of the largest acreage positions in Ohio

At 21 years old, EnerVest is not a traditional E&P company. Its primary business has been to raise private equity from institutional investors and use this capital to buy relatively immature producing properties, further develop these assets, and then sell them opportunistically. To complement this "buy-enhance-sell" model, in 2006 EnerVest formed EV Energy Partners (EVEP), a publicly traded upstream master limited partnership. A majority of EVEP's capital comes from retail investors. The focus of EVEP is to acquire more mature properties that are in the "harvest" mode, providing its investors with a more predictable cash flow stream through quarterly distributions. These two complementary businesses allow EnerVest to build strong basin positions and maintain a competitive cost position in many areas.

Through a series of producing property acquisitions in a 10-year period, EnerVest and EVEP combined have built one of the largest acreage positions in Ohio, with more than 1.2 million gross (712,000 net) acres in the Utica shale. In 2011, the companies entered into a joint venture (JV) covering 57,000 net acres with Chesapeake and Total, in which Chesapeake is the operator. Through this JV, the companies have participated in 223 new horizontal Utica wells. They also have an interest in Utica wells being drilled by seven additional operators on other prospective Utica acreage. EnerVest and EVEP also have sold approximately 43,000 of their Utica acres at an average of US $12,900 per acre, while maintaining an override. Additional acreage sales are planned over time.

In 2010, the companies did not have a position in the Barnett shale. By 2013, they had acquired more than $2.5 billion of properties in the play. The companies are maintaining a modest but consistent drilling program and produce approximately 300 MMcfe/d, placing EnerVest among the top five largest producers in the Barnett. They planned to drill 70 wells in 2013.

The most recent Barnett acquisition closed in November 2013. The companies acquired wells and acreage from Carrizo Oil & Gas Inc., primarily in Tarrant County. These assets produce approximately 40 MMcfe/d net to EnerVest companies.

"These 'bolt-on' assets are very complementary to our strong operating position within the Barnett shale," said Mark Houser, EVEP president and CEO. "The Barnett reservoir within these new leases has estimated gas in place of 150 Bcf to 200 Bcf per 640-acre section, and the existing wells drilled have EURs [estimated ultimate recoveries] averaging more than 5 Bcf per well. We believe these properties will provide very attractive future development opportunities, even at current gas prices."

ExxonMobil/XTO Energy

• Fayetteville 704,000 net acres; Bakken 585,000 net acres; Marcellus 625,000 net acres
• Largest natural gas producer in the US

The world's largest publicly traded international oil and gas company became the largest natural gas producer in the US after it bought XTO Energy in 2010, and ExxonMobil remains one of the most active majors in unconventional resources in the country. In the past year, the company has expanded its position in both the Bakken and the Woodford Ardmore plays by more than 275,000 acres and is drilling in every major shale play in the US.

The Woodford shale is the company's most active unconventional play. Located in the Ardmore and Marietta basins of Oklahoma and Kansas, the formations caught ExxonMobil's eye because of the substantial liquids yield and higher per-well recoveries. The company said its acreage could deliver the potential to recover more than 1.5 Bboe from this play at an attractive development cost. In 2012, construction was completed on a 117-mile gathering pipeline from ExxonMobil operations to processing facilities in North Texas, with a view that daily production could grow to more than 150,000 boe/d net. The company is continuing delineation efforts in the Woodford and other shales in the Marietta basin to the southwest.

In the Haynesville/Bossier shale of East Texas and Louisiana, ExxonMobil said it continues to realize the benefits of its drilling and completion efficiency efforts. The North Texas Barnett shale play saw 95 wells brought online by ExxonMobil in 2012.

In the South Texas Eagle Ford shale play, ExxonMobil drilled 11 wells in 2012. In the Permian basin, the company continues evaluation of multiple unconventional reservoirs including the Bone Springs, Avalon, and Wolfcamp tight oil plays. In the Fayetteville shale, pad drilling, optimized well spacing, and improved drilling processes are increasing efficiencies. ExxonMobil also holds a material acreage position in the Marcellus shale and completed its first wells in the Utica shale in 2013.

ExxonMobil remains one of the most active majors in unconventional resources in the country.

The company prides itself on its research capabilities, which it said sets it apart from other unconventional explorers. One such innovation is ExxonMobil's new patent-pending acoustic fluid inclusion volatile technology, which enables the evaluation of production intervals within tight liquid and shale gas systems. The acoustic signals generated during the crushing of rock samples are correlated to specific rock properties, allowing the company to distinguish the more productive brittle, silica-rich shales from softer, clay-rich shales, which in turn allows for optimization in design and development plans to maximize profitable recovery.

"The properties of the ultra-low permeability rocks found in unconventional reservoirs are difficult to measure. Combining our industry-leading extended-reach drilling capability with our proprietary stimulation technology has significantly enhanced profitable recovery. By optimizing how and where stimulation fluid interacts with rock, we are able to sustain production rates along the length of the wellbore, delay compression investments, and increase recovery," the company said.

Goodrich Petroleum Corp.

• Tuscaloosa Marine shale 320,000 net acres; Haynesville 78,900 net acres; Eagle Ford 32,000 net acres
• Added a second rig to its horizontal drilling program in the TMS and plans to increase to five horizontal rigs running concurrently

Goodrich Petroleum Corp. is a dominant player in the Tuscaloosa Marine shale in southeastern Louisiana and southwestern Mississippi, where it said the economics are potentially superior to the much-touted Eagle Ford shale. The company added a second rig to its horizontal drilling program in the Tuscaloosa Marine shale in October 2013 and plans to increase to five horizontal rigs running concurrently in the play by year-end 2014. Even though the company's most recent Tuscaloosa Marine shale well ran into some problems, it was still completed as a producer. The CMR-Foster Creek 20-7H-1 in Wilkinson County, Miss., was successfully drilled with a 6,200-ft lateral and fracture-stimulated with 23 stages, but it encountered completion issues while drilling out the fracture plugs with coiled tubing (CT). This resulted in the loss of a bottom-hole assembly and fishing tools in the well; the company replaced the CT unit with a workover rig in an attempt to remove the downhole tools, but fishing operations were unsuccessful. Still, the well was subsequently placed on production from the approximately 2,100 ft of usable and unobstructed lateral, producing 527 boe/d (500 bbl of oil and 174 Mcf of gas).

"We continue to improve on our drilling efficiencies as well as utilize multiwell pad drilling, zipper fractures, and realize additional service company capacity in the play," Robert Turnham, Goodrich president, said. The company's multipad program uses rigs with skid packages to minimize rigup, rig-down, and move times. Zipper fractures save time and money on standby equipment.

Goodrich moved into the development phase of its Eagle Ford program in 2012 and now operates a one-rig program in the Eagle Ford shale, where it has 39 net wells in production. Rising oil

production from the Eagle Ford generated increased cash flow for the company, which it used both in reinvestment in the Eagle Ford and to fund additional operations in the Tuscaloosa Marine shale. The company has identified 320 net locations and allocated approximately 44% of its 2013 drilling budget to the Eagle Ford play.

"Our royalty burdens are lower in the Tuscaloosa Marine shale than other emerging oil plays, and in the industry-friendly states of Louisiana and Mississippi operators typically receive a severance tax exemption for approximately two years of operation. Though it is still early days, when factoring in the differences in well cost, royalty burdens, severance tax, and price realizations, we expect the Tuscaloosa Marine shale could have well economics as attractive as, and perhaps even superior to, our Eagle Ford assets," the company said.

Goodrich also is expanding its acreage position in the Haynesville shale trend, where it operates some areas and joint ventures with Chesapeake Energy in others.

Hess Corp.

• Bakken/Three Forks 725,000 net acres; Utica 95,000 net acres
• Exited the Eagle Ford, selling its assets and 43,000 net acres for $265 million

Hess is the second largest lease holder in the Bakken/Three Forks shale play with approximately 725,000 net acres, the largest gas producer, and the third largest oil producer in North Dakota with more than 71,000 boe/d. Hess discovered oil in North Dakota in 1951, and its presence in the region has continued to grow. In 3Q 2013, production from the company's Bakken oil shale play went up 14% from 3Q 2012, but drilling and completion costs were down 18% because of the use of pad drilling and new technologies. During 3Q 2013, Hess brought 50 operated wells on production, bringing the year-to-date total to 122 wells.

The company also is active in the Utica shale in Ohio, where it had drilled 21 wells by November 2013, completed 18 previously drilled wells, and was flow-testing one well in 3Q 2013 across both the corporation's 100% owned leases and those in the CONSOL joint venture acreage. Hess also contracted to acquire seismic data in 2013 across its Utica acreage.

Earlier in 2013, the company exited the Eagle Ford, selling its assets and 43,000 net acres to Sanchez Energy for US $265 million.

Newfield Exploration

• More than 225,000 net acres in the Anadarko basin; Eagle Ford 185,000 net acres
• Increasing its operated rig count in the Anadarko basin to eight rigs

On Nov. 4, 2013, Newfield announced the discovery of a new resource play in Oklahoma's Anadarko basin that "has the potential to more than double our unrisked resource potential in the basin and add thousands of new drilling locations," Gary Packer, Newfield COO, said. The Stack play is adjacent to and complements the company's South Central Oklahoma Oil Province (SCOOP) play. The new play was dubbed "Stack" because its "stacked" features provide potential access to multiple production zones.

"Our early results in the Stack play are very encouraging, with initial wells providing about a 35% rate of return," Packer said. "We are early in our learning curve in the Stack, and history proves that we can lower costs and enhance returns as we move to development mode. We will be increasing our planned activity levels in the Anadarko basin as this region has the potential to drive our corporate growth rates over the next decade. Our net production from the Anadarko basin is expected to exit 2014 at nearly 50,000 boe/d."

The Stack play ranges in depth from 8,000 ft to 11,000 ft, and horizons include the Meramec and Woodford shales. The Meramec ranges in thickness from 275 ft to 475 ft with comparable porosities to the Woodford. Stack wells have an estimated ultimate recovery of 800 Mboe to 1 MMboe, and reserves are approximately 70% liquids (40% oil). To date, Newfield has drilled seven wells in the

(Image courtesy of Newfield Exploration)

Newfield's operations in unconventional resources include drilling nearly 400 horizontal wells in the Arkoma Woodford.

Stack, with initial production rates averaging 900 boe/d and 30-day average production of 640 boe/d. Lateral lengths are approximately 10,000 ft, and working interest averages 93%.

Newfield is increasing its operated rig count in the Anadarko basin to eight rigs, with at least two rigs dedicated to its Stack development.

The company has been active in the Midcontinent region since 2001, and more than one-third of the company's total reserves are located there. In less than two years, the company's net production in the Anadarko basin has grown to approximately 25,000 boe/d.

The company was a founder of the Arkoma Woodford shale development and has drilled nearly 400 horizontal wells in the play. However, low natural pricing and a natural decline in production rates have forced Newfield to significantly curtail its investments in the Arkoma Woodford and shift focus to the liquids-rich Cana Woodford.

In the Cana Woodford, the company has drilled more than 35 wells and planned to invest approximately US $360 million on development drilling in the play in 2013, using six to eight drilling rigs at any given time, the company said. At year-end 2012, production in the Cana Woodford was more than 10,000 boe/d, consisting of 2,300 b/d of oil, 3,200 boe/d of NGL, and 28 MMcf/d. The company said production should more than double by year-end 2013.

Newfield also holds 50,000 net acres in the Granite Wash in the Anadarko basin of western Oklahoma and the Texas Panhandle. The largest producing field in the Granite Wash is the Stiles/Britt Ranch. At year-end 2012, net production from the area was approximately 17,000 boe/d, consisting of 3,000 b/d of oil, 1,700 boe/d of NGL, and 73 MMcf/d.

In the Bakken/Three Forks area of North Dakota and Montana, Newfield is focusing on drilling multiwell pads with super extended-lateral lengths as long as 10,000 ft. Net 3Q 2013 production from the company's holdings is approximately 13,400 boe/d. Activities are increasing in the area, and approximately $230 million was allocated to the Williston basin in 2013. Newfield expects its Williston basin net production to increase about 40% over 2012 levels (most recent growth guidance was 28%; original guidance was 15%). The increase is related to better well performance and early production from multiwell pads. Completed well costs year-to-date in the Williston basin have averaged $8.7 million gross for super extended-lateral wells including about $800,000 in artificial lift and facilities costs.

Also active in the Eagle Ford, Newfield said its average 3Q 2013 net production was up 9% quarter-over-quarter to 8,200 boe/d, and 4Q 2013 net production in the Eagle Ford is expected to average 12,200 boe/d, reflecting the completion of new pads in the company's West Asherton development. Average drill and complete costs for 7,500-ft lateral wells in the Eagle Ford year-to-date are $7.3 million gross, down more than 20% year-over-year. The company's full-year 2013 Eagle Ford production is expected to increase about 70% over 2012. Newfield's Eagle Ford acreage is located in the Maverick basin of Maverick, Dimmit, and Zavala counties in Texas.

Noble Energy

- **DJ basin of Colorado 600,000 net acres; Marcellus shale 300,000 net acres**
- **Northeast Nevada 350,000 net acres**

Noble Energy apparently has found its calling and is pursuing it with a driven focus. The company is selling noncore assets to fund its higher growth projects, consisting of "thousands of lower-risk development projects in our two onshore core areas: the Denver-Julesburg [DJ] basin and the Marcellus shale. These areas offer sustainable returns and a large inventory of repeatable reinvestment opportunities." The noncore assets on the sales block are located throughout the central US and Gulf Coast, and the company has raised more than US $1.4 billion since 2012 on these properties.

Noble Energy became a player in the Marcellus shale in 2011 when joining forces with CONSOL Energy, a company with similar philosophies and approaches to field development.

"In both the DJ basin and the Marcellus areas, we are operating at the highest levels of horizontal activity in our company history," Noble Energy said in a press release. "Accordingly, we are setting new production records, while optimizing drilling and completion techniques."

Noble Energy became a player in the Marcellus shale in 2011 when joining forces with CONSOL Energy, a company with similar philosophies and approaches to field development. The agreement has been a successful one so far as the joint venture (JV) contains provisions that ensure both partners are economically aligned in an environment of low natural gas prices. The JV also has significant flexibility to adjust development plans as the partners deem appropriate. CONSOL operates rigs in the dry gas portion of the Marcellus; Noble Energy operates in the wet gas areas, which are the most active areas for the JV team.

During 3Q 2013 in the wet gas portion of the Marcellus shale, Noble Energy drilled 15 wells ranging in lateral length from 8,700 ft to more than 10,000 ft. Noble Energy is operating five horizontal rigs in the Marcellus where it expected to drill a total of 75 wells in 2013.

In an interesting development, CONSOL drilled the JV's first Upper Devonian well from a Marcellus well pad. The NV-39F was drilled in the Burkett shale and was brought online in June 2013 at 3 MMcf/d. Exhibiting a nearly flat decline rate, the well was still producing 2.9 MMcf/d at the end of 3Q 2013. The two underlying Marcellus shale wells located beneath the NV-39F well are producing at, or above, expected projections. The partnership is planning to drill additional Burkett shale wells and to further test Upper Devonian wells located in the Rhinestreet shale formation from Marcellus pads in 2014, according to company reports.

Noble Energy is focused on horizontal drilling in the Niobrara and Codell formations of the DJ basin Wattenberg field, the company's largest onshore asset. The play produces strong returns for Noble Energy because of low operating costs and a high contribution of oil and NGL. Production from Wattenberg represents approximately 75% of Noble Energy's onshore US volumes.

"Our well completion and fracturing strategies are improving production and reducing our drilling times," Noble Energy said. "The performance of our latest wells demonstrates the improvements we have made. We drilled approximately 85 horizontal Niobrara wells in 2011 and approximately 200 horizontal wells in 2012 and plan to drill approximately 300 horizontal wells in 2013. We are focused on further accelerating the development of Wattenberg and continue to test the exploration opportunities in northern Colorado."

Within the central DJ basin, the company is focusing on the East Pony area located in northern Colorado, where it holds 45,000 net acres.

Another area of interest for Noble Energy is in northeast Colorado, where the company obtained acreage it said could contain up to 1.3 Bbbl of oil.

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Pioneer Natural Resources

• Permian 860,000 gross acres; Barnett 130,000 gross acres; Eagle Ford 230,000 gross acres
• Largest acreage holder in the Spraberry trend area field

The self-proclaimed "dominator" of the Permian basin continues to live up to its reputation. On Nov. 13, 2013, Pioneer Natural Resources said it had placed on production its fourth horizontal Wolfcamp D interval well with a peak initial production (IP) rate of 3,605 boe/d and an oil content of 74%. Sited in the Midland basin, the University 7-43-10H was completed using a 31-stage hybrid fracture stimulation over the well's perforated lateral length of 7,382 ft. The well represents the highest horizontal 24-hour peak IP rate for any interval in the Midland basin to date.

The company also announced a string of other successes in both its northern and southern Spraberry/Wolfcamp acreage. Pioneer is the largest acreage holder in the Spraberry trend area field, where the company believes it has more than 4.6 Bboe of estimated resource potential from horizontal drilling based on its extensive geologic data and its successful drilling results to date. Of this amount, 3 Bboe are in the northern Spraberry/Wolfcamp portion of Pioneer's acreage and 1.6 Bboe are in the southern Wolfcamp joint venture (JV) area.

The company has 16 horizontal wells on production across its northern acreage, of which 10 wells are Wolfcamp shale interval wells and six wells are Spraberry shale wells. Four of the six Spraberry shale wells were placed on production in late October/early November, are flowing back fracture-stimulation water, and have not yet achieved 24-hour peak IP rates. Since the Spraberry shale interval wells are at shallower depths than the Wolfcamp shale interval wells, these wells can flow back fracture-stimulation water for 30 days to 60 days before

achieving peak IP rates because of lower subsurface pressures, according to Pioneer.

The company is running five horizontal rigs across its northern acreage and expects to increase to 10-plus rigs in early 2014. The five-rig program was expected to spud 14 wells by year-end 2013.

Pioneer also said that it placed on production the company's first three horizontal Wolfcamp B interval wells on University Lands Block 2 in Reagan County in the southern Wolfcamp JV area of the Midland basin. In May 2013, Pioneer closed a JV transaction with Sinochem Petroleum US to sell 40% of its interest in 207,000 net acres of the horizontal Wolfcamp shale play in the southern portion of the Spraberry field. Pioneer continues as operator and retains its current working interests in all formations shallower than the Wolfcamp horizon. The US $1.7 billion transaction allows Pioneer to accelerate development in its southern acreage position and add significant production and reserves while enhancing shareholder value.

In the Barnett shale play in north Texas, Pioneer has acquired 340 sq miles of proprietary 3-D seismic data covering its acreage to assess future drilling location selections.

"Our first horizontal Wolfcamp D interval well in Andrews County achieved the highest IP rate from any horizontal interval well in the Midland basin and extended the productivity of the Wolfcamp play approximately 60 miles west of recent successful industry Wolfcamp drilling activity," Scott Sheffield, company chairman and CEO, said.

"These strong well results from our horizontal Spraberry/Wolfcamp shale drilling program further demonstrate the substantial oil resource potential across Pioneer's northern Spraberry/Wolfcamp acreage and our southern Wolfcamp JV area in the Midland basin," Sheffield said. "These areas hold an estimated net resource potential for the company of more than 4.6 Bboe."

To increase efficiencies, Pioneer also is experimenting with downspacing from 720-ft spacing between wells to 480-ft spacing between wells and increased use of pad drilling using zipper fracture stimulations in the play.

The company also is active in the Eagle Ford shale, where it has increased its production from less than 2,000 boe/d in 2010 to 38 Mboe/d by 2Q 2013. To support its substantial Eagle Ford shale production growth, Pioneer has constructed midstream infrastructure via its majority ownership of EFS Midstream LLC, which is an unconsolidated affiliate that provides gas and liquids gathering, treating, and transportation services. EFS Midstream has built 11 central gathering plants in Pioneer's Eagle Ford shale area, and one additional plant is planned for 2014.

Pioneer's drilling operations in the Eagle Ford shale continue to become more efficient. In addition to increased pad drilling in the Eagle Ford and the use of downspacing horizontal wells from 1,000-ft to 500-ft spacing with zipper fracturing, Pioneer also is testing the use of lower cost white sand instead of ceramic proppant to fracture-stimulate wells drilled in shallower areas of the field. Since August 2013, 84 wells have been tested, at a savings of approximately $1.1 million per well, and the company said early well performance has been similar to direct offset ceramic-stimulated wells. The company plans to continue monitoring the performance of these wells and planned to use white sand in 75% of its 2013 drilling program.

In the Barnett shale play in north Texas, Pioneer has acquired 340 sq miles of proprietary 3-D seismic data covering its acreage to assess future drilling location selections. The company drilled 25 Barnett shale combo wells in the first half of 2013 and is operating two rigs.

"Although 3Q 2013 production was slightly below our guidance range as a result of delays in bringing new wells on production in the Eagle Ford shale related to increased pad drilling, we expect 4Q 2013 production to grow significantly as these delayed wells and a substantial number of new pad wells from the Eagle Ford shale and the Spraberry/Wolfcamp areas are placed on production. We are forecasting 2013 production growth of 14% compared to 2012."

Range Resources

• Marcellus 835,000 net acres; Utica 580,000 net acres; Upper Devonian 565,000 net acres
• Devoted more than 75% of its capital budget to drilling in the Marcellus in 2013

Range Resources announced record production in 3Q 2013 and credits its "basin-leading liquids-rich wells" drilled in the Marcellus shale for the increase. "Our growth is led by our approximate 1 million-acre leasehold position in Pennsylvania, which essentially doubles when stacked pay reservoirs across most of our acreage in the basin are considered," Jeff Ventura, Range Resources' president and CEO, said. "This acreage position is anchored by the Marcellus, the most prolific gas reservoir in North America. Our southwest Pennsylvania acreage is strategically located at the nexus where the largest estimated gas in place exists when considering all three shale horizons."

The company said that this area also encompasses the core of the super-rich and wet areas of both the Marcellus and the Upper Devonian shales. It devoted more than 75% of its capital budget to drilling in the Marcellus in 2013. One advantage the company holds is that the majority of its activity is concentrated in southwest Pennsylvania, home of six of the largest pipelines in Appalachia. This significant amount of existing infrastructure has allowed Range to secure firm transportation at competitive rates, and the company said it expects that future transportation capacity will be added at similar rates using existing infrastructure. The company already has contracted for an additional 200 MMcf/d of capacity for 2017 and also is in discussions for additional firm capacity on several large takeaway systems.

"These future capacity expansions to multiple markets outside the Appalachian region will support our growth while maximizing net realized natural gas prices," the company said.

Marcellus production for 3Q 2013 averaged approximately 900 MMcfe/d (756 MMcfe/d net). During 3Q 2013, the company brought online 26 Marcellus wells in this area, with 24 wells in the super-rich area and two wells in the dry gas area. The 24-hour initial production (IP) rates of these super-rich wells averaged 2,657 boe/d (2,122 boe/d net) with 66% liquids (assuming 80% ethane extraction). All of the wells in 3Q 2013 were completed with reduced cluster spacing, and the average lateral length for the wells was 4,030 ft with around 21 fracture stages per lateral.

The company's best well in the super-rich area, with a 24-hour IP rate of 5,720 boe/d with 63% liquids (assuming 80% ethane extraction), came in 3Q 2013. Among liquids-rich wells with IP rates of 60% liquids or greater, the company believes that it has drilled five of the top 10 producing wells in the Appalachian basin.

The company also is active in Mississippian acreage plays, where it recently completed a 12-mile northern step-out well with an IP rate of 300 b/d with 94% liquids (85% oil and 9% NGL). The division tested completions with larger fracture stimulations on four wells that averaged production rates above the 600-Mboe type curve for the first 65 days.

(Photo by Lowell Georgia, Hart Energy)

A frac tech in the Marcellus awaits delivery of a plug via wireline atop a 25-ft-high wellhead assembly.

(Image courtesy of SandRidge Energy)

SandRidge is one of the nation's most active explorationists for domestic oil.

"Results from wells completed with the larger fracs continue to significantly exceed results seen from wells drilled in the early part of 2013 that were completed with smaller fracs," the company said.

Despite the larger fractures, the company has been able to drill and complete the wells at the same cost of US $3.2 million. Range Resources planned on bringing online four additional horizontal Mississippian wells with larger fracture stimulations during 4Q 2013.

In the Permian basin, the western portion of the company's 100,000-net-acre position planned to see both a Cline and a Wolfcamp horizontal well with 7,000-ft laterals by year-end 2013.

SandRidge Energy

• Mississippi Lime 1.9 million net acres
• Has drilled nearly half of all the horizontal wells in the Mississippian oil play

SandRidge may be tied with Chesapeake in the contest of "who holds the most acreage" in the Mississippi Lime play, but the mid-size independent is proud to say it has drilled nearly half of all the horizontal wells in the Mississippian oil play at 940, as of Sept. 30, 2013. The company expects to average 25 rigs operating in the play for 2014, and its Mississippian production averaged 47.9 Mboe/d in 3Q 2013, representing a 59% increase year over year, while operating costs have dropped 22% in the acreage in the same time period.

"Over the last couple of quarters, we have pursued several key themes operationally – being more efficient with our capital, consistent Mississippian production growth, reducing our costs, and identifying new opportunities," James Bennett, SandRidge's president and CEO, said. "We believe we are hitting the mark on all of these. Through successful high grading efforts and operational improvements, we have increased Mississippian production from 2Q 2013 even while reducing our rig count by 15%, again delivering more production for less capital. As a result, we are increasing full-year production guidance for the second quarter in a row without increasing budgeted capex and while continuing to lower other expenses."

The company predicts it will grow production in the play by 35% in 2014.

SandRidge is targeting all the prolific regional formations in its Midcontinent acreage, including the Marmaton; Chester; Upper, Middle, and Lower Mississippian; and the Woodford shale. For example, the company initiated a nine-well Woodford test program, with three wells drilled so far. The company is encouraged by industry results and plans further testing.

SandRidge is targeting each of the Upper, Middle, and Lower Mississippian zones and conducting multizone development in the same section as well as development in the Chester formation.

"The inventory of new opportunities within our midcontinent asset base continues to expand as we identify new formations and stacked pays and see encouraging results in our appraisal areas," Bennett said.

Seneca Resources (E&P arm of National Fuel Gas)

• Appalachian basin 1 million net acres; California (includes Monterey) 18,418 net acres
• Had a 57% increase in natural gas production

Seneca Resources, the E&P arm of National Fuel Gas, holds a significant chunk of prime Marcellus and Utica acreage, as well as acreage in the Mississippi Lime and, thanks to a legacy acquisition in 1987, some very interesting prospects and production in California.

"The long-term opportunity set for National Fuel continues to improve, and our team is working to turn those opportunities into sustained growth for the foreseeable future," Ronald Tanski, National Fuel Gas' president and CEO, said. "The fourth quarter topped off another great fiscal year for National Fuel. While operations in all of our business units improved, Seneca's E&P results were particularly impressive. Seneca had a 57% increase in natural gas production over the prior year and increased its total proved reserves by 24%."

While the company said it is not very active at the moment in the Utica, the Marcellus play is strengthening the company's balance sheet and bringing smiles to shareholders' faces. In fiscal year 2013 Seneca completed pad drilling on 31 new Marcellus shale wells. The first six wells, drilled from a multiwell pad operation, had 24-hour peak production rates averaging 17.8 MMcf/d, five of which represent the highest peak production rates of any wells operated by Seneca in the Marcellus. Treatable lateral lengths on these wells ranged between 4,292 ft and 5,101 ft, with 14 to 18 fracture stages per well. The company said 25 more wells are scheduled for completion in fiscal year 2014, and it has the "opportunity to drill as many as 2,000 future well locations across this acreage."

Infrastructure restraints have frustrated many operators in the Appalachian region, but National Fuel Gas said it expects to play a major role in alleviating some of these pipeline and processing woes for both Seneca and other producers. Many of Seneca's Marcellus wells are, conveniently, flowing into National Fuel Gas Midstream Corp.'s growing gathering systems, which are undergoing an impressive expansion to accommodate additional production.

Seneca operates more than 3,000 shallow wells and more than 150 shale wells in New York and Pennsylvania. Of Seneca's Marcellus holdings, approximately 80% are "fee acreage," with the mineral rights owned outright by Seneca with no royalty obligation or lease expiration. The remaining Marcellus land rights – approximately 20% – are leasehold interests, most of which are held by production.

"This industry-leading mineral ownership position greatly improves our production economics compared to other companies active in the Marcellus," Seneca said.

On the other side of the country, Seneca became active in California in 1987, when the company acquired several properties from Argo Petroleum in Ventura County. In 1998, Seneca expanded its

Seneca Resources operates in the Marcellus shale in western Pennsylvania.

base into Kern County by acquiring the HarCor, Whittier, and Bakersfield Energy companies and Ivanhoe Energy US in 2009. In 2012, Seneca acquired a portion of assets in the east Coalinga oil field, located in western Fresno County, from Chevron. The West Coast division fields are predominately oil producing reserves displaying long life properties, with low decline rates and low operating costs.

"Seneca's West Coast operations are focused on the development of these properties along with seeking acquisition of low-to-moderate risk properties throughout all the major producing basins in California," the company said. "Since 1998, Seneca has continued to maximize returns from its California holdings by optimizing lifting costs and drilling more than 700 new wells."

Of Seneca's six major fields in California, one in particular – the South Lost Hills field – targets the Monterey shale and produces approximately 1,500 boe/d from 222 active wells. The other five fields are equally as challenging geologically and many require steam-flooding and other techniques to extract the maximum hydrocarbons from the formations. The company is actively working in these areas and has raised production 8% in 4Q 2013 compared to 4Q 2012.

In the Mississippi Lime, the company is drilling its first well and plans five more for 2014.

Southwestern Energy

• Fayetteville 913,502 net acres; Brown Dense 507,000 net acres; Marcellus 337,300 net acres
• Largest leaseholder in the Lower Smackover Brown Dense formation

Southwestern Energy is not only the largest acreage holder in northern Arkansas's Fayetteville shale but said it was the first to discover the unconventional play's economic viability and the first to successfully produce its natural gas. In 3Q 2013, Southwestern placed on production its two highest rate wells since

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the inception of the play. The company's Sneed 08-12 6-1H7 well located in Faulkner County and the Ledbetter 07-16 12-14H well located in Conway County achieved peak 24-hour production rates of 10,084 Mcf/d and 9,148 Mcf/d, respectively. In fact, of the 89 horizontal wells Southwestern placed on production during 3Q 2013, 19 wells achieved peak 24-hour production rates greater than 6,000 Mcf/d. The company added another six wells in October 2013 producing at those same rates. In total, the company's wells placed on production during 3Q 2013 averaged initial production rates of 4,979 Mcf/d.

Southwestern Energy is not only the largest acreage holder in northern Arkansas's Fayetteville shale but said it was the first to discover the unconventional play's economic viability and the first to successfully produce its natural gas.

The company also is the largest leaseholder in the Lower Smackover Brown Dense formation, another Arkansas-Louisiana play that is starting to attract industry interest. The Brown Dense is the source rock for the Upper Smackover, which has been producing since the 1920s. Although the play is new to horizontal drilling, Southwestern believes the Brown Dense "has the critical properties necessary to be a successful play and compares favorably to other productive oil plays in the US."

The company has drilled 10 operated wells in the Brown Dense to date, with five that are testing or producing, one that is waiting on completion, and one that is drilling. The most recent well placed on production was the company's Sharp 22-22-1 #1 vertical well in Union Parish, La., which was drilled to a total vertical depth of 9,776 ft and completed with three stages. The company said it is encouraged by initial flow rates, which achieved a peak 24-hour production rate of 600 bbl of condensate and 1.3 MMcf of 1,240-Btu/d gas. After 88 days, the well was producing approximately 530 bbl of oil and 1.1 MMcf/d of gas on a 16/64-in. choke. Southwestern also spud another vertical well, the Plum Creek 13-23-2 #1V, in Union Parish, La., in late October 2013.

The company has since spread its wings outside of the Arkansas-Louisiana region, entering the Marcellus shale play in Pennsylvania in 2007. As of Sept. 30, 2013, the company had 151 operated horizontal wells on production and 80 wells in progress, resulting in net production of 44.7 Bcf in 3Q 2013, up 196% compared to 15.1 Bcf in 3Q 2012. In 4Q 2013, the company planned to spud its first well in Sullivan County, Pa., on a portion of the undeveloped acreage it purchased in May 2013.

Infrastructure is frequently an issue in the Marcellus, so in October 2013, Southwestern prudently secured additional firm transportation capacity, subject to completing a new interconnect project, beginning in November 2014 for up to an additional 150,000 MMBtu/d. This agreement increases the company's total contracted firm transportation capacity for its Marcellus shale gas to up to approximately 870 MMcf/d by year-end 2014 and more than 1 Bcf/d by year-end 2015.

Unit Petroleum

- **Marmaton Wash 118,000 net acres; Mississippian 133,000 net acres**
- **Boosted its acreage holdings with the purchase of 47,000 net Granite Wash acres**

Unit Petroleum is the second largest acreage holder in the Marmaton Wash play, where it has completed 117 operated horizontal wells since 2010. In 2013, the company averaged more than 4,000 boe/d from horizontal Marmaton wells and ran two Unit rigs in the Oklahoma-based play. Unit anticipates continuing the two Unit drilling rig program in this play, which should result in approximately 42 gross wells being drilled during 2013 for an approximate net cost of US $105 million.

The company also is quite active in the Granite Wash shale play and boosted its acreage holdings in 2012 after purchasing 47,000 net acres in the play from Noble Energy. Unit began its pad drilling program in the play in 3Q 2013 in the Buffalo Wallow field, which was part of the Noble Energy acquisition.


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The company is operating four to six rigs at any given time in the Granite Wash.

The Mississippi Lime shale play also is an area of focus for Unit. During 2012, the company acquired 105,000 net acres primarily in south-central Kansas and drilled its first horizontal well in the play in 2Q 2012. Since then, the company has identified 300 potential locations, with well depths averaging 8,000 ft including laterals around 4,000 ft, the company said.

"We are ramping up our exploration programs in our Granite Wash and Mississippian plays," Larry Pinkston, Unit's CEO and president, said. "In the Mississippian play, we resumed our drilling activity, which had been suspended awaiting pipeline and processing infrastructure. We entered 2013 with six operated drilling rigs and now have 12 drilling rigs working throughout our core plays. We anticipate seeing the initial results of this increased activity in 4Q 2013."

Venoco

• 57,000 net acres in the Monterey
• Has drilled 29 wells into the Monterey shale since 2010

The predicted prolific hydrocarbons located in the Monterey shale have been frustratingly hard to access, but Venoco is convinced it will solve the puzzle and reap the rewards at some point. The company has drilled 29 wells into the formation since 2010, but none has produced a fraction of what explorationists envisioned it could. Throughout California, the Monterey shale holds an estimated 15 Bbbl of recoverable hydrocarbons, is a world-class source rock, has produced since the 1800s, and holds the promise of massive future production. Venoco wants to be there to realize its share of that potential.

Take, for instance, Venoco's latest exploration effort targeting the offshore Monterey. During 3Q 2013, Venoco successfully completed an exploratory well to a probable location in a separate geologic structure known as Coal Oil Point, located to the northeast of Platform Holly in the South Ellwood field.

"The Coal Oil Point structure has two separate fault blocks. The well path of the probable well resulted in the intersection of the northern fault block in only the lowermost Monterey zone (M7), whereas the southern fault block was intersected in only the uppermost Monterey zone (M1)," the company said.

The well was completed in two sections, the first of which was completed in early August 2013 and was tested for about 30 days. This section, which intersected only the lowermost Monterey zone (M7), produced a high volume of water with no measurable oil cut. However, the second section, which intersected only the uppermost Monterey interval (M1) (out of seven potentially productive zones) was successful and was put on production in early September 2013, averaging 220 gross b/d of oil for about a month until the platform was shut down for maintenance. Following the maintenance, production from this well has averaged approximately 100 gross b/d of oil.

"We are very encouraged by the positive results from the well we drilled to Coal Oil Point," said Ed O'Donnell, Venoco's CEO. "Since the second section of the well intersected and was completed in the


(Photo by Lowell Georgia, Hart Energy)

Significant onshore seeps can still be found in Carpinteria as well as Gioleta, Calif. Early Americans used the oil to waterproof their canoes.

uppermost interval of seven Monterey zones, which is typically not the most productive zone, we believe the success of this well strongly indicates that additional opportunities exist for further development of the fault block. We will continue to analyze the results from this well to help us better understand those opportunities and aid us in constructing our development plan for the area."

The Monterey shale extends both onshore and offshore, with the onshore portion covering an estimated 1,750 sq miles of central and southern California. Although a substantial portion of Venoco's current production is from offshore wells targeting the fractured Monterey shale formation, "we believe that there are significant exploration, exploitation, and development opportunities relating to the Monterey shale formation onshore as well, and that our offshore expertise will help us take advantage of those opportunities," the company said.

Venoco vice president of exploration and new ventures, Mike Wracher, said Venoco is seeking a partner for its onshore Monterey acreage and has made "some progress" in that effort. "We are currently testing our existing onshore wells, but looking to team up with a partner to further explore and turn the corner toward economic viability onshore."

Wracher said the Monterey play is not getting the attention it deserves. In addition to the structural complexity of the play, industry perception of California's strict environmental stance is that there are too many hurdles to make exploration worthwhile.

"Companies are often afraid to work in California because of the perception of the regulatory environment," Wracher said, "but we have worked here a long time, we have drilled many of the exploratory wells in the Monterey shale, and we understand the regulatory environment here. We know the process.

"Unlike other unconventional plays in the rest of the country where there are 15 to 20 companies actively exploring," Wracher continued, "in California there are only a handful. Not having enough companies exploring has slowed the play down – we need more companies working here in order to determine how to make this play economically successful, and we're just not seeing that at this time. The majors seem to be sitting back and letting the independents figure it out, while still holding substantial acreage positions."

Although the company has not yet seen material levels of production or reserves from its onshore Monterey program, Venoco remains confident that its diligence will pay off. "Based on the data we have gathered and the results we have seen to date at the Sevier field in the San Joaquin basin, we believe that our testing efforts and delineation drilling in the area will ultimately result in commercial levels of production from the field," the company said.

Whiting Petroleum

• Bakken/Three Forks 714,567 net acres; Niobrara 119,978 net acres
• The No. 2 oil producer in North Dakota

Whiting Petroleum controls one of the largest acreage positions in the Bakken resource play in North Dakota and is the No. 2 oil producer in that state. The company recently sold some assets so it could accelerate development of its two high rate-of-return assets: the Bakken shale and the Denver-Julesburg (DJ) basin's Niobrara shale plays.

"We were one of the first successful operators in the Bakken/Three Forks hydrocarbon system in the Williston basin with the discovery of our Sanish field in early 2007," the company said. "Outside of our Sanish field we have assembled lease positions on seven separate prospects in the Williston basin targeting the Bakken/Three Forks and Pronghorn Sand formations."

The company continues to acquire prospective acreage in its core areas. In the western Williston basin, the company acquired 39,310 gross (17,282 net) additional acres during 3Q 2013 to complement its existing holdings in the Missouri Breaks and Hidden Bench prospects. The acquisition brought Whiting's total acreage in the western Williston basin to 205,581 gross (120,309 net) acres, and production for the company from this area averaged 13,710 boe/d in 3Q 2013, representing a 46% increase compared to an average 9,385 boe/d rate in 2Q 2013.

The company also aggressively pursues optimization technologies to increase efficiencies. "We have implemented a new completion design in our Missouri Breaks area that utilizes cemented liners and higher sand volumes," the company said. "The new fracture design appears to significantly improve production rates. On Aug. 24, 2013, we completed the Sundheim 21-27-1H flowing at an initial rate of 1,136 boe/d using a cemented liner and our first slickwater fracture. Cumulative production from this well during its first 30 days of production totaled 16.7 Mboe, which was approximately 75% better than the offset well that was completed by another operator using different technology."

The last eight wells at Missouri Breaks that were completed using cemented liners and plug-and-perf (PNP) technology averaged cumulative production during the first 30 days of 14.4 Mboe, which was approximately 60% better than the previous 31 area wells completed using uncemented liners and sliding sleeves.

Whiting is now using new PNP completion designs with cemented liners in all its Bakken wells, with similar positive results. The company also is testing well spacing to optimize drilling efficiencies.

The company added 48,131 gross (32,419 net) acres to its Redtail Niobrara prospect, located in the DJ basin in Weld County, Colo., in 3Q 2013. The acquisition brought Whiting's total acreage at Redtail to 168,644 gross (119,978 net) acres. Whiting's Redtail acreage produces from the Niobrara "B" zone and also is prospective in the Niobrara "A" and "C" zones as well as the Codell formation.

The company has shifted to pad drilling and added a third rig to the play in 2013, with plans to add a fourth in January 2014 and a fifth in June 2014.

"As of Oct. 15, 2013, we had three wells flowing back and 10 wells waiting on completion," the company said. "Our development plan for the Redtail prospect is to drill eight wells per spacing unit to the Niobrara B zone and eight wells in each spacing unit to the Niobrara A zone. We estimate that we have more than 3,300 gross locations and 1,650 net locations at our Redtail prospect on this development pattern." ■

(Image courtesy of Schlumberger)

Efficiency and Effectiveness Curves Drive Unconventional Production into 2014

Glenn R. Meyers, Contributing Editor

From maximizing RSS on multiwell pads to integrated stimulation strategies, emerging technologies showcase production increases.

Let it never be said traditional factories are marginal templates for unconventional plays. Simply take the best in R&D from operators, service companies, and universities, and then investigate how emerging technologies and a factory mindset are now being applied in unconventional field factories to create production showcases.

Concerning the tools that are driving increased efficiencies, Dave Sobernheim, unconventional resources principal petroleum engineer for Schlumberger, said, "There is still much that needs to be looked at for improving the reliability of operations in the field, ultimately leading to improved efficiency for the operating companies."

Indeed there is.

On the operator side, Magnum Hunter has deployed large multiple-well pads. Its Ohio Stalder pad is designed for 18 wells including 10 in the Marcellus shale and eight in the Utica – all using a robotic rig. This trend will no doubt continue elsewhere.

Compound such moveable pad innovations (many already in the Bakken) with demand for longer laterals at closer proximities – adding the call for smart rotary steerable systems, better bottomhole assemblies, and tools that deliver the curves and laterals in one run – and it becomes clear that efficiency is no longer a simple request but a standard.

As highlighted by the 20 plays reviewed in this yearbook, dynamic changes are taking place in strategies that increase production and target efficiencies in data analysis. Add drilling and completions that bolster how effectively a play is being handled, and the trends are apparent.

THE TECHNOLOGIES

Completions

As drilling performance improves dramatically, longer lateral lengths and more hydraulic fracturing stages have increased and are beginning to plateau in some of the plays. "The idea is to get more of the rock effectively stimulated than what has been done in the past, in order to improve well productivity per foot of pay drilled," said Dave Sobernheim, unconventional resources principal petroleum engineer for Schlumberger.

In some plays, a "super-frac" technique is applied where perforation clusters are spaced very closely to create the maximum amount of fracture surface area. This technique is modeled using new software technology including an unconventional fracturing model embedded in Schlumberger's Mangrove engineered fracturing design workflow for the Petrel E&P software platform.

According to Schlumberger, including features such as stress-shadowing (an issue with the closely spaced clusters), explicit models calibrated to microseismic information and conditioned by discrete fracture network models can be used to optimize stimulation treatment volumes, pump rates, and proppant scheduling.

"In 2013 the big jump has been to actually calibrate [unconventional fracturing] models in plays such as the Marcellus and Eagle Ford, and then to use auto-gridding technology on the new INTERSECT next-generation reservoir simulator to match

Facing page: A rig-up for high-rate pumping treatment is on location in northwest Louisiana.

and forecast productive performance," Sobernheim said. While this process is still in its infancy, he added it holds great promise to improving a comprehensive understanding of how these plays perform under different drilling and completing scenarios.

Channel fracturing via the HiWAY flow-channel hydraulic fracturing technique is continuing to have a significant impact in plays such as the Eagle Ford. Currently, the technique is also seeing greater use in the Bakken.

Long-term field results are supporting the technology, with an ever-expanding improvement in recovery over time on wells treated with the HiWAY technique, according to Schlumberger. More than 20,000 stages have been performed around the world using the flow-channel hydraulic fracturing technique.

Plug-and-perf (PNP) techniques still dominate in most plays but with refinements. The KickStart pressure-activated rupture disk valve eliminates coiled tubing or tubing-conveyed perforating in the first stage of PNP operations, offering a more effective and efficient method to start the fracturing process, according to Schlumberger.

Uncemented, openhole completions still dominate in the Bakken play, and new technology also is having an impact there. The company's new ELEMENTAL high-performance degradable alloy balls combined with the Falcon multistage stimulation system allow efficient multistage operations without the need to drill out the balls at a later date, since they are fully degradable.

Case study: Eagle Ford

According to the Schlumberger website, the company and four Eagle Ford operators formed the Eagle Ford Completion Optimization Consortium to investigate improving completion design for horizontal wells through the use of log data. Of particular interest was accounting for the effect of lateral variation in stress along a well to improve the percentage of contributing perforation clusters, termed perforating efficiency, from the 64% average achieved with conventional geometric spacing.

Schlumberger developed engineered completions using Mangrove reservoir-centric design software with input log data from ThruBit logging services and the Sonic Scanner acoustic scanning platform, with the latter obtained in the cased hole conveyed by the TuffTRAC cased-hole services tractor.

ThruBit logging services were used to acquire through-the-bit quad-combo logs in 12 wells with minimal interruption to the operators' existing field development workflows.

Each of the wells was stimulated according to its customized treatment grouping for similarly stressed intervals, flowed back for cleanup, and logged with the Flow Scanner horizontal and deviated well production logging system conveyed on the MaxTRAC downhole wireline tractor system. Perforation efficiency increased to 82%.

Flow Scanner production logging showed that on average 82% of the perforation clusters placed following an engineered completion strategy are producing oil, representing a significant improvement over the benchmark 64% average for conventional geometrically spaced Eagle Ford completions.

Case study: Haynesville

With Haynesville wellhead pressures reaching up to 15,000 psi, these wells present logistical and operational challenges. Pumping slickwater or hybrid fracturing treatments at these high rates requires a significant amount of horsepower on location.

A Haynesville operator wanted to reduce the operational footprint and simplify logistics without compromising well productivity. Schlumberger proposed a field trial of HiWAY channel fracturing, engineered specifically for the complex fracture networks in shale plays.

The operator and Schlumberger selected two well candidates with similar lengths and completion parameters drilled from the same pads as the offset wells. The conventional wells had been treated with slick water followed by a conventional crosslinked fluid. Schlumberger applied a combination of slickwater stages and HiWAY stages. The operator placed all 29 stages without a single screenout.

On average, the HiWAY wells used 47% less proppant and 26% less water than offset conventional wells. Over the first 240 days of production, the HiWAY wells produced 6% more normalized gas than offset conventional wells.

Case study: Marcellus

Because significant production variability exists between seemingly identical wells, this heterogeneity contributes to completion problems such as increased screenout rates, high treating pressures, and extended pump times. To mitigate some of these challenges, Seneca Resources partnered with Schlumberger for a three-well test comparing an engineered completion methodology with the conventional approach.

Engineers delivered customized completion designs in under an hour. Well A used geometric perforation spacing, while wells B and C used engineered designs. All three wells were drilled from the same pad location and in the same direction to similar lateral lengths. All wells were placed in the same target zone and spaced approximately 800 ft apart.

Schlumberger conveyed a reservoir saturation tool and Sonic Scanner acoustic scanning tool on wireline to determine lithology and stresses along the laterals. Mangrove software allowed engineers to analyze the data and develop optimized completion strategies for wells B and C in less than an hour. The three wells were stimulated simultaneously using the "zipper-frac" approach, which alternated stages between wells. While one well was being fractured, a second team performed PNP operations on the next well.

The StimMAP LIVE real-time microseismic monitoring service showed approximately 35% of the perforation clusters in the lateral portion of well A had little to no microseismic activity. In contrast, only 20% of the perforation clusters in wells B and C had little to no microseismic events. On a per-foot basis, well B, which was approximately the same distance from the monitor well as well A, had 25% more stimulated volume. Initial gas flowback rates of wells B and C were respectively 33% and 40% higher than the rate of well A on a ⅝-in. choke.

Seneca Resources realized lower treating pressures at higher pump rates, leading to lower operational risk.

Case study: Wolfbone

Because the Wolfbone comprises multistacked conventional and unconventional packages, the interval is characterized by highly heterogeneous lithologies and formation properties.

For its Wolfbone campaign, Endeavor Energy partnered with Schlumberger to characterize the reservoir and understand the acreage's spatial variability. Detailed completion and production evaluation of the vertical well program were critical in identifying and ranking productive horizons for future horizontal well developments.

Schlumberger proposed an integrated strategy encompassing detailed reservoir characterization, complex fracture modeling with Mangrove software, and the HiWAY channel fracturing technique.

For its Wolfbone campaign, Endeavor Energy partnered with Schlumberger to characterize the reservoir and understand the acreage's spatial variability.

The company constructed oil shale montages using data from the Platform Express integrated wireline logging tool, elemental capture spectroscopy sonde, and combinable magnetic resonance tool. This provided petrophysical interpretations of the Wolfbone interval and improved identification of the pay zones. The Sonic Scanner acoustic scanning tool also was run on the subject wells to derive anisotropic mechanical rock properties and stress models, which are critical inputs for accurate hydraulic fracture simulations.

All available reservoir data were imported into Mangrove stimulation design software to determine treatment staging and perforation placements and to perform hydraulic fracturing simulations – optimizing fracture treatment parameters. To address completion costs and fracture conductivity concerns, the subject wells were treated with the HiWAY technique.

Initial oil production of the subject wells ranked in the Wolfbone play's top 20%. The flow-channel fracturing technique also used 30% less proppant and 6% less fluid than conventional stimulation treatments. Based on the production results and commodity reductions of this project, Endeavor Energy converted all of the stimulation treatments from conventional systems to HiWAY channel fracturing.

The completion and production evaluation also provided critical input into the future drilling and completion program. The evaluation validated the effectiveness of the HiWAY technique, allowing further optimization of this completion method. The company identified cost savings of US $734,000 per well in regard to drilling and completions operations. This analysis also identified high-potential horizontal targets within the Wolfbone play that would be targeted in future horizontal developments.

Multistage fracturing systems

Baker Hughes' FracPoint multistage fracturing system is field-proven for many applications, including unconventional reservoirs, according to the company. The FracPoint portfolio expands across both single-ball/single-sleeve systems to single-ball/multiple-sleeve systems and includes cemented sliding sleeves.

This system accelerates return on investment (ROI) with continuous fracturing using ball-activated fracturing sleeves, eliminating rigup and rigdown between stages and reducing overall pumping time.

Each stage is isolated with hydraulically set openhole packers or reactive-element packers. When the fracture is complete for one stage, the ball for the next stage is dropped into the flow path without shutting down pumping.

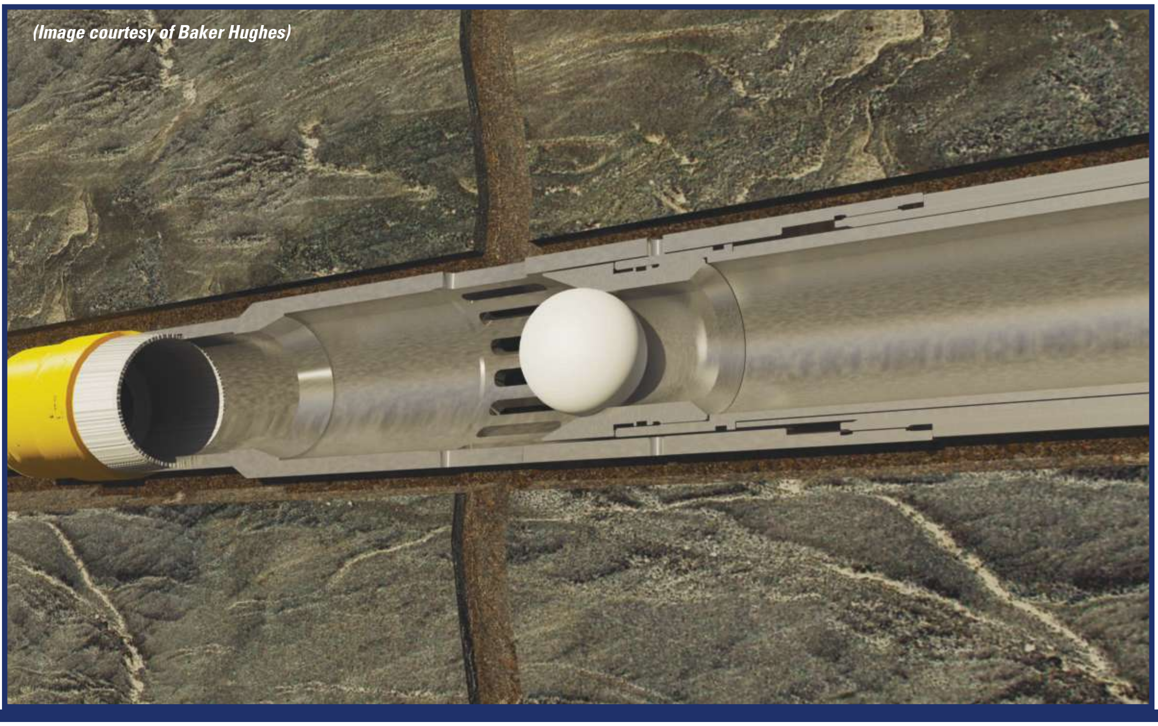
IN-Tallic frac balls used with the FracPoint system maintain shape during pumping and then disintegrate to provide an open production path without milling.

Case study: Cleveland

An independent operator with an unconventional well in the Cleveland formation in Oklahoma needed to perform a multistage completion with more than 24 stages. The operator also elected to tie back the well from the liner top to the surface to provide the necessary pressure capacity for the fracturing treatments.

The well was drilled to 14,350 ft with a 5,143-ft lateral section from the kickoff point. To complete the well, Baker Hughes recommended using its FracPoint multistage completion system, which would allow the operator to isolate as many zones as needed, and then to fracture all zones in one continuous pumping operation.

To maximize the operator's access to the pay zone, Baker Hughes deployed a 30-stage FracPoint system using a combination of ⅛-in. increment EX-C frac sleeves and 1/16-in. increment EXPress frac sleeves. Openhole packers completed the 8,000-psi-rated system and were used between the sleeves for zonal isolation.


(Image courtesy of Baker Hughes)

The Baker Hughes FracPoint multistage fracturing system accelerates ROI with quick, continuous hydraulic fracturing using ball-activated fracturing sleeves in openhole and cemented applications.

Once the system was in place, a FracPoint pressure-activated sleeve was used in the toe to fracture the first stage. IN-Tallic frac balls were used to divert treatment because they maintain shape and strength during fracturing and then disintegrate in the well.

No milling was required, and an unobstructed flow path for immediate production remained. The operator had another FracPoint system installed on the same pad.

Case study: Mississippi Lime

In Woods County, Okla., a 4,500-ft lateral section in the Mississippi Lime needed to be fractured. Previously, the operator had run plug-and–perf (PNP) style completions in its wells because of the high pump rates that were achieved. Over time, however, the operator found the overall fleet time for fracturing and wireline expense, along with decreased efficiency resulted in increased upfront costs. To decrease operating expenses and enhance operational efficiency, Baker Hughes was queried about an alternative completion method.

Based on the operator's well and the desire for a more efficient approach, Baker Hughes engineers recommended the FracPoint multipoint system with DirectConnect ports. The system uses openhole packers to isolate zones, and the multipoint sleeves have ball seats that allow one frac ball to open multiple sleeves per stage.

Baker Hughes treated the well in one continuous pumping operation, and the FracPoint multipoint system transitioned the operator from the required 40 perforation clusters in the well to 40 total sleeves compartmentalized into nine stages. Fluid restrictions were avoided because the system was designed to maintain large ball-seat inside diameters (IDs). Efficiency was further enhanced by activating multiple sleeves per stage, which enabled a larger ball-seat ID in the toe stages. The operation took a total of 15 hours, and 75 bbl/min frac rates were maintained throughout the toe stages, with a maximum of 120 bbl/min throughout the job.

The multipoint system helped minimize time on location and allowed maximum pump rates. Use of the DirectConnect ports improved the placement and effectiveness of the fracturing treatment to further enhance production.

The multipoint system reduced total fracturing time by more than 50% compared to a standard PNP-style completion that would have taken 30 hours.

Baker Hughes' OptiPort multistage fracturing system provides enhanced treatment placement by allowing multiple targeted fracture stimulations.

Multistage fracturing

Baker Hughes' OptiPort multistage fracturing system combines enhanced treatment placement by allowing multiple targeted fracture stimulations, providing speed, reliability, flexibility, and economic benefits for optimized well completions, according to the company.

The system contains multiple fullbore ID sleeves that hydraulically open by means of coiled-tubing (CT) tools. An unlimited number of OptiPort sleeves can be run in the casing/liner string to divert the fracture in the desired location and have the flexibility to be cemented in place or completed via the openhole method. A CT-conveyed bottomhole packer assembly is used to isolate each stage, open the sleeve, and direct the pumping treatment to the desired fracture point.

"By optimizing fracture placement with the OptiPort system – as opposed to simultaneously fracturing multiple clusters – operators in the Granite Wash and Bone Spring plays have been able to dramatically increase hydrocarbon production," Luis Castro, Baker Hughes marketing manager of completions, said.

Case study: Barnett

Targeted fracturing was planned in the 4,000-ft horizontal section of a Barnett shale well using the OptiPort multistage fracturing system.

The CT equipment consisted of a 2-in. outer diameter 16,000-ft long CT string with 15,000-psi pressure control equipment.

A Baker Hughes SureSet isolation packer was set up for 5½-in. casing, a mechanical casing collar locator, and a memory gauge package. The bottomhole assembly lasted 24 stages before the slips needed service. The fracturing job was designed to be 30 bpm to 35 bpm using up to 3 lb of proppant-added sand stages and 68,000 lb of proppant per stage.

Baker Hughes personnel were able to dial in the fracturing design by stage 4. Controlling fracture height was critical because the Barnett shale has the water-bearing Ellenberger formation stacked below the hydrocarbon-producing zone.

The crew reduced time between stages by 70% from the beginning of the job. At one point, 10 stages were pumped in 12 hours. A total of 48 OptiPort collars were run and cemented in the well with only four screenouts, totaling only 12 hours of recovery time.

This targeted fracturing technique and associated operational efficiencies reduced power and fluids used, shrinking the operating footprint by 30%, lowering nonproductive time, and preventing water production. The entire job took nine days, with the crew only working during daylight hours.

Batch fracturing system

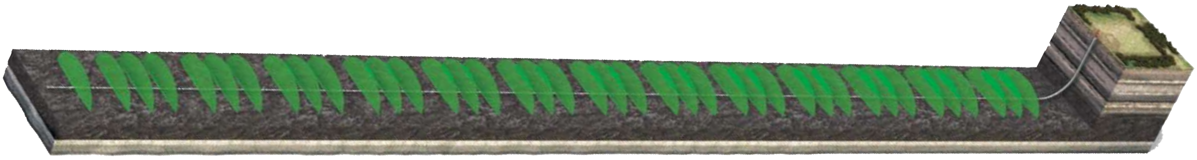
The Packers Plus QuickFRAC batch fracturing system features a set of tools capable of simultaneously stimulating multiple stages with a single fracture treatment known as limited entry. This system provides openhole benefits with the ability to induce more fractures at the same time in a single treatment zone, which can be beneficial for plays like the Niobrara and Mississippian.

"The one thing we hear operators saying is they like the openhole philosophy," Snyder of Packers Plus said. "They don't want to cement their wellbore off. They know there are natural fractures that contribute to production, so they want to take the benefit of the openhole [method], but they want to treat multiple spots along the lateral at the same time."

The batch fracturing system can be set up to allow multiple open clusters, just like the plug-and-perf method. "We can treat that stage with limited entry to get even distribution throughout that stage's lateral section," Snyder said. "We see a lot of people toying with this idea. I'd say it's more predominant up in Canada than in the US, but it is definitely on everybody's radar. I think that will probably be the next technology that takes off."

For each treatment zone, the QuickFRAC system includes a number of QuickPORT sleeves and packers. Because the system design is modular, the sleeves can be set up with single or multiple sleeves between packers, depending on the stimulation goal.

On the operational side of the equation, a ball is pumped down onto the seat, and the string is then pressured up to activate and open the sleeves, allowing stimulation fluid to flow into the annulus at the appropriate points and rates. The limited-entry design is maintained during high concentrations and volumes of proppant.



The QuickFRAC batch fracturing system induces more than one fracture per treatment stage.

(Image courtesy of Packers Plus)

A variety of ball seat sizes are available, which can allow for multiple limited-entry treatments to be run in sequence. After well stimulation is completed, balls can be flowed back.

The system can then be milled out based on the operator's completion requirements, according to the company. The QuickFRAC system can be used in horizontal and vertical wells in combination with the StackFRAC system for customized stimulation design.

Multistage stimulation

Halliburton provides a wide selection of products for multistage stimulation completions. These products provide flexibility for operators in handling play-specific challenges, from enabling more efficient plug-and-perf (PNP) operations to optimizing entire completion strings.

Halliburton's RapidSuite technologies include the RapidShift ball-drop actuated mechanically closed stimulation sleeve; the RapidStage single-entry point stimulation sleeve; the RapidFrac multientry point stimulation sleeve; the RapidShift mechanically shifted stimulation/production sleeve; the RapidStart Initiator interventionless hydraulic sleeve; and the RapidSuite mechanical shifting tool.

The RapidSuite Engineering Toolbox (ETB) mobile app provides a series of technical calculators to assist in designing, modeling, simulating, and executing horizontal completion jobs. Whether operators are concerned with a frac sleeve completion or a traditional PNP horizontal completion, the mobile app can ensure the completion design is suited for the application.

The ETB provides access to the following calculators while out on location:

- Displacement. Calculates the displacement volume of each target sleeve or set of perforations to estimate when a frac ball will land on the target frac sleeve;
- Ball differential. Simulates differential pressure across the frac ball or isolation packer during stimulation treatment;
- Restriction port differential. Calculates pressure increase through a target sleeve or set of perforations to help increase the effectiveness of a frac placement; and
- Baffle selector. Helps choose the right baffle inside diameters for a completion based on frac rate, isolation method, and casing size.

Case study: Eagle Ford

An operator in South Texas wanted to improve well economics and lower the cost per barrel of oil equivalent for a well in a new part of the Eagle Ford shale. Looking for alternatives to the PNP completion process, the operator sought new methods to complete and hydraulically fracture these new wells.

Halliburton proposed running a 16-stage cemented RapidStage system on a long string of production casing. The RapidStage system allows each stage to be fractured by dropping a ball from the surface, eliminating the need for wireline intervention. The process would begin with Halliburton's RapidStart Initiator sleeve at the toe to provide a flow path by opening with tubing pressure. Efficiency would be increased through the use of the RapidSuite Pneumatic Ball Launcher to remotely release balls in the fracture stream during continuous pumping. The entire completion would be cemented in place with SoluCem acid soluble cement to make fracturing the formation easier.

With the use of the cemented RapidStage system, the operator was able to complete 15 fracture stages as designed in 24 hours compared to an estimated three days for a PNP completion. This represented a 66% increase in completion efficiency, saving both time and money. Production results also were similar to offset wells, helping ensure that the RapidStage system could reduce the cost per barrel of oil equivalent.

(Image courtesy of Halliburton)

The RapidStart Initiator CT sleeve delivers a casing pressure test in a cemented horizontal application.

Case study: Marcellus

In the Marcellus shale Seneca Resources operates more than 150 deep shale wells. To help ensure leaks will not pollute aquifers or the air, Seneca pressure-tests all casing before fracturing. However, traditional methods for testing casing required intervention and were costly. According to the Halliburton website, when Halliburton approached Seneca about field-testing new RapidStart Initiator CT sleeves, Seneca agreed.

Designed to enable a casing pressure test prior to opening, the pressure-activated fracturing sleeves also establish a fluid flow path to the target formation, according to Halliburton.

In the first well, the sleeves cut casing test costs by 40% by eliminating time and expenses associated with CT and tubing-conveyed perforating. The sleeves also reduced the risk of unobserved casing damage due to sleeve activation pressures that exceed test pressures. The unique method of opening these sleeves helps ensure that the simulated fracturing pressure used in testing will not be exceeded. On a six-well pad, Seneca could cut casing test costs even more and gain revenue by bringing wells on production sooner.

RapidStart Initiator CT sleeves do not require pressures in excess of test values to open. The sleeve opens only after certain test pressures have been achieved for 20 minutes to 60 minutes or more. This can eliminate time, cost, and risk with running, testing against, and retrieving a plug, according to the company.

The sleeve is run as part of a normal completion so a crew is already on site. There are no additional costs or risks associated with wireline or CT units and rigging the units up or down to set bridge plugs.

The cost associated with prepping the well can be as low as US $60,000. However, costs also can easily exceed $100,000 depending on location and problems that might arise. This can delay production, negatively impact well and field economics, and reduce return on investment.

The new sleeves open only when the test pressure has been maintained for a period of time. If crews reduce the pressure, they can stop the meter. This lets them fix any issues they find and retest the well – before the sleeve opens.

To comply with regulations, some operators set the activation pressure of conventional toe sleeves very close to the maximum casing pressure test value. This caused sleeves to open earlier than anticipated (or sometimes not at all). This could trigger the need for an expensive intervention.

Case study: Niobrara

According to Halliburton, an operator in the Denver-Julesburg basin northwest of Denver needed a cost-effective and efficient way of completing a 4,000-ft horizontal section in the Niobrara play.

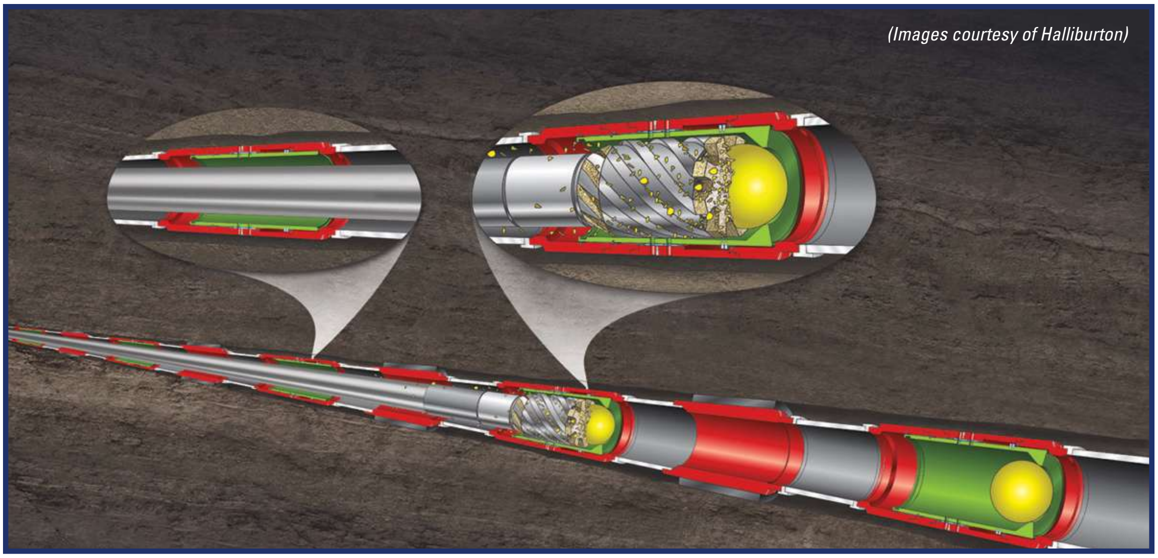
Halliburton proposed a 16-stage completion installation using its new 30+ RapidStage system for reservoir entry to address the operators' concerns with slow baffle mill-out, baffle ID restrictions for CT passage when sand cleanout was needed, and limited rate availability through the toe stage.

In addition, the proposal included Swellpacker isolation systems for reliable openhole isolation and a VersaFlex liner hanger to hang and seal off the liner.

Installation of the 16 Swellpacker systems and RapidStage sleeves, including expansion of the VersaFlex liner hanger and retrieval of tools, was completed in less than 18 hours.

The 30+ RapidStage system allowed a narrower range of large IDs to be applied for the balls and baffles. This provided the advantage of placing the customer's treatment at higher rates throughout the lateral without sacrificing mill-out times. The larger IDs also allow CT passage, should it become necessary.

When compared to a PNP option, this technology saved the operator up to three days of pump time and its associated risks and costs. The fracturing crew's standby time and unnecessary water use also were eliminated. The operator chose to not flow the balls back after the treatment.



The 30+ RapidStage system saved one operator up to three days of pump time and its associated risks and costs, according to the company.

Halliburton's RapidSuite ETB mobile app offers a series of technical calculators to assist in designing, modeling, simulating, and executing horizontal completion jobs.

CT mill-out of the 16 baffles and balls – averaging just more than 12 minutes milling on each set – was successfully accomplished in only eight hours, including one wiper trip. The operator was able to bring the well on sooner and save on excessive CT or stuckpipe mill-out costs.

Drilling and drillbits

Baker Hughes developed the AutoTrak Curve rotary steerable system (RSS) to provide improved drilling economics, precise wellbore placement, and faster drilling in unconventional plays, while maintaining the well in the sweet spot.

"Each project requires special evaluation to optimize the well placement and drilling efficiency," Paul Bond, product line director for directional drilling, said. "Some areas require multiple bit runs due to formation types, while some can be completed in one run; others have stresses that require that the build section be cased off with a different hole size through the reservoir. There are multiple conditions to consider."

Launched in March 2012, the AutoTrak Curve RSS has drilled 7.5 MMft. It can drill build sections of the wells with 15°/100-ft doglegs, while rotating continuously, compared with 7°/100-ft doglegs achieved using conventional RSS.

"Complex 3-D well profiles can be drilled in the same time as simpler profiles since the system is steering all the time while rotating ahead. This is a key factor for its success in areas where pad drilling is becoming the norm," Bond said. "Also, the performance has been very consistent. We are not talking about a one-off record well but record wells over and over again, saving days off wells and reducing significantly the time to drill up a pad while ensuring the quality of the wellbore."

Steering ribs in the sleeve adjust direction to provide accurate steering without the requirement to trip out of the hole to change the buildup rate as is required with conventional motors. Each rib is controlled by its own dedicated hydraulic control mechanism – operating independent of the bit pressure differential. Steering parameters are adjusted using a short down link while drilling so as not to impact the drilling process.

(Image courtesy of Baker Hughes)

The AutoTrak Curve is paired with a fit-for-purpose Baker Hughes drillbit engineered for optimized performance, steerability, and wellbore quality.

Case study: Utica

Working in the Utica shale an operator contacted Baker Hughes to drill a horizontal well with a 10°/100-ft dogleg severity curve section. The client chose to drill the section using the Baker Hughes AutoTrak Curve RSS along with an 8¾-in. Baker Hughes drillbit.

The operator required a target change at 70° of inclination in the curve section of the wellbore, and the system delivered a buildup rate of 17.56°/100 ft at an ROP of 52 ft/hr. The system's ability to deliver excellent buildup rate capability while drilling allowed the operator to land the well in the planned reservoir zone of interest. Baker Hughes delivered cost savings and critical directional performance in the Utica curve and lateral sections and maximized reservoir exposure without spending the nonproductive time required by conventional drilling systems to trip drillpipe and change motor-bend angle settings to accomplish the same feat.

The lateral was drilled at a high ROP, and the wellbore was kept in the target reservoir interval using the close-proximity gamma sensor along with near-bit inclination.

The 1,048-ft curve section was accurately landed in two rig days, which included trip time while running in the hole. The 5,400-ft lateral section of the wellbore was drilled to total depth in just 3.2 rig days, which included rig time tripping to the surface after the well had been drilled to total depth for a total picture of true operational rig time. The average ROP for the combined curve and lateral section was 95.4 ft/hr, and the AutoTrak Curve system averaged 1,247.1 ft of drilled footage per rig day while it was in the hole.

The system eliminated a total of 5.2 rig days from the 10-day drilling plan, saving the client major expenses in associated rig spread rate costs.

Hybrid bit technology

Another bit that has been successful in various unconventional plays is the Hughes Christensen Kymera hybrid bit technology by Baker Hughes. It combines polycrystalline diamond compact (PDC) fixed cutters and roller cones into one design that addresses drilling challenges in complex wells and interbedded formations.

"This technology combines the best of both worlds," Alan Holliday, Kymera product line manager, said. The smooth, low-torque crushing action of roller cones, combined with the aggressive shearing of the PDC blades improves drilling efficiency and reduces costs.

"Torque becomes a limiting factor with PDC drillbits," Holliday continued. "However, hybrid technology provides better vibration control, which leads to increased drilling efficiency and ROP. By reducing vibrations, this bit also helps extend the life of the tools components in the bottomhole assembly."

PDC drillbits

Impact damage can occur on a PDC cutter in a highly transitive environment, where it may quickly hit a hard section after drilling fast in relatively soft rock. When extensive cutter chipping and breakage occur, the cutter will wear down much quicker than designed, and the drillbit gets dull.

Halliburton designed its MegaForce drillbits product line with new PDC cutter layouts to help bits drill more smoothly in transition. The new bits also include SelectCutter technology that is more impact resistant than the previous-generation X3 cutter without sacrificing abrasion resistance. In addition, impact arrestor technology keeps the new bits from over-engaging with softer rock, which can lead to impact damage when transitioning to harder rock. Improved matrix material for the drillbits reduces erosion from drilling fluid and cuttings.

Through R&D, the number of bits needed to drill through hard shale formations like the Haynesville has dropped from typically four or five to a consistent two or three, depending on well location. This reduces not only the cost of using drillbits but also trip time on the drilling rig, according to Eric Helgesen, Halliburton's application design engineer.

In the deeper areas of the Bakken, it has always been difficult for the vertical section to make the kickoff point using one bit, Rick Clemons, Halliburton's global marketing manager of drillbits and services, said. "There is a group of interbedded formations

SelectCutter PDC technology provides the highest level of abrasion resistance, impact resistance, and thermal mechanical integrity available.

(Image courtesy of Halliburton)

called the Minnelusa, which are made up of the Broom Creek, Amsden, and Tyler," he added. "They vary from sandstone, limestone, and dolomite and have historically been hard on bits. If care is not taken, you are probably going to trip not long after those formations due to the cutters breaking because of impact damage, which leads to large wear flats and broken cutters that decrease the bit's efficiency."

To try to help mitigate the impact damage that can occur in these formations, an MM65D was designed with the new MLFB layout method, and Select Cutters were used to better help the bit through the areas of transitional drilling. The changes made to the MM65D helped increase the amount of one-run verticals as well as increase their ROP and has helped operators drill their vertical sections in the shallower areas more consistently.

Case study: Eagle Ford

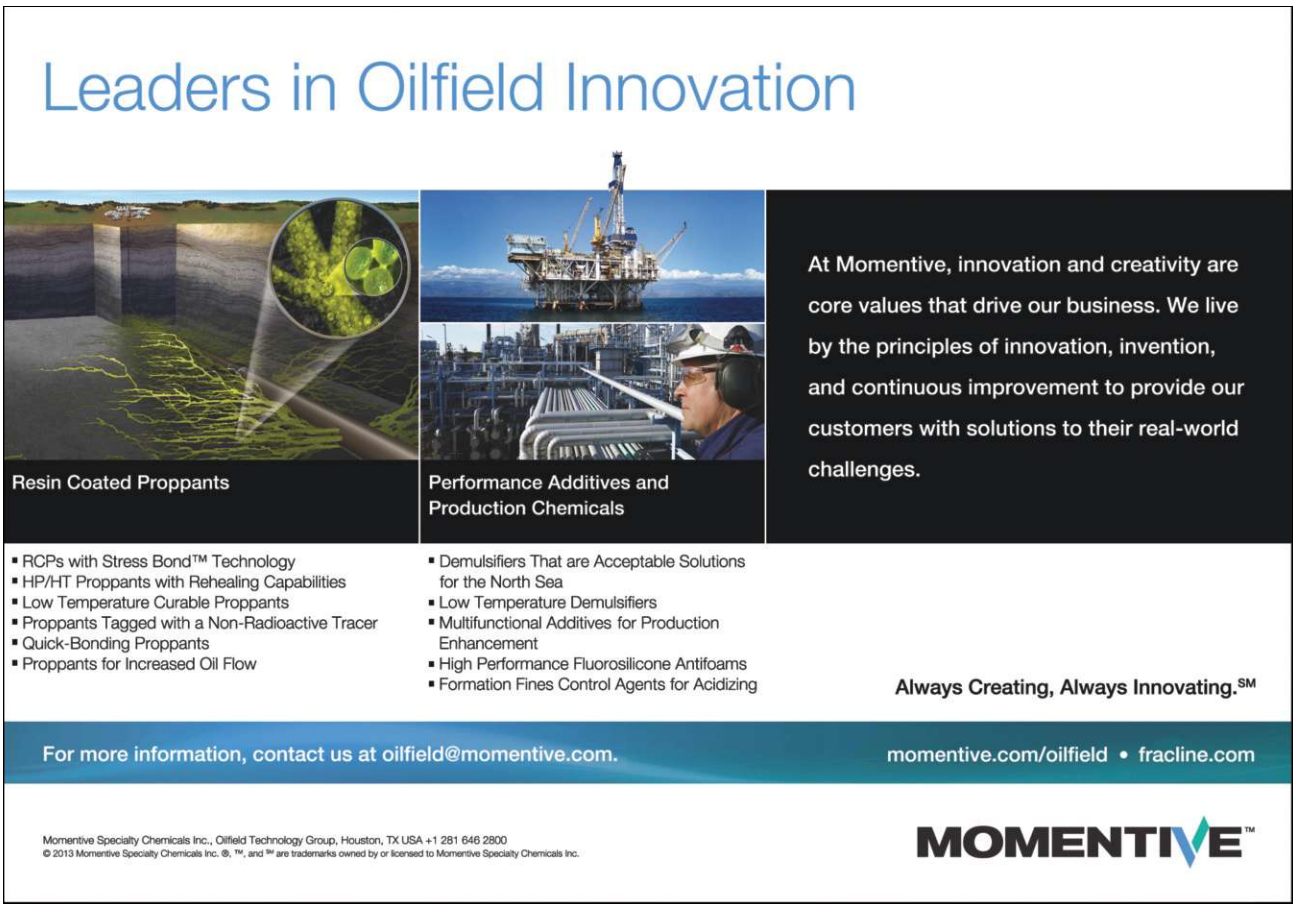
One of the main challenges of the intermediate section of the Eagle Ford shale play using 8½-in. to 8¾-in. drillbits has traditionally been getting through the hard and abrasive Upper and Lower Wilcox formations. These formations can be up to 3,800 ft thick in combination. A vast majority of the damage to PDC drillbits occurs when transitioning into and out of these abrasive sands.

According to Clemons, impact damage can occur on a PDC cutter in a highly transitive environment when it may be drilling fast in a relatively soft rock and quickly hit a hard section.

Halliburton's 8½-in. MM66D MegaForce PDC drillbit with SelectCutter technology drilled 8,070 ft to 10,612 ft measured depth in 34.5 hours at an average ROP of 233.0 ft/hr.

The MM66D provided outstanding overall performance and had the fastest ROP compared to competitor offset runs. The drillbit was pulled and had an excellent dull condition of 1-2-WT-N-X-I-NO-BHA.

Elsewhere, the drillbit drilled 6,360 ft to 8,880 ft measured depth in 23.5 hours at an average ROP of 270.6 ft/hr. The MM66D provided outstanding over-



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all performance and had the fastest ROP compared to offset runs, according to the company. The MM66D was pulled and had an excellent dull condition of 1-1-WT-N-X-I-NO-BHA.

Due to R&D, the number of bits needed to drill through this formation has dropped from typically two or three to one regardless of the location of the well. This reduces not only the cost of drillbits but also trip time on the drilling rig.

Case study: Haynesville

A major challenge drilling in the intermediate section of the Haynesville using 9⅞-in. drillbits has traditionally been getting through the hard and abrasive Hosston-Travis Peak and Cotton Valley formations. These formations can be up to 4,000 ft thick in combination. This rock includes quick changes in compressive strength and lithology, making for drilling with many transitions.

These challenges tend to change moving east to west and north to south through this play, making it imperative that cutting structures are application specific. MegaForce PDC drillbits with SelectCutter technology were used in a vertical application in the lower intermediate Haynesville shale play in the Holly field in DeSoto Parish, La. The 9⅞-in. MM84D drilled 1,790 ft at an ROP of 38.1 ft/hr to successfully access the lower intermediate interval at total depth.

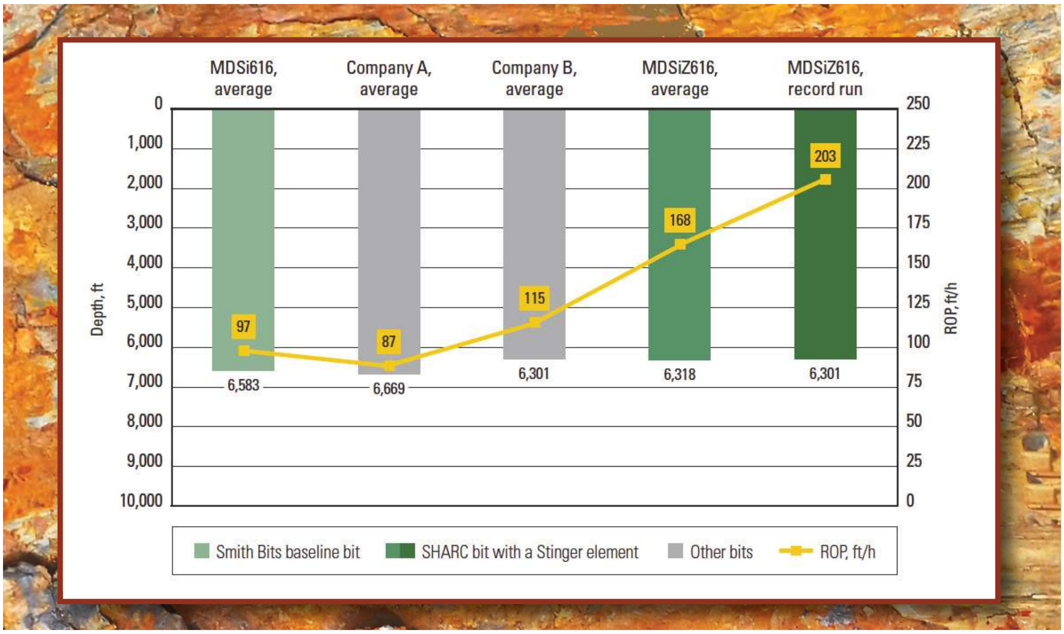
The MM84D drilled the most footage, had the fastest ROP, and provided the lowest cost per foot compared to offset runs. The MM84D had a dull grade of 2-2-WT-A-X-I-BT-TD.

Conical diamond elements, RSS

New technology in drilling is driving reliability and efficiency and is ultimately reducing drilling times in unconventional plays globally, said Dave Sobernheim, unconventional resources principal petroleum engineer for Schlumberger.

The Stinger conical diamond element from Smith Bits, a Schlumberger company, has increased ROP in the Bakken play 46% by improving bit efficiency, according to the company. The tool efficiently breaks the rock in the center of the bit using point-loading, something that has not been achieved before. Additionally, the new ONYX 360 rolling polycrystalline diamond compact (PDC) cutter technology has significantly improved the cutting edge of bit performance in hard and abrasive formations.

Greater performance can be achieved with this bit technology when combined with rotary steerable system (RSS) technology, like the PowerDrive Archer high build rate RSS. Available for hole sizes from 5⅞ in. to 8¾ in., this fully rotating system is the only RSS that builds high



The SHARC PDC bits with a Stinger element drilled North Dakota's Bakken basin with an average ROP of 168 ft/hr and a maximum ROP of 203 ft/hr.

(Image courtesy of Schlumberger)

(Images courtesy of Schlumberger)

The Stinger conical diamond element (foreground) centrally placed in a PDC drillbit cutting structure has increased ROP by more than 46%.

angles from any deviation – in one run without requiring a trip out of the hole – for increased hydrocarbon production potential and reduced risk. "In the Eagle Ford we are seeing a 40% improvement in ROP over motors by using this system," Sobernheim said.

Case study: Bakken

A Bakken operator wanted to increase ROP while reducing the bits needed to drill 8¾-in. vertical sections of at least 6,000 ft in hard and abrasive interbedded formations.

An 8¾-in. MDSiZ616 SHARC high-abrasion-resistance PDC drillbit was run, fitted with 16-mm cutters and a Stinger conical diamond element on a directional bottomhole assembly (BHA).

The low rotational velocity at the center of conventional PDC bits limits the amount of rock they can remove, especially in hard formations.

To increase drilling efficiency and stability, the Stinger conical diamond element was used because it featured twice the diamond thickness of conventional PDC cutters.

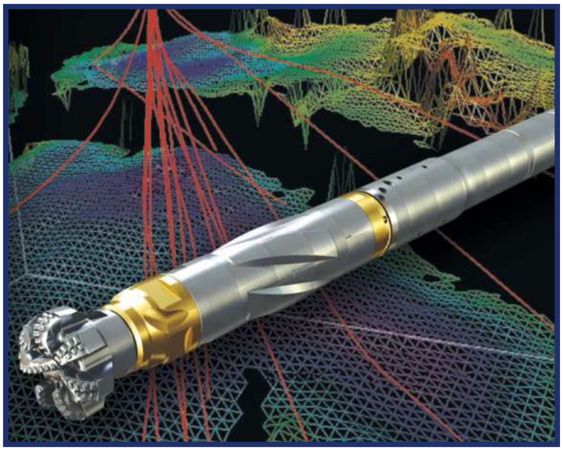
To ensure that placement of the Stinger element at the PDC bit's center would maximize drilling efficiency, engineers used an IDEAS integrated drillbit design to further optimize the cutting structure.

This bit drilled 8¾-in. vertical sections of between 6,209 ft and 6,477 ft with an average ROP of 168 ft/hr. When compared with the next best average ROP reported by other bits in offset wells, the SHARC bits with a Stinger element increased ROP by 46%.

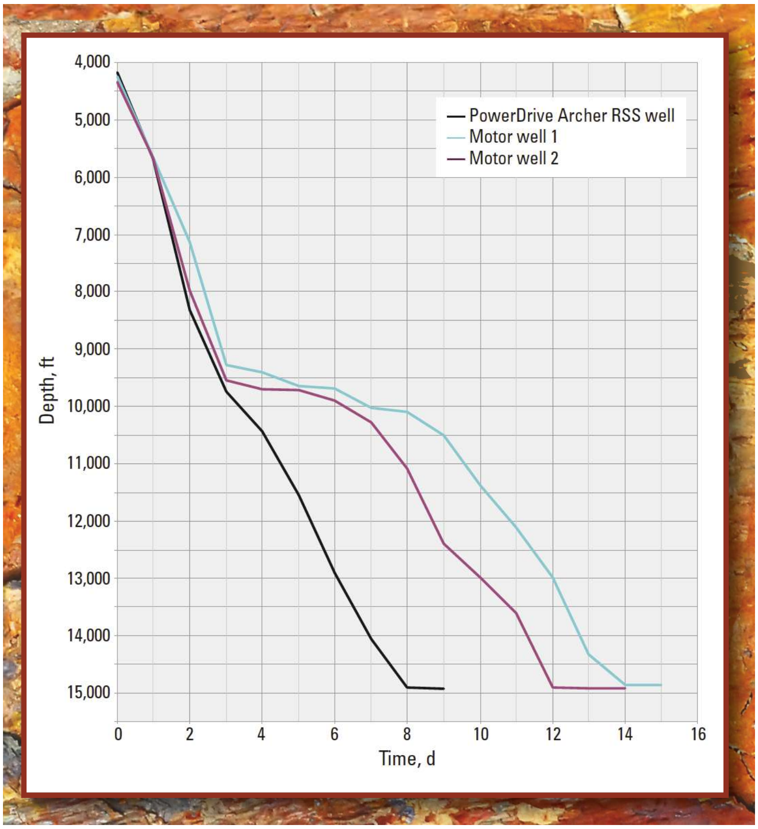
Case study: Eagle Ford

An Eagle Ford operator's stated goal was to drill an 8½-in. horizontal well in one run using an RSS to improve motor performance.

Deploying directional drilling services from PathFinder, the team developed a BHA with the durability and performance specifications to meet

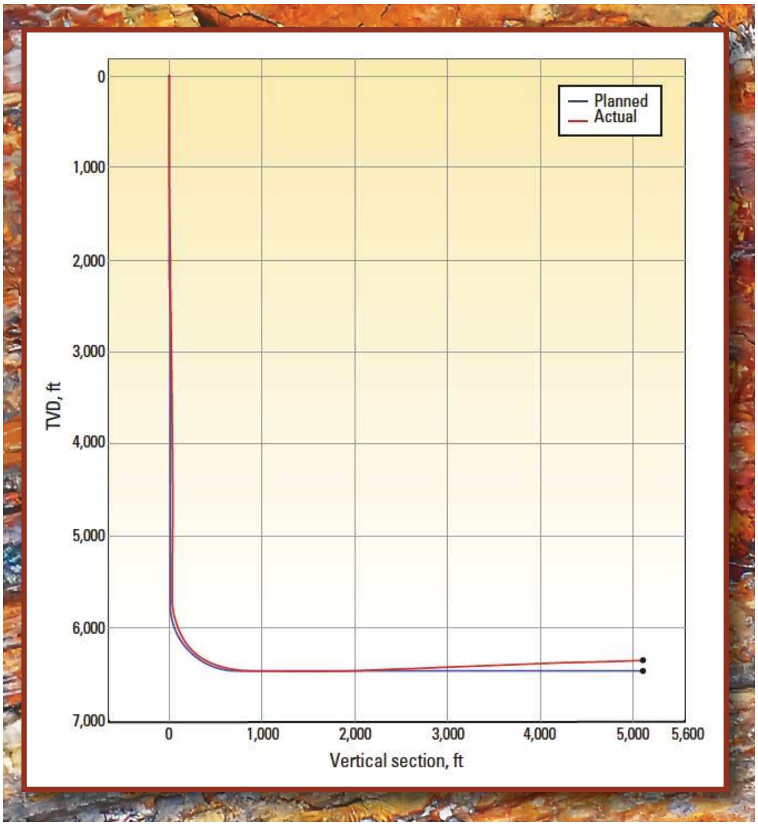


The PowerDrive Archer high build rate RSS can drill well profiles previously only possible with motors.



A time-vs.-depth plot shows the PowerDrive Archer RSS performance improvement that saved four days of drilling time compared with motors.

(Images courtesy of Schlumberger)



In the Marcellus, the curve was landed 1 ft to the right and 1 ft above plan, and the lateral was placed 100% in zone.

the operator's objectives. The 6¾-in. PowerDrive Archer RSS was selected to drill high-dogleg trajectories while maintaining a high ROP. A Spear SDi513 shale-optimized steel-body PDC drillbit from Smith Bits was specially designed for the project.

The PowerDrive Archer BHA drilled the entire 10,754-ft well in one run, with a total of 137.67 drilling hours and an average on-bottom ROP of 78.12 ft/hr. The ROP achieved exceeded expectations for the project, according to the company.

For drilling efficiency and stability across a wide range of PDC bit applications, the Stinger conical diamond element was used – an MDSiZ616 SHARC PDC bit fitted with 16-mm cutters.

A Stinger element run on a directional BHA drilled 8¾-in. vertical sections of between 6,209 ft and 6,477 ft in single trips. Bits attained an average ROP of 168 ft/hr and a maximum ROP of 203 ft/hr.

Case study: Marcellus

An operator in the Marcellus shale wanted to improve ROP and decrease trips in horizontal wells and sought to complete the curve and lateral in one run.

PathFinder, a Schlumberger company, proposed using the PowerDrive Archer high-build RSS with an electromagnetic telemetry system to drill the curve and lateral.

The RSS drilled the curve and lateral with an average ROP of 128 ft/hr, landing in one run approximately 1 ft to the right and 1 ft above the plan. The lateral was placed 100% in zone with the use of real-time gamma-ray measurements. The well exceeded expectations, with no deviation from the plan. The operator now plans to use the PowerDrive Archer RSS and electromagnetic telemetry for other wells in the Marcellus shale.

PDC bit

The Hughes Christenson Talon platform of polycrystalline diamond compact (PDC) bits improves cuttings evacuation for greater bit cleaning, offers application-specific bit profiles for superior directional control, and uses StaySharp premium PDC cutter technology. The polished cutter minimizes friction and reduces heat buildup for improved wear resistance and cutter and bit balling. The shorter shank decreases makeup length for higher levels of directional control and increased bit-side forces.

"These improved efficiency designs mean more energy for rock removal, less vibration, increased durability, and improved large-volume cuttings removal – all factors that boost ROP and run life," Connie Burch, Baker Hughes diamond product manager, said.

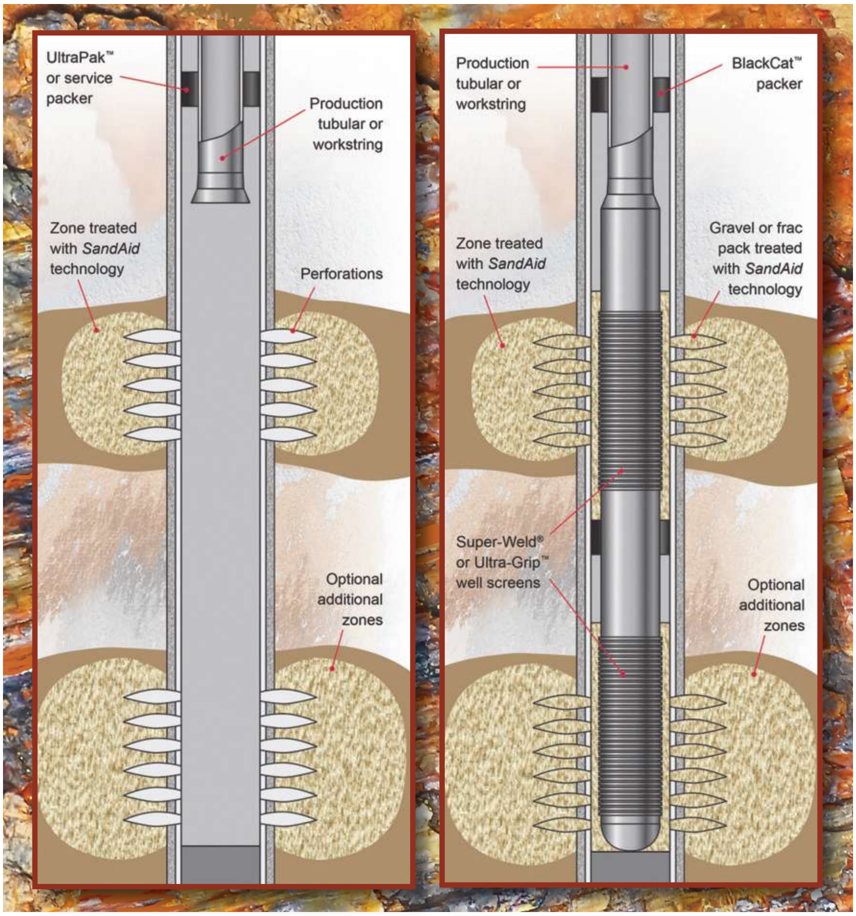
Sand control

Sand production remains a persistent challenge that, if left unchecked, can reduce flow rates and damage equipment. According to Weatherford, its SandAid chemical treatment provides a solution to this costly challenge. This chemistry treatment uses a low-molecular-weight polymer that disperses in the base fluid and rapidly coats any metal oxide substrate such as sandstone. The treatment also contains a penetrating alcohol that disrupts any water layers that may coat solid surfaces in the formation.

By coating the fine formation particles, the polymer acts to modify its zeta potential to create an ionic attraction between them. This attraction, and subsequent agglomeration of fines into larger aggregates, serves to reduce or stop fines migration, increase the maximum sand-free rate, and reduce the water cut in some wells.

Because the SandAid treatment operates on the principle of ionic attraction, unlike bonding agents or glue-type resins, it allows the formation to remain ductile. Sand particles retain relative movement and can adapt to stress changes near the wellbore that arise due to drawdown forces, reservoir depletion, or other downhole conditions, according to Kern Smith, Weatherford global product line manager. If the stress changes are so great as to dislodge the SandAid-treated particles, these typically retain ionic attraction and are able to reagglomerate. In a similar instance, a resin-based system may crack and lose its bonding; in some cases, it may reduce permeability near the wellbore and contribute to further fines creation.

The treatment can be mixed with a variety of fluids and has been applied in the field with potassium chloride-based brines, formation water, and seawater. It also can be mixed with power-law fluids, which may enable relatively simple diversion



SandAid technology can be pumped through current tubular, flow line, or coiled tubing in existing or new wells.

(Image courtesy of Weatherford)

techniques and effective treatment of very long intervals. The treatment exhibits very low risk to the reservoir; in both lab tests and field trials, no significant reduction in permeability has been observed.

Logging

Baker Hughes' StarTrak LWD service provides high-definition electrical images of the near wellbore environment with no interruption to the drilling process. In real time, images are sent up mud-pulse telemetry at resolutions of 16, 32, or 64 azimuthal sectors, depending on the decoding rate and available telemetry bandwidth. From the memory data, a very high-resolution log with 120 azimuthal sectors is generated.

StarTrak electrical images also provide important reservoir navigation input, especially in areas where there is little contrast in gamma-ray readings, such as carbonate formations. This benefit has allowed operators to not only stay in the zone of interest but also to stay in the best part of that zone. Faults, bedding planes, and many other geological features of the formation are clearly identified.

(Image courtesy of Baker Hughes)

The StarTrak LWD service allows operators in unconventional plays to optimize completion and hydraulic stimulation programs with high-definition images that show details of the formation such as fracture type and density.

Also benefiting the driller, the StarTrak high-definition imaging service can detect drilling-induced fractures, breakouts, and other drilling hazards via real-time images, allowing the driller to take mitigating actions before serious problems occur.

Post well, the high-resolution images have become an integral part of the completion optimization process and offer invaluable insight into intervals to be perforated as well as packer and frac-stage placement.

Reservoir characteristics

New characterization technology is leading to an improved understanding of unconventional plays, particularly in regard to vertical pilot wells that are used to optimize a package of horizontals in an area. With Schlumberger's XL-Rock large-volume rotary sidewall coring service, sidewall core samples measuring 1.5 in. in outer diameter and 2.5 in. long are obtained for up to 50 plugs in a single run. These can be used for both routine core analysis and specialized analysis.

"We are combining the XL-Rock service with the Litho Scanner high-definition spectroscopy to obtain accurate [total organic carbon] values and accurate mineralogy in the plays," Sobernheim said.

Case study: Marcellus

An operator drilling a well in north-central Pennsylvania wanted formation samples from a black shale targeted for unconventional gas. In this environment core samples would be valuable for determining composition, texture, and physical properties of the rock. Conducting rotary sidewall coring would be more efficient than coring the full openhole interval, but uncertainty would be introduced for some analytical techniques such as tight rock analysis that would require combining sidewall core samples to have a sufficient volume of core material.

Schlumberger's XL-Rock large-volume rotary sidewall coring services were developed to close the gap between core plugs from continuous conventional coring and wireline-conveyed rotary sidewall cores. Retrieving up to 50 sidewall core samples – measuring 1½ in. in outer diameter by 2.5-in. long – from a single descent, XL-Rock service can deliver cores that are more than 300% of the volume of previous-generation sidewall cores. XL-Rock core samples deliver a rock volume equivalent to that of conventional core plugs, matching the industry's standard sample size for analysis and enabling key answers in less time and at a lower cost than conventional coring.

Of the 100 core points planned for the full openhole interval, 96 of the samples were brought to surface, achieving 96% core recovery. The large-volume samples improved measurement precision by enabling analytical techniques such as tight rock analysis to be conducted on a single sample instead of having to combine multiple small samples.

Predictive software

An independent operator holding leases in the Eagle Ford shale play found it would soon need to make an economic decision about its assets and needed information about key production drivers, oil in place, the effective drainage area of a typical horizontal well with multistage fracture completions, and oil recovery expectations over a 10-year period.

Using ECLIPSE software, the Schlumberger team built a typical vertical well simulation model and performed history matching with production data from eight wells to derive formation permeability and estimate the drainage area. Petrotechnical experts modified the completion to represent a single-stage hydraulic fracture treatment and ran the model to predict oil and gas production for a 10-year period. Next, the experts constructed a typical 5,000-ft horizontal well simulation model, assuming a 14-stage hydraulic fracture treatment, and ran the model to forecast potential recovery. A sensitivity analysis was performed.

The results of petrophysical analysis and reservoir modeling indicated the acreage under consideration contained significant volumes of oil in place. The report provided a reliable estimate of oil per acre. Petrotechnical specialists found that the two highest ranking production drivers in the study area were natural fractures and hydrocarbon pore volume. They were able to forecast low, median, and high oil and gas cumulative production estimates for up to 30 years.

Real-time visualization service

To optimize their costs, shale operators need to make the most accurate and informed decisions about where to place their frac stages for optimal production, said Rob Fulks, Weatherford's director of strategic marketing for pressure pumping. Weatherford developed its new real-time visualization service, ResSure Live, specifically with this goal in mind. The service provides a dynamic 3-D view of the well and reservoir.

The system integrates datasets from multiple reservoir monitoring techniques, including LWD measurements like gamma-ray resistivity, sonic and neutron density, microresistivity imaging, real-time cuttings and gas analysis, and microseismic data. It uses these data to provide a real-time picture of the fracturing event as it is occurring downhole.

"Working across multiple datasets in this way provides a dynamic view of the field, which also allows one to optimize drilling trajectories to stay in the target zone, adjust stimulation plans, and improve overall field development workflows," Fulks said. By having real-time access to parameters such as lithology, total organic content, and brittleness in different parts of the formation, one can develop a smarter completion. Instead of geometrically placing stages of equal distance, the operator can now place stages and perforations in locations that promise the greatest production potential.

Once the well is producing, the ResSure Live service provides extended benefits. For example, the service can continuously monitor reservoir temperatures and pressures from unique permanent monitoring systems. The service correlates this pressure and temperature data with logs and reservoir structure, resulting in more focused drilling and geology-based simulations for future well construction activities in the area. It also provides valuable intelligence on producing zones and decline trends, allowing the operator to manage a field's productivity decline and lower its field development and operating costs.

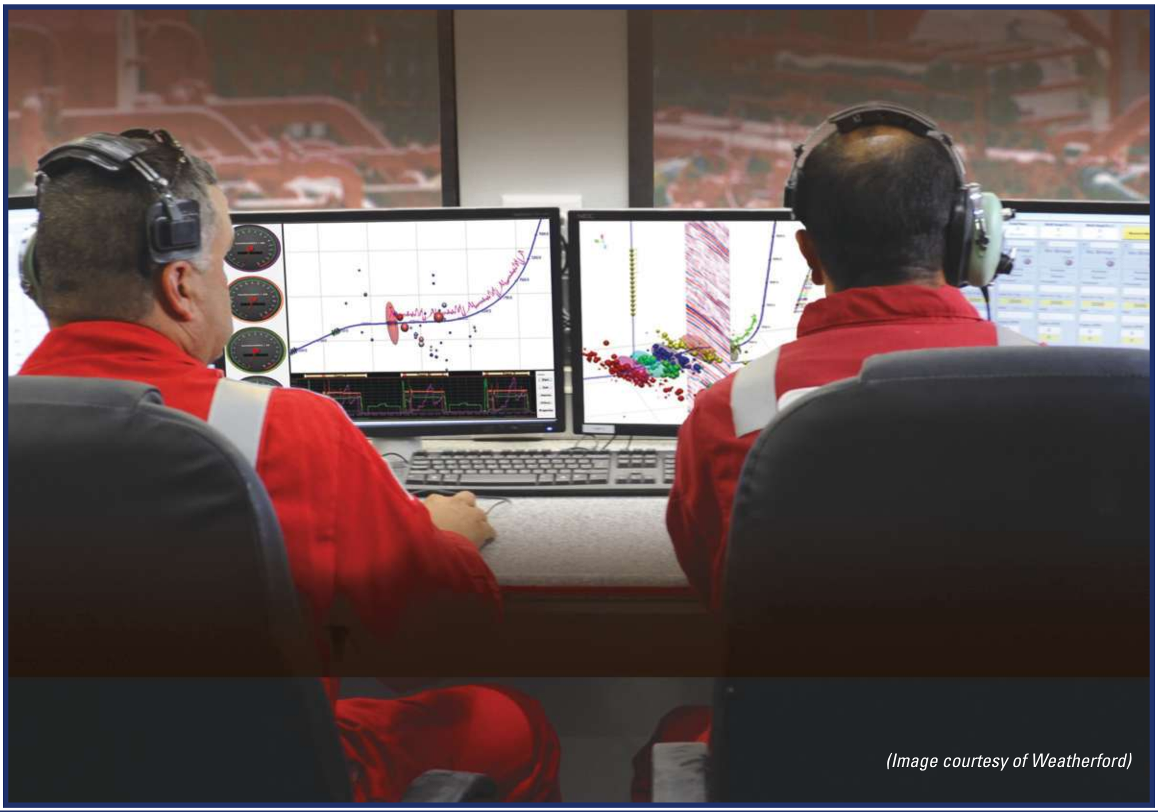
ResSure Live has been field-tested in North American shale plays over the past 12 months and has consistently demonstrated improvements to operators' frac designs and overall field development, the company said.

Wireline microresistivity imaging

Borehole microresistivity images provide essential high-resolution information for applications including facies analysis, stratigraphic studies, and mapping of structural features. They also correlate with variations in mineralogy, porosity, and fluid content, making them useful in petrophysical analysis. Acquiring these images with wireline tools is achieved with electrode arrays that are embedded in pads mounted on calliper arms, which are subsequently pressed against the borehole wall. This arrangement commonly limits the circumferential coverage of the measurement to less than 70% of the entire borehole, making accurate measurement of important formation features challenging, according to Peter Williams, Weatherford's senior technology champion of wireline services.

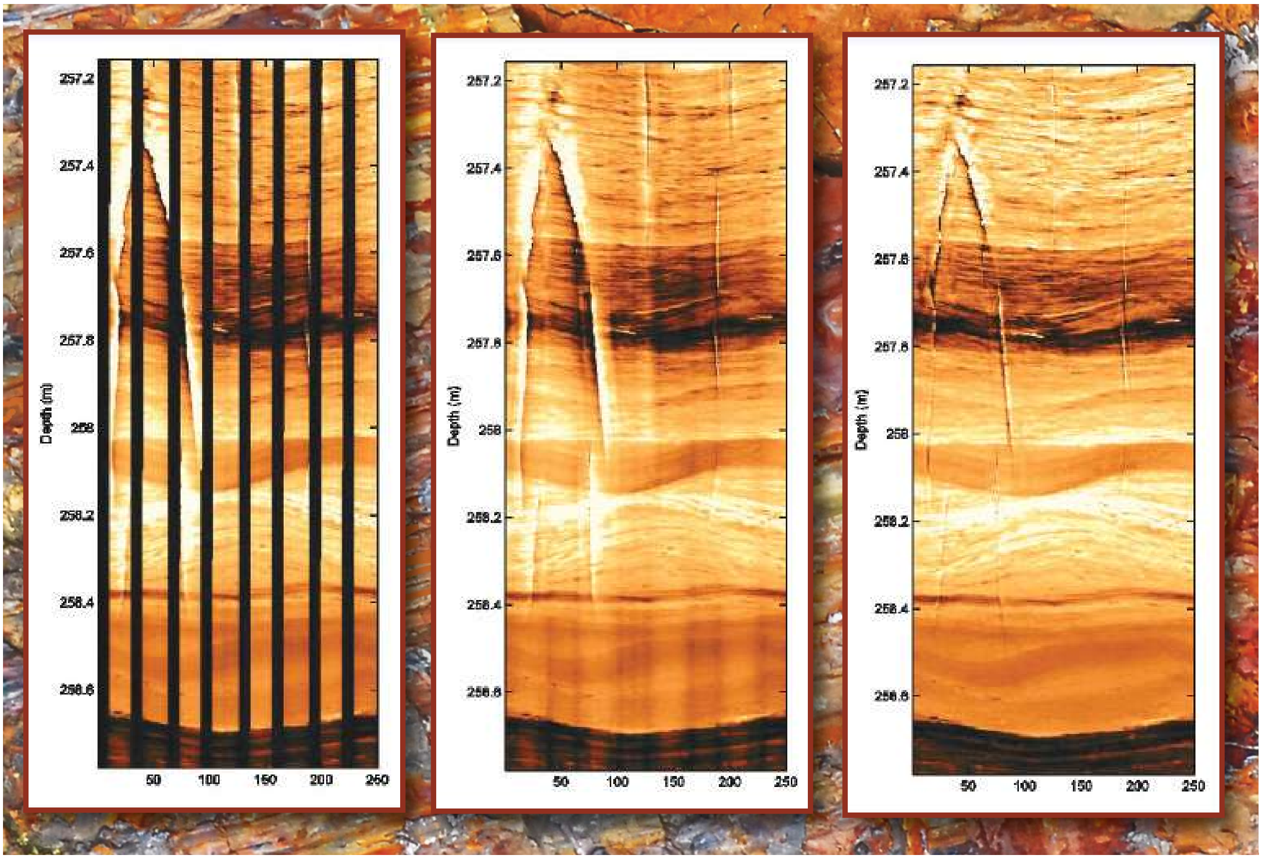
Weatherford has developed a new technique for reconstructing the data that are missing from the gaps – those sections of the borehole that were not measured by the imager's pads. The technique uses a process known as inpainting, in which gaps or null values between the pads of the wireline tool are replaced with values consistent with the structures and textures in the measured parts of the image. The process begins by decomposing the sections of the borehole that were measured into sparse representations of the morphological components using dictionaries of multiscale, multiorientation transforms – a technique known as morphological component analysis. The representations are then reconstructed using information from the dictionaries to fill in missing information.

Inpainting has been shown to provide unbiased and reproducible estimates of the nonmeasured parts of images and as such is an enabler for automated pattern recognition algorithms that would otherwise be challenged by gaps in the data. In clastic rock formations that exhibit a wide variety of sedimentary and structural features, inpainted images are qualitatively and quantitatively almost



(Image courtesy of Weatherford)

Weatherford's ResSure Live service uses data-interpretation software to analyze formation evaluation data, and surface logging and microseismic data to help identify ideal completion intervals for enhanced stimulation.



(Image courtesy of Weatherford)

An original calibrated CMI image (left) is shown next to an inpainted calibrated image without environmental correction (middle) and a calibrated, environmentally corrected and inpainted image (right).

identical to full-coverage images for coverage loss up to about 30%. The method has been used to reconstruct a broad range of attributes including common continuous curvilinear features such as partial and full sinusoids as well as textural elements.

The method has been tested on full-coverage data from small-diameter wells artificially obscured to simulate partial coverage. For images dominated by curvilinear features, reconstruction accuracy is 92% for 50% coverage loss (typical in 12¼-in. diameter wells). At a 30% loss (typical in 8½-in. wells), images are almost indistinguishable from the original unobscured images for all apparent dip angles below the near vertical point, regardless of the degree of feature parallelism. Successful reconstruction of near vertical features – including those with complex boundaries such as breakouts – is more dependent on coverage loss, but in these cases the results are consistent with judgments made by human interpreters.

Wellbore tools/intervention

In the Williston basin, an operator drilling an unconventional oil well ran a 4½-in. liner with a liner hanger and packer into the horizontal wellbore. A retrievable bridge plug was then set in the liner to allow the drilling rig to make room for the fracturing crew. But the well began building pressure at the surface, indicating communication problems downhole that had been caused by a hole in the casing 150 ft below.

The Baker Hughes fishing services team retrieved the problem liner, liner hanger, and packer and ran a casing patch with a Baker Hughes HMC liner hanger and ZXP liner top packer to repair the 4½-in. liner.

With the repaired liner, the operator continued with hydraulic fracturing operations with pressures of 7,000 psi to 9,000 psi, showing no integrity loss or drift limitations to the casing patch. ■

(Image courtesy of Blue Racer Midstream LLC)

Midstream Operators Draw Closer to Producers as Both Seek to Optimize Shale Output

Gregory Morris, Contributing Editor

From boom to bonanza, the sheer size and scale of the unconventional revolution have dawned on both producers and processors. Many speak in terms of collaborating closely to develop basins most efficiently.

During the early 1980s when George Mitchell was only just realizing that the Barnett shale could be a very big deal, bleached bad-boy rocker Billy Idol promoted MTV by sneering "too much is never enough!" Three decades and tens of thousands of unconventional wells later, the US has become the largest hydrocarbon producer in the world. The response from the global market has been that too much is never enough.

The only question relating to North American energy self-sufficiency is when, not if. Those implications for global markets in crude, refined products, natural gas, and NGL are profound. Within that when-not-if question is a challenge to North America midstream operators.

The secret is out that the market wants molecules but not just any molecules. The market wants very specific ones, and that has created serious new dislocations in price and availability. Too much also can be a problem. The situation is most obvious in the liquids market of the Northeast, but also is evident in the Permian, Midcontinent, and Eagle Ford, among the largest shale plays.

Getting the Marcellus (and the Utica) to market

For most of September 2013 and October 2013, Brad Olsen, director of midstream research at Tudor, Pickering, Holt, & Co. (TPH), was on the road around the country presenting the consulting firm's extensive new 120-page analysis of the Marcellus and Utica shales, with a particular emphasis on how the burgeoning production from those plays will get from the wellhead to paying customers.

"The big picture is that, already, Marcellus delivery can supply the Northeastern regional market 40% of the time," Olsen said. There always will be major seasonal swings, because there is such a strong demand for heating in the winter, both for methane and for propane, that a bifurcated seasonal market is a structural reality.

"By the end of next year the Marcellus will be able to meet regional needs half of the year, and by the end of the decade that will reach 90% of the time," Olsen said. He suggested that, given the seasonal heating spike, it would not actually be economical to try to dedicate production and build delivery infrastructure to supply regional needs for 100% of the year, which would be overbuilding and a waste of resources.

"There will always be some need for warm-weather storage, but that is manageable," Olsen said. Again turning to the big picture, he reiterated the remarkable accomplishment that the huge cold-weather metropolitan megaplex of New York stretching as far north as Boston and as far south as Philadelphia will be supplied with gas and liquids sufficient for all but a few weeks of its annual needs.

"After that we are looking at what to do with the surplus," Olsen said. "The first, lowest cost option is to move Marcellus and Utica production to the Midwest." The knock-on effect of that, he anticipates, will be to "upset the apple cart and back out

Facing page: The Blue Racer Natrium Gas Process Plant is in Marshall County, W. Va. on the Ohio River.

Rockies and Canada production that is currently supplying the Midwest."

Even the anticipation of Marcellus and Utica supply already has started to show. "Look at Chicago prices; there is no premium anymore. Can that market absorb another 2 Bcf/d of gas? Rockies and Canada will have to be backed out," Olsen said. The next alternative for Marcellus and Utica production and also for displaced Rockies and Canada gas is the Gulf Coast. "Luckily, that is the fastest growing demand center for both power generation and for industrial demand."

Olsen noted the number of incremental takeaway projects from the Marcellus and Utica, in addition to the growing number of projects designed to move gas out of the Northeast. In examining projects for moving gas to the greater New York-New Jersey-Pennsylvania area – even though those projects do not necessarily access new gas demand as well as pipes to destinations outside of the Northeast – Olsen concluded, "We will be short pipelines during low-demand periods. As a result, downside risk remains for differentials 2014 to 2016. Announced capacity will not be sufficient to fully evacuate the Northeast in the mildest 20% of the year."

However, he continued, there is a significant amount of underutilized pipe that could be converted to alleviate the Northeast, with TETCO and Transco having the most capacity available. That analysis is based on historical gas demand, with the impact of nuclear plant retirements, conversions from heating oil, and organic demand growth all reducing needed takeaway pipeline capacity.

At the far end of the takeaway pipes, and also at the far end of the cost curve, Olsen said that the displacement domino chain is likely to end in the dry gas fields. "The clingers who are still running rigs in the Fayetteville and the Haynesville are going to find things very difficult. We also will see declines in dry gas drilling in the Rockies continue to decline," he said. In effect, the high-cost dry gas plays will become a *de facto* strategic gas reserve, available but not economical to produce unless demand soars in both domestic and export markets, tightening prices.


(Image courtesy of MarkWest Energy Partners LP)

The Majorsville system allows the gathering and delivery of Marcellus gas from Pennsylvania and West Virginia to the MarkWest Liberty Majorsville processing plant.

A new phase of getting oil and gas production from the Marcellus shale to market, and eventually from the Utica as well, opened in late summer 2013 when pipeline and terminal giant Kinder Morgan and regional processing major MarkWest announced plans to form a midstream joint venture (JV) to pursue three new projects. The first would be a 400-MMcf/d cryogenic processing complex in Tuscarawas County, Ohio, to be built on an existing, 220-acre site that Kinder Morgan has under option. The second project would be a 200,000-b/d ethane and NGL pipeline from that processing complex to the Gulf Coast. The third is the development of new fractionation facilities, including the use of third-party operations.

The pipeline project will be in contention with one by Williams and Boardwalk Pipeline Partners, which is good for the industry, said Randy Nickerson, executive vice president and chief commercial officer. "There are two projects in competition, and that is fine. I think only one will get built, but the most important thing is that there will be multiple options for moving liquids out of the basin."

Nickerson estimates that the propane fraction in the Marcellus could reach 200,000 b/d. He added that the challenge will not be for the midstream industry to build processing capacity for that but for producers and processors to work together to build markets, especially in light of further capacity coming out of the Utica.

The MarkWest-Kinder Morgan JV expects the initial 200-MMcf/d cryogenic processing plant to be in service by 4Q 2014 with a twin in service shortly thereafter, depending on customer commitments. The existing 220-acre site is expandable and could accommodate more than 1 Bcf/d of processing capacity.

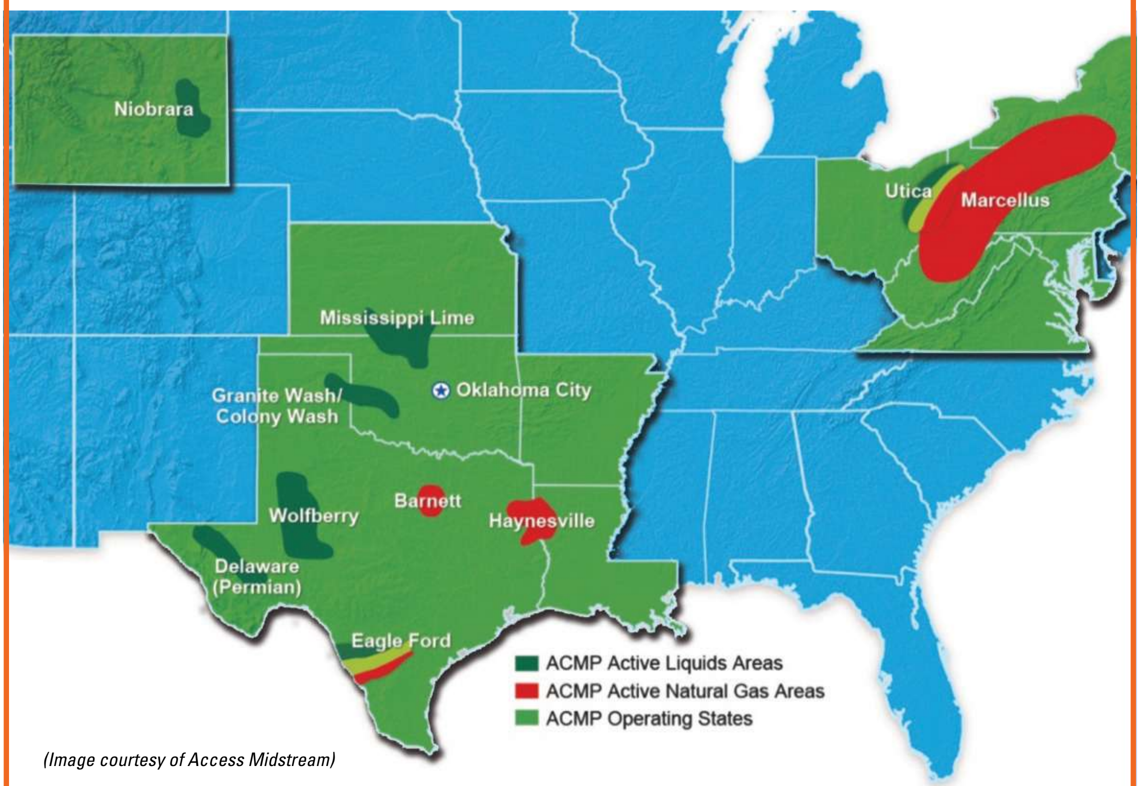
MarkWest would deliver rich-gas volumes to the JV processing complex through an extension of its existing rich-gas gathering system in Harrison, Belmont, Guernsey, Noble, and Monroe counties in Ohio. The processing complex would provide additional residue outlets into the Tennessee Gas Pipeline (TGP) and Dominion Transmission pipeline systems and would serve new customers in Carroll, Columbiana, Mahoning, and Trumbull counties in northern Ohio.

To deliver the northern Utica gas to the processing complex, Kinder Morgan has obtained regulatory approval to convert a portion of an existing 26-in. TGP line for rich-gas gathering, which could begin receiving rich gas by 4Q 2014.

Subject to shipper commitments, permitting, and all related regulatory approvals, a 4Q 2015 in-service date for the NGL pipeline is anticipated. Kinder Morgan would own at least 75% and would operate the pipeline. The NGL pipeline would be expandable to 400,000 b/d with the addition of pump stations.

But there is more to the Marcellus than liquids. "The realization is finally dawning on the industry that the Marcellus dry gas resource is one of the biggest success stories of the overall unconventional shale boom," said J. Mike Stice, CEO of Access Midstream Partners, based in Oklahoma City. While other liquids-rich plays have received more of the attention, Stice noted the scale of the Marcellus. "This small company is gathering more than 2 Bcf/d of dry natural gas from just two Pennsylvania counties. This two-county subset produces more than 3% of the entire domestic supply, which is amazing."

Access Midstream Assets



(Image courtesy of Access Midstream)

Stice is proud of the producers and midstream operators that have brought this vast resource to market. "We have the supply to meet the demand and then some. We have actually satisfied the previously insatiable northeast regional demand and now are working to increase demand through increased gas-fired power generation," Stice said.

"It is just remarkable that the Marcellus and the Utica have overwhelmed the largest demand center in North America," notwithstanding the seasonal spikes in mid-winter.

"The next mission for gas from these basins is the southeast," Stice said. "We have already seen Midcontinent gas backed out, and next, Gulf Coast production into the Southeast could be backed out. Rockies gas has already been backed out, and the Florida east coast could be next."

Access Midstream owns and operates midstream assets across 12 states, with an average throughput of approximately 3.5 Bcf/d and more than 6,000 miles of natural gas gathering pipelines. The firm handles gathering, processing, treating, and compression to producers under long-term, fixed-fee contracts. The firm has its own unregulated gathering infrastructure in the Barnett, Eagle Ford, Haynesville, Marcellus, Niobrara, and Utica shales and various Midcontinent plays, with reliable access to numerous major delivery points.

Late in summer 2013, M3 Midstream completed the first phase of the Utica East Ohio Midstream (UEO) project receiving rich Utica shale production, processing NGL, and redelivering residue gas to interstate markets. That milestone made UEO – a JV owned 49% by Access Midstream, 30% by M3, and 21% by EV Energy Partners – the first fully integrated gathering, processing, and fractionation complex to be put into operation in eastern Ohio. M3 serves as the facility manager of the plant facilities and is responsible for their construction and operation. Access Midstream is responsible for the construction and operation of all pipeline facilities upstream of the UEO plants.

At project startup, the UEO system included approximately 63 miles of gas and NGL gathering; 11a 200-MMcf/d cryogenic processing facility located near Kensington in Columbiana County; and a 45,000-b/d liquids fractionation, storage, and rail facility near Scio in Harrison County. With the completion of the second and third phases of the project, the UEO system will consist of 800 MMcf/d of


(Image courtesy of Dominion Transmission Inc.)

Although Dominion Transmission Inc.'s Hastings, W.Va., plant has been through several renovations, it still operates today as a modern processing and fractionation facility.

Photo: the Natrium processing plant along the Ohio River in Marshall County, West Virginia. Natrium I has cryogenic processing capacity of 200 MMcf/d and fractionation capacity of 36,000 bbl/d. Near term expansion plans call for a total of 400 MMcf/d in processing capacity and 59,000 bbl/d in fractionation capacity with additional 200 MMcf/d processing plants to be built in Monroe County, Ohio and Mahoning County, Ohio.

cryogenic processing; 135,000 b/d of fractionation; 870,000 bbl of liquids storage; and a rail facility capable of loading 90 cars per day with full scalability to increase processing, fractionation, and rail-loading capacity to almost double the initial amount.

There has been a good deal of private-equity money poured into midstream in all the booming unconventional basins. In one major initiative to get the Utica play to market, though, bank lending has played a leading role. In August 2013 Blue Racer Midstream, the JV of Caiman Energy that is based in Dallas, and pipeline major Dominion Resources secured a five-year, US $800 million credit facility, which can be expanded to $1 billion. Blue Racer was only formed at year-end 2012, so a $1 billion backing shows banks are not shy about midstream. To be fair, private equity backs Caiman; Dominion is public.

Wells Fargo Securities and RBS Securities acted as joint bookrunners and joint lead arrangers on the credit facility. A syndicate of 19 banks participated in the credit facility, with Comerica Bank, RBC Capital Markets, SunTrust Robinson Humphrey, and US Bank also acting as joint lead arrangers.

Blue Racer secured the financing just a week after Dominion transferred ownership of its Natrium processing and fractionation plant to Blue Racer. Under the terms of the JV, Dominion still operates the 3-million-sq-ft Natrium facility. It is on the Ohio River, about 6 miles from New Martinsville, W.Va. With a cryogenic capacity of 200 MMcf/d already online, Natrium is the first large-scale processing plant to serve rich-gas production in the Utica shale. Blue Racer already has started construction of a second 200-MMcf/d cryogenic plant, Natrium II, which will bring the facility's total processing capacity to 400 MMcf/d early in 2014. Late in September 2013 the Natrium plant suffered a fire. There were no injuries, but the date of the plant reopening is not yet set. Other construction at the site continued on schedule.

Dominion also contributed existing midstream assets to Blue Racer, including 500 miles of

Dominion East Ohio gathering lines that span the Utica shale and the Natrium Natural Gas Processing and Fractionation Plant in Marshall County, W.Va. Additional contributions of physical assets were expected in 2013 and 2014. Caiman's contribution includes up to $800 million in equity capital commitments and the experience and expertise required to manage and expand Blue Racer's asset base.

"The key to Utica development has been the continued delineation and refinement of the heart of the play by the major developers: Chesapeake, Gulfport, Antero, Hess, CNX, PDC, and the others," said Jack Lafield, chairman and CEO of Caiman and CEO of Blue Racer. "We are seeing a wider diversity of dry gas, wet gas, and liquids than we saw in the Marcellus. That is causing both producers and processors to step back and reassess the timing and needs for midstream facilities and capacity."

Noting the challenge of hitting a moving target, Lafield said, "Midstream operators are moving as quickly as we can to try to keep up." In some cases the complication has been in transport rather than production, with some pipelines a bit behind schedule in connections and full power, especially in liquids takeaway.

In the meantime, Lafield said that midstream operators are helping each other handle volumes until the asset base is fully in place. "For us that would be 1 Bcf/d, 400 million at Natrium and 600 million at Berne. In five or six years, we are looking at 2 Bcf/d of capability and 6 Bcf/d for all operators, potentially going to 10 Bcf/d in the long run for rich gas being produced."

Lafield said it can be difficult to think in such terms, and that "we can take midstream in steps." The bigger question concerns downstream operations including access to market and continued growth in demand. "My prediction is that we are going to see bottlenecks, especially for liquids. The Mariner East project by Sunoco is a good move, as are some of the other smaller projects. Rail transport is another part of the solution, but how much can the trains carry? In the end, someone big is going to have to build a big pipe. The only questions are who and how soon can they start, given a finishing point three years from any start," Lafield said.

"The pipelines are not hesitating; they just need some time to confirm all the details," Lafield added. "That is the nature of major decisions like a big transmission pipe. At our end with our extensive gathering system throughout the Utica, we are letting some producers test a few wells without having to make a commitment. That has been very helpful to everyone and very successful."

One interim solution is the reversal of some existing lines, or modification to carry liquids."We all need some interim solutions because the Marcellus and the Utica together constitute the largest gas field in the world. There has been and will be a lot of investment, and we all have a lot of work to do to take the gas and liquids to market," he said.

Taking a step back, Lafield tried to keep the last few years in perspective. "The Marcellus is already producing more than 10 Bcf/d. That is astounding and all still very new. The Marcellus only really got started in 2008 to 2009, and we are only at the end of 2013. The things we are doing today and the new midstream assets we are putting in place can be made to be very flexible, but the long-line assets already on the ground were not built to be flexible. They were built for fixed volumes from one point to another. FERC [Federal Energy Regulatory Commission] is proving to be much more supportive in permitting new and redefined facilities so we can be more flexible in processing and delivery. We all have to be ready for the wave of new production and hopefully new markets anywhere."

New ideas in the Permian

For all of the massive volumes of oil and gas coming out of monster shale plays like the Bakken and the Marcellus/Utica, the leader among producing basins is still the Permian. It is the place where the huge potential of the other newer plays is layered on top of a century of experience and infrastructure. While other shales have challenged midstream providers to hurry with big capital commitments to get molecules to market, the Permian has highlighted midstream's sophistication in adding capacity and its own sophistication to extant operations.

One prime example came in October 2013 when Nuevo Midstream, based in Houston, completed a major expansion of its amine treating capacity and began the third phase expansion of its gas processing

Nuevo Midstream's Ramsey natural gas midstream system, including this processing facility and its gathering system, covers a significant portion of the Permian basin region.

(Image courtesy of Nuevo Midstream LLC)

system in the Delaware basin near Orla, Texas. Nuevo is a full-service midstream company serving oil and gas producers in the Delaware basin. Operations are focused on production from the Bone Springs and Wolfcamp formations and the Avalon shale trend in southeast New Mexico and West Texas.

Nuevo was formed in April 2011. "Just two and a half years ago, we were recommissioning an idle 10 MMcf/d processing plant for our first Avalon shale and Bone Springs customer and installing a small rented treating plant with plans to truck and rail NGL," Jay Lendrum, Nuevo Midstream's president and CEO, said. "Now we have 310 MMcf/d of processing capacity installed and under construction, 1,800 gal/min of treating capacity operational or under construction, an expansive gathering system that spans roughly 6,475 sq km [2,500 sq miles], and an NGL line connection to Mont Belvieu. Planning is under way to bring total cryogenic processing capacity to more than 900 MMcf/d and treating capacity to 3,800 gal/min."

Nuevo's new amine treating plant at its 110 MMcf/d Ramsey processing site in Reeves County, Texas, is rated at 1,300 gal/min, bringing Nuevo's total treating capacity to 1,800 gal/min. Nuevo also has completed its interconnect to DCP Midstream's Sand Hills NGL pipeline to the industry hub Mont Belvieu, Texas.

Based on demand for additional processing capacity to serve the significant growth in Avalon, Bone Springs, and Wolfcamp production, Nuevo has begun construction of an additional 200-MMcf/d cryogenic processing plant known as Ramsey III. Nuevo expects to bring that online in April 2014, for a total cryogenic processing capacity of 310 MMcf/d.

"In the Delaware basin we are really seeing greenfield development in a brownfield area," said Lendrum. "We have all new capacity and all new assets because producers are finding that each horizon is very different. The Avalon is gassy with CO_2. Other formations make more water. Then we still have the whole Pennsylvanian series and the deep Barnett below that."

Drilling projections from existing and potential customers, the strong performance of wells in the Delaware basin, and additional producer dedications have prompted Nuevo to plan further expansions that are expected to bring cryogenic processing capacity to as much as 910 MMcf/d and treating capacity to up to 3,800 gal/min. Permitting is under way for those contemplated expansions with appropriate producer support. Nuevo expects to bring the first of these expansions online by the middle of 2015, at which point the company will have 510 MMcf/d of processing capacity at Ramsey.

Nuevo also has closed on a revolving credit facility and an equipment lease facility. These facilities, combined with equity commitments from private-equity firm EnCap Flatrock Midstream and others, provide Nuevo with approximately $450 million of total capital to finance the build-out and expansion of its midstream infrastructure network in the Delaware basin.

Lendrum said that three essential components have come together to facilitate rapid and effective development of the Permian in the new unconventional era. The first is the resource. The second is ample capital, provided extensively but not exclusively by private-equity firms and management. The third is a new camaraderie between producers and processors.

"Our producers are the top of the class," Lendrum said. "When they trust us enough to give us their drilling plans, not just for the next few months but for the next few years – sometimes out to four or five years – we can really make reliable plans of our own to get that production to market. There are our plants and at least a few others and rumblings of more. There is a lot of interest in the Delaware basin. But you are talking about lead times of several years for some of this new capacity. That is why it is so important for producers to work closely with midstream operators."

Lendrum is not coy about Nuevo's "first-mover advantage," but he also is realistic about the size of his firm and the amount it can accomplish even with solid backing and a lead time. "The big movers will roll in, but there are tens of thousands of wells to be drilled in the Delaware basin. The work will extend beyond a lifetime, but I know that it will all be developed eventually."

In the shorter term, however, Lendrum is more sure of the asset development than the politics that may affect demand growth particularly for liquids. "Theoretically, exports are a great idea, and if you look at things now, people are talking about rejecting ethane because the value is so low. But exports of any cut are great only until they start to move prices higher domestically. I believe balancing that should always be left to the market, but it always ends up as a political issue, too."

In practice, production tends to come on incrementally, while processing and transportation is always added in chunks. "So long as we can see ahead and hear from the producers about what they expect, we can plan to match that as closely as possible," he said. Lendrum suggested that producers are well served to maximize their liftings, while his firm and other midstream providers will be aggressive in adding capacity. Then the supply will foster demand.

Minding the Midcontinent

One of the fast-growing new players in the Midcontinent is Meritage Midstream Services based in Golden, Colo. Meritage is backed by initial equity commitments of up to $500 million from Riverstone Holdings of New York, and it made a splash in August 2013 when it acquired all of Thunder Creek Gas Services from Devon Energy and PVR Partners.

Thunder Creek owns and operates natural gas gathering, treating, and processing assets in Wyoming's Powder River basin (PRB), including more than 500 miles of high- and low-pressure gas gathering pipelines, three treating facilities, and compression and processing facilities, as well as various NGL and condensate handling facilities. Evercore Partners acted as sole financial adviser, and Vinson & Elkins served as legal adviser to Meritage.

"Since the transaction closed, we have been out working with producers in the area, and the more we talk with them the more excited we get about the PRB," Steve Huckaby, chairman and CEO, said. He acknowledged that the play is not as widely revered as some other unconventional basins in North America, but said, "Early expectations have been exceeded for producers, and the diversity of formations they have found is analogous to the Permian. Everyone in the play is eager to understand the sweet spots."

Meritage brought the first plant to process liquids-rich gas at Thunder Creek – a modest 14 MMcf/d train – into service in October 2013, according to Huckaby. A second plant, rated at 70 MMcf/d, is due in service about the middle of 2014, with a third projected if expected demand is borne out. That third plant would add a further 100 MMcf/d and bring total capacity close to 200 MMcf/d. "Bundling midstream services is a strategy we will continue to pursue," Huckaby said. "By placing multiple gathering lines in one ditch we can help alleviate truck traffic and provide our customers with meaningful efficiencies and cost savings."

Meritage also is developing the Black Thunder Terminal, a JV with Arch Coal, in Campbell County, Wyo., at the coal company's eponymous mining complex. The terminal will provide storage, blending, and rail-loading for crude and condensate from the PRB as well as offloading, storage, and distribution services for inbound frac sand. Meritage expects to expand the Thunder Creek gathering system to feed the terminal.

In September, Meritage brought on board C. Cole Stanley as vice president to lead its crude oil services division. His responsibilities include asset management, marketing and trading, and business development. In particular, Stanley will play a key role in developing the Black Thunder Terminal.

Huckaby is sanguine about liquids, at least in the long run. "There are several projects around the industry that are expanding processing and fractionation as well as adding export capabilities, but 2014 still might be a tough year. Things should get better in 2015 to 2016 when those large projects start to come onstream. We'll just have to muddle through until then."

Construction on the first phase of the Black Thunder Terminal began in October 2013. "We are definitely seeing a lot of interest from crude producers. We are in the middle of the basin," Huckaby said. "There also is a lot of excitement about the possibility of bringing frac sand into the facility. Right now sand is being brought by truck from the DJ [Denver-Julesburg] basin, where it is brought in from the mines, mostly in Wisconsin by train and stockpiled. The DJ is a mature basin, and that is where there are facilities currently. But the truck option is very expensive."

Providing ready responses to market disconnects, Huckaby explained, is why private equity and other investors are so eager to participate in the midstream sector. "In uncertain times, midstream looks like a good place to put money." Part of the reason investors are sanguine is because there is a new spirit of collaboration between midstream and upstream players.

"There really is quite an appetite to work with quality midstream operators," Huckaby said. "Discussing development plans and production goals with us in a way that assures that our midstream plans are aligned with their drilling programs allows producers to take dollars they would otherwise have to commit to midstream and return those dollars to their core business, acquisition, and drilling.

"The level of transparency these days, it is really remarkable," Huckaby added. Many producers are eager to discuss plans informally on a confidential but no-obligation basis, which helps midstream companies align their own plans more closely with the actual pace and volume of development in a basin.

Once the two Thunder Creek projects are well advanced, Huckaby said, Meritage will cast its eye elsewhere. "We are still looking at other areas with the goal of becoming a two- or three-basin company."

Letting the Eagle Ford flow

"Sittin' on the dock of the bay" is not just a timeless lament from Blues prodigy Otis Redding; it has been a very real, expensive, and frustrating challenge for crude shippers out of Corpus Christi, Texas, the closest major tidewater loading center for the Eagle Ford and other South Texas producing areas. Pipeline and terminal operator NuStar Energy, based in San Antonio, Texas, expects to alleviate the problem with a dock expansion to be completed in Corpus Christi in 2Q 2014.

"Waterfront access has been a bottleneck for us and everyone," said NuStar president and CEO Curt Anastasio. "Our expansion should be done in the spring, and that will solve the problem."

Feeding down to that new waterfront facility, NuStar completed a successful open season on its South Texas pipeline. The goal was a 35,000-bbl incremental increase in commitments to justify the next phase of its expansion. "We have a pipeline availability that currently runs from Houston to Corpus Christi that we could fill with crude to Houston or instead bring NGL or LPG down the line – one or the other," Anastasio said.

NuStar, formed from Valero's midstream assets, has been expanding and focusing its operations, most notably in a series of back-to-back transactions. At year-end 2012, the firm completed the purchase of a crude oil pipeline and gathering and storage assets in the Eagle Ford shale region from TexStar Midstream Services for approximately $325 million. NuStar also acquired NGL assets in the Eagle Ford from TexStar for an additional $100 million in a subsequent transaction that was concluded early in 2013.

"The TexStar acquisition and related projects made NuStar one of the top logistics players in the Eagle Ford," Anastasio said. The crude pipeline system runs from LaSalle County and Frio County to

Corpus Christi, Texas, is the closest major tidewater loading center for the Eagle Ford and other South Texas producing areas.


(Image courtesy of MarkWest Energy Partners LP)

MarkWest's Houston, Pa., gas processing plant is a key component to keeping Marcellus liquids moving.

Live Oak County and can handle as much as 100,000 b/d through 1,140 miles of transmission and gathering lines. NuStar also acquired five storage terminals along the right-of-way with a combined capacity of 643,400 bbl.

Then on the first business day of 2013, NuStar sold its 14,500-b/d San Antonio refinery and related assets – including a terminal in Elmendorf, Texas, and a pipeline connecting the terminal and refinery – to Calumet Specialty Products for $115 million, including inventory of $15 million. NuStar had purchased the refinery and terminal out of bankruptcy in April 2011 for $41 million and invested another $54 million on improvements, so the return was just 5% exinventory and transaction costs. Still, it pleased customers and analysts by concentrating operation in the midstream.

That left NuStar with 8,621 miles of pipeline; 87 terminal and storage facilities that store and distribute crude, refined products, and specialty liquids; and a 50:50 JV that owns a terminal and an asphalt refinery with a throughput capacity of 74,000 b/d. NuStar's combined system has approximately 97 MMbbl of storage capacity, with operations in the US, Canada, Mexico, the Netherlands including St. Eustatius in the Caribbean, the UK, and Turkey.

Taking liquids strategically

The case for NGL is open and shut, Olsen said at TPH. "Look where development has taken place without infrastructure already in place. That is where you see the biggest discounts for NGL to the point where the solution becomes rail. Look at the Northeast; it is a bowl of spaghetti for gas pipelines, but there are not those same options for getting NGL to market.

"In short, 2014 and 2015 are going to be a bloodbath with NGL crammed into storage," Olsen said. "Propane also is losing market share in the Northeast as a fuel. Frankly, everyone would rather burn gas at $3/MMBtu to $4/MMBtu than propane at $10/MMBtu to $12/MMBtu. Some people are thinking of rail or truck transportation, but the netbacks for those alternatives are very poor."

Longer term there is a rosier picture with at least one NGL pipeline likely to be completed. "Both proposals are sound," Olsen said. "But at this early stage, I would have to say that the Bluegrass is more likely to be completed only because it is more important to Williams than the competing line reversal is to Kinder Morgan."

MarkWest's proposed NGL pipeline would access the firm's extensive pipeline network that extends throughout the rich-gas areas of the Marcellus and southern Utica. By converting more than 900 miles of existing TGP assets and using MarkWest's existing network, the partners' pipeline is best positioned to provide the most cost-effective Y-grade outlet from the Utica and Marcellus shale plays to Gulf Coast area markets.

"We believe that the combination of fractionation in the basin as well as a pipeline to the Gulf Coast are both viable," Nickerson said. "In fact, having both is better for everyone: for producers, midstream service providers, and buyers. Others may disagree with that point, but it is a critical insight. Both are viable, and both are better if both are in place."

Putting its money where its mouth is, in 2013 MarkWest began operations of the first large-scale de-ethanization facility in the Northeast, which is producing purity ethane for delivery initially to Mariner West and ultimately to all planned ethane projects including ATEX and Mariner East. MarkWest is planning to install four additional de-ethanizers in the Marcellus and two in the Utica. The company also announced expansion of its Mobley processing complex by 200 MMcf/d to support EQT Corp. and other producers, bringing the total expected capacity in the Marcellus shale to nearly 3.6 Bcf/d. The company also reported processing capacity expansions at all five complexes in the Marcellus.

Across its whole operation MarkWest has 23 major processing and fractionation facilities under construction. In 2013 it placed into service three processing facilities with a combined capacity of 525 MMcf/d. Those include agreements with Antero Resources to expand the Seneca processing complex by 200 MMcf/d, bringing total capacity in the Utica shale to more than 900 MMcf/d by 3Q 2014, and seven additional fractionation projects, which will increase total fractionation capacity in the Marcellus and Utica shales, adding 138,000 b/d in the Utica and 96,000 b/d in the Marcellus for a total of 234,000 b/d by 1Q 2015.

Nickerson is a passionate advocate for continued NGL production and processing. "Just as we saw in dry gas, the US is at the beginning of a fundamental shift in liquids on a national scale that has global implications. We just don't know yet the full effects," he said. Nickerson cited some firm numbers. "Two or three years ago American propane exports were less than 150,000 b/d. Exports are going to be about twice that for 2013, and another 800,000 b/d of new export capacity is coming online."

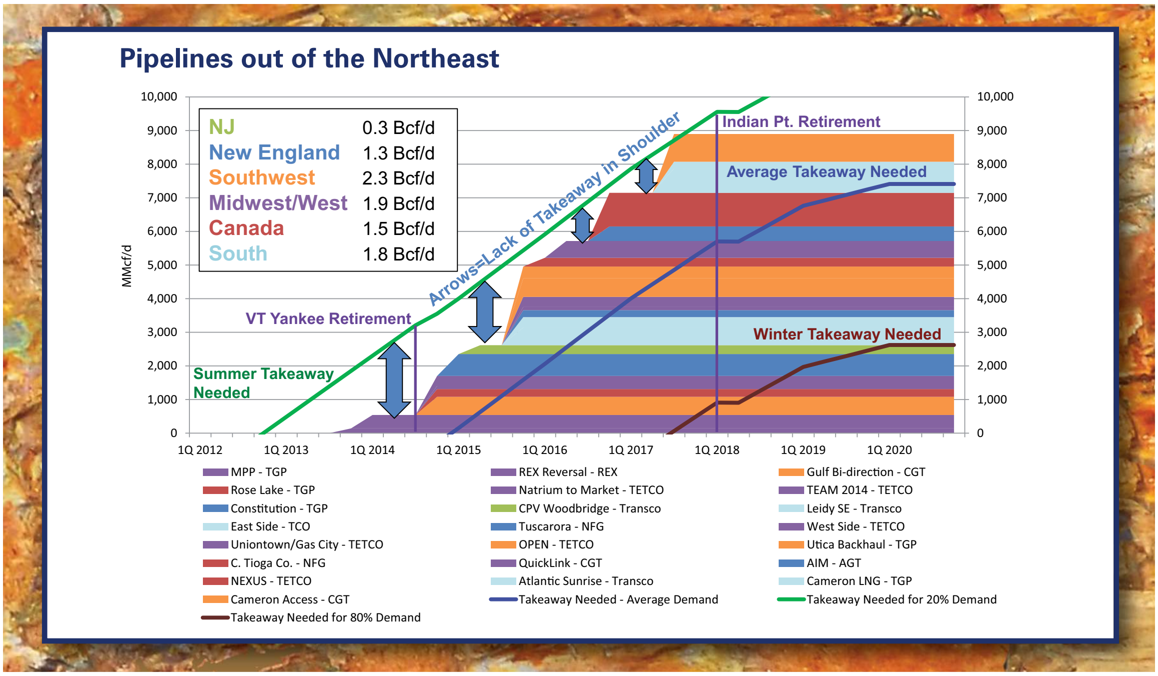
The essential shift that Nickerson emphasizes is that export market. "It used to be that exports were not the critical market that set the price. Now exports will set the price. If export prices are high, then so will be prices in the US," he said. He is adamant that despite low prices domestically, demand will burgeon to require as much volume as unconventional developers can produce.

"China is building 16 propane dehydrogenation units over there as well as some here," Nickerson said. "The same is happening in other regions to meet the need for polymers. Normal butane is headed the same way. Two of the five major NGL [types] are already internationally correlated. Condensate and natural gasoline will continue to grow with demand from refineries and diluent for heavy crude. So that is four of the five," he said.

> **"Look where development has taken place without infrastructure already in place. That is where you see the biggest discounts for NGL to the point where the solution becomes rail."**
>
> *— **Brad Olsen**, director of Midstream Research, Tudor, Pickering, Holt & Co.*

That leaves ethane. "Ethane is tougher," Nickerson said. "There are some new steam crackers planned to make olefins, but there is still oversupply of ethane. Still overall, the shale wave in North America is affecting the world NGL market. There already have been enormous changes, and there will continue to be. The NGL world four years from now will be very different from the way things were just four years ago." Exports planned from Marcus Hook via the Mariner West project to Europe will be a new source of demand. Additionally, the seven Gulf Coast crackers planned by 2017 and the possible development of olefins projects in the Northeast have the potential to impact supply and demand in addition to prices.

For all the flurry of midstream expansion, Stice of Access Midstream said that both producers and processors are nearing a peak for the current stage of development. "The original drive in the Marcellus was to get dedicated acres held by production. That has largely taken place in the core of the play. Now we might see some throttling back to a more



(Source: Tudor, Pickering, Holt & Co.)

prudent and timely development plan that considers local demand."

In liquids, however, Stice said the picture is "more interesting." "In the Marcellus South and the Utica wet area, the industry needs a fully integrated array of services: gathering compression, processing, fractionation, and dehydration. Propane always will be a challenge in that there is ample demand in the winter for heating but no demand in the summer. Our part of the solution is the Harrison Hub, a central rail-loading management point for all liquids. UEO built and owns it and hired RailLink to operate the loading facility."

Butane also has been a challenge. "The local refinery had been overwhelmed with new supplies of butane and natural gasoline," Stice said. "Natural gasoline will likely find its home as a diluent in Canada. We may even see X-grade [propane, butane, and natural gasoline] streams moved to the Gulf Coast and fractionated, with some products sent back to the region. Everyone is trying to develop the offtake solution to this new abundant supply of NGL."

Acknowledging that the next year or so will be a scramble, Stice predicted that the upstream side of the industry will take a breather to allow these offtake solutions to develop. He suggested that producers and processors have delivered volumes – often huge volumes – and the consuming sectors of the economy are in the process of trying to step up to the energy and feedstock bonanza already on the table.

Expanding on that thesis, Bob Purgason, Access COO, said the midstream industry is entering the third phase of its response to the shale boom. "First there is the game of risk — where on the map board do you put your pieces? How long does it take to get permits, and how do you deal with local communities? We heard a lot about the upheaval when the Marcellus was first being developed, but we are not hearing about much upheaval in Ohio. I think both industry and regulators have learned a lot and are being much smarter," he said.

The second phase is the sprint to build out the development. "That is pretty much done in the Marcellus, especially in the north," Purgason said. "In the south we are still chasing some rigs, as we also are in the Niobrara. The Eagle Ford is shifting, too." The final phase is consolidation and cost control. "That is where we are in the Barnett and the dry gas parts of the Haynesville," Purgason said.

Across the midstream, capital spending on processing and gathering infrastructure in the Utica exceeds the capital costs of drilling but not leasing. "We are feeling relatively comfortable that we can get our own projects done on time and on budget. This is

our peak year for capex – $1.8 billion. So far our suppliers have been able to meet our needs for pipe and equipment. Labor does get tight in some focus areas, but that is to be expected," he said.

More broadly, Purgason is excited for the prospects of the whole sector. "There is such tremendous opportunity. This is just an incredible time to be in the industry – maybe the best ever – and it is good to know that there is still another two or three generations' worth of work to do," he said.

Anastasio of NuStar also is optimistic about the long-term outlook for NGL. "Our friends in gas – wet or dry – have seen better times, but I doubt that the situation is as bad as having to shut-in liquids. They can still be sold even if only at gas prices, and the cost of production keeps going down. We are very active in the Eagle Ford, talking to producers every day. I really doubt that there is a cataclysm in natural gas because of weakness in liquids."

Exports are a major component in any North American hydrocarbon market, Anastasio said. "It is a big theme everywhere you turn, whether it is gas for LNG, the new NGL terminals, or even maybe crude someday." The export of refined products is less politically fraught and probably more profitable, he said.

"Product export is a huge driver of profitability for the downstream sector. That means getting crude to tidewater where the big facilities are. Our vision through 2014 and into 2015 and 2016 is to be very active in the Eagle Ford because that will continue to grow and need more pipeline. Rail will persist out of the Bakken and other basins that lack full pipeline systems, so we are in that service as well. Basically, people need takeaway in some form everywhere," Anastasio said.

Fresh from the successful development and sale of its Colt Hub in the Bakken, Rangeland Energy, based in Sugar Land, Texas, is accelerating the development of its next major project: the Rio Hub near Loving, N.M. Rangeland bought more than 300 acres in the Delaware basin of the larger Permian basin and is developing a large terminal capable of handling crude oil, condensate, frac sand, pipe, and other materials both inbound and outbound. The company also will build the Rio Pipeline to connect the region's crude oil and condensate production to the Rio Hub and to market centers in Midland, Texas, and Colorado City. "We looked at opportunities from the Permian to Canada," Chris Keene, Rangeland president and CEO, said. "In New Mexico and West Texas we saw several trends come

(Image courtesy of BNSF Railway Co.)

BNSF locomotives head out of the Bakken on a crisp day with another load of crude oil. The railroad has announced plans to expand its system in North Dakota and Montana to accommodate shipments of 1 MMb/d.

together." One is the need for a hub complex where trucks, rail, storage, and pipeline come together for sand and equipment inbound, then crude and condensate outbound. Rangeland expects to invest more than $150 million in the New Mexico terminal, pipeline, and supporting infrastructure. The company is working with customers to negotiate and execute commercial contracts for the system. Rangeland is backed by private-equity firm EnCap Flatrock Midstream of San Antonio.

Rangeland will receive crude oil and condensate produced in southeast New Mexico and West Texas via trucks and gathering pipelines. Unit-train loading facilities will allow access to high-value markets across the country that are not currently accessible by pipeline. Initial rail services will include truck-to-rail transloading in advance of the unit-train rack being completed.

The Rio Hub will be served by the BNSF Railway, which was a crude-by-rail pioneer out of the Bakken formation in North Dakota. Rangeland developed a similar system at the Colt facility in Epping, N.D., also served by the BNSF. That terminal and the associated pipeline connections were sold to Inergy Midstream in December 2012 for $425 million.

"For the industry, 2014 will be a time of decision-making," Keene said. "We are seeing some of the same patterns play — out in the Delaware basin as we did in the Bakken an aggressive drilling "program and production ramping up with producers thinking about many options to get to market." Getting crude to market is likely to remain a fairly straightforward proposition, but Keene is watching the condensate market carefully. "Condensate is beginning to be an issue for producers. We have seen that in the Marcellus and the Eagle Ford, too. The first option is always to blend with crude and send it on down the pipeline, but eventually, you reach the gravity limit for the pipelines," Keene said.

The next option is to move condensate by any mode — truck, rail, or pipe — to a market or processing center. "You can move it to a splitter and then the fractions to market, or just take raw condensate to a heavy-crude region to be used as diluent," Keene said. "We want the Rio Hub to be a market center for Delaware basin condensate, providing producers access to a variety of higher value market opportunities."

One of the major emerging markets for crude by rail is bringing heavy crude, primarily out of Canada, in heated and insulated cars that obviate the need for diluent. Producers and refiners prefer that in theory, but Keene said that in practice "there are significant technical challenges to loading and unloading straight bitumen. It is true that there are significant cost savings and economic benefits, but the challenges are large. In some cases, small shippers and refiners have thrown up their hands and said, 'Just diluent it and ship it.' As a result, we believe there will continue to be demand for diluent in Canada."

A more ambitious idea would be to bring crude to the diluent. "We have had inquiries about bringing heavy crude in by rail car, custom blending it here, and then sending it by pipe or rail to refiners that want a specific feedstock. There is definitely an opportunity there. It all goes back to finding a condensate solution," Keene said.

The third stage for condensate oversupply is less clear. "Once we reach saturation in the crude pipelines, an oversupply will start to form. Producers will have to start taking a discount just to move it. Most producers recognize this trend is coming to the Permian, just like in the Eagle Ford and Marcellus," Keene said. "We are trying to provide alternatives for producers via the Hub. Discounts hit producers in the pocketbook. When that financial pain gets large enough, producers and marketers will look for options – [both] domestic and international."

Keene said that exports of crude or raw condensate are presently not allowed, but added that a fractionator is a potential processing option for companies that both meets the requirement of exporting refined products and also may enhance profitability of the total stream to greater than that of a mixed raw condensate.

Canada focus is crude by rail

One other potential snag for condensate is the delay in permitting for the Keystone XL pipeline bringing heavy crude out of Canada. "As long as that line is not yet operating, that means about 800,000 b/d of heavy crude are going to have to come south by rail, which means they will not need diluent," Olsen said at TPH. Indeed, he reckons the big remaining growth market for crude by rail is "Canadian crude jilted from the planned pipelines."

While acknowledging the torrid rise in crude-by-rail volumes, Olsen said he doubts that near-term growth can continue at that pace. "We have very quickly reached saturation for light sweet crude on the east and west coasts. The east coast refineries are generally not that large, and on the west coast it is really only the facilities in the Northwest that can take the Bakken light sweet. The California refineries generally run more heavy and sour slates. With freight rates about $12/bbl to $15/bbl from the Bakken to the east coast, there really is no arbitrage anymore against African light sweet."

NuStar also has been a leader in crude by rail with a unit-train terminal in St. James, La. The second track was due to be completed in November 2013, after which there will be further tank storage expansion.

"Our asphalt JV is sending pure bitumen from Canada to our Paulsboro, N.J., refinery in heated and insulated rail cars," Anastasio said. He expects that a combination of pipelines and crude by rail will be the permanent solution to getting Canadian crude to market, especially heavy crude. "The bulk of the pipe projects are running north to south, with only some heading east or west. There is some effort to get crude across the mountains to British Columbia. Even with all the pipeline projects, there is going to be a continued need for rail out of Canada."

Anastasio suggested that in the long run there will have to be large-scale, long-distance transportation solutions for Canada. "Right now Western Canadian Select is about $30/bbl below WTI [West Texas Intermediate]. That kind of differential is not going to vanish overnight. There will have to be massive multi-billion dollar projects," he said.

(Image courtesy of TransCanada)

TransCanada's proposed Keystone XL pipeline could carry Alberta crude oil south.

Outlook for LNG

Olsen at TPH is sanguine about LNG exports. "The momentum has definitely shifted just in the past year. After a very long, very slow start, it now looks like there is some permitting momentum. There have been several new approvals in the past few months."

He said that the major discriminator among competing LNG projects is the cost basis. "The cost to build these new terminals on the Gulf Coast is less than half of what they cost in Australia, and there is a 40% discount to the projects envisioned for Canada. The challenge is not so much in the marketing or the pricing but the capital costs. Now I believe a couple of the Canadian liquefaction plants will get built, because Canada has to have some exports. But the engineering and construction advantage definitely lies in the US."

One caveat that Olsen added, even for the US LNG plants, is that he calculated they will be coming into service a year or two later than they are planned and will run over budget. "I am always skeptical about schedules and budgets of big-ticket projects. That is just the way they are." ■

(Image courtesy of Access Midstream Partners)

Money Following Midstream Demand

Travis E. Poling, Contributing Editor

Private equity, master limited partnerships, and mergers are propelling a rapid expansion of natural gas and crude transportation and processing assets.

Editor's note: Below is a roundup of some of the key players in the US midstream sector, based on recent activity levels.

Hundreds of billions of dollars are flowing into new projects from pipelines to rail terminals with project commitments through 2016 to transport the massive production increases of crude oil and natural gas from unconventional plays throughout the continent.

Midstream companies also are taking advantage of energy production companies shedding their midstream assets and growing through acquisition. Merging assets also is becoming a popular way to leverage capital for growth through limited partnerships. Perhaps one of the largest mergers in 2013 was the combination of Crosstex Energy LP and the midstream assets of Devon Energy.

Chesapeake Energy's sale of midstream assets gave several companies access to unconventional plays from the Eagle Ford shale to the Granite Wash.

And even as another phase of TransCanada's massive Keystone XL pipeline came to a close – linking an Oklahoma hub to the Gulf Coast – the company was still lobbying hard from the US White House to the court of public opinion to get approvals to finish the last link and connect vast reserves to the nation's largest refining regions.

Several studies from 2011 and 2012 concluded that it would take about US $200 billion in investment in new midstream infrastructure to meet transportation and processing needs through 2035. But investment capital from private equity investment groups has followed the need, quickly allowing midstream companies – most of them tax-advantaged master limited partnerships – to move into planning and construction phases.

Access Midstream Partners LP

- **Estimated organic growth through capex is $3.5 billion for 2013 through 2015**
- **Acquired $2.16 billion in Chesapeake Energy midstream assets**

With operations in 12 states, Access Midstream is making the most of contracts with producers in the Midcontinent regions and the Barnett, Eagle Ford, Haynesville, Marcellus, Niobrara, and Utica shales. The general partnership of the Oklahoma City-based company is now 50% owned by Williams Cos. Inc. and 50% owned by Global Infrastructure Partners.

By fall 2013, the company had about 6,300 miles of natural gas pipelines handling 3.5 Bcf/d, according to the company's website.

In the first half of 2013, Access increased net income 24% to US $128.8 million compared to the first half of 2012. Revenue in the first half of the year was up 59% to $484.2 million, according to filings with the US Securities and Exchange Commission. In August, Access issued $400 million in senior notes to the public to raise money for capital expenses and acquisitions along with working capital and paying down debt, according to a statement from the company.

Facing page: The morning sun lights the new Harrison Hub fractionator in Harrison County, Ohio, part of a $1.8 billion joint venture of Access Midstream Partners, Momentum/M3 Midstream LLC, and EnerVest Ltd. in the Utica East Ohio midstream service complex.

The company has a 49% stake in pipeline and storage construction in the Utica shale in Ohio near Pennsylvania's western border, according to a presentation at the Barclays CEO Energy Conference in September. The project includes four processing plants and 870,000 bbl of NGL storage.

By 2Q 2012, the company had grown considerably in the Eagle Ford shale of South Texas and set a daily record for throughput of 2 Bcf/d in the Marcellus shale, Access CEO J. Mike Stice said in a written statement.

Blue Racer Midstream LLC

- **The joint venture company was formed with assets from Dominion and a capital investment from Caiman Energy II LLC**
- **A recently completed cryogenic processing and fractionation plant in Marshall County, W. Va., will provide more than 1 Bcf/d of processing capacity to service the Utica shale**

Blue Racer, named for a swift snake found in Ohio, was founded at year-end 2012 with a contribution from Dominion of assets including more than 500 miles of natural gas gathering and transportation lines in the eastern part of Ohio and into West Virginia and US $800 million in capital from Caiman Energy II.

In just one year, the firm is well under way into an aggressive expansion campaign that includes several 200-MMb/d natural gas processing plants with the first new one open for business in summer 2013 in Marshall County, W.Va., and a second coming online at the same facility in March 2014. The Natrium complex also includes a 36,000-b/d fractionation plant, which also will be expanded to approximately 60,000 b/d, according to the company's website.

Similarly sized facilities are in the works for Monroe, Harrison, and Mahoning counties in Ohio.

"With 500 miles of gathering pipeline and significant processing and fractionation capacity already up and running, Blue Racer's assets are uniquely situated to handle rich-gas volumes from all areas of the Utica shale," Jack Lafield, CEO of Blue Racer and Caiman Energy, said in a written statement in September 2013. "As producers continue to delineate the play, Blue Racer will keep pace by providing top-tier customer service and the region's best opportunity to gather and process rich gas and market NGL."

Buckeye Partners LP

- **Increased liquid petroleum storage capacity by more than 50% with the $850 million acquisition of 20 terminals from Hess Corp.**
- **Is creating a network of New York Harbor marine terminals, including 2012 acquisition from Chevron**

Even as Buckeye Partners sought to deepen its services to the Bakken and Utica plays, the company made a major move all along the East Coast and the Caribbean.

The acquisition of 20 terminals from Hess Corp. was announced in early October and was expected to close by year-end 2013, pending an antitrust review by federal regulators. The acquisition adds 39 Bbbl of storage capacity to the company's existing 70 MMbbl, according to a written statement from Buckeye.

About 10 MMbbl of capacity will be gained with the addition of the St. Lucia terminal in the Caribbean, allowing the company to handle more storage of products from Latin America.

The other 29 MMbbl of capacity come from 19 East Coast terminals, including several in the Southeast and Florida to play a greater role in those fast-growing markets, according to a company statement on the acquisition. Hess primarily used them as proprietary facilities, but Buckeye will open them to customers.

In 2012, the company became better positioned to handle Bakken and Utica shale flows to the Northeast when it acquired a terminal from Chevron in the Perth Amboy area of New York Harbor. Additional assets in New York Harbor are expected to increase those abilities.

"The proximity of the Port Reading terminal to our Perth Amboy terminal and Linden hub provides the opportunity to create a large, integrated network in New York Harbor that would leverage the pipeline connections between these facilities and allow us to optimize the capabilities at each

facility for our customers," Buckeye CEO Clark C. Smith said.

The company moved 1.41 MMb/d of petroleum products through its pipelines and terminals in the first half of 2013, according to a quarterly filing with the US Securities and Exchange Commission. Revenue for the first half of 2013 was US $2.35 billion, up nearly $108 million from the same period in 2012.

Caiman Energy II LLC

- **The private equity firm is invested heavily in the Utica shale in partnership with Dominion through Blue Racer Midstream**
- **Management team also experienced in the Marcellus shale with assets that the original Caiman Energy sold to Williams Partners for $2.5 billion**

Caiman Energy II provided US $800 million in capital investment to Blue Racer Midstream, a partnership with Dominion. (See Blue Racer key player profile.) Caiman's top executives also serve on the management team for Blue Racer.

Caliber Midstream

- **Adding 100 miles of gathering pipelines in the Bakken and Three Forks shale plays**
- **Formed in October 2012 as a joint venture of Triangle Petroleum Corp. and First Reserve Corp.'s Energy Infrastructure Fund**

Denver-based Caliber Midstream was formed in fall 2012 to further develop existing midstream assets in McKenzie County, N.D., which is central to the Bakken and Three Forks plays with initial capitalization of US $180 million.

First Reserve Corp., which bills itself as the largest private equity firm focused solely on energy, is pumping another $80 million into capital expansion projects of the Caliber partnership, according to a news release from partner Triangle Petroleum.

The expansion will include 100 miles of additional gathering lines, crude oil stabilization and transportation, freshwater delivery, and production water transport and disposal by June 1, 2014, according to a statement issued by Triangle.

The pipeline expansion will move up to 50,000 b/d from Caliber's central location to Alexander, N.D., where a 40,000-bbl crude oil storage facility is

(Image courtesy of Caiman Energy)

The Caiman Fort Beeler cryogenic processing plant near Cameron, W. Va., processes about 520 MMcf/d and was sold, along with a number of other Marcellus facilities, to Williams Partners in spring 2012.

in the works to reach several pipelines, rail terminals, and Williston basin markets.

Cheniere Energy Partners LP

- **Purchased the Cheniere Creole Trail Pipeline in western Louisiana**
- **Building a liquefaction project at Sabine Pass to handle as many as six LNG trains**

In May, Cheniere Energy Partners purchased the Cheniere Creole Trail Pipeline for US $480 million from Cheniere Energy Inc., the 58% owner of the partnership. The 94-mile pipeline provides for the key delivery of natural gas along the Louisiana-Texas border to the Sabine Pass LNG terminal.

The partnership, which also includes a 29% ownership from private equity giant Blackstone and 13% in public shares, is pumping an additional investment into the Sabine Pass terminal on the Gulf Coast.

The company is situated to receive gas from conventional Gulf Coast onshore production and the Barnett, Haynesville, Bossier, and Eagle Ford plays, according to a company investor presentation.

Sabine Pass facilities in Louisiana's Cameron Parish will include six LNG trains with the first three expected to be ready for use from 2015 to 2016. Completion of a fourth train is expected in 2017. When all six LNG trains are complete, Cheniere will have the capacity for 27 million tons per annum of LNG, according to the company's website.

Separate from the partnership, Cheniere Energy Inc. is working on a new LNG terminal in the Corpus Christi, Texas, area that will have as many as three LNG trains and 13.5 million tons per annum.

Chevron Pipe Line Co.

- **Network includes about 10,000 miles of pipe**
- **Sold 760-mile Northwest Products Pipeline and some terminal operations to Tesoro Logistics LP for $355 million**

A wholly owned indirect subsidiary of Chevron Corp., Chevron Pipe Line boasts that it moves about 1.13 MMb/d of oil and 1.3 Bcf/d of natural gas through a 10,000-mile pipeline network.

In West Texas, southern Louisiana, and Canada, Chevron Pipe operates storage facilities holding about 104 Bcf for its subsidiaries taking advantage of unconventional plays. The Chevron Keystone Gas Storage facility near Midland, Texas, has seven salt caverns available for natural gas storage of up to 6.38 Bcf, according to the company's website.

Aitken Creek Gas Storage LLC, 93% owned by Chevron, maintains a capacity of 77 Bcf of natural gas in British Columbia, Canada. Chevron subsidiary Bridgeline Holdings LP has three salt dome storage caverns in Assumption and Ascension parishes of Louisiana with a capacity of 11 Bcf, according to the company's website.

Chevron Pipe Line sold its Northwest Products Pipeline to Tesoro Logistics LP in June 2013 for US $355 million after Tesoro divested some of its existing holdings in the Boise, Idaho, area, according to a Tesoro Logistics news release.

The pipeline firm expects to complete a 136-mile, 24-in. crude oil pipeline from the deepwater Jack/St. Malo production facility to a platform on the Gulf of Mexico shelf in 2014.

Columbia Pipeline Group

- **Building a $131 million pipeline of 21.1 miles across Baltimore and Hartford counties in Maryland for more reliable natural gas delivery to central Maryland customers**
- **Planning 19 miles of new gas pipeline in Pennsylvania and New Jersey for a fall 2015 completion**

Columbia Pipeline Group, which changed its name from NiSource Transmission & Storage in early 2013, specializes in providing natural gas to utilities in 16 states and the Washington, D.C. area. The NiSource Inc. subsidiary boasts 15,000 miles of pipeline delivering 1.4 Tcf of natural gas to 40 markets. The company also can store 640 Bcf of natural gas at its 37 storage fields, according to the company's website.

The company is building several projects to improve throughput and reliability to utility customers in the Northeast, including several in joint ventures with other midstream companies. Columbia also will gain access to more supply from unconventional plays through projects done by other companies owned by NiSource Inc.

In August 2013, Columbia's sister company NiSource Midstream Services completed a major compressor upgrade to double throughput of liquids-rich Marcellus shale gas in West Virginia. Columbia will benefit by receiving the residue gas from the process plant in its pipelines, according to a company news release.

Crestwood Midstream Partners LP

- **Merged with Inergy in October 2013 to form a diversified midstream player growing in core areas**
- **Merged company will acquire Arrow Midstream for $750 million for bigger Bakken shale presence**

Crestwood is wasting no time after merging with Inergy this fall to create a diversified midstream partnership with a presence in every premier shale play in North America.

Two days after closing the deal to reach US $8 billion in enterprise value, the newly combined Crestwood announced a $750 million agreement to expand its footprint in the Bakken shale by buying Arrow Midstream. The acquisition aims to make Crestwood one of the largest midstream providers in the Bakken, serving about 18% of crude oil production by connecting Arrow's gathering systems with Crestwood's COLT Hub crude rail and pipeline terminal.

Crestwood assets, including announced expansion projects, consist of 1.3 Bcf/d of natural gas transportation capacity, 1,100 miles of natural gas pipeline, and 80 Bcf of natural gas storage. NGL and crude oil-related assets include trucks and rail cars, pipelines for crude and water gathering, eight natural gas processing plants, terminals, and NGL storage.

Crestwood is "keenly focused on growing our crude and NGL businesses" through a balance of organic expansion in core areas of the Marcellus, Bakken, and Niobrara plays with acquisitions that expand the service offering for producers and end users, Chairman and CEO Robert G. Phillips said in a written statement from the company.

Crestwood also has operations in the Barnett, Eagle Ford, Fayetteville, Granite Wash, Haynesville, Monterey, Permian basin, Powder River basin, and Utica plays.

The enterprise operates through two publicly traded entities: Crestwood Midstream Partners LP and Crestwood Equity Partners LP.

Crosstex Energy LP/Devon Energy

- **Combining its midstream assets with the pipeline and processing assets of Devon Energy Corp. to create a new midstream services company**
- **The new company will have deeper roots in several major shale plays and operate more efficiently**

Crosstex Energy Inc., Crosstex Energy LP, and Devon Energy Corp. are combining their processing and pipeline operations in a deal that is expected to close in 1Q 2014. The planned general partnership and master limited partnership, which had yet to be given a name when the deal was announced in late October, will both have publicly traded shares.

While Devon will have a controlling interest in both entities, Crosstex CEO Barry Davis has been tapped to run the operation with headquarters in Dallas. Devon, based in Oklahoma City, is putting in approximately US $4.8 billion of its $26 billion in assets to the deal as an alternative to taking those midstream assets into a public company on its own.

When the assets are combined, the company will have midstream assets throughout several highly active unconventional shale plays including the Barnett shale, Permian basin, Cana and Arkoma Woodford, Eagle Ford, Haynesville, Gulf Coast, Utica, and Marcellus.

On the NGL side of the business, the combination is 650 miles of NGL pipeline, six fractionation plants, and 3 MMbbl of underground storage, according to a presentation by Crosstex and Devon.

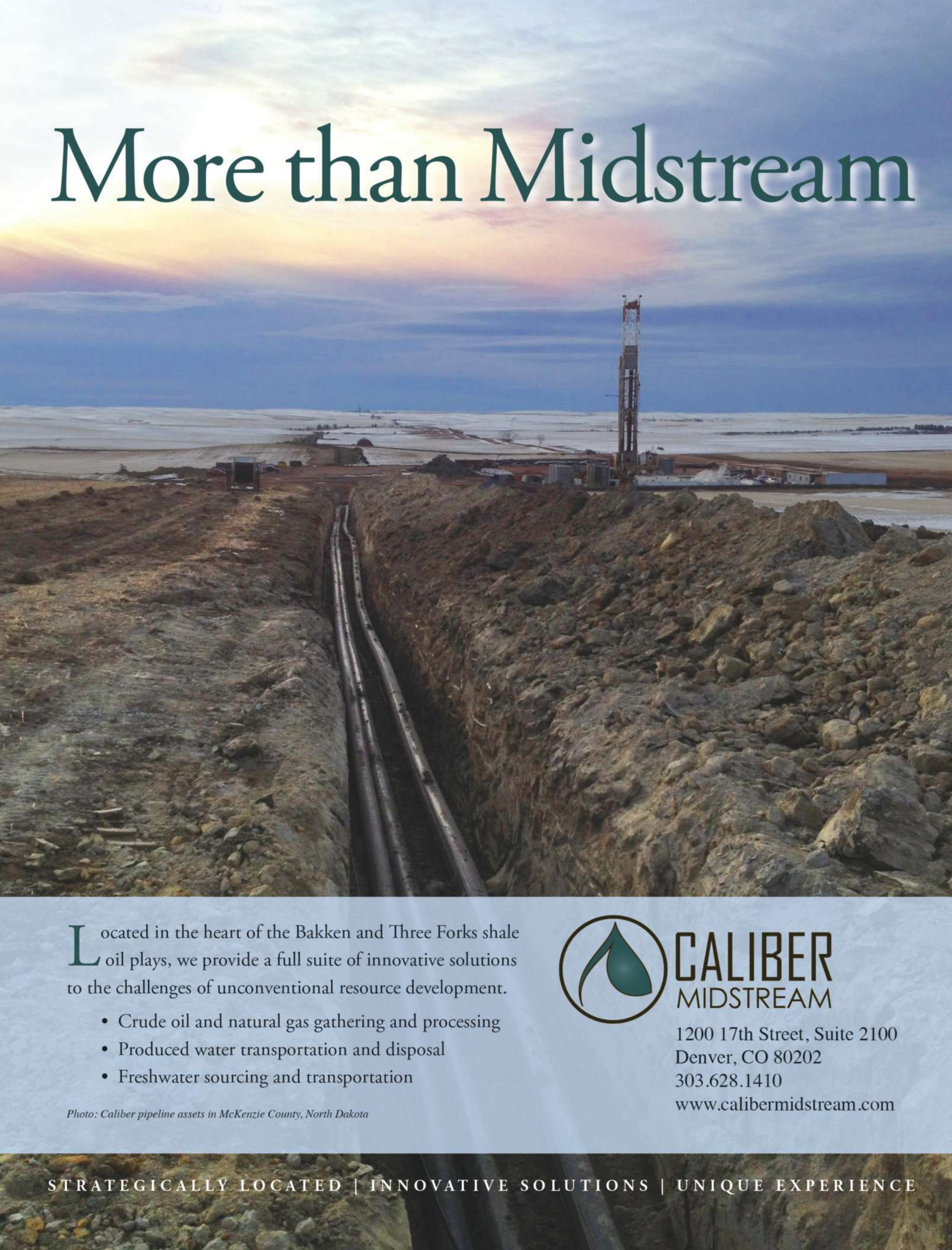

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Photo: Caliber pipeline assets in McKenzie County, North Dakota
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Crosstex Energy's Benbrook compressor station located in Fort Worth, Texas, serves Barnett shale producers.

(Image courtesy of Crosstex Energy LP)

Crude, condensate, and brine handling would include barge and rail terminals, 200 miles of crude pipeline, 500,000 bbl of storage capacity, a fleet of 110 trucks, and eight brine disposal wells.

Gas gathering and transportation systems include 6,500 miles of gathering and transmission pipelines and 13 plants with total capacity to process 3.3 Bcf/d of gas.

DCP Midstream LLC

- **Opened the Eagle Plant, which serves the Eagle Ford shale, owned 100% by DCP Midstream Partners LP**
- **Began service on the Sand Hills Pipeline for NGL takeaway from the Permian basin and Eagle Ford shale to Mont Belvieu, Texas**

DCP Midstream LLC, jointly owned by Phillips 66 and Spectra Energy, is the general partner of DCP Midstream Partners LP, a master limited partnership. The DCP Midstream enterprise is the largest natural gas processor and producer of NGL in North America, including several unconventional plays, according to the company. In all, the DCP Midstream enterprise owns or operates 66,000 miles of pipeline for NGL, gathering and transmission, 63 plants, and 12 fractionating units in 18 states.

DCP Midstream participates in some of the most prolific basins for unconventional plays. In the Eagle Ford shale, where the DCP enterprise has approximately 1 Bcf/d of processing capacity, assets will include a 200 MMcf/d cryogenic processing plant in Goliad, Texas, slated for an early 2014 opening and jointly owned by DCP Midstream Partners LP and DCP Midstream LLC. The Eagle Ford joint venture (JV) has one of the largest gathering systems in the Eagle Ford shale – 6,000 miles in all – along with three fractionators with a capacity of 36,000 b/d and six cryogenic processing plants. The system draws production from 900,000 acres dedicated through long-term agreements.

In the Permian basin, where DCP has approximately 1.3 Bcf/d of processing capacity, assets include a 75 MMcf/d plant in Glasscock County, Texas, that commenced operations in mid-2013. In the Denver-Julesburg (DJ) basin, where the DCP enterprise has approximately 600 MMcf/d of processing capacity, assets include a 110 MMcf/d cryogenic processing plant that commenced operations in late 2013 and is owned by DCP Midstream Partners LP.

As part of DCP's effort to provide takeaway capacity for unconventional production in the Permian and Eagle Ford, in mid-2013 the company began service on the 720-mile Sand Hills Pipeline, which carries NGL from the Permian basin to fractionation facilities in Mont Belvieu, Texas, according to a statement from the company. DCP also began service on the 800-mile Southern Hills Pipeline in mid-2013 for NGL takeaway from the Midcontinent to Mont Belvieu. DCP Midstream, Phillips 66, and Spectra Energy each own a one-third interest in the pipeline entities. DCP Midstream Partners LP is participating in two JV pipelines: the 435-mile Front Range Pipeline and the 583-mile Texas Express Pipeline, both of which will provide producers with takeaway capacity from the DJ basin to Mont Belvieu. Texas Express began operations in late 2013, and Front Range is slated for 1Q 2014. DCP Midstream Partners LP owns a one-third interest in Front Range and a 10% interest in Texas Express.

The DCP enterprise continues to identify and develop critical midstream assets for additional processing capacity and takeaway and increased reliability in these unconventional plays.

Eagle Rock Energy Partners LP

- **By summer 2013, gathering commitments in the Texas Panhandle reached production on 640,000 acres**
- **Completed two new cryogenic processing plants and acquired two more from BP America Production for a total of 20 processing plants and stations**

Eagle Rock's midstream operations put it in four highly active natural gas regions including the Texas Panhandle, East Texas/Louisiana, South Texas, and the Gulf of Mexico.

The company has been transitioning its business mix away from commodity-based income to fee-based since 2011, when 79% of the business was commodity. The company estimates that 55% will be fee-based by year-end 2014, according to an August 2013 presentation during the Citi One-on-One MLP/Midstream Infrastructure Conference.

The Houston-based company also has significant upstream assets in Alabama, the Midcontinent, the Texas Panhandle, and the Permian basin that make up 57% of the business mix.

Midstream assets and the contracts grew significantly when Eagle Rock acquired Texas Panhandle assets from BP America Production. Assets include 8,134 miles of pipeline and 20 gas processing plants and stations with 787 MMcf/d of processing capacity, according to the company's website.

The most recent new processing plant is the Wheeler plant in the Texas Panhandle, which went online in July 2013 with a capacity of 60 MMcf/d and brought processing capacity in the Granite Wash area to 540 MMcf/d, up from 100 MMcf/d in early 2010, the company said.

Enable Midstream Partners LP

- **Formed in 2013 from the field and interstate pipeline assets of CenterPoint Energy and Enogex Midstream**
- **$11 billion in combined assets in nine states**

One of the biggest midstream marriages of the year was the formation in May of Enable Midstream Partners LP, which is 58.3% owned by CenterPoint Energy, with OGE Energy holding 28.5% in the LP and 50% in the general partnership.

With asset contributions from CenterPoint and OGE Energy's Enogex Midstream, Enable has 8,400 miles of interstate pipelines, 2,300 miles of intrastate lines, and more than 11,000 miles of gathering pipeline that carried about 4 Bcf/d of natural gas, according to a company news release announcing the deal.

The company also boasts 11 large processing plants and natural gas storage capacity of more than 90 Bcf.

Production areas served in Oklahoma, Texas, Arkansas, and Louisiana include the Barnett, Cana Woodford, Fayetteville, Granite Wash, Haynesville, Mississippi Lime, Tonkawa, and Woodford plays.

In the summer, the company received regulatory approval from the US Bureau of Land Management to construct a crude oil gathering project in the Bakken shale, according a conference call with CenterPoint executives discussing 2Q 2013 results.

An initial public offering (IPO) for Enable had not been scheduled as of late October, but a CenterPoint executive told analysts during a conference call that the company hoped to complete the IPO by the end of 1Q 2014.

Enbridge Energy Partners LP

- **Expansions will add 1.7 MMb/d in transportation capacity in new markets from 2013 to 2016**
- **Major crude oil transporter from Western Canada and operator of natural gas gathering, transmission, and processing in the US Midcontinent and along the Gulf Coast**

Enbridge is positioned for a greater role in unconventional plays and long-proven basins for natural gas gathering and transmission, particularly in Texas, with 11,400 miles of line, 2.2 Bcf/d of processing, and 1.1 Bcf/d of treating capacity.

The company said in a September 2013 presentation that it is especially well positioned for the Granite Wash area of the Texas Panhandle, the Haynesville shale on the East Texas-Louisiana border, and emerging shale plays such as the Barnett.

Enbridge is investing US $140 million in expanded processing capacity in the Haynesville region to bring it to 820 MMcf/d when it comes online in early 2015.

In the Barnett shale, the company is expanding the pipeline and rail capacity and doing several mainline expansions into 2016. In the Bakken shale, Enbridge expects to reach 580,000 b/d of crude pipeline capacity from Saskatchewan, Canada, and North Dakota and take it away across the Great Lakes via the expanded Sandpiper Pipeline.

The company forecast that it will spend more than $1.5 billion on average from 2014 to 2016 on capital projects.

Spending also is heavy on line expansions from Canada to the Gulf Coast, where the company supplies crude oil from Western Canada to numerous refineries. Eastern access capacity also is undergoing improvements by both Enbridge Energy Partners and Enbridge Inc.

Energy Transfer Partners

- **Lake Charles LNG export capabilities in Lake Charles, La., will reach an export capacity up to 2.4 Bcf/d from three trains**
- **Mariner South project will create an LPG export/import operation along the Gulf Coast with an initial capacity of 6 MMbbl of LPG per month beginning in early 2015**

Dallas-based Energy Transfer Partners (ETP) sees a market in selling domestically produced LNG to countries throughout the world and has set out to build three liquefaction trains at the Lake Charles, La., facility owned by subsidiary Trunkline LNG. Barring any regulatory or investment delays, construction would begin in 2015, and LNG export would start in 2019, the company said in a news release.

ETP's subsidiary Southern Union Co. sold the assets of Missouri Gas Energy to Laclede Gas Co. for US $975 million in September 2013 and expected a 4Q 2013 completion of the $60 million sale of assets of the New England Gas Co. also held by Southern Union. The assets are considered "noncore assets," according to a news release from the company, and the sales are expected to streamline the business and provide cash to repay debt.


(Image courtesy of Energy Transfer Partners)

Construction takes place on the Rich Eagle Ford Mainline, a rich gas gathering system in the Eagle Ford shale.

Since it was founded in 1995, the company has grown into one of the largest energy partnerships in the US with approximately 43,000 miles of natural gas, NGL, refined products, and crude oil pipelines.

The ETP family of companies includes Sunoco Inc. and Sunoco Logistics Partners, which operates a geographically diverse portfolio of crude oil and refined products pipelines, terminaling and crude oil acquisition, and marketing assets. It also includes a 70% interest in Lone Star NGL, a joint venture that owns and operates NGL storage, fractionation, and transportation assets. ETP's general partner is owned by Energy Transfer Equity.

EQT Corp. /EQT Midstream Partners LP

- **Operates in 22 counties in West Virginia and Pennsylvania**
- **EQT Midstream Partners LP has acquired additional midstream assets from EQT Corp. since it was formed in 2012**

EQT Corp. is general partner and has a 44.6% interest in EQT Midstream Partners LP, which makes up 30% of the corporation's midstream business. Pittsburgh-based EQT operates 11,000 miles of pipeline in its midstream unit. About 70% of revenue from EQT Corp.'s directly owned midstream assets comes from movement of EQT's own production in the Marcellus shale and Appalachian basin.

EQT Midstream Partners LP has 700 miles of interstate pipeline and 32 Bcf of gas storage in 14 reservoirs, according to a company presentation to investors. Those lines, doing business as Equitrans Transmission and Storage System, connect to five interstate pipelines. The Equitrans Gathering System has about 2,000 miles of low-pressure gathering pipelines.

Part of the master limited partnership's strategy is to acquire key midstream assets from EQT Corp. To that end, the limited partnership bought the Sunrise pipeline from EQT for US $507.5 million plus additional shares in the partnership.

The limited partnership also is exploring organic growth and "increasing access to existing and new delivery markets," according to the company's website. While the company has good fixed contracts with EQT Corp. to move its products, the partnership also is working to gain more volume from third-party customers.

Eureka Hunter Pipeline LLC

- **Magnum Hunter Resources has begun monetizing its midstream assets through Eureka Hunter beginning with a $200 million investment from ArcLight Capital Partners**
- **Acquired gas treating company TransTex, which is active in the Eagle Ford shale**

Eureka Hunter operates 90 miles of gathering pipelines in the Marcellus play in West Virginia and the Utica in eastern Ohio. In an investor presentation, the company said the 350-MMcf/d capacity of the system also has "unlimited expansion opportunities."

The company, which is operated by production company Magnum Hunter Resources, has several new processing plants for NGL and is building an additional pipeline into the Utica shale.

As part of Magnum Hunter's efforts to bring in more money from the midstream assets, ArcLight Capital Partners made a commitment of up to US $200 million in Eureka Hunter and now owns 40% in the entity. Additional monetization of the assets is expected in 2014.

Several pipeline expansions were slated to come online in 3Q 2013 and 4Q 2013, and more are expected in 2014, according to a news release from the company.

Howard Energy Partners

- **Building a 200 MMcf/d cryogenic natural gas plant and NGL pipeline in the heart of the Eagle Ford shale**
- **Developing a bulk liquids storage facility at the Port of Brownsville with truck and rail loading and unloading and blending capabilities**

Howard Energy Partners made major investments in the first half of 2013 in the South Texas shale plays, where it operates nearly 500 miles of natural gas gathering pipelines including three distinct gathering systems.

The San Antonio-based company purchased most of the South Texas assets of Meritage Midstream in spring 2012 including the Eagle Ford Escondido Gathering System and the Cuervo Creek Gathering System.

In February, partnership officials said they would begin building a cryogenic natural gas plant to serve producers and midstream clients in the Olmos, Escondido, and Eagle Ford shale plays, all in South Texas. The 200 MMcf/d Reveille gas plant is slated for completion in early 2014. In conjunction with the Reveille plant, Howard Energy also is constructing the Falcon NGL Pipeline, which is designed to transport NGL after separation. The Falcon NGL Pipeline will consist of about 58 miles of 6-in. pipeline capable of moving 18,000 b/d to an interconnection with Enterprise's Eagle Ford NGL line.

Howard Energy Partners also is building a logistics railroad hub in Live Oak County for oilfield products that include NGL and condensate, water, pipe, and fracture sand in the heart of the Eagle Ford shale, according to a company news release.

Howard also is leveraging the Live Oak Rail Park location for access to multiple downstream markets for liquids products with a 10,000 b/d liquids stabilizer facility near Three Rivers, Texas, and the adjacent rail hub.

The Brownsville Terminal project will consist of 21 tanks providing a total of up to 225,000 bbl of bulk liquid storage. The strategic location gives access to the truck corridor between the Port of Brownsville and Mexico, the intercoastal waterway, railroads, and deep water.

A newly constructed pipeline crosses a Pennsylvania creek. Systems serving the state's developing Marcellus and Utica plays face complex permitting requirements due to the area's terrain.

Kinder Morgan Energy Partners

- **Opening an NGL pipeline with MarkWest Utica from the Utica and Marcellus shales to Mont Belvieu on the Texas Gulf Coast**
- **Gained ownership interest in 7,000 miles of pipeline with the $5 billion acquisition of Copano Energy**

As one of the largest pipeline limited partnerships in the US, Kinder Morgan Energy Partners has an interest in the major unconventional plays and has expansion projects in some of the largest, including the Marcellus, Utica, and Eagle Ford.

The limited partnership has an interest in 54,000 miles of pipeline and 180 terminals. Kinder Morgan Inc., the general partner in the limited partnership, has an interest or operates an additional 28,000 miles of pipeline.

In November, the limited partnership announced a joint venture with MarkWest Utica EMG to convert more than 1,000 miles of 24- and 26-in. Kinder Morgan Energy natural gas pipeline to handle NGL from Mercer, Pa., to Natchitoches, La., according to a company news release. Another 200 miles of similar pipeline will be constructed to make a completed connection between the heavy production in the Utica and Marcellus shale to a fractionation facility in Mont Belvieu, Texas. When the pipeline is operational, which is expected by 2Q 2016, initial capacity will be 150,000 b/d of NGL. It is being designed to add pump stations that would bring capacity up to 400,000 b/d.

In May 2013, the company bought out another Houston company, Copano Energy LLC, in a US $5 billion deal. The deal includes assets in Texas, Oklahoma, and Wyoming and 7,000 miles of pipeline that can handle up to 2.7 Bcf/d of natural gas, according to a company news release.

Kinder Morgan Energy Chairman and CEO Richard Kinder said the move expands the company's midstream services footprint and provides more services to customers.

"We will now pursue incremental development in the Eagle Ford shale play in South Texas and gain entry into the Barnett shale combo in North Texas and the Mississippi Lime and Woodford shales in Oklahoma," Kinder said in a written statement.

Magellan Midstream Partners LP

- **Increasing capacity of Longhorn pipeline in Texas by 50,000 b/d to 275,000 b/d to move Permian basin crude oil to Gulf Coast refineries**
- **Planning a 75,000 b/d refined-fuels pipeline with 160 miles of newly constructed line from Fort Smith to Little Rock, Ark.**

With 9,600 miles of pipeline and 50 terminals in 13 states down the center of the US, Magellan has plotted a course to move increased production from major shale plays and has increased production in the Permian basin.

The Tulsa, Okla.-based company is planning a 160-mile pipeline from its Fort Smith, Ark., terminal to the Little Rock area to provide that market access to gasoline, diesel, and jet fuel from Gulf Coast and Midcontinent refineries. If the 75,000 b/d project gets enough of a commitment from potential customers, it would be in operation by 3Q 2015, according to a company news release.

To meet increasing demand from producers in the Permian basin, Magellan is expanding the capacity of its existing Longhorn pipeline by 50,000 b/d to 275,000 b/d in a US $55 million project, according to a statement from the company. A $25 million project also will establish a new origin in Barnhart, Texas, about 75 miles east of an existing Permian basin origin in Crane, Texas. The new receiving point could start moving crude oil to the Gulf Coast for refining by early 2015.

MarkWest Energy Partners

- **Nearly $1.8 million invested in capital growth in 2013 and construction of 23 processing and fractionation plants under way**
- **Acquired Granite Wash-area midstream assets of a Chesapeake Energy subsidiary for $225 million**

MarkWest is extending its reach into unconventional plays with acquisitions and projects that began in 2013, including significant expansions in several formations in Texas and the Utica shale in the Northeast.

The company has gathering, transportation and fractionation, and storage assets from the Southwest to the Northeast with concentrations in the Marcellus, Utica, Huron/Berea, Haynesville, and Woodford shale plays along with the Granite Wash formation in the Texas-Oklahoma panhandle region. It is the largest processing and fractionation operator in the Marcellus shale and the southern Appalachian basin.

In the southern portion of the Marcellus shale, the company is constructing plants that will add 800 MMcf/d of cryogenic processing capacity, according to an August 2013 presentation at the Barclays CEO Energy Power conference.

In November, MarkWest Utica EMG, of which the limited partnership is part of, entered into an agreement with Kinder Morgan Energy Partners to convert more than 1,000 miles of Kinder Morgan Energy natural gas pipeline to move NGL from Mercer, Pa., to Natchitoches, La., and add another 200 miles of pipeline to connect Utica and Marcellus shale production to fractionation plants in Mont Belvieu, Texas, by mid-2016.

Another big move was the May 2013 acquisition of midstream assets from a Chesapeake Energy subsidiary. The US $225 million deal increased MarkWest's presence in the Granite Wash area across parts of Texas and Oklahoma. The one-time Chesapeake assets were connected to MarkWest's existing gathering system in August and began processing about 50 MMcf/d. The nearby Buffalo Creek plant is expected to be complete in 1Q 2014.

Martin Midstream Partners LP

- **Completed construction of a new dock at the Corpus Christi Crude Terminal for improved throughput**
- **Three new storage tanks, slated for completion in 2Q 2014, will add 300,000 bbl of additional crude storage at the Gulf Coast facility**

The Kilgore, Texas, company is focused primarily on the Gulf Coast. In February 2013, Martin purchased six pressure barges and two commercial push boats to expand its ability to handle NGL, especially from the Eagle Ford shale production in South Texas. The US $50.8 million purchase will add 96,000 bbl of barge capacity.

The November 2013 completion of the Corpus Christi Crude Terminal dock means better access and faster loading for Martin customers and will allow a higher throughput on barrels of crude at the facility.

Also in Corpus Christi, Martin expects to complete three additional storage tanks that will add 300,000 bbl of storage by mid-2014, according to a company news release.

Martin Resource Management Corp., recently sold a 50% interest in Martin Midstream's general partner to Alinda Capital Partners. In a statement announcing the company's 3Q 2013 financial results, CEO Ruben Martinez said the influx of capital has given the limited partnership "access to multiple acquisition opportunities that previously would have been unobtainable for the partnership on a standalone basis."

Meritage Midstream

- **Acquired with Thunder Creek Gas Services in August 2013**
- **Developing Black Thunder Terminal in a JV with Arch Coal for crude and condensate**

Meritage Midstream of Golden, Colo., made its mark in 2010 when it began development of 185 miles of gas gathering pipeline along the western edge of South Texas' Eagle Ford shale. When it sold those assets in spring 2013 to Howard Energy Partners, company leaders began looking to other promising unconventional plays.

By summer, backed with a US $500 million commitment from equity firm Riverstone Holdings, Meritage acquired Thunder Creek Gas Services from Devon Energy Corp. and PVR Partners, with 500 miles of gathering pipeline and gas processing facilities in the Powder River basin of Wyoming, according to a company news release.

In a joint venture (JV) with Arch Coal, Meritage also is developing the Black Thunder Terminal in Campbell County, Wyo., for Powder River basin crude and condensate storage, bleming, and railcar loading. The terminal will be at Arch Coal's Black Thunder mining complex.

Meritage has plans to develop additional crude gathering capacity, including linking the Thunder Creek lines to the Black Thunder Terminal to give more access to downstream markets.

In October 2013, Meritage announced the start of a binding open season for a new interstate common-carrier pipeline system that will transport unfractionated NGL produced in Wyoming's Powder River basin to potential delivery points on the Overland Pass Pipeline near the Colorado-Wyoming border and the Front Range NGL Pipeline near Lucerne, Colo. The Thunder Creek NGL Pipeline will provide Powder River basin producers delivery to NGL markets at Mont Belvieu, Texas, and/or Conway, Kan. The pipeline has a preliminary design capacity of 40,000 b/d and is expected to become operational in 2Q 2015.

Other areas under consideration for acquisition or greenfield development are Utah's Uinta basin and the Permian basin of West Texas and southern New Mexico, according to the company's website.

NuStar Energy LP

- **Will begin construction on two phases of expansion of the South Texas Crude Oil Pipeline System to add 100,000 b/d of capacity**
- **Building a private dock in Corpus Christi, Texas, to handle increased capacity coming from the Eagle Ford shale**

NuStar Energy has nearly 8,600 miles of pipelines and 87 storage and terminal locations for crude and refined products. The San Antonio-based partnership has assets worldwide, but many of its US assets are positioned to take advantage of the increased production from unconventional plays, particularly in Texas, along the Gulf Coast, and in the Midcontinent.

The company became highly focused on the Eagle Ford shale opportunities in the last year, and said it would proceed with the first phase of a South Texas Crude Oil Pipeline System project. The first phase would add 35,000 b/d of capacity. A second phase, slated for completion in 1Q 2015, would add capacity to move another 65,000 b/d, according to management discussion of operations with the release of 3Q 2013 earnings.

To help handle increased volumes from the first phase of the Eagle Ford expansion project, NuStar is building a private dock at its North Beach terminal in Corpus Christi, Texas, to double loading capacity to about 125,000 b/d.

Subsidiary NuStar Logistics had a late November 2013 target date to open a unit train rail terminal that can unload crude at a rate of as much as 100,000 b/d in St. James, La. The company operates a similar sized terminal for EOG Resources.

NuStar also has the capacity to store up to 97 MMbbl of crude and refined products.

ONEOK Partners

- **Capital investment in growth projects and acquisition reaches nearly $5.6 billion committed from 2010 through 2015**
- **Expansions include heavy investment in pipelines and plants in the Williston basin and in Oklahoma and Texas, including improvements at Mont Belvieu on the Gulf Coast.**

Specializing in natural gas gathering and processing and NGL transportation, ONEOK Partners is concentrated primarily in the Midcontinent region with expansion projects reaching to the Gulf Coast.

The company has 17,300 miles of gathering pipeline and 6,600 miles of transmission line

(Image courtesy of Hart Energy)

Service vehicles traverse the dusty caliche roads near Tilden in McMullen County, Texas, to support midstream development in the Eagle Ford shale.

for natural gas. The natural gas segment also includes 52 Bcf of storage and 16 processing plants. NGL assets include 4,125 miles of gathering pipeline, 3,660 miles for distribution, five fractionation plants, and 23 MMbbl of storage capacity, according to the company's website.

In an investor presentation in September 2013, the company reported that it already had committed nearly US $5.6 billion to capital projects and acquisitions beginning in 2010 and going through 2015 but indicated another $2 billion to $3 billion in projects have yet to be announced.

The company expects to complete the last of five processing plants and other infrastructure in the Williston basin of North Dakota by 1Q 2015. NGL Bakken and Overland Pass pipelines also completed expansions in 2013.

Midcontinent expansions included the 540-mile Sterling III NGL pipeline with a target opening of late 2013 to add up to 250,000 b/d.

Plains All American Pipeline

- **Approved expansion projects have reached $3.6 billion**
- **$120 million expansion under way of the Eagle Ford JV pipeline to handle up to 470,000 b/d of crude oil**

Plains All American Pipeline (PAA) has a foothold in most major basins and unconventional plays, where it is investing heavily in the coming years.

The company has committed US $3.6 billion to projects in the next few years, including $1.3 billion to $1.5 billion in 2014 and more than $1.6 billion in projects started in 2013, the company reported in a presentation to investors.

Permian, Eagle Ford, and Midcontinent activity was the primary driver of growth for the transportation segment, and the company forecast continued volume increases from those areas in 2014, PAA reported.

In presenting its 3Q 2013 earnings, PAA said it would place numerous projects in service in 1Q 2014, including Bakken North, a western Oklahoma extension, and a Gulf Coast pipeline project. An Eagle Ford shale joint venture (JV) with Enterprise Products for a 125-mile oil and condensate system is being put into service in stages into 2015. In September, the company announced an expansion of the Eagle Ford JV pipeline to a capacity of 470,000 b/d of light and medium crude oil to handle volume increases coming from Plains' Cactus pipeline when construction is complete. Cactus, which will carry crude from the Permian basin to Gardendale, Texas, will have a capacity of 200,000 b/d.

The $120 million Eagle Ford JV project is scheduled for completion by mid-2015 and includes 2.3

BNSF has the largest share of crude-by-rail traffic originating in the Bakken. It serves 10 loading terminals in the Williston basin, moving crude to customers throughout the US.

(Image courtesy of BNSF Railway Co.)

MMbbl of storage capacity in Gardendale, Corpus Christi, and Tilden, Texas.

The company also put an additional 90 miles of its Gardendale Gathering System into operation in 2013.

Total crude transportation reached an average of 3.74 MMb/d in 3Q 2013.

Regency Energy Partners

- **Acquiring PVR Partners in a $5.6 billion deal expected to close in early 2014 to establish a presence in the Appalachian and Midcontinent regions**
- **Nearly $500 million in organic growth projects under way**

Between mid-2012 and August 2013, Regency completed nearly US $1 billion in growth projects including increasing capacity in liquids-rich plays in the US. A $490 million project expanding assets in the Eagle Ford shale is slated for completion in early 2014, according to a company presentation in August during the Citi One-on-One MLP/Midstream Infrastructure Conference. Another $470 million in expansions are under construction.

The Dallas-based company operates gathering, processing, contract compression and treating, storage, and transportation of natural gas and NGL in the Barnett, Eagle Ford, Fayetteville, Haynesville, and Marcellus shale plays along with assets in the Permian Delaware basin, according to the company's website.

In 2Q 2013, Regency acquired Southern Union Gathering from Energy Transfer Partners for $1.5 billion. The acquisition included 5,600 miles of gathering and NGL pipeline, five natural gas processing facilities, and five treating facilities in West Texas and southeastern New Mexico.

Regency also announced the intent to acquire PVR Partners in October 2013 in a deal worth $5.6 billion, according to a company news release. The deal would give Regency a strategic foothold in the Marcellus and Utica shale plays in the Appalachian basin and the Midcontinent Granite Wash.

The merger will propel Regency into one of the largest independent gas gathering and processing master limited partnerships in North America. "Scale is increasingly necessary to profit from organic development and [merger and acquisition] opportunities in midstream," the company said in a presentation about the merger with PVR.

SemGroup Corp.

- **$850 million in 2013 capex for SemGroup and Rose Rock Midstream, with $300 million to $400 million planned for 2014**
- **Two-year spending on Mississippi Lime gas gathering and processing acquisition totals $470 million**

Assets of SemGroup and Rose Rock Midstream are focused on the Midcontinent area including the Bakken, Montney/Duvernay, Denver-Julesburg (DJ) basin and Niobrara, and the Mississippi Lime and Granite Wash plays. The company also has a presence in the major liquids transit interchange of Cushing, Okla., according to the company's website.

The 527-mile White Cliffs Pipeline for crude oil from the DJ basin to Cushing is undergoing an 80,000 b/d expansion that is expected to be complete by 2Q 2014, the company reported in an October 2013 presentation during the Deutsche Bank Leveraged Finance Conference.

The Glass Mountain Pipeline, slated for completion in late 2013, will move 140,000 bbl of crude daily over 210 miles with two lateral lines that join the Granite Wash and Mississippi Lime areas and go to Cushing. In 4Q 2013, the company expected to complete the 37-mile Wattenberg Oil Trunkline, which connects to the White Cliffs Pipeline and includes storage in the DJ basin.

Rose Rock Midstream crude assets are concentrated in the Kansas-Oklahoma and Bakken shale areas with connections to Cushing, where the company has 7.25 MMbbl of storage and capacity for another 250,000 bbl for blending as of late 2013.

The Kansas-Oklahoma system has 640 miles of gathering and transportation pipeline and a capacity of 40,000-plus b/d.

In September 2013, Rose Rock acquired Barcas Field Services with its fleet of 114 crude oil trucks.

Sunoco Logistics Partners

- **The Granite Wash area of the Texas Panhandle and southeast Oklahoma will have 200 miles of new pipeline by year-end 2014**
- **Committed $700 million in organic expansion capital in 2013**

Sunoco Logistics Partners is heavily focused on organic growth of pipeline capacity of existing assets, many of them in the heart of unconventional plays in Texas and Louisiana. The firm currently has 4,900 miles of crude oil trunkline, 500 miles of gathering lines, and a large fleet of transport trucks.

Also in the crude oil segment, Sunoco has 41 terminals for refined crude oil products and storage capacity of 8 MMbbl. The company has 22 MMbbl of storage capacity at the Texas Gulf Coast Nederland Terminal, 5 MMbbl of capacity on the Delaware River in New Jersey, and another 3 MMbbl of capacity at three facilities in the Philadelphia area, according to the company's website.

Refined products pipelines include 2,500 miles transporting throughout the Northeast, Midwest, and Gulf Coast of the US. The company also owns a two-thirds stake in the 100-mile Harbor pipeline and is a joint venture partner in four other refined products pipelines around the country.

Sunoco Logistics, based in Philadelphia, is a master limited partnership owned by Energy Transfer Partners, which also owns Regency Energy Partners.

Among the numerous organic expansion projects in the works are the Permian Express I, which will be able to move 150,000 b/d when finished in early 2014. By mid-2014, Sunoco will have greater capacity for the Eaglebine Express and Allegheny Access pipelines, the company reported in an August 2013 presentation during the Citi One-on-One MLP/Midstream Infrastructure Conference.

The Mariner East I pipeline will be ready for increased propane transportation by mid-2014 and for ethane and additional propane transportation by mid-2015. The Granite Wash expansion is expected to be ready by year-end 2014, and Marine South by 1Q 2015.

Superior Pipeline Co.

- **Conservative growth with a focus on the Mississippian play in Kansas and Oklahoma and the Granite Wash in Texas and Oklahoma**
- **Operating gas gathering pipeline in the Marcellus shale of Pennsylvania and West Virginia**

Most of Superior's operations and expansion are focused on unconventional plays in the Texas/Oklahoma panhandle; southeastern, central, and western Oklahoma; Southeast Texas; Pennsylvania; and West Virginia.

The Tulsa, Okla.-based Superior, a wholly owned subsidiary of Unit Corp., moves more than 525,000 gal/d of NGL through 1,411 miles of pipeline. An October presentation to investors in Unit showed the midstream operations of Superior have grown by 144% for natural gas processing, with a 177% increase for daily volume of liquids sold since 2008.

Unit increased exploration in the Mississippian play on the border of Kansas and Oklahoma, while Superior completed an associated pipeline and a processing plant. The company expected to have a gathering pipeline in the play connected to 164 wells by year-end 2013 in the Mississippian and to complete several cryogenic plants at a cost of US $34.5 million, according to the information given to investors.

The company also had approximately $12 milion in capex in the Granite Wash area of the Texas

Panhandle and stretching into western Oklahoma, where Superior has a processing facility and 308 miles of pipeline.

Targa Resources Partners LP

- **$1.7 billion in organic growth projects through 2014, including expansions in major shale plays**
- **Expanding export capabilities from the Galena Park Marine Terminal on the Gulf Coast**

Most of the capital investment of Targa Resources Partners LP in 2013 and in 2014 is targeted to increasing processing capacity and NGL fractionation for increased liquids from several US shale plays.

The company, in a presentation during the Barclays CEO Energy-Power Conference in September, said it would spend US $1.7 billion to that end by year-end 2014. That includes operations in Louisiana and the Permian basin in Texas and developing and entering the Bakken shale in North Dakota and Montana.

The company also is working on growing its ability to handle the additional oil and gas at its Gulf Coast facilities for export. In early 2013, Targa acquired more property on the Houston Ship Channel to expand the Targa Patriot Marine Terminal. That terminal, the company said in a news release, can be easily connected to its Galena Park Marine Terminal 2 miles away and a complex at Mont Belvieu, Texas, where it does fractionation.

Already active in the Barnett shale of Texas, Targa has added a compressor station in Jack and Palo Pinto counties and expects to complete the 200-MMcf/d Longhorn plant in early 2014, the company said in the Barclays presentation.

TransCanada

- **Completed the Gulf Coast Pipeline Project from Cushing, Okla., to Nederland on the Texas Gulf Coast in late 2013**
- **Developing a 435-mile pipeline for Shell Canada Ltd. to move natural gas from Dawson Creek to Kitimat, British Columbia, Canada**

The Keystone pipeline is TransCanada's biggest claim to fame, but even as it awaits approval to finish the Keystone XL, the company is already moving substantial amounts of oil from Canada to the Midwest US and into Cushing, Okla.

The completion of the US $2.3 billion Gulf Coast Pipeline project allows up to 830,000 MMb/d to flow from Oklahoma to Gulf Coast refineries through 485 miles of line. The project also added 2.25 MMbbl of new oil storage capacity at the Cushing facility and six pump stations, according to a company news release.

The Houston Lateral Project, which is in the works, will take oil from Nederland, Texas, on to Houston-area refineries.

TransCanada also has 42,500 miles of natural gas pipelines, thousands of miles of oil lines, and partial interest in additional assets.

At press time, TransCanada was still awaiting US governmental approval to complete the last leg of the 36-in. Keystone XL pipeline, the last 1,179 miles of which have been stalled by environmentalists and political wrangling. At issue is the stretch from Hardisty, Alberta, Canada, to Steele City, Neb., on the Kansas border.

The project also includes the Bakken MarketLink, which would receive Bakken oil in Baker, Mont., and take it to Oklahoma and on to Gulf of Mexico refineries.

Valero Energy Partners LP

- **Subsidiary formed in July 2013 and a $345 million IPO possible in the first half of 2014**
- **Initial assets are pipelines carrying crude and refined projects to and from Valero Energy Corp. refineries in the Midcontinent and Gulf Coast regions**

Valero Energy Corp. will be the primary customer in the master limited partnership Valero Energy

Partners, which will include crude and refined-products pipelines associated with existing Valero refiners in the Midcontinent and Gulf Coast regions. Those include assets related to refineries in Sunray, Texas; Memphis, Tenn.; and Port Arthur, Texas, according to a statement from the company.

Although the company is keeping quiet on what other assets could potentially "drop down" into the limited partnership, Valero Energy has significant terminal and railcar assets under development that could fit the bill. In its 3Q 2013 earnings release, Valero Energy CEO Bill Klesse said the company completed a rail unloading facility at its Quebec City refinery to receive shipments of lower cost Canadian and US crude oil.

The subsidiary has filed a registration statement with the US Securities and Exchange Commission for a probable initial public offering (IPO) to trade under the ticker symbol VLP on the New York Stock Exchange. The San Antonio, Texas-based company expects to raise at least US $300 million in the IPO.

This is not the first time Valero has spun off midstream assets into a limited partnership. That spin-off eventually went on to become an independent company now called NuStar Energy, with master limited partnerships of its own.

Williams Partners LP

- **Expanding pipeline from Pennsylvania to New Jersey and into Alabama at a cost of $610 million**
- **Expects the company will gather 5 Bcf/d in the Marcellus shale by 2015**

Several ongoing expansions of existing assets are aimed at growing natural gas processing and transportation capacity for Williams Partners LP, which operates mostly in Colorado, New Mexico, Wyoming, the Gulf of Mexico, and the Marcellus shale.

An integrated natural gas company, Williams Cos. Inc. owns 68% of the partnership and has operations along the Gulf Coast, in the Pacific Northwest, in the Rocky Mountains, along the eastern seaboard, and in the Marcellus shale in Pennsylvania.

Billions of dollars' worth of expansion plans are in the works, mostly through joint ventures (JVs). Some came online in 2013, and several more each year will reach completion through 2017, according to a company presentation made at the Barclays CEO Energy-Power Conference in September.

Those capital projects include a US $354 million JV in the Utica shale with Blue Racer Midstream, $610 million on the Leidy line from Pennsylvania to New Jersey and into Alabama, and more than $450 million for the Geismar expansion.

The Bluegrass Pipeline calls for constructing new NGL lines from the production areas of Ohio, Pennsylvania, and West Virginia and connecting to Texas Gas in Kentucky, where the pipeline will hitch a ride to the Gulf Coast. In coastal Louisiana, Williams is building a large-scale fractionation plant and expanding storage for NGL. ■

Continued Growth For North American Unconventionals

Mike Warren
Senior Vice President, Hart Energy Research & Consulting

Production from shale and light tight oil formations ramps up, with liquids-rich plays attracting significant capex.

North American production of oil and gas from shale and light tight oil formations continues unabated. Production has increased year over year with only two dry gas plays experiencing a decline. Many states have registered all-time highs in oil/condensate production as a byproduct of the high oil price environment. Continued production of NGL has helped the US double and triple butane and propane exports, respectively, during the past three years. Consequently, the *North American Shale Quarterly* (NASQ) forecasts continued growth in petroleum supply into the next decade for existing shale and light tight oil formations. Moreover, several plays currently not covered by the NASQ – among them Huron, Heath, New Albany, and Antrim – are waiting for a pickup in natural gas demand to be delineated.

Commodity pricing for hydrocarbons has stabilized the past year, but the industry still prefers to develop liquids-rich plays, owing to their better economics. Natural gas prices remain well below the historical 6:1 ratio to oil, but Henry Hub prices are 23% above the 3Q 2012 average of US $2.88/MMbtu. Also, natural gas has clawed back some pricing gains vis-à-vis NGL since 1Q 2013.

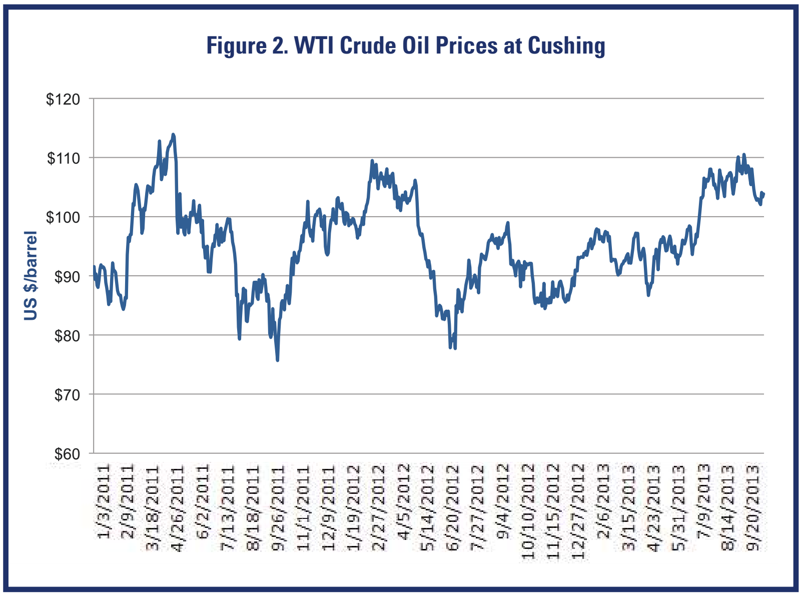
Turmoil in the Middle East and North Africa region has prompted West Texas Intermediate (WTI) crude oil prices to climb to an average of $105.82/bbl or 14% above 3Q 2012. Moreover, the spread between Brent and WTI has narrowed considerably the past year. In 3Q 2012, Brent sold for $17.74/bbl more than WTI, but that differential narrowed to $4.22 in 3Q 2013. The emergence of crude by rail has undoubtedly been a determining factor in the narrowing differential.

The Hart Energy NGL price (see editor's note) has averaged roughly $40/bbl the past 12 months, but the actual price continues to decrease as a percentage of WTI despite a 33% increase in exports of LPG, according to January-to-July data from the US Energy Information Administration.

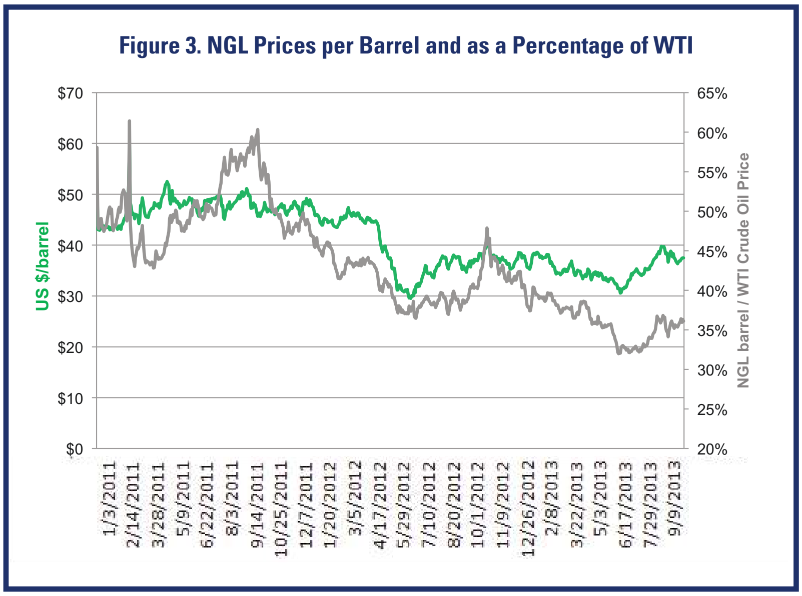
Figure 1. Natural Gas Prices per MMbtu and as a Percentage of NGL Barrel Theoretical Prices

(Source: Bloomberg)

Editor's note: Hart Energy Research & Consulting uses this weighting for calculating an assumed NGL barrel price: 36.5% ethane, 31.8% propane, 11.2% natural butane, 6.2% isobutane, and 14.3% C5 (or natural gasoline).



(Source: Bloomberg)

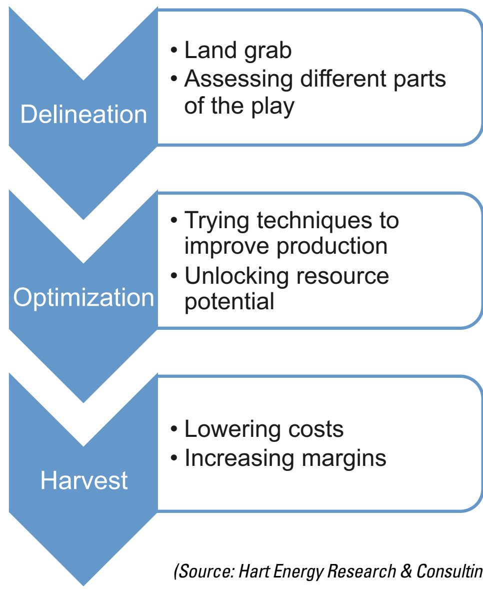


(Source: Bloomberg)

- During the optimization phase, operators experiment with different completion techniques such as the length of laterals, the number of fracturing stages, and the type of sand and water used to unlock hydrocarbon resources; and
- The harvest phase of production kicks off when the play is delineated and operators have identified the best completion techniques to unlock the resource potential; during the harvest phase, pad drilling is used to reduce costs and increase margins.

Several plays have moved to the harvest phase of production, and pad drilling has increased rapidly in the Marcellus, Bakken/Three Forks, and Eagle Ford, with many other plays moving more quickly into this final phase of development.

Figure 4. Play Life-cycle Phases



(Source: Hart Energy Research & Consulting)

Pad drilling reduces rig count

The biggest year-over-year change in North American onshore unconventional oil and gas production has been the advent of pad drilling. Hart Energy Research & Consulting's analysis of a play's life cycle identifies three distinct phases:

- The delineation phase best describes operators' search for the play's sweet spot(s); operators drill individual wells to map out future drilling locations;

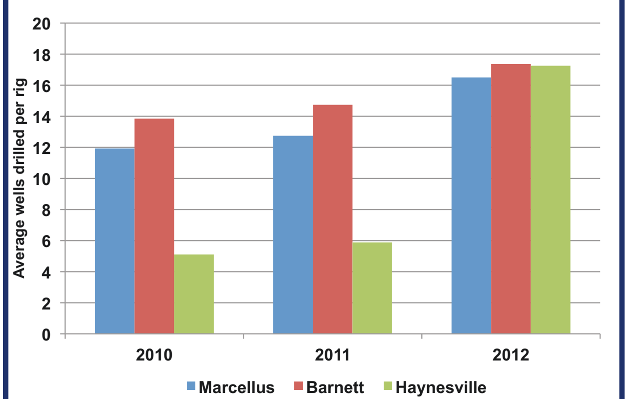
In a recent survey conducted for Hart Energy Research & Consulting, nearly all industry respondents were satisfied with time and cost savings associated with pad drilling when compared to drilling standard, individual well locations. Overall, roughly 60% of all wells were drilled on pads in 2013, according to the survey of four key unconventional plays – the Marcellus, Bakken/Three Forks, Permian basin, and Eagle Ford. The overall share of wells drilled on pads will increase to roughly two-thirds in 2014. The average number of wells drilled per pad in North America was 4.2 in 2013, with the Marcellus averaging six and the Permian basin averaging only two.

While pad drilling is definitely making inroads, there is no consensus on the best approach to drilling multiple wells on pads. Some operators are moving to a "batch" drilling approach in which the top holes are drilled first for all wells on the pad, followed by the intermediates and laterals. The biggest drawback to pad drilling is coordinating logistics (equipment, goods, and services) that are needed at the site given the heightened drilling cadence. Safety also is a concern, given the close proximity of the wells with multiple activities taking place.

The bottom line for operators using pad drilling, however, continues to improve. According to the proprietary survey, well costs have fallen by 17.6% in comparison to individual wells drilled. The amount of cost savings in dollars varies by play, but the average calculated by the survey is $900,000 per well. Cost savings accrue from reduced rig downtime and lower logistical costs, given fewer truckload miles. Of course, offtake capabilities need to be present when moving to the harvest phase.

Pad drilling also has affected rig count. According to the well count analysis, 2013 would see more wells drilled than 2012. Rig count, however, has actually fallen. Efficiencies gained from pad drilling are best represented by Figure 5, which demonstrates the increased number of wells drilled per rig in the Marcellus, Barnett, and Haynesville shale gas plays.

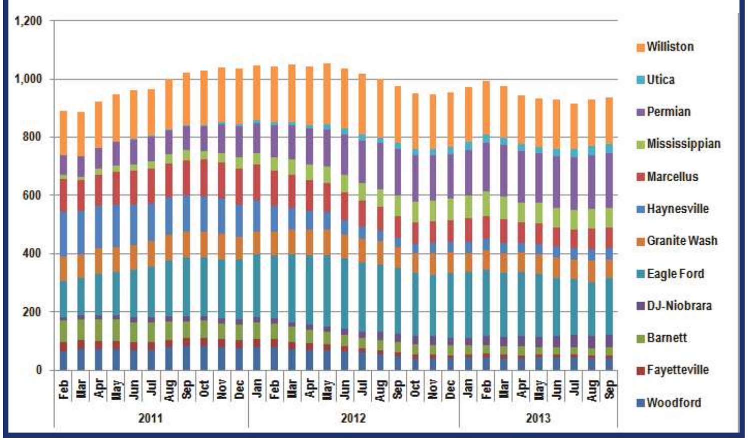
Figure 5. Wells Drilled per Rig by Play



(Source: Hart Energy Research & Consulting, North American Shale Quarterly, 3Q 2013)

In comparison to September 2012, the September 2013 rig count fell by 4%, or 41 rigs, in the US. The Utica and Niobrara have seen rigs double from a low base in a year-over-year comparison, while most areas have seen marginal declines.

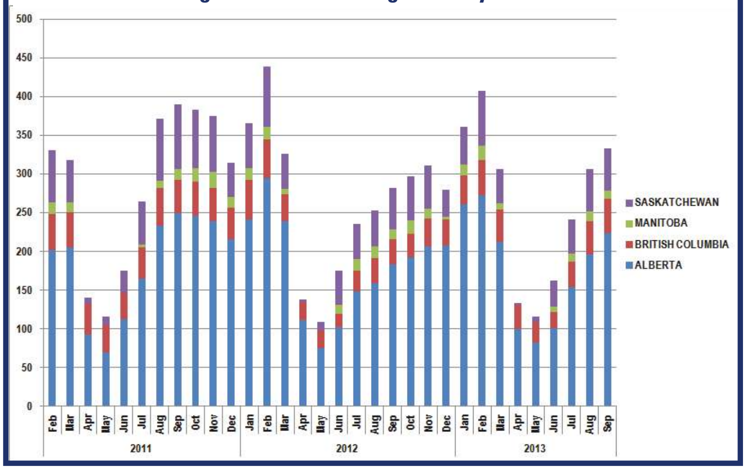
Figure 6. US Rig Count by Play



(Source: Baker Hughes International)

The Canadian rig count has increased by 50 from September 2012, up 18% year over year. The Duvernay and the liquids-prone part of the Montney are attracting attention north of the border.

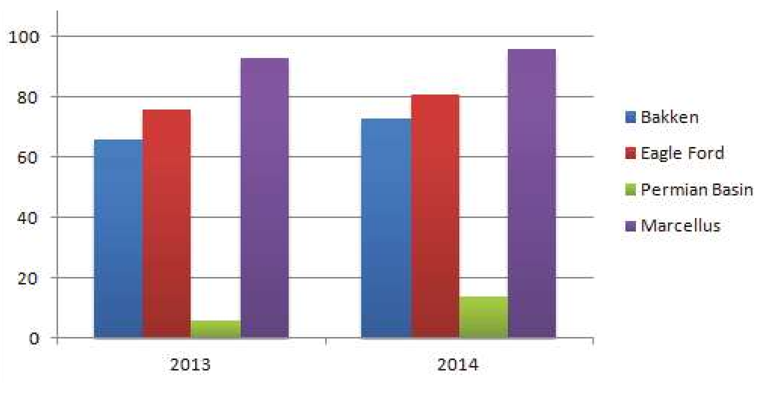
Figure 7. Canadian Rig Count by Province



(Source: Baker Hughes International)

Pad drilling has had an impact on rig count in 2013, but that impact could be larger in 2014 as more plays move into the harvest phase of production. Of the four plays that were surveyed, respondents reported that the operators expected to further increase the number of wells drilled on pads in 2014. The Marcellus already had the highest percentage of wells drilled on pads, according to a 2012 Petroleum Equipment Suppliers Association industry survey. The 2013 NASQ survey also reveals surging pad drilling activity in the Bakken. For the two Texas plays, the Eagle Ford was expected to deploy a higher percentage of wells on pads in 2013 than the Bakken, demonstrating that the condensate/NGL fairway is well into the harvest phase. The Permian basin, however, is in the delineation phase as only 6% of its wells were expected to be drilled on pads in 2013.

Figure 8. Pad Drilling Market Share Forecast



(Source: Hart Energy Research & Consulting, North American Shale Quarterly, 3Q 2013)

Overall, the number of unconventional wells drilled is expected to increase by 9% in 2014 compared to 2013. Although the percentage increase is lower on a year-over-year comparison when looking at 2013 vs. 2012, the increased number of unconventional wells drilled more than offsets the decline in vertical wells drilled during the same period. In 2013, the NASQ forecast suggested the same: the increased number of horizontally drilled wells will offset the decline in vertical well drilling. More than one-half of the decline in vertical wells drilled in 2014 should come from the Permian basin as operators deploy an increased number of rigs drilling horizontal wells.

Liquids-rich plays

Given the increase in the well count forecast for 2014, liquids-rich plays will be attracting significant capex in North American shale and light tight oil plays. Of the plays described in more detail in this report, the Bakken/Three Forks, Eagle Ford, Permian basin, Niobrara, Panhandle light tight oil formations (Tonkawa, Cleveland Tight, and Marmaton), Utica, Mississippi Lime, Duvernay, Cardium, and the Alberta Bakken (Exhaw) are considered liquids-rich.

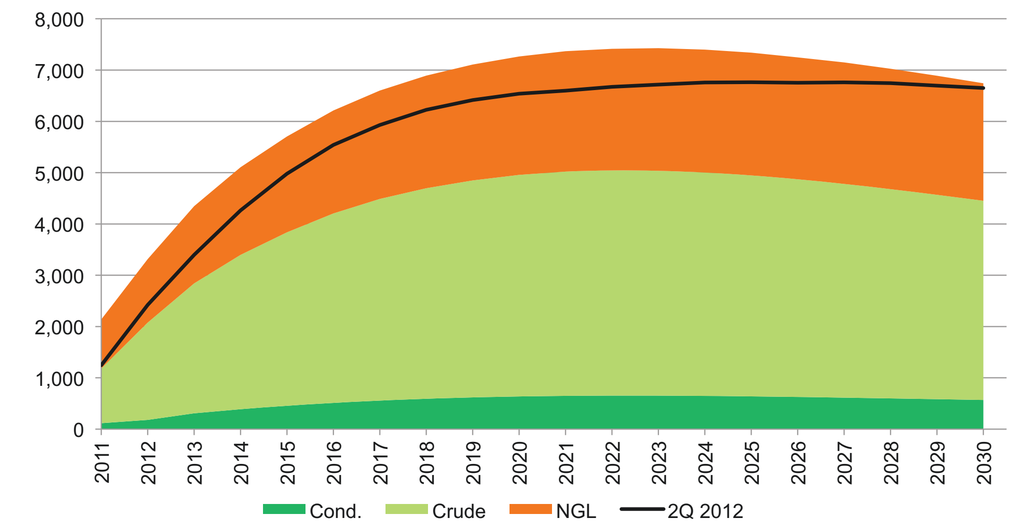
Given triple-digit oil prices, more capex, and more wells drilled in liquids-rich formations during 2014, the NASQ forecasts a year-over-year increase of 550,000 boe/d in liquids (condensate/oil) production and nearly 200,000 b/d of NGL. Figure 9 calculates production on a barrel of oil-equivalent basis, which captures oil, condensate, and NGL. Compared to the NASQ 3Q 2012 forecast, the oil/condensate production is roughly the same; however, NGL production has increased as more operators have moved to liquids-rich gas plays and are squeezing more value from their production streams. For example, most drilling activity in the Eagle Ford has been concentrated in the NGL/condensate fairway. Operators in the Haynesville/Bossier have redirected their focus to Cotton Valley liquids production, which sits atop the shale play in East Texas.

Natural gas plays

In the earlier developments of North American shale resources, natural gas received most of the attention. Today, there are significant volumes of natural gas production from plays that are loosely grouped together as liquid-producers. In comparison to 3Q 2012, two dry gas plays have rolled over in regard to production. The Barnett is past its peak, with most drilling activity happening in the liquids-rich part of the play called the Combo.

Haynesville production also has declined, but as soon as natural gas demand – specifically LNG – comes online in 2016 to 2017, it is expected that production will reach new highs but not approach production coming out of the Marcellus. In fact,

Figure 9. North American Resource Play Liquids Production Forecast (Mboe/d)



(Source: Hart Energy Research & Consulting, North American Shale Quarterly, 3Q 2013)

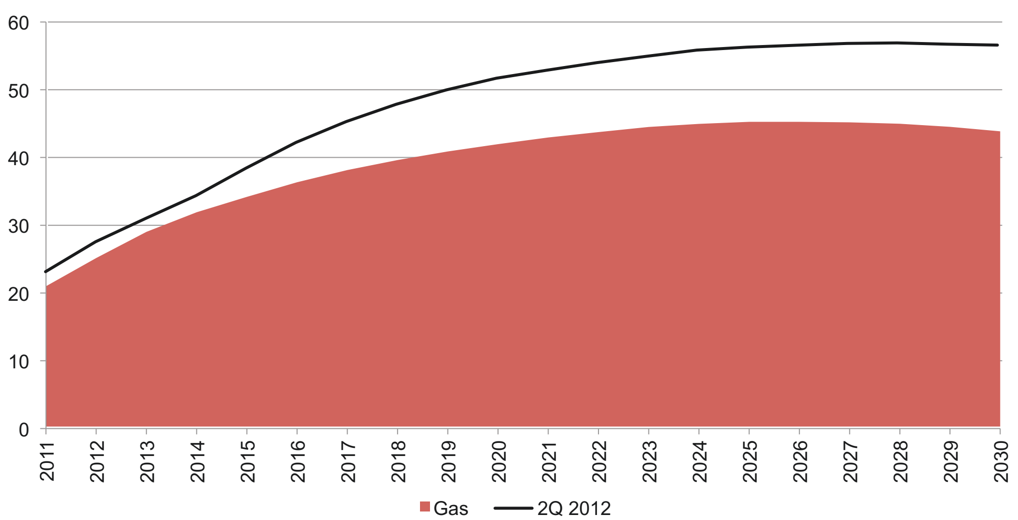
the Haynesville rig count increased by six year-over-year in September 2013.

The "Beast in the East" already is having a profound effect on natural gas markets in the northeast US. The Marcellus quickly surpassed lagging production from Haynesville in 2012, becoming the No. 1 dry gas-producing play in North America. Going forward, the Marcellus will have a dramatic effect on the nation's natural gas grid, pushing back Gulf of Mexico and Rockies production.

Although the natural gas production forecast has been pared back, year-over-year growth in dry gas production from the 17 shale plays has occurred because of associated gas production from aforementioned liquids plays.

More importantly, there are several dry gas plays – Huron, New Albany, Cordova Embayment, and Antrim – that could be put into production when demand (domestic as well as export via LNG) increases after 2016. ■

Figure 10. North American Resource Play Dry Gas Production Forecast (Bcf/d)



(Source: Hart Energy Research & Consulting, North American Shale Quarterly, 3Q 2013)

Additional Information on the Top 20 US Resource Plays

For more details on the top 20 US unconventional resource plays, consult the selected sources below.

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Senior Editor, *E&P*

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