HARTENERGY

2015 Unconventional Yearbook

The Top 20 North American Resource Plays

Oil and Gas Investor
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2015 Unconventional Yearbook

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2015 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 2015 Unconventional Yearbook presents the most important facts and figures on the Top 20 North American resource plays. This fifth 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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Cover photos *(clockwise from top left)*: PowerDrive Orbit features a new pad design *(photo courtesy of Schlumberger)*, the Schramm T500XD rig features a 360° walking system *(photo courtesy of Schramm)*, workers loosen the lubricator atop one Gloria wheeler well as another well on the same pad is prepped *(photo by Tom Fox, courtesy of Oil and Gas Investor)*, hydrogen sulfide and CO_2 are removed from condensate in the amine contactor at Howard Energy Partners' Live Oak Stabilizer in the Eagle Ford *(photo by Joseph Markman, Hart Energy) Cover Design by Melissa Ritchie*

(Photo by Dan Young, courtesy of Oil and Gas Investor)

A Geologic Review of the Top 20 Plays of North America

By **Steve Thornhill**, Contributing Editor

Snapshots of the 20 current unconventional plays scattered across North America and Canada are listed below.

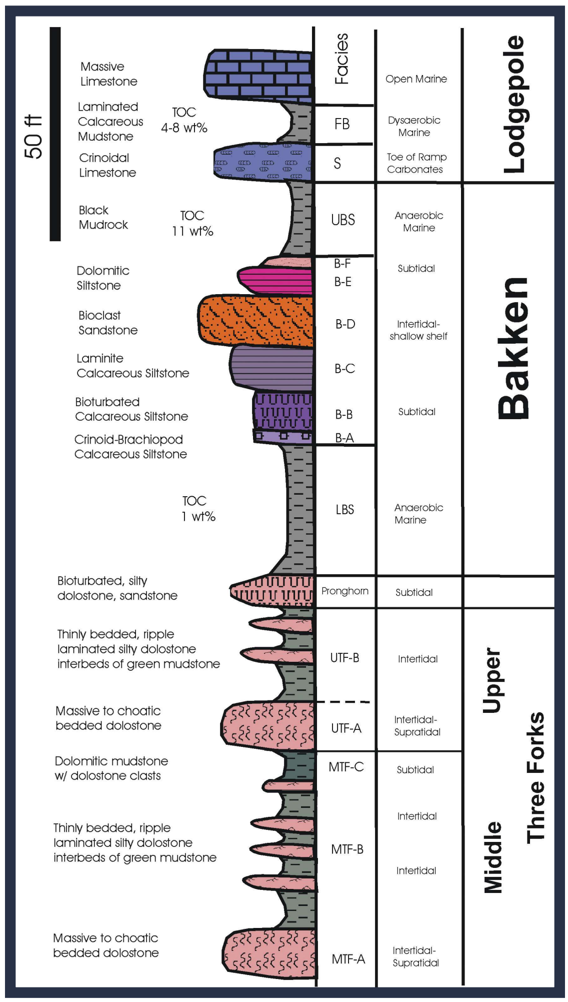
It's incredible to believe that just a few years ago a well-respected oil company executive stated that the Barnett Shale and Eagle Ford Shale plays were simply anomalies and that they were the beginning and end of the road for unconventional production. Recent history has certainly shown that naysayer a thing or two. It's good to remember that there was a time when the world's so-called experts were convinced that the world was flat.

Listed below are snapshots of 20 current unconventional plays scattered across North America and Canada. Because of today's economics, these plays are generally either oil or gas liquids; however, some gas plays were just too spectacular to leave out.

Bakken/Three Forks

The Upper Devonian/Lower Mississippian Bakken/Three Forks oil play in Montana and North Dakota's Williston Basin keeps getting better as geologists and engineers learn more about the formations and as technology improves. The formations blanket about 200,000 sq miles and produce from depths of 10,000 ft or greater. The Canadian oil industry is reaping riches from the formation where it extends into Canada's Saskatchewan and southwest Manitoba provinces. Stratigraphically, the Bakken consists of three members: upper and lower organic-rich black shale members and a highly-friable mixed silt, sand and carbonate middle member. The Three Forks Formation directly underlies the Bakken and consists of dolomite, mudstones and bituminous shale, reaching thicknesses ranging from 110 ft to 260 ft. Typically, wells are drilled to the Bakken's middle member and are then drilled horizontally for 2 miles or more through the petroleum-rich, friable, silty and sandy dolomitic layer. Multistage hydraulic fracturing applied throughout the horizontal length releases the formations' hydrocarbons.

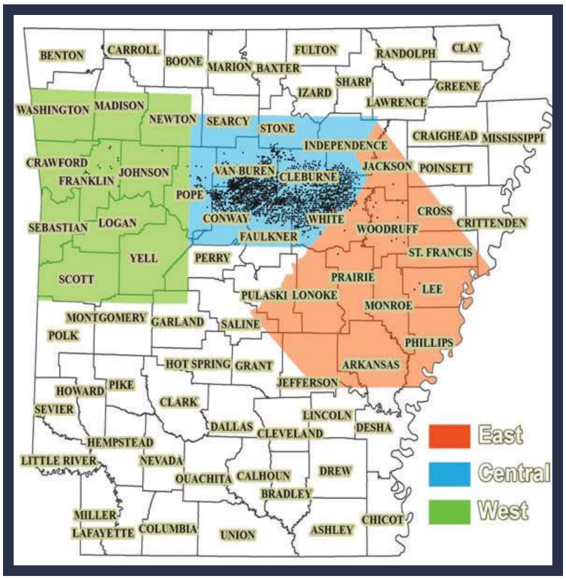
(Resistivity lines drawn from Hester and Schmoker, 1985)



A stratigraphic column for the Bakken Petroleum System shows the various facies, which are recognized in the core. Targets for horizontal drilling are Middle Bakken facies B, C, D and E and all facies in the Middle and Upper Three Forks.

Facing page: BHP Billiton Petroleum zipper fractures its Crozier A wells, a five-well pad targeting the upper Eagle Ford Shale in DeWitt County, Texas.

(Source: Arkansas Geological Survey)



The east, central and west regions of the Fayetteville Shale run across the Arkoma Basin in Arkansas.

Because the Bakken consists of three layers—upper and lower source/seal rock layers and a friable middle layer—when the formation produces oil from its source/seal layers, the oil is expelled into the middle layer where the volume increase causes natural fracturing in the highly-friable confined rock. Hydrocarbons also are expelled into the underlying Three Forks Formation. In addition to natural fracturing, the Bakken's highly-friable middle layer is highly susceptible to induced hydraulic fracturing as well. The underlying Three Forks Formation has been generating operator interest in central basin areas where the upper parts of the formation, close to the Bakken base, have been producing economic hydrocarbon volumes.

More good news regarding the Bakken is that operators are learning newer, better and more economic Bakken completion methods. Multiple laterals of 15,000 ft or more drilled from a single well are not uncommon. Although Bakken wells remain expensive, wells such as a recent Halcón Resources well with an IP of 4,225 boe/d make the Bakken a continued economic success.

Barnett

When many operators hear Barnett, they think about natural gas. However, the Mississippian Barnett Shale play also has a liquids-rich component. The Barnett Shale blankets a 5,000-sq-mile area, much of it in the Dallas/Fort Worth metroplex. The shale is found at depths ranging from 7,500 ft to 10,000 ft and with thicknesses of 1,400 ft to 1,700 ft in Fort Worth Basin's oil-rich Barnett Combo play area. It's typically described as a friable, organic-rich black marine shale source rock. Operators drill horizontally through the shale with lateral extensions based on area geology and operator lease holdings. The wells are stimulated with multistage hydraulic fracturing, applied throughout the laterals' length. The Barnett's oil-window is found in Montague, Cook, Clay and Jack counties.

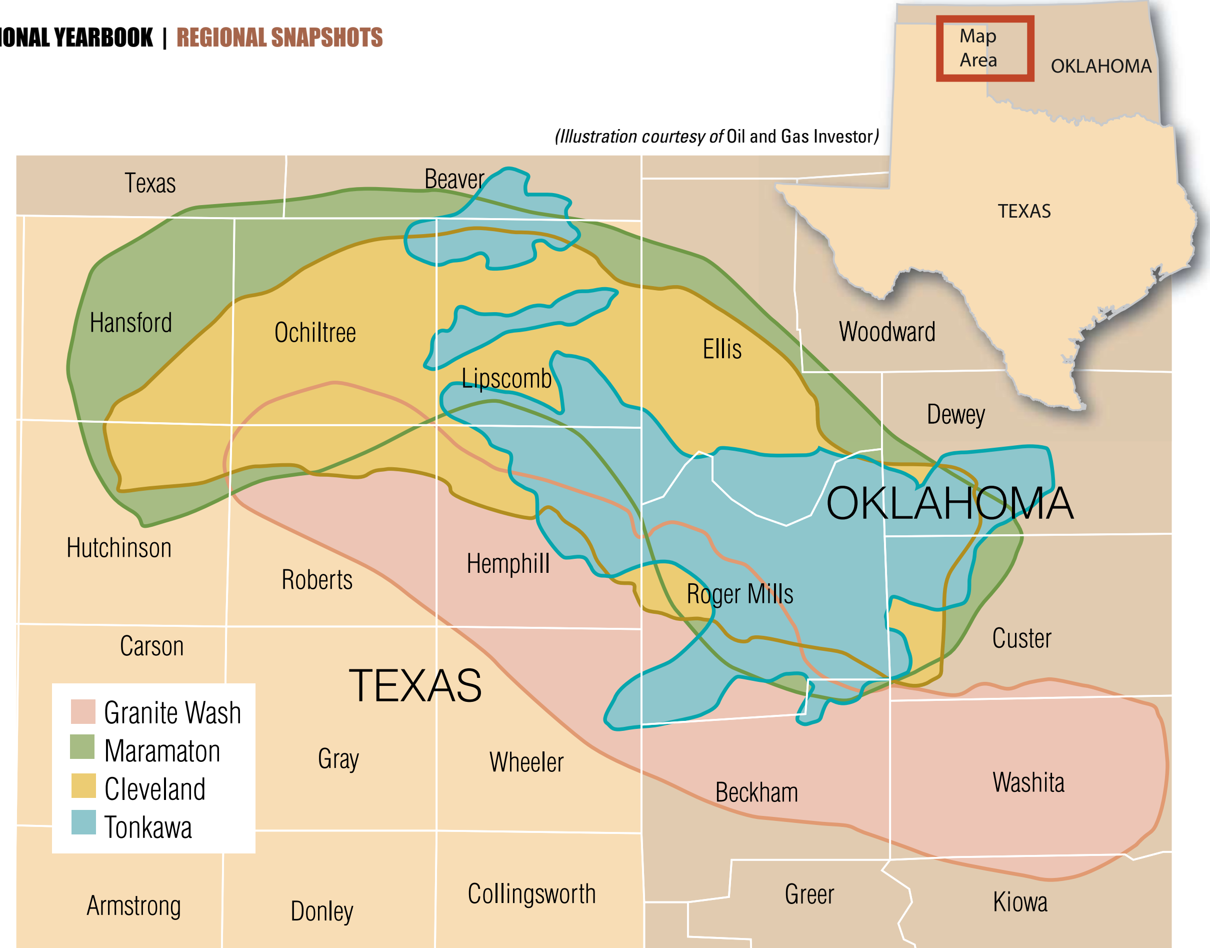
EOG Resources continues to operate in the Barnett Combo with published production results from its 2013 annual report listing total play production at 36 Mbbl/d of liquids and 305 MMcf/d of natural gas. Furthermore, according to EOG's 2013 annual report, it planned to drill 105 additional Barnett wells in 2014.

Cleveland

The Cleveland Formation was deposited during the Lower Pennsylvanian and is a tight gas sand varying in thickness from 0 ft to 590 ft with thicker areas in the eastern Texas Panhandle areas of Lipscomb, Hemphill and Wheeler counties. The Cleveland generally thins to the west, northwest and north into Oklahoma. In eastern Oklahoma, the Cleveland is found at measured depths ranging from 2,500 ft to 3,500 ft and produces oil. In western Oklahoma, the Cleveland is found at measured depths ranging from 7,000 ft to 9,000 ft and produces gas and wet gas. It's bound top and bottom with radioactive shales, making it easy to map. The Cleveland is underlain and probably sourced by Marmaton Group shales as well as other Pennsylvanian shales. Indeed, petroleum sampled from Cleveland reservoirs suggests multiple hydrocarbon sources.

One of the keys to economic Cleveland production is sweet spot location. The Cleveland Formation is heterogeneous and has areas with high enough porosities and permeabilities that don't require the same degree of hydraulic fracturing as similar shale plays to achieve economic production. However, because of its heterogeneity, smart operators will do detailed lithological interval analysis while planning their fracturing programs.

Maps showing first-year Cleveland production totals through Ochiltree and Lipscomb counties



(*Illustration courtesy of* Oil and Gas Investor)

The western Anadarko Basin includes the Granite Wash, Marmaton, Cleveland and Tonkawa formations.

in Texas and Ellis County in Oklahoma revealed first-year oil productions ranging from 10 Mbbl to more than 100 Mbbl and first-year gas production ranging from 100 MMcf to more than 1 Bcf.

Duvernay

The Duvernay Formation, found in a 1,300-mile-long fairway in central Alberta, is deposited at depths from 9,200 ft to 11,800 ft with its thickness ranging from 490 ft to 820 ft. The overpressured formation is described as a low-porosity, low-permeability organic-rich laminated black shale and argillaceous limestone source rock. The formation also is called the Muskwa Shale in northwest Alberta and northeast British Columbia. It is made of silica and carbonate-rich friable rock with a low clay content, making it an excellent hydraulic fracturing candidate.

Duvernay operators have been completing wells with IPs ranging from 2 MMcf/d to 8 MMcf/d of gas and 75 bbl to 100 bbl of condensate per 1 MMcf.

Eagle Ford

The Late Cretaceous Eagle Ford Shale extends in a crescent-shaped swath through South Texas from the Texas/Mexico border in the south, to Fayette County, Texas, to the north. As the Eagle Ford extends toward the coast it deepens to more than 17,000 ft before plunging to greater depths off the buried Cretaceous shelf margin edge, which extends through Webb County at the Rio Grande River in a northeast direction through Colorado County.

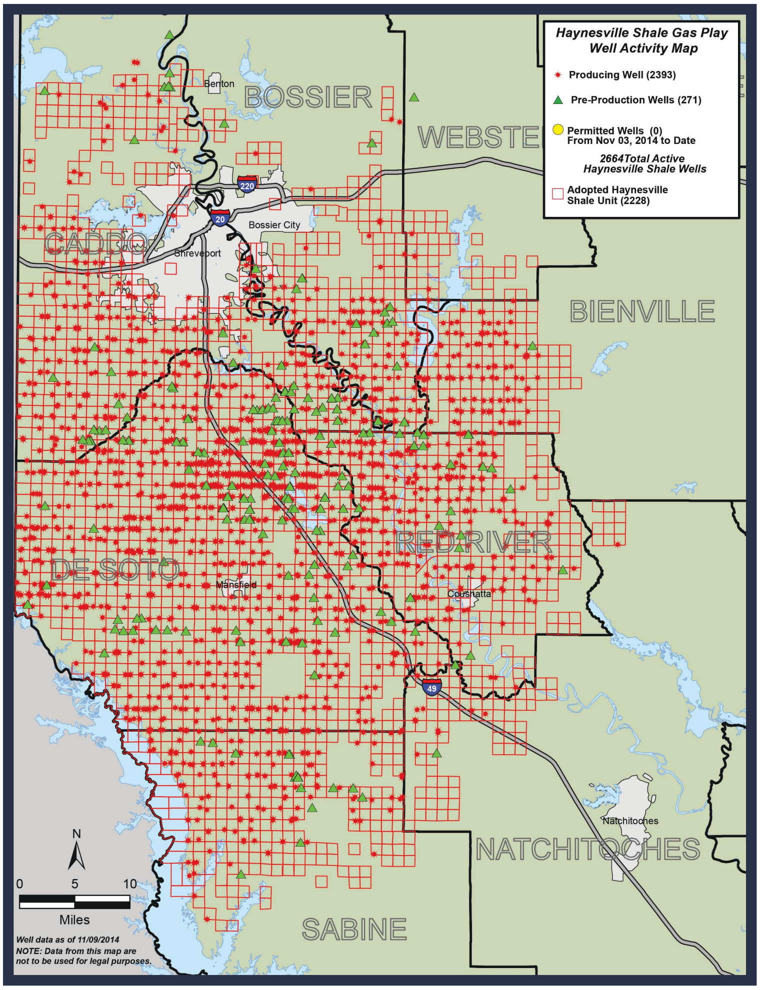
As the Eagle Ford goes from deep to shallow, it goes from producing dry gas in the deeper eastern Eagle Ford to wet gas moving west. The far western, shallower Eagle Ford produces oil.

One Eagle Ford operator has been completing wells with IPs ranging from 1,042 boe/d to 1,302 boe/d and 20.6 MMcf/d to 23.3 MMcf/d of gas. Another operator has completed wells with IPs ranging between 3,015 bbl/d and 3,400 bbl/d of oil with the same wells producing 325 boe/d to 425 boe/d and 1.9 MMcf/d to 2.5 MMcf/d of gas.

Fayetteville

The Mississippian Fayetteville Formation is an organic-rich, black marine shale, located in the Arkansas portion of the Arkoma Basin, covering about 4,000 sq miles while stretching in a 50-mile-wide east/west

(Source: State of Louisiana Department of Natural Resources)



The map shows well activity in the Haynesville Shale gas play.

band through northern Arkansas. It ranges in thickness from 50 ft to more than 550 ft, and measured depths range from 1,500 ft to more than 7,000 ft.

The Fayetteville is an older play getting its start in 2004 when its similarities with the Barnett Shale led to the first economically successful horizontally drilled and fracked Fayetteville well.

Southwestern Energy, a major Fayetteville operator, completed its best well with an IP of 14.1 MMcf/d of gas, with the IPs of three other wells exceeding 13 MMcf/d.

Granite Wash

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

Up until the last few years the heterogeneous Granite Wash was best known as a bail-out zone, tested only when an operator's primary exploration target was dry. However, due to the formation's heterogeneity, drilling the formation horizontally can produce economic wells, with some that pay out in months.

Although the formation is known for its heterogeneity, sweet spots with high porosities and permeabilities along with pay zones as thick as 3,000 ft go a long way in making up for the formation's heterogeneous nature.

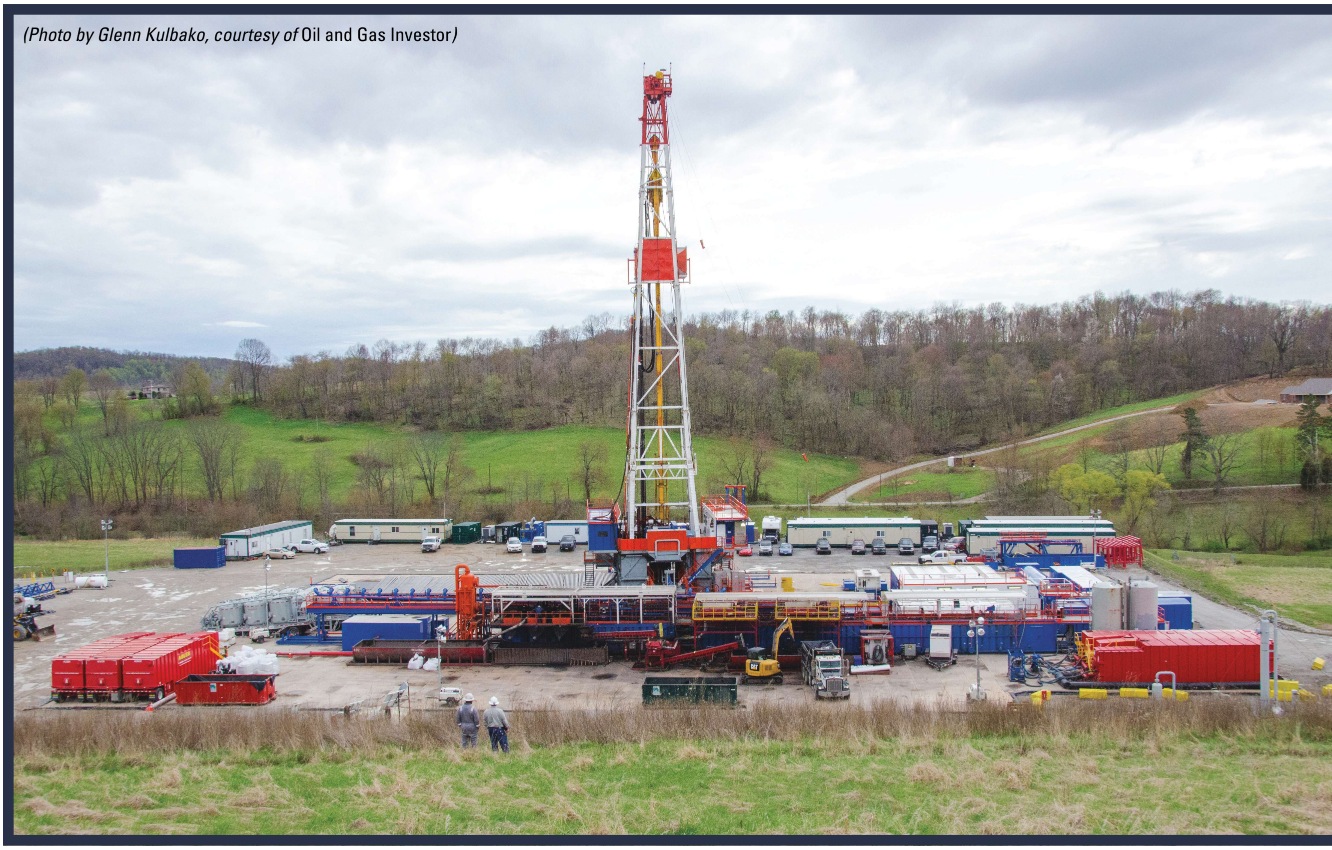
There are actually three different rock types composing the Anadarko Basin's Granite Wash. The first two are carbonates, with the oldest being limestone and chert, followed by dolomite. Only the third is actually composed of igneous rock. The three rock types originated from adjoining mountainous areas. During the last 300 million years, the adjoining mountains eroded, filling the adjoining Anadarko Basin with sedimentary, carbonate and igneous rock.

Like other heterogeneous formations, the Granite Wash is an ideal horizontal drilling candidate. Since individual accumulations can vary in aerial extent, lateral drilling should be closely monitored to assure that the drillbit stays with the original Granite Wash accumulation confines.

Haynesville

The Upper Jurassic-age Haynesville Formation is a diverse organic-rich, black marine mudstone varying from calcareous to argillaceous with above-average porosity but with low permeability. It underlies southwestern Arkansas and northwest Louisiana and extends into East Texas covering an estimated 9,000-sq-mile area. There's controversy as to whether the formation is the Haynesville Shale and/or the Bossier Shale arising from different names given to the same formation in Texas and Louisiana. Most geologists agree that the East Texas Lower Bossier Shale interval correlates with the Louisiana Haynesville Shale. As for the Upper Bossier, it has more sand than the Lower Bossier and is located more to the southwest of the Haynesville trend. The formation is about 200-ft-thick to more than 300-ft-thick, lies at depths ranging from 10,500 ft to more than 13,000 ft and is overpressured with a 0.72 psi/ft to 0.90 psi/ft pressure

(Photo by Glenn Kulbako, courtesy of Oil and Gas Investor*)*



Patterson-UTI Rig 349 drills the Big Daddy Shaw-14H well targeting the Marcellus for Rice Energy in Washington County, Pa.

gradient. It is considered the main Cotton Valley Formation source rock. The Haynesville has been unconventionally producing gas since 2008.

Haynesville horizontal wells are typically completed with 4,000-ft to 7,000-ft laterals and with staged hydraulic fracturing. Haynesville IPs in 2014 ranged from as low as 1.274 MMcf/d to as as 24.509 MMcf/d.

Horn River

The Middle Devonian Horn River Formation is an organic-rich, dark gray-to-black siliceous and calcareous shale and argillaceous bituminous limestone. The formation is composed of three members. The Evie Member is the oldest and is composed of organic-rich, dark gray-to-black calcareous and siliceous shale. The middle Otter Park Member is composed of organic-rich gray-to-dark gray argillaceous and calcareous marls. The youngest is the Muskwa Member, composed of organic-rich, gray-to-black siliceous radioactive shale. The formation is being produced from numerous areas in the northern section of the 5,058-sq-mile Horn River Basin located to the north of Fort Nelson, British Colombia. The formation's three members have a total thickness of more than 535 ft with net pay thickness up to 160 ft. The formation lies at depths to the formation top ranging from less than 4,600 ft to more than 10,200 ft beneath the surface.

Interest in the Horn River Formation was a spinoff from horizontal drilling and fracturing successes in the Barnett Shale. The play heated up dramatically in 2007 to 2008 with the run-up of natural gas prices, only to slump for a short period during the following global recession. Horn River interest is once again on the rise.

Toward the start of 2013, Encana, an early Horn River player, was completing wells at an average of $14.18 million to $19.49 million per well. Encana's horizontally drilled natural gas wells had an average IP of 30 MMcf/d and EURs, depending on their lateral length, of between 15 Bcf and 35 Bcf.

Hunton

In central Oklahoma's Anadarko Basin, the Late Ordovician/Silurian/Early Devonian Hunton Group

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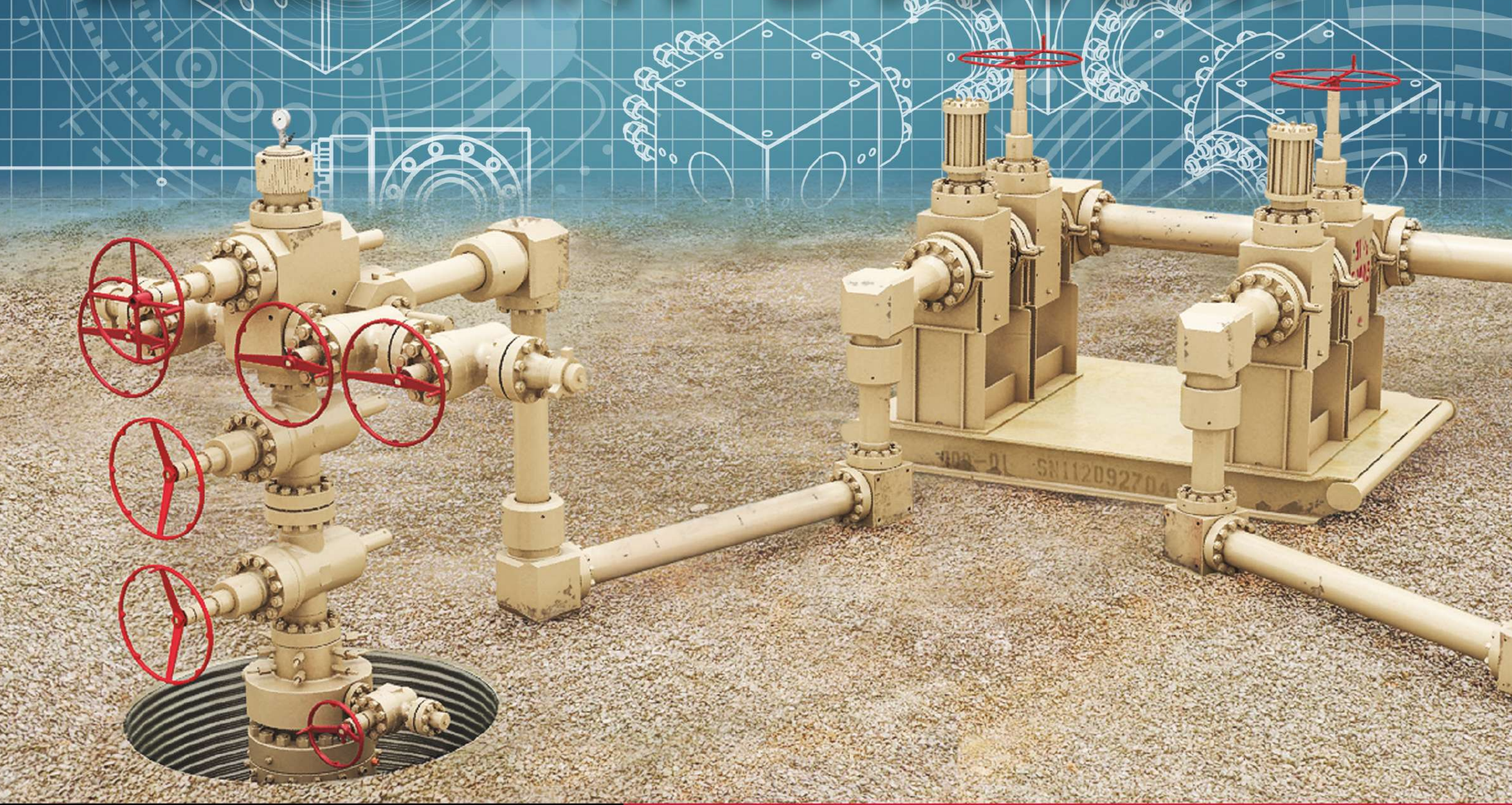

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consists of dolomite, limestone and calcareous shale sequences with the early Silurian Chimneyhill subgroup at its base, overlain by the Henryhouse Formation, Haragan Shale and Bois d'Arc Limestone as well as the Frisco Limestone in central and southern Oklahoma. Principal production typically comes from the Bois d'Arc and Frisco limestones, with the remainder of the Hunton Group making lesser production. The Hunton Group generally ranges from 100 ft to 500 ft in thickness but has a maximum thickness of 1,000 ft. Hunton hydrocarbons are sourced from the overlying Woodford Shale Formation. The Hunton top is typically encountered between 3,000 ft and 4,000 ft below sea level. Long laterals coupled with staged hydraulic fracturing are key to economic Hunton Lime production. Initially, during a well's production the Hunton Lime produces large water percentages, with a decreasing water cut as production progresses. Geoscientists suspect that the rock's large pore spaces are water-filled, while the hydrocarbons are confined to the formation's tighter zones. With the drop in reservoir pressure associated with production, the oil locked up in the tighter zones is released. Nonetheless, water production, particularly in a well's early stage, makes water disposal wells mandatory. Even with associated water disposal costs, the Hunton continues to be an economically attractive play.

The 2012 edition of the *Shale Shaker* reported an average recovery per completion of 10 MMbbl of oil and 551 MMcf of gas. Because of the dewatering aspect of these wells, IPs give an inaccurate well representation. Some of the wells reported were Misner/Hunton completions, with the Misner being a thin dolomitic sandstone or sandy dolomite deposited between the Hunton and overlying Woodford Shale in some basin areas.

A rig crewman attaches visual markers onto Dan D. Drilling Rig No. 7 anchors while drilling Eagle Energy's horizontal Reed 1H-10 in Woods County, Okla., targeting the Mississippi Lime.


(Photo by Lowell Georgia, courtesy of Oil and Gas Investor, April 2011)

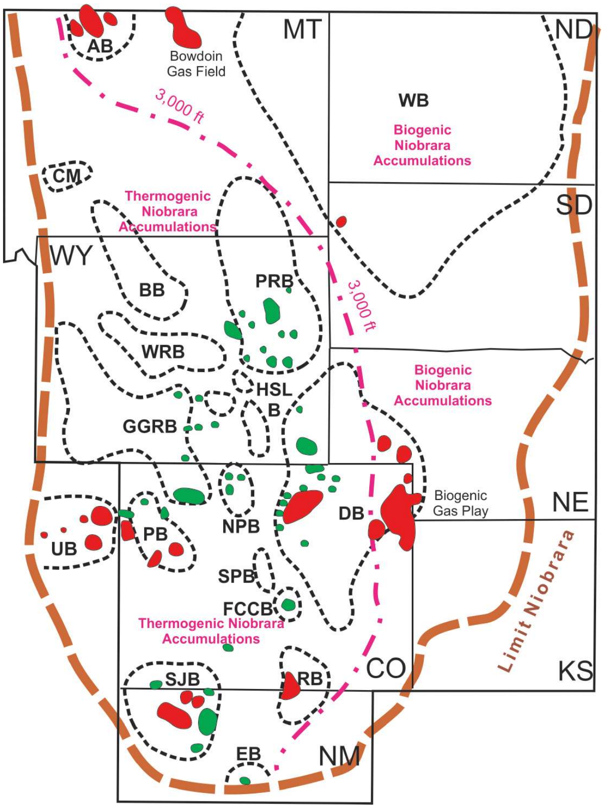
Mancos

The San Juan Basin covers about 19,000 sq miles and is about 150 miles north to south by 125 miles wide. It's predominantly located in New Mexico with a portion extending north into Colorado. The basin owes its shape and structure to regional uplifting associated with the Laramide Orogeny. The San Juan Basin's deepest portion is located in the northeast basin area just south of the Colorado-New Mexico border. In its deepest northeast area, the San Juan Basin is filled with sediments to a depth of 15,000 ft.

In the New Mexico San Juan Basin, the Mancos Shale member of the Gallup Sandstone Formation represents fine-grained deep marine shale and siltstone deposition. In addition to the shale and siltstone, scattered bentonite beds, thin limestone deposits and some sandstone beds are found interbedded in the Mancos. Because of its low porosity and permeability, most oil production is from natural fractures or more recently from 4,000-ft to 5,000-ft laterals combined with 10- to 20-stage hydraulic fracturing. Oil produced from the Mancos is a sweet paraffin-based crude with API gravities ranging from 33°API to 43°API. In Colorado, the Mancos member is sometimes referred to as the Gallup Sandstone.

According to Encana's July 2014 corporate presentation, its San Juan Basin Mancos Shale wells have been achieving 400 bbl/d to 500 bbl/d 30-day IPs.

(Image modified from Lockridge and Schoole, 1978)



Niobrara producing areas, northern Rockies (modified from Longman et al., 1998). AB-Alberta Basin; CM-Crazy Mountain; WB-Williston Basin; BB-Bighorn Basin; PRB-Powder River Basin; WRB-Wind River Basin; GGRB-Greater Green River Basin; NPB-North Park Basin; PB-Piceance Basin; UB-Uinta Basin; SPB-South Park Basin; FCCB-Florence-Canon City Basin; SJB-San Juan Basin; RB-Raton Basin; DB-Denver Basin; EB-Estancia Basin. Dashed line = Niobrara source rocks (Meissner et al., 1984). Dot-dashed line = 3,000 ft burial depth.

Marcellus

The Appalachian Basin's Devonian-age Marcellus Shale is an organic-rich, highly-friable black 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 about 102,000 sq miles extending north into Canada, south into Pennsylvania, and southwest through Pennsylvania into eastern Kentucky and Tennessee.

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

Marcellus Shale depths range from 2,000 ft to more than 11,000 ft, and the formation ranges in thickness from less than 50 ft in eastern Ohio to about 900 ft in New Jersey. Net pay ranges in thickness from 25 ft to 300 ft.

Chesapeake, a key Marcellus player, claims that the first-month IP of an average completed well is 1,360 boe/d. The play area is crisscrossed with existing gas pipelines, which facilitate natural gas gathering and transport.

Mississippi Lime, Mississippi Chat

The Anadarko Basin's Mississippi Lime Formation ranges in thickness from a few feet to more than 400 ft, 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. Laterals of 5,000 ft or more, coupled with hydraulic fracturing, are key to economic production from the Mississippi Lime. The formation produces water with its hydrocarbons, making water disposal wells mandatory. But even with the necessary water disposal, because of the Mississippi Lime's shallower depths and the friable formation, wells are relatively inexpensive to develop.

The Mississippi Chat overlies areas of the Mississippi Lime. The Mississippi Chat is a heterogeneous and often compartmentalized erosionally altered rock that can have porosities ranging to more than 50%. Even with its high porosities, the formation typically has low matrix permeability but can be naturally fractured. Operators have learned that drilling horizontally and fracking the Chat will produce very economic oil volumes. Like the underlying Mississippi Lime, the formation produces water with its hydrocarbons, necessitating the drilling of water disposal wells.

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

Montney

The Montney Formation is found in northwest Alberta and northeast British Columbia at depths ranging from 2,600 ft to 7,200 ft. The formation ranges in thickness from an erosional edge in northwest Alberta and northeast British Colombia to a maximum thickness of 918 ft near the Canadian Rockies. It's composed of two zones. The upper zone is a light brown, blocky siltstone with interlaminated fine-grained sandstone. The lower zone is dark gray, dolomitic sandstone with shale interbeds. The Doig Formation unconformably overlies the Montney Formation. However, at the Montney Formation's eastern erosional limits, it is overlain by Jurassic and Cretaceous strata. During the last few years, operators have been targeting the deeper basin areas for shale with horizontal wells and hydraulic fracturing. With the depressed gas market, operators have been moving updip to exploit the formation's more oil-prone sections using horizontal drilling and hydraulic fracturing.

According to Encana's October 2014 corporate presentation, its Montney wells are expected to have an average EUR per well of 7 Bcfe to 9 Bcfe of gas and 650 Mboe to 1,000 Mboe.

Niobrara/Codell

Things have been heating up in the Denver Basin's Wattenberg Field with the ongoing development of the Niobrara/Codell horizontal oil play. The Upper Cretaceous Niobrara Formation in the Wattenberg Field area is an organic-rich shale and marl formation with thick chalk zones or benches notated as A through C. The formation ranges in gross thickness from 240 ft to 330 ft, and production is from the chalk benches, each of which ranges in thickness from 20 ft to 30 ft. Niobrara production comes primarily from the B bench and secondarily from the C bench. The underlying Codell Sandstone in the Wattenberg Field area is a tight sandstone with 14% porosity and 0.1 mD permeability. Its average thickness ranges from 15 ft to 20 ft with a net pay thickness of 14 ft to 16 ft. The Wattenberg Field Niobrara/Codell is found at depths ranging from 7,000 ft to 8,500 ft.

One recently drilled Niobrara well, with laterals extending more than 9,000 ft combined with 40-stage hydraulic fracks along the length of the lateral, achieved a 30-day IP of 795 Boe/d, of which 76% was oil. A second recently drilled Niobrara well had an IP of 16 MMcf/d of gas, with production during its first 100 days exceeding 1 Bcf of gas. The Codell play is generating new excitement in the Wattenberg Field. A recent horizontal well completed with multistage hydraulic fracturing achieved a stabilized production rate of 1,300 bbl/d of oil.

Parkman

The Powder River Basin's Parkman Sandstone member of the Mesaverde Formation represents a

(Photo by Mieko Mahi, courtesy of Oil and Gas Investor)

Roughnecks on Ensign Rig 753 work on the Crosby 21H-1 in Wilkinson County, Miss., targeting the Tuscaloosa Marine Shale.

A stratigraphic map of common formations in north-central Oklahoma and south-central Kansas, including the Woodford, is shown.

(Source: U.S. Geological Survey)

Strat Column Oklahoma/Tx Panhandle

System	Series	Formation
Cret		eroded
Permian	Leonard	Brown Dolomite
	Wolfcamp	
Pennsylvanian	Virgilian	Douglas SS
		Tonkawa SS
	Missourian	Lansing Ls
		Cottage Grove SS
		Layton SS
		Hogshooter
		Checkerboard Ls
		Cleveland SS
	Des Moines	Marmaton/Big Lime
		Oswego
		Cherokee/Carpenter
		Red Fork/Hart
		Granite Wash SS
Lower Pennsylvanian	Atokan	Atoka/Novi
	Morrow	**Morrow SS**
	Springer	Springer SS
Mississippian	Chesterian	Chester SS
		Caney Sh
	Meramac	Mayes Sh
		Miss/Meramac
	Osage	Sycamore SS
Devonian		**Woodford Sh**
Silurian		Hunton Ls
Ordovician	Champlanian	Sylvan Sh
		Viola Ls
		Bromides SS
Lower Ordov.	Arbuckle	Arbuckle
Cambrian		Lower Arbuckle
Lower Cambria	Timbered Hills	Timbered Hills
PreCambrian		Granite

progradational delta complex with lithologies that include an upper prodelta shale interbedded with very fine-grained, well-sorted sandstone. This is underlain by nearshore coarsening upward successions of medium-grained sandstone and interbedded siltstone. The basal member deposits consist of terrigenous-sourced carbonaceous to lignitic silt and mudstone. The Parkman member ranges from 10 ft to 150 ft in thickness. Porosities range from 12% to 18%, and permeabilities range from 2 mD to 34 mD, with occasional sweet spots having permeabilities in excess of 100 mD. The Parkman produces from depths ranging from 5,000 ft along the basin's east side to 9,500 ft along the deeper basin axis area toward the west side.

Several EOG 2014 Parkman wells have been reported; two specifically had IPs of 1,310 bbl/d of oil, 45 boe/d and 405 Mcf/d of gas, and 955 bbl/d of oil, 80 boe/d and 760 Mcf/d of gas, respectively.

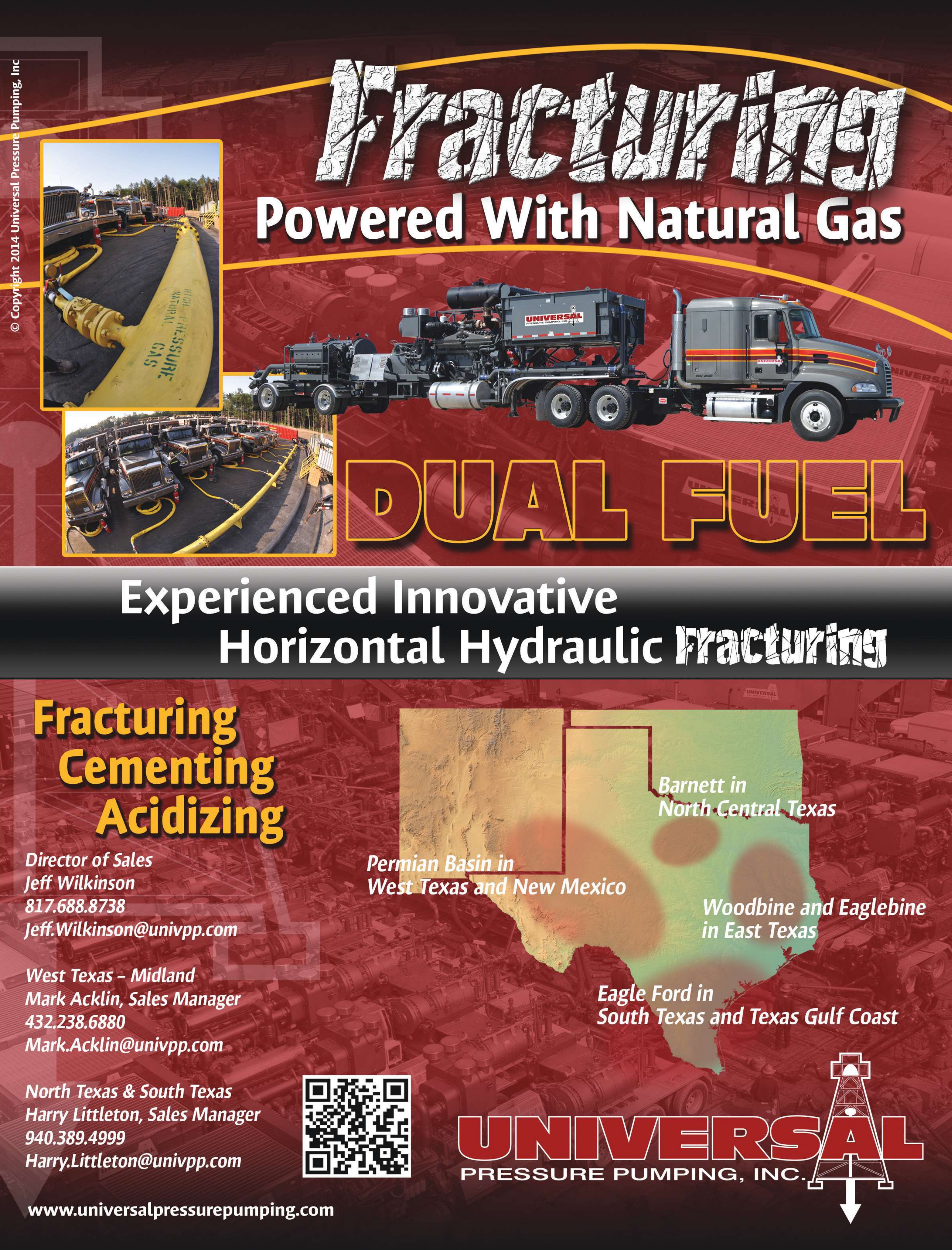
Tuscaloosa Marine Shale

The Middle Cretaceous Tuscaloosa Marine Shale Formation is an organic-rich, gray-to-black finely bedded sandy marine shale. The shale stretches in an east-to-west band that is 55 miles wide and 250 miles long across southern Louisiana and southwestern Mississippi, covering about 14,000 sq miles. It ranges in thickness from 500 ft in southwestern Mississippi to more than 800 ft in southeastern Louisiana, with a net pay thickness ranging from less than 20 ft on either end of the band to more than 140 ft near the middle. The formation is found at depths ranging from 11,000 ft in the north to more than 15,000 ft in the south.

Tuscaloosa wells are completed with laterals ranging in length from 3,000 ft to more than 6,000 ft coupled with multistage hydraulic fracturing. Two highlighted Goodrich Petroleum wells had laterals of 6,681 ft and 6,600 ft. The two wells had initial IPs of 1,300 bbl/d of oil and 1,450 bbl/d of oil, respectively. The same two wells after 30 days had IPs of 1,137 bbl/d of oil and 1,074 bbl/d of oil, respectively. The play continues to heat up, and operators are working hard to lower well costs from the current $12 million-plus range down into the $10 million range or lower.

Utica Shale

The Appalachian Basin's Ordovician Utica Shale is an organic-rich friable black carbonate mudstone underlying the Marcellus Shale by 3,000 ft to 7,000 ft and covering an area extending from eastern New York westward to central Ohio. The shale extends north to Quebec, Canada, and south into Pennsylvania, running southwest through Pennsylvania into



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West Virginia and eastern Kentucky. Overall, the Utica underlies a total area larger than the 102,000 sq miles covered by the overlying Marcellus Shale. The Utica Shale, while typically having lower total organic carbon than the Marcellus, is generally thicker and has a natural fracture system running through it. In Ohio, the oil-prone Utica extends into the underlying Point Pleasant Formation, which consists of carbonates interbedded with black shales. Utica Shale depths range from surface outcrops in Utica, NY, to more than 12,000 ft in southwestern Pennsylvania and West Virginia. The shale thickness ranges from 75 ft at the basin margins to more than 500 ft, with the shale generally thinning from east to west.

Numerous companies are pursuing Utica production, drilling horizontal wells anywhere from 2,000 ft to more than 7,500 ft in length with multistage fracking. Two recent Utica gas wells drilled in eastern Pennsylvania had IPs of 11.2 MMcf/d and 26.5 MMcf/d. Utica wells make wet gas farther west in western Pennsylvania and eastern Ohio.

Wolfcamp

The Permian Basin has several sub-basins, the two largest of which are the Delaware and Midland basins. Because the two basins subsided at different rates, they both have different depositional thicknesses and slightly different depositional histories.

In the Delaware Basin, the early Permian Wolfcamp Formation thickness exceeds 2,000 ft. It's a multilithological source rock made up of both siliclastic and redeposited carbonate sediments. The formation is divided into upper and lower zones and is found at subsurface depths ranging from 11,000 ft to 12,000 ft. The two zones are both about 1,000-ft thick with the upper zone being more oil-prone than the lower. Delaware Basin operators have been comingling the Wolfcamp with the overlying Bone Spring Formation, resulting in the Wolfbone Play. The vertical Wolfbone Play, at a depth of about 11,000 ft, simultaneously produces from both the Wolfcamp and the overlying Bone Spring Formation. Wolfbone wells are generally overpressured and have completion zone thicknesses of about 1,250 ft.

The Midland Basin Wolfcamp Formation has a thickness of 1,000 ft. Like the Delaware Basin Wolfcamp, it is a multilithological source rock, with similar sedimentary history to the Delaware Basin Wolfcamp. The Midland Basin Formation is generally found at depths ranging from 7,700 ft to 11,700 ft, depending on the basin area. In the northern Midland Basin, operators are comingling the overlying Spraberry Formation with the Wolfcamp. The resulting vertical Wolfberry play, at depths from 9,500 ft to 9,800 ft, 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 horizontal Wolfcamp Play is found at depths ranging from 9,500 ft to 11,700 ft with a thickness of about 1,000 ft. As with other unconventional plays, horizontally drilled Wolfcamp wells have long and often multiple-stacked laterals with lengths of 10,000 ft or more and use multistage hydraulic fracturing to further release the hydrocarbons trapped in the low-permeability rock. Multiple-stacked pay zones improve well economics in this play. Thirty-day IPs ranging from 154 boe/d to 359 boe/d have been reported for the horizontal Wolfcamp play.

Woodford

The Late Devonian-Early Mississippian Woodford Formation, or its geological time equivalent, is a petroleum source rock that covers much of the midcontinent. The Woodford is made up of organic-rich siltstone and silty black shale layers reaching 900-ft thick. Although found at depths ranging from 6,000 ft to 11,000 ft, it is typically produced from depths between 7,500 ft and 8,500 ft, where the formation thickness can vary between 50 ft and 300 ft or more. Thanks to horizontal drilling and multistage hydraulic fracturing, economic Anadarko and Ardmore Basin Woodford wells are being drilled. The play kicked off in 2007 with the Cana Woodford play in Oklahoma's Canadian County with a successful, horizontally completed Woodford well. Since 2007, the play has spread southeast into the Ardmore Basin where it's called the South Central Oklahoma Oil Play (SCOOP).

Woodford wells with laterals of more than 9,000 ft are not uncommon, and multistage hydraulic fracturing is the norm. The result is wells having IPs ranging from 8.66 MMcfe/d to 14.8 MMcfe/d of gas. ■

(Photo courtesy of Apache Corp.)

Playmakers Lead Resource Action

By **Don Lyle**, Contributing Editor

Get in early, get in big and create a resource factory. That's the key to success in resource plays.

Large independents led the rush to shales, limes and other resource plays, and their names lead the list of the most active and most rewarded operators in those plays.

Their success drew in major oil companies, smaller independents that wanted to build their companies quickly and even smaller independents who got in for a piece of the action or the hope of selling their properties to nearby larger companies.

Those resource plays in North America range from the established Barnett, Fayetteville, Bakken and Eagle Ford in the U.S. to the growing Marcellus in the U.S. and Montney in Canada to the emerging Duvernay in Canada to the Utica, Niobrara, Parkman, Mississippi Lime, Hunton, Tuscaloosa Marine Shale, Mancos Shale and Wolfcamp Shale in the U.S. They also include the huge gas resources that are waiting for markets in the Horn River Basin.

The Woodford is gathering new fans, while the Haynesville waits on higher gas prices. The Cleveland and Granite Wash are in steady development with a multitude of buys and sells as operators either consolidate their positions or sell out to raise money for other ventures.

There's no shortage of resources in the U.S. and Canada and no shortage of companies willing and able to chase the profits from those resources, either on their own or with the help of large companies as far away as Russia, Norway, the U.K., Australia, China and Japan.

In this section, the most active companies in the top 20 resource plays in North America are highlighted, and snapshots of their positions in the plays and plans for the future are offered.

Anadarko Petroleum Corp.

- **Multibasin leader**
- **Unconventional pioneer**

Anadarko Petroleum Corp. stretches its unconventional activity from Pennsylvania in Appalachia through the Rockies and deep into South Texas.

The company holds strong positions in most of the high-return plays in the U.S.

MARCELLUS

The company claims 773,000 gross (260,000 net) acres in the Marcellus play, according to its Marcellus Fact Sheet.

It likes the play because the "Marcellus Shale is among the largest natural gas opportunities in the U.S. and is estimated to hold the second largest deposit of natural gas in the world. This tremendous resource has the potential to supply the U.S. with clean-burning energy for more than 100 years."

The company's gas-prone operated properties lie in Centre, Clinton and Lycoming counties in north-central Pennsylvania. It has nonoperated holdings in Porter, Sullivan and Tioga counties.

Those holdings generated more than 553 MMcf/d of gas in fourth-quarter 2013 from wells that give the company EURs between 7.7 Bcf and 10 Bcf and a 50% before-tax rate of return.

Anadarko also is a member of a group of the most prolific producers in the play, known as the

Facing page: The most active driller in the Permian Basin calls the Barnhart area the scene of one its most active operations.

Appalachian Shale Recommended Practices Group, which created Recommended Standards and Practices for Exploration and Production of Natural Gas and Oil from Appalachian Shales. It shares components of its stimulation applications on a public website.

Anadarko holds 388,000 gross (185,000 net) acres in the Eagle Ford play, which it calls "among the most capital-efficient shale plays in [the company's] U.S. onshore portfolio."

UTICA

Anadarko hasn't reported any Utica Shale activities and didn't claim the popular shale play among its high-profile operations in 2014. The apparent last public report said the company had seven producing wells in Ohio, and a 2012 report said it held 390,000 gross acres in the play.

PARKMAN

The company is the largest private landholder in Wyoming, thanks to a railroad land grant that runs along most of the southern boundary of the state. It's also an active driller and producer in the state, but its shale work is moving more slowly than some of the more popular shale plays.

A major part of the company's holdings are wrapped up in coalbed methane wells in the Powder River Basin, but Anadarko is looking for oil as well.

In early 2012 it had three rigs at work seeking oil and produced from 19 operated wells on its 350,000 net acres of land, and the company planned 10 wells in 2013. Its oil program targeted the Parkman, Niobrara, Shannon and Frontier/Turner formations.

NIOBRARA

Anadarko directed its primary Niobrara activity to the giant Wattenberg Field in the Denver Basin of Colorado.

In a September 2014 presentation, Al Walker, chairman, president and CEO, said the company is accelerating its activity in the Wattenberg Field. At that time, it operated 13 rigs and planned more than 360 wells for the year.

The company's holdings in the field offered between 1 Bboe and 1.5 Bboe in net resources with an upside of more than 500 MMboe from downsizing.

Its Niobrara play, combined with the adjacent Codell Formation, covers some 350,000 net acres and offers Anadarko a before-tax rate of return of more than 100%.

EURs from wells range from 350 Mboe to 450 Mboe with a 60% to 65% liquids content. It produced about 120 Mboe/d in 2013 and planned to reach 300 Mboe/d in 2018.

WOLFCAMP

The Wolfcamp Shale play has drawn extensive industry attention, and Anadarko has chosen the West Texas Delaware Basin segment of that play for its focus.

It holds 600,000 gross (245,000 net) acres in the play where its horizontal wells give back 600 Mboe to 700 Mboe of EUR. The area also offers the company stacked pay potential, including the Bone Spring and other zones.

Anadarko planned to operate eight to 10 rigs during 2014 to drill more than 80 wells to the Wolfcamp in Ward, Reeves and Loving counties in Texas.

Its wells offer IP potential between 1 Mboe and 1.6 Mboe, gross, and that production is more than 85% liquids.

EAGLE FORD

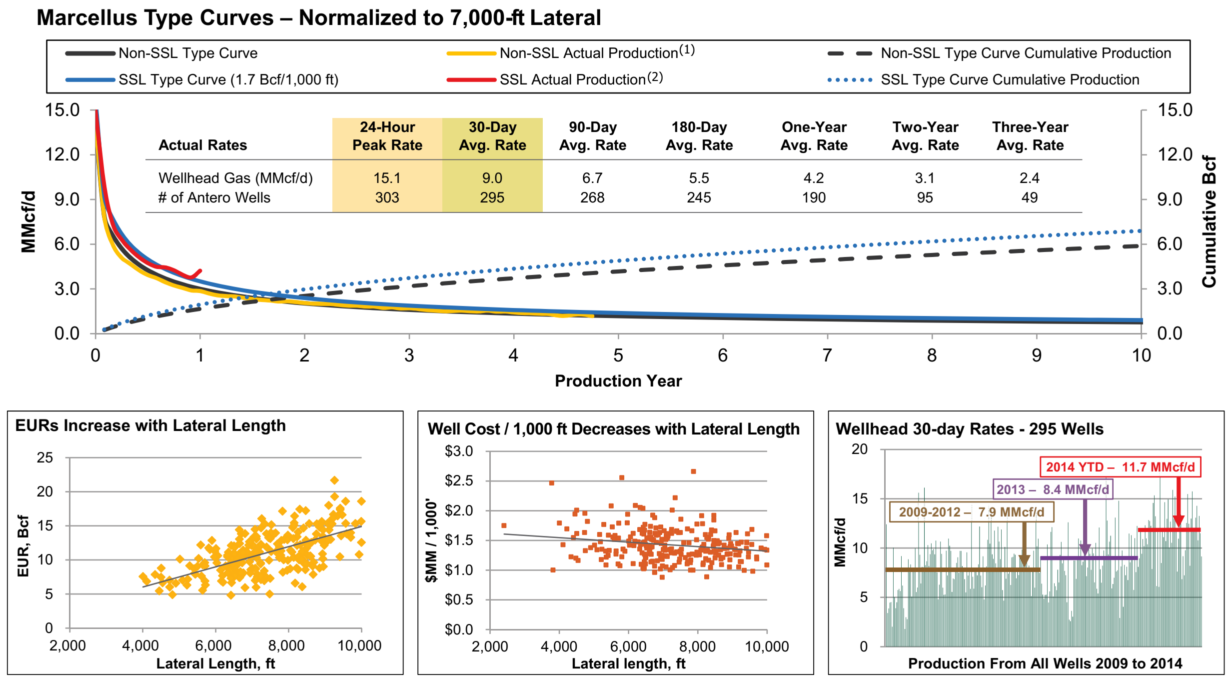
The Eagle Ford Shale is a bright spot in the operating portfolios of several of the most aggressive and profitable companies in the business, and Anadarko is no exception.

It holds 388,000 gross (185,000 net) acres in the play, which it calls "among the most capital-efficient shale plays in Anadarko's U.S. onshore portfolio."

It has drilled more than 1,000 wells, has some 2,500 well locations in its drilling inventory and continues to bring wells online at a rate of one well per day. It operated 10 rigs and planned to drill about 400 wells in 2014.

As the company learns from its wells, it is drilling longer laterals at lower costs and has the infrastructure to back up its ambitious drilling program. Lessons learned also raised Anadarko's expectations of

ANTERO'S MARCELLUS SHALE TYPE CURVE



1. 200 Antero Marcellus Non-SSL wells normalized to time zero, production for each well normalized to 7,000-ft lateral length.
2. 103 Antero Marcellus SSL wells normalized to time zero, production for each well normalized to 7,000-ft lateral length.

(Graphic courtesy of Antero Energy Corp.)

Experience shows typical Marcellus decline curve and financial advantages of long lateral well sections.

production from 48 Mboe/d in 2013 to between 68 Mboe/d and 71 Mboe/d in 2014.

Among its holdings, its Dimmit County wells give it EURs of 550 Mboe with 70% liquids and a before-tax rate of return of more than 50%.

Webb County offers 600 Mboe per well with 60% liquids and a before-tax rate of return of more than 70%. The company also has properties in La Salle and Maverick counties in Texas.

As it drilled, the company's well cost dropped from $1.9 million in 2011 to $1.4 million in first-half 2014. It cut drilling days from 19 in 2011 to about nine in first-half 2014.

Anadarko also holds Eagle Ford properties in East Texas where it combines production with the Woodbine Formation, which the industry calls the Eaglebine play.

On Oct. 29, 2014, KKR & Co. said it became a nonoperating partner in the Eaglebine acreage in Brazos, Burleson and Robertson counties in Texas, an area that can support 500 wells.

Antero Resources Corp.

- **Most active operator in the Marcellus**
- **Among top Utica producers**

Antero Resources Corp., after selling out of its position as the second largest operator in the Barnett Shale, turned its attention to shales in the northeast.

MARCELLUS

The company built its Marcellus Shale position to 378,000 net acres in the southwestern core of the play in southwestern Pennsylvania and northern West Virginia.

It operated 15 drilling rigs, including five intermediate-depth rigs, in West Virginia during 2014. It produced 770 MMcfe/d in second-quarter 2014. That production included 12.5 Mbbl/d of oil and NGL.

By mid-2014, the company had drilled and completed 303 horizontal Marcellus wells with no failures.

It also is building its own gathering system in Doddridge, Tyler and Ritchie counties in West

Virginia to get its production of processing and compression facilities. That production reached 600 MMcf/d of rich gas.

In a September 2014 presentation, the company said it had 8.5 Tcfe of gas of net proved reserves in the Marcellus and 26.5 Tcfe of gas in net proved, probable and possible reserves on its remaining 3,057 net undrilled locations.

UTICA

Antero controls another 120,000 net acres of leases in the Utica Shale in eastern Ohio where it operates seven drilling rigs.

During second-quarter 2014, it produced 121 MMcfe/d, which included 7,600 bbl/d of oil and NGL.

Through first-half 2014 it had drilled and completed 37 horizontal Utica wells, all producing to sales.

The company's Utica leases held 537 Bcfe of gas of net proved reserves and 6.4 Tcfe of gas of net proved, probable and possible reserves on 835 net undrilled locations.

It operates seven rigs, including two intermediate rigs targeting rich gas, which offers a rate of return of more than 100%.

In addition to its Ohio Utica properties, Antero has Utica Shale properties in West Virginia and Pennsylvania with a net resource of 9.5 Tcf of dry gas. It has 146,000 net acres of land with 1,359 undrilled locations underlying its existing Marcellus properties.

The company planned one Utica well in West Virginia in 2014.

Supplementing the company's Marcellus and Utica properties, it holds a strong position in the Upper Devonian Shale with net proved reserves of 40 Bcfe and net proved, probable and possible reserves of 4.6 Tcfe of gas on 1,119 undrilled locations.

Apache Corp.

- **Shales and limes produce profits**
- **U.S. and Canada assets push growth**

Apache Corp. cultivates profitable operations from Australia to Egypt to the North Sea, and some of its strongest assets lie in unconventional resources in the U.S. and Canada.

HORN RIVER

The Houston company holds extensive properties in the Horn River and Liard basins in far northern British Columbia along with a half interest in the Kitimat LNG plant on Canada's West Coast, which will transport up to 10 MMtons/year of product to Asian markets.

Apache estimates it controls 100 Tcf of recoverable natural gas in the two basins.

It holds 430,000 acres in the Liard Basin with an estimated 48 Tcf of recoverable gas and an interest in another 200,000 net acres in the Horn River Basin.

By second-quarter 2014, the company had completed and placed on production 69 horizontal wells in the Horn River Basin. Those wells, now drilled on multiwell pads, reached peak production at 149 MMcf/d of gas in September 2011.

During second-quarter 2014, Apache drilled two vertical wells to retain 40,861 gross (18,480 net) acres of land. It also completed planned 3-D seismic winter programs with 515 sq miles of data.

MONTNEY AND DUVERNAY

Apache sold some of its properties in the Western Canada Sedimentary Basin in Alberta and British Columbia, principally assets that produced dry gas, but it held onto liquids-prone properties in the Montney and deeper horizons.

It holds some 3.8 million gross (2.8 million net) acres in the basin and produced 58 Mboe/d in second-quarter 2014. It runs eight drilling rigs in the stacked pay in the area, including two rigs on its Duvernay properties and one in the Montney play.

Results provide reasons for the company's fondness for the plays. In first-quarter 2014, the 00/02-28-062-20WS well in the Duvernay play in the Kaybob area tested for an initial potential of 1.963 Mboe/d, and the 00/13-18-067-07W6 well drilled to the Montney play in the Wapiti area tested for 926 boe/d.

It planned 15 new wells by the 2015 spring breakup on its 177,000 net Duvernay acres and four wells on its 146,000 net acres in the Montney trend.

GRANITE WASH AND CLEVELAND

Apache's central region takes in the stacked pays in the Texas Panhandle and western Oklahoma, including the Granite Wash, Cleveland, Marmaton, Tonkawa and Canyon Lime.

(Photo courtesy of Apache Corp.)

Rig hands work with drillpipe at a drilling site for Apache's Canadian operations.

Although the company didn't break out formation-by-formation numbers, it said its second-quarter 2014 production from the area reached 89.9 Mboe/d with a 51% liquids contribution.

It worked 33 rigs in the area and drilled 98 wells during the quarter.

Among highlights, its R. Moore #21H horizontal well in Wheeler County, Texas, tested for 756 boe/d from the Granite Wash.

Recently, however, the company has concentrated resources on its 100,000 contiguous acres in the Canyon Lime in the Texas Panhandle, a resource play that gives the company production with more than 80% liquids.

Its second well, the Bivins East 94-1H tested with a 30-day initial potential of 1.7 Mboe/d from a 4,472-ft lateral. It has two rigs working that play.

WOLFCAMP

Apache produced a record 155.2 Mboe/d, 77% of which is liquids, from its Permian Basin properties with strong contributions from the Wolfcamp in Irion County, Texas, the Bone Spring in Loving County, Texas, and the Yeso in Eddy County, N.M. It operated 37 rigs in second-quarter 2014.

It's the most active driller in the Permian Basin on its 3.3 million gross (1.7 million net) acres of leases, and it ranked second in production in second-quarter 2014 at 155 Mboe/d.

The company drilled 37 wells to the Wolfcamp Shale in Irion, Reagan and Upton counties with the Barnhart area in Irion County being one of its most active areas. That activity resulted in 12 Upper Wolfcamp and seven Middle Wolfcamp wells, including four wells with 2-mile lateral sections.

Apache drilled four wells with two rigs in Reagan County, including the SRH 1335 HU, which tested for 1.2 Mboe/d.

In Glasscock County, the company got excellent results from a combination of Wolfcamp and Strawn vertical wells.

In the Delaware Basin, where the company concentrates on the Bone Spring, it drilled one Wolfcamp well during second-quarter 2014.

EAGLE FORD

The company holds 511,000 gross (203,000 net) acres in the Eagle Ford backed by more than 300 sq miles of 3-D seismic data.

Apache worked eight rigs in the Eagle Ford in Brazos and Burleson counties in Texas during second-quarter 2014 as it ramped up toward 10 rigs by year-end. It started drilling 26 wells in the quarter using pad drilling for efficiency, and it brought one well online. It planned to bring the remaining wells online during second-half 2014.

Its 15 gross operated wells produced 5.2 Mboe/d, and in September 2014, the company had another 15 wells in various stages of completion.

Approach Resources Inc.

- **Permian, pure and simple**
- **Working the growth path**

Approach Resources Inc. started working the Permian Basin zones in 2007, focused on the Wolfcamp in 2010 and has been growing since that time.

WOLFCAMP

In an August 2014 presentation, Approach said it held 160,000 gross (138,000 net) acres in the Permian Basin and that property held more than 1 Bboe in gross unrisked potential resource.

Since its Wolfcamp program started in 2010, oil production has grown from about 220 Mboe to 1.5 MMboe in 2013, not counting NGL.

In the same period, proved reserves grew from about 30.1 MMboe to about 114.7 MMboe with a 45% oil cut.

The company has about 2,000 identified horizontal Wolfcamp well locations, and it currently is testing stacked wellbore production and optimizing spacing and completion designs.

It is drilling the Wolfcamp A, B and C benches in Crocker and Schleicher counties, and it is moving to two-bench completions for higher per-well production.

Its recent Wolfcamp wells take 10 to 11 days to drill with 7,500-ft laterals at a cost of $5.5 million. Those wells come in with EURs of 450 Mboe and higher.

With $100/bbl oil, Approach can generate a before-tax internal rate of return of nearly 70% from a well with an EUR of 550 Mboe.

The company had completed 16 horizontal wells by August 2014 and increased its second-quarter year-on-year production by 50% to 14.1 Mboe/d.

ARC Resources Ltd.

- **Western Canada Sedimentary Basin player**
- **Putting cash into Montney development**

ARC Resources Ltd. feels strongly enough about its Montney holdings in British Columbia and Alberta, Canada, that it sold noncore shallow gas assets in southwestern Saskatchewan in second-quarter 2014 to increase its investment in the Montney play.

MONTNEY

The company sold some of its Saskatchewan assets for $29.57 million, and the company's directors bought parcels of land in the Montney play for $14.96 million and $20.07 million.

The board also approved an increase in its 2014 spending plans to $873.56 million from the previous level of $819.8 million. "The additional funds will primarily be allocated to certain strategic initiatives in the BC [British Columbia] and Alberta Montney regions," the company said.

In British Columbia, the Montney has 50 Tcf of gas and more than 1 Bbbl of oil in place with an estimated 2 Tcf of gas and 270 MMbbl of oil recoverable.

ARC holds more than 70 net sections of land in the Montney and is the second largest gas producer in the play with production of more than 250 MMcf/d. During second-quarter 2014, it produced 2.3 Mbbl/d of oil, 3.4 Mbbl/d of condensate, 288.9 MMcf/d of gas and 2.1 Mbbl/d of NGL for a total 56.1 Mboe/d.

Some $440 million ($394.07 million) of its 2014 capital budget is directed to British Columbia for 60 gross operated wells to reach an average 55.9 Mboe/d of production.

The company's Ante Creek operation in Alberta represents a growth opportunity in the oil-prone section of the Montney.

It started full field development at Ante Creek with pad drilling and produced 23.4 Mboe/d during second-quarter 2014. That production consisted of about 9.9 Mbbl/d of oil, 815 bbl/d of condensate, 67.8 MMcf/d of gas and 1.4 Mbbl/d of NGL.

The $192.56 million directed to the Montney in Alberta paid for 40 gross operated wells to produce an average 19 Mboe/d of production in 2014.

Overall, ARC holds more than 950 Montney sections in British Columbia and Alberta, making it the third largest acreage holder in the play behind Malaysia's Petronas and Canadian Natural Resources.

According to the company, the recoverable resources in the overall Montney play are equal to those of three Haynesville Shale plays or six Barnett Shale plays.

BHP Petroleum has large land positions in four shale plays, but the least economic and least active is the Fayetteville Shale in Arkansas. The company announced on Oct. 27, 2014, it would put its Fayetteville properties up for sale.

BHP Billiton Ltd.

- **Bought into some of the best shale plays**
- **Concentrating on liquids shales**

BHP Billiton Ltd. subsidiary BHP Petroleum put a deep footprint in the Fayetteville, Haynesville, Wolfcamp and Eagle Ford shales.

Like other companies, it is backing down on its gassy shales and taking care to maximize value from its liquids assets.

FAYETTEVILLE

The Australian company bought its Fayetteville properties in the Arkoma Basin in Arkansas from Chesapeake Energy for $4.75 billion. It now holds some 487,000 net acres in the play with an average 58% interest. That property gives it some 10 Tcf in resource in the play.

The company said it is lowering its overall shale rig count from 44 in 2013, to 30 in first-quarter 2014, to 28 in second-quarter 2014 and to 23 in second-half 2014.

Since the Fayetteville's dry gas can't compete economically with the company's other play options, it will get the least capital and the fewest resources.

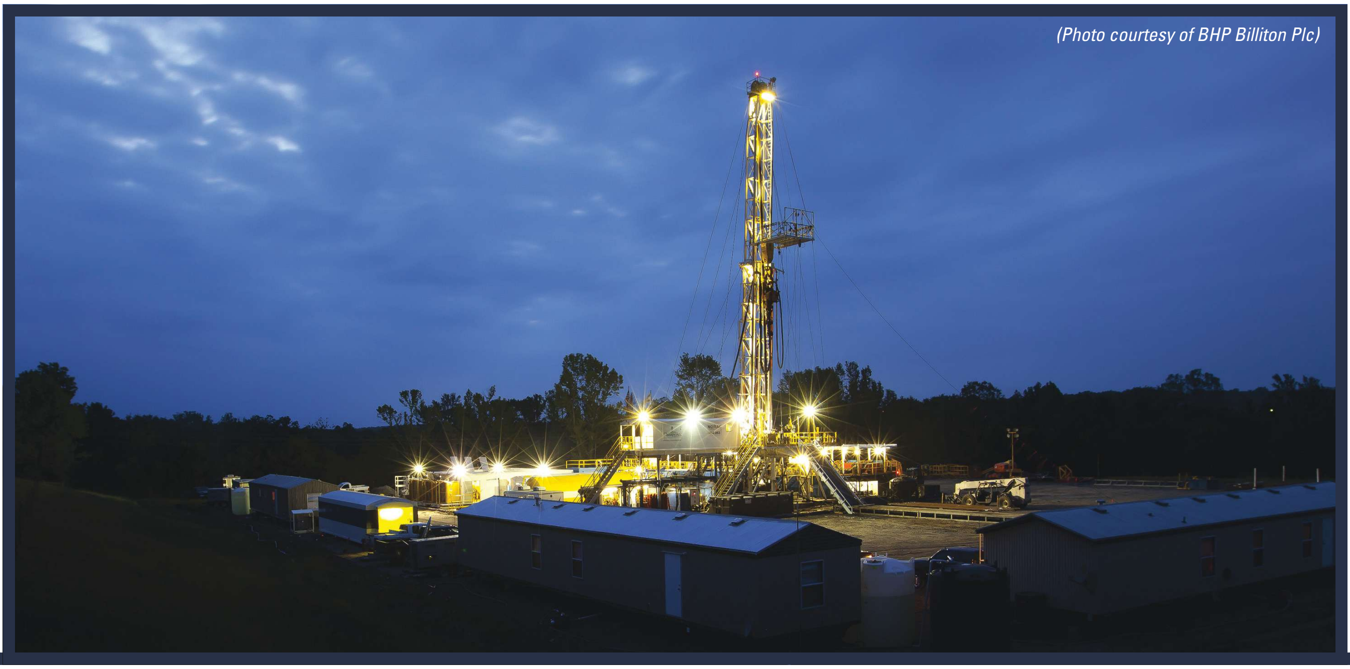
HAYNESVILLE

In spite of low natural gas prices, the Haynesville Shale play in Louisiana still generates profits for BHP, but those profits aren't on the same level as its liquids plays.

The company had some 22 Tcf in resource potential in the play in 2012 and the largest acreage position in the play as part of its acquisition of Petrohawk. That purchase, overall, gave it some 1.5 million acres of land with shale potential, including the Haynesville, Eagle Ford and Permian shales.

WOLFCAMP

Although BHP doesn't itemize figures for its shale and unconventional zones in the Permian Basin, the Wolfcamp is a part of that mix. The company entered the Permian Basin through its purchase of Petrohawk, and Petrohawk had drilled Wolfcamp wells in the Midland and Delaware basins.



(Photo courtesy of BHP Billiton Plc)

The company drilled 70 wells in the basin by August 2014 and increased its core area acreage by 25% to 74,000 acres. Its total acreage position is 240,000 acres.

The company's plans are well laid out, and it counts on building production to 100 Mboe/d by the end of its 2018 fiscal year.

Among wells drilled in the 2014 fiscal year, its 30-day average IP potential rate was 1,400 boe/d.

EAGLE FORD

The Eagle Ford Shale in South Texas sits high atop the priority list among BHP's shale plays in the U.S.

According to an article by Hart Energy senior editor Darren Barbee, the company held 57,000 net acres in the condensate window in the Black Hawk Field—its best Eagle Ford property—and that field produced more than 100 Mboe/d from wells in Karnes and DeWitt counties in Texas. That production gave the company an 80% liquids cut.

BHP holds another 250,000 net acres in Hawkville Field in La Salle and McMullen counties in Texas where it produced nearly 70 Mboe/d with a 50% liquids sample.

The company contracted 17 rigs for the Eagle Ford, and 14 will go into the Black Hawk area because of the high liquids content.

The company is increasing efficiency by lowering rig time, increasing recovery and lowering spud-to-sales times.

The company put 75% of its onshore drilling budget in the 2014 fiscal year into the Eagle Ford play as it put 138 net wells online. By the end of the fiscal year, it had 284 producing wells in the Black Hawk Field and an average net production of 82.5 Mboe in the quarter ending June 30, 2014.

Black Hills Corp.

- **Operates west of the Mississippi River**
- **Seeking Mancos pay**

The Black Hills E&P subsidiary of Black Hills Corp. has interests in more than 1,000 operated and nonoperated wells, but it looks to shale for growth opportunities.

It operates wells in the Piceance, Powder River and San Juan basins and holds nonoperated interests in wells in the Williston Basin in North Dakota and in California, Kansas, Montana, Oklahoma and Texas with some 87 Bcf of gas equivalent in reserves at year-end 2013.

BAKKEN

The company holds nonoperated interests in wells in North Dakota and it continued to support activity in the basin in 2014.

MANCOS

Black Hills holds operating interests in Mancos wells in the Piceance Basin of Colorado and the San Juan Basin of New Mexico.

It holds 94,000 acres of property in the Mancos area and has an estimated resource potential of more than 2 Tcf of gas.

It's working now to prove its Mancos properties in both basins with six wells in 2014 and another six wells in 2015. After evaluating those wells, it will "consider strategic options," including divestiture or a joint venture program.

The 2014 program calls for up to six wells in the Mancos Shale in the southern Piceance Basin while the company improves supporting infrastructure for its wells.

According to an August 2014 presentation, three horizontal successful tests in 2011 affirmed Mancos potential in the two basins.

The company drilled and completed two wells in 2013 with 8,000-ft to 9,000-ft horizontal laterals and put both wells on production to earn about 20,000 acres of additional leaseholds in the Piceance Basin. It needs further delineation to assess the value of the Mancos in the area, though.

Its southern Piceance Basin properties are in Winter Flats, Homer Deep, Horseshoe Canyon and Chalk Mountain. It drilled single-lateral wells in 2011 at Homer Deep and Horseshoe Canyon and two more single-lateral wells east of Winter Flats in 2013. The six wells (two triple-lateral wells) planned for 2014 are at Homer Deep. The two triple-lateral wells in 2015 will be drilled at Horseshoe Canyon and Homer Deep in Garfield and Mesa counties in Colorado.

The company's Mancos properties in the San Juan Basin are on the Jicarilla Apache Reservation in New Mexico. It drilled the Jicarilla 434-30 #724

H well some 16 miles southeast of WPX wells and 45 miles northeast of Encana Corp. horizontal wells to the Mancos.

BP Plc

- **Making U.S. onshore a separate business entity**
- **Controls some 5.5 million gross acres**

BP Plc keeps a strong presence in the U.S. among business operations that span the globe.

It holds some 21,000 wells with an estimated 7.6 Bboe in net resources in properties in the Wamsutter, Wyo., area; the San Juan and Anadarko basins; the Woodford Shale in the Arkoma Basin; and the Utica, Fayetteville, Haynesville and Eagle Ford shales.

UTICA

The company bought 100,000 acres in the Utica/Point Pleasant play in 2012.

WOODFORD

It purchased its 90,000 acres of Woodford Shale properties in the Arkoma Basin in 2008 for $1.7 billion from Chesapeake.

MANCOS

BP set up a Mancos Shale appraisal group within its San Juan Basin operations. It already is the biggest producer in the basin with some 1,500 wells in Colorado and 2,100 in New Mexico. Most of those wells produce coalbed methane.

Amoco, which was acquired by BP, drilled the Amoco No. 14 Jicarilla A 118 vertical well and tested the Gallup, which contains the Mancos, for an initial potential of 454 bbl/d of oil, 442 Mcf/d of gas and 50 bbl/d of water.

A Farmington (New Mexico) *Daily Times* article in March 2013, reporting on the San Juan Basin Energy Conference, quoted Darryl Willis, vice president of subsurface for the North American gas region for BP, as saying, "We're optimistic about the potential for liquids, and we're optimistic about the Mancos."

FAYETTEVILLE

BP acquired 25% of Chesapeake Energy's Arkansas properties, some 135,000 net acres, for $1.9 billion in 2008.

GRANITE WASH/CLEVELAND

BP consolidated a strong position in the Panhandle and western Oklahoma region through land purchases from Repsol-YPF. Production from the Atoka, Cherokee, Granite Wash, Cleveland, Douglas, Kansas City, Marmaton, Tonkawa and Upper Morrow highlighted BP's assets in the area. In addition to Texas Panhandle properties in Hemphill, Mendota, Northwest Mendota, Mills Ranch and St. Clair fields, it holds property in Beckham County, Okla.

EAGLE FORD

BP acquired its Eagle Ford properties in partnership with Lewis Energy in 2009.

Cabot Oil & Gas Corp.

- **Appalachian veteran**
- **Eagle Ford growth company**

Cabot Oil & Gas Corp. established a solid and profitable foundation for its activities in the Marcellus Shale in Pennsylvania. That position enabled it to build on its machine for growth in South Texas.

> **Cabot calls its Marcellus operations the "cornerstone asset of its portfolio," a position the play has held since Cabot started drilling horizontal wells in northeastern Pennsylvania in 2008.**

MARCELLUS

Cabot calls its Marcellus operations the "cornerstone asset of its portfolio," a position the play has held since Cabot started drilling horizontal wells in northeastern Pennsylvania in 2008.

Production grew from 20 MMcf/d in 2008 to more than 1.2 Bcf/d in July 2013. In a September 2014 presentation, the company said it produced 229 Bcf of gas equivalent from 279 wells in second-half 2013. At that time, it produced 14% of all of the oil and gas produced in Pennsylvania from only 6% of the total producing wells.

It has some 200,000 acres in the sweet spot of the Marcellus gas play, which gives it more than 3,000 locations. It planned to drill about 110 net wells during 2014.

Cabot also claimed a best-in-class EUR per 1,000 ft of lateral of 3.6 Bcfe in the Lower Marcellus and 2.75 Bcfe in the Upper Marcellus, and it is improving on those results with more proppant per foot of lateral and longer laterals.

A typical well gives the company a 102% before-tax internal rate of return with $3/MMBtu gas, 150% with $3.50/MMBtu gas and 206% with $4/MMBtu gas.

Cabot also drilled a Utica/Point Pleasant test in Wood County, W.Va.

EAGLE FORD

In September 2014, Cabot acquired about 30,000 net acres of land in the Eagle Ford Shale play for $210 million. The company didn't identify the seller.

The property produced about 1.6 Mboe/d with a 92% liquids cut at the time of the sale.

That property includes some 17,000 net acres near Cabot's Buckhorn operating area, raising its stake in that area to 60,000 net acres and its total lease area to 83,000 net acres. That new addition position gives it 191 more net locations for horizontal wells with a spacing of 400 ft between lateral legs.

The acquisition prompted Cabot to add a fourth operated rig in the Eagle Ford play. It also increased its 2014 capital budget from a range of $1.375 billion to $1.475 billion to a new high of $1.45 billion to $1.55 billion. That doesn't include the property acquisition cost.

It anticipated drilling 55 net wells in the Eagle Ford in 2014.

Those wells give the company a 48% internal rate of return at a price of $80/bbl for oil, a 66% return with a $90 oil price and an 86% return with oil priced at $100/bbl.

Canbriam Energy Inc.

- **Focused on Altares-Farrell Creek**
- **Seeking high return from liquids**

Canbriam Energy Inc. looked for a play with some of the best economics in North America and chose the Montney in northeastern British Columbia.

MONTNEY

Canbriam calls the Montney one of the most economic gas plays in North America with a liquids content that gives the company 10 Mboe/d with continuing growth.

Even at low gas prices the company's Altares-Farrell Creek property generates strong returns with long-term growth.

It holds a 100% operating interest in the field with some of the highest reservoir pressures and highest liquids yields in the Montney play.

Canbriam also claims top-quartile finding and development costs and top-quartile opex efficiency.

It entered the play in 2008 and holds 62,000 net acres of land with more than 1,000 ft of Montney pay zone. It has identified six target horizons in the formation and currently is developing its property on three of those horizons.

In a June 2014 presentation, the company said the property contained 38 Tcf of original gas in place with more than 11 Tcf of gas equivalent in place. Its year-end 2013 reserves reached 109 MMboe, and it has 1,500 net well locations to develop.

Those wells should produce 50 bbl of liquids for every 1 MMcf of gas on half of its land.

Canbriam had 56 Bcf of gas and 2.4 MMbbl of liquids in proved producing reserves at year-end 2013 and 519 Bcf of gas and 23.3 MMbbl of liquids in proved and probable reserves.

Canadian Natural Resources Ltd.

- **Payday from Canadian shales**
- **Focused on the Montney**

Canadian Natural Resources Ltd. controls a substantial land position in the Western Canada Sedimentary Basin and in the Cordova Basin. It looks for growth from the Lower Doig and Montney zones in the Deep Basin.

(Photo by Tom Fox, courtesy of Oil and Gas Investor*, February 2012)*

Workers put safety straps on standpipe before a fracking operation targeting the Eagle Ford in Karnes County, Texas.

MONTNEY

The company held a position in the Montney play and added to it substantially with the acquisition of Anadarko Canada. "We capitalized on our existing land position at that time, giving us early exposure to the play. This allowed us to acquire strategic sections of prime Montney land at a fraction of today's cost," the company said on its website.

It grew into one of the largest undeveloped landholders in British Columbia and built a comprehensive infrastructure to economically produce its assets. It's adding to those land assets.

In a September 2014 presentation, Canadian Natural said it held 8.3 Tcf of gas equivalent in reserves, including its Montney and Deep Basin assets.

A 2011 British Columbia government report said Canadian Natural held some 647,416 net acres (262,000 net hectares) along the Montney fairway.

It estimated the contingent resource at 1.3 Tcf in its Septimus Upper Montney project alone with 300 Bcf of proved and probable reserves in 2012 when the company expanded its gas processing plant. It drilled 20 horizontal wells that year and produced about 60 MMcf/d of gas and 1.8 Mbbl/d of gas liquids.

The company has additional shale resources. It received permission in 2009 to evaluate the potential of the Muskwa and Evie shales at its Helmet area in the Cordova Embayment in northeastern British Columbia. Those shales produce in the Horn River Basin to the west.

The company found substantial thicknesses of gas in the Muskwa and plans further evaluation.

Chaparral Energy Inc.

- **Marching through the Midcontinent**
- **Lime and shale guide profits**

Chaparral Energy Inc. likes its assets in the Texas Panhandle and Oklahoma using advanced completion techniques to harvest a large land base.

It holds 532,000 net acres of land in the area and produced 31.4 Mboe/d in second-quarter 2013. It has 1 Bboe in total potential production and about 23.7 Mboe/d in resource development production and ranks as the nation's third largest EOR producer.

The company's horizontal drilling touches the Mississippi Lime, Marmaton, and Meramec and Woodford shales.

MISSISSIPPI LIME

Chaparral's Mississippi play is largely carbonate near the Kansas border in Oklahoma moving toward the Meramec Shale toward the south. It drilled or participated in more than 100 wells in the area by mid-year 2014, including eight wells in the first quarter.

It holds 210,982 net acres with 2,088 gross drilling locations (1,123 operated locations) in the Mississippi Lime-Meramec combination. It has more than 250 MMboe in potential recovery.

For 2014, the company is running three to five rigs with $140 million in its capital budget. It planned to drill 34 to 38 wells. It expected those wells to offer 154 Mbbl of oil and 1.19 Bcf of gas at a drilling and completion costs between $3.3 million and $3.7 million.

Its best well to date was the Chaparral Gladys SH-25 with a 30-day initial potential of about 1.3 Mboe/d.

The company expects a 40% rate of return from its northern Oklahoma Mississippian properties.

WOODFORD

Chaparral controls 164,945 net acres with 2,108 gross drilling locations (1,033 operated) in the Woodford Shale.

It produces from the Cana Woodford, South Central Oklahoma Oil Province, central Oklahoma Woodford and Arkoma Basin Woodford.

It expects a 35% rate of return from its Woodford oil and 21% from the Cana Woodford.

The Woodford Shale offers the company 247 MMboe of potential recovery.

It had drilled or participated in 50 wells by June 2014 and planned to spend $20 million to drill three to five wells during the year.

Chesapeake Energy Corp.

- **Continuing noncore divestitures**
- **Connected 35% more wells in second-half 2014**

Chesapeake Energy Corp. continues to reap profits from efficient growth from captured resources by expanding its core areas while increasing cash flow and capital and cost efficiency.

MARCELLUS

Chesapeake said in mid-October 2014 it would sell its southern Marcellus Shale assets and some of its eastern Utica Shale properties in West Virginia to Southwestern Energy Co. for about $5.4 billion.

The sale includes 413,000 net acres with some 1,500 wells, 435 of them in the Marcellus and Utica plays in northern West Virginia and southern Pennsylvania, with associated infrastructure. The properties also offer Upper Devonian targets.

Chesapeake produced some 56 Mboe/d from the leases during September 2014, including 184 MMcf/d of gas, 20 Mbbl/d of NGL and 5 Mbbl/d of gas condensate. The sale included 221 MMboe in proved reserves at year-end 2013.

The company's Marcellus North area absorbed 10% of the company's 2014 capex as it tried to reach all of the expected 9 Tcf of gas in recoverable resources.

The company holds 230,000 net acres in the area with a 39% average working interest. It produced 878 MMcf/d of gas equivalent in second-quarter 2014, representing a 12% gain from the same quarter a year earlier. It operated an average of six rigs and connected 21 gross wells in the quarter.

Chesapeake expects 10 Bcfe of gas in gross EUR from its wells to give it an 85% rate of return.

UTICA

Chesapeake routed 15% of its capex budget to its Utica Shale operation to operate eight rigs and connect 48 gross wells during second-quarter 2014. Its second-quarter production averaged 67 Mboe/d, up 373% from a year earlier.

The company's more than 1 million net acres of land in the play include 250,000 acres in the wet gas window, 300,000 acres in the oil window and 540,000 acres in the dry gas window.

Chesapeake expects its Utica wells to provide EUR of 10 Bcf of gas equivalent and return 45%. It has more than 2,000 potential locations in the play.

The company is optimizing lateral placement and modifying fluid chemistry, volumes and frack geometries to enhance production. It also reduced spud-to-spud cycle time to 15 days and holds the record in the play for the longest usable lateral at 12,106 ft. It drilled the well in 20 days.

It estimated year-on-year production growth of 30% to 60% in 2015.

NIOBRARA

Some 5% of Chesapeake's 2014 capex went to the Powder River Basin of Wyoming and its stacked pays in the basin, including the Niobrara and Parkman Upper Cretaceous formations.

It worked three rigs in the Niobrara in 2014 and planned to increase its rig count to seven to nine rigs in 2015.

It produced an average of 11 Mboe/d in second-quarter 2014 and produced the fourth, fifth and sixth best Niobrara wells topped by the 31-33-69-A03H York Ranch Unit in Converse County, Wyo., with an IP of about 1.8 Mboe/d.

The company completed a deal in August 2014 with RKI E&P LLC that increased the company's land position to 388,000 net acres after adding 66,000 acres from the RKI deal. Chesapeake's working interest rose to 79% from 38%.

It also added 4.5 Mboe/d in incremental production to raise its overall rate to 14.5 Mboe/d. It plans to run seven to nine rigs in its Powder River Basin properties in 2015.

The company called the Powder River Basin its 2015 oil growth engine.

During the past two years Chesapeake cut drilling cost per foot and cycle times in half. It now uses longer laterals and completion improvements that should increase its rate of return.

PARKMAN SAND

Chesapeake is working several Upper Cretaceous sands, including the Parkman. It has drilled four successful Sussex wells to date and was completing

A rig drills to the Niobrara in the Converse County section of the Powder River Basin in northeastern Wyoming.


(Photo courtesy of Chesapeake Energy Corp.)

a fifth in third-quarter 2014. The Sussex III tested for more than 1 Mboe/d with an 85% oil cut.

The company planned further testing of the Sussex, Teapot, Parkman and Shannon formations in second-half 2014, including a Parkman well in the fourth quarter.

Chesapeake's largest investment area, at 40% of capex, is the Eagle Ford Shale in South Texas. It produced 91 Mboe/d in second-quarter 2014 and worked to increase that level with the help of 21 rigs.

MIDCONTINENT

Chesapeake's second biggest area of capex, 20%, is its Midcontinent area in 2014 to help it run 15 to 17 rigs and produce 98 Mboe/d.

It used part of that money to connect 52 gross wells in second-quarter 2014 on its 1.9 million acres of legacy leasehold. Its two prime plays are the Mississippi Lime and the Granite Wash.

It controls 195,000 net acres in the Mississippi Lime with a 44% working interest and estimates more than 500 MMboe of net recoverable resource.

The Granite Wash occupies another 91,000 net acres. Chesapeake has an 83% working interest in that play and estimates more than 350 MMboe in net recoverable resource.

HAYNESVILLE

Although most natural gas plays are low-priority assets with many oil and gas producers, Chesapeake thinks enough of its Haynesville properties that it devoted 10% of its capex to the play in 2014 to run seven to nine rigs.

It produced 508 MMcf/d of gas equivalent in second-quarter 2014.

The company controls about 10 Tcf of gas equivalent with EUR of 8.9 Bcf of gas equivalent on its 387,000 net acres in Caddo and DeSoto parishes in Louisiana.

Its well costs dropped from $10.1 million in 2012 to a target of less than $7.5 million at year-end 2014.

The company expects a rate of return of more than 100% on wells costing less than $7.9 million with a gas price of $4/MMBtu.

Now, it's working with competitors on laterals that cross section lines. It's also drilling additional 700-ft to 800-ft vertical sections to capture an additional 1 Bcf of gas per well. Those advances add 6 Bcf of gas per section. The company expected to drill 85% of its 2014 Haynesville wells across section lines.

BARNETT

The Barnett Shale in North Texas received 5% of Chesapeake's capex in 2014. That money kept one rig working the play to produce 69 Mboe/d in second-quarter 2014.

EAGLE FORD

Chesapeake's largest investment area, at 40% of capex, is the Eagle Ford Shale in South Texas.

It produced 91 Mboe/d in second-quarter 2014 and worked to increase that level with the help of 21 rigs. That was a 15% increase from the quarter a year earlier. By late July 2014, production had grown to more than 101 Mboe/d.

The company estimated about 1.2 Bboe in net recoverable resource from its property.

It connected 104 gross wells during second-quarter 2014 with an estimated 610 Mboe gross EUR per well and a 45% rate of return. Some 95% of its 2014 wells were completed on multiwell pads.

The company's wells are in the oil and wet gas window where production is 64% oil and 14% NGL.

Cimarex Energy Co.

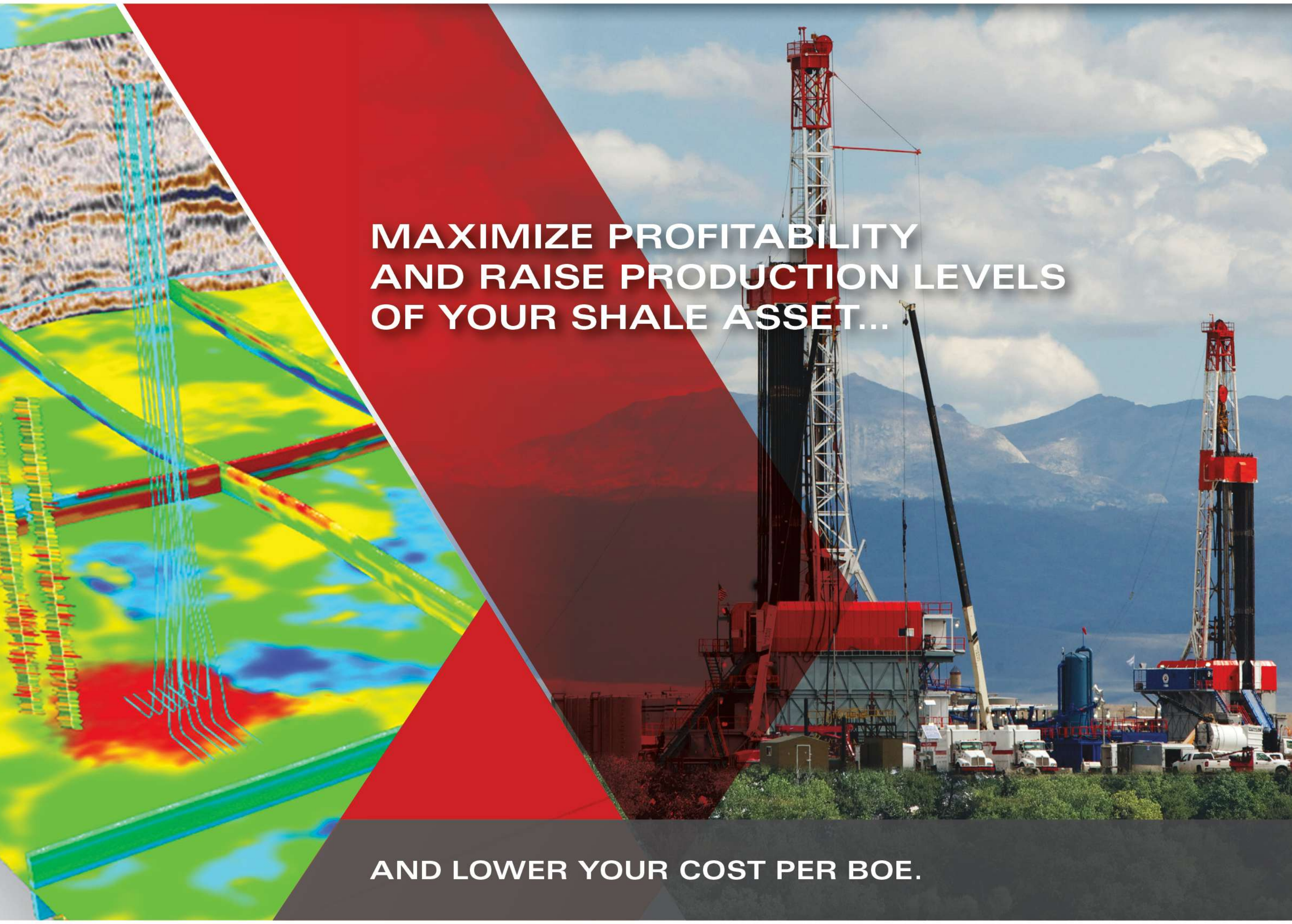
- **After-tax rate of return guides choices**
- **Woodford and Wolfcamp payout**

Cimarex Energy Co. started operations in the Midcontinent and, even though it spread its operations into the Permian Basin, still sticks to its origins.

WOODFORD SHALE

The Cana Woodford in western Oklahoma gives Cimarex its main area of operations. It drilled its first horizontal well there in 2007 and started a multiwell drilling program five years later.

The shale in its acreage ranges from 120 ft to 280 ft thick at a depth of 11,000 ft to 16,000 ft. The company has participated in more than 530 Cana Woodford wells since that first horizontal well.



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It controls some 75,000 net acres in the liquids-rich portion of the play.

The area provides 68% of the company's reserves and 51% of its production, and Cimarex expected its Cana Woodford production to grow 30% in 2014.

It directed $480 million of its exploration and development budget to the Midcontinent in 2014, and $360 million of that went to the Cana Woodford.

A Woodford well costs $7.2 million to $7.6 million to drill. These new completions with upsized fracture treatments return 86% before taxes.

Cimarex also planned to drill five Meramec Shale tests in north-central Oklahoma in 2014.

Of the $685 million in capex directed at the Wolfcamp, 52% will go into Reeves County, 28% into Culberson County, 13% into Ward County and 7% into Midland County in the Midland Basin.

WOLFCAMP

Cimarex produced 33.3 Mboe/d from the Permian Basin in second-quarter 2014, which was up 11% from the quarter in 2013. The Permian received 74% of the company's $1.95 billion budget for 2014.

The Wolfcamp Shale is a big part of the Permian Basin development plan.

In the Delaware Basin, Cimarex drills to the second and third Bone Spring and the Wolfcamp A, C and D zones in Culberson County, the A and B/C combination in Reeves County, and the A zone in Ward County.

Of the $685 million in capex directed at the Wolfcamp, 52% will go into Reeves County, 28% into Culberson County, 13% into Ward County and 7% into Midland County in the Midland Basin. The company planned to drill 20 extended-reach laterals to Wolfcamp zones in second-half 2014, including 14 in Culberson and six in Reeves County.

It has about 235,000 net acres in the Wolfcamp play. Part of its Culberson County activities reside in a joint venture with Chevron covering 104,000 acres.

The company's average 30-day peak IP in the Wolfcamp D zone is about 2.7 Mboe/d with a 27% oil cut and 33% NGL.

Concho Resources Inc.

- **Permian professional**
- **Early Wolfberry fan**

Concho Resources Inc. entered the Wolfberry play in 2008, a year after it went public, by purchasing the pioneer in the play. It has looked outside the basin, but returned to its roots.

WOLFCAMP

It bought Henry Petroleum—the company that put the Wolfberry on the oil and gas map—for $584 million.

At that time, it produced 7.1 MMboe with a capital budget of $390 million.

In 2009, Concho bought additional interests in the play for $271 million and produced 10.9 MMboe with a capital budget of $400 million.

The following year, it acquired Marbob Energy and its affiliates for $1.4 billion to move into the Yeso play in New Mexico.

In 2011, the company divested its Bakken assets for $100 million to raise money for more Permian acquisitions. It added more Wolfberry properties in the Midland Basin along with Wolfcamp properties and Avalon and Bone Spring holdings in the Delaware Basin.

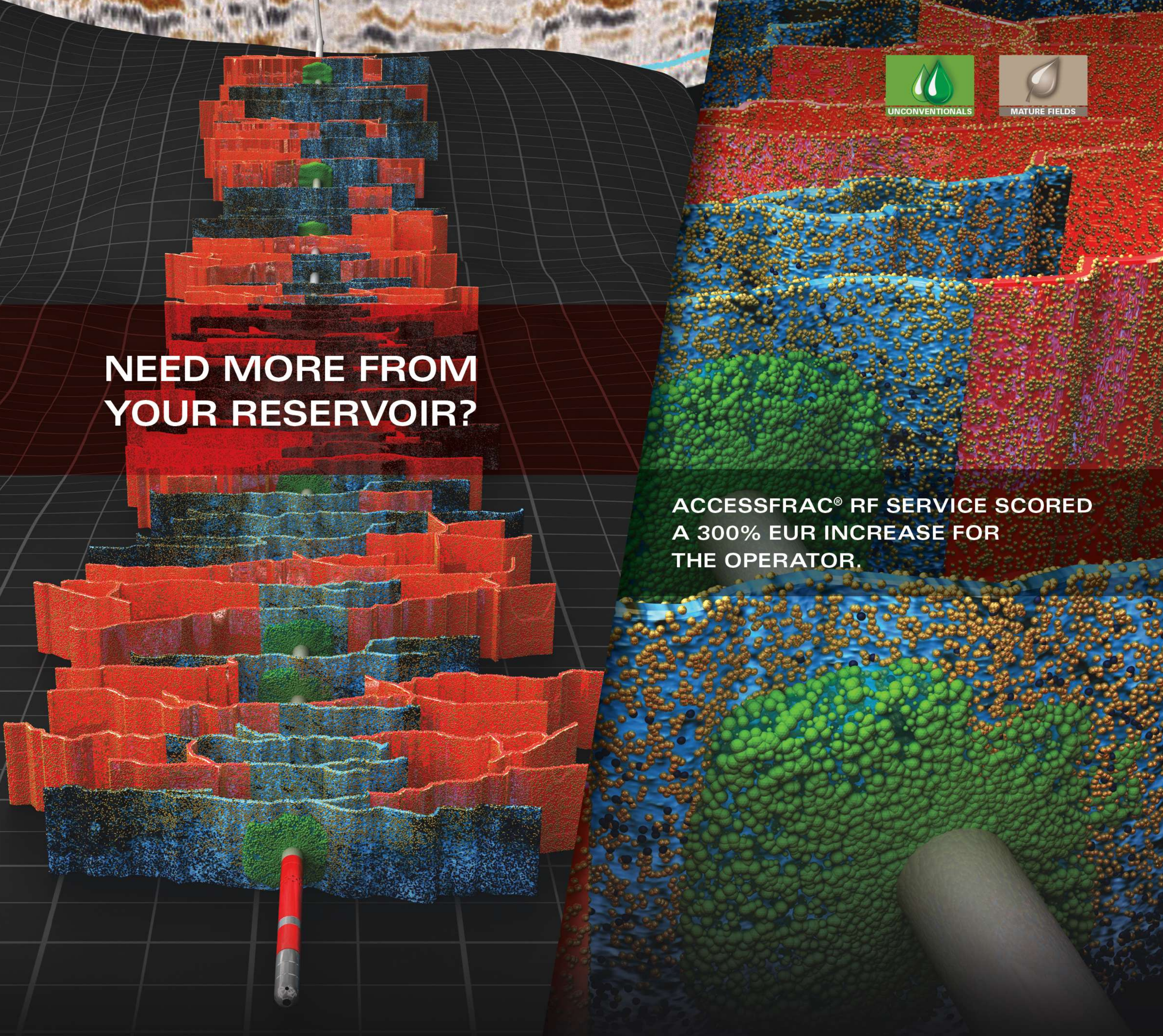
Purchases continued with Three Rivers Operating Co. in 2012 for about $1 billion for more Delaware, Midland Wolfberry and Midland horizontal Wolfcamp properties.

By 2013, Concho reported 20% year-on-year production growth from continued operations, including 25% growth in oil. It nearly doubled its drilling locations to about 22,000 by year-end 2013 and produced 33.6 MMboe with a $1.8 billion capital budget.

It had drilled or participated in 633 wells, 465 of them operated, and had year-end proved reserves of 502.9 MMboe in 2013, representing a 13% gain from 2012.

The company's southern Delaware Basin properties, with 10,000 drilling locations, included 2,000 Wolfcamp locations.

The Midland Basin in Texas offered prime targets in the vertical Wolfberry and horizontal Wolfcamp. Concho drilled 20 horizontal Wolfcamp wells in 2013, and confidence in the results per-



An early Eagle Ford shale well had an estimated ultimate recovery (EUR) of 1.1 Bcfe, but was underperforming compared to offset wells. The operator thought it should be doing better. He was right. Halliburton's **AccessFrac® RF** service was performed to contact previously undrained portions of the reservoir. The result? The EUR went from 1.1 Bcfe to 3.5 Bcfe. A 300% increase.

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suaded the company to add 2,500 horizontal Spraberry and Wolfcamp locations to its inventory.

It directed more than 85% of its drilled capital to the Texas side of the Permian Basin in 2014 to drill 195 gross wells, including 75 horizontal wells.

The company holds some 1.2 million gross (605,000 net) acres of land throughout the basin with about 3 Bboe in resource potential.

ConocoPhillips Co.

- **North to south shale interests**
- **Bakken and Eagle Ford sweet spots**

From gas supplies for LNG to high liquids content, ConocoPhillips Co. is riding the shale boom.

HORN RIVER

The company has properties in the Muskwa Shale in the Horn River Basin.

The company didn't detail its acreage position in the play, but it did say it held 363,000 acres of land in the Montney and Horn River plays and 230,000 net acres in the Montney. That would leave about 133,000 acres in the Horn River.

DUVERNAY

ConocoPhillips holds 120,000 net acres in the Duvernay Shale. It focused its operations there on a 107,000-acre core with a 25% to 90% liquids yield. It planned three horizontal wells in the play during 2014.

ConocoPhillips is a major producer in the San Juan Basin, where it produced 2 Mbbl/d of oil, 47 Mbbl/d of NGL and 750 MMcf/d of gas, according to its 2013 fact sheet.

MONTNEY

The company planned 14 horizontal wells on its Montney properties where it held a 90% average working interest in 230,000 net acres. It concentrated its activity on 135,000 net acres with a 30% to 40% liquids yield.

BAKKEN

The Bakken Shale, along with the Eagle Ford, is one of the brightest spots in ConocoPhillips' shale inventory. It controls some 620,000 net acres with a 45% average operating working interest in the Bakken/Three Forks play in the Williston Basin.

The company has identified 1,800 gross drilling locations and planned a 10-rig drilling program with a capital budget of $1 billion from 2014 to 2017.

That program should raise production from the current 30 Mboe/d to about 70 Mboe/d in 2017. The wells offer 83% oil and 6% NGL.

The company's properties lie along the Nesson Anticline in the heart of the play, and it was the top producer along the anticline in 2013.

ConocoPhillips currently drills to the Bakken and Upper Three Forks on 320-acre spacing. It is testing 160-acre spacing, though, and is evaluating the Middle Three Forks Formation.

It planned to drill 90% of its 2014 wells on multiwell pads.

NIOBRARA

ConocoPhillips has 130,000 net acres of land in the Niobrara-Codell play in the southern Denver Basin, and it's running an appraisal program with a single rig. That program covers its land in Adams, Douglas and Elbert counties and included two horizontal wells on a single pad within the Aurora, Colo., city limits.

It planned 19 horizontal wells in the play for 2014 as it combined well evaluation with improvements in drilling and completions design. A new design resulted in average early production rates of more than 600 boe/d. That's a 350% improvement in production from the industry standard, according to the company.

It produces 67% oil and 19% NGL from its wells.

MANCOS

ConocoPhillips is a major producer in the San Juan Basin, where it produced 2 Mbbl/d of oil, 47 Mbbl/d of NGL and 750 MMcf/d of gas, according to its 2013 fact sheet. Most of that production comes from conventional zones and coalbed methane, but it also has taken a hard look at the Mancos Shale, according to CEO Ryan Lance.

The company drilled the YERT COM HZMC horizontal well to the Mancos in October 2012

for 11 boe/d. It calculated an EUR of 66 Mboe for the wells.

BARNETT

The company is concentrating its efforts on 144,000 gross (65,000 net) acres in the liquids-rich portion of the Barnett Shale after selling off its properties in the southern gas-prone area.

WOLFCAMP

ConocoPhillips has property positions in the Delaware and Midland basins.

It works four rigs in the Delaware Basin and planned 26 horizontal wells in 2014 with the Avalon, Bone Spring and Wolfcamp as targets.

It holds some 1.1 million net acres in the Permian Basin with exposure in every productive play. In addition to its Delaware properties, it has Clear Fork, Wolfberry and Wolfcamp properties in the Midland Basin.

EAGLE FORD

The company holds 220,000 net acres with a 96% average operated working interest in the Eagle Ford play in South Texas. That property contains more than 3,000 identified drilling locations.

ConocoPhillips planned to spend $3 billion between 2014 and 2017 to grow production from the current 120 Mboe/d to 250 Mboe/d in 2017. It is running a 12-rig program in 2014 on its properties in the black oil and volatile oil, condensate and wet-gas window.

Greater well density and layered production are paying off in the Eagle Ford. A single layer of wells in the lower Eagle Ford on 80-acre spacing gives the company an EUR of 1.8 Bboe, while two layers in the same zone on the same spacing raise the EUR to 2.5 Bboe.

In testing, the increased use of proppant raised EUR per well by 30%. It also tightened spacing of frack clusters and reduced drilling days.

Continental Resources Inc.

- **Expanding from the Bakken**
- **Big pay in the SCOOP**

Continental Resources Inc. dipped its investment resources in several shale plays, but its favorites are the Bakken/Three Forks and the South-Central Oklahoma Oil Province (SCOOP).

BAKKEN

Continental Resources Inc. is the largest acreage holder in the Bakken/Three Forks play with 1.1 million net acres, most of it in North Dakota and some in Montana. The company also lists firsts in its activities there, including being the first company to complete a paired Bakken/Three Forks well in 2010, a horizontal well in the Three Forks in 2008, a 1,280-ft long lateral leg with a multistage frack treatment in 2007 and the first commercially successful well in the North Dakota Bakken to be both horizontally drilled and fracture-stimulated in 2004.

The company has some 4.1 Bboe in potential production from some 11,800 net undrilled wells and from the Three Forks two zone. It has drilled 73 wells in the Lower Three Forks, 59% of which are operated, including 53 wells in the Three Forks two zone, 18 wells in the Three Forks three zone and two wells in the Three Forks four zone.

At the same time, the company is refining its operations. It increased its recovery factor to 15% with higher-density drilling and has evidence to show it could raise its recovery rate to 20%. Better completions increase production by 25%.

Those refinements helped the company achieve a 58% annual production growth rate in the past three years, and its biggest gains came in second-quarter 2014 with more than 11.1 Mboe/d.

NIOBRARA

The company appears to be selling out of its Niobrara holdings in the Denver Basin of Colorado and Wyoming.

It built a position of 92,842 acres by first-quarter 2012 and was the first company to drill a 1,280-acre spaced well in the Niobrara in 2011.

After establishing its acreage position, it put 39,000 net acres of leases in Wyoming up for sale, and late in 2013, Pacific Energy Development Co. said it planned to buy 28,727 acres of Continental land in the Denver Basin for $30 million.

WOODFORD

Continental Resources has Woodford properties in the Arkoma and Anadarko basins in Oklahoma and in the SCOOP play.

It was the first company to simultaneously frack wells in the Woodford in the Arkoma Basin of eastern Oklahoma, and it has gathered 150 sq miles of 3-D seismic data.

The company has 315,675 net acres of land in the Anadarko Basin Woodford, which makes it one of the largest acreage holders in that play.

That includes the SCOOP, but the company also has other pay zones in south-central Oklahoma, including the Springer.

The Woodford is the source rock for conventional resources in the SCOOP that have produced 3.2 Bbbl of oil, and most of the generated oil remains in the Woodford, the company said.

Among Continental's top Woodford producers is the Nanssell well that tested for an initial potential of 973 boe/d and 90% oil.

The company doubled its rig count in the 12 months ended in early September 2014 and now operates 19 rigs drilling Woodford wells. It plans to raise that rig count to 21 in 2015.

For Continental, the SCOOP is similar to the Bakken with 3.6 Bboe of unrisked resource potential and returns equal to, or better than, the Bakken.

It holds 451,000 net acres in the Woodford.

In a late October 2014 development, Continental formed a joint venture (JV) that gave SK E&S Co. Ltd. of South Korea a 49.9% interest in Continental's Cana Woodford properties for $90 million at closing and another $270 million for half of the JV's drilling costs in the play.

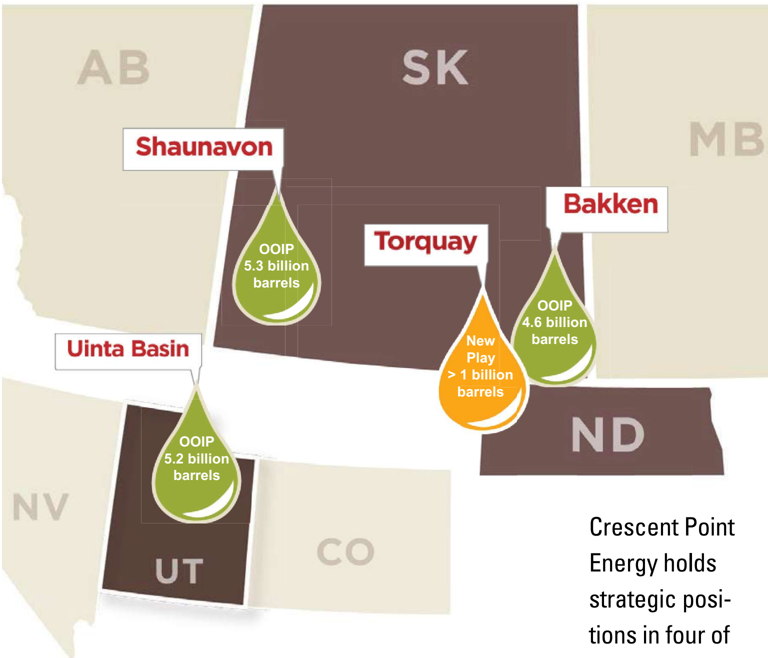
The property can support 360 wells with a net unrisked resource potential of 475 Mboe.

Crescent Point Energy Corp.

- **Major cross-border Bakken player**
- **Developing large resource assets**

Crescent Point Energy Corp. started operations in 2001 with the idea that it would acquire and develop high-quality large resources. It followed that strategy with acquisitions and development of the Bakken Formation in Canada and the U.S.

(Source: Crescent Point Energy corporate presentation, November 2014)



Crescent Point Energy holds strategic positions in four of the top seven medium to light oil resource pools in Canada, including the Bakken.

BAKKEN

The company's Canadian acquisitions include Bakken holdings in southern Saskatchewan and Manitoba, but it holds other properties in central and southern Alberta.

It controls Viewfield Field, the largest Bakken deposit in Canada, which makes the company the largest Bakken producer in Canada. Recent numbers weren't published, but Crescent had 512,000 net acres at Viewfield and more than 1 million total Bakken acres in 2010.

The company drilled both conventional wells and water-injection wells to enhance recovery from the field. It had drilled 81 water-injection wells by the end of first-quarter 2014 and planned to drill 15 more by year-end. The waterflood has added 15 Mboe/d of production, and Crescent Point expects waterfloods to double that number in the future.

It drilled 40 wells with a 100% success rate in southeastern Saskatchewan and Manitoba in second-quarter 2014, with 37 of those wells located at Viewfield.

The company also holds Flat Lake Field on the U.S.-Canada border that produces from the Three Forks and Torquay and Bakken property in Divide and Williams counties in North Dakota and Richland and Sheridan counties in Montana, and other properties in the Uinta Basin in Utah.

Devon Energy Corp.

- More than doubled oil output since 2008
- Shale operator from Wyoming to Texas

Devon Energy Corp. has played a pioneering role in the shale revolution since its acquisition of Mitchell Energy's Barnett Shale assets in North Texas in 2002. Devon has expanded its activity, working to make oil and gas volumes from shale formations more accessible with ongoing technical innovation and increasingly effective use of information technology. Only one pure-play North American operator—EOG Resources—produces more oil than Devon.

PARKMAN SAND

The star of Devon's Powder River Basin properties in Wyoming is the Parkman Sand, although its wells also target the Turner and Frontier formations. It holds some 150,000 net acres in the Powder River Basin and produced 21 Mboe/d, with a 46% liquids content, in second-quarter 2014 from about 300 net wells.

The basin offers the company 37 MMboe in reserves, and Devon developed those reserves in 2014 with $300 million pushing four rigs to drill 40 wells. It is accelerating its activity from three operated rigs in third-quarter 2014 to four rigs by year-end.

The Parkman gave the company wells in second-quarter 2014 with 30-day IP of 950 boe/d with a 95% oil cut. It has a risked drilling inventory of about 1,000 locations, and 75% of those are in the Parkman zone.

The Powder River Basin property, along with the company's Mississippian play in Oklahoma, is part of a $2.5 billion joint venture (JV) with China Petroleum & Chemical Corp. (Sinopec). Some $500 million of that company's $1.6 billion drilling carry remained at the end of June 2014. Sinopec has a 33% interest in the JV.

MISSISSIPPI LIME-WOODFORD

Devon combines numbers for its Mississippian and Woodford properties in northern Oklahoma and southern Kansas. It holds more than 600,000 net acres in north-central Oklahoma that is in the early stages of de-risking, but it's prospective for the Mississippi Lime and Woodford Shale.

That property contains about 5,000 risked locations and more than 800 MMboe of net risked resource potential. It produced 18 Mboe/d from 500 wells in second-quarter 2014, and 75% of that production was in liquids.

Like the Rockies, this play earned a $300 million capital investment in 2014, but that money will support eight drilling rigs and about 300 wells. Some 200,000 acres are in the JV area with Sinopec, and that's where the drilling focus lies. The best wells in the area tested for more than 1 Mboe/d.

CANA WOODFORD

The Oklahoma company claims the largest land position in the Cana Woodford with more than half of the best acreage in the play. Its current drilling targets the liquids-rich part of the play with one operated rig, but it plans to accelerate activity with 10 operated and nonoperated rigs by first-quarter 2015.

A 50,000-acre acquisition in June 2014 raised Devon's leasehold to 280,000 net acres with more than 5,000 risked drilling locations.

It produced 64 Mboe/d in second-quarter 2014 with a 40% liquids content. Devon performed acid treatments on more than 200 wells to raise average production rates from 1 MMcf/d of gas equivalent to more than 2 MMcf/d of gas equivalent, giving the treatment a three-month payback time. It also improved production by doubling frack stages to 20 and perforation clusters to 80 with high volumes of sand and transportation fluids.

The company's type curve for an $8 million Cana Woodford well is 30-day production of 920 boe/d with EUR between 1.4 MMboe and 1.7 MMboe.

As part of its Anadarko Basin operations, it also has 66,000 net acres in the Granite Wash, mostly in Hemphill and Wheeler counties in Texas. Those properties produced 24 Mboe/d for Devon in second-quarter 2014.

BARNETT

Devon holds the largest acreage position in the Barnett Shale play via the Mitchell Energy acquisition and has drilled more than 5,000 Barnett wells.

It produced 1.3 Bcf/d of gas equivalent in second-quarter 2014 from 600,000 net acres and about 5,300 producing wells. Its wells produce 27% liquids. It planned to spend $250 million in the Barnett in 2014 to drill 75 wells with two rigs.

WOLFCAMP

Devon controls Wolfcamp Shale assets in the Delaware and Midland basins, both of which are part of the Permian Basin of West Texas and southeast New Mexico. Devon has 1.3 million acres in the Permian with 7,600 wells that produced 95 Mboe/d in second-quarter 2014 with 76% liquids. The company dedicated $1.5 billion for capex to the Permian in 2014 to drill 400 wells with 23 rigs.

It controls more than 100,000 net acres in the Wolfcamp Shale in the Delaware Basin but is just getting started with evaluation there. In the Midland Basin, Devon holds another 117,000 net acres with Wolfcamp potential in Reagan, Irion and Crockett counties. Devon dedicated $200 million to Wolfcamp activities in the Midland Basin to drill about 150 wells. It has a $1.4 billion JV with Sumitomo Corp., with $1 billion of drilling carries for drilling in the Midland Wolfcamp; $350 million remained on those carries by the end of June 2014. That JV covers some 600,000 acres.

Devon also holds property with Wolfberry—Wolfcamp and Spraberry—potential along the eastern edge of the Central Basin Platform.

The company also runs 13 operated rigs on the Delaware Basin side of the Permian in New Mexico, where it holds 365,000 net acres. The principal targets are the Bone Spring, where Devon has 285,000 net acres of prospective properties, and Delaware Sands, where it has 80,000 net prospective acres.

Devon planned to drill 150 wells in the Delaware Basin in 2014, with 120 of those located in the Bone Spring, where the company brought 22 wells online in the second quarter with an average 30-day IP rate of 660 boe/d. Devon estimates it has 3,500 gross risked undrilled locations in the Bone Spring.

EAGLE FORD

DeWitt and Lavaca counties in South Texas host Devon's 82,000 net acres of Eagle Ford properties. The company has de-risked the DeWitt County properties (50,000 net acres) and found encouraging wells in Lavaca County (32,000 net acres). It has a 50% working interest in the Dewitt County properties and a largely 100% working interest in Lavaca.

The company has 400 wells that produced an average 65 Mboe/d in second-quarter 2014. Devon devoted $1.1 billion in 2014 capex to the Eagle Ford and planned to drill 200 wells with 19 rigs. Its property contains a 1,200-well drilling inventory. Devon expected to produce between 70 Mboe/d and 80 Mboe/d in 10 months of ownership in 2014 and more than 100 Mboe/d in 2015.

The Lavaca County property carries potential for Lower Eagle Ford production. The company's Ronyn 1H tested for a 24-hour initial potential of about 1.6 Mboe/d.

Encana Corp.

- **Leader in unconventional plays**
- **Reaching for 75% cash flow from liquids**

Encana Corp. looks at every opportunity in shale plays, from the most popular, such as the Eagle Ford, to the emerging plays, such as the Mancos Shale and Tuscaloosa Marine Shale (TMS).

Its activities range from the northern edge of British Columbia to South Texas and from New Mexico to Mississippi.

HORN RIVER

Encana's 1.8 million acres of land in the Greater Sierra area include some 264,000 net acres prospective for the Horn River Basin shale group.

Encana entered the play in 2008 and started development. By June 2013, its wells had tested for initial potentials around 30 MMcf/d of gas with EUR of 15 Bcf to 35 Bcf, largely related to the length of lateral legs on its horizontal wells.

DUVERNAY

Moving south and east from the Horn River, the company established a 50% average working interest in a 262,000-net-acre foothold in the Duvernay Shale and is moving forward on an appraisal program at Willesden Green.

It expects a 100% rate of return from Duvernay wells that cost $12 million to $18 million to bring to sales. It holds a 1,400 to 1,450 inventory of wells in the play.

Its 2014 production should average 2 Mbbl/d of oil to 2.5 Mbbl/d of oil with 400 bbl/d to 500 bbl/d of NGL and 15 MMcf/d to 20 MMcf/d of gas.

Encana planned to spend up to $300 million to drill 15 to 20 net wells in the play using five to seven rigs.

MONTNEY

Some 575,000 net acres of land in the Montney give Encana access to a potential of more than 2 Bcf/d of gas and 50 Mbbl/d of oil with a rate of return ranging from 60% to 100%.

By mid-year 2014 the company had used six rigs to drill 32 net wells.

Its 2014 plan calls for accelerated investment in the Gordondale, Pipestone and Tower liquids-rich areas to grow liquids production by 80% to about 20 bbl/d.

Moving south and east from the Horn River, Encana Corp. established a 50% average working interest in a 262,000-net-acre foothold in the Duvernay Shale and is moving forward on an appraisal program at Willesden Green.

It also has a partnership with Mitsubishi to develop the Cutbank area with Encana as operator with a 60% share.

The company also is drilling new wells three days faster than expected and drilled its first spud-to-rig-release well in seven days. In addition, the company drilled its third 10,000-ft-lateral well.

NIOBRARA

Dropping farther south into Colorado, Encana holds a half working interest in 49,000 acres of land in the Wattenberg Field in Colorado in the heart of the Niobrara Shale play where wells produce 70% liquids and returns can reach 85%.

For 2014, Encana plans 70% production growth as it increases the pace of its development.

Wells offer 325 Mboe to 425 Mboe EUR, and Encana has an inventory as high as 1,000 wells, depending on spacing.

Wells cost $4.5 million to $5 million to bring to sales, and the company plans production of 8 Mbbl/d to 8.5 Mbbl/d of oil and condensate, 3.5 Mbbl/d to 4 Mbbl/d of NGL and 40 MMcf/d to 50 MMcf/d of gas for 2014 with the help of up to $350 million in expenditures to power five to six rigs and drill 55 to 60 wells.

HAYNESVILLE

Encana hasn't talked much publicly about its Haynesville gas play in Louisiana lately, but the company acquired 325,000 net acres in the play in 2008.

It conducted a drilling campaign on the property and by September 2014 started a refracturing program with "excellent results" on two wells completed. The initial potentials on those wells were 100% higher than the company expected.

That campaign led the company to look at refracturing wells in the Niobrara, Montney and Eagle Ford plays.

TUSCALOOSA MARINE SHALE

Encana is a major player in the Tuscaloosa Marine Shale in Louisiana and Mississippi, and 80% of its 200,000 acres lie in the prime Tier 1 part of the play. The company drilled 10 gross (six net) wells during first-half 2014 and planned to complete its appraisal program by year-end with two working rigs.

The company's land has an estimated 4 Bboe to 5 Bboe of petroleum initially in place, and Encana has the potential to produce more than 50 Mboe/d from its properties.

By the time the play reaches resource play mode, wells should provide returns between 35% and 40%.

MANCOS

With a 54% average working interest in 176,000 net acres in the San Juan Basin in New Mexico, Encana discovered the Mancos Shale play and is the most aggressive operator in the play.

The play meets Encana's expectation of producing 50 Mboe/d when fully developed. It drilled 14 gross (nine net) wells by mid-year 2014 with three rigs running and expected to add a fourth rig in the third quarter. It can drill 25 wells per rig a year.

Those horizontal wells cost between $4 million and $5 million to drill, provide IP potential between 400 bbl/d and 500 bbl/d of oil and should return 45% to 70% to the company when it reaches resource play development mode.

Its acreage can support 700 gross wells.

Encana's 2014 production will average between 3.3 Mbbl/d and 3.6 Mbbl/d of oil and condensate, 550 bbl/d to 650 bbl/d of NGL and 7 MMcf/d to 10 MMcf/d of gas.

It planned to spend $300 million to $350 million to drill 45 to 50 wells to the Mancos in 2014 using two to four rigs.

WOLFCAMP

Encana entered the Permian Basin in September 2014 with its purchase of Athlon Energy for $7.1 billion.

EAGLE FORD

Encana bought 45,500 net acres of land in the Eagle Ford play from Freeport-McMoRan for $3.1 billion in June 2014 using money it had earned through the sale of noncore assets.

The self-funding acquisition encouraged Encana to invest up to $320 million in the play during 2014 to produce at an annual rate of 22 Mboe/d. It has two rigs working its property in Karnes, Wilson and Atascosa counties.

Energen Resources Corp.

- **Focusing activity in two plays**
- **Growing in the Wolfcamp**

Energen Resources Corp. is pinning its growth hopes on extensive properties in the Permian Basin and a smaller position in the Mancos play in New Mexico.

WOLFCAMP

Energen claims 5,500 unrisked drilling locations and about 2.7 Bboe of proved, probable, possible and contingent resources in the Wolfcamp and Cline shales in the Permian Basin. It could grow production from the basin by 30% from 2014 to 2015.

In the Delaware Basin segment of the Permian Basin it controls 106,000 net acres of land with 1,270 potential well locations in the Wolfcamp A zone, 1,165 potential wells on 102,600 net acres in the Wolfcamp B and 680 locations on 56,200 acres in the Wolfcamp C.

One of its best 2014 wells, the University 16-17 #1H, showed an initial potential of about 1.9 Mboe/d with a 78% oil cut from a 4,808-ft lateral in the Wolfcamp B bench.

Energen dedicated $415 million to Delaware Basin operations for 2014 including $180 million to contract two rigs to drill 14 net Wolfcamp wells.

Moving east to the Midland Basin, the company was in its first year of Wolfcamp development in the Midland Basin where it is delineating both the Wolfcamp and Cline shales.

In 2013, it spent $870 million, including $665 million directed to the Cline, to drill 76 net wells with six rigs. It spent $125 million to drill 50 net Wolfberry wells with two rigs.

In 2014, the company drilled 17 gross (16 net) Wolfcamp rigs and three net Cline wells.

Its Wolfberry A and B zones were targets for 57 gross (55 net) wells in southern Glasscock County with 19 gross (18 net) wells drilled in first-half 2014.

MANCOS

Energen entered the San Juan Basin in 1997 when it bought 319 Bcf of proved gas reserves from Burlington Resources. It expanded its operations from that point.

Currently it is a nonoperating partner on four Mancos wells with WPX in the south-central San Juan Basin. It called the results promising.

EnerVest Ltd./EV Energy Partners LP

- **Top 25 oil and gas producer**
- **Old properties offer new rewards**

EnerVest Ltd. and its EV Energy Partners LP (EVEP) MLP affiliate make a practice of acquiring properties in mature areas and finding ways to make those properties profitable.

Examples include the company's acquisition of properties in Ohio, which rose sharply in value with the popularity of the Utica Shale play, and its purchase of San Juan Basin assets, which are prospective for the emerging Mancos Shale play.

UTICA

EnerVest is the number two acreage holder in the Utica Shale and the largest conventional oil and gas producer in Ohio.

Its EVEP affiliate holds net working interests in 173,000 net working interest acres in the Utica, 48,000 in the wet gas window, 81,000 in the volatile oil window and an overiding royalty interest in 880,000 net acres.

It is in a joint venture (JV) with Chesapeake Energy and Total Petroleum, mostly in the wet gas window.

The companies planned to drill more than 540 wells by year-end 2014.

MANCOS

EVEP held 50.1 Bcf of gas equivalent reserves in the San Juan Basin at year-end 2013. It has more than 20,000 net acres that might be prospective for the Mancos Shale in the oil and wet gas windows.

EnerVest purchased the Bear Canyon Unit from Apache Corp. in San Juan County in 2007. That unit produces from the Mancos and Gavilan zones, and EnerVest drilled the Bear Canyon Unit #6 horizontal well to the Mancos in 2010 for 60 Mcf of gas in the Lindreth area.

The companies' properties lie generally east of Mancos properties being developed by Encana and WPX Energy.

BARNETT

EnerVest spent more than $2 billion buying Barnett Shale assets since 2010, becoming the sixth largest producer in the play in the process.

EVEP claimed 781.5 Bcf in proved reserves in the shale with August 2014 production of 89 MMcf/d of gas equivalent.

It drilled 34 wells and brought 18 wells online in first-half 2014 and planned a three-rig drilling program in second-half 2014 using five-well to six-well drilling pads and increasing lateral lengths.

CLEVELAND/GRANITE WASH

EnerVest and EVEP already hold properties in the Granite Wash and Cleveland Shale areas, but EnerVest agreed with FourPoint Energy LLC to form a JV in October 2014 to acquire more land from Linn Energy LLC and LinnCo LLC. The JV acquired all of Linn's Cleveland and Granite Wash properties in western Oklahoma and the Texas Panhandle for $1.95 billion.

The acquisition included interests in 1,358 producing wells, most of them in the Granite Wash, Tonkawa, Cleveland and Marmaton formations, with production of about 195 MMcf/d of gas equivalent on 145,000 net acres. About 97% of the properties are HBP.

Before the sale, Linn was running four drilling rigs and planned to spend $210 million on the play in 2014.

WOLFCAMP

EVEP holds some 54.2 Bcf of gas equivalent in proved reserves in the Permian Basin with properties in the Wolfbone and Cline shales in the Midland Basin and the Bone Spring and Avalon formations in the Delaware Basin, which it lists as emerging plays.

It ranks its Wolfcamp Shale horizontal play as a commercial development.

EAGLE FORD

EnerVest and EVEP agreed to sell their Eagle Ford properties in Brazos, Burleson and Grimes counties in South Texas with a closing date in fourth-quarter 2014, the companies said in September at the Hart Energy A&D Strategies and Opportunities Conference.

EVEP said it agreed to sell its rights for $30 million, but it retained Eagle Ford rights in Fayette, Lee and Washington counties.

The company has 19 rigs running in the play, and EnerVest recently drilled and completed the Unger 1EF well in Lee County for a peak production rate of 460 bbl/d of oil and 132 Mcf/d of gas. In September 2014, it continued to flow at a rate of 400 boe/d from a 6,100-ft lateral.

EOG Resources Inc.

- **Best horizontal crude oil assets in U.S.**
- **Shale and profits go hand in hand**

EOG Resources Inc. makes money by moving into plays early, gathering prime land, identifying more production on existing land and generating new plays internally.

That philosophy put it in plays from the Marcellus to the Eagle Ford in the U.S. and from the Horn River Basin to southeastern Alberta in Canada.

The company is aggressive, too. It added 2,300 net drilling locations in first-half 2014, or twice the number of wells in its entire 2014 drilling program. That new inventory will provide at least a 60% after-tax rate of return.

HORN RIVER

EOG holds 127,000 net acres of land in Horn River Basin gas shales.

MARCELLUS

The company produces natural gas from its 46,000 net acres of land in the Marcellus play in Bradford County, Pa.

BAKKEN

EOG controls about 90,000 net acres of land in the core area of the Bakken/Three Forks Shale play and another 20,000 net acres in the Antelope extension of the play.

Using new fracture techniques that improve recoveries and returns, the company is now delivering an after-tax rate of return of more than 100% from its wells in both the core and the extension.

It produced 86 Mboe/d at year-end 2013, representing a 38% increase from the previous year.

It planned to concentrate its 2014 efforts on the Antelope area with six rigs contracted to drill 80 wells at a targeted cost of $9 million through completion. It also planned to test Three Forks intervals in second-half 2014.

The company's best well in the core, the Parshall 47-2226H, tested for an initial potential of 2.71 Mbbl/d of oil and 875 Mcf/d of gas.

EOG planned to spend between $8.1 billion and $8.3 billion on capital projects in 2014, up from $7.1 billion in 2013. Most of that increase will go to the Bakken, Eagle Ford, Permian Basin and Rockies.

PARKMAN

The company holds an eight-year inventory of well sites in the Powder River Basin of Wyoming, most of which is focused on the Parkman and Turner.

It holds 30,000 acres of Parkman property, enough land for 115 net drilling locations. That land contains a net 75 MMboe of resources with a 69% oil cut. EOG drills horizontal wells with 7,300-ft laterals to reach 850 Mboe in gross EUR per well and a cost of $5 million to completion.

Recently the Mary's Draw 412-1527H tested for 1.19 Mbbl/d of oil and 270 Mcf/d of rich gas from perforations in the Parkman.

The company expects an after-tax rate of return of more than 100% from its Parkman wells.

NIOBRARA

During the first nine months of 2014, EOG added 10 years of high-return drilling inventory to its Denver and Powder River Basin properties.

It holds 50,000 net acres with 235 net locations and a net 85 MMboe in reserves in the Niobrara Shale. That produces 71% oil and gives the company a 45% after-tax rate of return.

EOG effectively opened the horizontal Niobrara play with its 2-01H Jake well in Weld County, Colo., which tested at 1.8 Mboe/d. That's still the third best well in the basin.

Even better, it holds 85,000 net acres in the adjacent Codell Formation where it has 226 net locations with 125 MMboe in reserves and a 78% oil cut, which gives EOG an after-tax return of more than 100%.

During 2014, EOG planned to drill 39 wells with 9,000-ft laterals to the Codell and Niobrara. It expects EUR of 695 Mboe from its Codell wells and 430 Mboe from its Niobrara wells.

Two recent Codell wells with 9,000-ft laterals tested for 1.4 Mboe/d each.

HAYNESVILLE

Gas plays aren't popular these days, but EOG holds 143,000 net acres in the Haynesville gas and combination gas and liquids shales in Louisiana.

BARNETT

EOG holds 298,000 net acres in the Barnett gas play and in the gas and liquids combination play. It expects an after-tax rate of return of 30% to 60% from the combination play.

WOLFCAMP

The company controls some 234,000 net acres of land in the Delaware Basin Wolfcamp play where it has a drilling site inventory of more than 75 years at the 2014 rate of 14 net wells.

Its property holds 800 MMboe in estimated net reserve potential in the Upper and Middle Wolfcamp zones.

It expects a gross EUR of 900 Mboe per well, or 700 Mboe after royalties.

The company occupied one rig during 2014. Among its recent wells, the Voyager 15 #3H tested for 1,890 bbl/d of oil, 385 bbl/d of NGL and 2.5 MMcf/d of gas from the Upper Wolfcamp.

It drilled another 10 wells on its Midland Basin Wolfcamp property.

It expects a 60% after-tax rate of return from its Delaware Basin Wolfcamp wells and 30% to 60% on its Midland Basin wells.

EAGLE FORD

EOG is the biggest leaseholder and producer in the Eagle Ford Shale play.

The company increased its Eagle Ford reserves to 4.2 Bboe, representing a 45% increase, and added some 1,600 net drilling locations.

It also increased oil production 46% from second-quarter 2013 to second-quarter 2014 to an output of 253 Mboe/d at the end of June 2014.

It planned to drill 520 net wells during 2014 and has a 12-year inventory of locations (7,200) on its 632,000 net acres of land at that rate. Some 564,000 net acres are in the oil window, 22,000 are in the wet gas window, and 46,000 are in the dry gas window.

Currently, the company gets an after-tax rate of return of more than 60%, but it's targeting a return of more than 100%.

EP Energy Inc.

- **Zeroing in on liquids**
- **Active in Texas**

EP Energy Inc. took the industry path to profits as it downplayed its gas holdings and accelerated activity in its liquids play.

HAYNESVILLE

The company leases 38,865 net acres in the Haynesville play in Louisiana but planned no activity there in 2014.

The company's properties is in DeSoto Parish and is 100% HBP. It has 197 gross drilling locations and produced 97.8 MMcf/d of gas equivalent in second-quarter 2014.

When gas prices reach $4/MMBtu to $4.50/MMBtu, EP Energy expects returns from 33% to 47%.

WOLFCAMP

EP Energy leased 138,130 net acres of land in the Wolfcamp Shale play in 2009 and 2010, mostly in Reagan, Crockett, Upton and Irion counties in the Midland Basin. That property offers stacked pay potential from the Wolfcamp A, B and C zones as well as the Cline Shale for horizontal wells and opportunities for production from vertical Spraberry wells.

The company acquired another 37,000 net acres of producing property with Wolfcamp potential in April 2014. That property is next to its existing Wolfcamp holdings and is 100% operated by EP Energy with 1.3 Mboe/d of production. That property gives the company another 475 gross drilling locations for horizontal wells in addition to the 3,400 locations it already held.

It drilled its first Wolfcamp A wells in second-quarter 2014, and the results of its program to combine production from the B and C benches exceeded the company's expectations as it raised EUR to 450 Mboe from the previous 400 Mboe.

EP Energy budgeted $2 billion for capex for 2014, with 36% of that directed at the Wolfcamp for 95 to 105 completions.

EAGLE FORD

The company got into the Eagle Ford play in 2008 and expanded to 91,675 net acres with 946 identified drilling locations. It produced 50.5 Mboe/d from the property in second-quarter 2014.

In that quarter, it operated five drilling rigs and two stimulation crews and completed 34 wells. It is increasing the number of frack stages in its wells and raised proppant volumes to increase production. The company currently sees IP rates of more than 692 boe/d.

Among recent wells, its Altito A Unit 194H showed an initial potential of about 1.4 Mboe/d.

Half of its $2 billion capital budget for 2014 was allocated to the Eagle Ford.

Exxon Mobil Corp./XTO Energy Co.

- **Big company likes big plays**
- **Shale feeds long-term plans**

Exxon Mobil Corp. and its XTO Energy Co. unconventional development affiliate have established strong positions in some of the best shale plays in North America, and they're still acquiring land in attractive areas.

HORN RIVER

Exxon Mobil controls 341,000 gross acres of land with Muskwa, Evie and Otter Park shale potential.

Both the Horn River Shale and Duvernay Shale to the south are in line to move gas to the British Columbia coast where LNG plants are in the works.

DUVERNAY

Exxon Mobil closed its $3.1 billion acquisition of Celtic Exploration Ltd. in third-quarter 2014 giving the major 41,000 net acres of land in the Duvernay Shale in British Columbia. Exxon Mobil's Canadian arm, Imperial Oil Ltd. bought into half of the deal for $1.6 billion.

MARCELLUS

The companies control 564,000 acres of land in 15 counties in the Marcellus play in southeast and central Pennsylvania. That property produces 185 MMcf/d, and the company is running two to four rigs for development.

It also holds 168,000 acres in nine counties in northwestern West Virginia. It's running up to two rigs on the property, which produces 37 MMcf/d. That property also might be prospective for Utica production.

Exxon Mobil Corp. and its XTO Energy Co. unconventional development affiliate have established strong positions in some of the best shale plays in North America, and they're still acquiring land in attractive areas.

UTICA

Exxon Mobil has 82,000 acres in two counties in eastern Ohio. It has no present production, but it could run up to three rigs in the near future.

BAKKEN

Both North Dakota and Montana contribute Bakken and Three Forks properties to Exxon Mobil. The company leases 531,000 acres in the play in North Dakota and produced 44.5 Mbbl/d of oil and 46 Mcf/d of gas in February 2014.

It planned to run 12 to 15 rigs in 2014 in the eight counties in which it has properties.

It planned to run one rig on its 314,000 acres in two counties in Montana where it produced about 5.8 Mbbl/d of oil and 5 Mcf/d of gas.

FAYETTEVILLE

The company is running only one rig on its 747,000 acres in 15 counties in the Fayetteville Shale in Arkansas. It produces 466 Mcf/d of gas.

HAYNESVILLE

Although the company doesn't break out the Haynesville Shale properties, it holds 297,000 acres of leases in an area that includes Haynesville and the Bossier-Cotton Valley production in East Texas and Louisiana. It's running one rig on its properties in 13 counties and produced about 4.1 Mbbl/d of oil and 125 Mcf/d in February 2014.

PERMIAN

Exxon Mobil signed a deal to acquire Permian Basin properties from Linn Energy LLC and LinnCo LLC in September 2014. Linn would get operating interests in Exxon Mobil's South Belridge Field in California in trade.

In an earlier trade, Exxon Mobil received more Linn properties in the Permian Basin exchange for Exxon Mobil/XTO holdings in the Hugoton Basin.

The latest trade gives Exxon Mobil 17,000 net acres prospective for horizontal Wolfcamp production, primarily in Martin, Howard, Midland and Andrews counties in the Midland Basin. Those properties currently produce 4.7 Mboe/d and hold proved reserves of 19 MMboe. The major operator also gets some 800 acres in the Delaware Basin in New Mexico.

EAGLE FORD

In 2012, Exxon Mobil controlled 90,000 net acres in the Eagle Ford play in South Texas.

Forest Oil Corp./Sabine Oil & Gas LLC

- **Merger combines complementary assets**
- **Shales important to growth**

Forest Oil Corp. and Sabine Oil & Gas LLC agreed to combine the two companies into a new entity called Saving Oil & Gas Corp., which will become one of the largest landholders in East Texas, primarily in the Cotton Valley trend.

Shareholder meetings were scheduled for November 2014 to approve the merger.

Both companies also cultivate interests in popular unconventional plays. Altogether, the companies hold 424,000 net acres in complementary properties.

FAYETTEVILLE

If the merger goes through, the new Sabine will hold 35,000 net acres of land in the Fayetteville gas play in the Arkansas portion of the Arkoma Basin. Premerger production was 22 MMcf/d of gas.

HAYNESVILLE

Sabine will contribute its Haynesville wells to the merger. It planned to test a new well design during 2014 that would potentially save $700,000. It also is evaluating its drilling program.

The company drilled seven wells in 2013 with an average initial potential of 10.4 MMcf/d of gas and a 30-day IP of 9.7 MMcf/d of gas equivalent with a 7% liquids content.

GRANITE WASH/CLEVELAND

Sabine controls 33,500 net acres of leases in the Granite Wash/Cleveland Sand area of the Texas Panhandle and western Oklahoma.

The company drilled five wells in the area in 2013 with an average initial potential of about 1.6 Mboe/d and a 76% liquids cut. Its $8.1 million wells return more than 100% with $4/Mcf gas and $90/bbl oil. It produced 15 MMcf/d of gas equivalent before the merger.

Sabine planned to run two rigs in the play in 2014.

EAGLE FORD

Both companies contributed Eagle Ford Shale properties for a total of 64,500 net acres and production of 74 MMcf/d of gas equivalent with a 31% gas cut.

Sabine's Shiner, Texas, area program produced 10 wells with an average initial potential of about 1.8 Mboe/d and a 30-day IP rate of 1.3 Mboe/d with a 78% liquids content. A $10.6 million well returned 17% with $4 gas and $90 oil.

Sabine planned to run four rigs in DeWitt and Lavaca counties and two rigs in Gonzales County during 2014.

Halcón Resources Corp.

- **Tracking the Eagle Ford**
- **Expanding its reach**

Halcón Resources Corp., successor to Petrohawk, a pioneer in the Haynesville Shale play in Louisiana and the Eagle Ford Shale play in South Texas, brought its technology to a new Eagle Ford play and to other shales around the country.

UTICA

The company leased 135,000 net acres of land prospective for the Utica and Point Pleasant combination in Ohio and Pennsylvania. It produced 618 boe/d in second-quarter 2014.

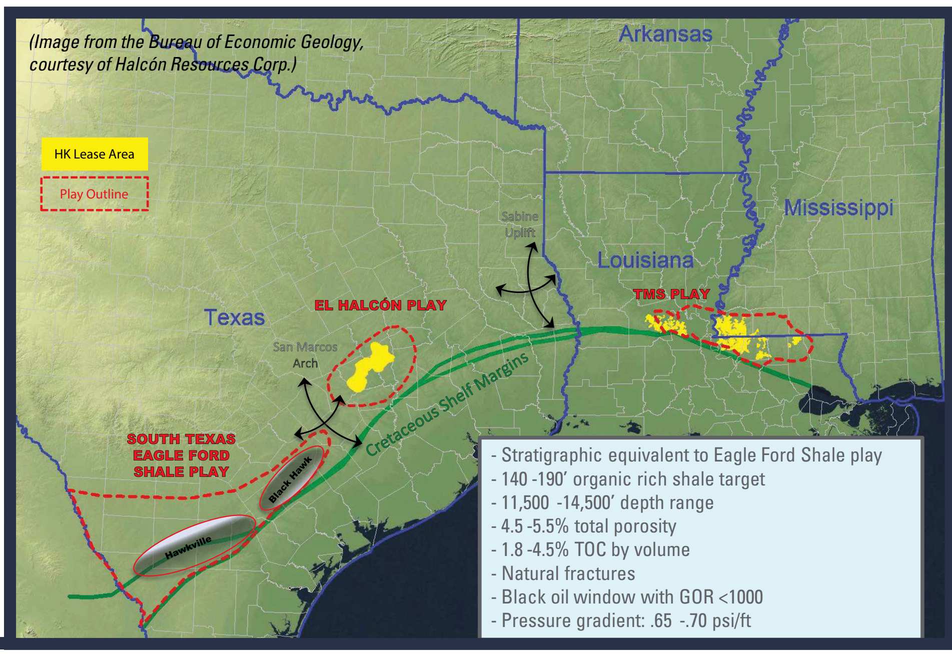
Halcón has 200 Mboe in proved reserves on its property with a 91% liquids content.

BAKKEN

Halcón acquired 131,000 net acres of Bakken/Three Forks land in North Dakota and Montana where it produces about 28.3 Mboe/d from 90.4 MMboe in proved reserves with a 94% oil cut.

The company directed half of its $1.1 billion 2014 capital budget to the Williston Basin play.

The Eagle Ford doesn't stop in South Texas. Its stratigraphic equivalents produce in the El Halcón play in East Texas and the TMS in Louisiana and Mississippi.



It anticipated spudding about 23 gross operated wells using three rigs in second-half 2014, and it planned to participate in 135 to 140 nonoperated wells with an average 5% working interest in Mountrail, McKenzie and Williams counties in North Dakota.

It has moved to slickwater fracture treatments on its Fort Berthold Indian Reservation wells in McKenzie and Dunn counties for better performance, and downspacing tests have been positive. The company operates wells there and in Williams County, N.D.

Its best well, the FB 30B-31-4H in Dunn County, tested for an initial potential of about 4.4 Mboe/d.

MISSISSIPPI LIME

The company has a concession to lease 45,000 net acres of land in north-central Oklahoma that is prospective for Mississippi Lime production.

The Utica Formation in Ohio, where Hess has a 50:50 JV on some of its property, is a future growth area for the company.

(Photo courtesy of Hess Corp.)

TUSCALOOSA MARINE SHALE

Halcón is one of the major players in the emerging Tuscaloosa Marine Shale (TMS) with 316,000 net acres under lease or contracted in Mississippi and Louisiana.

In second-quarter 2014, the company signed an agreement with affiliates of Apollo Global Management LLC, with Apollo agreeing to invest up to $400 million in Halcón's HK TMS LLC subsidiary to develop the TMS.

Halcón produced 173 boe/d from the shale in 2014. That play will take 10% of the company's $1.1 billion capital budget for 2014.

The company planned to spud eight gross wells in the play using two drilling rigs in second-half 2014 and participate in 10 to 12 nonoperated wells.

The shale is a stratigraphic equivalent of the Eagle Ford Shale.

EAGLE FORD

Halcón is opening a new play in East Texas, which it calls El Halcón, a far-eastward extension of the South Texas Eagle Ford play.

It contracted or leased 101,000 net acres in the area and currently is optimizing well spacing and completion design.

It produced 32.8 Mboe/d for the eastern Eagle Ford in first-quarter from 22.7 MMboe in proved reserves. Its wells give it a 97% oil cut.

Some 40% of Halcón's 2014 capex went into the play with plans to drill 22 gross operated wells with three rigs. Its best well was the Reveille 1H with an initial potential of 1.4 Mboe/d.

Hess Corp.

- Reviving in the Bakken
- Two-play specialist

Hess Corp. effectively opened the Williston Basin with the first commercial production, and it drilled the first well to the Bakken Shale on the Bakken Farm in North Dakota.

It's using lessons from its Bakken experience to develop properties in the Utica Shale.

UTICA

Hess leased some 180,000 acres in the Utica play in Ohio, and it dedicated about half of that

(Photo courtesy of Hess Corp.)

Hess opened the Williston Basin, discovered Bakken pay on the Bakken Farm in North Dakota and produced first oil from the formation in 1957.

acreage to a 50:50 joint venture (JV) with CONSOL Energy.

The JV's 90,000 acres lie in Jefferson, Belmont, Harrison and Guernsey counties where it is working the wet gas window. It divested its 77,000 acres of dry gas properties in the play in early 2014 for $1.1 billion.

Hess looks at the area as a long-term growth asset, and it's drilling 40 wells per year to back up that outlook. That 40-well program cost $550 million in 2014. It remained in the appraisal stage of the play during 2014 but plans to move to the development phase in 2015.

Among its recent operated wells, it drilled the Athens 1H-24 in Harrison County for an initial potential of 2.5 Mboe/d with a 52% liquids content.

BAKKEN

The Bakken Shale is a near-term growth asset for the company.

Hess discovered oil in North Dakota in 1951 and holds some 640,000 net acres in the Bakken play, including more than 550,000 acres in the core area.

It invested $2.4 billion in its North Dakota operations in 2011 and $3 billion in 2012 and planned to produce more than 54 Mboe/d by year-end 2012.

In a September 2014 presentation, Hess said the Bakken will be the company's biggest single contributor to its growth through 2018.

It estimated its 2014 production at 80 Mboe/d to 90 Mboe/d and set goals for 125 Mboe/d in 2016 and 150 Mboe/d in 2018.

It identified more than 3,000 operated drilling locations with an estimated 1.2 Bboe in recoverable resource.

Husky Energy Inc.

- Focused on Canada
- Shales spell growth

Husky Energy Inc. counts on shale plays throughout the Western Canada Sedimentary Basin to provide growth in the short term, middle term and long term.

HORN RIVER

Husky Energy has property in the Muskwa Shale in the Horn River Basin that it lists as a long-term growth prospect. The property includes 64.8 MMboe in contingent resource in the Muskwa and Evie shales that produces gas.

It also is offering farm-in opportunities on 128,000 acres about 100 miles southeast of its Horn River properties in the Rainbow Muskwa oil zone where it has 500 Mboe in proved, 500 Mboe in probable and 4.3 MMboe in contingent resource. It lists that as a midterm growth play.

DUVERNAY

Husky's Kaybob Duvernay properties represent near-term opportunity in natural gas. Its Kaybob South area contains 4.9 MMboe in proved, 15.8 MMboe in probable and 29.9 MMboe in contingent resource. The company is monitoring performance of wells on a four-well pad and a two-well pad as Husky refines efficiency in the play. The White River Duvernay prospect is a growth project after 2020 with no resource currently booked.

MONTNEY

Midterm growth opportunities make up the company's Sinclair and Kakwa Montney plays, which it plans to develop between 2017 and 2019. It scheduled its Graham and Cypress Montney project for long-term growth to exploit dry gas.

The Sinclair and Kakwa Montney contains dry gas and liquids-rich prospects, while the Montney in the Rainbow area contains oil and liquids-rich gas.

Kakwa contains 800 Mboe in proved and 1.2 Mboe in probable gas reserves and 200 Mboe in proved and 100 Mboe in probable oil reserves.

The Leland Montney area has an estimated 100 Mboe of proved and 700 Mboe of probable gas reserves and 3.3 MMboe in contingent gas resource.

It has 11.9 MMboe in contingent gas resource at Sinclair North and South Montney and 48.5 MMboe of contingent gas resource at Cypress.

BAKKEN

Husky also has an oil play at its Oungre Bakken area in South Saskatchewan. That's a near-term growth prospect that it is developing from 2014 through 2016. That play has 3.6 MMboe in proved and 1.1 MMboe in probable reserves.

Indigo II Louisiana Operating LLC

- **Aimed at the Tuscaloosa Marine Shale (TMS)**
- **Actively drilling the play in Louisiana**

The Indigo II Louisiana Operating LLC subsidiary of Indigo II Minerals LLC was formed to explore and develop properties in the TMS in Louisiana.

TUSCALOOSA MARINE SHALE

In addition to more than 110,000 acres in the Austin Chalk in Louisiana, the company leased more than 308,000 acres in the shale. The parent company has an additional 475,000 acres in oil-prone plays across the country.

Indigo II Louisiana formed a joint venture in 296,000 net acres with EOG resources in second-quarter 2013. EOG is operator for the partnership.

Indigo completed the Bentley Lumber 23H-1 horizontal well in Rapides Parish, La., in July 2013 with a 4,000-ft lateral and a 15-stage completion. That well gave the company an IP potential rate of 324 bbl/d of oil and 154 Mcf/d of gas.

Junex Inc.

- **Biggest Utica acreage holding in Canada**
- **Working Utica equivalent**

Bureaucratic snags smothered Junex Inc.'s attempts to work its Utica Shale holdings in southern Quebec, so it turned its attention to the equivalent Macasty Shale.

UTICA

Junex holds some 800,000 net acres in land in Utica plays with about 45 Tcf of original gas in place and more than 3.5 Tcf of net recoverable unrisked gas resource.

It also controls nearly all of the oil and liquids belt in the Utica in Canada.

Its first shale play is the Quebec lowlands Utica Shale gas play with an estimated 3.5 Tcf of net recoverable unrisked gas resources. That play is tied up as regulatory authorities in Quebec try to figure out how to regulate development.

Its second shale play is the Deep Macasty fairway on Anticosti Island located where the St. Lawrence River enters the Gulf of St. Lawrence. It holds 233,275 net acres in that play with 12.2 Bboe of undiscovered oil initially in place in shale.

The shale there lies 3,800 ft to 7,700 ft deep on the southwest side of the Jupiter Fault Zone.

The deep fairway seems to have the greater potential, the company said, because of its thickness, the amount of oil in place, reservoir energy, comparable depth with the Ohio Utica and thermal maturity comparable to the Ohio Utica and Eagle Ford shales.

The company also has acreage in the Galt Oil Project in eastern Quebec with an estimated 36 MMbbl of oil of discovered contingent resource.

Junex also has deeper potential in the Trenton/Black River combination and the Lorraine Shale.

LINN Energy LLC

- Eager to trade
- Focused on long-lived assets

LINN Energy LLC and its Linn Co. LLC affiliate find, acquire and develop attractive, long-lived oil and gas assets, but they don't hesitate to sell or trade if they see opportunity.

That philosophy has put the companies into attractive plays and taken them out of others, but the companies continue to grow.

LINN's latest piece of big news was its October 2014 sale of all of its properties in the Granite Wash and Cleveland plays in western Oklahoma and the Texas Panhandle to the FourPoint Energy/EnerVest joint venture for $1.95 billion.

BAKKEN

LINN holds a position in the Bakken/Three Forks play in the Williston Basin, but it isn't publicizing development details on the property other than to say it planned to spend 7% of its $1.55 billion capital budget in the area in 2014. The properties were part of a $2.3 billion acquisition from Devon Energy.

HAYNESVILLE

The company started acquiring property in East Texas in the Cotton Valley play and added Haynesville and Bossier shale holdings with the acquisition of Berry Petroleum. It planned to put about 1% of its 2014 capital budget into the area.

GRANITE WASH/CLEVELAND

LINN's latest piece of big news was its October 2014 sale of all of its properties in the Granite Wash and Cleveland plays in western Oklahoma and the Texas Panhandle to the FourPoint Energy/EnerVest joint venture for $1.95 billion. Those properties contained 1,358 producing wells and production of 195 MMcf/d of gas equivalent on 145,000 net acres of land.

WOLFCAMP

The company also traded a package of Permian Basin properties to Exxon Mobil Corp. in September for operating interests in the South Belridge Field in California. In May 2014, LINN traded Permian Basin acreage to Exxon Mobil and its XTO Energy Inc. subsidiary for operating interests in the Hugoton Basin.

In the latest deal, LINN gave up 17,000 net acres of Wolfcamp properties in the Midland Basin and another 800 acres in the New Mexico portion of the Delaware Basin.

LINN also planned to sell its Wolfberry properties in Ector and Midland counties in Texas for $350 million.

It said it had some 13,000 net acres of properties with about 10 Mboe/d of production and proved reserves of 40 MMboe for sale in the Midland Basin. That property is prospective for horizontal Wolfcamp development.

Marathon Oil Corp.

- Unconventional resources grow sharply
- Oklahoma offers big returns

Marathon Oil Corp.'s unconventional resources grew by 520 MMboe from year-end 2012 to September 2014 with 3 Bboe in proved and probable (2P) resources on the books.

Downspacing, delineation and acreage acquisitions provided the reserves increase and boosted the company's future drilling inventory to 4,650 wells.

BAKKEN

The Bakken/Three Forks play now represents a 1 Bboe resource with proved and probable reserves of about 750 MMboe.

The company's 370,000 net acres lie in North Dakota and eastern Montana where Marathon has an

89% average working interest. It uses automated rigs to enhance drilling performance and reduce well costs.

Downspacing in both the Bakken and Three Forks, along with development of deeper benches in the Three Forks in the Antelope area are increasing potential.

MISSISSIPPI LIME

Marathon has 100,000 net acres in the STACK in central Oklahoma, which include the Mississippi Lime, Meramec Shale and Osage Formation. Some 45,000 of those acres are in the Mississippian.

WOODFORD

Overall, Marathon's Oklahoma resource basins offer it 1.5 Bboe in total resource and 1.1 Bboe in 2P resource. That includes the STACK, Cana Woodford, South-Central Oklahoma Oil Province (SCOOP) and Granite Wash.

The company had about 142,000 net acres in the Anadarko Woodford play at year-end 2013 and 300,000 net acres throughout the state and in the Granite Wash. It added 22,000 acres in the SCOOP by September 2014 and hooked six operated wells to sales in first-half 2014. It planned another 11 operated wells in second-half 2014.

Among better wells, the Loren Brown 1-26H showed an initial potential of 2 Mboe/d. The company now is drilling extended-reach laterals to reach more of the pay zone.

HAYNESVILLE

Most of the company's 20,000 net acres in the Haynesville and Bossier Shale play in East Texas and Louisiana are HBP.

GRANITE WASH/CLEVELAND

Marathon put together some 70,000 net acres in the Granite Wash, Cleveland, Tonkawa and Marmaton play area. It is testing the horizontal redevelopment of Granite Wash wells and put two Marlow Field wells on to sales in 2014. It planned additional exploration of other Granite Wash structures in 2015.

EAGLE FORD

The Eagle Ford offers Marathon a 1 Bboe potential resource. By year-end 2013, it had 211,000 net acres in the popular shale. The company called the Eagle Ford the "premier U.S. resource play." It is concentrating its development work in Atascosa, DeWitt, Gonzales and Karnes counties.

National Fuel Gas Co./ Seneca Resources Corp.

- **Seeking shale payoff in Appalachia**
- **Pennsylvania property takes priority**

National Fuel Gas Co. and its oil and gas E&P arm, Seneca Resources Corp., have a variety of petroleum properties from California to Kansas to West Virginia, but its shale concentration lies in Pennsylvania.

MARCELLUS

According to an August 2014 presentation, National Fuel Gas, through Seneca, has 800,000 net acres of properties in Pennsylvania with 1.5 Tcf of gas equivalent in proved resources mostly in northwestern Pennsylvania.

Those reserves include 1.3 Tcf of gas and 41.6 Tcf of gas equivalent in oil.

The company's overall finding and development cost is $1.31/Mcf, but the Marcellus cost is only 99 cents/Mcf.

The company has been gathering land and drilling wells and has doubled its proved reserves since 2010.

It forecast production of 139 Bcf of gas equivalent to 147 Bcf of gas equivalent from its 780,000 net acres in the Marcellus in 2014. It predicted production of 150 Bcf of gas equivalent to 197 Bcf of gas equivalent from Appalachia for 2015.

Among its Marcellus properties, 30,000 acres are in the northeast core, and 200,000 acres are in the Tier One area that requires a gas price from $2.80/Mcf to $3.80/Mcf of gas equivalent. Another 250,000 acres are in long-term evaluation, and 300,000 acres require a gas price of $4 or more for profitable development.

The company also is conducting pad drilling in the Geneseo Shale in Lycoming County, Pa. Its first well in that project tested for an initial potential of 14.1 MMcf/d of gas and a 30-day initial potential of 8.6 MMcf/d of gas.

UTICA

The company has Utica Shale/Point Pleasant properties in the Mount Jewett area of northeastern Pennsylvania.

Newfield Exploration Co.

- **Sold Granite Wash**
- **Going strong in liquids plays**

Newfield Exploration Co. picks its plays carefully and focuses its efforts on refining drilling and production in those plays.

BAKKEN

Newfield backed its commitment to long-life production with an aggressive program in the Bakken/Three Forks play in the Williston Basin that planned to increase production by 35% during 2014. Its second-quarter 2014 production was ahead of that forecast with a 21% production increase over first-quarter 2014 and an increase of more than 54% over second-quarter 2013.

According to a July 2014 presentation, its 23 wells in the Williston Basin posted an average initial potential of 2.29 Mboe/d, a 30-day IP rate of 795 boe/d, a 60-day rate of 654 boe/d and a 90-day rate of 583 boe/d.

The company is drilling wells with 10,000-ft laterals for $7.9 million, including facilities costs, and it has moved into the full-field development phase in both the Middle Bakken and Three Forks zones. It estimated fiscal year 2014 production at 14.5 Mbbl/d of liquids and 2.7 Mboe/d of gas.

It holds about 100,000 net acres of land in North Dakota and Montana and is actively working 41,000 net acres in the Bakken with an emphasis on multiwell pads.

Newfield also has 225,000 net acres of land in the Uintah Basin in Utah with both conventional and unconventional production.

WOODFORD

The Woodford plays a big part in Newfield's strategy in the Midcontinent as it works properties in the STACK in north-central Oklahoma, the South-Central Oklahoma Oil Province (SCOOP) and the Arkoma Woodford. Among other zones, the STACK includes the Cana Woodford.

More than half of Newfield's domestic reserves are in the Midcontinent where it holds more than 400,000 net acres. It put all that acreage together in the past three years.

It has some 125,000 net acres in the southeast extension of the Cana Woodford play and has drilled more than 35 wells to the formation.

It planned to invest about $700 million on drilling in the SCOOP/STACK combination in 2014 with the help of eight drilling rigs.

It produced more than 25 Mboe/d at year-end 2013 and expected to double that production in 2014.

Newfield started the Arkoma Basin Woodford Shale play in Oklahoma where it has 150,000 net acres and nearly 400 horizontal wells, but it has cut back sharply on drilling in this gas-prone area.

GRANITE WASH

Newfield sold its 50,000 net acres of land in the Granite Wash in September 2014 for $588 million.

EAGLE FORD

The company controls about 160,000 net acres of land in the Eagle Ford play in Maverick, Dimmit and Zavala counties in the Maverick Basin in South Texas.

It is actively drilling on about 25,000 net acres of that land. It expected production to grow by more than 35% during 2014.

It currently is drilling extended-reach horizontal wells with initial potentials of more than 700 Mboe/d.

New Source Energy Partners LP

- **Young company growing**
- **Sights set on Hunton**

Less than two years old, New Source Energy Partners LP followed its February 2013 IPO with six oil and gas property acquisitions, all in the Hunton in east-central Oklahoma.

HUNTON

New Source and its predecessors have drilled 287 gross wells to the Hunton in Golden Lane Field since 1999, including 219 horizontal wells.

By December 2013, its properties encompassed 161 gross proved undeveloped drilling locations, including 60 gross infill locations on its 9,079 gross undeveloped acres in the play.

It now holds 20.6 MMboe in proved reserves, 60% of which are proved developed. Production comes with a 71% oil and NGL cut.

Nexen Inc./CNOOC Ltd.

- **Producing gas in the north**
- **Partnering in oil shale**

Nexen Inc., which was acquired in February 2014 by China's CNOOC Ltd., has high hopes for the future of its shale gas holdings in northern British Columbia, but that doesn't prevent it from getting in on the shale oil play in the U.S.

HORN RIVER

Nexen got in on the shale gas boom in Canada early when it began acquiring land in 2006 in the Horn River, Cordova and Liard basins along New Brunswick's northern border. It started producing gas in 2007 from its Dilly Creek plant in the Horn River Basin.

It joined with joint venture partners in assembling 300,000 net acres in the three basins, an asset which should pay off as LNG plants are up and exporting on the coast of British Columbia.

INPEX Gas British Columbia Ltd. and JGC are 40% partners in shale development with Nexen, and INPEX is a partner in the Aurora LNG terminal proposed for construction.

NIOBRARA

Nexen holds a 33.3% working interest in some 800,000 net acres of Niobrara properties in Colorado and Wyoming that are operated by Chesapeake Energy.

EAGLE FORD

Chesapeake Energy is the operating partner in 600,000 net acres in the Eagle Ford play in South Texas in which Nexen holds a one-third working interest.

Noble Energy Inc.

- Two shales focus funds
- Aggressive activity builds plays

Noble Energy Inc. works only two shale plays in the U.S., but it concentrates corporate resources in those plays. It is divesting noncore properties to raise more funds for its two core areas.

MARCELLUS

For 2014, Noble planned to drill 100 wet gas and 70 dry gas wells in the Marcellus play in West Virginia.

It's improving well costs and performance on horizontal wells with laterals longer that 7,000 ft, and it expects that combination to raise production by more than 90%.

It's trying to wring more production from the play by conducting 500-ft downspacing tests in several areas. That's the next step after the company found no well interference on wells spaced at 750 ft. After testing reduced stimulation stage spacing and fracture cluster spacing, it found its IP rates rose by 40%. It's also testing refracturing potential.

The company currently is delineating new pay potential in the Oxford, Pennsboro and Shirley areas of West Virginia.

Noble also has raised EUR by 60% while lowering costs by 10% since it acquired its property.

It also is one of two companies that has proposed drilling to the Marcellus with long laterals below a 14-mile-long segment of the Ohio River.

NIOBRARA

Between its Marcellus program and its Codell-Niobrara program in the Denver Basin of northeastern Colorado, Noble planned to drill about 450 wells in 2014.

It holds 610,000 net acres in the Denver Basin with year-end 2013 production of 95 Mboe/d. It owned 450 MMboe in proved reserves, or one-third of the company total.

It is using the same techniques in Colorado to improve well performance that it uses in Appalachia.

In a May 2014 presentation, Noble said it has increased production by 28% while lowering well costs. It is tightening spacing from the current 24 wells per section to 32 wells per section on more than 40% of its 2014 wells. With only 16 wells per section, Noble has 9,500 well locations in the Denver Basin.

Some 40% of its 2014 capital, or $2 billion, went toward its 2014 capital budget.

Noble also leases 372,000 gross acres of land in northeastern Nevada, which it calls an unconventional light oil play with similar deposition to the Uinta Basin. It planned further drilling and evaluation in second-half 2014.

Occidental Petroleum Corp.

- Moving out of Bakken
- Concentrating on Wolfcamp

Occidental Petroleum Corp. (Oxy) sees its best chances for a high-growth future in the Permian Basin, and it's considering selling a high-acreage position in North Dakota to accelerate its Texas production.

BAKKEN

Oxy leases some 330,000 acres of Bakken/Three Forks properties in North Dakota, largely undeveloped.

The company planned to spend $510 million, or 5% of its $10.2 billion capital budget, on the property in 2014. It produced about 17 Mboe/d at year-end 2013.

WOLFCAMP

In a May 2014 presentation, Oxy said 22% of its capex, or $2.19 billion, would go into the Permian Basin, which it called "the cornerstone operation of the domestic business." It expected its operations in the Permian Basin to grow by 20% to 25% in 2014 and more than 20% after that.

Its existing enhanced recovery projects would take a big piece of those expenditures, but its other operations will get $1.53 billion.

The company's biggest near-term growth will come from the Midland Basin, which contains two-thirds of Oxy's resource potential. It has more property in the Delaware Basin, and potential should grow there as well.

Overall, it has some 9,500 gross wells in the Permian Basin, with 54% operated by other companies. It has 4,400 net wells, 15% nonoperated.

It added 200,000 net acres of land to its unconventional holdings in 2013 to bring its total to 1.9 million acres. It also identified 4,500 drilling locations with more than 1.2 Bboe of resource potential.

It drilled 49 horizontal wells during 2013 and planned to drill 72 horizontal wells and 172 vertical wells in 2014 with an average count of 21 rigs.

Oxy has 215,000 gross acres (65,000 net acres), in the Wolfbone play in the southern Delaware Basin in West Texas and another 600,000 gross (210,000 net) acres in the Wolfcamp Shale.

It drilled five Wolfcamp horizontal wells in the Delaware Basin, one to the A bench and two each to the B and C benches. IP averaged 1.15 Mboe/d with 30-day IP of 760 boe/d with an 88% liquids cut. The company's current focus is on Barilla Draw, where drilling and completion costs average $8.5 million.

It planned 43 horizontal wells in the Texas Delaware Basin in 2014.

It planned another 78 horizontal wells in the Midland Basin where it holds 300,000 gross (105,000 net) acres prospective for the Wolfcamp A zone, 260,000 gross (90,000 net) acres prospective for the B bench, 50,000 gross (15,000 net) acres with C bench potential and 315,000 gross (115,000 net) acres of Wolfberry prospects.

It also has Cline Shale prospects in the eastern Permian Basin.

Oxy has 800 drilling locations on the South Curtis Ranch and Dora Roberts fields in the Midland Basin and put 12 horizontal wells of production in those fields in first-quarter 2014 with a focus on the Wolfcamp B bench, which yields 91% liquids.

Painted Pony Petroleum Ltd.

- **Montney focused**
- **Sold Bakken properties**

Painted Pony Petroleum Ltd. pinned its growth plans on the Montney play in northeastern British Columbia and raised money from the sale of its southeastern Saskatchewan holdings to help speed that growth.

BAKKEN

Painted Pony held 77,643 net acres of land with an average 75% working interest in southeastern Saskatchewan with Bakken assets in the Midale and Flat Lake areas.

MONTNEY

The company holds 119,763 net acres of land prospective for Montney production with an average 72% working interest in British Columbia with 66,586 acres at Blair town, 11,145 acres at Cameron/ Kobes, 15,928 acres at Townsend, 24,967 acres at Cypress and another 1,137 acres in other areas.

In a September 2014 presentation, Painted Pony said it had more than 45 Tcf of gas in place on its property and it was moving into full development. It forecast production of 100 Mboe/d by 2018.

As for marketing, its property, which is located at the northern end of the Montney play, is in place for production transportation to LNG plants planned on the coast of British Columbia.

Production comes from a dolomitic siltstone reservoir.

The company called the Montney "the Canadian Marcellus." In Painted Pony's area, it produces sweet gas from a reservoir four times thicker than the Marcellus.

The company has drilled 46 wells to date among the 63 wells in which it has participated and has 300 well locations on its five-year plan.

It planned to run two rigs in the play during 2014 and had drilled 12 wells by August. It planned to drill 22 wells during the full year.

Painted Pony planned to raise its rig count to four in 2015 to drill 37 gross wells and complete 32 wells.

PDC Energy Inc.

- **Selling Marcellus properties**
- **Raising liquids production**

PDC Energy Inc. got its start in Appalachia, moved its headquarters and operations to Colorado, established a strong presence in the Codell/Niobrara play and returned to the Appalachian Basin to find profits in the Marcellus and Utica plays.

MARCELLUS

PDC Energy operates its Marcellus properties through the 50:50 PDC Mountaineer joint venture. It planned to sell those properties with a closing in fourth-quarter 2014.

It held some 131,000 net acres of land, all HBP, with about 600 gross well locations, including 350 gross locations in Harrison, Taylor and Barber counties where it has done most of its drilling. It drilled 15 wells in 2013.

UTICA

PDC holds 67,000 net acres of land in the Utica Shale play in eastern Ohio, including 21,000 net acres in the condensate window and 45,000 net acres in the wet gas window. It identified 350 horizontal drilling locations and added a second rig to its program in July 2014. It planned to spud 22 wells during the year.

It claims 130 locations, a 60% internal rate of return in the condensate window and an 80% internal rate of return in the wet gas window.

Overall, it has 14 MMboe in proved reserves, 15 MMboe in probable reserves and 29 MMboe in possible reserves in the Utica.

NIOBRARA

The company's Codell/Niobrara properties are concentrated in the giant Wattenberg Field in Weld County in northeastern Colorado. It is the company's largest asset with more than 75% of 2013 production and year-end reserves.

It drilled 70 horizontal wells in the field during 2013 with a 100% success rate. Those wells have EURs between 285 Mboe and 500 Mboe.

It is the third largest producer and leaseholder in the core Wattenberg area with 97,000 net acres, which is room enough for about 2,800 wells, based on 22 wells per section.

The company planned to spend $467 million in the area during 2014 using four drilling rigs, until May when it added a fifth rig, to drill 115 horizontal wells.

Peak Exploration & Production LLC

- **Single-basin prospector**
- **Testing stacked pay**

Peak Exploration & Production LLC, working as Peak Powder River Resources LLC, found success drilling for oil in the stacked pays of the Powder River Basin.

NIOBRARA/PARKMAN

Peak holds 25,000 net acres in the basin with potential production from a number of zones, including the Niobrara and Parkman.

Its primary targets, however, are the Shannon and Turner zones. It also has potential in the Mowry, Dakota, Frontier and Muddy.

Its best well to date, completed in July 2013, tested at an IP rate of 2.6 Mbbl/d of oil and 4.298 MMcf/d of 1,385 Btu gas. That well was the Iberlin 1-10 TH.

It drilled the well with a 4,000-ft lateral and 14 fracture stages and has 40 potential drilling locations on its property.

Petroflow Energy Corp.

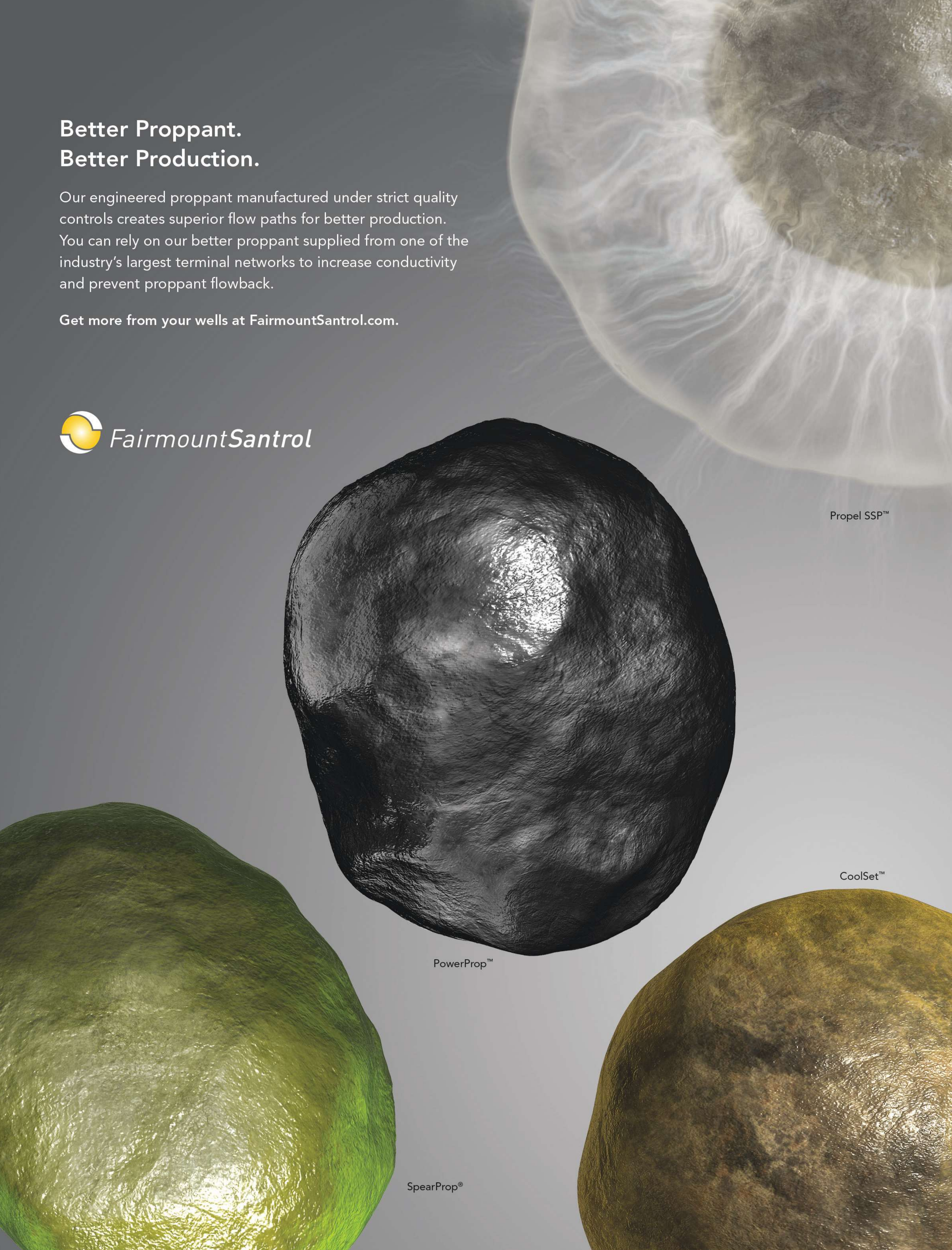
- **Huntin' in the Hunton**
- **Single-play specialist**

Petroflow Energy Corp., already one of the most active companies working the Hunton play in Oklahoma, is ramping up its activity.

HUNTON

Petroflow acquired Equal Energy Ltd., another active Hunton operator, in July 2014 for almost $200 million.

According to the company website, it has three drilling rigs working in the play. Since it took on a farm-out agreement in the play in April 2005, the company spud 43 Hunton wells and put 36 of them on production. The other seven are in various



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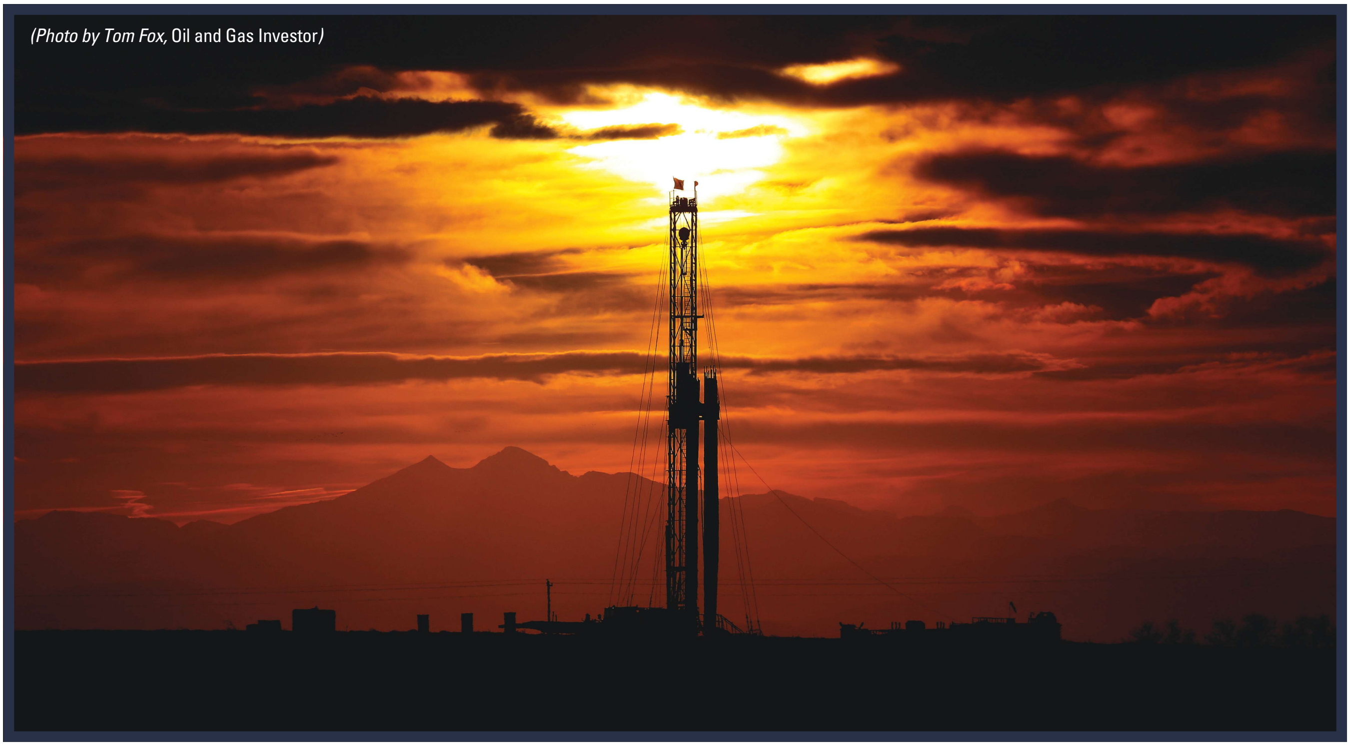
(Photo by Tom Fox, Oil and Gas Investor)

The Rocky Mountains at sunset provide a dramatic backdrop for a workover rig southeast of Greeley, Colo., in Weld County, where horizontal Niobrara activity is rapidly expanding.

stages of completion or hookup to pipeline. Most of the wells are at some level of dewatering.

An IHS Inc. report said Equal Energy started drilling the 1-9H Alice horizontal well in Kendrick Field in Lincoln County to the Hunton at a projected depth of 9,146 ft and a true vertical depth of 4,263 ft in September 2014.

Pioneer Natural Resources Co.

- Returning to the Permian Basin
- Sharpens shale focus

Pioneer Natural Resources Co. has put a lot of hard work into every play it has chosen. Lately, it has chosen to swing its focus back toward the Permian Basin where it already is one of the largest landholders and the biggest producer in the Spraberry play.

It is the second most active driller in Texas and the fourth most active in the U.S.

BARNETT

Pioneer closed on the sale of its Barnett Shale properties in September 2014 for $155 million. The company said it planned to sell the property and listed those assets as discontinued operations since fourth-quarter 2013.

The shale produced 10,300 boe/d during first-half 2014.

WOLFCAMP

Pioneer planned to spend $2.2 billion on its Spraberry/Wolfcamp properties in the northern Midland Basin and another $545 million in the Eagle Ford. It said it planned to add five to 10 rigs a year to its Permian Basin activities.

It held 825,000 acres of land in the Spraberry oil field in the Permian Basin at year-end 2013 in addition to 432 MMboe in proved reserves and 9.6 Bboe in net recoverable resource potential from the Spraberry/Wolfcamp shales on its property.

Pioneer produced 109 Mboe/d in second-quarter 2014.

On its northern Midland Basin property, 85% of its drilling is going to the Wolfcamp A, B and D benches, while the remaining 15% is in the Middle Spraberry, Jo Mill and Lower Spraberry formations. The company moved from horizontal appraisal drilling to horizontal development during 2014 and planned to increase its rig count from five at year-end 2013 to 16 in 2014 to drill 93 horizontal wells.

Two-thirds of its drilling on its 200,000-acre southern Midland Basin joint venture

properties will go to the Wolfcamp B bench, and the remaining third will test the A, C and D benches. Those properties worked with $205 million in capex in 2014, including $104 million for horizontal drilling and $65 million for infrastructure and land.

The company has 100 wells on production in the area with average 9,400-ft laterals. It put 24 new horizontal wells on production on its southern acreage in second-quarter 2014.

EAGLE FORD

Eagle Ford properties produced 47 Mboe/d during second-quarter 2014, and the play has an estimated 131 MMboe in proved reserves and a resource potential of 450 MMboe.

The company has 1,400 undrilled locations and worked eight rigs in the play to reduce that number.

Most of its 215,000 gross acres are in Karnes and DeWitt counties in the condensate window.

Progress Energy Canada Ltd.

- **Working in the international arena**
- **Building strength in the Montney**

Progress Energy Canada Ltd., a subsidiary of Petroliam Nasional Berhad (Petronas), is setting up a supply chain to deliver Montney gas to world markets through an LNG plant on the west coast of British Columbia.

MONTNEY

The market for its product is almost assured. Petronas is the majority owner of the proposed Pacific NorthWest LNG Ltd. project. JAPEX Montney Ltd. holds a 10% interest, and PetroleumBRUNEI jumped in for another 3% share.

In March 2014, Indian Oil Corp. Ltd. bought a 10% interest in Progress Energy's gas reserves in northeastern British Columbia that are dedicated to that project. Indian Oil also agreed to buy 10% of the LNG plant's production, about 1.2 MMtons/year for a minimum of 20 years.

China Petrochemical Corp. (SINOPEC) previously bought 15% of Progress Energy's reserves and agreed to take 4 MMtons/year of the plant's output for at least 20 years.

The Progress Energy project held proved and positive reserves of 8.35 Tcf of gas equivalent and best-case contingent resources of 24.7 Tcf of gas equivalent at year-end 2013. Total reserves and resource potential tops 50 Tcf of gas equivalent.

Progress holds some 1.2 million acres of land in the play after acquiring Talisman Energy's 127,000 acres. That makes it the largest holder of contiguous land in the Montney play.

Progress produces 400 MMcf/d of gas equivalent, but that's going to change. It plans to deliver 2 Bcf/d of gas to the Pacific NorthWest plant by year-end 2018.

Plans called for the company to ramp up to about 15 Tcf of reserves by fourth-quarter 2014 and 25 working rigs by year-end 2015.

It will continue to increase production and reserves through 2018 when the first LNG will leave the plant.

QEP Resources Inc.

- **Shedding noncore assets**
- **Shifting toward liquids**

QEP Resources Inc. produces more than 800 MMcf/d of gas equivalent from 4.1 Tcf of gas equivalent, and it has grown its oil production at a 50% compound annual growth rate since 2010.

Companywide oil production has reached 27% of its total production as it high-grades its properties for best returns.

BAKKEN

QEP divested its Fat Cat assets in the Williston Basin, has stopped drilling on its Fort Berthold properties and is running seven rigs on its South Antelope properties.

It holds 109,000 net acres of land prospective for Bakken/Three Forks shale production. Its average production reached 35.6 Mboe/d in second-quarter 2014.

It bought its South Antelope properties in September 2012. Bakken wells on the property offer an EUR of 1.07 MMboe from the Bakken and 1 MMboe from the Three Forks. The company has 250 remaining drilling locations at South Antelope.

It's not working the Fort Berthold properties, but when it was, those wells offered EURs of 550 MMboe from both the Bakken and Three Forks. QEP has 400 gross remaining locations on that land.

WOODFORD

The company sold properties in the Cana Woodford in a package deal with Granite Wash and the Fat Cat property in the Williston Basin for $700 million. It is trying to sell its property in the South-Central Oklahoma Oil Province.

HAYNESVILLE

QEP owns property in the Haynesville gas play in Louisiana, but it isn't actively developing that play.

GRANITE WASH

As part of its high-grading program, QEP sold its Granite Wash holdings.

WOLFCAMP

The company closed an acquisition of Permian Basin properties for $942 million in 2014, and it currently is drilling wells to the Atokaberry (Atoka-Spraberry) combination.

It still is evaluating the property, but operators surrounding the property in the Midland Basin are producing from wells drilled to the Wolfcamp B and D benches and the Cline Shale.

Its property in the northern Midland Basin has potential production from the upper and middle Spraberry, the Jo Mill Sand, Lower Spraberry Shale, Atoka and Wolfcamp A, B, C and D benches, or more than 3,000 ft of oil-charged vertical section. It has up to 775 horizontal drilling locations on the property.

Quicksilver Resources Inc.

- **Unconventional resource expert**
- **Working prime gas areas**

Quicksilver Resources Inc. built a portfolio of prime, long-lived gas resources following its initial operating strategy of developing unconventional resources.

It amassed 1.3 Tcf of of gas equivalent, 88% proved developed, by year-end 2013 and produced an average 276 MMcf/d of gas equivalent on a *pro forma* basis, down from 288 MMcf/d of gas equivalent in 2012.

HORN RIVER

Quicksilver had some 69.7 Bcf of gas in proved reserves on 129,109 net acres of land in the Horn River shales at year-end 2013. The land holds potential resources of 14 Tcf of gas. It averaged production of 57 MMcf/d of gas equivalent. The company also is attempting to bring in one or more potential partners for its Horn River project.

It had 12 wells connected to sales in December 2013. Its wells target the Klua and Muskwa shales. Activity was minimal in 2013 and 2014, but the company has devoted a portion of its capex toward a future drilling pad. Also in Canada, the company acquired property in British Columbia in a location that would allow it to export production through pipelines to LNG projects on the coast of British Columbia. It also holds coalbed methane properties in the Horseshoe Canyon area of Alberta, Canada.

NIOBRARA

Quicksilver had 334,050 gross (167,050 net) acres of land with Niobrara potential in the Sand Wash Basin of north-central Colorado, but it sold its Sand Wash assets to Southwestern Energy in May 2014. It also had a 50:50 agreement with Shell Western E&P on an 850,000-acre area of mutual interest in the basin.

The properties had 85 Mbbl of oil in proved reserves at year-end 2012 and an unbooked potential of more than 100 MMbbl of oil.

Quicksilver also purchased 124,000 gross acres of land in the Permian Basin in West Texas that it believes will produce from the Wolfcamp and Bone Spring shales.

BARNETT

Quicksilver leases about 135,000 gross (85,000 net) acres of land in the Barnett Shale play in North Texas. It has identified 1 Tcf to 2 Tcf of potential gas resources on the property. It planned to monetize some of those assets to reduce debt and interest obligations. That would help it raise funds for its Permian Basin activities.

Tokyo Gas made its first investment in U.S. shale through Quicksilver by taking a 25% interest in the Barnett properties. Quicksilver remains operator of those properties.

WOLFCAMP

The company also purchased 124,000 gross acres of land in the Permian Basin in West Texas that it believes will produce from the Wolfcamp and Bone Spring shales. During 2013, it signed participation agreements with Italy's Eni on 52,500 gross acres of land in Pecos County and an agreement with another party covering 7,500 gross acres, also in Pecos County. Those participations allowed Quicksilver to be carried on up to four wells during 2014 and 10 total wells.

It also has an agreement for additional acreage in Crockett and Upton counties.

So far, the company has two gross producing wells on its Midland and Delaware Basin holdings.

Range Resources Corp.

- **Growing production at 20%-plus per year**
- **Going for low-cost, low-risk reserves**

Range Resources Corp. captured major blocks of acreage in key unconventional plays, applied cost-lowering techniques and set itself up for strong growth.

"We have the potential to grow our proven reserve base by eight to 10 times," the company said on its website. From less than 500 MMcf/d of gas equivalent in 2009, it can reach nearly 3 Bcf/d of gas equivalent with a 25% growth rate by 2018, or 2.4 Bcf/d of gas equivalent with a 20% growth rate.

MARCELLUS

The Marcellus Shale plays a big part in the company's growth plans. It pioneered the play with the Renz #1 vertical well in 2004 and now holds 955,000 net acres of land in the largest natural gas field in the U.S. That acreage includes its Upper Devonian properties for 53 Tcf to 69 Tcf of gas equivalent resources and second-quarter 2014 production of 913 MMcf/d of gas equivalent.

With the liquids-rich window in southwestern Pennsylvania, it offers the best economics of any large-scale, repeatable play in the country, according to the company.

Range drilled its best Marcellus well in first-quarter 2014, in the super-rich area that registered IP of about 6.4 Mboe/d with a 65% liquids content. In that area, the company drills wells with 5,300-ft lateral sections and expects recoveries of 2.05 MMboe, or 12.3 Bcf of gas equivalent, per well.

For 2014, it planned 52 wells. It will drill 5,700-ft laterals in 2015.

It has placed more than 200 wells on production in the wet gas area of the Marcellus in the past four years. It planned to drill 4,200-ft laterals in 2014 and increase the length to 4,900 ft in 2015. It hooked 51 wet gas wells to sales lines in 2014 with an EUR of 12.3 Bcf of gas equivalent per well.

The company will work only one or two rigs in the gassy area of northeastern Pennsylvania to hold its acreage.

The company has 305,000 net acres in northwest Pennsylvania, largely HBP; 120,000 net acres in the northeast with one rig working to hold land positions; 530,000 net acres in southwestern Pennsylvania, 95% HBP; and about 140,000 acres prospective for the Marcellus in northwestern Pennsylvania.

It also holds 560,000 acres of properties prospective for Upper Devonian Shale production, including 330,000 acres in the wet area.

UTICA

Range still is evaluating results of drilling to the Utica/Point Pleasant where it holds 575,000 acres of land, including 175,000 acres in the wet area in northwestern Pennsylvania. The other 400,000 net acres are in the dry gas area of southwestern Pennsylvania.

MIDCONTINENT

The company lumps its Mississippi Lime, St. Louis Lime, Cleveland and Woodford properties under its Midcontinent division. It holds about 360,000 combined net acres in the plays with a resource potential between 7 Tcf and 11 Tcf of gas equivalent.

It drilled the first successful St. Louis Lime well in the Texas Panhandle, next to its Granite Wash properties. It also works the Mississippi Lime in northern Oklahoma and the Cana Woodford, where it has more than 40,000 net acres HBP.

Red Willow Production Co.

- **Owned by Southern Ute Indian Tribe**
- **Working plays across the U.S.**

Red Willow Production Co., formed by the Southern Ute Tribe in 1992 to handle its oil and gas assets, controls assets on the tribe's 700,000 acres of reservation, including 1,300 producing wells and another 1,800 wells in 10 basins on some 290,000 acres of land off the reservation.

MANCOS

Although nearly all of the company's on-reservation wells produce coalbed methane, the company drilled a well to the Mancos Shale in 2012.

It also planned to lease 12,000 acres for exploration that would include the Niobrara member of the Mancos Shale, according to a Bureau of Indian Affairs document. That property is on Fort Lewis Mesa east of the town of Marvel in La Plata County, Colo. Red Willow planned to drill horizontal wells with multistage fracture treatments.

Royal Dutch Shell Plc

- **Likes the Utica**
- **Trades enhance shale position**

Royal Dutch Shell Plc constantly tries to improve its position in plays worldwide, and its strategy in North America is no exception.

MONTNEY

Shell's Groundbirch project lies in the Montney Shale near Fort St. John and Dawson Creek in northeastern British Columbia, producing about 170 MMcf/d of gas from more than 300 wells on 50 drilling pads.

The company's technology lets it place up to 26 wells on a single pad to reduce costs and footprint.

In early 2012, PetroChina Co. bought a 20% share of Shell's Groundbirch complex. Shell remained the operator of that project.

MARCELLUS

Shell opened its Marcellus activity in 2010 with the acquisition of East Resources for $4.7 billion and built its position to 900,000 gross acres.

In August 2014, it traded its interests in the Pinedale area of southwestern Wyoming to Ultra Petroleum in exchange for Ultra's interest in 63,000 net acres in the Marshlands area and 92,000 net acres in the Tioga area of mutual interest in the Marcellus and Utica shale plays in Pennsylvania.

Shell also sold its 207,000 net acres in its Butler Operated Area in Pennsylvania to Rex Energy Corp. for about $120 million. That land has liquids-rich Marcellus, Upper Devonian and Utica dry gas potential.

UTICA

In a 2014 talk at the North American Gas Forum, Greg Guidry, executive vice president of uncon-

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DEVELOPING UNCONVENTIONALS DUG EAGLE FORD	**October 25-27, 2015**	**San Antonio, TX** Henry B. Gonzalez Convention Center	• Upstream & Midstream Operations • Eagle Ford & South Texas Plays **DUGEagleFord.com**

To **learn more** and **register**, visit **HartEnergyConferences.com** ventionals, upstream Americas, said the company's initial drilling results to the Utica in northern Pennsylvania have been "very impressive."

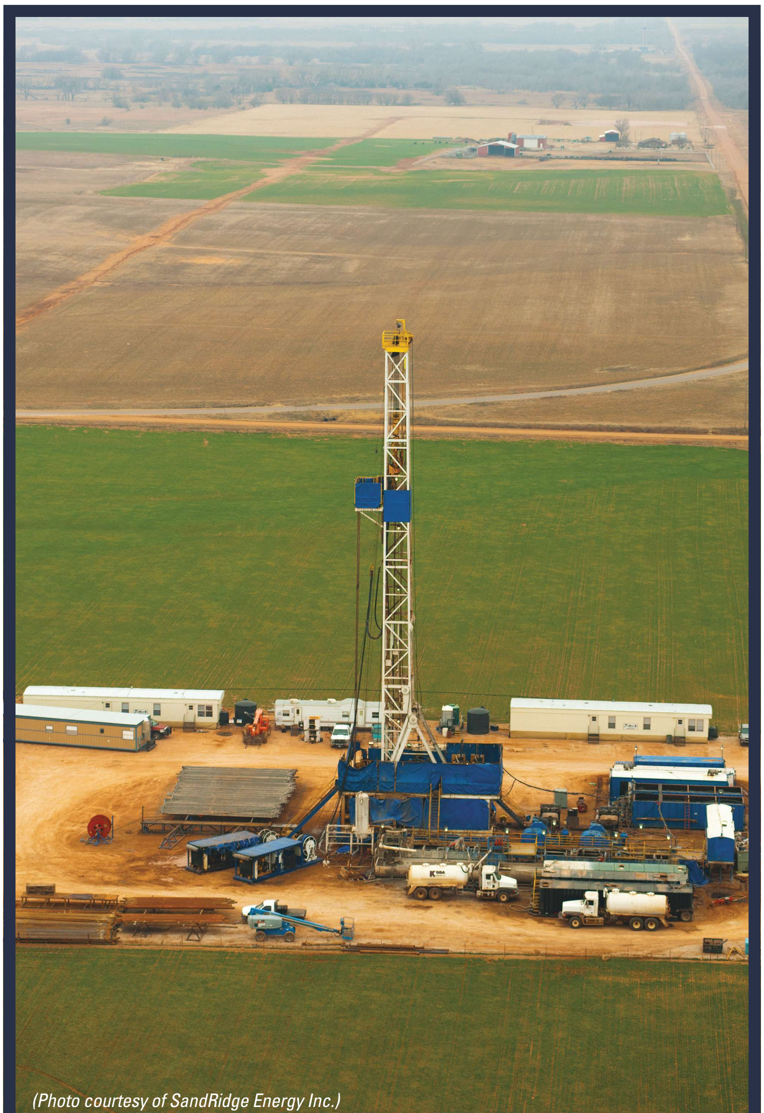
"The Utica has the potential to trump the Marcellus," he added. The company's Utica properties lie generally 300 miles northeast of the established Utica hot spot in eastern Ohio.

Shell has some 275,000 net acres, with an option to acquire another 155,000 net acres, in Tioga County, where Shell's Utica wells have shown IP rates from 11 MMcf/d to 26 MMcf/d of gas.

HAYNESVILLE

Also in August 2014, Shell agreed to sell its Haynesville Shale properties in Louisiana to Vine Oil & Gas LP for $1.2 billion in cash.

The rig is ready, and the pipe is racked as crews get ready to drill for Mississippi Lime oil in Oklahoma.



(Photo courtesy of SandRidge Energy Inc.)

That property included 107,000 net acres of land with 418 producing wells, 193 of them operated by Shell, and production of 700 MMcf/d of gas.

EAGLE FORD

Shell announced in May 2014 that it would sell its 106,000 net acres of land in the Eagle Ford Shale play to Sanchez Energy Corp. for some $639 million.

SandRidge Energy Inc.

- **High returns focused**
- **Most active Midcontinent operator**

Sandridge Energy Inc. holds properties in Oklahoma, Kansas and the Permian Basin, but Permian Basin gas properties lie on standby while the company drills the Mississippi Lime.

MISSISSIPPI LIME

Sandridge accumulated 1.85 million acres of leases in the Mississippi Lime play in northern Oklahoma and southern Kansas.

That land position gives the company more than 4,500 potential drilling locations.

In the company's latest presentation, it said it produced 69.8 Mboe/d in second-quarter 2014, and 80% of that came from the Mississippi Lime where it has 377 MMboe in proved reserves, with a 46% liquids content.

It allocated $1.5 billion in capex to the play and planned to expand as it keeps its capital investment at the $1.55 billion-per-year level.

Lowering costs helps the company meet that goal. It trimmed well costs to $2.85 million from $3 million and targets $2.7 million in the future.

It also is testing the Woodford and Chester zones for additional production.

In second-quarter 2014, its average well gave the company 30-day IP of 412 boe/d, but longer laterals on seven wells have produced more than 1 Mboe/d in four counties.

Garfield County, Okla., is a focal point with net production up 400% to 5 Mboe/d in first-half 2014. Wells there offer 30-day IP rates averaging 407 boe/d with a 54% oil cut. The company had 21 wells in that area with a seven-rig drilling program through 2014.

In the same area, it has drilled one horizontal Marmaton well and has identified 180 drilling locations, five horizontal Chester wells with 180 locations, 349 Upper Mississippian wells with 2,668 locations, 142 Middle Mississippian wells with 857 locations and 25 Lower Mississippian wells with 319 horizontal locations.

Six of the company's rigs in the area were drilling multilateral wells in second-half 2014, which means 18% of its second-half wells will be multilaterals.

If its plans work out, Sandridge will get a 130% internal rate of return on a completed multilateral full-section development with a well cost of $2.3 million per lateral. That compares to a 65% return on a single-lateral well drilled for $2.9 million.

WOODFORD

SandRidge completed its second Woodford well in third-quarter 2014. That well tested for 360 boe/d over a 30-day period with an 84% oil content.

WOLFCAMP

The company owns leases in the Midland Basin and the Permian Overthrust, but it hasn't drilled a gas well in those areas in about three years.

San Juan Resources Inc.

- **San Juan Basin specialist**
- **Holds Mancos interests**

San Juan Resources Inc. works in the San Juan Basin with both operated and nonoperated interests in properties in New Mexico and Colorado.

It has conventional production from Dakota, Gallup, Mesaverde and Pictured Cliffs formations and unconventional production from Fruitland coal seams.

MANCOS

The company holds Mancos Shale properties in the southeast corner of the San Juan Basin.

Among its assets, it has an interest in six wells in the Bear Canyon Unit, operated by EnerVest Operating Inc. That unit produces from the Gavilan Mancos zone.

It also operates the West Lindrith Gallup Dakota Field with five Gallup Dakota wells and has a working interest in the Canada Ojitos Unit, operated by Benson-Montin-Greer, at Puerto Chiquito Mancos (West) in Rio Arriba County, N.M.

SM Energy Co.

- **Focused on Bakken and Eagle Ford**
- **Combines conventional and unconventional**

SM Energy Co. carries several prime plays in its inventory, but in high-grading that inventory, it put its highest priority on the Bakken/Three Forks and Eagle Ford plays.

BAKKEN

SM Energy operated two drilling rigs in its Raven/Bear Den area in the Bakken/Three Forks play in McKenzie County, N.D., and another rig in the Gooseneck project in Divide County to the north.

It holds 42,000 acres of leases at Raven/Bear Den and another 97,000 acres at Gooseneck following a $330 million acquisition that added 61,000 acres of land adjacent to the area.

It also planned to increase activity in fourth-quarter 2014 and in 2015.

Most of its Rocky Mountain region activity is in its North Dakota properties where it produced 1.5 MMboe from the Bakken.

It also holds 33,000 net acres of leases in the Powder River Basin of Wyoming with plans to raise that acreage to 166,000. Wells target the Frontier and Shannon formations.

WOLFCAMP

SM Energy's Sweetie Peck Field in Upton County, Texas, covers 13,500 net acres and produces from the Wolfcamp B bench where an average well with a 5,000-ft lateral section yields an IP of 1 Mboe/d. An average well with a 7,600-ft lateral offers a 30-day IP rate of about 1.5 Mboe/d.

The company pulled its drilling and completions costs down 13% between January and September 2014.

It also drilled a test to the Wolfcamp D bench on its Buffalo prospect where it leased 47,500 acres of land.

EAGLE FORD

The company has grown its Eagle Ford yield at a 116% compound annual rate to 30.5 MMboe in 2013.

It holds about 144,000 net acres in the play, 46,000 of which are nonoperated. Most of its operated properties are in Webb County, with some in Dimmit County. The nonoperated properties are in Dimmit, Maverick and Webb counties in Texas.

SM Energy continues to improve its program in the Eagle Ford with new completions and longer laterals. Older completion methods gave the company wells with 30-day IP rates of less than 500 boe/d, while new methods yield more than 900 boe/d with a higher condensate cut.

Southwestern Energy Co.

- **Fourth highest U.S. gas production**
- **Testing new ventures**

Southwestern Energy Co., credited with opening the Fayetteville gas shale play in Arkansas, has spread its expertise to other shale opportunities with an eye to casing in on higher oil prices.

According to a September 2014 presentation, the company was the fourth most prolific gas producer in the U.S. behind Exxon Mobil, Chesapeake Energy and Anadarko Petroleum with 657 Bcf of gas equivalent in 2013 and 189 Bcf of gas equivalent in second-quarter 2014, representing an 18% gain, thanks to strong Marcellus and Fayetteville results. It planned to produce between 758 Bcf of gas equivalent and 764 Bcf of gas equivalent in 2014.

Its new ventures include evaluation in the Brown Dense, where it has 396,000 net acres of leases; Pennsylvanian carbonates in the Denver Basin, where it has 302,000 net acres; New Brunswick, where it controls 2.5 million acres of land with potential in the Frederick Brook Shale; and 380,000 acres in the Niobrara play in the Sand Wash Basin of northern Colorado.

It also has 152,937 net acres of land in the Ark-La-Tex area.

MARCELLUS

On Oct. 16, 2014, Southwestern said it would buy some 413,000 acres of leases in Chesapeake Energy's southern Marcellus area in southern Pennsylvania and northern West Virginia for $5.375 billion.

The deal includes some 1,500 wells, 435 of them drilled to the Marcellus and Utica shales and related infrastructure. The property also gives Southwestern potential production from the Upper Devonian shales. They produced some 56 Mboe/d in September 2014, composed of 184 MMcf/d of gas, 5 Mbbl/d of condensate and 20 Mbbl/d of NGL. Net proved reserves stood at 221 MMboe at year-end 2013.

Southwestern planned to begin running four to six rigs on the property in 2015 and planned to increase that number to 11 rigs by 2017.

It said it could drill for a minimum of 20 years running 11 rigs full time.

Before the planned acquisition of Chesapeake's property, Southwestern controlled 292,446 net acres of land in the Marcellus Shale in northeastern Pennsylvania with gross production of about 755 MMcf/d of gas on June 30, 2014. The Marcellus accounts for 23% of the company's total production and 28% of its reserves at about 2 Tcf of gas.

Some $740 million of the company's $2.4 billion 2014 capital program went into the Marcellus where it planned 33 wells each in Bradford and Susquehanna counties, five wells in Lycoming County and four wells in the Wyoming-Sullivan-Tioga-county area.

In all, the company planned 73 to 77 operated horizontal Marcellus wells in 2014 before the Chesapeake acquisition.

NIOBRARA

The company leases 380,000 net acres of land in the Niobrara Shale play in the Sand Wash Basin of Colorado.

One of the company's new ventures, the area has proven hydrocarbon systems. It is testing several Niobrara benches during the reentry of a previously drilled vertical well. In September 2014, it was drilling the second well in a four-to-five well program for 2014.

FAYETTEVILLE

Southwestern leases 905,684 net acres of land in the prime part of the Fayetteville gas shale play where it produced 486 Bcf of gas in 2013, or 74% of its production and counts 4.8 Tcf of gas or 69% of its reserves. As first-mover in the play, it picked up its land at an average cost of $320 per acre.

The company planned to invest $1 billion in the Fayetteville in 2014 to drill 460 to 470 operated

(Photo by Helge Hansen, courtesy of Statoil)

Drilling is in progress at one of Statoil's shale sites in Pennsylvania.

wells. It drilled seven of its top 10 wells for IP in the Fayetteville in second-quarter 2014.

Statoil ASA

- **Locked in on three shale plays**
- **Taking over operations**

Norway's Statoil ASA started its work in shale plays in 2008 as it acquired properties as a nonoperating partner learning the ropes from companies more experienced in shale operations. Now, it's taking over as operator.

MARCELLUS

Statoil made its first venture in shales through the purchase of an interest in Chesapeake Energy's property. Chesapeake was the operator of the play.

In 2012, Statoil added another parcel in the liquids-rich segment of the Marcellus to bring its holdings to 665,000 net acres.

By March 2013, 14 rigs were working on the property, and it was producing some 86 Mboe/d. In addition, the company was making the transition to being operator of the new acreage. According to Statoil, its agreement with Chesapeake "provided a platform for learning and growth potential across the U.S. and worldwide."

In a 2014 move, Statoil bid a 20% royalty payment and an $8,125 per acre cash bonus for permission to drill 1-mile-long laterals under a segment of a 14-mile stretch of the Ohio river in West Virginia.

BAKKEN

The Bakken Shale was Statoil's big operating leap into the shale industry when it bought Brigham Exploration in 2011. That acquisition made it a major operator in the Williston Basin with an experienced Brigham crew.

It now holds some 330,000 net acres of land in the play with treatment facilities and about 700 miles of pipeline and 10 unit trains to get its oil to markets.

EAGLE FORD

Statoil entered the Eagle Ford play in South Texas when it formed a 50:50 joint venture with Talisman Energy in 2010. Talisman was the initial operator on all of the acreage, but not for long.

On July 1, 2013, Statoil completed a transition into operator of the eastern half of the partnership properties. That gives the Norwegian company some 73,000 net acres of leases in Live Oak, Karnes, DeWitt and Bee counties in Texas.

Swift Energy Co.

- Seeking shale in the southwest
- Chasing sustainable growth

Swift Energy Co. works three core areas in southern states, but that didn't stop the company from looking for new opportunities in new areas.

It has conventional production in Louisiana and Texas along with the Austin Chalk fields in Louisiana. It works the Eagle Ford Shale in South Texas and is looking for more shale pay in the Mancos in southern Colorado.

Some 87% of its 2014 capital investment was directed to the Eagle Ford.

MANCOS

Swift Energy drilled one well to the Mancos Shale in La Plata County in Colorado during third-quarter 2013. It called that well a strategic pilot hole, the Waters 34-12-32 #1H.

It suspended operations in the area pending evaluation of the logs and cores, and it hasn't reported results or plans for further activity in the area since that time. It has room for 859 locations on the 70,000 acres it acquired in the area.

EAGLE FORD

In a September 2014 presentation, Swift said it held 8,302 acres with 58 Lower Eagle Ford locations in Webb County, Texas, in the Fasken Field. The company improved IP by 62% and EUR by 87% at Fasken during 2013.

The company closed a joint venture to develop the field with PT Saka Energi Indonesia. The Indonesian company paid $147 million in cash at closing with another $38 million to be paid in partial drilling carries in the development for a 36% full participating interest.

Among recent wells, the Fasken C 19H offered an initial potential of 22.4 MMcf/d of gas.

Swift's AWP Field in McMullen County, Texas, contains 15,987 acres with 133 locations in the oil zone of the Eagle Ford, 2,850 acres and 32 locations in the condensate zone, and 5,500 acres with 50 locations in the gas zone.

Its Artesia Field in La Salle County, Texas, includes 4,468 acres and 41 locations in the oil zone and 5,027 acres and 41 locations in the condensate zone of the Eagle Ford.

By September 2014, Swift had drilled 146 Eagle Ford wells since it started work in the play and was producing about 28.3 Mboe/d.

Talisman Energy Inc.

- Global operator with Canadian focus
- Unconventional activity in the Americas

Talisman Energy Inc. produced 373 Mboe/d worldwide in 2013 including 35 Mbbl/d of liquids and 883 MMcf/d of gas from North America.

Some of that gas came from the Montney and Duvernay shales in British Columbia and Alberta in Canada and the Marcellus Shale in Pennsylvania, while some of its oil came from the Duvernay and the Eagle Ford Shale in South Texas.

DUVERNAY

Talisman listed its Duvernay play in central Alberta as a future area in an August 2014 presentation.

It holds 300,000 net acres in the prospect area with 1.8 Bboe in unrisked prospective resource.

Its North Duvernay area offers more than 400 liquids-rich drilling locations and is being appraised by industry activity. Its South Duvernay area covers more than 1,000 liquids-rich locations with wells that produce between 200 bbl and 1,000 bbl of liquids per 1 MMcf of gas.

The company drilled three wells in the area in 2013 and planned to run three rigs there during 2014.

Talisman plans to plateau production in that area at 100 Mboe/d by 2020.

MONTNEY

The company's Montney properties produce natural gas.

It sold part of its acreage in northeastern British Columbia to Progress Energy Canada Ltd. in 2013. That sale included its Farrell Creek and Cypress properties.

Talisman kept its properties at Groundbirch and Saturn on about 48,000 net acres of prospective land.

UTICA

Quebec's regulatory authorities still haven't decided on rules governing drilling to the Utica/Lorraine shales in the lowlands area, and that

effectively locks up Talisman's 753,000 net acres of prospective land in the play. At this time, it can't commit capital to the play in the foreseeable future.

MARCELLUS

Moving into the U.S., the Marcellus Shale represents a foundation area for Talisman. It has Marcellus properties in Pennsylvania and New York, but, as in Quebec, regulatory authorities are deadlocked on drilling rules for the Marcellus. Talisman does produce from the Trenton/Black River combination in that state.

It planned to run one operated rig in the play in 2014 and possibly add a second rig during the year.

The company averaged 446 MMcf/d of gas production, according to its August 2014 presentation and obtained better-than-expected results from improvements in drilling and completions.

It has 193,000 net acres of leases in Pennsylvania and some 240 miles of gathering and transmission lines with seven compression and dehydration facilities to handle its production.

> **In July 2014, Whiting agreed to acquire Kodiak Oil & Gas Corp. That will make it the top producer in the Bakken/Three Forks with an approximate enterprise value of $18 billion. The acquisition will give Whiting 855,000 net acres in the play.**

EAGLE FORD

The Eagle Ford Shale sits in Talisman's inventory as a developing area where the company has about 60,000 net acres, most HBP.

The company has a joint venture agreement in the play with Norway's Statoil. From the beginning of that agreement, Statoil planned to take over operations on half of the property. It started working the eastern portion of the play in 2014.

Talisman's part of the play contains 118 MMboe in proved and probable reserves with a liquids content of more than 60%. The company doubled its production in the past two years to 27 Mboe/d at year-end 2013.

Meanwhile, it has lowered drilling and completion costs to more than $8 million per well in 2013 from $11 million in 2011. Its drilling cycle times dropped from 42 days to 21 days in the same period.

The company planned to run two operated rigs in the play during 2014, along with three nonoperated rigs on the Statoil side.

Whiting Petroleum Corp.

- **Motto: Energy plus technology equals growth**
- **Climbing in the Rockies**

Whiting Petroleum Corp. set its sights for unconventional production on two prolific areas in the Rockies, Bakken/Three Forks in North Dakota and Niobrara in Colorado.

The company also operates a large EOR project at North Ward Estes Field in the Permian Basin.

BAKKEN

The company's motto is "energy plus technology equals growth," but it might add acquisition as a third factor in its growth.

Whiting already controls one of the largest acreage positions in the Bakken/Three Forks play, and it's already the second largest producer in North Dakota.

In July 2014, it agreed to acquire Kodiak Oil & Gas Corp. That will make it the top producer in the Bakken/Three Forks with an approximate enterprise value of $18 billion. The acquisition will give Whiting 855,000 net acres in the play.

It already produced about 80.2 Mboe/d in second-quarter 2014, representing a 33% gain from the same quarter a year earlier, and it had 18 rigs turning to the right in July 2014.

Among significant wells, its Tarpon Prospect well in McKenzie County, N.D., flowed about 6.1 Mboe/d from the second bench of the Three Forks on June 7, 2014.

The company produces from the Middle Bakken and Three Forks in Sanish/Parshall Field, from the Three Forks in Lewis and Clark Field, and from the Middle Bakken and Three Forks at Hidden Bench, Tarpon, Starbuck and Missouri Breaks in North Dakota. It produces from both zones at Cassandra, Starbuck and Missouri Breaks in Montana.

NIOBRARA

Whiting's success isn't limited to the Williston Basin. Its 128,721 net acres in the Niobara play in the Denver Basin are doing well, too.

It allocated $575 million to drill 120 gross (104.9 net) wells in its Redtail development area in 2014. It produced 7.2 Mboe/d in second-quarter 2014, for a 59% gain over the first quarter.

Among significant events, its 30F super pad is testing spacing of 32 wells per section, and its Razor 271 pad with eight wells produced 4.7 Mboe/d, gross, in July 2014.

Redtail Field produced 7.2 Mboe/d from the Niobrara A and B benches in second-quarter 2014.

Whiting said it's in the sweet spot of the Niobrara in Weld County, Colo., with 1,344 potential drilling locations for the A bench, 1,343 locations in the B bench and 1,316 wells in the C bench of the Niobrara.

WPX Energy Inc.

- **Narrowing focus to Rockies**
- **Divesting all but three areas**

WPX Energy Inc. revealed a strategy to simplify its geographic spread and increase returns, margins and cash flow in an October 2014 announcement.

It will keep properties in the Williston, San Juan and Piceance basins and divest the remainder. Overall, it holds some 480,000 acres and 16,000 drilling locations in the three basins with more than 14 Tcf in proved, probable and possible reserves at year-end 2013.

MARCELLUS

One of the properties apparently on the sale block is the company's lease position in the Marcellus Shale where it produced more than 80 MMcf/d of gas in 2013. It completed 32 gross wells in 2012, down from 50 the previous year. It invested $126 million in the play in 2013 and $25 million in 2014.

The company holds interests in about 100 wells in the Marcellus.

BAKKEN

WPX has started completing wells in the Williston Basin. Doubling the size of its fracture treatments gave the company a 14% increase in production on three Bakken wells and a 13% production increase on three Three Forks wells.

It controls proved reserves of 105 MMboe in the Bakken and planned to invest between $580 million and $600 million to develop those North Dakota properties in 2014. It participated in 51 new oil wells in 2013, up from 41 in 2012.

The company's wells are on the Fort Berthold Indian Reservation. As a subsidiary of Williams Cos., it acquired Dakota-3 E&P Co. LLC, which had 80,000 net acres of land on the reservation in 2010.

It produces 15 Mbbl/d of oil from the Bakken on the property.

It planned to run up to five drilling rigs on the property in 2014.

NIOBRARA/MANCOS

WPX already had enough production from its 4,400 wells in Garfield and Rio Blanco counties in the Piceance Basin in Colorado to make it the state's largest gas producer.

Recently, it started working the Niobrara oil play. Its top two wells in the formation tested for an IP of about 2.7 Mboe/d and about 2 Mboe/d, respectively.

In June 2014, the company earned the *Oil and Gas Investor* magazine Best Discovery Award for its January 2013 Niobrara/Mancos discovery well.

WPX leases some 180,000 net acres in the play under its Mesaverde gas properties. It dedicated one drilling rig to the Niobrara in 2014.

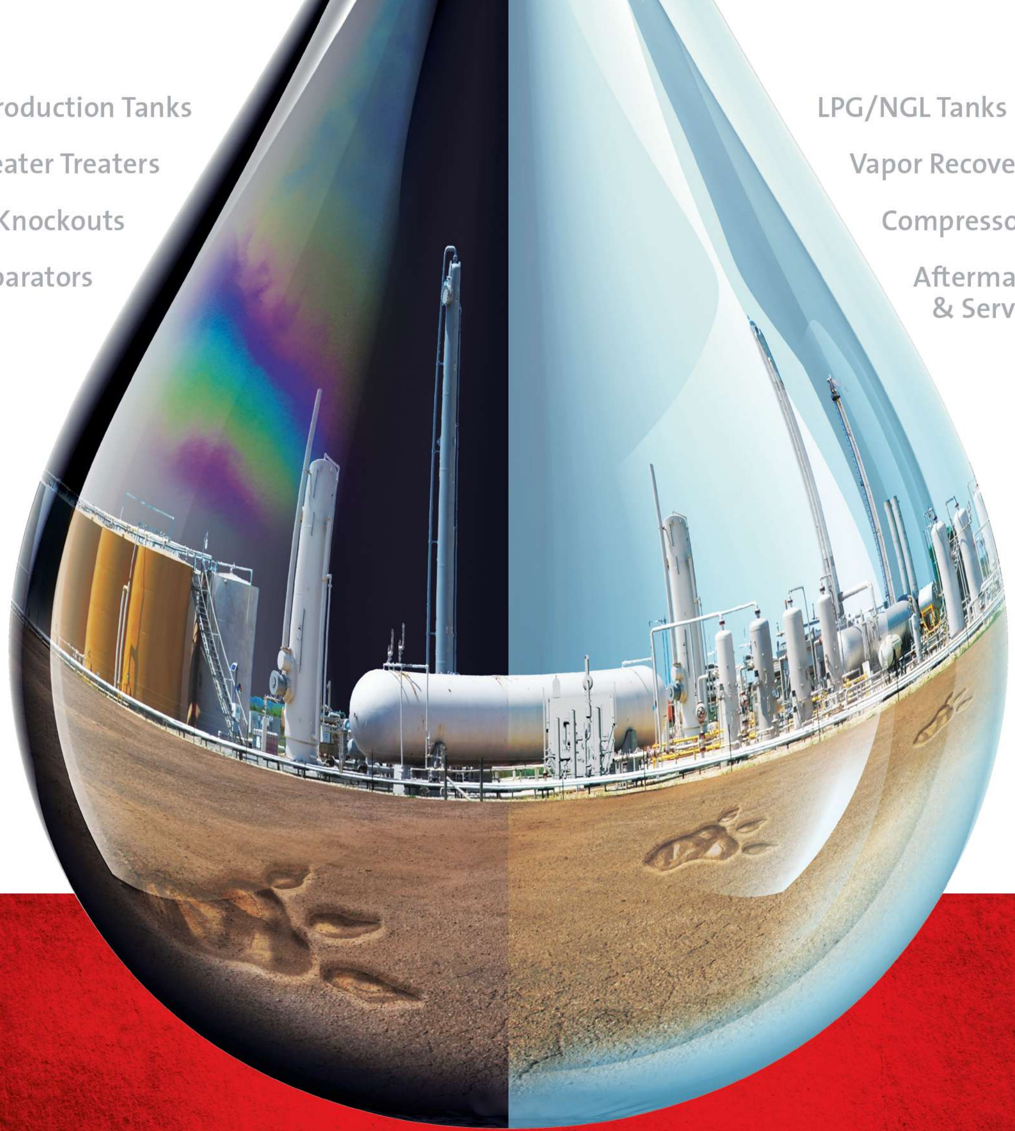
MANCOS

The company identified more than 400 oil-prone locations in the San Juan Basin in 18 months and drilled its first two 7,500-ft lateral wells in the Gallup Formation, which is fed by the Mancos Shale.

WPX demonstrated its enthusiasm for the San Juan Basin by increasing its well count in the Gallup from 29 wells to a planned 40 wells by year-end 2014 using two drilling rigs. It made its first Gallup Sand discovery in spring 2013 and drilled 15 wells during the year to reach a cumulative 290 Mbbl of oil. By mid-2014, it had produced 875,000 boe, and 700 Mbbl of that production was oil.

The company's IP rate on its Gallup wells in 2014 averages 626 boe/d, representing a 30% increase from the 2013 average.

WPX holds almost 50,000 net acres in the play after adding another 1,100 acres in second-quarter 2014. ■



The Schramm T250XD features a telescoping mast assembly that is self-erecting without the use of a crane. *(Photo courtesy of Schramm)*

New Solutions for Effective Production Are Flourishing

By **MJ Selle**, Contributing Editor

Technological advances aim to make unconventional resource development more efficient.

Technological advances in 2014 continued to push the E&P of North American shale basins. With about 1,300 horizontal rigs working in the U.S. to unlock unconventional reservoirs, gains in efficiency have been one of the primary forces behind technological development.

John Cadenhead, strategy manager for the Schlumberger Unconventional Resource Group, said, "This year has been a good year for us in terms of introducing technology specifically designed for shale. In years past, what's been done in the industry was [about] taking what's conventional and adapting it to shale, but we've really spent a lot of research and development money on coming up with technologies that are for the North American market and designed for shale."

He estimated Schlumberger has spent $1.2 billion on research and engineering for shale technologies. "We'll continue to do that for the foreseeable future. We want to make sure customers are as efficient as possible," he said. "We're trying to help continue to build that efficiency so that we never slow down operations, but we want to make sure we bring the technologies along with measurement and understanding to make each well effective and produce at the maximum rate. We want to take measurement quickly, get understanding quickly and use those measurements in the stimulation and completion of the well."

Rob Christie, global portfolio manager of Weatherford Petroleum Consulting Group, noted that the development of new tools for shale developments parallels the historical technological growth seen in the conventional market. "For many decades, all the tools focused on conventional reservoirs. We've developed a lot of empirical techniques for those reservoirs," he said. "Now, we're switching gears to unconventional, whether that is shale or tight sands and gas—areas that 20 years ago wouldn't have been economical. In the same way we had to go through development of tools for conventional oil, now we're going through the same learning curves for unconventional oil and gas.

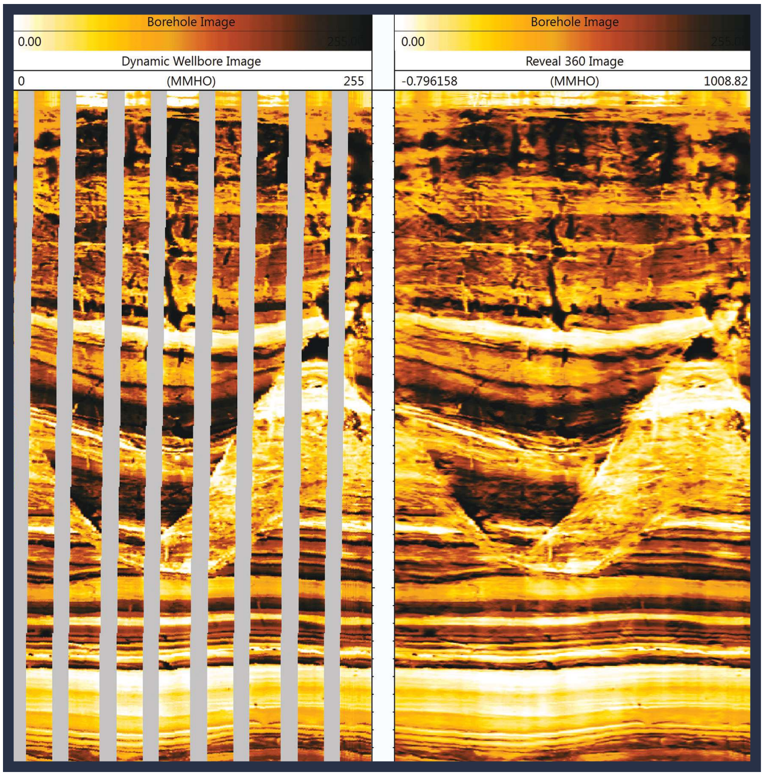
"You have to have the equipment designed for the pace of operations and the intensity of operations, but you can't forget we have to drill in the right spot and land the well in the right part of the reservoir," he added. "Once we've created that hole, we have to fracture all of it—that's key to bringing down costs and staying efficient. The pace of operations is going to continue to increase. There's no doubt about that."

As the industry has moved to including shale-specific tools in its E&P efforts, the trial-and-error approach of finding and producing hydrocarbons is undergoing a change to a more measured program.

John Pope, CEO of WellDog said, "One of the biggest problems operators have is getting feedback on their completion and production techniques. The trial-and-error approach in completion and production is very extensive and time-consuming. We've seen over and over again that the trial-and-error process can sometimes result in good resource being left behind."

He added that operators are in a difficult position. "You can spend a lot of time screening and describing your reservoir, but if the reservoir isn't

(Image courtesy of Weatherford)



Reveal 360 reconstructs wellbore images hidden by pads.

worth anything, it's a waste of time and money," he said. "Operators will try to find a resource that has some potential and will do simple things to produce that resource. Then they'll do harder things to produce it and have success to keep going. It's a very significant challenge to the operators with these types of complicated reservoirs—not only to have enough early success to convince the stakeholders to keep after it but to stay later to optimize and maximize their economics. We have a lot of sympathy for that process."

Technological solutions to increase efficiency have developed throughout the process of exploring and producing unconventional wells. With many companies in the industry introducing shale-specific solutions, a few key technologies are highlighted here.

FORMATION EVALUATION

Filling in wellbore image gaps

Interpreting data from wireline wellbore images can be challenging, since wireline tools use pads to maneuver, leaving gaps in the images that are estimated to include 30% to 50% of the total data. Weatherford's Reveal 360 imaging technique removes these blind spots by reconstructing images, bringing a 360-degree view of the wellbore.

"All wireline tools in existence have gaps between the pads," said Weatherford's Christie. "As the wireline tool gets logged up the well, those long pads make contact with the borehole wall, and after processing what you see is a false color image map. Reveal 360 closes these gaps by using a sophisticated digital imaging processing technique to reconstruct the image in its entirety. With no gaps between the pads, geologists can visualize all the features in the wellbore. They can concentrate fully on giving a complete interpretation of the subsurface."

Christie noted that sometimes it's difficult for the human brain to fill in the gaps and grasp all the nuances of a wellbore image. "A lot of people have a hard time mentally joining the dots when there are incomplete data," he said. "When you have a full image, your eyes can more easily pick out features and details that you might otherwise have missed."

By expanding the image via Reveal 360, Christie said everything in the borehole can be defined from stratigraphy through structural folds and faults. "You can look all the way into the fracture system. This will have an impact on drilling by pointing out the natural fractures that are already in place. We can see how dense they are and how thick they are, which could change your fracturing program."

Christie said Reveal 360 can work with any microresistivity tool on the market. "Reveal 360 is not vendor-specific, and it can work in any shale basin," he said.

The Reveal 360 process uses a technique known as morphological component analysis—taking the measure sections of the borehole wall and decomposing that information into sparse representations of the borehole wall's morphological components using dictionaries of multiscale, multi-orientation transforms. Then, the images are reconstructed using information from the dictionaries to fill in the missing information. By doing this, Reveal 360 allows the use of automated pattern recognition algorithms that are typically challenged by the gaps in the data.

Reveal 360 is part of a larger R&D effort by Weatherford. "This is one of the first steps in our R&D program that will focus on automation," Christie said. "All of the geologists who looked at Reveal 360 could see its value in reducing reservoir uncertainty."

Technology gets to the core of the well

Getting an accurate picture of the fluids in a shale reservoir has historically been a large challenge in the oil and gas industry, according to Jacob Thomas, senior director of technology at Halliburton. "Because of the low or lack of permeability in shale rock, it's difficult to get core samples back to the laboratory for analysis without a loss of volume and a loss of pressure."

However, with Halliburton's recently introduced CoreVault System that challenge is one step closer to being solved, according to the company. Thomas estimates that 50% to 70% of hydrocarbons escape from the rock as the samples depressurize. By preserving 100% of the fluids within the sample, the CoreVault system brings a better understanding of potential production within the reservoir.

CoreVault allows 10 core samples without loss of fluid or pressure.

(Image courtesy of Halliburton)

"There's still a lot of optimization that needs to be done," Thomas said. "Oftentimes, the completion design and the fracturing program are not as optimal as they need to be. If you look at shale plays, the whole effort of optimizing the completion design is to increase production rates and, ultimately, the recovery from these formations. Having an understanding of the potential production of the reservoir allows operators to come up with the appropriate completion design."

Using the Halliburton Hostile Rotary Sidewall Coring Tool device to recover the cores, up to 10 1.5-in.-outer-diameter cores can be sealed at reservoir conditions in a single wireline run. Cores can be recovered in temperatures up to 400 F and pressures up to 25,000 psi.

"The information from the CoreVault system will augment the analysis done by Halliburton's CYPHER collaborative workflow application," Thomas said. "CYPHER service starts by developing the earth model, then the stimulation model. The results of stimulation go through the completion and production phases, and that information comes back to update the earth model. It's a never-ending loop. Getting new data and improving the forecasting ability help customers to get a better predictive model."

Even though the CoreVault system technology was developed for unconventional wells, Thomas said it can be applied to conventional wells, too. "The ability to get the core sample without a loss of pressure or fluid is valuable even for conventional developments," he noted.

During field tests in Ohio and West Virginia, the CoreVault system retrieved 150 samples in five wells. Measurements of the samples showed more than two times the amount of oil and gas in place than had been previously estimated.

"This is one of those technologies that will definitely have a big impact on unconventional development as a whole," Thomas said.

INTEGRATED WORKFLOWS

Seismic-to-stimulation service offers answers

One of Halliburton's principle technology developments is its CYPHER seismic-to-stimulation service. Originally introduced to the oil and gas industry in 2013, Version 2.0 was released in mid-2014 with advances that model the interaction of the reservoir's natural fracture networks with the fractures induced by the hydraulic fracturing process, bringing a more accurate fracture network model for stimulation and completion.

"CYPHER's workflow components help bring answers to key questions such as, 'Where do you drill, how do you drill, how does the formation fracture and how do you need to complete the well?'" Thomas said.

"Shale is a source rock," he continued. "Ten years ago we didn't talk of shale as a reservoir. The genesis of CYPHER service at Halliburton began when we thought about what we as a service company needed to do. We had all these tools for conventional wells but realized we had to change them to fit the unconventional developments. We did not want to depend on tools for a different type of reservoir, so CYPHER service is our attempt to come up with more realistic expectations of what the shale looks like pre- and post-fracture."

The seismic-to-stimulation workflow is based on Landmark's DecisionSpace next-generation earth-modeling solution. By updating dynamically and iteratively with the seismic and well data required to model the structure, rock and fluid properties, the CYPHER workflow helps define the distribution of hydrocarbons in the reservoir to aid well placement. The integrated formation evaluation module identifies the best spots for optimizing the spacing of the perforation clusters.

Thomas said only having reams of data is no guarantee that problems will be solved; the correct expertise also is needed. "With advances in memory, connectivity and the volume of data, we are in a place where an engineer, geologist and geoscientist have a lot of data in their hands. The constraint on being able to use the data is a major problem, so part of the whole CYPHER process is Halliburton's ability to decide what data are appropriate and useful and then decide what to do with the data to respond with the appropriate technology. That's where the expertise of the people who handle the data comes into play. You can have the greatest tools, but you need technical teams with the understanding of the subsurface to handle those data."

Another key part of the seismic-to-stimulation system is the ability to customize the workflow for each client. "With so many shale plays in the U.S., each one is different in the quality of rock, the quality of hydrocarbons and the maturity of the basins," Thomas said. "CYPHER service is not a one-size-fits-all solution. We try to understand the economic drivers and size of the customer's assets. Even within the CYPHER system, there are multiple well complexities and analysis that can be done with the data available."

According to Halliburton, Devon Energy has used the service with positive results. After applying CYPHER to the grasslands area of the northern Barnett Shale and seeing improved production results and EUR with less production variations between wells, Devon incorporated the service into its Eagle Ford Shale operations.

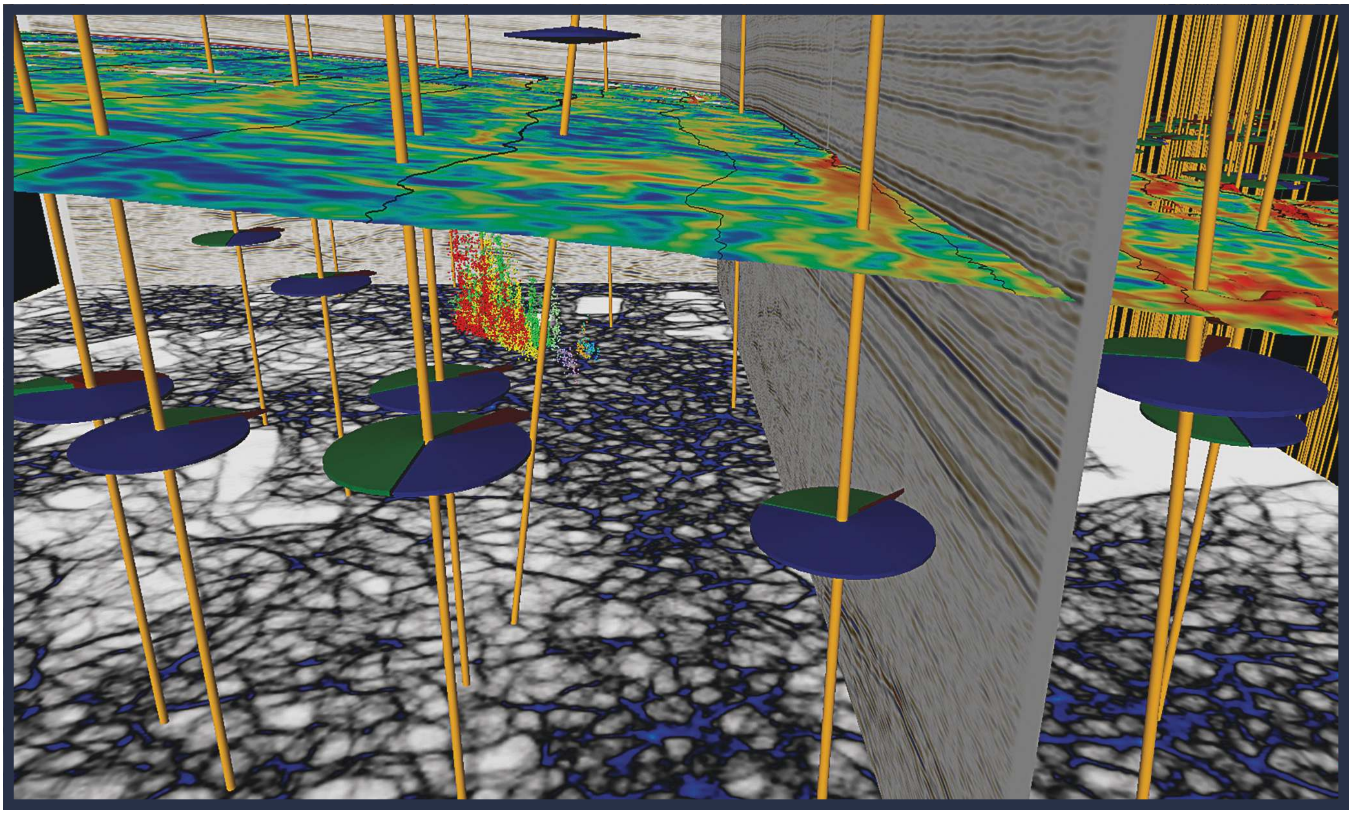
Workflows specific to unconventionals

Introduced in August 2014, Schlumberger's Petrel Shale software platform integrates shale workflows, offering a new user interface to drive multidisciplinary efficiencies.

"Petrel Shale transcends traditional domain boundaries," said Keith Tushingham, director of marketing operations for Schlumberger Information Solutions. "It combines classical geoscience and geography capabilities with tools and technology for completion and reservoir engineers. Multidisciplinary teams can look at the same rock at the same time but from different angles."

The software platform adapts the existing user interface from the Petrel E&P software platform, with a new display that presents shale-specific functionality from exploration through evaluation, drilling and completions to production. "We've grouped tasks according to different domains, so if you are a driller, you'll only see drilling-related functionality," Tushingham said. "Petrel Shale is

(Image courtesy of Schlumberger)



In the Petrel Shale software, users are able to characterize shale reservoirs from exploration to production.

laid out logically, mirroring the way users involved in unconventional shales carry out key tasks."

Shale wells produce huge amounts of data, and the software platform can help operators make sense of those data, according to Tushingham. He noted that shale wells are being spaced closer together, and the number of stages along each is increasing, as well as the number of perforations needed, all resulting in higher data volumes.

"Increasing data volumes from high well count shales requires efficient, searchable storage. That's something we paid a lot of attention to in Petrel Shale. Its database mechanism, the Studio E&P knowledge environment, stores all that information in the background and makes it quickly accessible. Operators want to know what makes a good well good and a bad well bad. If you have the information in a database and a mechanism with some logic behind it to figure out these differences, you can more easily determine an optimal development plan."

Tushingham acknowledges that all operators are trying to get costs under control. "They're looking to get more out of the ground in the most resource-efficient way," he said. "We can help optimize their investments through extensive and detailed modeling before executing the job." The Petrel platform has offered modeling functionality for more than 15 years, but not for a shale-specific userbase until now, he said. "Today, Petrel Shale meets that need."

"[Petrel Shale] gives customers the ability to put together a complete shale drilling package," said Schlumberger's John Cadenhead. "They can define how best to undertake critical measurements, giving them more choice. The flexibility comes down to how the customer sees their risk and how they want to approach reducing it, pre-well, to better address the 40% of the clusters that commonly do not contribute to well production."

DRILLING INNOVATIONS

Rigs designed to keep pace with unconventional needs

With the boom in U.S. unconventional shale development, drilling rigs have been high-demand items.

(Photo courtesy of Schlumberger)

TelePacer is designed for factory and pad drilling operations to reduce collision risk, improve drilling efficiency and maximize sweet spot exposure with a configurable suite of measurements, including spectral gamma ray.

"Shale plays have introduced a lot of new technology in general to the market and have driven development of our new T500XD and T250XD drilling rigs," said Schramm COO Bobby Bryan. "The T500XD is a robust machine that can be utilized in several different applications such as pad drilling, exploratory, heavy workover and top-hole drilling. This unit has drilled over 19,000 ft in certain wells."

In contrast, the T250XD rig is mainly used for top-hole drilling of up to 11,000 ft. "The T250XD can drill out the intermediate section of the well. This will be followed by a larger rig such as a T500XD to complete the well," Bryan said. "This provides an economic benefit to the operators. If you can use this smaller, fit-for-purpose rig, you have less capital associated with it. Our customers have realized over 30% savings by using the T250XD to conduct the top-hole drilling."

Bryan said both rigs offer unique features such as the Schramm Telemast "half triple" telescoping mast assembly that is self-erecting in two shifts or less without the use of a crane. "While other rigs have a complex rig-up process that has to be done in an exact sequence, both of the Schramm rigs have a simplistic, craneless rig-up process," Bryan said. "This makes it very easy for crews to rig up and rig down and get back to drilling."

The mast assembly also brings greater safety. "In a typical 1,500-horsepower (triples) rig, you have a derrickman a hundred plus feet up off the ground manipulating the drillpipe. It's a tough job, and it exposes people to safety concerns," Bryan said. "One of the key safety features of the T500XD and the T250XD is that you eliminate the need for a derrickman to be up in the air. Furthermore, you can bring the mast to the ground and carry out maintenance on the crown block there instead of 150 ft in the air.

The T500XD offers a 360-degree walking system that allows it to maneuver around a crowded drillsite. "Many drilling rigs only can maneuver on an X-Y axis," Bryan said. "Our rig can maneuver in 5-degree increments with greater mobility."

Greater mobility also is a feature of the rigs. "The smaller footprint of both the T500XD and the T250XD allows work to be accomplished in some very geographically demanding areas, such as the hills and tight areas of the Marcellus Shale," Bryan said. "We've been able to get in and out of many different places."

The T500XD and T250XD feature the Schramm LoadSafe hands-free pipehandling system. "When you automate the pipehandling system, you're simply putting people out of harm's way," Bryan said. "When you automate and take the human element out of it, the possibility for errors is reduced. There's no reason for a person to be handling heavy tool joints. That is a very physically intensive job, so by automating, your crews aren't as physically exhausted. In the long run, this can extend the career of a roughneck."

Use of the T500XD and T250XD also can bring decreased local truck traffic due to the rigs' automation and pipehandling capabilities. "We've seen a considerable reduction in truck traffic," Bryan said. "That brings benefits on many levels—greater efficiency, fewer loads, less logistics, less wear and tear on roads and less stress on the community where the drilling is occurring. It all comes back to cost and effectiveness."

The controls of the rigs are geared for ease of use. "There are some generation gaps in the oil field that the industry is trying to address," Bryan said. "When you see these joystick controls, it's right in the wheelhouse of the younger generation. They can sit right down in front of the touchscreens and control this rig much like they did their video games when they were younger. We'll be seeing more intuitive software and increased performance in drilling rigs in the years to come."

Flexibility for operators

While significant improvements have been made in drilling efficiency, especially in mature basins such as the Eagle Ford, there still exists a large variability in well performance because of the complex nature of shale reservoirs.

"According to IHS, even today 40% of unconventional wells are considered subeconomic," said Jonathan Hill, vice president of marketing and technique for PathFinder, a Schlumberger company. "With pad drilling becoming mainstream and increasing downspacing efforts, the subsurface continues to get more congested. Accurate well placement is becoming more and more important, both with respect to optimizing reservoir drainage as well as avoiding collisions."

PathFinder introduced two new drilling technology solutions in August 2014: the TelePacer modular MWD platform and the SonicPacer acoustic shale evaluation service.

"In conjunction with other Schlumberger technology, the Pacer unconventional MLWD services family helps address concerns of well spacing assurance, drilling efficiency and well effectiveness," Hill said.

He noted that the TelePacer platform allows operators to select and configure the telemetry, surveying and measurement packages they need. The modular design of the TelePacer platform allows the bottomhole assembly (BHA) to be tailored to drilling objectives. "The right BHA helps you achieve specific drilling efficiency targets without paying for things you do not need," he said.

Combined with the Schlumberger WellDefined Survey Services, the TelePacer platform allows operators to maximize the positional certainty of where the wells are and, equally importantly, position wells safely and optimally with respect to other wells. "This is extremely important as we continue to downspace laterals to improve the estimated ultimate recovery of these plays," Hill said.

"In conjunction with other Schlumberger technology, the Pacer unconventional MLWD services family helps address concerns of well spacing assurance, drilling efficiency and well effectiveness."

*– **Jonathan Hill,** PathFinder, a Schlumberger company*

The TelePacer platform can be configured with Express electromagnetic (EM) telemetry, with transmission rate capability of 16 bits per second, which is 10 times the speed of standard mud-pulse telemetry. "That allows us to drill fast while keeping bandwidth-hungry, critical drilling, decision-making data like formation dips at our fingertips while drilling," Hill said. "Every minute counts in these

(Photo courtesy of Schlumberger)

SonicPacer captures acoustic data while drilling to create a stress profile along the lateral, which provides insight into fractureability and enables engineered completion design.

tight plays, so we put a lot of effort into analyzing nonproductive time in order to improve our drilling efficiency. In land drilling, we know that the most common cause of downtime is plugged MWD pulsers. The beauty of EM telemetry is that there are no moving parts, so there is nothing to plug. As a case in point, during our nine-month field-testing campaign we didn't have a single downhole tool failure."

Effective in-zone steering is increasingly important as more and more operators embark on multibenching strategies, and the TelePacer platform offers multiple configurations to address such well placement needs. It can utilize API gamma ray, spectral gamma ray or azimuthal gamma ray. "It's totally customizable," Hill said. "In some wells, using the spectral gamma ray will help us place the well by providing further insight into the mineralogy and clay content of the formation. Steering and placing the well accurately are critical to maximizing the well performance."

The SonicPacer acoustic shale evaluation service captures acoustic measurements while drilling to create a continuous stress profile along laterals in shale reservoirs. "We're very excited about the SonicPacer service," Hill said. "It gives customers insight into the fracturability of the rock and allows them to engineer more effective completions.

"Increasingly, operators are becoming aware that defining stages geometrically in these highly heterogeneous laterals means that we are actually grouping random rock strengths together while fracturing," he continued. "This leads to huge stress differentials within each stage, and only the weakest rocks in each stage break. On average such geometric completions lead to 35% unfractured rock. Engineered completions, on the other hand, typically show a 30% improvement in fracturing effectiveness compared to geometric completions, as evidenced by production logs. During its early introduction, we have consistently seen fantastic results, in some cases also reducing completions costs through preventing screenouts."

Another new drilling technology introduced in 2014 is the DynaForce Flex shale drilling motor, an optimized bit-to-bend motor with a heavy-duty lower end. "The design premise here is that people have been using one drive system to drill the vertical, one drive system to drill the curve and a third to drill the lateral," Hill said. "What we're doing here is optimizing three-point geometry on the assembly. The drive shaft transmission has ultra-high torsional yield—35 ft-lb yield—which gives it total flexibility on the power section, harnessing maximum downhole torque and downhole horsepower for superior ROP."

Schlumberger also introduced the PowerDrive Orbit rotary steerable system in 2014. "This brings a much broader operating envelope for rotary steerable systems, up to 350 rpm," Hill said. "It's a technology that wasn't introduced specifically for unconventionals in North America land, but it has brought tremendous value to some of our clients here."

COMPLETIONS

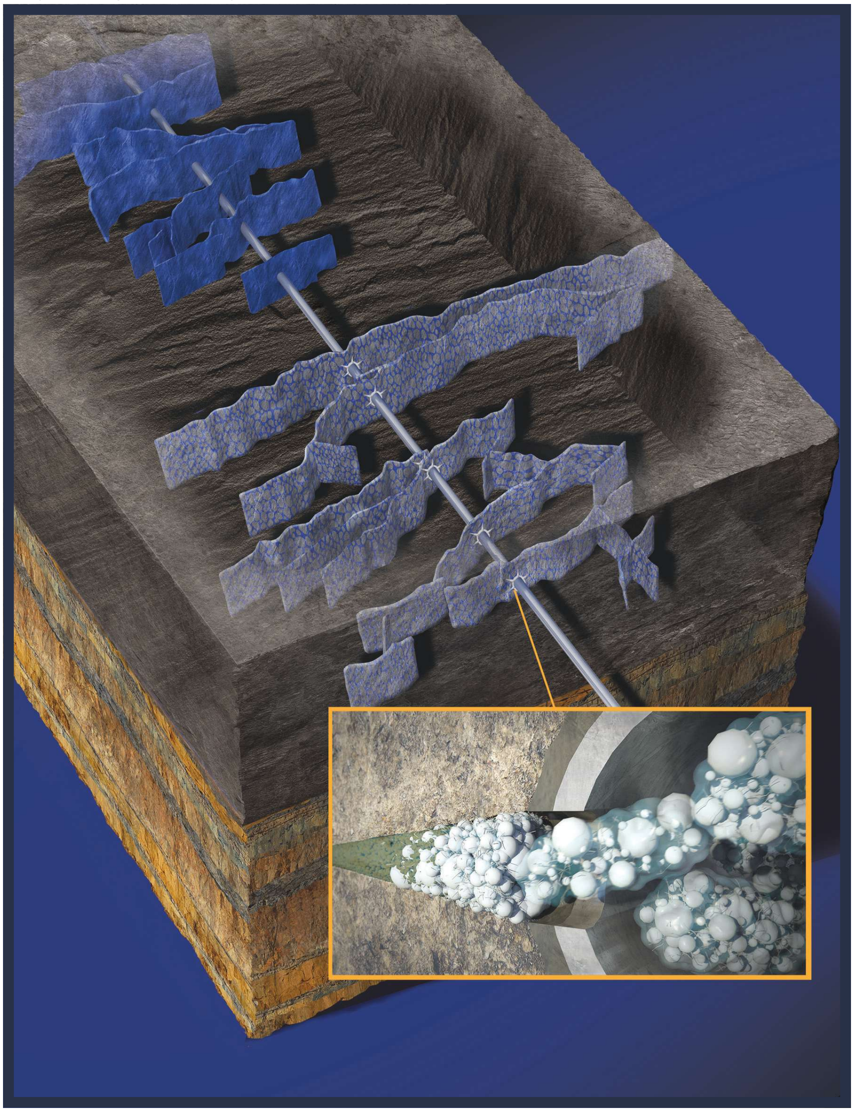
Expanding unconventional reservoir completion services

Initially introduced in February 2014, Schlumberger's BroadBand Unconventional Reservoir Completion Services grew by October 2014 to include two specialized completion services: BroadBand Sequence Fracturing Service and BroadBand Precision Integrated Completion Service.

"BroadBand is now the fastest-growing new technology in Schlumberger history," said Alejandro Peña, BroadBand services manager.

Peña explained that since the onset of unconventional development, completion has generally been accomplished through plug-and-perf systems. These complete the well geometrically by perforating a number of clusters with identical spacing over a

(Image courtesy of Schlumberger)



The BroadBand Sequence fracturing technique enables sequential stimulation of perforation clusters, resulting in greater production from investment.

fixed length of lateral, and then isolate the interval with a bridge plug.

"This is a 'factory mode approach' that we have relied on heavily for the last 15 years," Peña said. "However, Schlumberger went back and looked at well performance in different basins and tried to understand what we got back from this kind of approach. We realized that about 40% of the clusters or entry points did not contribute to production, so we are systematically leaving a significant amount of hydrocarbons behind.

"When you look at all the unconventional plays and analyze the average production per well, the picture we saw repeating itself—in the Eagle Ford, the Bakken, the Barnett and the Marcellus shales—was that the average daily production per well is getting to the point where it is no longer increasing regardless of longer laterals or bigger jobs. This called for rethinking how we are completing horizontal wells," he added.

Peña said Schlumberger's technology team then considered the possibility of transporting the proppant higher into the fracture network into places not being reached today to prevent those fractures from closing.

The BroadBand Sequence service works to ensure sequential stimulation of each perforation cluster in each target interval along the lateral. This service relies on the use of a composite pill comprised of a blend of multisize particles and fibers to enhance wellbore coverage. The composite pills are placed at the end of each fracture to enable temporary isolation of the clusters and promote redirection of added water and proppant to other clusters or entry points that otherwise would have remained unstimulated.

The newer BroadBand Precision service uses an array of mulistage tools with recloseable sleeves cemented in place along the completion to ensure adequate coverage of the lateral. In this manner, each entry point is stimulated one at a time, which provides ultimate control for fracture placement.

To enhance reservoir contact, both BroadBand services rely on the use of a new composite fracturing fluid, which uses proprietary fibers to enhance proppant transport and placement across the fractures created hydraulically in the reservoir. "Previous generations of fiber-enabled fracturing fluids were limited to the use of crosslinked or highly viscous fluids. This new generation of composite fracturing fluids can be used with low-viscosity fluids such as linear gel solutions and slick water, which significantly expands their applicability in shale reservoirs," Peña said.

He added, "We're seeing significant benefits from both BroadBand services. For new completions in the Eagle Ford, Bakken and Fayetteville shales, increases in excess of 20% in production have been achieved. This is a great enabler for refracturing operations, since we can go back and temporarily isolate fractures that were completed in the past or were stimulated poorly."

Peña said Schlumberger is in the process of setting up a consortium in the Eagle Ford to expand the BroadBand initiative. "We have five operators already committed to the program and expect to expand this to all unconventional plays across North America," he said.

PRODUCTION

Managing shale oil from the reservoir to the refinery

The growing streams of light shale oil that are now flowing into refineries present opportunities along the entire value chain, from the reservoir to the

GAS-ASSISTED PLUNGER LIFT FINDS SHALE SUCCESS

By **Jennifer Presley**, Senior Editor

Two old-school lift methods combine to find success in shale plays.

One is an artificial lift method that removes fluids by using the well's natural energy to move a plunger up and down. Another introduces energy into wells that have very little to help lift fluids to the surface. Combine the two and you have a gas-assisted plunger lift (GAPL). GAPL is an artificial lift method that utilizes an external gas supply to operate a plunger to aid in fluid production and/or controlling paraffin and scale.

"What we've done was take old technologies like gas lift and plunger lift and used them in a different way," said Kelly Raper, vice president of sales and corporate development for Priority Energy Services.

Although originally designed for use in oil wells, gas lift was utilized in the Barnett Shale in the early 2000s to remove the thousands of barrels of water used in the hydraulic fracturing process from the shale gas wells, according to Raper.

"Over a period of time, it has become probably one of the most cost-effective ways to unload wells after fracking," he said. "We've developed gas lift systems for these wells but when the price of natural gas dropped, there was a shift by industry to the oil plays."

In those oilier plays, application of the technology is the same, but it delivers additional benefits over traditional pumping units.

"It is basically the same technology in that we're unloading frack water but oil wells tend to need some form of artificial lift. A lot of customers put pumping units on these wells right away, but they run into a couple of obstacles," he said. "One is the units tend to gas lock," he said. "We're able to unload the wells with gas lift. Then at the time when you'd put a pumping unit on, we've already set the well up for future plunger lift operations, so it is just a process of setting the bottomhole plunger lift assembly just above the bottom valve, allowing the bottom gas lift valve to inject gas into the tubing and giving the plunger the needed horsepower to travel to the surface."

Paraffin is a challenge in many of the unconventional plays. To manage it, he suggests setting the plunger lift below the paraffin line and then tripping the plunger a couple of times during the day to help remove and cut the buildup. Another option is to inject chemical treatment directly above the plunger and then run the plunger through the entire tubing string to treat the well. ■

(Photo courtesy of Baker Hughes)

The Baker Hughes PAW8000 high-activity winterized paraffin inhibitor reduces paraffin deposition and flow resistance problems while reducing chemical use rates and chemical transportation costs.

refinery—if the quality of the crude can be managed and maintained at high levels throughout the process.

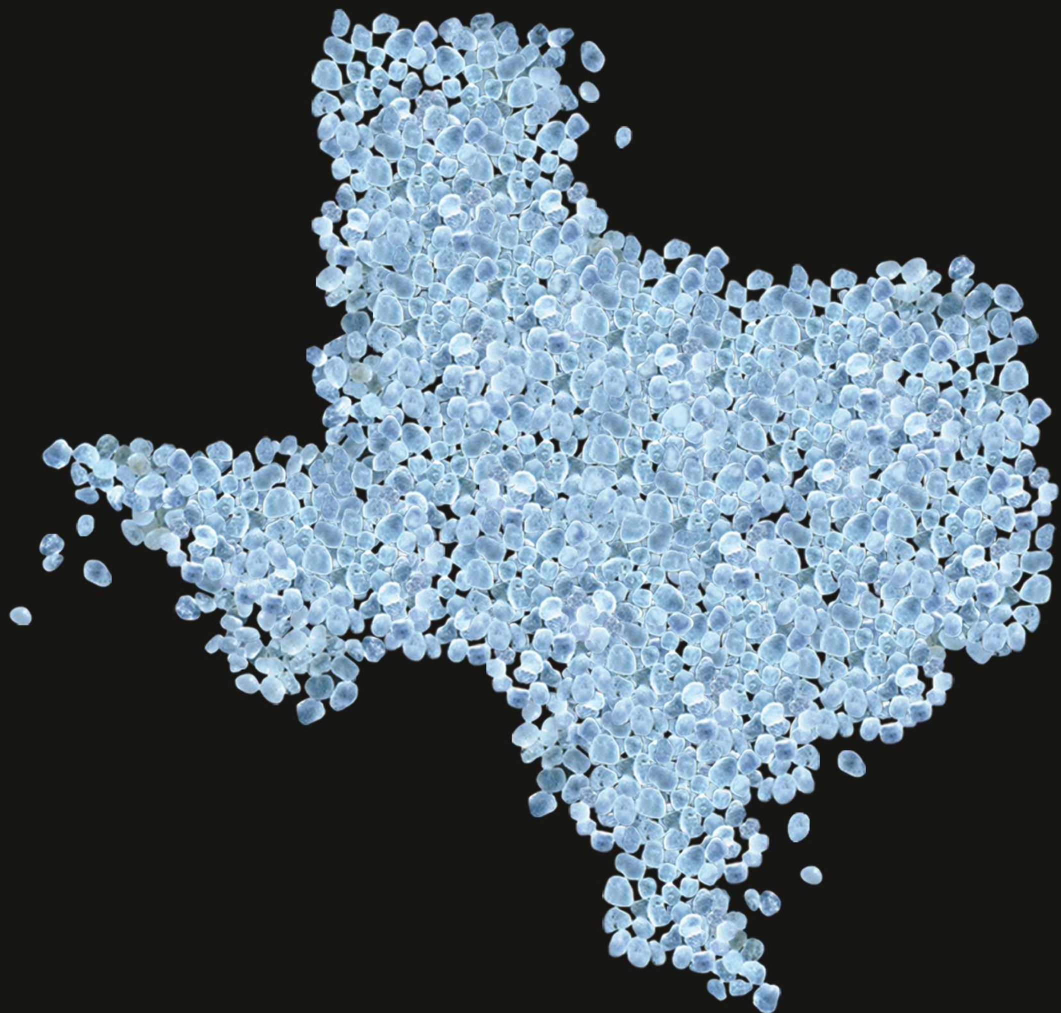
The Baker Hughes crude oil management program offers a systemic approach based on the company's understanding of the operations, challenges and economics of the upstream, midstream and downstream segments of the crude oil value chain that can prove invaluable in maximizing quality and return on investment (ROI) throughout the crude life cycle.

According to Doug King, upstream chemicals product line manager for Baker Hughes, there are three key points to remember to maintain crude quality and ROI at their highest levels:

- Challenges that are manifested in the refinery typically begin in the reservoir;
- Oil is treatable at every phase of its life cycle; and
- The way the oil is treated upstream impacts its value downstream.

While shale oil composition varies from basin to basin, from well to well, and even within wells, some of its common characteristics can lead to significant disruptions that cost time and energy and reduce throughput, which can negatively impact overall shale oil economics. "The reservoir challenges that can hinder production include organic and inorganic damage, which may occur as a result of the characteristics of the crude and of the way it is extracted. Among shale oil characteristics that pose challenges to managing its quality are variations in composition, high paraffin content, light paraffinic constituents and hydrogen sulfide content. Additionally, tramp amines may form as a result of H_2S treatment," King said.

Shale oils are highly paraffinic. Many of these oils feature waxes that melt above 200 F and that consequently can create wax deposits that can plug flowlines and foul storage tanks and process units. When light paraffinic shale oil is blended with heavy, asphaltenic crude oil, the resulting blend can exhibit asphaltene instability, creating sludge or deposits that reduce tank capacity in crude tanks,



stabilize emulsions in the desalter unit and foul process equipment.

Paraffin inhibitors can reduce paraffin deposition and flow resistance problems caused by congealing waxy crude oil. Effective chemical inhibition can increase revenue by increasing production. It also can reduce costs by reducing mechanical interventions, pumping costs and heating requirements. In 2014, Baker Hughes introduced its PAW8000 high-activity winterized paraffin inhibitor, a concentrated formulation uniquely designed for cold climates.

King explained, "While standard solvent-based paraffin inhibitor formulations are either not suitable for use or have very dilute activities in subfreezing environments, the PAW8000 high-activity winterized paraffin inhibitor remains fluid and pumpable at temperatures down to -40 F. The unique formulation of the inhibitor lowers chemical use rates up to 10 times versus what is used for other oil-soluble formulations used in cold climate areas.

"By lowering chemical use rates, chemical transportation costs are also reduced," he continued.

An independent producer in the Rocky Mountains used the Baker Hughes winterized inhibitor program to treat paraffin in this very profitable but challenging area. Baker Hughes scientists used cold-finger testing to select the best chemical product, and laboratory data confirmed the superior performance of the PAW8000 high-activity winterized paraffin inhibitor.

Before applying the inhibitor treatment, the Baker Hughes chemical automation services team qualified the chemical-injection system to confirm optimum treatment performance in cold weather environments. The PAW8000 inhibitor dispersion was applied at 1,000 ppm. After four rounds of weekly testing, results showed a significant decrease in paraffin deposition as compared to the performance of previously used inhibitors. Using the Baker Hughes high-activity winterized paraffin inhibitor, the producer reduced capex and maintenance and labor costs while enhancing the well's production.

To address dangerous and corrosive H_2S in shale oil, Baker Hughes recently introduced its PETROSWEET HSO3507 and HSO3510 H_2S scavenger programs for surface applications to sweeten production. The scavenger is effective in mixed production systems that are difficult to treat, including those with a high percentage of water. It maintains its scavenging efficacy at temperatures ranging from 68 F to more than 572 F and will not typically cause emulsions or scaling.

An operator of an oil and gas producer in the Eagle Ford Shale decided to use PETROSWEET HSO3507 scavenger to lower H_2S in the gas below the 10-ppm max for safe transport. After injecting PETROSWEET HSO3507 scavenger into the flowline at the wellhead at a rate of 8.5 gal/d, H_2S was reduced from its original 160 ppm to a safe 3 ppm.

EMERGING TECHNOLOGY

Spectroscopy technique shows promise for characterization

An emerging technology that shows promise for use in unconventional reservoirs is Reservoir Raman Spectroscopy from WellDog. The technology builds on a science named after Sir C.V. Raman who was awarded the Nobel Prize in Physics in 1930 for the technique. "Before World War II, Raman spectroscopy was the primary means of nondestructive analysis of materials until infrared technology became more widely used," said WellDog CEO John Pope.

The technology is based on inelastic scattering, or Raman scattering, of monochromatic light, usually from a laser. The laser light interacts with molecular bonds resulting in the energy of the laser photons being shifted up or down. The shift in energy gives information about the vibrational modes in the system.

When the telecommunications industry began investing in lasers, the components of Raman spectroscopy gained higher performance. "The spectrometers became more rugged, something you could take out in the field," Pope said.

Miniaturization also has made the technology more useful. "I built a Raman spectrometer in 1993 that was about the size of a picnic table and cost a bunch of money," Pope said. "The underlying technology shift has been dramatic. Now, you can buy a handheld Raman spectrometer that runs on

AA batteries and does an analysis of powders at border stations for $20,000. Fifteen years ago, we began applying Raman spectroscopy to interesting challenges in the coalbed methane industry, and now we're using it for the oil and gas, mining and environmental sensing industries."

WellDog has been collaborating intensely with Shell International E&P to use the science to locate natural gas and NGL in shale formations. "Core samples rarely contain all the geochemical information you need when you look downhole," Pope said. "In our process, we shine a green laser into the reservoir, and light bounces off the materials in the formation. As the light bounces off the materials, some of its energy is dropped into the materials so it changes color. The resulting color indicates what the materials are, and we get a fingerprint of each material. You can look at overlapping fingerprints—up to 20 at a time or more—and identify them. Once our team has quantified those signatures, you basically have a 'snapshot' of the reservoir."

This is the third application of the technology in Shell projects. "We've become very good at making sure the data are accurate and the sensor works properly," Pope said. "The data represent the reservoir. We're now inviting the industry to join us to build a larger body of data."

The technology has been used by WellDog in the CBM and coal mining industries for years. "We've used the data to calculate gas assets for customers," Pope said. "It's become a mature technology platform because of all the work we've done over the last 10 years. We continue to invest in technology to advance our knowledge. Our fifth-generation Raman spectrometer rolled off the production line in late October. We've only scratched the surface of this sensor technology in terms of possible oil and gas and environmental applications."

(Photo courtesy of WellDog)

WellDog's sensor technology views the entire reservoir.

While WellDog's shale work has primarily focused on identifying whether formations include wet or dry gas, shale oil measurement trials will be in the field sometime in 2015. "There are several things that this technology allows us to do to make these measurements special," Pope said. "First, it's a direct measurement of the oil and gas in a formation. We don't look at the rock; we measure and analyze the gas and oil directly so if we see the gas and oil, it's there. It's a direct measurement, not an inferential measurement."

The measurement also is done downhole. "We don't have to take a series of samples out of the reservoir to the laboratory and hope the sample still represents the reservoir," he added. "Most of those samples are under high-pressure and high-temperature conditions and have various chemical and stress regimes. If you touch them, you change them. Instead, we go into the reservoir with the sensor and analyze the reservoir as it exists."

Third, the Reservoir Raman Spectroscopy sees the whole reservoir. "Even if you can control core sample integrity and make sure the sample represents the part of the reservoir that you look at, you're still only seeing one spot in a complex reservoir," Pope said. "By going downhole, we can perform the equivalent of hundreds to thousands of sample analyses in a very short amount of time. You can look at the variability vertically and horizontally in the reservoir and even over time in a way that's just not possible with laboratory sampling techniques."

"Shale is only 10 to 15 years old," Pope said. "From an oil and gas industry standpoint, it's still a very young industry. It doesn't have a lot of the technologies it requires yet. We look at the number of nonproductive fracks—30% to 50%, according to recent studies—as a symptom that the industry needs more technology to be more successful. Our goal is to make the number of nonproductive fracks smaller."

A look ahead

Research into such areas as automation, geomechanics, nanotechnology and earth modeling will continue to push the technology envelope in the oil and gas industry.

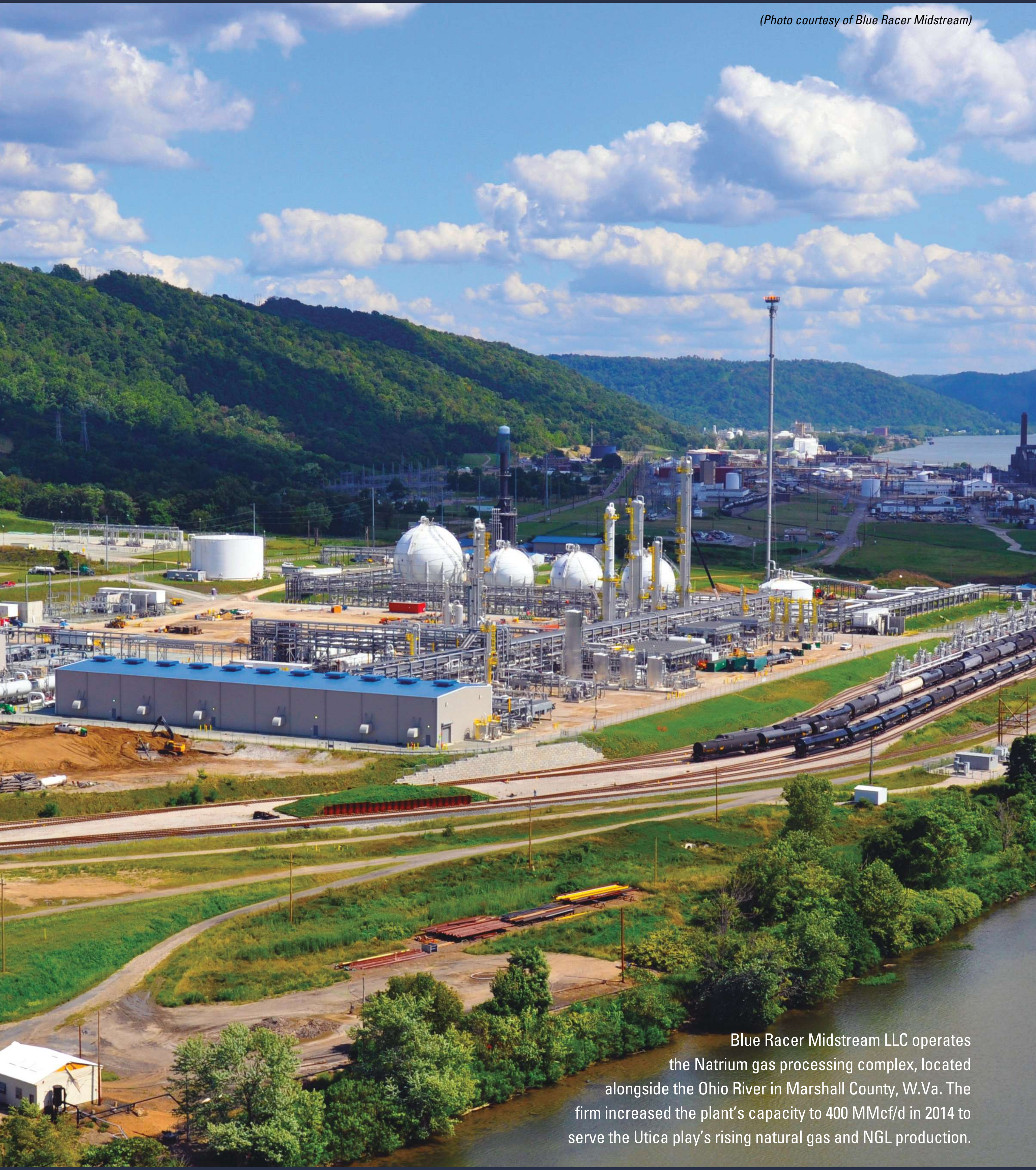
"There's an effort at Halliburton to look at things that are not on the hot burner today," said

Thomas of Halliburton. "We make an effort to consider technologies for the longer term, technologies like nanotechnology. It may not have an immediate application, but just by keeping up activities in those areas, we're looking to show how advances may be used. In the future, we'll have advances in technology that allow us to get more specific and more realistic earth models. That is where the industry should and will spend more time in the next few years."

Thomas also said the company is seeking solutions already in place in other industries. "We're also looking at adjacent industries that are not necessarily oil and gas to see how problems are addressed. At the end of the day, you can break down technology applicable to the oil and gas industry into physics, chemistry and engineering sciences. Many ways that problems are addressed in other industries allow us to consider using them for oil and gas. Sometimes a problem has already been solved in another industry."

Cadenhead of Schlumberger echoed the sentiments expressed by others in the technology field. "We're challenging our R&D to understand the mechanism at which these wells produce," he said. "Once we have that understanding, I think we'll be able to push not only how we access the wells through drilling and multilaterals but ultimately how we get the hydrocarbon out of the ground. Typically today, with most operators you spend a month building the well and getting it on production. Then there are some revisits where you change out methods of liquids or artificial lift. In the future, I think some kind of enhanced oil recovery [EOR] will come along, but I don't think the industry is ready for that. We believe that understanding how these bore spaces really produce can get to an effective EOR." ■

(Photo courtesy of Blue Racer Midstream)



Blue Racer Midstream LLC operates the Natrium gas processing complex, located alongside the Ohio River in Marshall County, W.Va. The firm increased the plant's capacity to 400 MMcf/d in 2014 to serve the Utica play's rising natural gas and NGL production.

Physical Expansion Drives Fiscal Consolidation in the Midstream

By **Gregory DL Morris**, Contributing Editor

Urges to merge among the largest midstream firms are expected to accelerate in 2015.

From booming expansions in the Northeast to exports of condensate and NGL, 2015 will be a pivotal year for the midstream sector. The last few years have closed the case on resource questions in North America, but now midstream operators and their upstream partners are coming to grips with how—logistically and financially—they are going to accomplish the oft-referenced replumbing of North America. The giddy days of declaring energy independence are over, with North America now facing the business of making it a reality.

The massive expansions require massive investment, and one significant response has been the start of an urge to merge among the largest midstream firms. The trend is expected to accelerate in 2015.

"This past winter's price spikes illustrated very clearly that we have a problem in this country. Not a supply problem, but an infrastructure problem," said Rory Miller, senior vice president for the Atlantic and Gulf of Mexico regions for Williams. "The energy infrastructure industry has a tremendous opportunity before us. This [presidential] administration understands all of the potential benefits of natural gas and what it can mean for our country's economy, environment and realizing the promise of true energy independence. However, that promise cannot be fully realized without adding the necessary pipeline infrastructure."

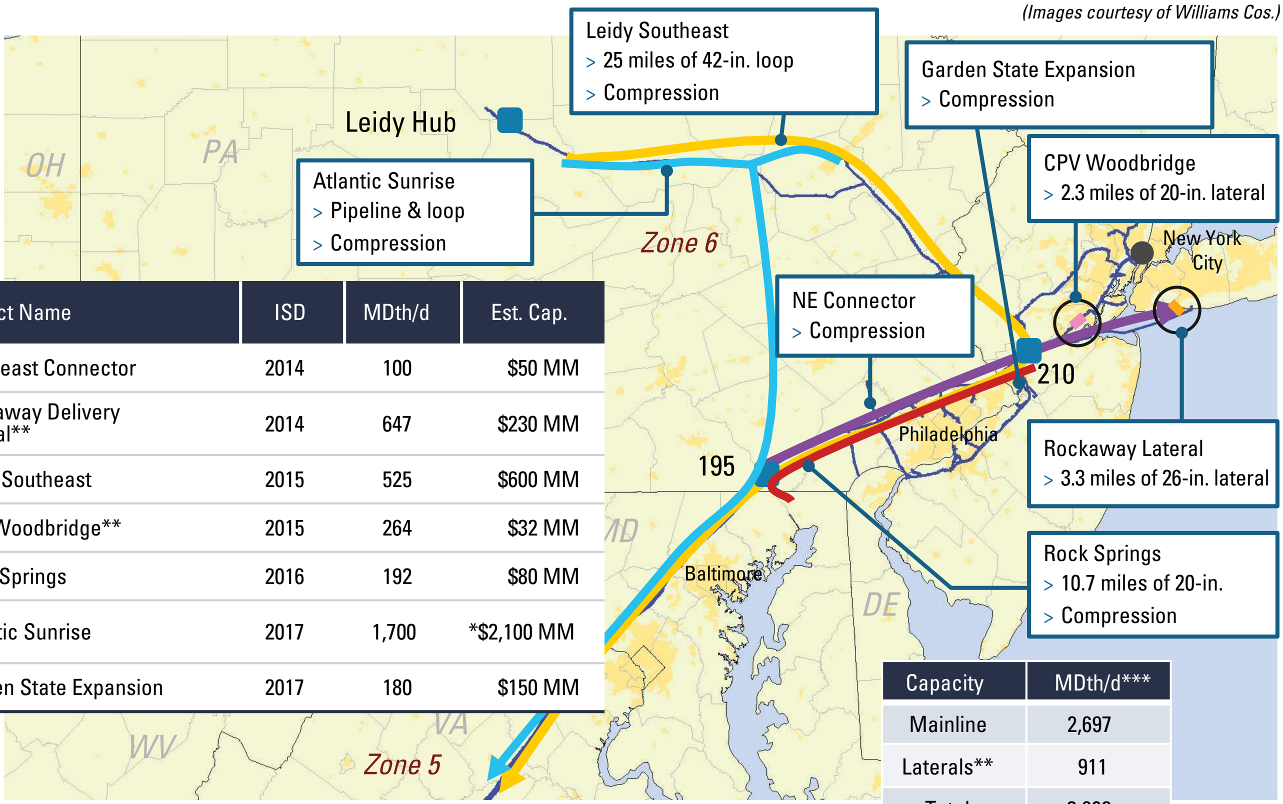
Williams announced over the course of 2014 a substantial expansion of the Transco system that will take place over the next few years, from Marcellus West to Diamond East, among several projects. While the commitment by Williams and others has been welcomed by producers, some industry observers have questioned why midstream operators held back so long.

"We can't overbuild in anticipation of future demand," Miller said. "As an entity regulated by the Federal Energy Regulatory Commission [FERC], we can only build what the market is willing to support. From our perspective, we've experienced some pretty dramatic shifts on our Transco pipeline system during just the past several years.

"We started seeing some Marcellus production coming into our system in Pennsylvania back in 2010," he added. "By summer 2011, we were receiving about 250 MMcf/d of Marcellus gas. Since then, that number has skyrocketed, and today we receive about 3.5 Bcf/d of Marcellus supply—about a 1,400%

The hilly Appalachian countryside can prove a challenge to midstream infrastructure. Williams Partners LP had to terrace adjoining hillsides to build its gas processing plant at Oak Grove, W.Va. The facility serves multiple Marcellus and Utica producers in the region.

(Images courtesy of Williams Cos.)



Project Name	ISD	MDth/d	Est. Cap.
Northeast Connector	2014	100	$50 MM
Rockaway Delivery Lateral**	2014	647	$230 MM
Leidy Southeast	2015	525	$600 MM
CPV Woodbridge**	2015	264	$32 MM
Rock Springs	2016	192	$80 MM
Atlantic Sunrise	2017	1,700	*$2,100 MM
Garden State Expansion	2017	180	$150 MM

Capacity	MDth/d***
Mainline	2,697
Laterals**	911
Total	3,608

*Represents Williams Partners expected net investment.
** The services for these projects are being provided under Rate Schedule FDLS.
*** MDth/d stands for thousand dekatherms per day.

In Transco's northern market, $3.3 billion of growth capex is anticipated through 2017.

increase in just three years. We are expecting that growth to continue. We have several projects we are working on that will increase our Marcellus takeaway capacity on Transco to about 6 Bcf by second-half 2017."

Turning the question around, Miller noted, "As an industry, we stand ready to respond to the challenge and opportunity created by the shifting supply. However, the biggest impediment is the lack of a more coordinated, synchronized and simultaneous review process by federal agencies and by the states where authority has been delegated to permit new energy infrastructure. It takes a relatively long time to navigate the regulatory hurdles required to place new pipe in the ground. The FERC process is about a three- to four-year timeline. It's critical that we modernize the federal infrastructure-permitting process, getting more timely decisions while improving driving accountability and transparency."

Never enough

Such a situation recalls the old story of two executives—one from the upstream sector, one from midstream—chatting at an industry event. "Your pipes are too small," the producer said. "We have some new projects to announce soon," the midstream executive retorted. "You just wait and see." The producer shrugged. "Whatever the new ones are, they are still too small."

That chestnut is rolled out during every boom time, but it does reflect the inherent challenge of matching fixed transportation to variable production. "This is a fluid process," Miller said. "I believe there will be more infrastructure projects that are developed in response to [the] changing market conditions we are seeing. The demand for gas is going to continue to climb, and the infrastructure connecting emerging supply with demand centers is still developing. There is probably a limited window for some of the major greenfield projects to come online, but the need for additional energy infrastructure will continue to be there as long as our customers' need for gas continues to increase. As noted earlier, the biggest challenge that is outside of our control is the permitting process, which can require long periods to certificate new projects."

Adding depth and complexity to the replumbing analogy, Teri Viswanath, director of commodity strategy for natural gas at BNP Paribas, said that the business involves far more than just expanding capacity or reversing lines. The landscape of production and consumption is also in flux.

"What we have in front of us currently is the task of trying to repave the transportation paths for both oil and gas delivery around the entire continent at the same time," she said. "How and where we produce oil and gas and how and where we consume it have changed dramatically in just a few years and remain in a state of incredible flux. As a result, we have more choices than ever, but we also have steep price differentials."

Midstream operators first responded by reversing some lines and reconfiguring others for handling different commodities. That interim measure helped, but the acceleration of production increases in most basins far outpaced the ability of gathering, processing and transportation. Viswanath noted that all across the continent, major capital projects are underway, which by 2018 or so should allow the midstream sector to catch up, especially in oil. "But we are still looking at several years of production growth in gas in regions that are constrained on transport, notably the Appalachian [region]."

With the major new links being forged, Viswanath is turning her attention to focus on the questions of "where are the bottlenecks that remain, and where are the new bottlenecks that are being created.

"Every major interstate pipe is being filled counter-seasonally in the summer," she continued. "We got into a rough patch last year getting to 85% of capacity, inching toward 90%."

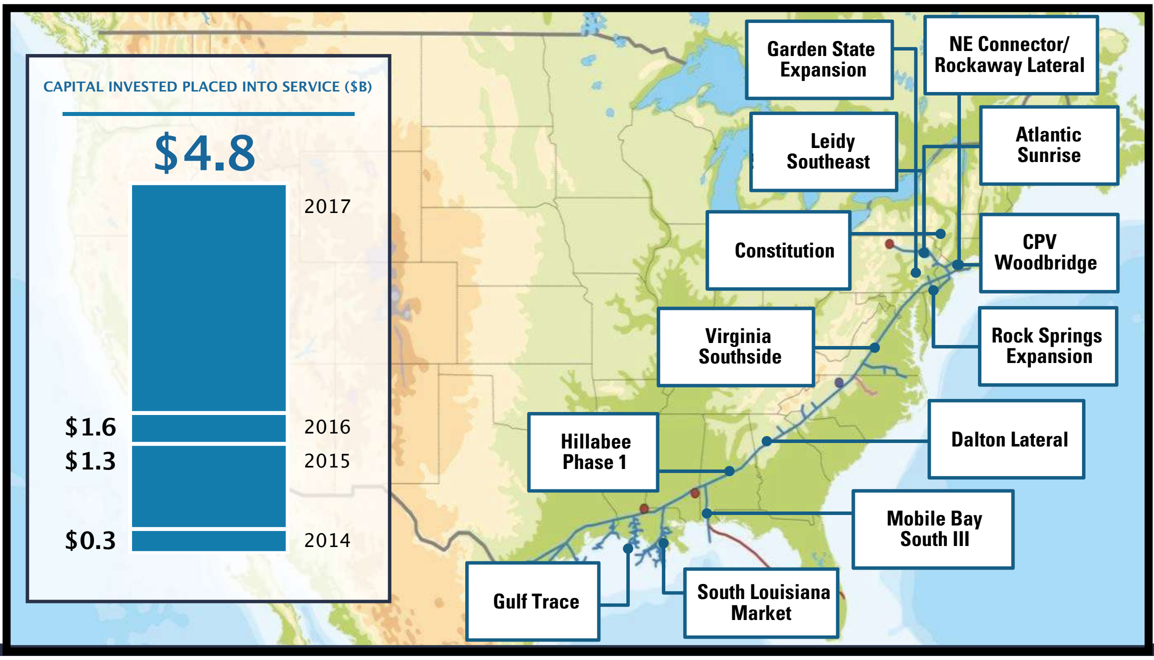
Viswanath reflected on the supposition that seasonality in gas might disappear or at least be diminished as power generators start to embrace the idea of inexpensive and plentiful gas. "Seasonality is not going away," she said. "Quite to the contrary, seasonality is on the rise in part because the U.S. is becoming the world's storage option for gas."

That might seem like an odd assertion, given that LNG imports have dwindled and exports have yet to begin in any meaningful way. 2015 will inaugurate the first of several years of U.S. natural gas LNG exports. Given the seasonality of global demand and the general lack of storage outside of North America, it appears increasingly likely that the U.S. will become the *de facto* storage option for global consumers.

What about Henry?

Another problem that is not going away is regional pricing. "The Henry Hub price simply does not reflect local markets in many situations," Viswanath said. "We still see isolated markets.

"The biggest challenge to the gas business is regional pricing," she continued. "The question is



The Transco Pipeline is the nation's largest, fastest-growing interstate pipeline system.

starting to be if Henry Hub pricing has a role in some regional markets. The Northeast is a fortress. It is tough to get gas into those big cities despite the demand."

In her analysis, Viswanath divided the country into four regions based on connectivity and price: the Gulf Coast, Northeast, Midwest and West. "The West is a huge area, but it is well connected by pipe. The Northeast is the smallest area, but it has the oldest pipe. Much of that just needs to be replaced. If you look at the historic data, this region is incapable of handling the wide swings."

Viswanath said that the energy future of North America depends on the midstream sector, not the upstream. "The dominant energy problem in the U.S. and Canada is not production; it is transportation. We know the resources are there, and we know we can get them out. The question is how to get them to market, which market and by what means. The upstream story has been exciting, but now the midstream story is much more nuanced."

As Exhibit A, Viswanath pointed to the Bakken. The prolificacy of the wells and the whole region surprised everyone. "We needed [both] oil pipelines and gas pipelines. But we did not build both. We even retrofitted gas lines for oil." Now the state government has had to implement gas-capture rules to reduce the massive scale of flaring.

Viswanath is not overtly critical of the midstream decisions made so far, both structural and financial. "We really have to get the design correct for this repaving. It is a very expensive story, and by its very nature is one that has to be funded as it goes along, even though there are so many parts yet unknown."

Broadly speaking, Greg Harper, president of gas pipeline and processing at Enbridge, said that permitting and landowner rights are expected to continue to be front and center through 2015 and beyond. On the business side he said, "Cost pressures have moderated; at least they are not as spiky as they have been in the last couple of years. So this is a good time to evaluate the basins you are interested in. The markets—production, demand and expansion—seem to be taking a breather, with the price of crude coming off sharply and the price of gas easing back a bit at the outset of fourth-quarter."

In that context, Harper said he will be watching closely how smaller producers react. "It will be interesting to see what they will do, especially with their capital expenditure." Not surprisingly, he concurs with most industry observers that a continued price decline will force producers to curtail their growth plans, while a stabilization of prices at lower levels than in the last year or two could be a bit of a wild card. Some producers of all sizes might press ahead with development for their own reasons, while others might dial back a bit if they can or choose to.

Taking a very high-level overview of the midstream, Charlotte Batson, president of Tuscaloosa Energy Services, said, "There have been several pipeline projects proposed [across North America] that have been developed with varying degrees of success because of various types of resistance." That resistance has included economic, financial, regulatory, environmental and political factors. In something of an oversimplification she deduced that the projects that are proceeding are those with the most economic mandate or the least opposition.

Most notably, Batson said, "The outlook for the Northeast is not as harsh as it was [in 2013]. It is definite that the Marcellus can provide all the gas that New York and New England need. Still, one of the most challenging markets to reach is the Northeast. We are even seeing some redirection of Marcellus gas south." That gas could be sent south and east as fuel for power generation or south and west as feedstock for downstream industrial development.

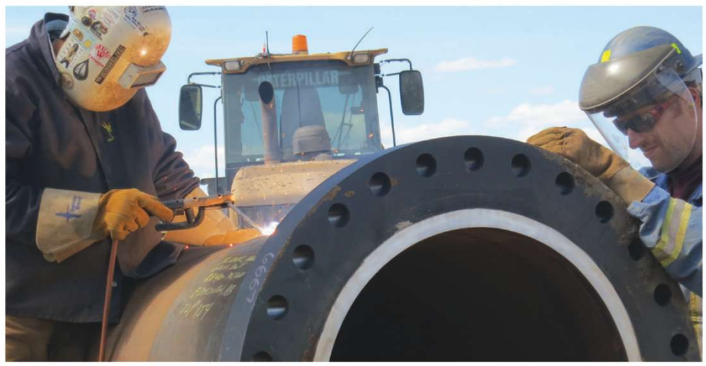
Returning to the bigger picture, Batson added, "Nationally there is a tremendous abundance of gas, and that is having a tremendous effect on our own industry as well as the wider U.S. industrial economy. The good news is that the story of shale development is finally getting out."

Consolidation

The Kinder Morgan consolidation and the big deal between Williams and Access Midstream could be seen as starting the dance music, and now it is time for all the players in the midstream sector to find a partner. But Jason Bennett, partner at the law firm of Baker Botts, suggested that those deals are the result of business conditions in the midstream





and in the wider economy. As a result, there will be more consolidation in addition to, rather than just because of, the two big consolidations.

Bennett knows much about the subject. Baker Botts participated in two of the biggest transactions in midstream history, with both announced in late October 2014. The firm advised Shell Oil on its formation and IPO of an MLP, Shell Midstream Partners, which was expected to raise more than $1 billion. The firm also represented Williams in the $50 billion acquisition of Access Midstream. Technically, that was a combination of Williams' operating MLP with Access and another MLP, and it created a large-cap MLP with expected 2015 adjusted EBITDA of about $5 billion.

While Bennett could not speak about the details of any one transaction, he sees a clear trend across the sector. "We are seeing so much new investment that there will definitely be more consolidation. There are lots of projects proposed, some of which get built. It is the economic environment that creates the incentives more than one or another deal ringing an opening bell."

The growing size of deals, both in number and value, also is bringing private and public equity into greater collaboration. "There will be more transactions with public and private elements," Bennett said. "It represents a shift among investors. There is so much capital in PE [private equity] now with a strong interest in energy. There are plenty of firms that specialize in oil and gas or at least have some history, and I expect more of that." He cautioned, though, that energy investment cannot be hot money. "[Moving] from initial assessment to full deal to development takes a long time."

Bill Kroger, another partner at Baker Botts, added, "Transportation is clearly an essential topic in the energy sector overall. Just taking the Eagle Ford, for example, the evolution from truck to pipeline has been a huge advantage and benefit to producers. In the Bakken there is still a huge challenge. Across the country there has been so much development in areas without infrastructure, or with insufficient infrastructure. In the Marcellus the challenge has been how to get into the New York market."

Bennett expects to see many more midstream deals through 2015, as compared to the previous year. "We are doing a lot of work in LNG right now, and I expect to see a lot of that in particular. We are also starting to see more dispute work. That is predictable. About 12 to 18 months after the start of any construction boom, there is a dispute boom."

That is a lagging indicator, but one area where legal work is a leading indicator is international. Indeed, Bennett is seeing an increase in activity regarding Mexico. "That is already a growth area for us. I think we are going to see a lot of deals in Mexico this year."

Disregarding volatility

That outlook does not conflict with midstream and upstream operators that say they are circumspect about Mexico. Quite to the contrary, it supports their views. "In situations like this legal work is often the tip of the spear," Bennett said. "We are involved in due diligence and regulatory research a year or two before any steel goes into the ground."

Whether the transactions are domestic or international, Bennett lauds investors and operators for their equanimity. "There has been a great deal of talk this autumn about the falling price of oil, but the industry does a great job of disregarding short-term volatility. That said, if the price of oil remains significantly lower in 2015 than it was in 2014, that will affect the investment environment. We will just have to see where the prices of both oil and gas are at this time next year."

There is definitely a trend to consolidate in the midstream sector, said Mark Druskoff, who follows the natural resources sector for the Mergermarket Group. "The deals that have been done are generating some pressure that will accelerate the trend."

Offering a finer point on the matter, Druskoff added, "We are seeing a bifurcation in the midstream MLP segment. As a result of its consolidation, Kinder Morgan, along with Enterprise and Energy Transfer, forms a new class of midstream supermajor. There has never been such a presence in that segment before as there has been upstream. The supermajors have very low costs of capital and high-operating budgets."

In the new league tables, Druskoff explained that MLPs below $10 billion in market capitalization will be considered small. "Those will be considered the consolidation targets, not necessarily because they are poorly run or in weak positions, but because they may just be too small now. Others may lack organic growth prospects or a partner that can drop assets into the MLP."

The other factor providing fuel to the consolidation is the steady stream of IPOs. "The IPOs of today can become the consolidation possibilities in two or three years," Druskoff said. He also noted that the Kinder Morgan consolidation "brought back the C-corp into the midstream. That is very interesting, because they were the ones who created the modern midstream MLP. Now they have changed their structure. It will be very interesting to see what follows."

As 2014 wound down, the trends were clear. In its quarterly analysis of merger and acquisition (M&A) activity, PricewaterhouseCoopers (PwC) reported that midstream deals drove the market to new highs. "M&A in the oil and gas industry reached the highest levels in the past decade during the third quarter of 2014. Midstream activity, along with continued interest from foreign buyers, specifically in upstream shale plays, and the overall impact of megadeals [deals with a value of more than $1 billion] contributed to record-breaking deal activity in the third quarter of the year."

Extraordinary activity

There were 15 midstream deals including three valued at more than $8 billion each that contributed $74.1 billion in value, representing a 50% growth in deal volume and a 517% growth in deal value compared to second-quarter 2014. Upstream deals accounted for 54% of total deal activity in third-quarter 2014 with 42 transactions representing $29.4 billion. The total number of downstream deals remained the same at nine, while total deal value decreased 10% to $8.4 billion, compared to $9.3 billion in second-quarter 2014. The number of oilfield service deals increased to 12 deals or 100%, with total value rising 313% to $11.1 billion compared to second-quarter 2014.

"This was a breakout quarter for deal activity," said Doug Meier, PwC's U.S. energy sector deals leader. "Third-quarter deal value reached a 10-year high due to a number of drivers coming together to bolster M&A flow, including the significant impact of $1 billion-plus deals, foreign and private-equity interest, and the attractiveness of shale plays.

"This extraordinary deal activity occurred while commodity prices declined sharply during the quarter—a trend that accelerated in the first half of October," he added. "If we continue to see a sustained lower crude pricing environment, we will likely witness an acceleration of the portfolio restructuring efforts we've been seeing in the past couple of quarters as companies focus on the importance of financial discipline."

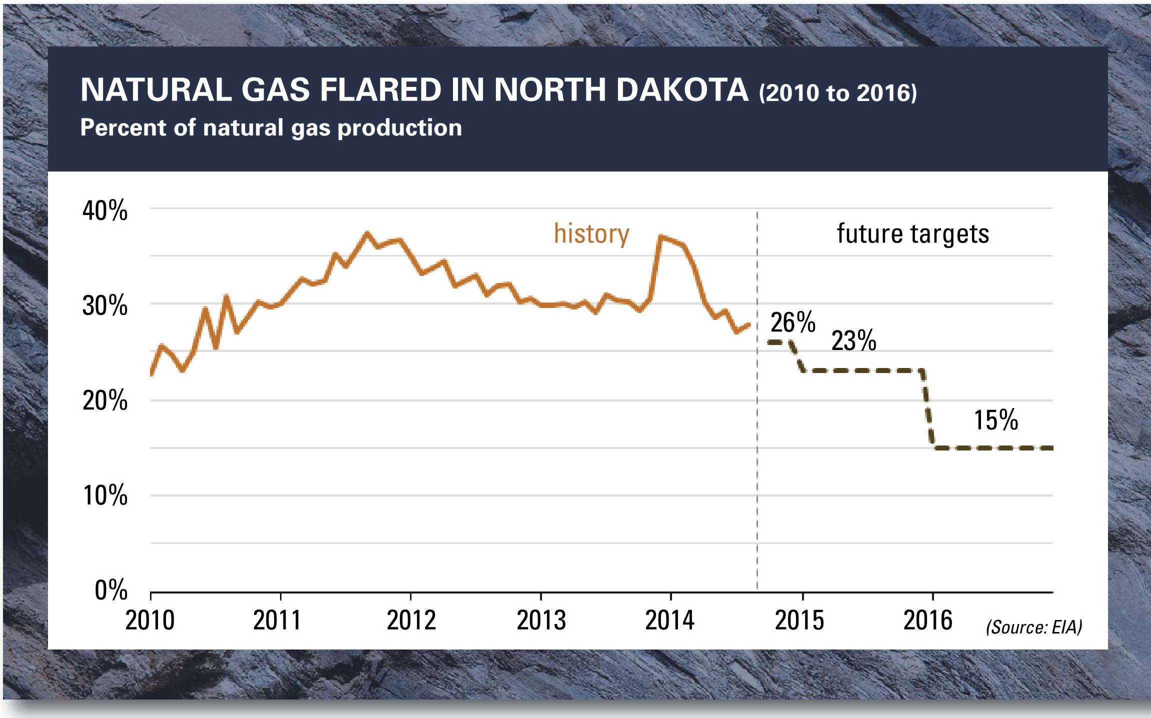
Corporate transactions led total deal value during the quarter, representing $99.1 billion, or 81%, of total deal value for third-quarter 2014. The 20 corporate transactions in the quarter represented the highest quarterly level since fourth-quarter 2012. Asset transaction volume during third-quarter 2014 totaled 58 deals, accounting for 74% of total deal volume, while total deal value reached $24 billion, or 20% of total deal value, for third-quarter 2014.

The most active shale plays for M&A with values greater than $50 million during third-quarter 2014 included the Eagle Ford, which had seven deals with a total value of $1.8 billion, followed by the Bakken with six deals representing $8.6 billion. The Permian had five deals worth $7.8 billion, the Marcellus had four deals valued at $1.1 billion, and the Niobrara had three deals worth $2.4 billion. The Utica generated two deals, while the Haynesville and Fayetteville each generated one deal.

During third-quarter 2014, MLPs were involved in 14 transactions, representing about 18% of total deal activity in the quarter, which is consistent with historical levels.

Financial investors continued to show interest in the oil and gas industry with six total transactions, accounting for $4 billion during third-quarter 2014, which was consistent with the number of deals but showed a slight drop in total deal value compared to the same time period in 2013.

"While financial investor M&A activity remains modest compared to corporate transactions, they remain very active backing management teams with equity lines of credit in E&P and midstream," said Rob McCeney, U.S. energy and infrastructure deals partner for PwC. "Once these management teams



execute greenfield or brownfield transactions, their businesses become fully operational, and they can execute on deals, which contributes to the ongoing corporate deal activity."

Stranded gas

About one-third of the natural gas North Dakota has produced in recent years has been flared, rather than sold to customers or consumed on site, according to an October 2014 report from the U.S. Energy Information Administration (EIA). The rapid growth in North Dakota oil production, which rose from more than 230,000 bbl/d in January 2010 to more than 1.1 MMbbl/d in August 2014, has led to increased volumes of associated gas.

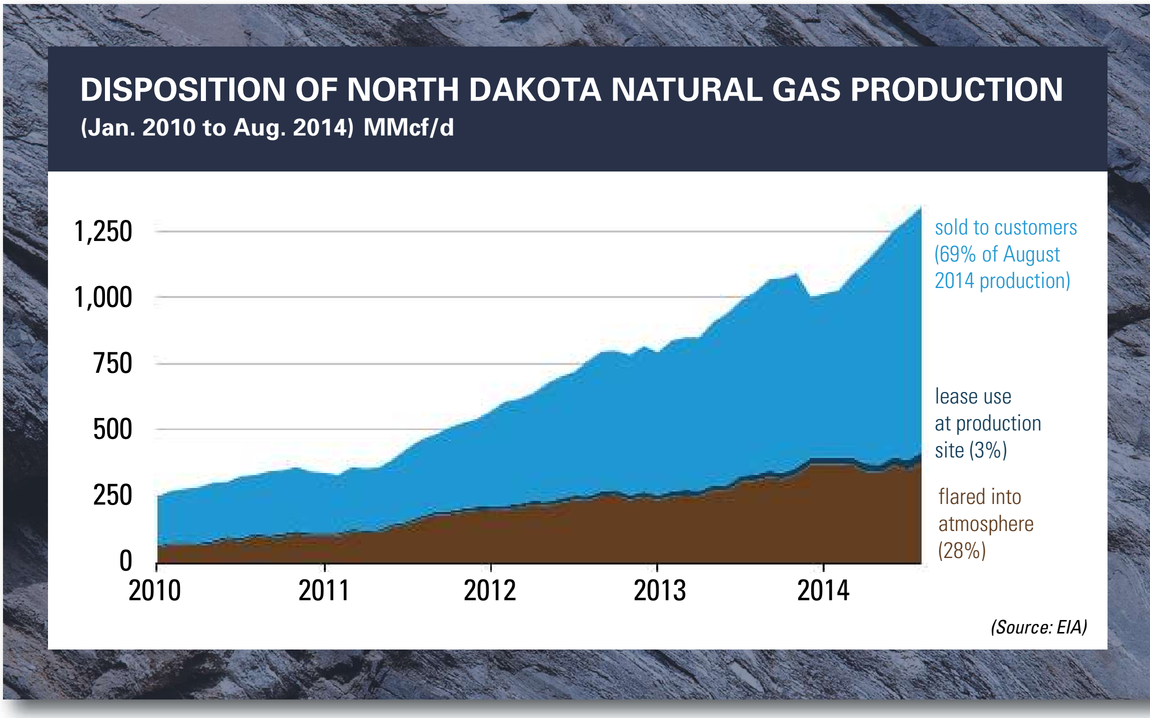
"Those increased volumes require additional infrastructure to gather, process and transport gas volumes instead of flaring them," the EIA said. "Those additions can take time to build, and well operators are often reluctant to delay production."

In an effort to reduce the amount of natural gas flared, North Dakota's Industrial Commission (NDIC) established a gas capture rule that decreases the amount of flared gas over the next several years.

The first target of 26% flared was set for fourth-quarter 2014, with continued decreases in flaring reaching 10% by 2020. North Dakota recently reported that it was close to achieving the 26% reduction target for natural gas flaring, as the percentage in August was 28% flared, or 375 MMcf/d, out of a total production of 1.34 Bcf/d. The rest of the produced natural gas was either sold or used at the production site. Natural gas is flared rather than being vented without combustion because North Dakota prohibits natural gas venting.

Notably, the NDIC seeks to reduce the volume of flared gas, even if it means cutting back production at its largest oil production areas, the Bakken and Three Forks. The NDIC's order issued on July 1, 2014, said it will "consider amending... field rules to restrict oil production and/or impose such provisions as deemed appropriate to reduce the amount of flared gas." Recognizing the difficult economics of dealing with rapidly declining production from newly drilled wells, the NDIC's order allows for exemptions on a case-by-case basis.

The EIA further detailed that the North Dakota Pipeline Authority estimates that more than one-third of the flared gas results from a lack of gathering pipelines. Infrastructure buildouts can cause delays in realizing the value of crude oil and other liquids that motivate drilling in North Dakota and



are uneconomic when natural gas volumes there are too low.

The largest challenge, according to the NDIC, is securing landowner permission for connection activities, which can delay projects by half a year or longer. Other obstacles include zoning and permitting delays, harsh weather and labor shortages. The remaining flared gas results from challenges to existing infrastructure, including the need for additional gathering-line pressure to offset higher pressure from newly drilled wells, additional gathering-pipeline capacity at high-pressure wells and additional clearing of existing lines to remove NGL volumes.

Increased capacity to process and transport gas also contributes to higher volumes of gas that are sold, rather than flared. By year-end 2014, expected completions of natural gas-processing plant projects would increase North Dakota's natural gas-processing capacity to 1.5 Bcf/d, or 440 MMcf/d more than 2013.

ONEOK plans to add another 400 MMcf/d of gas-processing capacity by year-end 2016. Capacity to move this additional gas on pipelines also would increase as a result of the Northern Border 55-mile Bakken Header pipeline as early as 2016 and WBI Energy's 375-mile Dakota Pipeline that is expected to add between 400 MMcf/d and 500 MMcf/d of capacity by year-end 2017.

Taking up the challenge

To understand the new phase-down rules for gas flaring in North Dakota, it is essential to go back to autumn 2012 when Governor Jack Dalrymple requested a broad task force to meet and address the issue of huge volumes of gas being flared in the Bakken. "Both the upstream industry and the midstream took up the challenge," said Alison Ritter, public information officer with the oil and gas division of the North Dakota Department of Natural Resources.

"From September 2012 to January 2014 the task force met 40 times," Ritter said. "They made recommendations from the industry to the industry on how to reduce flaring. The final order for the plan was signed on July 1 of [2014]." Ritter also noted that in addition to the step-down mandates for flaring, another rule was implemented on June 1, 2014, that requires gas-capture plans to be filed with any request for permits or temporary or approved spacing. Those capture plans must include how much gas the well can be expected to produce and where and how the producer expects to get the gas to the midstream.

It is unusual that producers, regulators, residents and environmentalists agree on much, but no one was happy about the rate of flaring in the Bakken. According to Ritter, the highest rate of flaring peaked at 36% of gas brought to the surface—an unsettling ratio. "How did we get to the point where these rules were necessary?" Ritter said. "It really stems from understanding the size of the resource. It also has to do with the legislative process."

She relates a midstream bugbear that was equally onerous to producers and midstream operators. "There were what were called 'bully wells' that would come onstream at enormous rates and knock other wells offline. There just is not another resource that is anything like the Bakken in its size and scope. We talk about unconventional rules for unconventional plays."

The Bakken play runs to 18,000 sq miles, "which is equivalent to a small state," Ritter said. "We had a perfect storm of development, demand and need for infrastructure. The gas-capture plans are now in place, and to be honest they really could not have been done at any earlier stage. We could not have withheld permits under the law. But now that most of the acreage is held by production, we have more flexibility."

One other important challenge to gas capture was simply the limited construction season, Ritter explained. "It was not so much right-of-way, although that has been a factor. And in right-of-way discussions, private landowners have not been the only parties. There have been some, but there have also been federal and tribal lands. But even more than that, the limited construction season has been a challenge to gas capture."

Despite that reality on the ground, Ritter added, "The midstream companies have responded very well. There have been a lot of headaches over the gas-capture plans. The rules need to be understood, but what also needs to be understood is that the rules were made with extensive industry input."

'We will be up there in a year'

Enbridge is the largest oil mover in the Bakken and has a great interest in North Dakota's new efforts to control flaring. "We are not yet there on the natural gas side, but we will be soon," Enbridge's Harper said. "It is my objective to be up there within a year."

In looking back on the development of transportation out of the Bakken, Harper has a personal opinion on how the basin got to the state where regulators had to step in. He is quick to stress that his observations are his own and not company policy. "Given the job creation and economic growth that have come from the crude development in the Bakken, it may have been the calculation by the state that clamping down on flaring earlier could have put a pinch on the broader economic development."

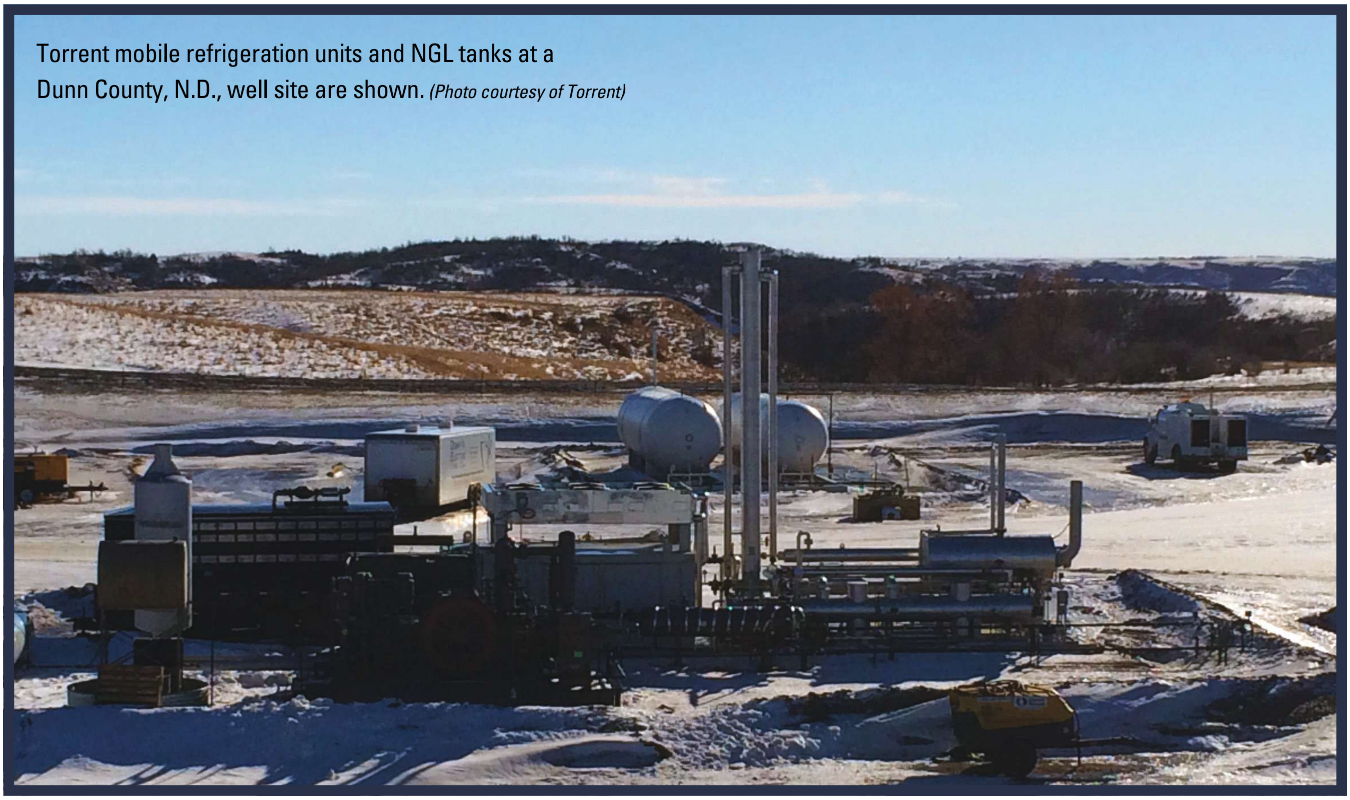
What is official company Enbridge policy is that the firm is in favor of exports of LNG from both the U.S. and Canada. "We are very excited about moving Canadian oil and gas to the U.S. and about the potential for LNG exports from the west coast of Canada," Harper said. "We can see that the booming oil sands, crude oil, gas and liquids are real and significant natural resources in Canada as well as in the U.S. If you look at the Montney and the Duvernay, they are very significant resources, especially for NGL. The challenge is getting those to more markets."

The same is true next door in Alaska. "We are waiting to see what Alaska does for itself," Harper said, noting that the recent elections might be seen as a referendum on how Alaskans want to see their hydrocarbon resources developed.

One knock-on effect of Alaska developments upstream and midstream is how the downstream market will evolve in California. At present, the Golden State is something of an isolated market, with crude demand met from considerable production within the state, plus waterborne imports from Alaska and the west coast of South America. At present that balance is sufficiently viable such that there is no compelling draw for crude from the Permian or Rockies beyond a bit that is brought in by rail.

At the other end of North America, Harper is intrigued by the energy-sector reforms in Mexico but expects that it will take several more years before the actual effects will be known. "The Mexican government has got to get the regulations to comport with the new legislation," he said. "I like the opportunities with delivering gas to electric generation, but we would proceed with caution in Mexico as we would with any international venture."

He added, "The question in a growth market like this is [one of] the electron as compared to the



Torrent mobile refrigeration units and NGL tanks at a Dunn County, N.D., well site are shown. *(Photo courtesy of Torrent)*

hydrocarbon molecule," not as in a competition but as in an assessment of what to move where and how in the most economical manner. "There are real opportunities for the midstream in Mexico, but the proof of the pudding is in the tasting, and that means final regulation. There is no indication at this point if that will be done state by state or nationally."

Well by well, pad by pad and field by field, the associated and flash-off gas from the Bakken has accumulated to a vast volume. "The latest figures were something like 300 million cubic feet a day," Tuscaloosa Energy Service's Batson said. "That is an awful lot to flare. The State of North Dakota has made its goals of reducing flaring very clear, but some in the industry say that the rules are going to constrict oil and liquids production. If that is the case, then the gas-containment rules would backfire because liquids are king. The state may have underestimated how fast liquids could be affected by rules to limit flaring and mandate gas containment."

Target-rich areas

As producers, midstream operators and regulators grapple with ways to reduce flaring in the Bakken and other unconventional plays over the long term, interim measures are having their turn in the spotlight. "For us right now, North Dakota is a target-rich area with lots of opportunities," said Lance Perryman, CEO of Torrent Energy Services. "There is a lack of infrastructure for gas capture and gathering, and now there is a regulatory requirement on top of that."

Torrent is one of several firms providing wellhead gas-processing, treating and compression equipment and services. Most components are skid-mounted and leased either as standalone equipment or including operations and maintenance. "In the industry we know that when oil is produced, there is associated gas," Perryman said. "And in 2010 when my business partners and I were coming up with this concept, we knew that the infrastructure was lacking in the Bakken."

The same principle applies in other shale basins. "The associated gas market is very underserved in the early discovery and delineation phase," he added. "Prior to infrastructure being put in place—and often that is very much behind—there are limited ways to address the gas questions. The drillbit always outruns the pipe."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That sprint grew into a huge problem in the Bakken. "As producers have discovered, landowners are not happy to see all that valuable secondary resource go to waste," Perryman said. "At night you can look across the topography or even just look at the satellite images. There are lots of flares."

Beyond the waste of resource, the heat, light, noise and air pollution have exacerbated the situation. "Now, with the state's gas-capture rules, regulation is forcing the issue, and that may speed the process of laying pipe," Perryman said. "But even when pipe is laid, it has limitations in capacity and location."

Bringing market pressures to bear, at least one Native Nation has announced it will begin to gather royalties on all gas produced. That puts increased cost pressure on the industry to monetize the molecules that have been declared "uneconomical" to gather until now.

But associated gas is not the only issue. "With Bakken crude, even after the heater/treater where the associated gas is broken out of the crude emulsion, the crude that goes to the tank battery still has solution gas entrained in it. That is going to work itself out," Perryman explained. While the prevalent way to address that problem is to vent to flare, "solution gas can be captured, processed and stripped. In time, producers are likely to be required to capture all fugitive vapors."

Even as gas capture is driven by both market and regulatory forces, Perryman is confident that enough wells will remain beyond the reach of hard pipe. And beyond the Bakken, his firm is primarily active in the Permian and Eagle Ford in addition to the San Joaquin Valley of California, the Piceance and the Utica. Beyond conventional processing and treating, Perryman said he is watching other technologies for gas capture in the field, including CNG and LNG, as well as gas-to-liquids processes.

Upstream on the river

David Scobel, COO of Caliber Midstream, sees opportunity for infrastructure improvements in all U.S. shale plays. However, in the Bakken and Three Forks formations of North Dakota, Scobel sees a particularly large opportunity for midstream innovation, especially as the downspacing trend continues and gas-capture rules become increasingly strict. "In the Bakken, it seemed like we got to flaring half the basin, but progress is being made."

Caliber is a joint venture (JV) supported by an initial total of $180 million in equity capital contributions from First Reserve Energy Infrastructure Fund and Triangle Petroleum. Caliber subsequently put in place a $200 million credit facility. The Denver-based company operates primarily in McKenzie County and is involved in crude processing and transportation, gas processing, freshwater delivery and produced-water disposal.

The company was formed in 2012 from Scobel's expectation that the shift from HBP drilling to production models and batch completions in the Bakken would create an increased need for new pipeline and efficient midstream infrastructure, including crude oil vapor capture and live-crude stabilization.

"There are opportunities not just for new connections and new business but also for increased safety, economics and environmental protection," Scobel said. "Our objective in each play is to get trucks off the road. Our target in each case is zero trucks in and zero trucks out." He explained that decreasing truck traffic increases safety by eliminating logistical complications on well pads during simultaneous operations. It also reduces emissions as well as dangerous traffic congestion and costly damage on local roads.

The low-hanging fruit for Caliber are freshwater delivery and produced-water disposal. "There is sufficient density now in the Bakken to deliver water to a frack job by hard pipe," CEO Poe Reed said. "The pace and the intensity of drilling and completions make hard pipe a sensible approach now."

Caliber has been developing its own freshwater supply system, drawing 1 MMbbl/year of low-turbidity water from the Yellowstone River. The intake facility was due to be completed by the end of November 2014. The company noted that the supply is not subject to curtailment by any municipality.

Caliber also is taking flowback water and produced water using transfer skids and filtration on site. "In contrast to the companies that provide gathering services, we actually take custody of the produced water," Scobel said. "It goes down our own disposal wells."

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Technology does exist for recycling produced water from the Bakken, but Scobel said that at present it is not economical. "The water coming up from Bakken wells is extremely high in total dissolved solids and chlorides on the order of 300,000 to 600,000 parts per million [ppm]. By comparison, seawater is 30,000 ppm. To clean that is very expensive. The technology for doing that is not quite ready for prime time."

Dissociating gas

On the hydrocarbon side, Bakken producers typically use atmospheric tanks to store crude on location prior to transporting it to processing facilities, pipeline interconnects or rail terminals by truck. For all its revered lightness and sweetness, however, Bakken crude is almost effervescent. This causes the crude oil to "shrink" while it is in atmospheric tank batteries awaiting truck transport. The oil naturally releases high-Btu gases, and Bakken operators are typically forced to flare these vapors through ground flares on each well pad.

Caliber's approach is to obviate atmospheric tanks altogether by stabilizing high vapor-pressure crude at a centralized oil storage facility, where high-Btu gases and NGL are captured. "Our gathering systems use a separator at the wellhead so that nothing flashes off at the drillsite," Scobel explained. "The flashing takes place at our central location, which allows all the components to be monetized. The high vapor-pressure gathering system is unique to Caliber. There has been a lot of attention focused on reducing the flaring of associated gas, but there is also a lot of flaring at tank batteries from flash-off. That is significant value going up in flames."

The flaring of gas at well pads is also a considerable regulatory matter. "If you have a well pad with an initial production rate of 8,000 barrels a day, using calculations provided by the North Dakota Industrial Commission you come under federal Prevention of Significant Deterioration rules as would a power plant or other major emitter," Scobel said. He added that there are areas in other basins where producers are not allowed to flare tank gases, so it would appear that the market for Caliber's technology stretches well beyond North Dakota.

Measurement and allocation are considerable challenges when engineering such a gathering and processing system. "The challenge in the high-VP [vapor-pressure] system is not really the technology," Scobel explained. "It is also the accounting: how to credit each vapor molecule back to the respective crude to credit the appropriate producer."

On top of federal considerations come the new state gas-capture rules by the NDIC. The regulations set phase-down levels for flaring and can limit permitting and production if plans are not filed for dealing with associated gas. "Producers need to make sure they are protecting their oil interests," Scobel said.

Those are vast indeed in the Bakken. "Since 2006, the midstream industry has put 10,000 miles of pipe in place at an investment of $6 billion," he continued. "That was just as the play was being understood. Now we are seeing downspacing and new producing horizons. This play is still very much in flux. Just two years ago, who would have thought that drilling times would get down to 12 days. And just the other day we heard about a 16-well pad.

"Even if producers had predicted the kinds of rates we are now seeing, the midstream sector would not have built out to that because the risk would have been too great," Scobel added. Even forewarned, prudence would have dictated an incremental approach to gathering and transmission.

Northeast

"When pipelines are built on the basis of differentials, those differentials are guaranteed to go away," said Jack Lafield, CEO of Caiman Energy II LLC and Blue Racer Midstream LLC, Caiman II's JV with Dominion to develop midstream infrastructure in the Utica Shale. "One pipeline may look better than another at any given point in time, but that changes. That is why it is very important for us to create operational flexibility. We want to be able to move hydrocarbons around our system."

Blue Racer has the only fractionator in the region with a barge-loading facility at Natrium Natural Gas Processing Plant on the Ohio River in Marshall County, W.Va., Caiman Energy developed a very large midstream footprint in the Marcellus, selling those assets to Williams Partners in April 2012 for about $2.5 billion.

The markets in the Northeast continue to evolve, said Enbridge's Harper. "The last mile is always very

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*– **Jack Lafield**, Caiman Energy II LLC and Blue Racer Midstream LLC*

difficult. There has been major capacity [that has] come onstream in the last two years, but what is missing is the power-generation load to step up and demand more, specifically in the Northeast. The issue, I think, is the electric market structure. There are lots of studies and FERC hearings have been held regarding the gas and electric day, but the electric markets really need to step up and engage relative to capacity commitment. I was chairman of INGAA [Interstate Natural Gas Association of America] three years ago, and we were talking about these issues then."

The original East Ohio pipeline that Dominion contributed to Blue Racer crisscrosses the Utica play, giving Blue Racer numerous options for making connections. Midstream companies like to emphasize their flexibility, but Lafield made the point that multiple connections serve producers and markets, not just midstream operators.

Blue Racer's first processing train at Berne complex in Monroe County, Ohio, was completed early in October 2014 and was put into service in November 2014 with the completion of pipeline connections to the Natrium complex and utility service to the plant. "We have firm commitments to Berne, and we are confident that we will be full very soon," Lafield said. He expects that nameplate capacity of 200 MMcf/d will be exceeded by 10% or even more.

The second 200 MMcf/d processing facility at Berne will be ready early in 2015, but the complex is not expected to reach full capacity until April when the expansion of fractionation capacity at Natrium is completed, taking that unit from 46,000 bbl/d to 125,000 bbl/d. "Once that is completed we will be able to process the output from six cryogenic processing plants through that fractionator." Of those six, a second train at Berne will be the fourth, after the two at Natrium and the first Berne plant.

Then, in third-quarter 2015, Blue Racer's Lewis plant in the middle of the Utica play will come into the mix. There is space for a total of three gas plants at Lewis and three at Berne, each with the capacity to process 200 MMcf/d.

Extracting value

Blue Racer's ethane pipeline provides direct access to Enterprise's ATEX Pipeline. Additional market access out of Natrium provides connectivity to Dominion Transmission, Dominion East Ohio, Sunoco's Mariner East and Mariner West pipelines, Enterprise's TEPPCO Pipeline, the Rockies Express Pipeline, Texas Eastern Transmission and other long-haul NGL pipelines in development including the Rover Pipeline Project, the Rockies Express and Texas Eastern.

"We will also look at the possibility of a fractionator at Lewis," Lafield said. "All of these plants are interconnected, which is in line with our strategy. We expect to have a total of 1.5 billion cubic feet a day of processing capacity, and we want to have as much flexibility in the system as possible from gathering to processing to market access. And this is all based on dedicated production, not speculation."

That situation, with midstream development in sync with production, is not unique to the Utica, but it is certainly not uniform across all unconventional basins. "All the shale plays are different," Lafield said. "The Eagle Ford has an established midstream history from big conventional production. In other areas like the Marcellus, there is a long history of production but on a much smaller scale." That means that the existing midstream infrastructure is only of nominal benefit to the shale bonanza.

Lafield also noted that the Eagle Ford has multiple competing midstream operators and large plants. "In contrast, when we got to the Marcellus in 2009, MarkWest was just starting to process for Range, but there was nothing else. The basin was not even delineated as to where the Btu line was. It is very difficult for midstream operators to develop and execute a master plan without that essential knowledge."

Trunk lines, he added, "are the toughest to build greenfield because of placement, size and right of way. It is tough to justify the capital and effort without knowing drilling success."

In the Bakken, there was simply no infrastructure. "We looked at the Dakotas years ago," Lafield said. "At that time, there were a lot of very small gas wells. The economics just were not there. Our planning tends to be very strategic. That means taking more risk, but the advantage is that we can be a step ahead by integrating systems whenever possible. That is Blue Racer's strategy in the Utica."

The beast of the East

Ethane is still a challenge in the Northeast. "There is not a local market, so it has to be transported by pipeline; other NGL can be moved by truck or rail, but ethane cannot," Lafield said. "ATEX and the Mariner East 1 and 2 are very important, and I hope by the end of 2016 we'll see some relief."

Shell and Braskem have proposed projects for olefins and polymer complexes, but those would take four years from groundbreaking. No formal investment decision has been made, although Shell does have land. Sarnia, Ontario, is already taking some ethane via the Mariner West line, but there is not expected to be much growth in that area.

Having noted several current projects that address the most immediate needs, Lafield looks to a strategic solution. "The Marcellus and Utica could easily grow to provide half the gas supply for the entire nation. There is a tremendous potential for the Philadelphia area in all this. We could have the next Mont Belvieu, [Texas], right there. They have the capability and the opportunity to rebuild the area's industrial infrastructure."

In contrast to ethane, propane is in high demand throughout the Northeast. However, challenges include connection and storage. "The Marcellus provided 14% of the propane nationwide last year," Lafield said. "The pipeline map looks like a starburst. The situation is similar to gas, and the key issue in the Northeast is lack of storage. There are no caverns, and surface storage is very expensive."

Broadly speaking, Lafield noted that "there are already 1 million barrels of NGL trying to get out of the Northeast, and we are seeing that crude oil is already challenging the rail system." Water transport is one of the most promising new options, from ethane exports to Europe to Blue Racer's barge terminal at Natrium that was due in service at the first of the year. The Williams complex at Moundsville, W.Va., is on the Ohio River but at present does not have a barge facility.

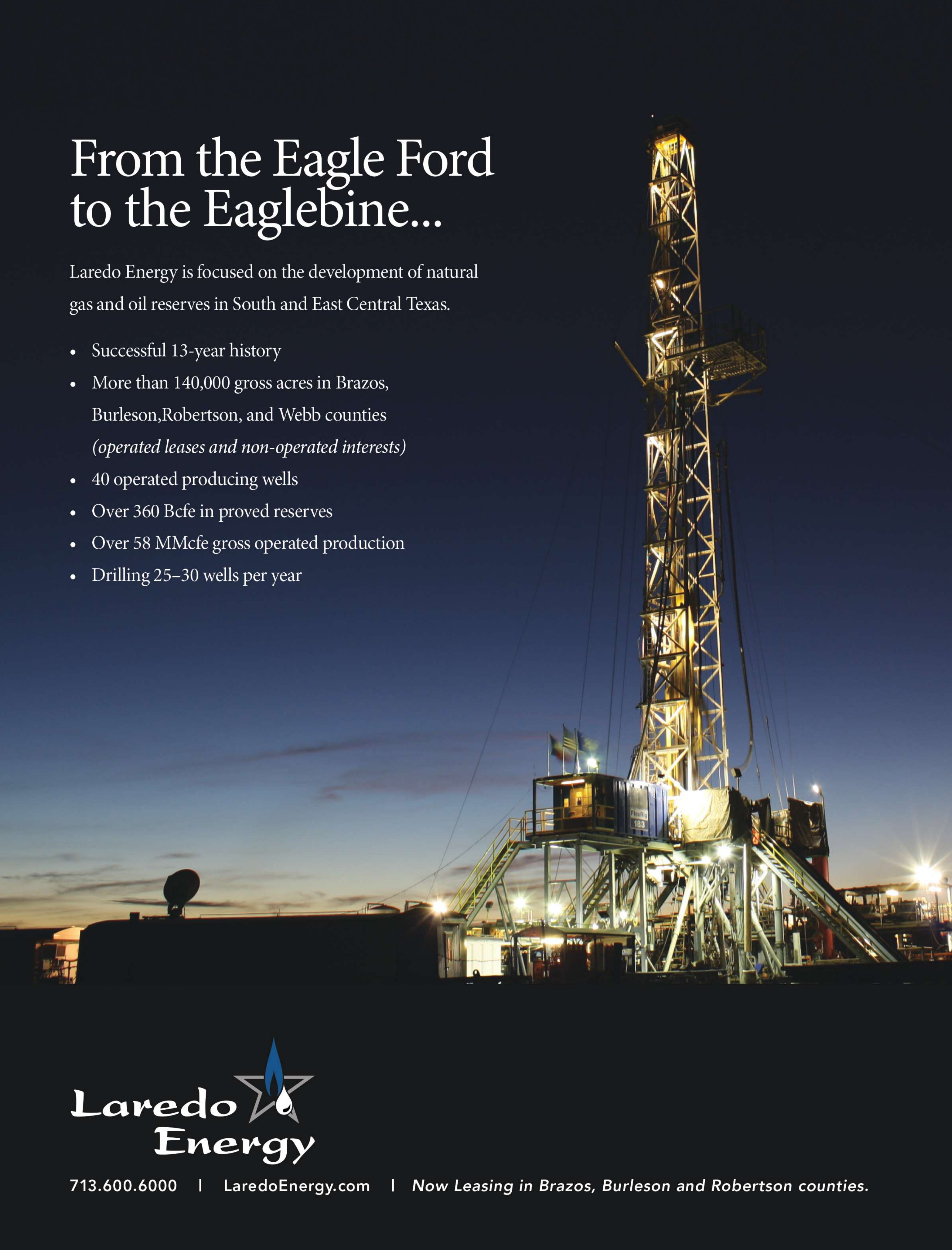
Pipe remains the preferred mode for NGL transport, and Lafield noted that purity systems prevail. "If you look around the country, the Y-grade options have failed. You hear some whispers of things here and there, but the economics just don't seem to favor Y-grade. For the most part, projects have had to come up with local fractionation and purity transport."

In all, Lafield believes that NGL solutions have moved to the forefront. "It is as good here in the Northeast as it is anywhere, but we could see some slowing if a near-term market cannot be found for liquids."

The sea's the limit

The tantalizing prospect for liquids is export potential. In 2014 one producer, Pioneer Natural Resources, and one midstream major, Enterprise, were given permission to export condensate in private letters from the U.S. Department of Commerce's Bureau of Industry and Security. The letters, formally known as a commodity classification, confirmed that condensate would be categorized as a refined product and would therefore not be subject to the law prohibiting crude exports.

But far from opening the floodgates, the private letters are one-offs. The department has not made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(Photo courtesy of Enterprise Products Partners)

Enterprise Products Partners LP and Enbridge Inc. finished looping their Seaway Pipeline in third-quarter 2014. The project increased Seaway's capacity to 850 Mbbl/d between the Cushing, Okla., crude oil trading hub and the Jones Creek storage and terminal facility outside Freeport, Texas, which has links to refineries along the Gulf Coast.

any general ruling, and so other aspiring exporters of condensate have had to request their own letters. As of November 2014, those letters have been put on "hold without action" by the bureau.

"I don't know and I don't think anyone else knows whether the federal authorities will approve other exports," said Tuscaloosa Energy Services' Batson. If they do not, however, she and others in the industry noted that not authorizing other exporters would mean "making everyone else sell their outbound condensate to those two. That sort of smacks of the government as picking winners."

This is not an esoteric trade issue, either. "The producers have 200 rigs running in the Bakken and another 900 running in Texas. Then there are all the other shale plays with almost 2,000 rigs running nationwide. Even though those rigs are drilling primarily for crude, they are going to generate a lot of condensate. There is going to be tremendous growth."

Harper at Enbridge believes that exports are a good idea because the producing regions are becoming saturated, and there is only so much local demand that can be created. "Once exports come to a meaningful level, domestic markets may be facing higher prices because they will be competing with other markets around the world. But even if prices are slightly higher, the development of a competitive global market is ultimately better for all."

He detailed several reasons for that including the overall increase in size, scale and reliability of a global supply chain, as compared to a regional or even national one. He also noted the economic activity including jobs and taxes that will come with a larger, export-oriented market. There is hardly a question of sufficient volumes or resources to recover, so slightly higher prices would seem to be a good investment in a large and efficient market.

As for Enbridge's direct participation in exports of NGL, Harper is circumspect. "We are not really interested in marketing exports at this point. We prefer to get the liquids to the port and let others get them to the overseas market. We are part of the Texas Express project into Mount Belvieu, so we are a player from that regard." ■

(Photo courtesy of Boardwalk Pipeline Partners)

Midstream
a Capital Idea

By **Travis E. Poling**, Contributing Editor

Infrastructure capital spending is expected to top $80 billion per year into the next decade, with more mergers in the offing as midstream companies diversify across multiple shale plays.

Making up for lost time and keeping up with future demand for midstream infrastructure related to unconventional shale oil and gas might cramp the hands of company officials signing billions of dollars in purchase orders in the coming years.

IHS Global Inc. estimated in a December 2013 study that capital spending on oil and gas midstream assets and downstream infrastructure rose 60% to $89.6 billion in 2013 compared to 2010.

That doesn't seem to be slowing as shale oil and gas production rises in already-bustling shale plays such as the Eagle Ford and Bakken, and a new boom is underway in the Permian Basin of Texas and New Mexico. All of the key players in the midstream sector have capital expansion projects underway and some have multibillion-dollar spending plans at least through 2017.

"This recent surge in oil and gas transportation and storage infrastructure investment is not a short-lived phenomenon," according to the most recent IHS analysis of the midstream industry. "Rather, we find that a sustained period of high levels of oil and gas infrastructure investment will continue through the end of the decade."

The study estimates that direct capital projects will average about $80 billion per year through 2020 and then gradually back off to about $60 billion per year by 2025.

Projects in the works include new rail unloading facilities, fractionation plants, cryogenic compression units and thousands of miles of pipeline from small regional gathering systems to major transmission lines connecting the rich oil and gas fields to hubs, refineries and ports.

One of the biggest new projects, proposed in late October 2014 by TransCanada Corp., is a $12 billion crude oil pipeline linking the liquids-rich plays in western Canada to refineries and ocean ports in the eastern provinces.

In 2013, asset sales were the order of the day, not just with diversified energy companies dropping down midstream assets to MLPs, but also from companies such as Chesapeake Energy leaving the sector.

In 2014, mergers picked up again with heavy hitter Williams Partners LP announcing a 2015 merger with Access Midstream Partners LP and Regency Energy Partners buying the midstream assets of Eagle Rock Energy Partners. EnLink Midstream also was formed in 2014 from the midstream assets of Crosstex Energy LP and Devon Energy.

Boardwalk Pipeline Partners LP

- **Acquired 176-mile interstate Evangeline Pipeline system through Chevron Petrochemical Pipeline LLC buyout**
- **Subsidiary Gulf South Pipeline Co. plans a pipeline supply header for its liquefaction terminal in Texas**

The October 2014 acquisition of the Evangeline Pipeline system added 176 miles to the Houston-based MLP's system for about 14,450 miles of natural gas and liquids pipeline in 13 states. The

Facing page: Boardwalk Pipeline Partners' Sulphur, La., hub is part of an extensive ethylene distribution system that connects to the Evangeline Pipeline.

company also has storage capacity of 207 Bcf of gas in underground caverns and 18 MMbbl of liquids.

Plans to add 65 miles of line to a supply header in Freeport, Texas, which is expected to get underway in 2018, will include modification of existing facilities and could lead to long-term agreements with shippers from that terminal.

"Boardwalk's pipeline network is well-suited to deliver to growing markets on the Gulf Coast," said John Haynes, senior vice president of Boardwalk subsidiary Gulf South Pipeline, in a written statement in September 2014. "We ... are located near, or attached to, many natural gas shale supply sources including the Eagle Ford, Barnett, Haynesville, Cana Woodford, Fayetteville, Marcellus and Utica; and over time, Gulf South's Perryville Exchange will become a meaningful hub for producers, end users and LNG offtakers to trade volumes."

Boardwalk's operating subsidiaries include Gulf South, Texas Gas Transmission, Gulf Crossing Pipeline, Petal Gas Storage, Boardwalk Field Services (mostly in South Texas) and Boardwalk Louisiana Midstream.

Buckeye Partners LP

- **Paid $860 million in September 2014 for an 80% stake in Buckeye Texas Partners LLC**
- **Increased LPG storage capacity by more than 50% with acquisition from Hess Corp.**

Houston-based Buckeye Partners made a major service expansion into the Bakken and Utica plays in 2013, and in 2014 it gained an even greater presence in the Eagle Ford Shale of South Texas and the Gulf Coast.

The majority stake in Buckeye Texas Partners alongside Trafigura AG gives the company integrated assets including a high-volume marine terminal on the Corpus Christi Ship Channel, a condensate splitter and LPG storage complex in Corpus Christi and three crude and condensate gathering facilities in the Eagle Ford.

The acquisition of 20 terminals from Hess Corp. also was completed in the last year, adding 39 MMbbl of storage capacity to the company's existing 70 MMbbl. About 10 MMbbl of capacity was gained with the addition of the St. Lucia terminal in the Caribbean, and it can handle more storage of products from Latin America.

The other 29 MMbbl of capacity comes 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 opened 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 network of New York Harbor marine terminals, including a 2012 acquisition from Chevron, has aided in handling increased business from the Bakken crude market.

The company has about 6,000 miles of pipeline and more than 120 liquid petroleum terminals. Storage capacity is more than 110 MMbbl.

Caiman Energy II LLC/ Blue Racer Midstream LLC

- **Caiman has invested heavily in the Utica in partnership with Dominion through Blue Racer Midstream**
- **Management team is experienced in the Marcellus with assets that the original Caiman sold to Williams Partners for $2.5 billion**

Caiman Energy II provided $800 million in capital investment to Blue Racer Midstream, a partnership with Dominion. Caiman's top executives also serve as the management team for Blue Racer.

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 $800 million in capital from Caiman Energy II.

Recent expansions in the Utica include an additional 200 MMcf/d of natural gas processing at the Natrium facility in Marshall County,


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(Photo by Joseph Markman, Hart Energy)

The five massive tanks at Cheniere Inc.'s Sabine Pass, La., LNG plant provide 17 Bcf of storage capacity.

W.Va., for a total capacity of 400 MMcf there. The company's Berne processing complex in Monroe County, Ohio, will have three cryogenic processing units, each with a capability to handle 200 MMcf/d. That will give Blue Racer the ability to process up to 1 Bcf/d of natural gas at the Berne and Natrium facilities.

The fractionation facility at Natrium offers barge service to Utica producers, and a 30-mile pipeline will carry processed liquids from Berne to the Natrium complex, which is expected to be upgraded to handle 126 Mbbl/d by March 2015.

Caliber Midstream Partners LP

- **Added 100 miles of gathering pipelines in the Bakken and Three Forks shale plays in 2014**
- **Formed as a joint venture of Triangle Petroleum and First Reserve's Energy Infrastructure Fund**

Denver-based Caliber 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 $180 million.

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

A $200 million line for operations and additional expansions was finalized in December 2013.

The most recent expansion includes 100 miles of additional gathering lines, crude oil stabilization and transportation, freshwater delivery, and production water transport and disposal. The pipeline expansion will move up to 50,000 bbl/d from Caliber's central location to Alexander, N.D., where a 40,000-bbl crude oil storage facility reaches 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 2013, Cheniere Energy Partners purchased the Cheniere Creole Trail Pipeline for $480 million from Cheniere Energy Inc., the 58% owner of the partnership. The 94-mile pipeline provides 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 through 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 (mtpa) of LNG, the company reported on its 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 mtpa.

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**

A wholly owned, indirect subsidiary of Chevron Corp., Chevron Pipe Line boasts that it moves about 1.13 MMbbl 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 Line 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 with natural gas storage of up to 6.38 Bcf, according to the company 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 saltdome storage caverns in Assumption and Ascension parishes of Louisiana with a capacity of 11 Bcf, the company website said.

Chevron Pipe Line sold its Northwest Products Pipeline to Tesoro Logistics LP in June 2013 for $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 expected to complete a 136-mile, 24-in. crude oil pipeline from the deepwater Jack/St. Malo production facility in the Gulf of Mexico to a shallow-water platform on the continental shelf in 2014.

Columbia Pipeline Group

- **Building a $131 million pipeline of 21.1 miles in Maryland**
- **Planning 19 miles of new gas pipeline in Pennsylvania and New Jersey for 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 Washington, D.C. 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 website.

In September, Columbia filed with the U.S. Securities and Exchange Commission to do an IPO as a separate company. The IPO is anticipated in first-quarter 2015.

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, a company news release reported.

Columbia said in August 2014 that it would be investing $1.75 billion in infrastructure to move as much as 1.5 Bcf/d of natural gas from both the Marcellus and Utica shale plays. That includes a new 160-mile pipeline in Ohio and West Virginia.


(Photo courtesy of DCP Midstream Partners LP)

Night falls on DCP Midstream's O'Connor gas processing plant, located on the high plains of eastern Colorado. The facility is a key link in the midstream infrastructure serving the Denver-Julesburg Basin.

Crestwood Midstream Partners LP

- **Crestwood and Inergy merged in 2013 to form a diversified midstream player growing in core areas**
- **Further expanded the Willow Lake Project in the Permian Delaware Basin**

Crestwood, after its merger with Inergy, gained a foothold in every premier shale play in North America.

Two days after closing the deal to reach $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, include 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.

The company has been largely focused on expanding the crude and NGL business in the Marcellus, Bakken and Niobrara plays. Crestwood also has operations in the Barnett, Eagle Ford, Fayetteville, Granite Wash, Haynesville, Monterey, Permian Basin, Powder River Basin and Utica plays.

In April 2014, Crestwood said it would make additional commitments to the Permian Basin with the cryogenic gas processing plant and additional gathering systems purchased in the area.

The enterprise operates through two publicly traded entities: Crestwood Midstream Partners LP and Crestwood Equity Partners LP.

DCP Midstream LLC

- **Opened a 200-MMcf/d cryogenic natural gas processing plant serving the Eagle Ford**
- **Began service on the Sand Hills Pipeline for NGL takeaway from the Permian and Eagle Ford to Mont Belvieu, Texas**

DCP Midstream LLC, jointly owned by Phillips 66 and Spectra Energy, owns the general partner of DCP Midstream Partners LP, an MLP. The DCP Midstream enterprise is the largest natural gas processor and largest 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 about 1 Bcf/d of processing capacity, assets will include a 200 MMcf/d cryogenic processing plant in Goliad, Texas, which was 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 Mbbl/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 about 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 about 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, the company began service on the 720-mile Sand Hills Pipeline in mid-2013, 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, to provide producers with takeaway capacity from the DJ Basin to Mont Belvieu. Texas Express commenced operations in late 2013, and Front Range was slated for first-quarter 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.

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 2014 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 7,900 miles of interstate pipelines, 2,300 miles of intrastate lines and more than 11,000 miles of gathering pipeline.

The company also boasts 12 large processing plants and natural gas storage capacity of more than 90 Bcf. A new plant is undergoing construction.

Production areas served in Oklahoma, Texas, Arkansas and Louisiana include the Barnett, Cana Woodford, Fayetteville, Granite Wash, Haynesville, Mississippi Lime, Tonkawa and Woodford plays.

The company is building a crude oil gathering project in the Bakken Shale of North Dakota. In September, Enable announced it would build another 200 MMcf/d natural gas processing plant to take advantage of the new play in central Oklahoma.

Enbridge Energy Partners LP/ Midcoast Energy Partners LP

- **On target for 2017 to handle an additional 1.7 MMbbl/d of Canadian and Bakken Shale crude oil**
- **Major crude oil transporter from western Canada**

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 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.

Much of the work is done through Enbridge's new Midcoast Energy Partners, which focuses on developing natural gas and NGL gathering and processing development in the U.S., particularly in Texas and Oklahoma.

Enbridge is investing $140 million for 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 Mbbl/d of crude pipeline capacity from Saskatchewan, Canada, and North Dakota and take it away across the Great Lakes via an expanded Sandpiper Pipeline.

The company forecasts that it will spend more than $1.5 billion on average in 2014 through 2016 on capital projects and has a total of 27 projects totaling $27 billion in capital investment in the works.

Spending is heavy on line expansions from Canada to the Gulf Coast, where the company supplies

The Henderson plant of Midcoast Energy Partners lies just outside its namesake hometown of Henderson, Texas. The cryogenic operation forms part of a midstream network of more than 3,900 miles of pipelines, 11 treating plants and a fractionator serving East Texas producers active in the Bossier and Haynesville plays.

(Photo courtesy of Midcoast Energy Partners LP)

EnLink Midstream LLC serves Barnett Shale producers with its Bridgeport gas processing plant, northwest of Fort Worth, Texas.

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

- **Developing Dakota Access Pipeline with Phillips 66 to move up to 450 Mbbl/d of Bakken and Three Forks crude oil to the Midwest**
- **Mariner South project will create an LPG export/import operation on the Gulf Coast with initial capacity of 6 MMbbl/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 reported in a news release.

Since it was founded in 1995, the company has grown into one of the largest energy partnerships in the U.S. with about 35,000 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, terminalling and crude oil acquisition and marketing assets. It also includes a 70% interest in Lone Star NGL, a joint venture (JV) that owns and operates NGL storage, fractionation and transportation assets. ETP's general partner is owned by Energy Transfer Equity.

The company expects to start operations for its under-construction Dakota Access Pipeline in late 2016 to transport 450 Mbbl/d of Bakken and Three Forks crude to the Midwest. Unit train loading facilities in the Midwest also will transfer oil from that pipeline to East Coast refineries. Phillips 66 owns 25% of the JVs.

In June 2014, the company announced it will build a pipeline to transport processed natural gas from the Marcellus and Utica shale regions to markets throughout the U.S. and Canada. It will move up to 2.2 Bcf/d, but that amount could be expanded up to 3.25 Bcf/d, according to a company news release. Deliveries to a Midwest hub and for transfer to the Gulf Coast will begin in late 2016, while Michigan and Canadian market deliveries will commence by second-quarter 2017.

EnLink Midstream

- **Formed with the midstream assets of Crosstex Energy and Devon Energy in early 2014**
- **7,400 miles of pipelines with operations in most of the North American unconventional plays**

The merging of Crosstex Energy Inc., Crosstex Energy LP and the midstream assets of Devon Energy Corp. in March 2014 created EnLink Midstream, which has a reach across most of the North American unconventional plays, including in North Texas, the Gulf Coast, Haynesville, Permian Basin, Utica, Marcellus, Eagle Ford, Cana and Arkoma-Woodford plays.

Oklahoma City-based Devon has a controlling interest, but the company is run by the former Crosstex management team from Dallas. Devon contributed about $4.8 billion of its $26 billion in assets to the deal.

The company now has 7,400 miles of gathering and transmission pipelines, seven fractionators with 252,000 bbl/d of net fractionation capacity and 13 gas processing plants with a capacity of 3.4 Bcf/d. The firm also operates barge and rail terminals, storage facilities and a crude oil trucking fleet.

In September 2014, the EnLink Midstream companies announced an intended acquisition of the Gulf Coast natural gas pipeline assets of Chevron Pipe Line Co. The $235 million deal, which includes the Bridgeline system in southern Louisiana, adds about 1,400 miles of additional pipeline from Beaumont, Texas, to the Mississippi River. It also adds about 11 Bcf more of natural gas storage capacity to the existing EnLink assets in Louisiana.

The company also is adding new infrastructure with a $200 million expansion of its natural gas gathering system and a 120 MMcf/d gas processing plant in the Permian Basin. It will be mostly supported by production from 18,000 acres under development by Devon in Martin County, Texas.

A joint venture between EnLink and a subsidiary of Marathon Petroleum Corp. called Ascension Pipeline Co. will build a new 30-mile pipeline to transport NGL from an existing fractional plant in Riverside, La., to Marathon's Garyville refinery. It is expected to go into operation in first-half 2017.

Enterprise Products Partners LP

- **52,000 miles of pipeline and 24 natural gas processing plants**
- **Building a ninth NGL fractionator at Mont Belvieu, Texas**

The 46-year-old Enterprise Products Partners, based in Houston, has grown rapidly through acquisition and capital building projects in recent years and has an ambitious program underway for the next three years.

Enterprise has about $6.3 billion in assets under construction that will come online in 2015 and 2016, the company said in its third-quarter 2014 earnings release. In the 12 months prior to October, the company completed construction on and put to work about $4.9 billion in assets.

The company now has about 52,000 miles of pipeline, 24 natural gas plants and a capacity to store 200 MMbbl of NGL, crude oil, refined products and petrochemicals. Storage capacity for natural gas is 14 Bcf.

To accommodate growth in unconventional plays, the company is proposing that it build a

(Photo courtesy of Enterprise Products Partners LP)

Abundant gas liquids production from the shale plays is creating a rebirth of the U.S. petrochemical industry. Towboats move a reactor vessel to Enterprise Products Partners' new propane dehydrogenation complex, set to open in 2016 at the big Mont Belvieu, Texas, NGL hub outside Houston. The plant will have a capacity to produce 1.65 Blb/year of polymer-grade propylene.

new crude oil pipeline from the Williston Basin in North Dakota to the Cushing hub in Oklahoma.

To serve the Delaware Basin, Enterprise is building a cryogenic natural gas processing facility in Eddy County, N.M. Associated pipelines will include construction of 80 miles of natural gas gathering lines and a 75-mile line to move NGL from the Eddy plant to an existing fractionation and storage hub in Gaines County, Texas.

EQT Corp. and EQT Midstream Partners LP

- **Operates in 21 counties in West Virginia and Pennsylvania, serving the Marcellus and Utica shales**
- **EQT Midstream Partners 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 company presentation materials to investors. Those lines, doing business as Equitrans Transmission and Storage System, connect to five interstate pipelines. The Equitrans Gathering System has about 1,600 miles of low-pressure gathering pipelines.

Part of the MLP's strategy is to acquire key midstream assets from EQT Corp. To that end, the LP bought the Sunrise pipeline from EQT for $507.5 million plus additional shares in the partnership.

In April 2014, the limited partnership agreed to buy EQT Corp.'s Jupiter natural gas gathering system for $1.18 billion. The Jupiter assets in the Marcellus region are undergoing several expansions for completion from late 2014 through 2015.

The partnership also is taking over EQT's interest in Mountain Valley Pipeline LLC, which has secured capacity commitments of 2 Bcf/d of volume. When completed, the pipeline project will have about 300 miles of line in service by year-end 2018.

Work also has started on a 36-mile pipeline that will connect northern West Virginia transmission and storage systems to Clarington, Ohio, in the Ohio Valley by mid-2016.

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 in Texas**

Howard Energy Partners is making major investments 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, Texas-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.

A cryogenic natural gas plant with 200 MMcf/d of processing capacity was completed in 2014 to serve producers and midstream clients in the Olmos, Escondido and Eagle Ford shale plays, all in South Texas. In conjunction with the Reveille plant, Howard Energy built the Falcon NGL Pipeline, which is designed to transport NGL after separation. The Falcon NGL Pipeline consists of about 58 miles of 6-in. pipeline capable of moving 18 Mbbl/d to an interconnection with Enterprise's Eagle Ford NGL Line.

Howard Energy Partners also built a logistics railroad hub in Live Oak County for oilfield products that include NGL and condensate, water, pipe and frack sand in the heart of the Eagle Ford Shale.

Howard is leveraging the Live Oak Rail Park location for access to multiple downstream markets for liquids products with a 10 Mbbl/d liquids stabilizer facility near Three Rivers, Texas, and the adjacent rail hub. That project went online Oct. 1, 2014.

The Brownsville Terminal consists of 21 tanks providing up to 225 Mbbl of bulk liquid storage. The strategic location gives access to the truck corridor between the Port of Brownsville, Texas, and Mexico, including the intercoastal waterway, railroads and deepwater.

Kinder Morgan Inc.

- **Consolidating Kinder Morgan Energy Partners LP, Kinder Morgan Management, and El Paso Pipeline Partners into Kinder Morgan Inc.**
- **Opening an NGL pipeline from the Utica and Marcellus shales to Mont Belvieu on the Texas Gulf Coast**

As one of the largest pipeline companies in the U.S., Kinder Morgan Inc. has its fingers in most of the major unconventional plays and has expansion projects in some of the largest, including the Marcellus, Utica and Eagle Ford.

Kinder Morgan Inc., which will be a merger of four related publicly traded companies if shareholders give approval in late November 2014 (after press time), has 80,000 miles of pipeline and 180 terminals.

The company has a joint venture with MarkWest Utica EMG to convert more than 1,000 miles of 24-in. and 26-in. Kinder Morgan Energy natural gas pipeline to handle NGL from Mercer, Pa., to Natchitoches, La. Another 200 miles of similar pipeline will be constructed to make a completed connection between the heavy production in the Utica and Marcellus shales to a fractionation facility in Mont Belvieu, Texas. When the pipeline is operational, which is expected by second-quarter 2016, initial capacity will be 150 Mbbl/d of NGL. It is being designed to add pump stations that would bring capacity up to 400 Mbbl/d.

In May 2013, the company bought out another Houston company, Copano Energy LLC, in a $5 billion deal. The deal includes assets in Texas, Oklahoma and Wyoming and 7,000 miles of pipeline that can handle up 2.7 Bcf/d of natural gas, according to a company news release.

The company also has completed a 60-mile, 36-cu.-in. pipeline from existing mainlines in the Tuscon, Ariz., area to a new international line in Mexico to provide natural gas to the Mexican market.

Howard Energy Partners' new stabilizer plant at Live Oak, Texas, processes Eagle Ford condensate, which might see export via Gulf Coast ports. *(Photo by Joseph Markman, Hart Energy)*

In the Utica Shale, Kinder Morgan is constructing a 240-mile pipeline to move ethane and ethane propane mixes from the Utica in Ohio to a Kinder Morgan pipeline in Michigan before being transported to the Ontario, Canada market. Initial capacity when it opens in early 2018 will be 50 Mbbl/d of product with expansion capabilities up to 75 Mbbl/d.

Magellan Midstream Partners LP

- **Building the Saddlehorn crude pipeline from northeastern Colorado to storage facilities in Cushing, Okla.**
- **Capital expansion project spending in 2014 hit $775 million**

With 9,500 miles of pipeline and 53 terminals in 13 states down the center of the U.S., Magellan has plotted a course to move increased production from major shale plays and 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. The 75 Mbbl/d project is slated to go into operation by third-quarter 2015.

To meet increasing demand from producers in the Permian Basin, Magellan is expanding the capacity of its existing Longhorn pipeline by 50 Mbbl/d to 275 Mbbl/d in a $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.

The company recently announced it would build the 600-mile, 20-in.-diameter Saddlehorn Pipeline to connect the Niobrara play in Colorado to Cushing, Okla., where Magellan has storage facilities. The pipeline, slated for completion in second-quarter 2016, will be able to transport about 400 Mbbl/d of crude oil.

For capital expansion project spending, $450 million is slated for 2015, and $75 million is committed to finishing projects in 2016.

MarkWest Energy Partners

- **Building Bluestone III and IV plants at its Keystone complex in Pennsylvania for processing production from the Marcellus Shale and Upper Devonian Formation**
- **Acquired Granite Wash-area midstream assets of a Chesapeake Energy subsidiary**

MarkWest is increasing its reach into unconventional plays with acquisitions and projects, which started 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.

The recent addition of the Bluestone III and IV plants will add another 200 MMcf/d of processing in the Marcellus and Upper Devonian, with one in fourth-quarter 2015 and the other in second-quarter 2016.

In November 2013, MarkWest Utica EMG, of which the limited partnership is a part, entered into an agreement with Kinder Morgan Energy Partners to convert more than 1,000 miles of Kinder Morgan 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 $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 2014 and began processing about 50 MMcf/d of natural gas. The


(Photo courtesy of Martin Midstream Partners LP)

nearby Buffalo Creek plant was expected to be complete in first-quarter 2014.

Martin Midstream Partners LP

- **Acquired controlling interest in Cardinal Gas Storage Partners**
- **Completed three storage tanks in 2014 to add 300 Mbbl of additional crude storage at Gulf Coast facility**

The Kilgore, Texas, company is focused primarily on the Gulf Coast and has been expanding its storage capacity and interest in additional storage companies to take advantage of increased production from unconventional plays.

In August 2014, Martin completed a $120 million deal to gain a controlling interest in Cardinal Gas Storage Partners, which owns and operates four natural gas storage facilities with 50 Bcf of gas storage in Mississippi and northern Louisiana.

In May 2014, Martin acquired several subsidiaries of Atlas Pipeline Partners, gaining a stake in Chevron's West Texas LPG Pipeline.

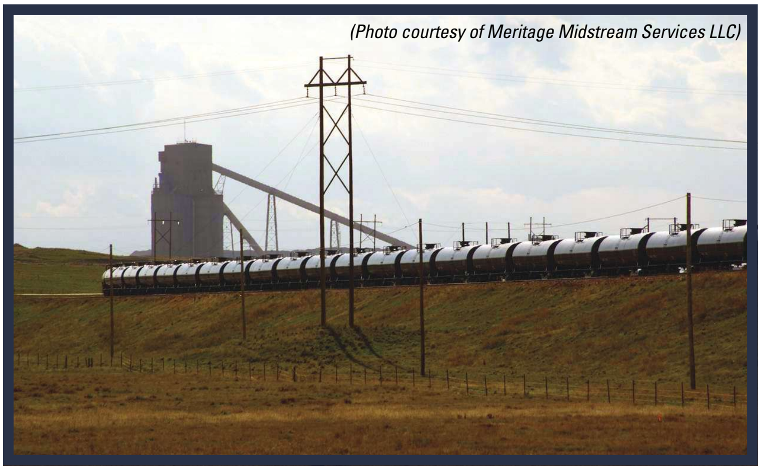
In February 2013, Martin purchased six pressure barges and two commercial push boats to expand its ability to handle NGL, especially from the Eagle Ford Shale production in South Texas. The $50.8 million purchase will add 96 Mbbl of barge capacity.

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, Texas, Martin completed three additional storage tanks that added 300 Mbbl of storage.

In 2013, Martin Resource Management Corp. sold a 50% interest in Martin Midstream's general partner to Alinda Capital Partners to provide for access to capital markets and expansion.

Storage represents a crucial link in the midstream chain. Martin Midstream Partners' crude terminal at Corpus Christi, Texas, serves the seaport's multiple refineries.


(Photo courtesy of Meritage Midstream Services LLC)

Wyoming's Black Thunder Terminal, a joint venture of Meritage Midstream Services LLC and Arch Coal Inc., uses existing railroad infrastructure to handle the Powder River Basin's growing volume of crude-by-rail shipments.

Meritage Midstream

- **Acquired Thunder Creek Gas Services, gaining 500 miles of gathering pipelines and gas processing facilities**
- **Black Thunder Terminal saw its first unit train roll in June 2014**

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 2013, backed with a $500 million commitment from equity firm Riverstone Holdings, Meritage acquired Thunder Creek Gas Services with 500 miles of gathering pipeline and gas processing facilities in the Powder River Basin of Wyoming from Devon Energy Corp. and PVR Partners.

In conjunction with Arch Coal, Meritage developed the Black Thunder Terminal in Campbell County, Wyo., for Powder River Basin crude and condensate storage and rail car loading. The terminal is at Arch Coal's Black Thunder mining complex and began operation in June 2014.

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 Mbbl/d and is expected to become operational in second-quarter 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.

NuStar Energy LP

- **Construction began on two phases of expansion of the South Texas Crude Oil Pipeline System to add 100 Mbbl/d of capacity**
- **Opened a private dock at Corpus Christi, Texas, facility to handle increased production**

NuStar Energy has more than 8,600 miles of pipelines and 82 storage and terminal locations for crude and refined products. NuStar also has the capacity to store up to 97 MMbbl of crude and refined products.

The San Antonio, Texas-based partnership has assets worldwide, but many of its U.S. assets are positioned to take advantage of the increased production from unconventional plays, particularly in Texas, along the Gulf Coast and in the Midcontinent region.

The company has become highly focused on Eagle Ford Shale opportunities in the last two years and said it would proceed with the first phase of a South Texas Crude Oil Pipeline System project. The first phase would add 35 Mbbl/d of capacity. A second phase, slated for completion in first-quarter 2015, would add capacity to move another 65 Mbbl/d.

To help handle increased volumes from the first phase of the Eagle Ford expansion project, NuStar recently opened a private dock at its Corpus Christi North Beach terminal to double loading capacity to about 125 Mbbl/d.

Subsidiary NuStar Logistics opened a unit train rail terminal that can unload crude at a rate of as much as 100 Mbbl/d in St. James, La. The company operates a similar-sized terminal for EOG Resources.

In October 2014, NuStar signed a letter of intent with the Mexican-government-owned oil company Pemex for a joint venture to develop new pipeline infrastructure and storage to transport LPG and refined products from NuStar facilities in Corpus Christi and Mont Belvieu in Texas, to Pemex lines in the Mexican/U.S. border cities of Nuevo Laredo and Reynosa.

ONEOK Partners

- **Committed to reaching up to $9 billion in capital expansions through 2016**
- **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 the Gulf Coast.

The company has 17,300 miles of gathering pipeline and 6,600 miles of transmission line 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 information for investors on the company website.

The company has committed to reaching up to $9 billion in capital expansions through 2016, beginning with investments made in 2010.

In October 2014, ONEOK announced that it had completed several projects including the 100-MMcf/d natural gas processing plant Garden Creek III in North Dakota, expansion of the Bakken NGL and Overland Pass Pipelines to 135 Mbbl/d from 60 Mbbl/d, and the Niobrara NGL Lateral connecting the Sage Creek processing facility to the Bakken NGL Pipeline.

The company expects to complete the last of five processing plants and other infrastructure in the Williston Basin of North Dakota by first-quarter 2015.

Recent Midcontinent expansions include the 540-mile Sterling III NGL pipeline, which added up to 250 Mbbl/d.

Phillips 66 Partners LP

- **$330 million acquisition by the MLP of two crude oil rail-unloading facilities from Phillips 66**
- **A connector pipeline under the Houston Ship Channel will be further developed to move up to 180 Mbbl/d by second-quarter 2015**

The Phillips 66 Partners LP became a publicly traded company in July 2013 to operate existing pipelines and terminals related to crude oil and refined products previously owned by Phillips 66.

Company assets include a crude oil pipeline in Sulphur, La., that delivers to a Phillips refinery in

Multiple downstream operators have created separate midstream operations recently. Phillips 66 Co. has dropped down certain assets at its Sweeny, Texas, refinery to its new midstream unit, Phillips 66 Partners LP.


(Photo by Deon Daugherty, Hart Energy)

Lake Charles, La. A 681-mile pipeline transports refined products from Borger, Texas, to Cahokia, Ill., and two lateral lines of 53 miles each run parallel from Paolo to Kansas City, Kan.

The Hartford Connector is an Illinois system that includes refined-products pipeline, a terminal and related storage with connections to the Wood River refinery co-owned by Phillips 66 and Cenovus Energy and third-party systems.

The Medford, Okla. product spheres has a capacity of 70 Mbbl/d for propylene delivery from the Phillips 66 refinery in Ponca City, Okla., to coastal Mont Belvieu, Texas.

Another system transports refined products from the Sweeny refinery in Old Ocean, Texas, to a terminal in Pasadena, Texas.

In October 2014, Phillips 66 agreed to pass down to the MLP two new crude oil rail-unloading facilities for $330 million. The rail facility inside Phillips 66's Bayway Refinery can unload up to 120 rail cars at a time with about 30 Mbbl/d of crude oil. The second is next to the Ferndale refinery and can unload 54 cars simultaneously.

Also included in the deal was the Cross-Channel Connector Pipeline running under the Houston Ship Channel to move refined products from the Phillips 66 Partners terminal to a Kinder Morgan terminal in Pasadena.

Plains All American Pipeline

- **Expansion projects in 2014 of about $2 billion**
- **$900 million Diamond Pipeline will connect the Cushing, Okla., hub to Valero Energy's Memphis, Tenn., refinery**

Plains All American Pipeline handles more than 3.9 MMbbl/d of crude oil and NGL and has a foothold in most major basins and unconventional plays, where it is investing heavily in the coming years.

Permian, Eagle Ford and Midcontinent activity was the primary driver of growth for the transportation segment, and the company expected continued volume increases from those areas in 2014.

In 2014, the company put numerous projects in service 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 2013, the company announced an expansion of the Eagle Ford JV Pipeline to a capacity of 470 Mbbl/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, will have a capacity of 200 Mbbl/d.

The $120 million Eagle Ford JV project is scheduled for completion by mid-2015 and includes 2.3 MMbbl of storage capacity in the Texas cities of Gardendale, Corpus Christi and Tilden.

The company also put an additional 90 miles of its Gardendale Gathering System into operation in 2013.

In August 2014, Plains announced construction of the 440-mile Diamond Pipeline from Cushing, Okla., to the Valero Energy refinery in Memphis. The $900 million project is slated for completion in late 2016 and will handle up to 200 Mbbl/d of domestic sweet crude.

Plains opened the new Rainbow Pipeline II in September with a capacity of 195 Mbbl/d and began construction on the 80-mile Indigo Pipeline System. The $535 million project is slated to open in 2017.

Regency Energy Partners

- **Took over PVR Partners in a $5.6 billion deal to establish a presence in the Appalachia and Midcontinent regions**
- **Acquired the midstream assets of Eagle Rock Energy Partners**

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 website.

Regency acquired Southern Union Gathering from Energy Transfer Partners for $1.5 billion in 2013. 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.

In March 2014, Regency acquired PVR Partners in a deal worth $5.6 billion. The deal gives Regency a strategic foothold in the Marcellus and Utica shale plays in the Appalachian Basin and the Midcontinent Granite Wash.

The company also gained a greater foothold in active natural gas regions with the acquisition of the midstream assets of Eagle Rock Energy Partners LP, which has 20 gas processing plants and more than 8,100 miles of gathering pipeline. The assets are concentrated mostly on East Texas and the Texas Panhandle.

To take advantage of the growth opportunities in the Utica Shale, Regency increased the size of a joint venture with American Energy-Midstream LLC to handle 2 Bcf/d through a 52-mile trunk line. The project, with an anticipated completion in third-quarter 2015, also will include a 25,000-hp compression unit.

Regency also closed on the acquisition of Hoover Energy Partners, which includes 800 miles of gathering line.

SemGroup Corp.

- **Completed the 80 Mbbl/d expansion of the White Cliffs Pipeline serving the DJ Basin**
- **Expanded crude oil trucking fleet to 250 trucks in eight unconventional plays**

Assets of SemGroup and its Rose Rock Midstream are focused on the Midcontinent area including the Bakken, Montney/Duvernay, Denver-Julesburg Basin (DJ)/Niobrara and the Mississippi Lime/Granite Wash plays. The company also has a presence in the major liquids transit interchange of Cushing, Okla.

The 527-mile White Cliffs Pipeline for crude oil from the DJ Basin to Cushing is undergoing an 80-Mbbl/d expansion, and the company is gauging interest in another expansion of the system.

The Glass Mountain Pipeline, completed in late 2013, has a capacity of 140 Mbbl/d of crude over 210 miles with two lateral lines that join the Granite Wash and Mississippi Lime areas and go to Cushing. The company also opened 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/Okla. and Bakken Shale areas with connections to Cushing, where the company has 7.25 MMbbl of storage and capacity for another 250 Mbbl for blending as of late 2013.

The Kansas/Oklahoma System has 640 miles of gathering and transportation pipeline and a capacity of 40 Mbbl/d or more.

In September 2013, Rose Rock acquired Barcas Field Services with its fleet of 114 crude oil trucks. In June 2014, Rose Rock made another trucking expansion with the buyout of crude oil trucking assets from a subsidiary of Chesapeake Energy. The deal included 124 trucks and 122 trailers in Texas, Oklahoma and Ohio.

Sunoco Logistics Partners

- **Delaware Basin extension of 125 miles will connect New Mexico and West Texas to a hub in Midland, Texas**
- **Expanded Permian Express I for an additional 150 Mbbl/d of crude**

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 trunk line, 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 on the Delaware River in New Jersey and three facilities in the Philadelphia area with another 3 MMbbl of capacity, according to the company website.

Refined products pipelines include 2,500 miles transporting throughout the Northeast, Midwest and Gulf Coast regions of the U.S. 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 an MLP owned by Energy Transfer Partners, which also owns Regency Energy Partners.

(Photo courtesy of Port of Vancouver)

The West Vancouver Freight Access Project at the Port of Vancouver, Wash., is scheduled for a 2017 completion. Tesoro Logistics LP and Savage Cos. plan a major rail terminal at the location to handle Bakken crude oil headed for the plants of Tesoro Corp. and other West Coast refiners.

In 2014, the company opened its Permian Express I with a capability to move 150 Mbbl/d. Sunoco also added greater capacity for the Eaglebine Express and Allegheny Access pipelines.

Sunoco added 200 miles of pipeline in the Granite Wash area of the Texas Panhandle and southeast Oklahoma. The Mariner East I pipeline was expanded for more propane transportation in 2014, and additional capacity for ethane and additional propane will be ready by mid-2015.

Another 125-mile stretch under construction will connect the Delaware Basin to a hub in Midland, Texas, by mid-2016.

Superior Pipeline Co.

- **Conservative growth with a focus on the Mississippian play and Granite Wash**
- **Operating gas gathering pipeline in the Marcellus Shale of Pennsylvania and West Virginia**

Most of Superior's operations and expansion efforts 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 550,000 gal/d of NGL through 1,450 miles of pipeline.

Unit increased exploration in the Mississippian play on the border of Kansas and Oklahoma, while Superior completed associated pipeline and a processing plant. The company added gathering pipeline to 164 Mississippian wells in late 2013 and completed several cryogenic plants at a cost of $34.5 million.

The company also had about $12 million 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

- **Acquiring Atlas Pipeline Partners LP and Atlas Energy for $7.7 billion**
- **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 2014 was targeted to increasing processing capacity and NGL fractionation for increased liquids from several U.S. shale plays. The company spent about $1.7 billion by year-end 2014. That includes operations in Louisiana, the Permian Basin in Texas and developing and entering the Bakken Shale in North Dakota and Montana.

The pending deal to buy Atlas Pipeline would give Targa Resources Corp. and Targa Resources Partners a larger position in the Permian Basin, Bakken and Barnett shale and the Louisiana Gulf Coast. It also puts Targa into additional plays including the Woodford, Mississippi Lime and Eagle Ford Shale. Closing is expected in first-quarter 2015.

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, which is 2 miles away, and to a complex at Mont Belvieu, Texas, where the company does fractionation.

Already active in the Barnett Shale of Texas, Targa has added compressor stations in Jack and Palo Pinto counties and completed the 200 MMcf/d Longhorn plant in 2014.

The firm announced in October 2014 that it will build a new cryogenic processing plant in the Delaware Basin with a capacity of 300 MMcf/d for completion in early 2016. Targa also acquired a 200 MMcf/d plant in the Williston Basin of North Dakota.

Tesoro Logistics LP

- **Acquired west coast terminalling and storage assets and Tesoro Alaska Pipeline Co. from Tesoro Corp.**
- **Acquired the QEP Field Services natural gas gathering and processing business of QEP Resources**

The San Antonio, Texas-based Tesoro Logistics is an MLP that was launched by refining company Tesoro Corp. in 2011.

The company is slated to acquire more than 2,000 miles of pipeline, including natural gas and crude oil gathering and transmission lines, in a $2.5 billion deal with QEP Resources. Tesoro Logistics gains the assets of QEP Field Services and a 58% stake in QEP Midstream Partners. The deal also includes four natural gas processing facilities and a fractionation plant.

In two acquisitions completed in July and September 2014, the limited partnership bought Tesoro Corp.'s west coast terminalling and storage assets, including three marketing terminals. It also bought Tesoro's refined products pipeline firm Tesoro Alaska Pipeline Co.

Through its subsidiary Tesoro High Plains Pipeline Co. (THPP), the limited partnership is expanding crude oil capacity on its High Plains pipeline to the Mandan, N.D., refinery and to other points of delivery in North Dakota and eastern Montana. THPP also is building a new $160 million pipeline system in Dunn County, N.D., slated for completion in late 2015.

The company also is expanding its Bakken Area Storage Hub terminal near the existing Ramberg Station. It will eventually be developed to store 1 MMbbl of crude oil.

TransCanada Corp./TC Pipelines LP

- **Proposed a crude oil pipeline system to move crude oil from western Canada to refineries in the east**
- **Developing a 435-mile pipeline for Shell Canada Ltd. to move natural gas from the Dawson Creek area to Kitimat area in British Columbia, Canada**

The Keystone XL Pipeline is TransCanada's biggest claim to fame, but even as it awaits approval to finish the Keystone XL, it already is moving substantial amounts of oil from Canada to the Midwest U.S. and into Cushing, Okla.

In late October 2014, the company proposed that its $12 billion Energy East Pipeline could move up to 1.1 MMbbl/d of crude oil from western Canada oil fields to eastern refineries and tanker ports in Quebec and New Brunswick, Canada. The work, if approved by Canadian authorities, would repurpose some of its existing natural gas pipeline to move crude as far east as Ontario, Canada. New pipeline construction would then connect from there to refineries and ports.

In the U.S., the completion of a $2.3 billion Gulf Coast Pipeline project allows up to 830 Mbbl/d of oil 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 in the works will take oil from Nederland, Texas, on to Houston-area refineries.

(Photo courtesy of TransCanada Corp.)

A construction crew finishes another weld along the Gulf Coast Project of TransCanada Corp. The new pipeline entered service in 2014, providing 700 Mbbl/d of new capacity between the Cushing, Okla., crude trading hub and Gulf Coast refiners. It forms the southern leg of TransCanada's sprawling Keystone system.

TransCanada also has 42,500 miles of natural gas pipelines, thousands of miles of oil lines and partial interest in additional assets.

TransCanada is still awaiting U.S. government approvals to complete the last leg of the 36-in. Keystone XL Pipeline, the last 1,179 miles of which has 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 at Baker, Mont., and take it to Oklahoma and Gulf of Mexico refineries.

Valero Energy Partners LP

- **Subsidiary formed in July 2013 and went public in a $345 million IPO in first-half 2014**
- **Initial assets are pipelines carrying crude and refined products to and from Valero Energy Corp. refineries**

Valero Energy Corp. will be the primary customer in the MLP Valero Energy Partners, which will include crude and refined-products pipelines associated with existing Valero refiners in the Midcontinent and Gulf Coast. Those include assets related to refineries in Sunray, Texas; Memphis, Tenn.; and Port Arthur, Texas.

The first assets to drop down to the limited partnership were the Texas crude systems business from various Valero subsidiaries in July. Those include the McKee crude system in North Texas, Three Rivers crude system in South Texas and Wynnewood products system in east Oklahoma.

This isn't 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 MLPs of its own.

Williams Partners LP/ Access Midstream Partners LP

- **Merger with Access Midstream Partners will create one of the largest natural gas pipeline and processing companies**
- **Expanding pipeline from Pennsylvania to New Jersey and into Alabama**

The pending merger with Access Midstream Partners, which Williams leaders expect to close in early 2015, would create a company with more than 21,000 miles of natural gas gathering and transmission lines across most unconventional plays, 1,800 miles of NGL lines and 11,000 miles of oil and gas gathering and transmission pipeline.

Even before the merger, Williams Partners was expanding existing assets in Colorado, New Mexico, Wyoming, the Gulf of Mexico and the Marcellus Shale. The Access merger would add operations in the Barnett, Eagle Ford, Haynesville, Utica and Niobrara shale plays.

Integrated natural gas company Williams Cos. Inc. owns 68% of the partnership and has operations on the Gulf Coast, in the Pacific Northwest, Rocky Mountains, along the eastern seaboard and in the Marcellus Shale in Pennsylvania.

Billions of dollars of expansion plans are in the works, mostly through joint ventures (JV), with completion dates through 2017.

Those capital projects include a $354 million JV in the Utica Shale with Blue Racer Midstream, $600 million on the Leidy line from Pennsylvania to New Jersey and into Alabama and more than $450 million for the Geismar expansion, which began manufacturing ethylene in late 2014.

The Bluegrass Pipeline calls for constructing new NGL lines from the production areas of Ohio, Pennsylvania and West Virginia and connecting them to Texas Gas in Kentucky where NGL will hitch a ride to the Gulf Coast. In coastal Louisiana, Williams is building a large-scale fractionation plant and expanding storage for NGL. ■

Production Plans, Optimization Continue

A Staff Report by **Stratas Advisors**
a Hart Energy company

Although oil prices are falling, efficiencies in the oil field have supported the rapid increase in unconventional production.

Operators are ramping up production from North American shale and tight oil reservoirs even in the face of falling oil prices. The cost of production is decreasing largely as a result of improved drilling and completion efficiencies.

The rapid increase in North American unconventional production can be attributed to improvements in horizontal drilling and hydraulic fracturing technologies. Most of North America's plays have gradually moved from delineation mode, where operators were trying to identify the sweet spots in the plays, to optimization, where operators adjust lateral lengths, the number of fracture stages and the completion cocktail that unlocks hydrocarbon resources. At this stage, these plays are in the harvest mode, where operators have moved toward pad drilling and the optimized completions that are facilitated by drilling multiple wells from a single pad. This has resulted in half-cycle breakeven prices for sweet spots in liquids-rich plays as low as the $40/bbl to $65/bbl range. Pad drilling also is contributing to cost reductions, as operators drill up to 12 wells on a single pad using zipper-fracture jobs on several wells simultaneously that could be targeting multistacked formations. While global oil prices are declining, North American operators continue to wring out further efficiencies.

Stratas Advisors updates its production forecasts and well economics quarterly for each of the 18 unconventional plays covered by the North American Shale Quarterly (NASQ). The forecasts are generated using a proprietary SQL well database, known as the Workbench, which houses production histories for more than 250,000 unconventional vertical and horizontally fractured wells.

Pad drilling

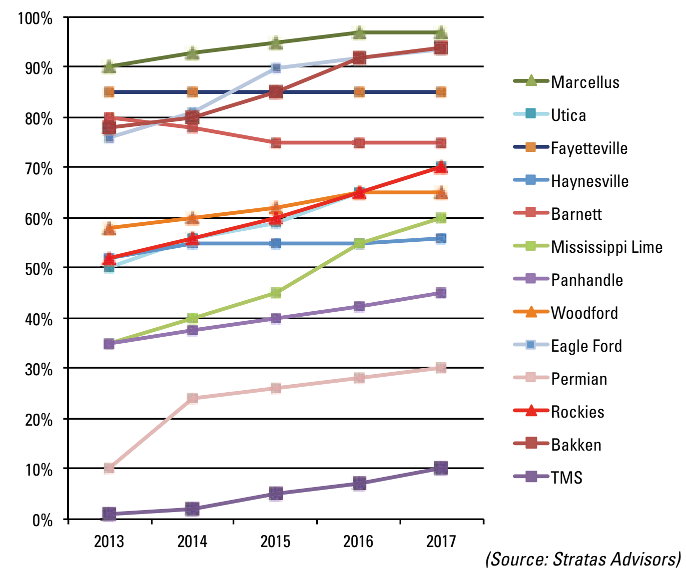
Pad drilling generally applies primarily to plays or portions of plays that are in the optimization or harvest phases of development. This implies that sweet spots have been defined, and most of the acreage is HBP. In the optimization phase, operators test different completion techniques to increase productivity. At this stage, pad drilling begins to increase. In the harvest stage, pad drilling dominates the drilling process.

Today, more than half of the wells drilled in unconventional plays are on pads, with the only exceptions being in the Tuscaloosa Marine Shale (TMS), parts of the Permian Basin unconventional landscape and the light tight oil formations in the Oklahoma/Texas Panhandle.

Hart Energy conducts a survey every quarter on every play to understand how rig prices, utilization and completion technologies are employed from play to play. Our latest survey suggests that pad drilling continues to increase in plays such as the Marcellus, Fayetteville, Barnett, Bakken/Three Forks and Eagle Ford. All of these plays are in harvest phase of the play life cycle where operators have had success and are finding ways to raise return on investment (Figure 1).

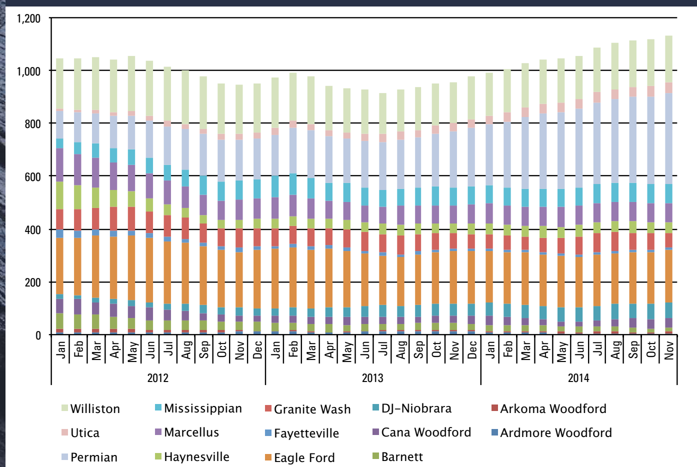
Plays such as the Panhandle, Mississippi Lime, Woodford, Utica, Rockies and Haynesville where operators are testing different completion techniques are considered to be in the optimization phase and are seeing pad drilling pick up quickly as well.

FIGURE 1. Percentage of Wells Drilled Using Pad Drilling



(Source: Stratas Advisors)

FIGURE 2. Horizontal Rig Count in US Plays



(Source: Baker Hughes)

Plays such as the TMS where operators are still de-risking acreage to find sweet spots are in the delineation phase, and pad drilling techniques are not yet being applied.

The Marcellus has the highest percentage of wells drilled on pads, and Stratas Advisors expects more than 90% of wells to be drilled on pads in the Eagle Ford and Bakken by 2016. Pad drilling also is picking up in the Permian as operators move from vertical to horizontal development.

Rig count

Pad drilling affects rig count, and hence tracking play growth using rig count numbers is increasingly challenging. Although there are fewer rigs in mature plays, the number of wells drilled and consequently produced has increased due to rig efficiency gained through pad drilling.

Using the Baker Hughes North America Rig Count, Stratas Advisors estimated there were 1,417 drilling rigs in the first week of November 2014 operating in unconventional formations vs. 1,311 rigs a year ago (Figure 2). Looking at the top U.S. plays, the Williston Basin had 193 rigs in November 2014 vs. 177 in November 2013; the Eagle Ford had 212 in November 2014 vs. 226 in November 2013; the Permian had 567 in November 2014 vs. 466 in November 2013; and the Marcellus had 82 rigs in November 2014 vs. 87 in November 2013. The reduction in rig count in the Marcellus and Eagle Ford can be attributed to pad drilling and other rig efficiency improvements.

Vertical rigs are being deployed less and less in unconventional plays as operators shift to horizontal drilling. This is evident from the Permian and Rockies plays where the horizontal rigs are ramping up. The Permian horizontal drilling activity increase is evident from the horizontal rig count rising to 342 in November 2014 from 211 a year ago and vertical rigs declining by 8% year-over-year (yoy). The Denver-Julesburg (DJ) Basin Niobrara horizontal rig count also increased by 27% yoy.

In Canada, the Montney, Cardium and Duvernay are the unconventional plays that continue to attract operators due to their liquid content. The Canadian horizontal rig count increased to 410 in November 2014 from 385 a year ago (Figure 3).

Production

The majority of North American production comes from five major U.S. plays: the Bakken/Three Forks, Permian, Eagle Ford, Marcellus and Rockies plays. The Permian and Rockies plays are tight oil formations that have been producing conventionally for many decades but now are being rejuvenated using unconventional drilling and completion techniques.

Most of the unconventional Canadian plays are in early development stages, while the Montney is a mature play where liquids-rich areas are highly sought after and operators are optimizing drilling and completion techniques.

In addition to the top plays, other shale and tight oil plays in the U.S. and Canada contribute to North American production growth. These include the Woodford, Granite Wash, Anadarko tight oil, Mississippi Lime, Utica, Haynesville and Barnett in the U.S. and the Duvernay, Cardium and Alberta Bakken in Canada.

The Fayetteville and Horn River are dry gas plays where activities remain subdued. The TMS is a more recent liquids-rich play where operators are delineating acreage and working to reduce well costs and increase productivity.

Stratas Advisors' production forecasts are estimated using history-matched type curves and well count forecasts based on geology, well spacing assumptions and ultimate well count estimates that are a function of an assumed well spacing appropriate to the underlying prospectivity within regions of the play as defined by the geology. Other factors, such as gas flaring and ethane rejection, are accounted for in the relevant play level forecasts.

FIGURE 3. Horizontal Rig Count in Canadian Plays

(Source: Baker Hughes)

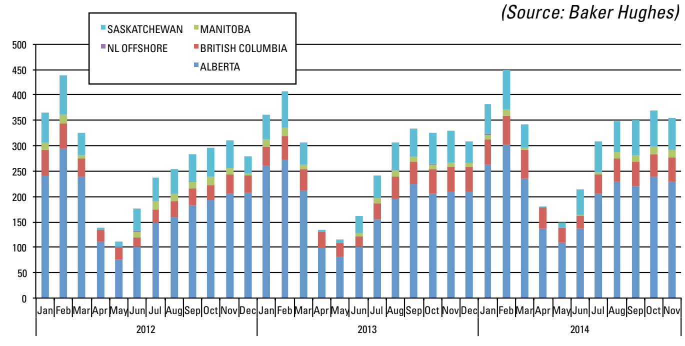
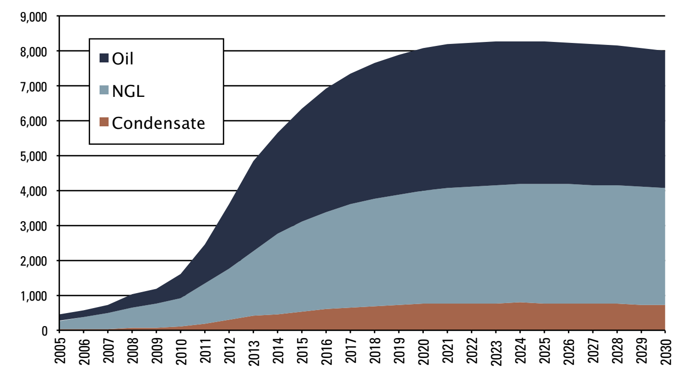


FIGURE 4. Liquids Production from 18 Unconventional Plays (Mbbl/d)



(Source: Stratas Advisors)

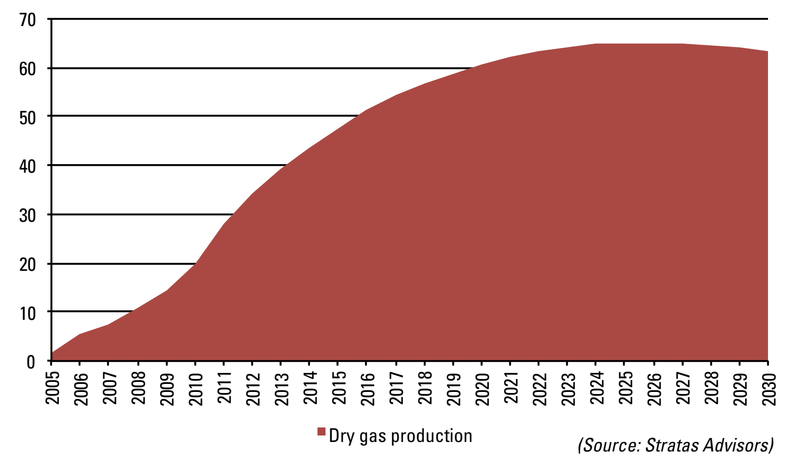
Liquids-rich plays

Liquids-rich plays such as the Bakken/Three Forks, Eagle Ford, Permian, Rockies, Panhandle and Anadarko tight oil, Woodford, Mississippi Lime, Utica, TMS, Montney, Duvernay and Cardium continue to attract operators. Stratas Advisors' reference case predicts oil production will increase rapidly to reach a peak of 4.11 MMbbl/d in 2021, and condensate production could reach a peak of 786 Mbbl/d in 2024. NGL production is expected to peak at 3.41 MMbbl/d in 2026. The total liquids production in the forecast period from 2014 to 2030 is estimated to be nearly 48 Bbbl (Figure 4).

Bakken/Three Forks production continues to grow with liquids production averaging 1.04 MMbbl/d in 2014, and Stratas Advisors expects it to peak at 1.34 MMbbl/d in 2018. The state of North Dakota announced new regulations in late 2013 to reduce and eliminate gas flaring. The NASQ forecast takes into account historical gas flaring in the play and assumes that flaring will be reduced by 2020. Gas and NGL production forecasts are estimated by taking the above flaring assumptions into account.

The Eagle Ford production forecast was determined by estimating production from multiple maturity windows separately and then aggregating them. Stratas Advisors separated the play into west condensate, center condensate, west gas, center gas, center low maturity, center oil and east regions. Well count and type curve forecasts for each region were done separately. Stratas Advisors expects NGL and condensate regions to be developed first followed by gassier acreage development later in the forecast period. Eagle Ford liquids production continues to grow with production averaging 1.31 MMboe/d in

FIGURE 5. Dry Gas Production from 18 Unconventional Plays (Bcf/d)



(Source: Stratas Advisors)

2014, and Stratas Advisors expects it to peak at 1.66 MMboe/d in 2019.

The Permian play was divided into six regions. Stratas Advisors expects future production growth to occur differently from how it has historically developed in the play, as operators are shifting from vertical to horizontal development. Horizontal wells have resulted in large improvements in well productivity and, with reductions in spud-to-rig release time, are seeing lower well costs. Stratas Advisors expects a rapid increase in activity in the Bone Spring, Midland Wolfcamp and Delaware Wolfcamp and a gradual decline in vertical drilling in the Spraberry and Dean formations in the Midland Basin. Permian unconventional liquids production continues to grow with production averaging 760 Mbbl/d in 2014, and Stratas Advisors expects it to peak at 1.74 MMbbl/d in 2030.

The Rockies total production includes hydrocarbon volumes from four basins: the Greater Green River (GGR), Powder River, Piceance and DJ basins. Each basin is evaluated separately because of differences in the hydrocarbon content and activity levels. The DJ Basin has the highest current activity, but major operators are now moving toward the Powder River Basin. The Parkman, Sussex, Teapot and Shannon are the primary target formations in the Powder River Basin. NASQ currently does not cover the Mancos Shale in the Rockies but will extend coverage once activity picks up. The Piceance and GGR basins are liquids-rich gas plays where the activities are slower because of low prevailing natural gas prices. Rockies liquids production continues to grow, averaging 526 Mbbl/d in 2014 and will peak at 825 Mbbl/d in 2025.

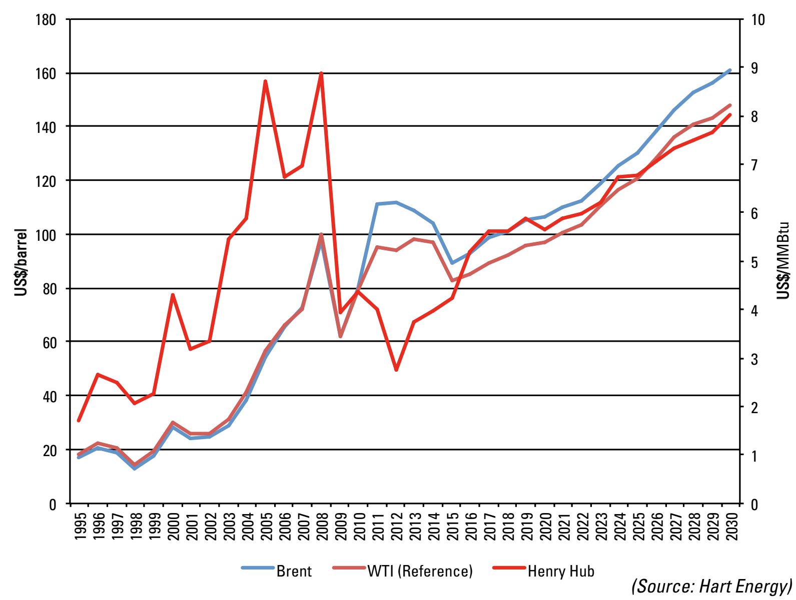
The Granite Wash, Anadarko tight oil, Mississippi Lime and Woodford are Midcontinent plays that contribute to the overall yearly production growth. The South Central Oklahoma Oil Province (SCOOP) and STACK areas are hot as operators drill multiple pay zones such as the Woodford, Meramec and Springer Shale. Hence, Woodford Shale production in the Anadarko and Ardmore basins continues to increase, while the activity levels in the gassier Arkoma Basin remain low. Stratas Advisors does not cover the Hunton in the Midcontinent forecasts. The Tonkawa, Marmaton and Cleveland are tight oil formations in the Anadarko Basin that have marginal economics and lower activity levels. The shallower Mississippi Lime, which was conventionally drilled for many decades, has complex geology that very few operators have had success reviving. Despite a few setbacks, total Midcontinent production continues to grow with liquids production averaging 477 Mbbl/d in 2014 and peaking at 708 Mbbl/d in 2023.

The Utica play has gained attention as many operators have reported highly productive well results. The play activity is currently concentrated in the core area of eastern Ohio. Stratas Advisors expects production growth as operators continue drilling and delineating the southern portion of the play. The Utica playwide production forecast increased to 226 Mboe/d in 2014 with a peak of 616 Mboe/d in 2029.

Although the TMS play is still in the early delineation phase, major operators continue to increase drilling activity. A base case TMS forecast estimate for 2014 is at 5.9 Mboe/d with peak production in 2029 at 31.56 Mboe/d. Goodrich Petroleum seems to be the leader in the TMS at this time.

Canadian plays such as the Montney, Duvernay, Cardium and Alberta Bakken (Exshaw) contributed about 5% of liquids production in 2014. The total unconventional liquids production from these

FIGURE 6. WTI Crude Oil and Henry Hub Price Forecasts



(Source: Hart Energy)

Canadian plays is at 267 Mbbl/d in 2014, and that amount is expected to grow continuously to peak at 786 Mbbl/d in 2030.

NGL-rich plays continue to attract capex. Stratas Advisors projects that NGL production will increase to 3.35 MMbbl/d in 2030. The major contributors include the Marcellus and Utica in the Appalachian Basin and the Eagle Ford, Bakken, Rockies and Mid-continent plays. The Marcellus and Utica contributed about 40% of total NGL production in 2014. The Bakken and Rockies together contributed about 15% of total NGL production in 2014.

Natural gas plays

Natural gas plays such as the Marcellus, Barnett, Haynesville, Fayetteville and Horn River also contribute to yoy production growth (Figure 5). Appalachian Basin development increased rapidly in 2014 with operators targeting the Upper Devonian, Marcellus and Utica shales. The Marcellus Shale, which is currently active in Pennsylvania, West Virginia and Ohio, continues to see a steady increase in production as operators allocate more capex and as infrastructure constraints are being alleviated, allowing the gas to reach markets. The majority of the activities are focused in the southwestern liquids-rich area and northeastern dry gas areas of the play. Stratas Advisors estimates 2014 production at 15.47 Bcfe/d, in line with the U.S. Energy Information Administration's estimates that the play would exceed 15 Bcfe/d in 2014. Stratas Advisors also estimates ethane rejection based on fractionation capacities and NGL/ethane infrastructure capacities to calculate the gas forecast in the Appalachian Basin.

The Barnett play hit peak production in 2011, and production has been declining steadily since. Most of the current drilling activity in the play is in the "combo area," the liquids-rich part of the play. With low natural gas prices, Haynesville production also has declined. Haynesville production is expected to increase in late 2016 into 2017 when LNG facilities come online. Fayetteville production remains subdued with only a few smaller players focusing in the play besides Southwestern Energy. Drilling activity in the Horn River remains suppressed due to lack of a market for the gas. Although production from dry gas plays is declining at present, Stratas Advisors anticipates an increase in activity contingent on an improvement in natural gas prices.

Price environment

Favorable high oil prices over the past four years have enabled operators to increase production from many liquids-rich and oilier unconventional plays in the U.S. But the pace of drilling in the oilier plays is slowing because of falling oil prices (Figure 6). According to Hart Energy's Market Intelligence survey of drilling contractors and operators in the Bakken and Marcellus, operators are cancelling or postponing newbuild rig orders. And some Bakken-leading producers, including Continental and Hess, have announced a pullback in capex.

As stated earlier, breakeven prices for the core areas of liquids-rich plays that have passed through the delineation mode and optimization phase into the harvest phase indicate these plays should remain on production if prices remain in the $70 to $80 range. Although some operators might have higher breakeven prices in different parts of these plays, the plays on aggregate have enough operators to lower breakeven prices to continue production.

Stratas Advisors' oil price forecast suggests there will be an industry pullback next year and into 2016. However, a natural gas price forecast suggests there could be a switching of capex to gassier plays at the expense of the liquids-rich plays—basically a reversal of the activity from 2010 to first-half 2014.

The region that should benefit the most is the Appalachian Basin, where the Marcellus Shale gas play is one of the lowest cost sources of gas in North America. Although the Utica is still in the delineation mode, it too should benefit first in regard to liquids-rich plays. While drilling activity is forecast to decline in the Utica in 2015, Stratas Advisors foresees a slight uptick in 2016 and a strong uptick in 2017.

The Eagle Ford and Bakken/Three Forks also should see a slight decrease in activity despite the fact that they are low-cost, light, tight oil sources. Expectations are for operators to be more judicious with their capex for the Permian. In the Midcontinent, the Mississippi Lime play will suffer the most as economics were only marginally profitable for SandRidge and MidStates Petroleum—two of the top five producers in the play. The SCOOP and STACK also will see a downturn in activity.

The Rockies play has several liquids-rich formations, each with its own economics. The region will see a pullback, but some formations might attract more capex in 2015 to 2016 than in 2014. As far as the gassier plays, capex will flow to the low-cost producers. The plays that should benefit the most other than the Appalachian Basin should be the Fayetteville and some formations in the Panhandle—such as the Granite Wash—and the Eagle Ford gas window. The deep Haynesville play, which sits closest to the Gulf Coast LNG infrastructure, will see limited capex increases because of higher well drilling and completion costs. ■

While another busy day begins in Midland, Texas, activity worldwide varies in the development of unconventional resources. Here, Helmerich & Payne Rig 232 drills Crossbar Ranch #3025H targeting Wolfcamp B for RSP Permian.

(Photo by Tom Fox, courtesy of Oil and Gas Investor*)*

Ready, Set, Saturated – Shale Hits the Road

By **Nissa Darbonne**, Contributing Editor

Some reticent countries' embrace of developing their unconventional resources is warming, and some others' interest has become red hot. Yet, challenges remain.

Where oil and gas have been produced in the past, there is source rock. Where there is source rock, there is the potential for an unconventional resource play. Thus, unconventional resource plays are possible across the globe in known basins—and elsewhere, where oil and gas have been lightly or not yet explored.

But the uptake of unconventional resource E&P outside North America will continue to be slow, concede U.S. tight rock explorers who have advised operators, legislators and regulators in other countries.

"A lot of people ask why shale exploration is so advanced in the United States—and increasingly in Canada—and it hasn't happened anywhere else of scale," said Chris Wright, CEO of Bakken-focused Liberty Resources II LLC. Wright has twice testified to the U.K. House of Lords on the nature of tight rock plays and their potential. His frack-mapping and -diagnostic firm, Pinnacle Technologies Inc., worked in the 1990s on the Cotton Valley sandstone trials that led to an economic hydraulic fracturing recipe in the Barnett Shale. Pinnacle is now part of Halliburton Co.

"By far, the biggest reason is simply property rights," Wright said. "In the U.S., private landowners own the mineral rights. Their compensation is the same as ours—the producer. The more oil and gas coming out, the more compensation. Our interests are aligned.

"Elsewhere, the mineral rights are owned by the government—not an ideal partner for the dynamic, innovative companies that have driven the shale revolution."

Europe-based petrochemicals manufacturer Ineos Group Ltd. might change that. Founder and chairman Jim Ratcliffe announced on Sept. 28 that it is offering 6% of its shale gas revenue to homeowners, landowners and communities in Scotland's Midland Valley and elsewhere in the U.K. where it might obtain leasehold. The company estimates the revenue-sharing might exceed $4 billion.

"It's what they do in the U.S. and we think it is right to do this here," Ratcliffe said in a press release. "It democratizes the shale gas revolution."

Kent Bowker and Dan Steward, both geologists, and Nick Steinsberger, a petroleum engineer, are advising Ineos on producing from shale. The triumvirate was on the Mitchell Energy & Development Corp. team in the late 1990s, which figured out how to make economic amounts of gas from the Barnett, spawning the Fayetteville, Marcellus, Haynesville and other tight gas plays.

Ineos already has a contract for ethane extracted from Range Resources Corp.'s Marcellus production for delivery to its plants in Scotland and Norway and a 51% interest in shale formations in some 81,000 acres in Scotland.

Scotland's Midland Valley is a long-time conventional oil and coal-gas producer. In northern England, however, the Bowland-Hodder Shale might be more challenging, Bowker said. "The geology there is much more complex than we have here. The geologists there will be quick to point out—and I agree—that we have it easy here, compared with the geology they have. But, if you can spend time with people who know the geology there, apply what we've learned here and be patient, you may come up with some ideas that work.

"It's going to be high-risk; there's no doubt about it. It's not going to be a slam dunk, but I think they have some real potential."

Scotland's voters, in mid-September, rejected ceding from the U.K., which was scheduled to host an onshore-licensing round on Oct. 28. "They got through that—whether Scotland was going to be a different country," Bowker said. "Now, developing onshore shale is the next big deal."

Wright noted that, unlike countries that have expropriated property, such as Venezuela and Argentina, the U.K. is advantaged by its reliable history of respecting property rights, thus it is potentially attractive to investors. Meanwhile, the country needs energy to refuel its industries.

"Their industrial revolution was achieved with access to cheap energy. Now, they have expensive energy, which is why the blue-collar communities in the midlands and north of England are so depressed these days," he said. The area, including Liverpool, Manchester and Leeds, is the home of the Bowland and Hodder shales.

Wright expects development to be slow: Nascent unconventional resource exploration is, initially, more time-consuming than U.K. North Sea exploration, for example, where the nature of the reservoirs already is known. "You know 90% of what you want to do five years before you start construction.

"You can't do that with unconventional rocks. They're not permeable, and you don't know where the sweet spots are. We don't know the mechanism that is going to drive production. You need to go in with an idea and be ready to innovate quickly."

Being quick and nimble have been hallmarks of independent E&Ps rather than supermajors. The former has less cash, thus less time, for tooling around; the latter, more cash, thus more time. "This is why it's been Mitchell, Devon [Energy Corp.], EOG [Resources Inc.] and other small and midsize companies that have driven the shale revolution," he continued. "But who partners with governments most commonly? Very big entities."

On the other hand, Bowker said, "The people of the U.K. are clamoring for natural gas. I think they got down to seven days of gas storage. That's scary." And Germany is switching from nuclear-fueled power generation to coal-fired as a result of the Fukushima accident in Japan. "That just floors me. Why are they doing that? They have shale resources. I don't know if Europe accepts its energy needs.

"Obviously, Britain is more in tune than others with what needs to be done."

Elsewhere in the EU

There is great potential for unconventional resource production elsewhere in Europe, which has long produced from conventional rock, Bowker said. "But outside of Poland, there hasn't been much political will." Meanwhile, Poland turned out to be a dud.

"I studied the Baltic Basin [in northern Poland] for a couple of clients and advised both of them to get out. Unfortunately, the Baltic Basin was a bit oversold. The USGS [U.S. Geological Survey] and the Polish government were looking at it through rose-colored glasses.

"But other places in Poland and Eastern Europe could work."

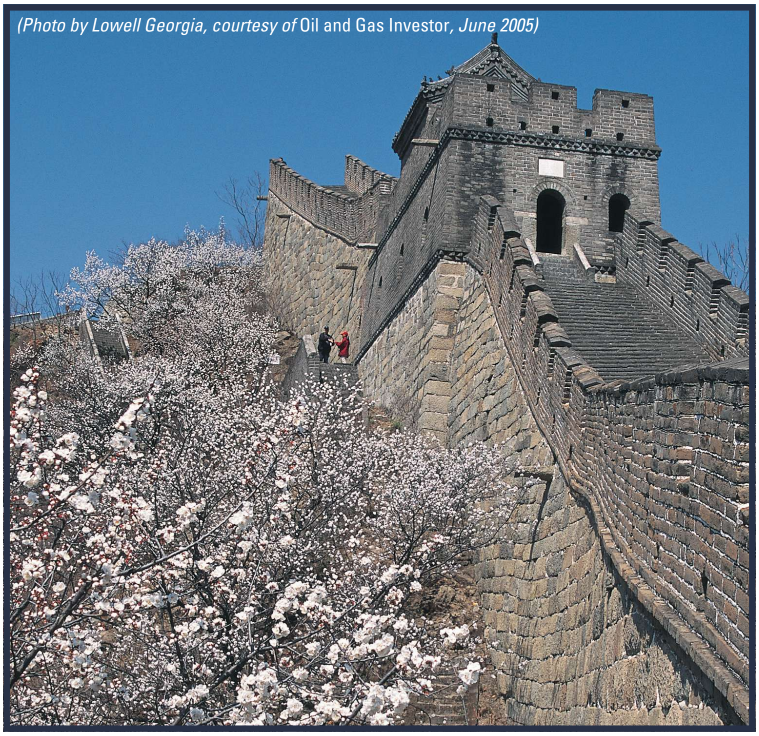
France has simply outlawed hydraulic fracturing. "For European nations, it is simply too easy to have a small protest group stop or slow anything from happening," Wright said. "It is very easy to stop something from happening in Europe, and it's quite hard to make something happen. European nations are much more afraid of doing something and it going wrong than of not doing something when something is wrong.

"So, you have the relatively poor condition of blue-collar and low-wage workers in the U.K., Germany and elsewhere. Europe, in general, is truly a tragedy, and it is very hard to get the government to do something about it. The wealthy are highly activistic and afraid of anything new."

China

The government owns both the land and mineral rights in China, but it is highly incented to produce more of its indigenous oil and gas resources. "They are very committed to trying to get a shale revolution going there," Wright said.

The work has been underway for more than 20 years. Steward, the ex-Mitchell geologist who is co-advising Ineos with Bowker and Steinsberger, has a photograph of a contingent of Chinese oil-company officers who visited Mitchell Energy's offices in 1988 to understand the Barnett Shale. Mitchell Energy had begun tests of the shale's potential in 1981. The



(Photo by Lowell Georgia, courtesy of Oil and Gas Investor, June 2005)

While China faces significant technological challenges in shale resource development, the country is highly incented to increase production of unconventional resources.

visit was initiated by the U.S. State Department at the request of the Chinese government.

"They are able to drill and develop their onshore resources," Wright said. "Do they have the right mix of innovative companies? They don't right now. They also have geology that is complicated by when India crashed into the Asian continent and formed the Himalayas. It created a significant, compressive stress in a lot of the shales.

"They have hydrocarbon-saturated shales, but the technical challenge is a bit bigger there."

Dick Stoneburner, the geologist who led Petrohawk Energy Corp.'s development of the Haynesville Shale and its horizontal, commercial discovery of the Eagle Ford Shale, said China is making headway. "They need it the most. They import high-priced gas, so they're incentivized to not only find and produce domestic resources but to replace their significant coal usage.

"They are under domestic pressure to reduce their air pollution and global pressure to reduce their greenhouse-gas emissions."

Australia

Stoneburner is the retired president of BHP Billiton Petroleum Ltd.'s North American shale production division and is currently a managing director of private-equity firm Pine Brook Partners LP. A 2013 American Association of Petroleum Geologists distinguished lecturer, he has presented in Australia, Amsterdam, Barcelona and Vienna.

"Australia is certainly there [and] ready," he said. "They're in a very early exploration phase, but it's a receptive political regime, by and large. It has infrastructure—at least in some of the basins—and I think it has quite prospective rock from a reservoir-quality standpoint.

"The biggest issue in Australia is cost. Everything in Australia is very expensive. It's unionized, and the country is vast." The distance between the Perth and Surat/Bowen basins by highway is 2,700 miles—roughly that of the route via highway from Los Angeles to New York City. Between the two is largely unpopulated desert, lacking services.

"So, from top to bottom, you have a much higher operating environment in Australia, and that's the challenge in making these plays commercial," Stoneburner said. "Their drilling and completion costs will be significantly higher for a comparable U.S. Lower 48 well. It makes the burden of commerciality more precarious.

"But, on the other side of that, they have $10 gas. It doesn't take a 5- or 10-Bcf well to be commercial."

How the resources will be developed is also of interest. "They really don't encourage a lot of competition," he continued. "They will, typically, give very large licenses and, quite often, to companies that aren't well capitalized.

"We all know the capital intensity of shale plays. So a lot of these companies are creating joint ventures [JVs] with IOCs [international oil companies] and NOCs [national oil companies], but it creates a slower pace of development when you have so many acres in the hands of so few operators."

U.S. shale plays were developed at an almost frenetic pace, while operators were faced with lease expirations. Typically, one well will hold a section, which is 640 acres or 1 sq mile. Many private-lease terms are for five years; some are for as few as three years.

"We were on the other end of the spectrum," Stoneburner said. "We had so many players with fairly short lease terms, relative to a lot of these concessions people get overseas. Probably some measured pace in between these two examples would be ideal to get some of these international plays beyond the exploration phase into the appraisal and development phases."

Argentina, Russia

Wright agrees that Australia's unconventional resources are highly prospective. Argentina and Russia each host vast, quality shale as well. "They both could be massive, massive shale producers. But there you have, again, the property rights issue and regulatory and fiscal problems again," he said.

Argentina expropriated Repsol SA's interest in YPF SA in 2012. Meanwhile, the U.S. and EU have imposed sanctions against Russia over its involvement in Ukraine. "It is now illegal for American or European countries to bring technology or innovation into developing unconventional resources in Russia," Wright said. "In Argentina, it is simply the risk of dealing with the current government. Both of these will change one day." Bowker said of Argentina, "It's a shame, a real shame." Journalists had contacted him recently to discuss the country's Vaca Muerta Shale. "They asked me, 'You think it will work?'

"I said, 'Maybe. But, if it had been left up to the majors in the U.S., shale would still be shale. It wouldn't be producing. Independents did this, and no small company can invest in Argentina with that kind of country-risk profile. The resource might be there. Talk to your president. Your country could be one of the richest in the world, but you decided to go socialist and that's what you get.'"

Paul Zecchi, co-founder and president of Central Resources Inc., a U.S. independent that has explored abroad since 1997, currently operates in California, Argentina, Brazil and Canada. His first foray outside the U.S. was in Argentina; it was tough sledding. "We fell off a few times, skinned our knees and elbows, knocked off a shoe or two and wrecked at least one," he told *Oil and Gas Investor* in a recent article. "We're used to it now. In time and with experience, you become a lot smarter, know what to look for and know what you don't know."

Zecchi is confident the investment climate will improve when Argentina's president leaves office in 2015. "There is much anticipation that her successor will be significantly more business-oriented. I get a call a week now about our plans. In the past, if I called someone in reference to a potential acquisition there, I would be talking to myself as soon as I said 'Argentina.'"

And the U.S. itself is not without fiscal risk, Zecchi added. "I have to remind some of my friends from time to time that we did have a windfall-profits tax here."

Canada, Colombia, Tunisia, Turkey, the Middle East

Wright said Colombia and perhaps Tunisia and Turkey have shale potential. And Canada has world-class

(Photo courtesy of Santos)

Santos estimates it will spend about $4.2 billion (AU$5 billion) over the next 10 years on drilling and infrastructure in Australia's Cooper Basin, including adding additional field gas compression and more gathering lines.

resources and a lot of innovative, go-getter companies. Several of its unconventional resource plays already are online, including the behemoth oil sands.

"Canada has most everything needed to make an unconventional resource revolution happen," Wright said. "But the problem in Canada is simply takeaway markets. Their only external market for hydrocarbons is the U.S., and the U.S. is ground zero of the shale revolution.

"The Canadians have to compete with the cost of farther transportation to sell into a country that has low-cost, massive shale. Canadian operators will accelerate when they have export markets besides the U.S."

Stoneburner also likes Colombia as well as Argentina for having good rock and "at least acceptable" fiscal regimes.

There also have been reports of Middle Eastern countries looking at their shale reservoirs. "There is probably a lot more going on in the Middle East than we know about because this exploration is in basins that are already productive and because there is no need for them to publicize it," Stoneburner said. "From what I've heard, there is a fair amount of success occurring in the Middle East."

Meanwhile, "I think Europe will lag," he continued. "It is just a challenged environment. Politically, it just doesn't embrace drilling like some other countries." Overall, he expects Australia and Latin America will lead tight rock development outside of North America.

Mexico

And that includes Mexico. Stoneburner said, "If they proceed with what they have outlined, which I have every confidence they will, Mexico could have a pretty accelerated exploration phase in the coming years—if those who get the licenses will spend the capital these plays will need."

Mexico has several known hydrocarbon basins, thus it has source rocks. Possibly, even its conventional resources are underexplored. "I would certainly say Mexico is underdeveloped. They haven't had the capital, technology and human resources we have," he added.

The country nationalized its hydrocarbon resources in 1937 and recently changed its constitution to allow non-national ownership of its reserves. It is currently a net gas importer and is decreasingly an oil exporter. Is exploration of its resources roughly as advanced as that of the U.S. Lower 48 in, say, the 1940s?

"Whether it is 80 years of lag or 30 or 20, they are certainly lagging in the unconventional space and in their deepwater exploration," Stoneburner said. "I'd say their deepwater gulf and the unconventional shale resources are virtually untapped. There is no reason either one of these shouldn't be significant due to their proximity to the U.S. deepwater gulf and to the U.S. shale plays.

"There is no doubt their deepwater and shale opportunities are totally virgin."

Mexico has 42 Bbbl of 3P resources and 111 Bboe of conventional and unconventional prospective resources. Mexico has vast undeveloped potential of unconventional and deepwater opportunities.

Some of the largest deepwater Gulf of Mexico discoveries have been just inside the U.S. side of international waters. Among these is Trident, which Unocal Corp. drilled in 2001 in Alaminos Canyon Block 903. It involves seven blocks and is now owned by Norway-based Rocksource ASA. A Unocal vice president said of the discovery at the time that the size of the structure Unocal tested had "up to 10,000 acres in structural closure."

Bowker said, "Mexico has recognized it needs to bring in external experts with the right incentives. There is huge potential there if the government stays out of the way and allows people to apply the best technology and understanding of reservoirs that we have here in the U.S."

China has been leveraging relationships with U.S. operators in understanding unconventional resources via JVs in the Eagle Ford and other shale plays. "It's been interesting to watch," Bowker said. "China decided to get its expertise by buying interests in the U.S. and hoping to take that technology home. Mexico may be going about this better: 'Instead of sending our engineers to the U.S. to learn, we'll just have the U.S. expertise come straight here.'

"I think that's the best way to do it. There are political issues that need to be overcome but, geologically, there is huge potential there."

Longtime U.S.-based, energy-private-equity provider EnCap Investments LP has co-committed 50:50 with international investor Riverstone Holdings LLC $450 million in Mexico's first independent E&P company, Sierra Oil & Gas. A Mexico-based private-equity firm has committed $75 million.

Sierra CEO Ivan Sandrea said in the release, "The opening of Mexico's energy sector represents a transformational opportunity for the country. Mexico has a world-class petroleum system, significant oil and gas industrial base,...professional institutions, and...human capital and is one of the most progressive economies in the world."

While Mexico is a net importer of natural gas, there is a concern about how much will be invested in exploiting the country's gas resources when it can be bought for $4/Mcf currently from the U.S. via a pipeline connect at the border. "I'm sure operators in the U.S. will be happy to sell Mexico all the gas it wants," Bowker said.

And many U.S. operators have plenty to work on without looking abroad. "The problem is it's just too exciting back home," he concluded.

Opening Mexico's hydrocarbon reserves to non-national ownership also could prompt Mexican entities to seek ownership of U.S. oil and gas reserves. But Dan Pickering, an equity analyst, petroleum engineer and co-president of investment-banking firm Tudor, Pickering, Holt & Co., doesn't expect much of that. "If Mexico progresses as it appears it will, I think they will have plenty to do there. Their own sandbox is pretty attractive."

Pemex, Mexico's state-owned oil company, has been saddled with contributing some of its profits to the government and lacks the cost efficiencies that investors require of privately funded E&Ps. "The name of the game in the U.S. right now is efficiency," Pickering said. "I just wouldn't see Pemex as a particularly competitive player in the U.S. upstream business. You have to be the low-cost player in gas, and you'd better be low-cost in oil because there is more competition.

"I don't think Pemex is coming this way."

Meanwhile, Mexico's independent E&Ps "will be busy with how to attack opportunity in Mexico."

Foreign operators might team up in JVs with Mexican entities in trade for their understanding of the country. "It will be helpful to have a Mexican partner, even if all that partner is doing is bringing in some money and relationships," Pickering said.

Zecchi said in the *Oil and Gas Investor* article that Central Resources is looking to invest in Mexico and concurs that local knowledge is essential in operating abroad. "When entering a foreign country, something you need to know is that you can't do it alone. A lot of U.S. companies fail internationally, thinking they will go in with a bunch of expats, expecting it is going to be a taut ship.

"The expats may be more technically knowledgeable, but it is a foreign country and things are different—not better, not worse, just different. When in Rome, do as the Romans do. And that means bringing in local expertise to assist in the launch and ongoing operations." ■

Nissa Darbonne, editor-at-large for Oil and Gas Investor *magazine, is the author of* The American Shales, *the history of the U.S. shale plays, their founders and their leaders.*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Additional Information on the Top 20 North American Unconventional Plays

For more details on the top 20 North American unconventional plays, consult the selected sources below.

By Ariana Benavidez
Associate Editor

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Signs of a new oil boom sprout among the scenic scrub around Midland, Texas. ***(Photo by Tom Fox, courtesy of* Oil and Gas Investor*)***

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