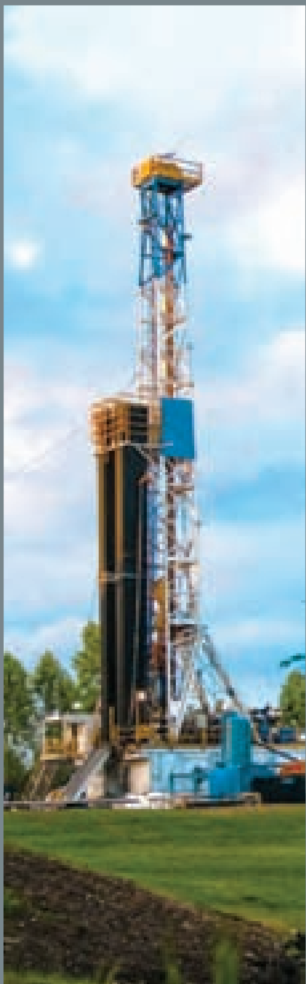
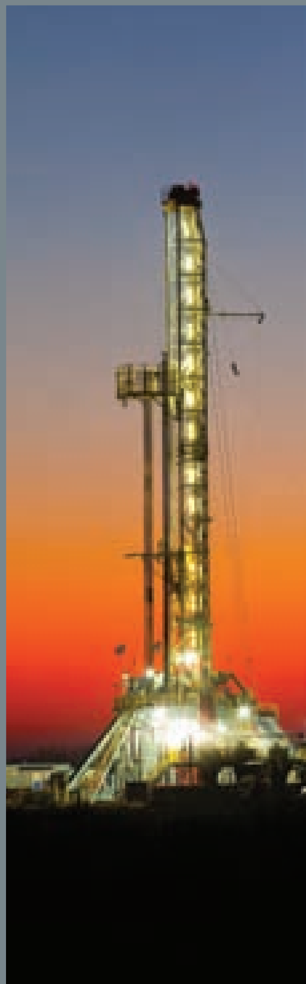
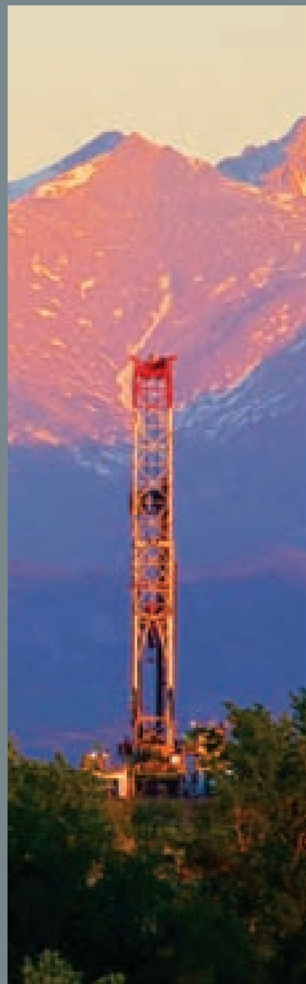
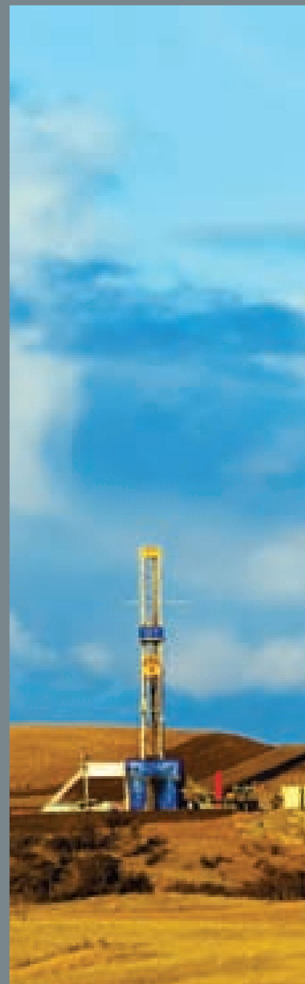
THE TOP 20 LIQUIDS-RICH PLAYS

2012 North American Unconventional Yearbook

A Supplement To

Oil and Gas Investor

E&P

MIDSTREAM Business

2012
North American Unconventional Yearbook

A supplement to *E&P, Oil and Gas Investor,* and *Midstream Business*

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2012 NORTH AMERICAN UNCONVENTIONAL YEARBOOK

In an extension of Hart's unconventional resources playbook series, known for its in-depth coverage of the most compelling shale plays in North America, the 2012 North American Yearbook presents the most important facts and figures on the Top 20 liquids-rich plays in the US and Canada. This second in an annual series of yearbooks provides an overview of current activity, snapshots of the regional plays, profiles of key players, a review of technology, a look at midstream activity, and economic analysis and data. Like the playbooks, this yearbook includes a full-color map. To learn more, visit ***www.ugcenter.com/subscribe***.

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On the cover (left to right): Activity continues in North America's unconventional plays, including the Marcellus (*photo courtesy of Chesapeake Energy Corp.*), the Eagle Ford (*photo courtesy of Newfield Exploration Co.*), the Niobrara (*photo courtesy of Anadarko Petroleum Corp.*), and the Bakken (*photo courtesy of Marathon Oil Corp.*).

(Photo courtesy of Continental Resources Inc.)

Unconventional Completions, Techniques Return Oil the Throne

By Larry Prado
Activity Editor, *Oil and Gas Investor*
Hart Energy

US E&P companies are reshaping their portfolios to include unconventional drilling in liquids-rich gas plays.

Civil unrest in the Middle East, the February 2011 uprising in Libya, and international sanctions against the Qaddafi regime stirred great fear of reduced oil production by the 17th highest producing nation in the world. Although several key OPEC members lead by Saudi Arabia raised oil production to stabilize increasing oil prices, the threat of oil shortages prompted US operators to increase oil exploration and production.

In addition to international political worries, falling gas prices, the disparity between oil and gas prices in the first part of the year, and the Macondo accident drove E&P companies to reshape their portfolios to unconventional drilling in liquids-rich gas plays such as the Niobrara, the Eagle Ford, the Bakken, and the Permian Basin. Smaller US operators also increased recovery and revived conventional exploration and drilling in shallow, older fields across Illinois, Indiana, and Ohio.

A Baker Hughes rig count activity report showed that by August 2011, more than half (53.9%) of the rigs working nationwide were drilling oil wells (1,055), while less than half (45.7%) were drilling gas wells (896). By drilling type, the number of rigs drilling horizontal wells rose by 19 to 966. Twelve fewer rigs were drilling vertical wells (523) and the directional rig count dipped by one to 211.

According to IHS Inc., 2011 well completions through July increased almost 21%, and oil well completions increased almost 40% compared to July 2010 numbers. The oil-directed rig count in July exceeded 54% for the first time since June 1972.

A "tight oil renaissance" seems to be occurring with improving and, in some areas, record-setting results from the Niobrara, the Bakken, the Granite Wash, the Mississippian, the Eagle Ford and the Permian Basin's Wolfcamp and Bone Spring plays. Following improved production techniques, the Utica play in the northeastern US could be on the brink of development due the focus by Chesapeake Operating Inc. The Uteland Butte member of the Green River Formation in the Uinta Basin could be a new entrant in commercial tight oil plays, and operators plan to revisit the Cane Creek play in the Paradox Basin.

Pictured far left: The sun highlights a drilling rig and a nearby church in the Bakken play in the Williston Basin.

In addition to international political worries, falling gas prices, the disparity between oil and gas prices in the first part of the year, and the Macondo accident drove E&P companies to reshape their portfolios to unconventional drilling.

The Illinois Basin, site of conventional drilling, has also seen a resurgence of shallow drilling activity during 2011. CountryMark Energy Resources' #1 Hulman Farms was tested over a three-week period flowing approximately 400 b/d of oil from the Middle Devonian Lime.

NORTHEAST REGION

Marcellus

While there were several significant Marcellus completions in Pennsylvania during 2011, the Marcellus in West Virginia seemed to attract the most attention. Most of the major operators in the area, including Chesapeake Operating Inc., EQT, Ultra Resources, Encana Oil & Gas, Cabot Oil & Gas, and Talisman Energy Inc., announced plans to drill or have locations staked.

Magnum Hunter Resources' #1001 Weese Hunter vertical completion in eastern Tyler County, W. Va., was tested flowing 7 MMcfe/d of gas with an estimated economic ultimate recovery 4 Bcfe. The company also purchased two companies with Marcellus assets, PostRock (W.Va. assets) and Appalachian Basin-focused NGAS Resources Inc.

Gastar Exploration Ltd. completed two horizontal Marcellus wells from a common drill pad in Marshall County, W Va. The #1H Wengerd and #7H Wengerd were tested at a combined stabilized rate of approximately 15.5 MMcf/d of 1,285 Btu gas and 1,100 Bbbl/d of condensate. A horizontal Marcellus completion by Trans Energy Inc. in Marshall County, W.Va., #1H Keaton, flowed 5.67 MMcfe/d during its first 30 days in production.

A Pennsylvania Marcellus well by EOG Resources Inc., #3H Hoppaugh, was tested flowing 14 MMcf/d in Bradford County, Pa. Penn Virginia Corp completed three Marcellus Shale wells in Potter County, Pa. During three-day tests, #1H-A Risser had a flow rate of 2.1 MMcf/d, #2H-A Risser had test flow rate of 1.7 MMcf/d, and #1H-A Dunn had a test flow rate of 2.7 MMcf/d.

Enerplus sold 91,000 net acres of primarily non-operated shale assets across Pennsylvania, Maryland, and West Virginia for $575 million to an unnamed buyer. EQT Corp. sold its Big Sandy Pipeline and will invest the majority of the proceeds in developing the company's 520,000 Marcellus Shale acres. Chevron completed its purchase of Atlas Energy and made a deal to buy 228,000 net acres from Chief Oil & Gas. Gastar Exploration Ltd. and Atinum Marcellus I LLC, an affiliate of South Korean private equity firm Atinum Partners, entered a joint venture agreement: Gastar assigned an initial 21.43% to Atinum in all of its existing Marcellus assets in West Virginia and Pennsylvania, approximately 34,200 net acres. Noble Energy and Consol Energy have established their Marcellus Shale joint venture partnership where Noble purchased a 50% interest in 628,000 Marcellus acres in southwestern Pennsylvania and northwestern West Virginia.

Utica

In September, Chesapeake Operating Inc. announced plans for a Utica drilling program in the Appalachian Basin. The company anticipates having eight operating rigs by the end of 2011 and 16 to 20 rigs operating by the end of 2012 and stated that its leasehold position will support at least 40 rigs by year-end 2014. Rex Energy Corp. acquired leasing rights to approximately 11,000 net acres in Carroll County, Ohio.

By October, Chesapeake had drilled 12 horizontal wells in the wet gas and dry gas phases of the play. In Ohio's Harrison County, #8H Buell flowed 9.5 MMcf of gas and 1,425 bbl/d of oil. In Carroll County, the #8H Mangun was tested at a peak rate of 3.1 MMcf and 1,015 b/d of liquids, and #3H Neider achieved a peak rate of 3.8 MMcf/d and 980 b/d. In Beaver County, Pa., #3H Thompson had a peak rate of 6.4 MMcf/d.

Michigan's Utica/Collingwood Shale activity continued with Encana Oil & Gas announcing drilling plans for #1-34 State Tuscarora, #1-21 State Wilmot, #1-1 State Oliver, and #1-24 State Excelsior, following 2010 discoveries at #1-3 HD1 State and #1-27 HD1 State Koehler & Kendall, which was named as the Cheboygan County-Utica Collingwood Field opener by state regulators.

GULF COAST REGION

The liquids-rich Eagle Ford play in Texas dominated the Gulf Coast unconventional activity due to limited offshore drilling and higher oil prices while Haynesville activity slowed due to low natural gas prices.

Eagle Ford

Of the 17 Eagleville Field completions reported during 2011, EOG Resources Inc. had 10. In Karnes County, Texas, the #1H Horse Thief flowed 1,342 bbl of 44.2° oil and 1.01 MMcf of gas, #3H Dullnig had an initial potential of 1,085 bbl of 42.3° crude and 1.03 MMcf, and #4H Dullnig Unit had an initial daily potential of 1,119 bbl of 41.3° oil and 1.49 MMcf of gas. The largest


0 Ma
0.6 Ma
3.0 Ma
4.8 Ma

Karnes County producer by EOG in 2011 was #2H Joseph Unit that was tested flowing 1,653 bbl of 45° gravity oil and 1.44 MMcf of casinghead gas.

A record-setting Eagle Ford completion in Eagleville Field in Wilson County (RRC Dist. 1) Texas by EOG was tested pumping 1,891 bbl of 44° gravity oil, 1.46 MMcf/d from #1H DeLeon-Wiatrek Unit.

Four Gonzales County discoveries by EOG, #2H Spahn Farms Unit and #4H Spahn Farms Unit, produced 1,439 bbl/d and 1,259 b/d of crude respectively, while #2H Hansen-Kullin was completed for 1,199 b/d. The #2H Kerner-Carson Unit flowed 1,178 boe/d (1,717 bbl and 1.48 MMcf/d).

Other high volume Eagle Ford producers during 2011 were Talisman Energy Inc.'s #1 Halepeska Gas Unit that produced 11.92 MMcf and 678 bbl from Sugarkane Field while Swift Energy Operating's Hawkville Field well, #5H E.F. Fasken A, flowed 10.04 MMcf/d.

The first Eagle Ford discovery in East Texas' Jasper County was completed by Krescent Energy: #1 Cartwright was tested flowing 1.66 MMcf/d through an openhole interval at 13,953 to 16,308 ft. Another east Texas-Eagle Ford discovery in Fayette County by Southern Bay Operating, #2H Flatonia East Unit, was tested flowing 1,242 bbl of 37.5° gravity crude, 480,000 cf/d through fracture-treated perforations at 11,308 to 15,810 ft.

Efforts are being made to extend the Eagle Ford play even farther to the east into central Louisiana. Indigo II Louisiana Operating permitted a horizontal test in Rapides Parish, La. The #1 Bentley Lumber 23H is slated to reach a total depth of 15,500 ft and is projected to include a 4,000-ft horizontal lateral section tar-

Top 12 I.P. Wells in the Eagle Ford

Flow	Operator	Well #	County	Section, Survey, RRC	Date
21.87 Mmcfe/d *(1,010 bbl condensate + 15.81 Mmcf/d)*	Enduring Resources LLC	1 Keach Gas Unit 1	DeWitt	Section 31, I RR Co Survey, A-253, Dist. 2	May 2010
19.9 Mmcf/d	Pioneer Natural Resources Co.	1 Handy	Karnes	Charles Martinez Survey, A-6, Dist. 2	Apr. 2010
17.26 Mmcf/d	Common Resources LLC	1501H Nueces Minerals Co	LaSalle	Section 150, CCSD&RGNG RR Co Survey, A-1193, Dist. 1	Dec. 2009
17 Mmcf/d	Pioneer Natural Resources Co.	1 Robert Crawley Gas Unit	Live Oak	Bridget Hangby Survey, A-9, Dist. 2	Jan. 2010
15.99 Mmcfe/d *(678 bbl condensate + 11.92 Mmcf/d)*	Talisman Energy Inc.	1 Halepeska Gas Unit	DeWitt	Section 30, I RR Co Survey, A-607, Dist. 2	Dec. 2010
15.76 Mmcfe/d *(680 bbl condensate + 11.6 Mmcf/d)*	Pioneer Natural Resources Co.	1 Charles Riedesel Gas Unit 1	DeWitt	William Putman Survey, A-381, Dist. 2	Mar. 2010
15.59 Mmcfe/d *(1,348 bbl condensate + 7.51 Mmcf/d)*	Burlington Resources Oil & Gas	2 Butler A-304	LaSalle	Franciso Leal Survey, A-304, Dist. 2	June 2010
12.81 Mmcfe/d *(1,891 b/o, 1.46 Mmcf/d)*	EOG Resources Inc.	1H DeLeon-Wiatrek Unit	Wilson	Andres Hernandez Survey, A-4, Dist. 1	Aug. 2011
11.78 Mmcfe/d *(1,717 b/o + 1.48 Mmcf/d)*	EOG Resources Inc.	2H Kerner-Carson Unit	Gonzales	Samuel H. Gates Survey, A-228, Dist. 1	Aug. 2011
11.45 Mmcf/d	Petrohawk Operating Co.	4H Caroline Pielop	LaSalle	Section 295, BBB&C RR Co Survey, A-130, Dist. 1	Aug. 2010
11.43 Mmcfe/d *(1,711 b/o + 1.16 Mmcf/d*	Burlington Resources Oil & Gas Co.	1 Ruckman Trust Unit C	Karnes	Ramon Musquiz Survey, A-7, Dist. 2	May 2011
11.36 Mmcfe/d *(1,653 b/o + 1.44 MMcf/d*	EOG Resources Inc.	2H Joseph Unit	Karnes	George Elliott Survey, A-101, Dist. 2	June 2011

Table compiled by Larry Prado, Activity Editor, Oil and Gas Investor
Data Source: IHS Inc., November 2011
Conversion: 6,000 cu. ft. of gas = 1 boe

geting the Eagle Ford The wildcat is within 10 miles of the company's vertical Eagle Ford test, #1 Bentley Lumber 32, in adjacent Vernon Parish. It was drilled to a total depth of 12,020 ft and production-tested through fracture-treated perforations at 11,562 to 11,704 ft. In neighboring Natchitoches Parish, Brammer Engineering has also permitted an Eagle Ford test: #1 Olympia Minerals is scheduled to reach a total depth of 4,850 ft.

A view up the mast shows a working top drive drilling faster wells into the Eagle Ford Shale.

(Photo courtesy of Chesapeake Energy Corp.)

Haynesville

While most operators' portfolios concentrated more on oil plays, there were several significant Haynesville gas discoveries in 2011.

In Red River Parish, La., an Encana Oil & Gas completion, #1 McLelland Trust 29, was tested flowing 17.04 MMcf of gas and #1 Rex Young 2H flowed 23.43 MMcf/d. In DeSoto Parish, the Calgary-based company also finaled #1 Henry McKinney 14H that produced 24.35 MMcf/d.

In DeSoto Parish, La., Chesapeake Operating Inc. had two discoveries in Red River-Bull Bayou Field. The #1 Awtbegood 19-14-11H flowed 18.43 MMcf and #1 ABG 37-30-14-11H (an offset of #1 Awtbegood 19-14-11H) had initial daily potential of 17.59 MMcf. EXCO Operating Co.'s #1H S.U. Walker A in DeSoto Parish produced 24.35 MMcf/d.

Chesapeake also had a Pleasant Hill Field discovery in Sabine Parish, #1 CHK La 36-10-13 that flowed 17.34 MMb/d.

MIDCONTINENT REGION

Avalon Shale, Bone Spring, Wolfcamp

The Permian Basin boomed in 2011 because of horizontal drilling in the oil-rich Wolfcamp and Bone Spring (Wolfbone). According to Baker Hughes, rig employment in West Texas (RRC Dists. 7C, 8, and 8A) and southeastern New Mexico reached 437 during the first week of June. A year ago, the Permian Basin tally sat at 279 rigs.

The majority of the significant new discoveries were in the Delaware Basin.

In January, Energen Resources purchased three-year leases totaling approximately 17,000 net acres in the Bone Spring and Avalon Shale trends of the Permian Basin from various Texas state agencies and other entities for US $15.3 million. Based on 320-acre spacing, Energen estimates that the West Texas acreage in Reeves, Ward, Loving, and Winkler counties (RRC Dist. 8) offers potential for about 50 Bone Spring locations and 50 Avalon Shale locations.

According to Energen, it currently owns 50,000 net undeveloped acres in a third Bone Spring play with 150 potential undrilled locations, based on 320-acre spacing. In the Avalon Shale play, it now has 80,000 net undeveloped acres with 250 potential locations that are


ONE WAY WE'RE DRIVING ENERGY INDEPENDENCE ...
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based on 320-acre spacing. In December 2010, Energen purchased a Permian Basin package from SandRidge Energy for $110 million. The transaction included about 40,000 net acres with development potential in the Avalon Shale and Bone Spring reservoirs. There is no production or proved reserves associated with the assets, and SandRidge will retain all rights above and below the Avalon Shale and Bone Spring formations.

Anadarko Petroleum Corp.'s #2H Mooney 32-222 in Ward County (RRC Dist. 8), Texas, flowed 1,543 boe/d (1,242 bbl, 1.77 MMcf/d) from Wolfcamp. Two Chesapeake Operating Inc. wells in Ward County (RRC Dist. 8), #1H Monroe 1-10 (Bone Spring), and #2H Monroe 1-17 (Wolfcamp) produced 1,246.67 boe/d (1,010 bbl, 1.42 MMcf/d) and 1,166.33 boe/d (858 bbl, 1.85 MMcf/d) respectively.

A horizontal Wolfcamp play in the southern Midland Basin is being developed by several operators including El Paso E&P, EOG Resources Inc., and Devon Energy. The activity is centered in Lin Field, which comprises wells in Irion, Crockett, and Reagan counties (RRC Dist. 7C), Texas. The biggest Lin Field well to date was completed by EOG in July. The Irion County well, #0401H University 40A, had initial daily potential of 660 bbl of 39.1° gravity oil and 668,000 cf of gas

In the Avalon Shale, American Standard Energy entered into an agreement to purchase various non-operated working interests in over 65,000 gross (14,400 net) acres in the Avalon Shale/Wolfbone play. The Delaware Basin leases are in New Mexico's Eddy and Lea counties and include two 100% working interest sections on the Texas side, in Loving, Reeves, and Culberson counties (RRC Dist. 8). All of the acreage included in the agreement is held by production.

Top 12 I.P. Wells in the Permian Basin

Flow	Operator	Well #	Formation/Basin	Location	Date
1,543 Boe/d *(1,242 b/o, 1.77 Mmcf/d)*	Anadarko Petroleum Corp.	2H Mooney 32-222	Wolfcamp, Delaware	Section 222, Block 34, H&TC RR Co Survey, A-866, Ward County (RRC Dist. 8), Texas	Apr. 2011
1,349.0 Boe/d *(1,064 b/o, 1.71 Mmcf/d)*	Anadarko Petroleum Corp.	1H Mooney 34-222	Wolfcamp, Delaware	Section 222, Block 34, H&TC RR Co Survey, A-866, Ward County (RRC Dist. 8), Texas	Sept. 2010
1,246.67 Boe/d *(1,010 b/o, 1.42 Mmcf/d)*	Chesapeake Operating Inc.	1H Monroe 1-10	Bone Spring, Delaware	Section 10, Block 1, W&NW RR Co Survey, A-860, Ward County (RRC Dist. 8), Texas	July 2011
1,220 Boe/d *(375 b/o, 5.07 Mmcf/d)*	Yates Petroleum Corp.	1H B. Graham BPU State	Bone Spring, Delaware	Section 1-26s-28e, Eddy County, N.M.	Nov. 2010
1,166.33 Boe/d *(858 b/o, 1.85 Mmcf/d)*	Chesapeake Operating Inc.	2H Monroe 1-17	Wolfcamp, Delaware	Section 17, Block 1, W&NW Survey, A-328, Ward County (RRC Dist. 8), Texas	July 2011
1,136.5 Boe/d *(606 b/o, 3.18 Mmcf/d)*	Devon Energy Co.	1H Snapping 11 Federal	Bone Spring, Delaware	Section 11-26s-31e, Eddy County, N.M.	Dec. 2010
970.67 Boe/d *(384 b/o, 3.52 Mmcf/d)*	Cabot Oil & Gas Corp.	14H SRO State Unit Com	Bone Spring, Delaware	Section 10-26s-28e, Eddy County, N.M.	Dec. 2010
923.33 Boe/d *(475 b/o, 2.69 Mmcf/d)*	Devon Energy Corp.	1H Snapping 10 Federal	Bone Spring, Delaware	Section 10-26s-31e, Eddy County, N.M.	Dec. 2010
911.67 Boe/d *(675 b/o, 1.42 Mmcf/d)*	Anadarko Petroleum Corp.	1H Monroe 34-220	Bonecamp, Delaware	Section 220, Block 34, H&TC RR Co Survey, A-868, Ward County (RRC Dist. 8), Texas	May 2010
869.33 Boe/d *(81 b/o, 4.73 Mmcf/d)*	Yates Petroleum Corp.	2H Jericho BKJ State Com	Bone Spring, Delaware	Section 15-25s-27e, Eddy County, N.M.	July 2010
734 Boe/d *(34 b/o, 4.2 Mmcf/d)*	Cabot Oil & Gas Corp.	13H SRO State Unit Com	Bone Spring, Delaware	Section 15-26s-28e, Eddy County, N.M.	Dec. 2010
658 Boe/d *(308 b/o, 2.1 Mmcf/d)*	Marbob Energy Corp.	1H SRO State Unit	Bone Spring, Delaware	Section 4-26s-28e, Eddy County, N.M.	Dec. 2009

Table compiled by Larry Prado, Activity Editor, Oil and Gas Investor
Data Source: IHS Inc., September 2011
6,000 cu. ft. of gas = 1 boe

American Standard also plans to purchase a 100% working interest in over 12,800 West Texas acres in the Wolfcamp play, of which 10,000 acres are held by production. The position is located in Crockett and Reagan counties (RRC Dist. 7C), according to the company, and is contiguous to University of Texas leases auctioned in April for over $2,700 per acre.

In early May, W&T Offshore completed its acquisition of about 21,900 gross acres (21,500 net acres) in the West Texas Permian Basin from Opal Resources. The transaction included estimated proved reserves of about 27 MMboe as of year-end 2010. The reserves are over 91% oil and natural gas liquids and are approximately 77% proved undeveloped. The properties include interests in producing wells that currently produce about 2,950 net boe/d.

Barnett and Barnett Combo

Chesapeake Operating Inc. completed two horizontal Barnett gas producers in Newark East Field in Johnson County (RRC Dist. 5), Texas. The initial daily potential for #4H King B was 10.78 MMcf of gas. The #3H King B is a direct offset and flowed 9.32 MMcf.

A horizontal Barnett discovery was completed as part of Newark East Field in Tarrant County (RRC Dist. 5), Texas, by Titan Operating LLC. The #1H Courtney Unit was tested flowing 2.46 MMcf.

Range Production Co. had a horizontal Barnett well that was completed as part of Newark East Field. The producer is in Dallas County (RRC Dist. 5), Texas, and the initial daily potential for #1H Waddle A was 2.72 MMcf.

The Barnett Combo play in north Texas continued activity with a mix of several high-volume oil producers and gas producers on the north flank of the Fort Worth Basin. A recent EOG Resources Inc. well, #4H Stephenson in Cooke County (RRC Dist. 9), had an initial daily potential of 902 bbl of crude. A production test in early March yielded 1,020 b/d of crude. The company has also tested its #2H and #3H Stephenson for 938 b/d and 790 b/d, respectively.

A Cooke County (RRC Dist. 9,) Texas, completion in Fort Worth Basin by EOG had an initial daily potential of 1,099 bbl of 42.4° oil and 1.63 MMcf. The #1 Strickland Unit was tested through perforations ranging from Barnett at 7,633 ft to Viola at 8,750 ft.

Granite Wash and Tonkawa

According to IHS Inc., horizontal wells accounted for nearly three-quarters of the permits issued (375 of 511) for the first half of 2011, largely on the strength of the Granite Wash, Marmaton, and Cleveland plays. In six contiguous western Oklahoma counties (Beckham, Custer, Dewey, Ellis, Roger Mills, and Washita), the number of permits for horizontal wells totaled 237 for the first half of 2011, more than doubling the number for first six months of 2010.

Two important discoveries were Apache Corp's #1-17H Smith in Beckham County, Okla., that had an initial flow rate of 12.6 MMcf/d of gas, with 1,095 bbl of 54-gravity condensate.

Chesapeake Operating had a Wheeler County, Texas, producer, #2H T West, that produced 33.6 MMcfe/d (1,717 bbl of condensate and 23.3 MMcf).

According to IHS Inc., Apache controls some 200,000 gross acres in the Granite Wash fairway of western Oklahoma and the Texas Panhandle, mostly held by production. The company plans to drill 40 wells targeting the Des Moines-aged Caldwell, Marmaton, and Granite Wash A, B, and C zones during 2011 and 200 wells during 2012 to 2015. The company estimates ultimate recovery at 4.0 Bcfe per well (15% liquids) and well costs at about US $9 million.

In the western part of the Permian Basin Cordillera Energy Partners completed two new horizontal wells that produced from Tonkawa sand in western Oklahoma. An Ellis County well, the #1-14HC Grand, flowed 1,205 b/d and 1.69 MMcf/d. The #1-25HB Glass in Roger Mills County flowed 568 bbl with 2.48 MMcf/d.

Woodford

The Woodford play fared quite well in 2011 in terms of the number and size of discoveries, and some operators are optimistic due to the additional liquids found in the play. A Marathon Oil presentation estimated an industry/basin average resource per well of 750 to 1,000 MMboe for wells in the Cana-Woodford play and well costs (including facilities) of about US $7.5 million. The company holds some 88,000 acres in the play and has an ongoing acreage acquisition program. Cimarex Energy Co., another active operator with eight rigs running in the region, estimates ultimate recovery for Cana-Woodford wells at 6.5 Bcfe to 8.5 Bcfe, and well costs between $7.5 and $8.5 million. Cimarex has

a leasehold of more than 100,000 acres in the area. In the Anadarko Basin, QEP Energy's #1-23H Austin in Canadian County, Okla., produced 7.05 MMcf of gas, and 37 bbl of 59° gravity condensate.

Two very large Woodford discoveries also were brought in this year in the Arkoma Basin's Woodford play. PetroQuest Energy's #1-34 Dash Ranch in the Arkoma Basin had an initial daily flow rate of 8.53 MMcf. A Kaiser-Francis Oil Co. completion in Coal County, Okla., #1-13H Harlow Cunningham, flowed 7.1 MMcf from an acidized and fracture-stimulated Woodford lateral.

In Ashland Field, Newfield Exploration Inc. drilled two producers from the same pad in Pittsburg County, Okla. The #3H-15E Hatridge initially flowed 5.6 MMcf after fracture stimulation and acidizing. The #4H-15E Hatridge flowed at an initial rate of 3.46 MMcf. The #4H-15E Hatridge was drilled about 30 ft to the southeast on the same pad as #3H-15E Hatridge.

WESTERN REGION

Two plays – Bakken and Niobrara – stole the headlines in the western region with new developing technology, numerous and large volume completions, and expansion. Meanwhile, plenty of new exploration is planned for the Uinta, Piceance, and Paradox basins where several significant gas discoveries were reported. Big North Dakota Bakken completions, including Three Forks discoveries, were the norm for the play. Of equal interest was the rapid western expansion into the Alberta Basin and other points into Montana.

In October, Norway giant Statoil acquired Brigham Exploration. The transaction gave Statoil access to more than 375,000 net acres to Bakken and Three Forks oil and gas production. Brigham also holds interests in 40,000 net acres in other areas — onshore Gulf Coast (Texas and south Louisiana), the Anadarko Basin (Texas Panhandle and western Oklahoma), and the Permian Basin (West Texas and eastern New Mexico). At this early stage of development the risked resource base is estimated at 300 MMboe to 500 MMboe equity. The Brigham transaction also provides Statoil with approximately 430 miles of oil, natural gas, and water transportation systems centrally located in the Williston Basin.

Brigham has drilled six of the 10 highest IP rate Bakken wells in the play to date and reported a record 2Q 2011 production at 10,401 boe/d. Brigham has drilled 79 North Dakota Bakken/Three Forks wells and has 794 net development locations remaining in the current core acreage and it could grow to 1,299 net development locations based on Rough Rider Three Forks potential.

> **Two plays – Bakken and Niobrara – stole the headlines in the western region with new developing technology, numerous and large volume completions, and expansion.**

Alberta Bakken/Exshaw

The Bakken play is expanding into northeastern Montana's Roosevelt County with important wells producing from Middle Bakken. A July oil and gas lease sale held by the Montana State Office of the BLM set a record in bonus bids, nearly doubling the amount from 2010 – almost US $67 million was bid in 2011 and the December 2010 (the previous record) amount was just over $36 million.

The southern Alberta Basin Bakken play in northwestern Montana attracted more industry interest in 2011. At the March Montana state lease sale, Glacier County brought in the second highest per-acre average bid at the sale. The Glacier County acreage is east of the Blackfeet Indian Reservation, where Rosetta Resources and Newfield Exploration are currently accessing an emerging Bakken oil play in the basin. Rosetta reports that true vertical depths in this over-pressured Bakken play range from 4,500 to 7,500 ft. The company estimates that its position in the play contains 13 to 15 MMboe per sq mile of resource in place.

By late 2011, Rosetta Resources Inc. completed two southern Alberta Basin vertical Bakken wildcats on the Blackfeet Indian Reservation in Glacier County. The #3608-34-01 Simonson produced 496 boe/d (447 bbl, 298,000 cf) during a 10-day period and was the beginning of commercial Bakken production a Glacier County.

Bakken

Bakken wells are now consistently drilled to 20,000 ft with 9,000-ft laterals. New technology has created 20 to 30 stage fracturing and multiple laterals from

common pads, perhaps making it the cleanest and most efficient play in the world. Continental Resources is developing its Bakken acreage using its ECO-Pad technology (currently up to four wells – two Middle Bakken and two Three Forks) to drill from a single pad on two adjoining 1,280-acre spacing units. Application of the company's technology is expected to increase per-well recoveries and to reduce drilling costs, completion costs, and environmental impact by centralizing operations on a single pad.

Brigham is developing microseismic monitoring to support development of at least four wells per producing horizon per 1,280-acre spacing unit (eight total Bakken and Three Forks wells). The company is using "smart pad development," which can be implemented either by drilling multiple wells from the same location in a single spacing unit or by drilling stacked 1,280-acre spacing units from the same location. According to Brigham, the smart pad is anticipated to save approximately 10% to 20 % per well on drilling and completion capital expenditures.

A record-setting well in March by Brigham, #2-H Sorenson 29-32 in Alger Field, flowed 5,330 boe/d (4,661 bbl, 4.01 MMcf/d). The #1H Sorenson (5,133 boe/d) was drilled from the same pad in 2010. A July discovery by Newfield Exploration in McKenzie County produced 5,200 boe/d at #152-96-4-2H Wisness-Federal.

Montana Bakken production began quietly enough with a 2008 discovery by Slawson Exploration: #1-4H Piranha initially flowed 630 boe/d from a lateral at an exploratory test in Roosevelt County. A 2009 completion by Sinclair Oil & Gas Co. in Richland County was one of the northernmost horizontal producers to date in the Montana Bakken play. Sinclair's #1-21H Ralston flowed at an average rate of 291 boe/d from a fractured horizontal lateral in Middle Bakken. In 2010, the discovery ramped-up with an EOG Resources horizontal wildcat, #2-33H Carat, produced 2,811.7 boe/d (2,585 bbl, 1.36 MMcf).

In late 2010, Brigham brought its North Dakota Bakken exploratory techniques to Montana where #1-H Rogney 17-8, a 909 boe producer, was fracture stimulated in 30 stages and was tested in a two-section lateral. The initial nine stages were stimulated at lower fracture pump rates and the rest of the 21 stages were tested at higher fracture pump rates. The

Top 12 I.P. Wells in the Bakken Shale

Flow	Operator	Well #	County/State	Section, Survey	Date
5,330 boe/d *(4,661 b/o, 4.01 Mmcf/d)*	Brigham Exploration Co.	2-H Sorenson 29-32	Mountrail, ND	20-155n-92w	Mar. 2011
5,200 boe/d*	Newfield Exploration Co.	152-96-4-2H Wisness-Federal	McKenzie, ND	4-152n-96w	July 2011
5,133 boe/d *(4,335 b/o, 4.79 Mmcf/d)*	Brigham Exploration Co.	1-H Sorenson 29-32	Mountrail, ND	29-155n-92w	Mar. 2010
5,061 boe/d *(4,438 b/o, 3.73 Mmcf/d)*	Brigham Exploration Co.	1-H Clifford Bakke 26-35	Mountrail, ND	26-155n-92w	Oct. 2010
5,035 boe/d**	Brigham Exploration Co.	1-H Jack Cvancara	Mountrail, ND	19-155n-92w	May 2010
4,761 boe/d***	Whiting Oil & Gas Corp.	11-27H Maki	Mountrail, ND	27-154n-91w	Oct. 2009
4,675 boe/d**	Brigham Exploration Co.	1-H Domaskin 30-31	Mountrail, ND	30-155n-92w	Jan. 2010
4,570 boe/d***	Whiting Oil & Gas Corp.	11-9H Richardson- Federal	Mountrail, ND	9-153n-91w	Oct. 2008
4,431 boe/d***	Whiting Oil & Gas Corp.	12-10H Fladeland	Mountrail, ND	10-154n-92w	July 2010
4,169 boe/d**	Brigham Exploration Co.	1-H Abelmann 23-14	McKenzie, ND	23-152n-101w	Jan. 2010
4,144 boe/d***	Whiting Oil & Gas Corp.	12-20H Hansen	Mountrail, ND	20-153n-91w	June 2010
4,030 boe/d *(3,240 b/o, 4.74 MMcf/d)*	Brigham Oil & Gas Corp.	1-H Lloyd 34-3	Mountrail, ND	34-151n-100w	Jan. 2011

Table compiled by Larry Prado, Activity Editor, Oil and Gas Investor
Data Source: IHS Inc., August 2011
Conversion: 1 bbl condensate = 6,000 cu ft of gas

**Source: Newfield Explxoration Co.: 24-hour average*
***Source: Brigham Exploration Co.*

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Rogney discovery was designated Elm Coulee Northeast Field by the state.

In early 2011, Zenergy Inc.'s horizontal exploratory test in Roosevelt County, #11-2H Amazing Grace, initially flowed 1,168 boe/d (1,043 bbl, 751,000 cf) from a fractured horizontal Middle Bakken lateral. Brigham soon followed with a horizontal well that initially flowed 1,065 boe/d (#1-H Swindle) in Roosevelt County. By the middle of 2011, Brigham's #1-H Johnson 30-19 in Richland County had a record-breaking initial flow rate of 2,962 boe (2,684 bbl and 1.67 MMcf) and produced from a two-section lateral in Middle Bakken following 36-stage fracture stimulation.

Three Forks

In March, Whiting Oil & Gas Corp.'s #21-18TFH Hecker produced a record 3,606 boe/d from a site in Stark County. In April, Kodiak Oil & Gas reported two big Three Forks completions in McKenzie County, N.D.: #9-5-6-5H Koala flowed 3,043 boe/d and #9-5-6-12H3 Koala flowed 2,327 boe/d. In September, Denver-based Whiting reported the completion of two significant producers, #21-14TFH Lydia producing 1,960 boe/d in Stark County and a lateral at #34-12TFH Smith initially flowing 2,939 boe/d in Billings County.

Niobrara

In the first part of 2011, there was a flurry of leasing activity for Niobrara property, which followed on the heels of surprising 2010 discoveries in the Denver-Julesburg Basin and Wattenburg Field across northern Colorado and central and southern Wyoming, and the Piceance Basin in western Colorado.

Chesapeake Operating Inc. received approval for a multi-well exploration program that looked to extend the play to neighboring counties of Denver (Elbert and Douglas). Chesapeake also sought to establish 640-acre drilling and spacing rules in now-suburban Douglas County. The Oklahoma City-based operator also sold a 33.3% undivided interest in 800,000 Niobrara acres to the China National Offshore Oil Corporation (CNOOC). Chesapeake has locations staked for approximately 14 horizontal Niobrara wildcats in northeastern Colorado's Weld and Larimer counties, several of which it has drilled with no details disclosed. The company holds approximately 570,000 net acres in the Niobrara, Frontier, and Codell plays in the Denver-Julesburg and Powder River basins.

Anadarko Petroleum scheduled its second horizontal wildcat targeting Niobrara in northeastern Colorado's Arapahoe County at a site about four miles east of Aurora. The company plans to drill more than 40 horizontal Niobrara wells this year.

Houston-based Ultra Petroleum Corp purchased the Banning Lewis Ranch in southern Colorado's El Paso County that has about 18,000 undeveloped acres on the east and southeastern boundaries of Colorado Springs. Ultra is currently negotiating with city officials about the company's plans to drill for oil and gas on this newly acquired property.

Ultra believes that the Denver-Julesburg Basin Niobrara play can be extended south and southwestward into non-producing El Paso County and the Banning Lewis Ranch. Ultra acquired leases covering approximately 100,000 acres in El Paso County from Pine Ridge Oil & Gas LLC for US $1.67 million. The Pine Ridge deal also included an exploratory well drilled late last year east of Fountain, Colo., #32-4 Naos-State. It was projected to 4,600 ft to evaluate Pierre and Niobrara and was drilled to a total depth of 4,630 ft. The top of Niobrara was logged at 4,127 ft.

Ultra is negotiating with the Colorado Oil & Gas Conservation Commission on its Popeye exploration program for El Paso County. The company has applied with the Colorado Oil & Gas Conservation Commission to expand two existing exploratory units, Spinach and Olive, and create a third, Brutus, that are east and southeast of Colorado Springs in unincorporated El Paso County.

Significant Niobrara completions during 2011 include Chesapeake's Powder River Basin well, #33-71 25 1H Sims in Converse County, Wyo., that flowed 1,110 boe/d (2.4 MMcf and 1,270 bbl). The #16-13H Wild Horse by Whiting Oil & Gas well in Weld County, Colo., produced 1,321 boe/d (1.56 Mcf and 1,061 bbl) in the Denver-Julesburg Basin. An SM Energy discovery (#1-24H Polaris) in the Denver-Julesburg Basin in Laramie County, Wyo., pumped 950 boe/d. Carrizo Oil & Gas Inc.'s #36-44-8-62 Bob White in Weld County, Colo., produced 855.8 boe/d (785 Mcf and 725 bbl). In addition Carrizo announced eight more horizontal Niobrara tests in Weld County.

In the Piceance Basin, Encana Corp. has accumu-

(Photo courtesy of Continental Resources Inc.)

One Williston Basin ECO-Pad hosting eight wells with 603 Mboe per well offers 4.8 MMboe of potential recovery.

lated more than 600,000 net acres of land it believes has Niobrara and/or Mancos Shale potential. In 2010, Encana's #16-16H2 (P16OU) Orchard Unit flowed 6.9 MMcf/d from a comingled horizontal Niobrara/Mancos zone in western Colorado's Mesa County. Meanwhile, Delta Petroleum's #2C-22-433D N. Vega in Mesa County flowed 2 MMcf and 30 bbl of condensate daily from a deeper pool wildcat from two fracture stimulated Frontier and Niobrara intervals and had gas shows in Corcoran, Mancos, and Mancos B, plus evidence of hydrocarbon liquids.

Uinta, Paradox Basins

The Uteland Butte member of lower Green River in Utah's Uinta Basin seems to be a new unconventional target. Newfield Exploration Co. completed six horizontal Uteland Butte oil producers in the basin, all in a 10-sq-mile area on the western flank of Monument Butte Field. The six horizontal wells in Duchesne and Uinta counties were completed for 24-hour average initial potential rates that ranged from 298 to 503 boe. Newfield staked locations for 10 horizontal tests. According to Newfield, the Uteland Butte is a new horizontal oil play being developed from 6,000 to 9,000 ft (true vertical depth) and is prevalent across Monument Butte.

Bill Barrett Corp. completed its first horizontal Uteland Butte (lower Green River) producer in the Uinta Basin that initially flowed at an average rate of 717 boe/d over its first 30 days of production. The #13H-20-46 Lake Canyon-Tribal is producing from a 3,100-ft horizontal lateral in Uteland Butte and Barrett fracture-stimulated the well in 15 stages. Denver-based Barrett is planning up to five additional horizontal wells targeting Uteland Butte in the second half of 2011. The company anticipates drilling approximately 50 wells on the Blacktail Ridge-Lake Canyon prospect. In 2010, Barrett initiated a continuous development program in the Blacktail Ridge-Lake Canyon area, where, according to the company, rates of return on oil development are nearing 50%.

According to IHS Inc., a 2011 decision by the BLM helps pave the way for a Cane Creek Shale (Paradox-Pennsylvanian) exploration program in southeastern Utah. The BLM's Moab field office released an Environmental Assessment and accompanying Finding of No Significant Impact covering a plan by Denver-based Fidelity Exploration & Production Co for a multi-well exploration project in a Paradox Basin area 9 to 12 miles west of Moab, Utah.

CANADA

Canadian oil and gas development didn't keep pace with the Bakken, Niobrara, Eagle Ford, and Permian Basin plays; however, significant discoveries occurred during 2011. Most reported completions were in the Western Canadian Sedimentary Basin and new exploration activity was reported in Quebec's Utica Basin and the Cambrian Ordovician-Anticosti Basin in Newfoundland.

Cardium

Solara Exploration Ltd. completed a horizontal Cardium well in the Pembina (Buck Lake) area of central Alberta that produced 700 boe/d (580 b/d and 720 Mcf/d of gas) for the first 14 days. Solara has five additional horizontal Cardium development drilling locations on its lands in the area. A second Cardium horizontal completion in Pembina (Buck Lake) produced 1,509 b/d and 568,000 cf/d at a stabilized rate.

Exshaw/Bakken

Calgary-based DeeThree Exploration Ltd. completed a Bakken well in the Lethbridge area of Alberta. The completion was drilled to 9,711 ft, including a 4,265 ft horizontal section. After a seven-day cleanup, #04-D3EXP 2HZ 13 flowed 250 b/d of oil and 25 Mcf/d of gas. DeeThree completed a 15-stage fracture stimulation using an oil-based fluid. No measurable amounts of water were recovered.

Horn River/Muskwa

Storm Resources Ltd. completed a horizontal Horn River Basin producer. The #D-9-D/94-P-12 was drilled to 14,107 ft with a 5,741-ft horizontal section in the Muskwa and Otter Park shales. After 12-stage fracture treatment, gas initially flowed at an average (restricted) rate of 8.8 MMcf/d during a clean-up period. The company reported a recent gas flow rate of 9.1 MMcf/d at a flowing casing pressure of 1,160 psi.

Montney

Montney test by Donnybrook Energy Inc. flowed 15 MMcf/d of gas and 30 to 40 bbl per MMcf of natural gas liquids from an 8,530-ft lateral. The test was completed after 12-stage fracturing along the horizontal portion of the lateral at partner Blackburn Energy's Bigstone property that is south of the Bigstone/Fir area in Alberta.

Cequence Energy Ltd. completed its first Deep Basin Montney horizontal well in Alberta. According to Nickle's Petroleum Explorer initial results from the post-fracturing cleanup had flow rates of 6.4 MMcf and 100 b/d of condensate after completion with 15-stage fracturing over 4,314 ft of horizontal well bore. A Lower Montney prospect by Painted Pony Petroleum Ltd. in British Columbia flowed in-line for 19 days at an average rate of 11.6 MMcf/d with a peak rate of 13.1 MMcf/d. From the same drill pad, the horizontal #9-B Gundy c-67-J/94 is currently producing 11.5 MMcf/d at more than 1,400 psi after one month on production.

According to Nickle's Petroleum Explorer, a Yoho Resources Inc. Montney completion at Umbach/Nig Creek, British Columbia, flowed 4.2 MMcf/d at a flowing pressure of 531 psi with 55 b/d of free condensate. The well had a final up-casing flow rate of 6.3 MMcf/d with 78 b/d of free condensate.

The Maritimes

Quebec City-based Junex Inc. finished Utica Shale coring after drilling to 5,603 ft at its #1 Villeroy exploration well in Quebec. The well had many gas-saturated intervals and five intervals were cored between 2,756 and 4,147 ft. The Junex acreage is in the structured portion of the Utica Basin, approximately 9 miles from the #1H St-Edouard in the structural extension of the St-Flavien gas field, which produces from Beekmantown dolomites.

A Nalcor Energy Oil and Gas well in western Newfoundland, #1 Finnegan, was drilled to 10,269 ft at Parsons Pond. The well encountered gas and further evaluation is proceeding. The wildcat was drilled in an area known historically for numerous surface oil seeps and in shallow well bores within the Cambrian Ordovician-Anticosti Basin. A second well, #1 Seamus, was drilled to about 3,000 ft and encountered a hydrocarbon-bearing zone on exploration permit 03-103.

Viking

Magnum Energy Inc.'s first Provost Viking oil project well flowed 119 b/d of oil, and 220 Mcf/d of gas. The well was fracture stimulated in 13 stages. Nextraction Energy Corp. completed its first horizontal Viking light oil well in the Provost Viking Pool. The 3,937-ft horizontal leg was fractured in 13 stages and flowed at an average rate of 177 boe/d during the first five days of testing. Average flow rates were comprised of 109 bbl and 410 Mcf/d of natural gas, with a 75% water cut.

Petro One had a conventional discovery of a previously unknown light oil pool on the company's 100%-owned J5 property in Saskatchewan. The well flowed about 61 b/d of light oil during an eight-hour period from Viking sand at a depth of 2,416 ft without stimulation, swabbing, or pumping. Flowing pressure in the tubing measured at surface was stable at 145 psi throughout the flow period. ■

(Photo courtesy of Chesapeake Energy Corp.)

A Condensed Review of the Top 20 Liquids-rich Plays

By Louise S. Durham
Petroleum Geologist

The industry is now focused on the potential of the liquids-rich shale plays, described in these regional snapshots.

Natural gas prices cannot seem to break through the US $4/Mcf barrier, while crude oil prices might tumble several percent only to return to the $90-plus per barrel berth within perhaps a couple of days.

Ironically, the production success from the numerous North American shale gas plays has played a major role in creating a natural gas supply surplus and, in turn, lowering the price for this commodity. Never ones to give up, a number of E&P folks equipped with advanced horizontal drilling and hydraulic fracturing technology essentially turned their collective backs on natural gas to focus on those shale plays that are rich in oil and natural gas-associated liquids, or plays produced as oil from the get-go.

For example, production from the many prolific Bakken Shale oil fields reportedly has elevated the US to third place among world oil producers. Bakken reserves estimates range between about 5 Bbbl up to 24 Bbbl, depending on the information source.

Harold Hamm, founder and CEO of Continental Resources, which has a major presence in the Bakken play, was recently quoted as saying that the US can be the Saudi Arabia of oil and natural gas in the 21st century given the right set of national energy policies.

The following "snapshots" highlight the top 20 liquids-rich unconventional plays in North America that might help the US realize this goal.

Avalon

The Avalon Shale sits atop the Bone Spring Formation in the Delaware Basin in the western-most area of the Permian Basin Province.

The Avalon-Bone Spring play sometimes is called simply "the Avalon Shale play." The Avalon also is often dubbed "the Leonard." Confusing nomenclature aside, there are apparently hydrocarbons aplenty.

Typically, operators have drilled through the Avalon in search of other reservoirs, which is a fairly common circumstance in many of the now-ubiquitous shale plays. Still, Avalon production potential has been recognized for some time and it has been one of the main targets of the current action in southeastern New Mexico. Its potential nearby in Texas also is being evaluated

In some instances, the Avalon is two layers of shale separated by a limestone layer.

The consensus among the operators in the combined play appears to be that oil and liquids tally about 75% of reserves. Large fracs are said to be key to success in the Avalon.

There's activity in the Leonard Shale aka Avalon aka upper Bone Spring. One of the operators not long into the play in 2010 stated that the production stream in this particular accumulation is an even three-way split between crude oil, NGLs, and residue gas.

Bakken

The Bakken Shale oil play in Montana and North Dakota continues to be a star attraction in the "world of shale." The widespread Upper Devonian-Lower Mississippian Bakken Formation consists of an upper and lower shale member and a mixed siliciclastic carbonate middle member, ordinarily referred to as a dolomitic sand or sandy dolomite. The middle section

Oil country tubular goods follow the drill bit down the hole to produce hydrocarbons from the Eagle Ford Shale.

is the prime target of the wells that encounter it about 10,000 ft deep, prior to turning horizontal into the brittle dolomite where multistage fracing is applied for more efficient oil production.

The *modus operandi* in the Bakken play for the most part has been to scout out tectonic fractures that appear on the surface as lineaments even though they actually occur thousands of feet deep.

The other fracture mechanism is hydraulic, which is key to really prolific wells in the Middle Bakken, according to Scott Stockton, executive vice president of Vector Seismic Data Processing in Denver.

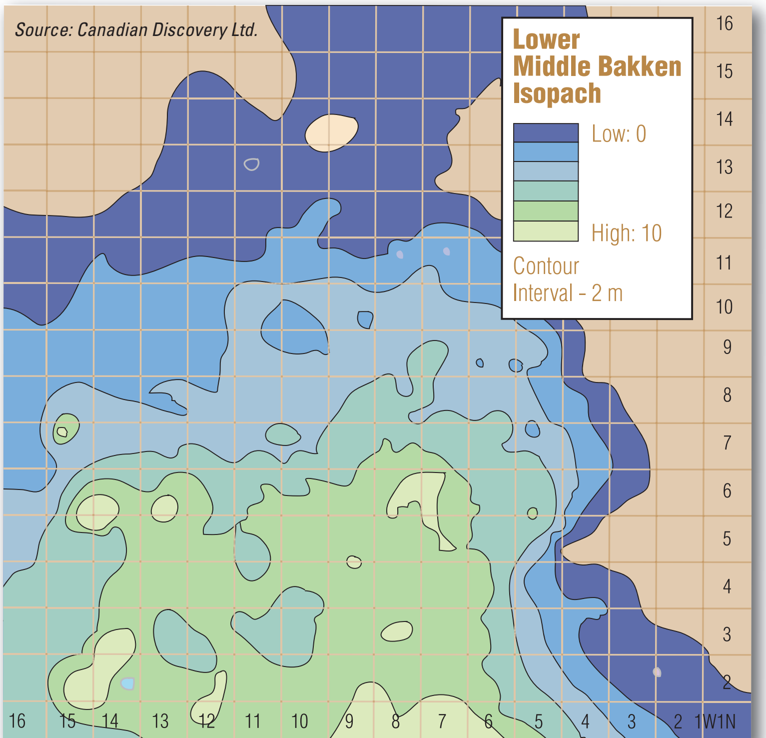
He says it is all about the Bakken petroleum system, which is a closed, self-sourced system.

When kerogen cooks out of the shale, it undergoes an intense volumetric increase rife with stored energy to fracture the rock, primarily along bedding planes.

The combo of a uniquely closed petroleum system, a high thermal gradient and volumetric expansion of the Upper and Lower Bakken kerogen into oil has resulted in high potential for creating *in situ* fractures parallel to bedding planes.

Stockton notes that the horizontal fractures can be a prime factor in terms of where the reservoir is situated and the quality:

The Middle Bakken reservoir is a dolomite sandstone that thins to the north and east.



- Where the tectonic fractures intersect the hydraulic, the wells are best;
- Where both types of fractures are present, the wells are great;
- Hydraulic fractures yield good wells; and
- Vertical (tectonic) fractures result in okay to good wells.

The Bakken extends into Saskatchewan and western Manitoba, where it is also productive.

Barnett Combo

The Barnett Combo play in Montague and Cooke counties in Texas looks promising indeed, particularly because it establishes an avenue toward higher oil production rather than natural gas. A well-defined oil window has always been a part of the now-famous Mississippian-age Barnett Shale play, but operators chose to concentrate on the natural gas areas.

The Combo play actually produces a somewhat balanced mix of oil, natural gas, and natural gas liquids.

EOG, which was an early entrant into the original Barnett play, says there are specific reasons why the Combo play works. The resource base ranks as one of the world's largest, with oil in place ranging from 40 MMboe to 200 MMboe/sq mile. Numerous vertical wells having long production histories were drilled, revealing the play's potential. Cores and logs have revealed pore throats large enough to produce oil. What was once a vertical well drilling area now has segued to a horizontal heyday of sorts to facilitate production.

Bone Spring

The Delaware Basin on the far western edge of the Permian Basin province is beckoning to the oil finders, particularly Lea and Eddy counties in southeastern New Mexico. The allure is the Bone Spring Formation, which spreads into West Texas. It has been subjected to several cycles of production via vertical wells over the years albeit without much commercial success.

The Leonardian-age Bone Spring is made up of interbedded sandstones, carbonates, and shales. Production is from deepwater carbonate debris flows and fine-grained turbidite sandstones, according to a DOE-funded study conducted by scientists at the Bureau of Economic Geology, University of Texas at Austin and the New Mexico Bureau of Geology and Mineral Resources.

The Bone Spring series includes first, second, and third Bone Spring sands and corresponding carbonates, and the shallower Avalon Shale, which is frequently referred to as "the Leonard." Often lumped together as one play, the Avalon actually stands on its own as a separate play in some instances.

The initial targets in the Bone Spring were conventional sandstones. Wells then tapped into carbonate lenses and, ultimately, low permeability sandstones. Thanks to horizontal drilling technology combined with hydraulic fracturing, very thin sands and other facies are now being produced. It has been reported that vertical sections of Bone Spring wells can encounter hard, abrasive rocks, rendering the wells prone to deviation from the planned drilling trajectory. Vertical drilling depths are said to reach as much as 9,800 ft prior to drilling the lateral leg(s).

Low reservoir bed-to-boundary resistivity contrasts are the norm for the Bone Spring sands, with a dearth of features within the zone that can be differentiated using standard gamma ray measurements.

Bone Spring player Anadarko has noted that wells testing 1,000 b/d IP are not that unusual, according to John Christiansen, communications director of corporate public affairs at the company.

The aforementioned study notes that cumulative production from the Bone Spring basinal sandstone and carbonate stood at 70,703,460 barrels as of Dec. 31, 2000.

Cana Woodford

The Cana Woodford Shale is located in western Oklahoma, and the area has reportedly become a respectable size oil play with a number of companies hitting pay. Even though the play is mostly liquids-rich with oil, natural gas also can be found.

According to Devon Energy, the Mississippian-age Cana is the world's deepest commercial horizontal play with total vertical depths of 11,500 to 14,500 ft and measured depths of 16,700 to 19,000 ft.

The Cana Woodford is considerably deeper and more expensive to reach than the Arkoma Woodford to the east. It is said to be one of the most economic shale plays in North America, mainly because of high volumes of condensate and other pricey liquids.

The Mississipian-Devonian Woodford Shale play is located in eastern Oklahoma where it is 120 to 220 ft thick, with reservoir pressures in the 6,000 to 12,000 psi range.

The Woodford exhibits a high range of thermal maturities depending on the locale. The shale boasts high concentrations of organic matter, with TOC values slightly higher where the shale occurs in the Permian Basin.

Bone Spring player Anadarko has noted that wells testing 1,000 b/d IP are not that unusual, according to John Christiansen, communications director of corporate public affairs at the company.

Cardium

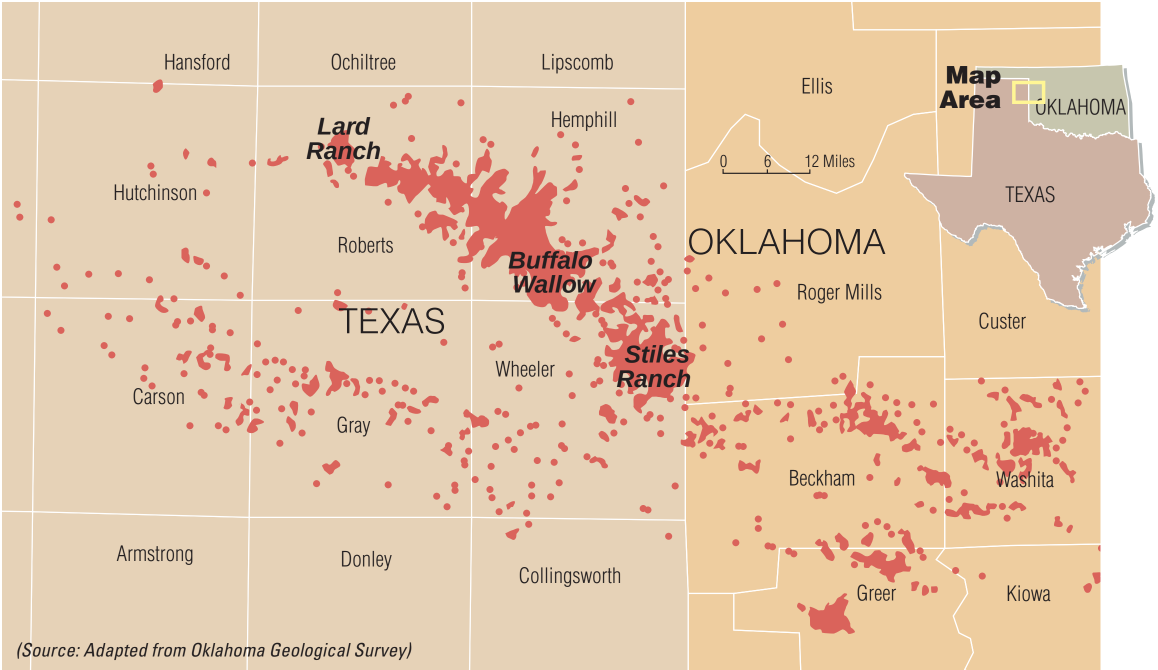
The Cretaceous-age Cardium Shale is a sand/shale formation that occurs in Alberta and extends into eastern British Columbia and south into Montana.

It has long been penetrated by vertical wells drilling through to production below. Of the 12 Bbbl of oil in place estimated by Canada's Energy Resources and Conservation Board, about 1.5 Bbbl have been produced via vertical drilling technology. Given the many vertical penetrations, the Cardium carries little geologic risk.

The Cardium forms a sizeable stratigraphic trap in its eastern shaleout, creating Canada's largest conventional onshore oil field, dubbed "Pembina." The field was discovered in 1953 and contains some lesser producing zones as well. Cardium thickness there is said to range from 0 to more than 440 ft. In the overall Pembina area, the light-oil-containing Cardium reportedly produced as much as 200,000 b/d at its peak in the early 1970s. Ironically, fracing technology in the vertical wells is credited with kicking the field into high gear.

Vertical well production declined over time to about 35,000 b/d.

Parts of the Cardium are undergoing waterflooding, and horizontal multi-frac drilling technology gets the credit for stimulating production today. Current thinking is that it won't be a stretch to reach more than 125,000 b/d.



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

Operators are said to be extending the lengths of the laterals, implementing more fracs and getting better production and well results on a month-to-month basis and booking more reserves per well.

Cleveland

The Upper Pennsylvanian Cleveland Formation can best be described as a tight gas sand made up of fine-grained clean sands frequently interbedded with thin shale. It occurs at depths as much as 12,000 ft with permeability values said to range between .03 md and 1.1 md, with some reports of 20 md. Porosity is tagged between 4% and 14%.

The Cleveland occurs throughout much of the northeastern Texas panhandle and western Oklahoma. It was discovered in the 1950s as players explored for deeper Morrow objectives. Where the sand pinches out to the north and west, the Cleveland is a stratigraphic trap.

The formation was initially developed using vertical wells with fracs. Now it is all about horizontal drilling to maximize production potential of the wells and minimize completion expense. A major expansion of older productive areas occurred in 2010, along with the addition of new areas of production.

Despite the high oil volumes registered on initial tests and their general classification as oil wells, horizontal Cleveland production on a boe basis is about two-thirds natural gas, says Dan Boyd, petroleum geologist at the Oklahoma Geological Survey. He notes that the play's cumulative production in Oklahoma is 3.3 MMbbl of oil and 46 Bcf of gas.

Eagle Ford

The Eagle Ford Shale play spans a geographic area in South Texas ranging from far western Webb County northeastward to Gonzales County. Today, there's talk about a Louisiana Eagle Ford occurring in far west Louisiana. The shale occurs at depths between 4,000 ft and about 14,000 ft and is as much as 250 ft thick in some locales; natural fractures generally are absent in this brittle zone. The shale is long known for sourcing hydrocarbons to Austin Chalk fields as well as the renowned East Texas Field.

The Eagle Ford shale produces a liquids-rich gas stream as well as oil in certain areas of the play. Generally, the oily part is the northern area where lower pressures rule. The midsection of the play is said to harbor the condensate, or wet gas, window with a sweet spot of high concentrations of light oil. Much drier gas is found in the deeper section of the shale to the south in the play.

The discovery well, drilled by Petrohawk Energy Corp. (now a part of BHP Billiton) in 2008 in what


DISTINCT
ADVANTAGE
Acreage
Experience
Technology
Infrastructure
Liquids-rich
Eagle Ford Shale
• Oil, liquids and gas
• ~ 300,000 acres
• Technology leader
- 2,000 sq. miles of 3-D seismic
- Logs from more than 150 operated wells
• ~ 2,000 potential drilling locations
• Accelerating drilling
• Successful joint venture
Permian - Spraberry
• Oil and liquids
• ~ 900,000 acres
• ~ 6,500 operated wells
• ~ 20,000 drilling locations
• Capturing incremental production and reserves from deeper drilling and shale/silt intervals
• Accelerating drilling
• Vertical integration provides significant cost savings and improves execution
PIONEER
NATURAL RESOURCES
For more information on Pioneer, visit www.pxd.com. NYSE: PXD

would be christened "Hawkville Field," flowed 7.6 MMcf and 250 bbl condensate per day. Fourteen miles to the southwest, a second well tested 8.3 MMcf/d with no condensate.

Positioned between the Edwards and Sligo shelf margins, the Hawkville Field is in a kind of mini-basin, or topographic low, containing high porosity and high-resistivity facies. Like the play overall, the field is characterized by a downdip dry gas pay in the southwest, a mid-dip gas/condensate, and an updip oil play.

The differing thermal maturities evident are mainly a function of burial history, according to Petrohawk executive president and COO Dick Stoneburner. He notes the southwest end of the field at one part was considerably deeper than today but has been uplifted, likely owing to the Chittim Arch, a prominent Laramide feature.

Exshaw

The Devonian-Mississippian Exshaw Formation correlates with the Lower and Middle Bakken Formation in Alberta and British Columbia. In fact, the two are often referred to as the Bakken/Exshaw interval, which usually is no more than perhaps 131.2 ft thick.

The Exshaw petroleum system is said to include the overlying and underlying limestone reservoirs of the Banff and Big Valley, which are the most likely candidates for horizontal drilling.

The type section for the Exshaw occurs at Jura Creek in western Alberta.

The Exshaw transitions to the Bakken at the Alberta-Saskatchewan border. Beneath the Alberta plains and in certain exposures in the Rocky Mountains, the Exshaw is made up of a lower black shale member and an upper siltstone. The basal black shale unit of the overlying Banff is a second organic-rich interval. The black shales, which are said to contain as much as 35% TOC, have been determined to be both regionally important source rocks as well as local reservoirs.

The Exshaw occurs at depths in the 4,000- to 5,000-ft range.

Granite Wash

The tight sands Granite Wash play is found in parts of western Oklahoma and the Texas Panhandle, covering an area about 160 by 30 miles.

It has been a drilling target and/or pass-through zone for decades using vertical wells. Today, horizontal drilling and completion techniques appear to be a kind of magic bullet for respectable-plus production, reducing dry hole risk and rendering some reservoirs highly economic. Zones as thick as 3,000 ft have been reported, along with measured well depths of 11,000 ft and porosity 4% to 12%.

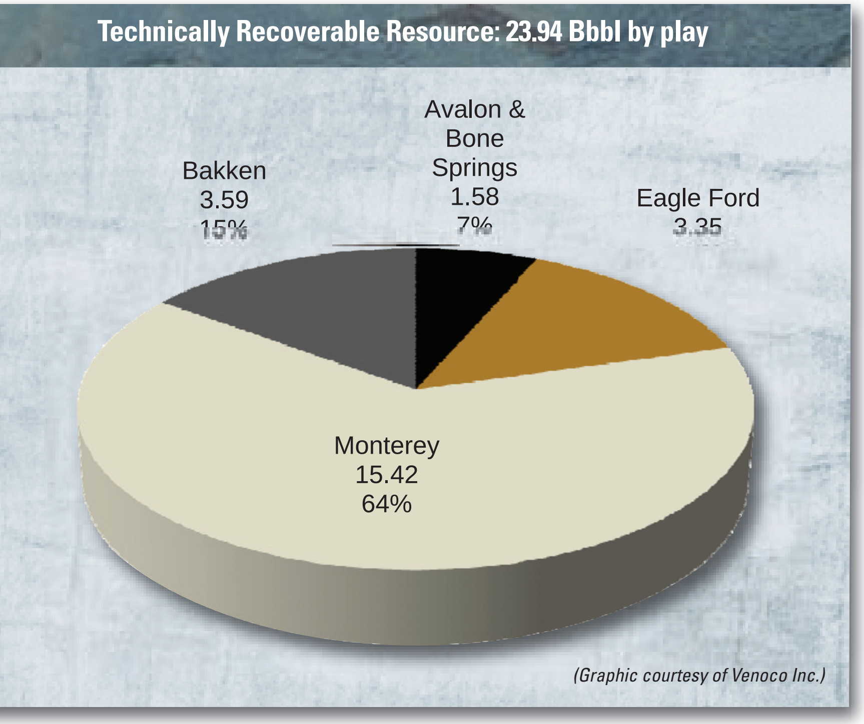
Granite Wash reservoirs span almost the entire Pennsylvanian System through the Lower Permian. To call them unusual is an understatement.

They are comprised of thick, low permeability sediments shed from the Wichita Uplift. In turn, they vary in lithology based on the formation exposed on the uplift at the time of deposition, according to Dan Boyd, petroleum geologist at the Oklahoma Geological Survey.

The relationship of the Marcellus Shale to the Middle and Upper Devonian stratigraphy, central Appalachian Basin, is shown.

	Western Virginia	West Virginia	Western Maryland	Eastern Ohio		Western Pennsylvania	Eastern Pennsylvania		New York
Upper Devonian	Chattanooga Shale	Hampshire Formation	Hampshire Formation	Ohio Shale			Catskill Formation		Catskill Formation
					Cleveland Mmber	Ohio Shale			Chautauqua
						Perrysburg			Hume Shale
					Chagrin Shale	Java			Dunkirk Shale
						West Falls			Pipe Creek Shale
		Foreknobs Formation			Huron Member	Sonyea Formation			Rhinestreet Shale
		Scherr Formation							Middlesex Shale
		Brallier Shale	Brallier Shale	Olentangy Shale		Brallier Shale	Brallier Shale		Genesee Formation
		Harrell Shale	Burket Shale			Burket Shale	Burket Shale		
Middle Devonian	Millboro Shale	Tully Limestone	Mahantango Formation			Tully Limestone	Tully Limestone		Tully Limestone
		Millboro Shale		Prout Limestone		Mahantango Formation	Hamilton Group	Mahantango Formation	Hamilton Group
				Plum Brook Shale					Skaneateles Shale
	Marcellus Shale	Marcellus Shale	Marcellus Shale	Delaware Limestone	Marcellus Shale	Marcellus Shale		Marcellus Shale	Marcellus Shale
Lower Devonian	Onondaga Limestone	Onondaga Limestone	Onondaga Limestone	Onondaga Limestone		Onondaga Limestone	Onondaga Limestone	Selinsgrove Limestone	Onondaga Limestone
		Needmore Shale	Needmore Shale			Needmore Shale	Needmore Shale		
	Oriskany Sandstone	Oriskany Sandstone	Oriskany Sandstone	Oriskany Sandstone		Oriskany Sandstone	Oriskany Sandstone	Ridgeley Sandstone	Oriskany Sandstone
	Undifferentiated Lower Devonian formations								

(Modified from deWitt, Roen and Wallace, 1993 and Oliver and others, 1971. Courtesy of Global GeoData)



The Monterey, with 15.42 Bbbl of technically recoverable oil, holds more potential production than the Bakken, the Eagle Ford, and the Avalon/Bone Springs combined.

The Wash changes both vertically and horizontally across the play. Local geology, impacted with varying lithological detritus from different uplifts in the region, can be a challenge for operators.

Geologically speaking, the Granite Wash is kind of a jumbled mess, making it difficult to rigidly define.

According to Boyd, the Desmoines Granite Wash horizontal play in the deepest part of the Anadarko Basin is the most important of the Granite Wash reservoirs to date. Boyd says the play is notable for spectacular rates on initial potential tests and wells with payouts often measured in months.

Marcellus

The Marcellus Shale member of the Devonian black shales in the Appalachian Basin spans a distance of approximately 400 miles, trending northeastward from West Virginia and into New York. The sheer size of the continuous shale makes it quite unique in terms of potential production, according to recognized Marcellus expert and Pennsylvania State University geosciences professor Terry Engelder.

He stresses that the Marcellus play is all about the natural hydraulic fractures in the rock and how they are drilled. The shale has two sets of vertical fractures – J1 and J2. The east-northeast trending J1s are denser, more closely spaced, and cross-cut by the less well-developed northwest-trending J2 joints. Fracturing in gas shales encourages higher productivity.

It is a play with something to please most everyone in that there are wet gas areas, dry gas areas, and areas of varied geological complexity.

At Range Resources, which kicked off the play in 2007, geologists Bill Zagorski and Martin Emery note that two major core areas have developed in the Marcellus play fairway. One of these is the southwest Pennsylvania region (the original discovery area). The other is the northeast core area in the northeastern part of the state.

Marcellus Shale thickness ranges about 100 ft average gross in southwestern Pennsylvania, where it occurs about 8,000 ft deep, and more than 250 ft in the north-central region. The two geologists say one can basically call the core areas a northeast dry gas play and a southwest combination NGL and dry gas play. The most productive wells in terms of initial production are in the northeast part of the Marcellus fairway, e.g., Susquehanna, Bradford, and Tioga counties, Engelder notes.

The organic-rich Marcellus Shale was deposited in a foreland basin setting that allowed for accumulation and preservation of the organic material, according to Zagorski and Emery. They emphasize that high organic content and the associated porosity and greater overpressure are some of the key Marcellus gas productivity factors.

Mississippi Lime

Shale play fever has spread to other formations ripe for production by the same types of technology, e.g., horizontal drilling and hydraulic fracturing. At the top of the list of new targets is the Mississippi Lime in northern Oklahoma and southern Kansas. An oil ratio usually above 50% is a strong draw for operators.

Vertical fractures occur in this regional carbonate deposit, which lies beneath the productive Atoka and Morrow sands and above the Devonian-age Woodford and the older Silurian-age Hunton.

It is really a new/old target given that vertical wells

have been drilled in this area for decades, where the Mississippi Lime has yielded only marginal production.

Reservoir quality tends to be poor owing to minor porosity and permeability albeit greater than most shale plays. The wells in the play can be fraced using water and acid, incorporating the readily available Ottawa sand as the proppant.

A variety of rocks occur in the play, including chert, tripolite, speculate, and chat, which some operators equate to tripolite or weathered chert.

According to Dan Boyd, petroleum geologist at the Oklahoma Geological Survey, the Mississippi Chat is a thin, siliceous zone of variable reservoir quality that intermittently develops on top of the Mississippi Lime. The Chat also has yielded minimal production for decades via vertical wells. Today it can be identified seismically, and horizontal wells drilled on seismic anomalies enable operators to maximize reservoir exposure. The Chat has sufficient permeability that the wells ordinarily do not need to be treated.

More than 140 horizontal wells had been drilled into the Lime as of May 2011, according to Tom Ward, chairman, president, and CEO of SandRidge Energy Inc., which is the leading leaseholder in the play. Fifty-two of these wells were drilled by SandRidge, and Ward notes they believe the wells are "best in class in all of the US."

There's still a steep learning curve for the Lime, and Boyd cautions there will be sweet spots in the play but not to expect everything to pan out. On the other hand, he predicts that the really juicy spots are going to make a lot of money.

Monterey

The Miocene-age Monterey Shale in Southern California has sourced almost all of the oil in California. Think big fields: Kern River, Elk Hills, Midway-Sunset, and other giants. The shale, which is estimated to contain more than 500 Bbbl of oil in place, has been produced in one fashion or another for more than 100 years.

The Heritage platform hosts the most powerful drilling rig ever built on a fixed offshore platform. Exxon Mobil ordered the rig to drill extended-reach wells to the Monterey Formation.

(Photo courtesy of Exxon Mobil Corp.)

Not surprisingly, it is now being eyed in a whole new way as being an unconventional play ripe for application of today's new tools and technologies.

The Monterey differs considerably from other shale plays being pursued that are typically associated with 300 million-year-old, or older, structures. It is five to 17 million years old, according to Venoco Inc. There are now large areas in the peak oil generation window, so it is currently generating oil. Monterey Shale oil gravity ranges from 6°API up to the 30-plus°API mark of light oil.

Some of the older Monterey fields have been in geological existence for fewer than 1 million years. For example, the Ventura Avenue anticline is very young and has already produced perhaps more than 1 Bbbl of oil from a Monterey-sourced sandstone reservoir.

This region's subsurface has been highly twisted and broken from the extreme physically altering activity in this tectonically active area. The bright side to this is the generation of a variety of hydrocarbon traps.

Reportedly, the Monterey producing gross column is hundreds of feet thick at Oxy's Elk Hills Field, which the company produces via vertical wells.

The Monterey also produces offshore California, e.g., the South Ellwood Field discovered in 1997. It is said to have jump-started the Monterey play in the Santa Barbara channel.

Montney

The currently popular Lower Triassic Montney Formation is principally a siliciclastic-dominant unit found west of Edmonton in west-central Alberta and northeast British Columbia. Wherever the Montney occurs, it unconformably overlies either Permian or Carboniferous strata; above the Montney is the Middle Triassic Doig Formation, which also can be a drilling target in the young play.

According to a Halliburton solutions document, the Montney Shale gas play consists of four distinct pay intervals: the upper, middle, middle lower, and lower. The most prolific and actively targeted areas by the company's customers are the upper and lower intervals.

The lower Montney is a dark grey, dolomitic siltstone, interbedded with shales, while the upper interval is a light brown, blocky siltstone with interlaminated fine-grained sands, according to the Lexicon of Canadian Geologic Units. The sand or arenaceous content increases to the east, where traces of glauconite can be seen.

Halliburton noted that the Montney Formation ranges in depth from 5,000 to 7,500 ft, with average pressure being 2,500 to 3,000 psi. A Raymond James report tagged it as one of the largest economically viable resource plays in North America, estimating a resource size of 50 Tcf of gas.

It is a common theme among shale plays for operators to have drilled right on through the shale intervals on the way to other targets, and the Montney is no exception. The play did not spring to life until horizontal drilling was implemented.

Today, the Montney reportedly is the most prolific unconventional play in Canada. Its IP rates exceed 10 Mcf/d.

Niobrara

The self-sourced Niobrara Shale play in the Rocky Mountain region is expansive, to say the least. In fact, the Late Cretaceous Niobrara Shale extends across New Mexico, Colorado, Wyoming, Kansas, Montana, and North and South Dakota.

It is a shale, but not exactly a shale.

The Niobrara petroleum system is a major system in this area, comprised of extremely rich source rocks with TOC between 3% and 8% in places with the reservoir rock primarily limestone or chalk intervals, according to geologist Steve Sonnenberg, petroleum geology professor at the Colorado School of Mines.

Because the oil- and liquids-rich shale is so brittle, it has a unique fault and fracture pattern, very different from the overlying and underlying units. Denver-based geologist Randy Ray likens it to a brittle sandwich, with a limestone facies between organically rich shale zones that source the chalk.

The industry had long known the oil was there, but no one had pursued it using a combo of horizontal drilling and staged fracs, which essentially provide the key to unlock the hydrocarbons long trapped in the shales, making the plays economic.

The Denver (DJ) Basin in southeast Wyoming and northeast Colorado has been an extremely active area in the Niobrara play. The DJ Basin extends into western Kansas and Nebraska as well.

Natural fractures of multiple origins, along with temperature gradients, affect production type in the deep basin area. Depth of the Niobrara at the busy Silo Field in Wyoming in the basin's northern reach is 7,500 to 8,000 ft.

The B interval of the Niobrara is the target of choice in the DJ Basin and also in the Powder River Basin.

It likely will entail multiple models to make this play attain its potential. It is vitally important to understand the regional stress field, but local faults and folds also impact fracture orientation, according to Sonnenberg.

Tonkawa

The Pennsylvanian-age Tonkawa sand in north-central Oklahoma and south-central Kansas is a fluvial dominated deltaic reservoir. This characteristic can restrict the size of a play in a couple of ways. For starters, the distribution of fluvial sandstones having deltaic origin is limited. Additionally, Tonkawa reservoirs are closely associated with the Nemaha uplift and Nemaha fault, meaning oil likely migrated vertically to the Tonkawa in such cases, according to the Oklahoma Geological Survey.

Drilling depths between 2,200 and 4,200 ft are common, but earlier drilling focused on deeper, commonly more productive targets. The shallow accumulations were not well understood, as Tonkawa accumulations are dependent on the distribution of favorable reservoir facies and structural condition.

In the Blackwell Field area in Kay County, north-central Oklahoma, the Tonkawa B sandstone is the main oil and gas reservoir, having an average porosity of 24%. Measured reservoir properties include bottomhole temperature of 100°F, 44°API oil gravity, and bottomhole pressure of 950 lb psi, according to Kurt Rottmann, consulting geologist in Oklahoma City. The reservoir has a strong natural water drive evidenced by the persistence of reservoir pressure without pressure maintenance.

Tuscaloosa Marine

The Tuscaloosa Marine Shale extends about 2.7-plus million acres across central Louisiana, reaching into southwestern Mississippi. The deep, high-pressure shale occurs between the upper and lower units of the Cretaceous Tuscaloosa Formation and are thought to have sourced the hugely productive sands in the region's famed Tuscaloosa Trend.

The Marine Shale has thrown oil for years, piquing operators' interest as they drilled through it targeting deeper horizons. Given today's available advanced technology to drill and complete shale zones, it now appears quite possible to commercially produce some of the estimated 7 Bbbl held by this particular shale.

It is not yet known how brittle or ductile the Marine Shale is, and this likely will fluctuate across the play and impact the rock's susceptibility to successful hydraulic fracturing. No doubt, the operators are developing a "Plan B" to apply to the rock where it is too soft to hold the fractures open.

According to well logs, resistivity varies across the play. Higher resistivities of 7 ohm-m average occur consistently across the area of the Louisiana-Mississippi state line in Wilkinson and Amite counties and the parishes of West and East Feliciana, St. Helena, and Tangipahoa, according to Kirk Barrell, president of Amelia Resources. To the east in Washington Parish, they are in the 2.5 ohm-m range, whereas they average 3.5 ohm-m in Rapides and Vernon parishes to the west.

The western area of the play is usually referred to as the Louisiana Eagle Ford as the shale is similar in age and lithology to the liquids-rich Eagle Ford Formation in Texas. It reportedly contains a greater percentage of calcite than the Marine Shale to the east, which would make it a better target for fracturing.

Depending on the location within the play, vertical depth to the shale ranges between 10,000 to 15,500 ft, Barrell notes.

In the general region of the Louisiana-Mississippi border, e.g., East Feliciana Parish, Marine Shale thickness tallies about 200 to 400 ft.

Utica

The Late Ordovician-age Utica Shale in the Appalachian Basin occurs much deeper than the geologically younger Marcellus Shale. It extends beyond the geographic limits of the highly productive Marcellus.

In addition to its new role as a target reservoir, the Utica is the primary source rock for a number of conventional hydrocarbon-bearing reservoirs throughout the Appalachian Basin.

In this Basin, major rock units tend to thin toward the west, where the Utica is about 200 ft thick versus about 700 ft to the east. The depth of the Utica decreases westward in Ohio and northwestward beneath the Great Lakes; it eventually outcrops in Quebec. It can be as much as 7,000 ft beneath the Marcellus in central Pennsylvania and less than 3,000 ft beneath to the west in eastern Ohio.

The thermally mature, organic rich, carbonaceous Utica often draws comparisons to the Eagle Ford Shale, which also has a high carbonate component. The Utica tends to be more liquids prone to the west, trending to wet gas and then dry gas to the east. It contains Type II kerogen that ordinarily is prone to oil generation.

The impetus for early activity to focus in Ohio is the liquids window found in the eastern part of the state, as well as in Kentucky and reaching into Ontario and the St. Lawrence Lowlands of Quebec.

To those not directly involved in the play, it may come as a surprise that the Point Pleasant Formation is the bulk of the play in Ohio rather than the Utica.

Within much of Ohio the Utica is directly underlain by, and in part in an equivalent facies arrangement with, the Point Pleasant Formation, which is comprised of interbedded organic-rich limestones and black shales, according to Larry Wickstrom, Ohio's state geologist and division chief of the Geological Survey Division at the Ohio Department of Natural Resources. He notes there has also been some earlier oil production from that interval in central Ohio.

Viking

The Viking oil play is a series of legacy oil pools reaching from central Alberta to southwest Saskatchewan. It is an established conventional play delineated via vertical drilling using older technology since its discovery in 1957.

The Cretaceous-age Viking Formation is estimated to contain about 6 Bbbl of original oil in place, making it second only to the shallower Cretaceous-age Cardium play.

The Viking lithology varies from coarse to fine sand to silt and silty shale. Sand horizons of varying thickness can be present, and variation in the porosity of the lenticular sands combined with updip loss of permeability creates a number of stratigraphic traps.

Owing to its continuous or blanket nature, seismic is not a requisite. The mantra for the play: Drill a well, find oil.

Similar to so many other high profile plays, the Viking is being rejuvenated using horizontal multistage fracs, enabling the operators to tap into oil ensconced in thick shaly intervals. Some players, however, say success is less about applying any one technique or interpretation but rather a combo of practices and significant fine-tuning.

Adding to the attraction of light oil (about mid-30°API), the Viking is a shallow play occurring about 2,100 ft deep. Operators are drilling shorter lateral legs with measured depth of the wells often maxing out at 5,000 ft; typical operating costs are about US $11/bbl. Well costs tally about $1.2 million to drill and place onstream.

Wolfcamp: Wolfberry and Wolfbone

Ordinarily, the name of a play denotes the formation(s) being targeted for production.

Not so with the lower Permian-age Wolfberry play in the Midland Basin in the Permian Basin province.

The Wolfberry acquired its name from the commingling of oil from the long-producing Spraberry sandstone and the deeper packed-limestone Wolfcamp Formation. Often called "the Spraberry-Dean" to include the underlying Dean sandstone, the Spraberry is a tight sand overall with isolated sandstone lenses that are conventional pay zones.

The Spraberry has a long reputation for being a formation where wells will always produce at least so-so volumes with the potential to keep on going for years. The Spraberry Trend field has been kicking out hydrocarbons since its discovery in 1949.

The Wolfberry play reportedly includes a 2,000- to 3,000-ft section from the top of the Spraberry Formation to the bottom of the Wolfcamp.

The play stretches through the heart of the Permian Basin. The western flank, which is said to contain most of the sweet spots, measures about 100 miles laterally and 15 miles wide and stretches from Upton County, south of the city of Midland to the northwest into Andrews County. There is also an eastern flank to the play, which includes parts of Reagan, Glasscock, Sterling, and Howard counties.

At the end of the day, the key to the Wolfberry play successes is said to be the ability to use multistage fracs on multiple zones in vertical wells and then commingling those.

Depending on the circumstances, the Wolfberry exhibits either little primary porosity or high porosity. In the Wolfcamp, the best porosities and permeabilities occur close to the edge of the Central Basin Platform, but wells drilled too close tend to be wet because of recharge on the platform itself.

At the end of the day, the key to the Wolfberry play successes is said to be the ability to use multistage fracs on multiple zones in vertical wells and then commingling those. Indeed, the success of the wells is attributed to more frac stages into deeper well bores rather than the size of the fracs, according to Tim Dove, president and COO of Pioneer Natural Resources, which is the largest leaseholder in the Spraberry Trend field and a major force in the Wolfberry play.

Just as the Wolfberry play acquired its moniker from the commingling of Wolfcamp and Spraberry production, the Permian-age Wolfbone on the western edge of the Delaware Basin is now part of the hydrocarbon lexicon owing to commingled production from the Wolfcamp and the Bone Spring. These two formations are made of limestone and sandstone and are typically encountered by the drill bit at depths of 8,000 to 13,000 ft.

According to ExL president Doug Robison, the Wolfbone is not a development play like the Wolfberry, but there are some look-alikes in the geological sense. There will continue to be a strong technology component to developing the Wolfberry play, and Robison says the application of that technology will determine how successful the Wolfbone will become. As with all new plays, there is a learning curve the players must scale. ■

Shale Liquids Show Strong Growth

By Don Lyle
Contributing Editor
Editor's Note: Information current as of Nov. 1, 2011

Drilling opens new resource potential.

Liquids-prone shale plays act like bread in the oven. The demand for fresh product is strong in the market. The mix is being perfected. The yeast (profit) has been proportioned, and the bread is in the oven and rising.

In late 2011, the US Geological Survey upped its estimates for the Marcellus to 84 Tcf of undiscovered, technically recoverable gas-heavy resource from 2 Tcf and 10 MMbbl of oil in 2002. The US Energy Information Administration (EIA) downgraded its estimate from 410 Tcf to close in on the lower figure. Cabot Oil & Gas, Chesapeake Energy, Range Resources, and Ultra Resources estimated their properties alone – 2.9 million acres – contain 76 Tcf of resource.

The signs of an active play are apparent. States and companies are tussling over ownership of the gas and grappling with regulations to handle the surging production demands in Appalachia.

The EIA estimated the 1,752 sq miles of Monterey in the San Joaquin and Los Angeles basins contain 15.42 Bbbl of technically recoverable oil.

Canadian Quantum estimated up to 40 Tcf of gas in the Utica Shale in Canada alone, and companies in the US are closing in on the liquids-rich portion of the play in Ohio, near the Pennsylvania border, where Quantum's land position could host up to 40 rigs by 2014.

In short, the liquids-prone plays are hot, as operators take advantage of their high profit potential compared to gas.

Profiles of the more significant companies operating in the established and emerging liquids-rich shale plays in the US and Canada are listed below. Unfortunately, because of space limitations, the editors cannot include all of the companies working all of the plays. This is an extremely fluid list. Mergers and acquisitions are taking place and more are being discussed as this publication goes to press.

This is an exciting time for the liquids-prone shales, and the excitement is far from over.

Abraxas Petroleum Corp.

BAKKEN/THREE FORKS

Abraxas Petroleum Corp. holds 20,835 net acres in the Bakken/Three Forks with 130 net unrisked locations. Planned 2011 spending called for US $25.5 million for 2.5 net operated wells and a half interest in a non-operated well among 15 gross wells on properties with 8.1 MMboe in proved and probable reserves.

Abraxas Petroleum Corp. holds 20,835 net acres in the Bakken/Three Forks with 130 net unrisked locations.

It also holds more than 10,000 net acres of land with Bakken potential in Glacier and Toole counties in the Alberta Basin in western Montana. In late 2011 it was holding the properties and watching industry activity.

EAGLE FORD

Abraxas has 75 net unrisked locations on its 12,073 net acres of Eagle Ford property in McMullen, DeWitt, and Atascosa counties in Texas. It also has

(Photo courtesy of Anadarko Petroleum)

Rocky Mountains north of Denver frame rigs drilling for Anadarko Petroleum Corp. in the Denver-Julesburg Basin of northeastern Colorado.

a joint venture with Talisman Energy and a 50-50 venture, called Blue Eagle Energy LLC, with Rock Oil Co. Its Eagle Ford properties have 18.9 MMboe of proved and probable potential.

NIOBRARA

The company's plans for the Niobrara Shale in Converse, Campbell, and Niobrara counties in Wyoming included spending $8 million on two horizontal wells in the fall of 2011 where the company hoped to reach part of its 14 MMboe of proved and probable potential on its 17,800 net acres. It will drill one well to the Niobrara and the other to the Turner Formation. It has room for 56 gross wells on the property.

WOLFBONE

Other companies are drilling wells near 3,000 net acres controlled by Abraxas in the Wolfbone (Wolfberry/Bone Spring) play in the Delaware Basin in West Texas. It has 8,700 net acres and a proved and probable potential of 3.7 MMboe in all of its West Texas oil plays.

Anadarko Petroleum Corp.

AVALON/LEONARD/BONE SPRING

Anadarko's Permian Basin properties produced 14.7 Mboe/d in 2Q 2011, and the company spent US $75 million to operate five rigs on the property in 2Q 2011.

It spud 18 wells and completed 20. Only one of its rigs is working the Avalon Shale; the rest are examining the Bone Spring Formation. To date, it has participated in 13 Avalon wells with initial potential production rates of 800 boe/d to 1 Mboe/d. The Bone Spring play covers some 170,000 net acres for Anadarko, and the Avalon Shale has potential under all that land.

EAGLE FORD

Anadarko's Eagle Ford play covers a gross 400,000, net 200,000, acres of land with more than 2,000 identified drill sites. Wells average more than 450 Mboe/d in EUR, and Anadarko planned to operate 11 rigs in the play in 2011.

In March 2011, Anardarko signed a US $1.55 billion agreement that gave Korea National Oil Corp. 80,000 net acres in the Eagle Ford and another 16,000 acres with Pearsall gas shale potential. The Korean company's funds will go to carry Anadarko's full interest in drilling during 2011 and will cover 90% of drilling costs on the land until all the funds are used, probably by the end of 2013.

In 2010, Anadarko spent $93 million to buy 93,000 net acres of Eagle Ford land from TXCO.

By 4Q 2010, before the agreement, Anadarko was the biggest producer in the play. It drilled its longest lateral at 8,340 ft and drilled 22 of its wells in less than 10 days each.

During 2Q 2011, it produced 25 Mcf/d of gas, 3 Mb/d of natural gas liquids, and 6 Mb/d of oil from the South Texas shale. It finished 2Q 2011 producing 45 Mboe/d after spudding 60 wells and adding production from 33 wells.

MARCELLUS

Anadarko held 760,000 gross, 260,000 net, acres in the Marcellus play in Centre, Clinton, and Lycoming counties in Pennsylvania; part of that gross holding is in a partnership with Chesapeake Energy Corp. The company was working seven rigs in the popular shale, and said it held 1 Bboe in net risked resources in the play.

During 2Q 2011, Anadarko set a drilling record of 13.2 days for a Marcellus well and has drilled 13 wells in less than 18 days from spud to rig release. It produced an average 119 MMcf/d of gas, up from 31 MMcf/d a year earlier.

It operated 10 rigs and set a weekly production record at 456 MMcf/d gross, 116 MMcf/d net of gas from 117 wells. By August 2011, it produced 500 MMcf/d from 125 wells. It spudded 29 wells and participated in another 33 wells.

Anadarko lowered its average drilling cycle times in the Marcellus during 2Q 2011 to 19.6 days from 26.8 days in 1Q 2011.

Anadarko also increased its production potential when it signed a joint-venture agreement with Japan's Mitsui E&P USA LLC to make Mitsui a 32.5% partner in Marcellus operations. It spent $1.4 billion to earn some 100,000 net acres by funding all of Anadarko's development costs in the Marcellus in 2010 and 90% through 2013.

NIOBRARA

Anadarko is the largest acreage holder in Wyoming with railroad land in a strip across the southern part of the state. That grant land also extends from southeastern Colorado north through the Denver-Julesburg Basin. Its Colorado and southeastern Wyoming properties alone cover 900,000 net acres, and it has another 360,000 acres in the Powder River Basin, all with Niobrara Shale potential.

By mid-November 2011 it was producing from 11 horizontal wells in Wattenberg Field alone with 40 Niobrara wells planned throughout its properties for the year. The company said it held between 1,200 and 2,700 drilling locations with EUR between 300 Mboe and 600 Mboe per well. That would give the company a net resource potential between 500 MMboe and 1.5 Bboe, assuming it combined Codell and Niobrara production. Initial production rates on its Wattenberg wells average 800 boe/d with a best rate of 1.1 Mbo/d and 2.4 MMcfg/d at its Dolph 27-1HZ well. That well paid out it less than four months. Its success in the play prompted Anadarko to plan seven rigs for the play in 2012, up from three rigs in 2011, to drill approximately 160 wells.

During 2Q 2011, Anadarko set a drilling record of 13.2 days for a Marcellus well and has drilled 13 wells in less than 18 days from spud to rig release.

Angle Energy Inc.

CARDIUM

Angle Energy Inc. tested its fifth Cardium horizontal well in the Ferrier area of southwestern Alberta at a rate of 1,475 boe/d after 115 hours of flowback. It owns a 0.6% interest in the well. In the second half of 2011, Angle planned to drill one Cardium well in its Harmattan area and an additional Cardium well at Ferrier. In a corporate presentation, the company said it held 190 net sections of Cardium land with only 90% undeveloped.

It has 90 to 130 Cardium oil locations in the Harmattan/Garrington area and expects initial potential rates around 150 boe/d and EUR of 150

Mboe. Its Edson property holds 50 to 75 Cardium locations with anticipated initial potentials of 220 boe/d and EUR of 180 Mboe per well.

Cardium oil varies by field, returning 155% at Strachan, 39% at Garrington, and 42% at Edson with break-even EUR of 130 Mboe, 70 Mboe, and 86 Mboe, respectively.

VIKING

Angle completed and tested three Viking horizontal wells in the first half of 2011 and determined propane-based fracture treatments worked better than oil-based frac jobs. In the four months to the end of July 2011, it completed one net Viking well at Harmattan. It planned another well to that formation in the same field during 2011 where it holds 60 to 120 Viking locations with an initial per-well potential of 250 boe/d and EUR of 400 Mboe per well.

Angle holds 50 to 100 locations in the Viking in the Harmattan area. Throughout the company's holdings, the Viking offers a 21% internal rate of return, and wells break even with initial potentials of 160 boe/d and EUR of 250 Mboe.

In the second half of 2011, Angle planned to drill one Cardium well in its Harmattan area and an additional Cardium well at Ferrier.

Anschutz Exploration Corp.

BAKKEN

Anschutz Exploration Corp. said in July 2011 it sold its operated and non-operated properties in the Williston Basin in North Dakota and Montana to an undisclosed Canadian oil company for US $115 million. In December 2010, Anschutz sold its Dunn County, N.D., properties to Oxy USA for $1.4 billion.

MARCELLUS

Anschutz sold its 500,000 acres of Ohio and Pennsylvania properties, including Marcellus holdings, to Chesapeake Energy for $850 million in November 2010. Anschutz said it continued to focus on emerging shale oil plays in the US with more than 1 million net acres of leases, primarily in Texas, Montana, Colorado, and New York.

Antero Resources Corp.

MARCELLUS

Antero Resources Corp. holds 194,000 net acres in Appalachia's Marcellus play in Pennsylvania and West Virginia with only 9% classified as proved reserve properties. The company's 2Q 2011 report said it currently was working only in northern West Virginia with five operated rigs. It planned to add a sixth rig in October and a seventh by the end of the year. Gross gas production of 180 MMcf/d comes from the Marcellus with 98% of that coming from its 47 horizontal wells. Net production is 133 MMcf/d, or more than half of total corporate production of 250 MMcf/d. The net daily production figure includes approximately 2,500 b/d of natural gas liquids and oil.

At the end of 2Q 2011, Antero had another 10 horizontal wells either being completed, awaiting completion, or awaiting pipeline hookup. It also has two frac crews at work.

The company's average lateral was 6,000 ft, but it was drilling a 9,600-ft lateral at the end of the 2Q 2011.

Apache Corp.

BONE SPRING

Apache Corp. acquired Permian Basin properties with its acquisitions of Mariner Energy and BP properties in moves that built its Permian Basin holdings to some 3 million acres. The BP properties included acreage prospective for Bone Spring. Following that acquisition, the company said it is acquiring new properties through joint ventures (JVs), farm-ins, and straight leasing. It also formed a new ventures group to examine the Abo horizontal play along with the Bone Spring and Wolfcamp. Apache also holds properties in the 111-well Shugart North Field, one of the larger Bone Spring fields, and in Two Georges Field in Loving County, Texas.

EAGLE FORD

Although Apache is one of the largest leaseholders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Horizontal Wolfcamp – Enhancing Wolfcamp Value

	Well EUR (Bbbls)		
Oil Shale Play	Vertical	Horizontal	Potential Uplift
Eagle Ford	49,500	323,813	6.5x
Niobrara	40,000	290,000	7.3x
Wolfcamp	80,000	450,000	5.6x

Notes: Eagle Ford and Niobrara well EURs from industry publications. Wolfcamp well EUR is based on AREX estimates.

The horizontal Wolfcamp Shale play compares favorably with the Eagle Ford and Niobrara liquids-rich shale plays. *(Table courtesy of Approach Resources Inc.)*

in the Eagle Ford Shale with more than 450,000 acres, it hasn't made the popular shale part of its active operations.

GRANITE WASH

The Granite Wash play has proved a major asset for Apache, and the company announced a major find in the play in late 2010. It holds some 200,000 gross, 70,000 net, acres in the play, leasing 30,000 net acres in 2010 alone. In November, it reported completion of its first two wells in the Hogshooter section of the Granite Wash in the Anadarko Basin at rates of more than 2,000 b/d of oil each. The Hogshooter is shallower, younger, and more oil prone than previous Granite Wash targets, Apache said. It also said its two Hogshooter wells lie 15 miles apart, indicating potential for substantial numbers of additional productive wells. Both wells are in Beckham County, Okla. Even after two months on production, the wells continue to produce some 700 b/d of oil and 3.5 MMcf/d of gas. Apache planned to raise its rig count in the play to 10 for 2011 and drill more than 40 horizontal Granite Wash wells, including 10 Hogshooter wells.

MONTNEY

Late in 2010, Apache completed a massive land deal with BP, acquiring BP's Permian Basin properties and nearly all of BP's upstream assets in western Alberta and British Columbia, a total of some 1.3 million net acres, for $3.25 billion. Those properties held significant positions, according to Apache, in several unconventional plays, including the Montney, Cadomin, Doig Shale, and coalbed methane.

NIOBRARA

When Apache acquired Mariner Energy Inc., it picked up that company's offshore assets and Permian Basin assets, but it also gained some 54,000 net acres of land prospective for the Niobrara Shale in Laramie County in southern Wyoming in the Denver-Julesburg Basin. Following the Mariner acquisition announcement, Apache participated in a US $48.8 million auction of Wyoming properties prospective for Niobrara Shale production. Winning bids ranged as high as $4,725 an acre for all participants. Apache placed winning bids on 18 parcels with bids ranging from $9 to $850 an acre.

WOLFBERRY

Mariner Energy had been assembling Wolfberry (Wolfcamp/Spraberry) land in the Permian Basin for at least two years when Apache bought the company for $3.9 billion late in 2010. Mariner hadn't started a serious development effort by the time of the acquisition, but the potential remains. That potential was augmented by nearby Mariner acreage with its potential for Wolfcamp and Cline Shale in Deadwood Field.

Approach Resources Inc.

WOLFFORK

Approach Resources Inc. used its experience on some 525 Permian Basin wells drilled since 2004 to identify a new trend, the Wolfcamp/Clearfork combination, which it named the Wolffork. It focused its Wolffork drilling program on its Pangea project in Schleicher and Crockett counties in West Texas.

A vertical Wolffork well offers the company an average EUR of 110 Mboe at an average well cost of US $1.2 million. The company has 1,825 potential locations with a finding and development (F&D) cost of $10.91/boe. Wells come in at less than 7,000 ft with 75% of EUR in oil and natural gas liquids (NGLs). Those wells give Approach a resource potential of more than 200 MMboe. It is working the one rig in a start-up development program.

A side benefit in recompletions offers the company another 190 potential locations with a finding and development cost of $8.06/boe. Average EURs are at 93 Mboe/well at a cost of $750,000.

Vertical Canyon Wolffork wells give Approach another 85 MMboe of gross resource potential at 440 potential locations. The company has two rigs drilling vertical wells.

WOLFCAMP

Approach drilled four horizontal Wolfcamp Shale wells by August 2011, completing two in 2Q 2011. Its fourth well, the University 45 A 701H, used a 6,859-ft lateral and a 21-stage frac treatment to test at an initial 24-hour rate of 613 b/d of oil, 41 b/d of NGLs, and 237 Mcf/d of gas. The company planned to complete its fifth and sixth horizontal wells in 3Q 2011 with its seventh well awaiting completion and the eighth being drilled.

It looks for an average EUR of 450 Mboe from a horizontal well at a cost of $5.5 million. That play gives the company some 500 potential locations at an F&D cost of $12.22/boe and a gross resource potential of 225 MMboe.

ARC Resources Ltd.

MONTNEY

ARC Resources Ltd. started business in 1996 as an energy trust, piled up a 20% rate of return since its inception, and converted to a corporation in January 2011. It owes a considerable portion of its growth to its Montney properties. It holds more than 10 Tcf of gas initially in place in the play and is the second-biggest producer in the Montney after Encana Corp. It added a gas plant in 2010, another in 2011 (both now at capacity), and plans a third by 2014.

It expects its Dawson Field, where it's building the gas plants, to produce 165 MMcfe/d of gas by the end of 2011 after drilling 13 horizontal and one vertical well during the year. That field produces 5 bbl of liquids per thousand cubic feet of gas.

Parkland is a liquids-rich field, producing more than 30 bbl of liquids per thousand cubic feet of gas. It has a 10% probability of a 110% after tax internal rate of return from that field, compared to 70% for Dawson. It also has Montney operations at West Montney, and Attachie fields.

CARDIUM

ARC is the second-largest producer from the Cardium Formation in the Pembina area with 1,423 wells drilled to date. It holds interests in 166 gross, 125 net, sections of land. The company planned 42 horizontal wells in 2011 but said it has insufficient data to evaluate the full potential of its properties.

Atlas Energy LP

MARCELLUS

When Chevron Corp. acquired Atlas Resources for US $3.2 billion and $1.1 billion in debt in February 2011, it didn't buy out all of the Atlas properties. Atlas Energy LP kept some of the properties, including pipeline assets, major property positions, and the ability to continue raising money for drilling through its partnerships. Those retained assets included more than 200 vertical and 30 horizontal Marcellus wells. The company plans to connect 16 Marcellus horizontal wells already drilled by its partnership management business. It drilled eight of those wells in 2Q and 3Q 2011, five more wells were previously drilled and completed and are awaiting pipeline hookup, and the other three were in various stages of drilling, according to a July 2011 presentation by the company. Atlas still controls 600,000 acres of land in Appalachia with some 8,500 shallow wells.

In May 2011, Atlas joined a West Virginia-based company, which it did not identify, to drill Marcellus wells, all in Upshur County, W.Va., through its drilling investment programs, the company said. The partners will spend some $35 million.

NIOBRARA

Through a farm-in deal with Black Raven Energy, Atlas has interests in 178,000 net acres of land in northeastern Colorado prospective for the Niobrara play. Under the agreement, Atlas pays $60,000 per well and pays a production royalty of 6% to Black Raven to participate in the program. By July 2011, the companies had completed 23 producing wells with more recent completions averaging around 250 Mcf/d of gas in initial production testing. Second quarter daily production averaged 399 Mcf/d. The companies have land potential to drill more than 200 wells.

Aurora Oil & Gas Ltd.

EAGLE FORD

Aurora Oil & Gas Ltd. of Perth, Australia, put together 76,600 gross, 16,230 net, acres of land in the Eagle Ford play in South Texas and parlayed that position into a strong producing asset for the company. According to an August 30, 2011, report by Netherland, Sewell & Associates on the company's Sugarkane Field, the company held proved reserves of 15.75 MMbbl of liquids and 33.4 Bcf of natural gas and proved and probable reserves of 30.8 MMbbl of liquids and 67 Bcf of gas based on 51 gross wells, including nine farm-out wells in the proved developed producing and proved developed non-producing categories. The company has 229 proved undeveloped future well locations and 254 probable undeveloped locations based on 80-acre spacing. It also had eight wells awaiting stimulation or being fractured and five wells being drilled in which the company held an interest. It produced 2,970 boe/d, with 78% liquids, by the end of August. In May, the company said it produced 2,000 net boe/d and planned to raise that figure to 5,000 boe/d by the end of 2011 with average production of 3,400 boe/d for the full year. The Sugarkane area includes Sugarloaf, Longhorn, Ipanema, and Excelsior fields in an area of mutual interest with Hilcorp Energy with Hilcorp as operator. Marathon acquired Hilcorp's Eagle Ford assets for US $3.5 billion, and Aurora said that acquisition would accelerate development of its land in Live Oak, Karnes, and DeWitt counties.

Bill Barrett Corp.

NIOBRARA

Bill Barrett Corp. acquired a potential net 7 MMboe in August 2011 when it closed on properties in the Denver-Julesburg Basin from a Texas American Resources Co. affiliate. The properties include 650 boe/d of net production and some 28,000 net acres of leases with wells in Wattenberg Field in Colorado producing primarily from the Codell, Niobrara, and J Sand formations. The deal also included exploration properties predominantly in the Chalk Bluffs area in Laramie County, immediately north of the Colorado-Wyoming border, where Barrett plans to drill for Niobrara oil pay. Chalk Bluffs is north of the Hereford area in Colorado where EOG drilled the prolific Niobrara well that started the land rush in the play. The properties also include Sagebrush Field in Platte County, Wyo. Barrett paid US $150 million for the property and planned to start a single-rig program in October 2011.

The company already held more than 38,200 acres in the Niobrara play in the basin, but that property held pay with less oil content.

Barrett also holds properties at its West Tavaputs project in the Uinta Basin that hold production potential from the Mancos/Niobrara Shale, but that's a gas play.

The company's McRae Gas Field in the Wind River Basin of central Wyoming also targets Niobrara oil on 118,900 gross, 103,000 net, acres. The company budgeted up to two wells in that area in 2011 in an area with more than 300 ft of net pay at depths from 4,000 to 14,000 ft. The geology in that area is similar to Niobrara geology in the Powder River Basin of Wyoming.

Baytex Energy Corp.

BAKKEN/THREE FORKS

Baytex began assembling land in the Williston Basin in 2007 and 2008 and directed activities to Divide and Williams counties in the Bakken/Three Forks play in North Dakota in 2010. It holds some 303,400 gross, 126,400 net acres, in the area including 257,985 gross, 109,435 net undeveloped acres at the end of 2010. It drilled four gross, 1.5 net wells in 2009 and 26 gross, 9.5 net wells in 2010, all but one in the Bakken/Three Forks. It planned 22 gross, 9.4 net horizontal wells in 2011 in acreage with the potential to drill 100 to 300 wells with average initial production rates of about 420 boe/d per well and average estimated ultimate recoveries of 420 Mboe per well on 1,280-acre spacing.

CARDIUM

Baytex holds some 13,600 gross, 7,700 net, acres of land in the Cardium play in the Pembina Trend in west-central Alberta. It drilled 11 gross, 4.7 net, horizontal wells in the Cardium in 2010 and completed all of them with multistage frac treatments. It has room for up to 60 gross, 34 net wells on its property but planned to drill only eight wells in 2011.

VIKING

The company developed a new resource play in the Viking Sand in southwestern Saskatchewan at Dodsland and in southeastern Alberta in the Bon Accord area. Overall, it holds approximately 54,000 net acres of land prospective for the Viking Formation with a 70-30 split between Saskatchewan and Alberta. For 2011, Baytex planned 15 Viking wells with single laterals and multistage frac treatments. It could have as many as 300 drilling locations in the play.

Berry Petroleum Co.'s northwestern Wolfberry properties near the Wolfcamp carbonate platform offer significantly better production than its eastern properties. That's the area that gives the company its 180 Mboe EUR and its 85% liquids content.

Berry Petroleum Co.

WOLFBERRY

Berry Petroleum Co. started Wolfberry activity in the Permian Basin in 2010 with a US $126 million purchase from a private company. It estimated the properties held 11.2 MMboe in proved reserves, 23% proved developed and containing 85% oil. It added two more purchases, and, at the time of an August 2011 presentation, held more than 30,000 net acres of property with Wolfberry potential. It ran five rigs in the play on a $150 million budget in 2011 and said it could grow production to 9,000 b/d over the next four years using only four rigs and drilling on 40-acre spacing. Berry held a drilling inventory of more than 450 locations on that spacing and 650 drilling sites on 20-acre spacing. Wells in the formation generally come in between 120 boe/d to more than 250 boe/d with EUR of 160 Mboe to 180 Mboe. Production averaged 3,850 boe/d in 2Q.

The company's northwestern Wolfberry properties near the Wolfcamp carbonate platform offer significantly better production that its eastern properties. That's the area that gives the company its 180 Mboe EUR and its 85% liquids content.

MONTEREY

Berry Petroleum Co. has no Monterey production and has published no plans for development from the Monterey zone of its California properties, but company executives apparently believed at one time those properties had Monterey potential.

It currently has production from steam-flood operations in giant Midway-Sunset Field in Kern County, Calif., and ranks as California's fourth-largest oil producer with operated production of 35,000 b/d, following Chevron, Aera, Oxy, and Plains.

In 2005, Berry staked the P9-33 Severini to the Monterey Formation. It was listed as an outpost well in the field in the application for a permit, but it apparently never drilled the well, according to IHS Inc. records.

BHP Billiton Petroleum

AVALON/BONE SPRING/WOLFCAMP

BHP Billiton Petroleum acquired some 325,000 net acres of properties in the Midland and Delaware basins in the Permian Basin, with properties in the Avalon Shale, Bone Spring Sand, and the Wolfcamp Shale in its purchase of Petrohawk Energy Corp. for $15.1 billion in cash and debt. Petrohawk started assembling acreage in the basin in the second half of 2010 with Lower Wolfcamp as a target in the Midland Basin. The Lower Wolfcamp Shale, Bone Spring Sand, and Avalon Shale are primary targets in the Delaware Basin. It planned to spend US $75 million on drilling and completions in the Permian Basin in 2011 as it runs four rigs to drill 15 wells with a focus on the Delaware Basin portion of the property. It planned 5,000-ft laterals on its Midland Basin wells at a cost of approximately $7 million per well. While the southern portion of the basin has been partially de-risked, the northern portion is largely untested.

Delaware Basin well costs were projected at $6.5 million to $8 million to drill to a vertical depth of 5,000 to 12,000 ft to reach a 3,000-ft gross interval across the three target formations.

EAGLE FORD

When BHP Billiton bought the Petrohawk properties, Petrohawk had 332,000 net acres in three regions of the Eagle Ford with 457 Bcf of gas, 19 MMbbl of condensate, and 27 MMbbl of natural gas liquids (NGLs) in proved reserves and a risked resource potential of 7.36 Tcfe of gas. Petrohawk discovered Hawkviille Field in La Salle and McMullen counties in 2008 when it held 160,000 net acres. It built that position to 236,000 net acres along with 69,000 net acres in Black Hawk Field in Karnes and DeWitt counties and 77,000 net acres in Red Hawk Field in Zavala County. Black Hawk was its main area of operations, and it planned 85 wells there in 2011. It planned to run five rigs in Hawkville Field during the year to take part in 51 operated and 23 non-operated wells. It listed Red Hawk as an exploration area with only five wells planned in 2011, but it dropped funding in 2Q 2011 when well results didn't meet financial expectations.

Bonavista Energy Corp.

CARDIUM

Bonavista Energy Corp.'s Cardium light oil properties lie in its western core region. It holds 120 well locations in the area, a six-year drilling inventory, and planned 19 wells in 2011. Its properties in southern Alberta cover 300 net sections, and half of those are prospective for horizontal drilling to the Cardium Formation with sweet spots at East Pembina, Willesden Green, Ferrier, Garrington, and Lochend.

According to an August 2011 company presentation, average wells produced 185 boe/d during their first month online, 133 boe/d during the first six months, and 94 boe/d during the first year with 115 Mboe in total reserves. Payout comes in less than two years, and those wells offer a 32% before-tax internal rate of return. It drilled two vertical and two horizontal wells in the area and planned two more horizontal wells during 2011 to delineate its properties.

MONTNEY

In the company's northern core region, it has a strong inventory of undeveloped acreage with a substantial potential in its Blueberry Montney project area and further potential for horizontal drilling in the Halfway, Doig, and Notikewin Formations. It produced 15.5 Mboe/d from 63 MMboe in reserves at the end of 2010 from its 786,000 net acres of land. It completed at 20-MMcf/d processing plant to handle the 75 bbl of liquids per million cubic feet of gas, and it conducted a 3-D seismic survey in the area in 1Q 2011. Average wells produce 740 boe/d during the first month, 455 boe/d during the first six months, and 352 boe/d during the first year online from 504 Mboe in EUR. Payout comes in less than 19 months with a before-tax internal rate of return of 41%.

VIKING

Bonavista's eastern core region in eastern Alberta and western Saskatchewan holds its Viking unconventional properties along with heavy oil assets near Lloydminster. It plans horizontal drilling in east-central Alberta where other operating companies have drilled successful Viking wells. Bonavista holds 674,000 net acres in the area with 160 drilling locations, 41% horizontal. It drilled its first horizontal well in 2Q 2010 and recovered 60 b/d of liquids from 70 Mboe in recoverable resource. It drilled its second well in 2011; it awaits completion.

BP America Inc.

EAGLE FORD

BP America Inc. entered the Eagle Ford play in South Texas in early 2010 when it signed an agreement with Lewis Energy Group LP, one of the larger companies in the play. According to Lewis, BP paid US $200 million to farm in as a 50% partner on 80,000 acres of land in the play.

GRANITE WASH

BP holds Granite Wash properties in the Texas Panhandle. According to Texas Railroad Commission records, those properties include Mendota, Northwest Mendota, Mills Ranch, Hemphill, and St. Clair fields. The company also produces from the Atoka, Cherokee, Cleveland, Des Moines, Douglas, Kansas City, and Marmaton formations in the same area. It sends some of its production in Roberts County through a Crestwood Midstream Partners pipeline to a nearby processing plant.

TONKAWA

BP produces from the Tonkawa Formation in Alpar Field in the Texas Panhandle.

Brigham Exploration Co. focused its efforts on the Bakken/Three Forks formations in the Williston Basin because the play offers great economics.

Brigham Exploration Co.

BAKKEN/THREE FORKS

Brigham Exploration Co. focused its efforts on the Bakken/Three Forks formations in the Williston Basin because the play offers great economics. Norway's Statoil ASA apparently agrees with that assessment. In mid-October 2011, it signed an agreement with Brigham to merge the two companies with Statoil paying US $36.50 per Brigham share, or $4.4 billion, for the Austin, Texas, company. The companies anticipated completing the deal in late 2011 or early 2012. According to the Brigam website, it has drilled more than 1,075 gross wells, including 79 successful Bakken and Three Forks long-lateral, high-frac-stage completions with average first-24-hour production of 2,803 boe. The company has some 375,800 net acres in the play in North Dakota and Montana and has de-risked 235,200 net acres. Its primary operations areas are in Easy Rider and Rough Rider fields in North Dakota and in eastern Montana. The Easy Rider Ross/Parshall/Sannish project area, 98,700 acres, gave the company 21 horizontal wells with an average 3228 boe/d initial production. Its 58 Rough Rider wells averaged 2,650 boe/d in the first 24 hours. It holds some 114,000 net acres in Montana. It completed seven Montana wells with an average initial potential of 1,576 boe/d and planned four more by the end of 2011. North Dakota wells pay out in 1.9 years with a 51% internal rate of return, two good reasons the company is increasing its rig count to 15 by 1Q 2012 to drill 132 gross wells a year. The company produced more than 13,000 boe/d from its Williston properties in July 2011. In 3Q 2011, it still had 94 Bakken and 1,299 Bakken plus Three Forks undrilled locations.

GRANITE WASH

Brigham once was involved in the Granite Wash play in southwestern Oklahoma, but it sold those properties for $36 million in September 2007 and used the money to retire debt. At the time, the properties produced 1.8 MMcfe/d of gas and held proved reserves of 23.5 Bcfe.

Cabot Oil & Gas Corp.

EAGLE FORD

Cabot Oil & Gas Corp. concentrated its US $250 million in southern region capital funds on Eagle Ford play in South Texas for 2011. Those properties include Powderhorn Field in Zavala County, Buckhorn Field in Frio and La Salle counties, Harlow Field in Frio and Atascosa counties, and Presidio Field in Atascosa County. The company has a 100% success record in the play, so far. It has 3-D seismic surveys covering more than 95% of its acreage. It planned 25 net wells in 2011 and lined up a dedicated frac crew one week every month. Cabot still has 400 to 500 drilling locations in the play where it gets initial potentials between 475 boe/d and 1,025 boe/d with EUR of 375 Mboe to 600 Mboe per well for a resource potential of 150 MMboe to 300 MMboe. The company also has 25,000 acres in the Marmaton Shale and 100,000 net acres in the Heath Shale.

MARCELLUS

Cabot gets a return of more than 100% from its northeast Pennsylvania Marcellus properties at a gas price of $5/MMBtu. Its operations are getting more efficient. Its average well in 2009 gave the company EURs of 7.8 Bcf of gas per well. In 2010, Cabot raised that number to 10 Bcf with an all-in finding cost of $1.05/Mcfe. The company can drill between 2,300 and 2,700 Marcellus wells on its property to reach a potential resource between 14.9 Tcf and 27 Tcf of gas. It already has seven of the top producing

wells in Pennsylvania and total production of 410 MMcf/d from 71 horizontal and 35 vertical wells on its 200,000 acres of properties. It runs five horizontal drilling rigs and one frac crew that conducts 60 to 70 fracture treatments a month. It planned 51 horizontal and three vertical wells in 2011 with an average lateral of 3,654 ft and 15 frac stages.

Canbriam Energy Inc.

MONTNEY

Canbriam actively works its 60,232 net acres of land in the heart of the Montney Shale play in British Columbia. Those properties surround Talisman Energy's Farrell Creek Montney holdings. Canbriam drilled three vertical and 13 horizontal wells into the Upper and Lower Montney by 1Q 2011. Those wells feed a newly commissioned gas plant and go to renewable capacity on the Spectra T-North sales line. A portion of the property has potential for liquids-rich gas production. According to Canbriam, it holds the largest private land position with an inventory of more than 1,800 development drilling sites.

UTICA

Canbriam controls 122,494 net acres of land in the St. Lawrence Lowlands with potential production from the Utica and Lorraine shales. The company entered the play in late 2008 through two farm-in deals that gave it 80% and 60% working interests, respectively. It operates both projects and completed its first wells in late 2009 with plans for additional drilling when the Quebec government sets down regulatory boundaries. The company estimates its properties hold up to 14 Tcf of original gas in place.

Canadian Natural Resources Ltd.

CARDIUM

Canadian Natural Resources put together a Cretaceous Cardium play in the southern portion of its northwest Alberta region. The Cardium occurs extensively throughout the region where the company gets high productivity with the help of higher matrix porosity or natural fracturing.

MONTNEY

Canadian Natural Resources works the Montney tight sand/shale play and Doig Shale play in northwestern Alberta and northeastern British Columbia with particular attention to its Septimus project in British Columbia. The company already had some properties in the area, but it enhanced its position with the acquisition of Anadarko Canada Corp. in 2006.

In a July 2011 presentation, the company said the Septimus area contained 1.3 Tcfe of gas in contingent resource with 300 Bcfe of proved and probable reserves in a liquids-rich gas. It drilled 15 wells in 2010 with nine to 13 fractures per horizontal well. It completed a 50 MMcf/d refrigerated gas processing plant in the play in November 2010 and produced 60 MMcf/d of gas and 2 Mb/d of liquids. The company's full-cycle target finding and development cost is US $1.25/Mcfe of gas. Canadian Natural Resources planned eight horizontal wells in the area in 2011 and increased the liquids recoveries to 30 bbl of liquids per MMcf of gas or 1,800 b/d of liquids. In 2012, it will expand the plant to 130 MMcf/d of gas and drill 20 more wells to keep the plant full.

Canadian Quantum Energy Corp.

UTICA

Canadian Quantum Energy Corp. joins substantial partners in the Utica Shale in Quebec, but like other Utica operators, it's concentrating its current efforts on other prospects while the Quebec government sorts out a regulatory framework for Utica development.

Canadian Quantum holds interests in four operating permits covering some 174,000 gross, 37,100 net, acres in the Utica in the St. Lawrence Lowlands with partners Talisman Energy, Questerre Energy, and Junex. A 2009 report by Netherland Sewell estimated 5 Tcf of gas resource on the Canadian Quantum land.

An early well by Shell, the Sainte-Francoise-Romaine #1, tested for 4.5 MMcf/d of gas, but a later 2007 report by Encana questioned the ability of the shales to accept a frac treatment. Forest Oil, in 2008, answered that question with two fractured wells that tested up to 1 MMcf/d. Talisman, with Canadian Quantum and Questerre, followed up with the Gentilly #1, which tested at 800 Mcf/d of gas during an 18-day test.

The Utica Fairway generally runs between the St. Lawrence River to the north and the Logans Line fault to the south, an area of more than 1.1 million acres, or 2,400 sq miles, Canadian Quantum said. The shale compares best with the Barnett Shale in northern Texas.

The Nicolet permit, in which Canadian Quantum holds a 50% working interest with Junex as a partner, covers 59,090 acres with an estimated net 4.33 Tcf of undiscovered original gas in place. A 10% recovery would give the company 433 Bcf of gas.

Talisman and Questerre are partners in the Gentilly and Parisville permit areas, where Canadian Quantum has a 3.75% working interest, and in the Leclercville permit, where it has a 15% working interest.

The Nicolet permit, in which Canadian Quantum holds a 50% working interest with Junex as a partner, covers 59,090 acres with an estimated net 4.33 Tcf of undiscovered original gas in place.

Carrizo Oil & Gas Inc.

EAGLE FORD

Carrizo Oil & Gas Inc. sold off a substantial portion of its Barnett gas shale properties and increased investments in the Marcellus, Niobrara, and Eagle Ford shales as it shifted operations to liquids. In an August 2011 presentation, the company said it drilled 16 Eagle Ford horizontal wells with eight wells on production and eight more awaiting completion with more to come as it keeps three drilling rigs working. Initial potential from the completed wells ranged from 700 b/d to more than 1,000 b/d of oil. If all goes as planned, it could increase oil production to more than 5,000 b/d by the end of 2011, thanks to the Eagle Ford and Niobrara. It planned to spend US $160 million in the Eagle Ford in 2011, up from $30 million the previous year. It holds 33,000 net acres of land, 80% drillable on 115-acre spacing, for a potential 230 wells. In September 2011 the company signed a joint venture (JV) agreement with India's GAIL (India) Ltd. that covers 20% of 20,200 net acres in the Eagle Ford play in La Salle County for $95 million, including $63.65 million in cash and $31.35 million of Carrizo's future drilling and development costs. The deal gives GAIL a net 4,040 acres and a 20% interest in eight horizontal wells. The property produces 1,700 b/d of oil and 3.8 MMcf/d of rich gas with proved reserves of 13.8 MMboe. A rig was drilling on a four-well pad on the property in late September. Throughout Carrizo's properties wells have an EUR of 400 Mboe, and the company expects total reserves of 92 MMboe. Most of that acreage is in the condensate window in La Salle County, Texas. Wells cost $7.5 million to $8 million with 5,000-ft laterals and 18 frac stages. From that investment, Carrizo gets a finding and development (F&D) cost of $25/boe and an internal rate of return of 67% with $100/bbl of oil and $4/Mcf of gas. Undiscounted payout with $85 oil comes in 2.1 years.

MARCELLUS

Carrizo holds 118,000 acres of Marcellus properties and focused its operations in northeast Pennsylvania, where it runs two rigs working on development wells. It anticipated initial operated gas sales in 3Q 2011. It raised its capex in the play to $41 million in 2011 from $8 million a year earlier. It operates 16,000 acres in New York and another 107,000 acres in West Virginia with Avista. In that deal, Carrizo contributed the land and Avista contributed cash to form a 50-50 partnership. It also holds 114,000 acres in Pennsylvania with India's Reliance Industries Ltd. Avista sold 57,700 acres to Reliance, and Reliance bought 20% of another 5,700 acres from Carrizo for $65 million in cash and development carries. Carrizo, as operator, owns 40% of the Pennsylvania venture and Reliance owns 60%.

A northeast Pennsylvania well costs $6.5 million to drill and yields net reserves of 7.5 Bcf of gas at an F&D cost of 87 cents/Mcf. The company's internal rate of return at $6/MMBtu gas is 88%, and it gets an undiscounted payout in 1.8 years at the same gas price.

NIOBRARA

Carrizo holds 61,658 net acres of Niobrara properties and raised its capex in the play to $35 million in 2011 from $12 million the previous year. It has a 50% interest in properties in Weld County, Colo., in the Denver-Julesburg Basin and expects to drill up to 97 wells on 320-acre spacing. Horizontal wells in its area produce 310 Mboe, and its property could yield 29.1 MMboe.

Carrizo had drilled and completed five wells showing initial potential production rates of 650 b/d to 725 b/d of oil by the time of its August 2011 presentation. In September, the company said it planned another eight horizontal Niobrara wells in Weld County. Wells cost $3.6 million to drill and complete with 5,000-ft laterals and 15 frac jobs in the Niobrara B bench. Its F&D cost is $15/boe, and its internal rate of return is 146% with $90/bbl of oil. Wells pay out in 2.4 years, undiscounted at an oil price of $75/bbl.

UTICA

Carrizo signed a JV agreement with Avista Capital Partners at the end of September 2011 to buy and develop acreage in the liquids-prone portion of the Utica Shale, starting with the acquisition of 15,000 net acres in eastern Ohio. Carrizo initially holds 10% of the venture with Avista controlling the remaining 90%. Avista can contribute up to $200 million to the venture, while Carrizo has two purchase options to raise its interest to 50% in properties acquired by the venture in the following 18 months. Carrizo will operate the properties.

Chaparral Energy LLC

AVALON/BONE SPRING

Chaparral Energy LLC holds 13,500 acres of land in the Avalon/Bone Spring area, much of it in the Haley area. That is part of the company's two core areas, the Permian Basin and Oklahoma. The company is putting 8% of its $250 million capital budget for 2011 into its Permian Basin properties.

BAKKEN

The company controls 5,000 acres in the Bakken Shale in the Williston Basin.

EAGLE FORD

Eagle Ford properties held by Chaparral total some 5,000 net acres.

GRANITE WASH

Chaparral holds 22,000 acres in the Granite Wash play in the Anadarko Basin. That play is part of its core-area activity. Eighty-five percent of the company's 2011 capex are directed toward the Oklahoma Granite Wash and Woodford shales.

Chesapeake Energy Corp.

AVALON, BONE SPRING, WOLFBERRY AND WOLFCAMP

Chesapeake Energy Corp. is a top-five acreage holder in the Permian Basin, which includes the Avalon, Bone Spring, Wolfberry, and Wolfcamp tight liquids plays in West Texas and southeastern New Mexico.

It holds 835,000 net acres in the basin with 1,810 risked undrilled well locations based on 160-acre spacing. An August 2011 presentation said the company holds 302 Bcfe of gas in proved reserves, 2.8 Tcfe in risked unproved resource and 9 Tcfe in unrisked and unproved resource. It produced 11 MMcfe/d at that time and was running 12 operated drilling rigs.

BAKKEN/THREE FORKS

An August 2011 presentation shows Chesapeake holds properties on the North Dakota side of the Williston Basin and holds a top-10 acreage position, but an activity report shows the company is not actively working in the area.

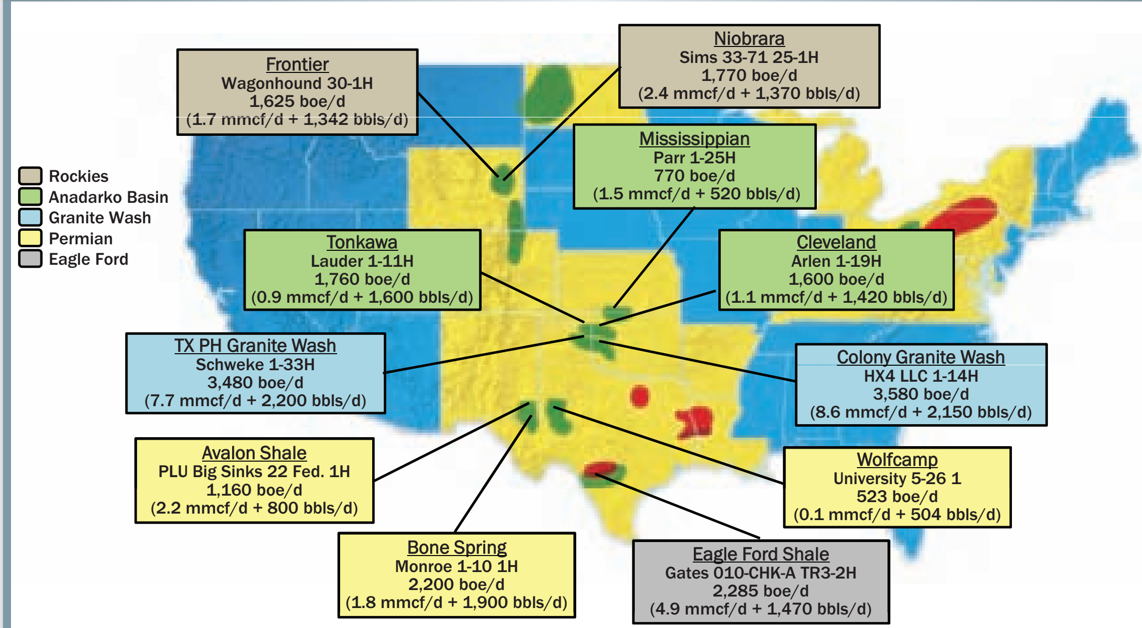
CLEVELAND/TONKAWA, GRANITE WASH

Chesapeake lumps its Anadarko Basin properties into a single bundle that includes the Cleveland/Tonkawa and Granite Wash in Texas and Oklahoma and the Mississippi Lime play on the Kansas/Oklahoma border. It holds two million acres of land in the plays with 4,355 risked net undrilled wells on 155-acre spacing. It has 2.5 Tcfe in net proved reserves, 12.5 Tcfe in risked and unproved resource and 33.1 Tcfe in unrisked and unproved resource. Chesapeake is running 35 rigs in the area. It is the top acreage holder in the Anadarko Basin and said it discovered the Granite Wash, Tonkawa tight sand, and Mississippi Lime plays.

EAGLE FORD

Chesapeake holds the second-largest acreage position in the Eagle Ford Shale play at 460,000 net acres, even after the company took in China's CNOOC at a one-third partner. Chesapeake continues to operate the properties. That acreage gives the company 2,830

1,000 BOE Per Day Wells in Multiple CHK Plays



(Map courtesy of Chesapeake Energy Corp.)

Chesapeake's unconventional properties around the US have given the company some outstanding wells.

risked net undrilled well locations on 80-acre spacing. It already has racked up 399 Bcfge in proved reserves, 8.1 Tcfe in risked unproved resources and 16.6 Tcfe in unrisked and unproved resources. In August 2011 it produced 50 MMcfe/d from those properties and 20 operated rigs working the play.

MARCELLUS

Even after turning over 32.5% of its land holdings in a deal with Norway's Statoil, Chesapeake remained the biggest leaseholder in the Marcellus play with a net 1.76 million acres in New York, Pennsylvania, and West Virginia. It claims 7,710 net risked undrilled well locations on 90-acre spacing in the play where it held nearly 1.1 Tcfe in proved reserves. Net risked and unproved resources totaled 37.1 Tcfe and unrisked and unproved resources could give the company 83.6 Tcfe. It produced 320 MMcfe/d in July 2011 and operated 30 drilling rigs.

MISSISSIPPI LIME

Chesapeake claims credit for the Oklahoma-Kansas border discovery of the Mississippi Lime play in 2007. It also holds the title of largest leaseholder in the Lime at 1.1 million acres. The company planned to increase rig count from six in early September 2011 to up to 10 rigs by the end of 2011. Chesapeake said, if it finds a joint venture (JV) partner, that rig count could top 30 units by 2014.

NIOBRARA

Chesapeake holds the number three land position in the Niobrara Shale in the Denver-Julesburg and Powder River basins with 595,000 acres in the play. That's a net figure after signing up CNOOC as a JV partner with a 33.3% working interest for US $1.3 billion in cash and drilling carries. Before that deal, Chesapeake held 800,000 acres of land with an estimated 4.5 Bboe in unrisked, unproved resource and planned to raise its operated rig count from four to six in 2011 and 2012. In August 2011, however, it had eight operated drilling rigs at work in the Niobrara play. At the end of 2010, before the JV deal, it had room for an unrisked undrilled 11,100 wells on 80-acre spacing.

A late August 2011 Chesapeake well, the #33-71 25-1H Sims in Fetter Field on the southern flank of the Powder River Basin in Converse County, Wyo., tested for 1,270 b/d of oil and 2.4 MMcf/d of gas.

UTICA

Chesapeake built itself into the top acreage holder in the Utica Shale play with 1.5 million acres in Ohio and

Pennsylvania after it started leasing in Ohio in mid-2010. It has full petrophysical data on some 200 wells. The company drilled six horizontal and nine vertical wells by August 2011 and had production results from three of those horizontal wells. Approximately 80% of its leasehold acreage lies in the wet gas and oil areas of the play near the Pennsylvania border with Ohio. The company called the Utica "analogous, but economically superior to the Eagle Ford in South Texas." That's a good reason to expand, and Chesapeake planned to raise its operated rig count from five in August to eight by the end of 2011 and 16 to 20 by the end of 2012. Its leasehold position could support up to 40 rigs by the end of 2014. In early November 2011, the company said it would sell a 25% interest in some 650,000 net acres in the wet-gas portion of the play to an international energy partner. It did not disclose the name of the partner. Chesapeake owns 570,000 of those acres and EnerVest holds the other 80,000 acres, all in eastern Ohio. Chesapeake will receive $640 million in cash and $1.5 billion in drilling carries, and EnerVest will receive $300 million in cash. Chesapeake will operate the properties. At the same time, Chesapeake said it will form a new entity called CHK Utica LLC. It will retain the common stock in the entity but will sell up to $1.25 billion in preferred shares in the 700,000-net-acre package in eastern Ohio. EIG Global Energy Partners already signed up for $500 million of the offer. Preferred partners will received a 7% annual return and plus a 3% overriding royalty interest in the first 1,500 wells drilled on the property. Chesapeake has committed to drill at least 50 wells a year through 2016.

A rig tests the Marcellus Shale in the Appalachian Basin.

(Photo courtesy of Chesapeake Energy Corp.)

Chevron Corp.

MARCELLUS

Chevron Corp.'s early 2011 acquisition of Atlas Energy for US $3.2 billion in cash and $1.1 billion in debt obligations put it into the shale recovery business in a big way as it assumed control of more than 700,000 net acres of land in the Marcellus Shale. Those leases held an estimated 850 Bcfe of proved gas reserves and a potential 14 Tcfe of potentially recoverable reserves, the company said. Atlas also had 80 MMcf/d of production. It also said it would begin an aggressive program to develop those properties. It followed up with a May 2011 announcement that it would buy another 228,000 aces of Marcellus properties from Chief Oil & Gas LLC and Tug Hill Inc. Most of those properties were in the southwestern liquids-rich segment of the Marcellus.

MONTEREY

Chevron holds properties in Kern River Field in the San Joaquin Basin that might have potential for production from the Monterey Shale.

UTICA

Chevron's Atlas Energy acquisition gave it more than 600,000 net acres in the Utica Shale, a largely undeveloped liquids-rich shale beneath the Marcellus.

Chief Oil & Gas LLC

MARCELLUS

After participating in early development in the Barnett Shale, Chief Oil & Gas LLC sold most of its holdings in North Texas and moved to the Marcellus Shale play in 2006. It drilled its first well in 2007 in Lycoming County, Pa. By 2009, it had assembled 560,000 acres of land in Pennsylvania, West Virginia, and Maryland and operated five drilling rigs. It planned to increase that count to seven and drill 70 wells in 2010. It held 600,000 gross acres in 2010 and reached the 100 MMcf/d mark with wells completed in Lycoming, Bradford, Susquehanna, Wyoming, Clearfield, Blair, Somerset, Greene, and Fayette counties in Pennsylvania and Marshall County in West Virginia.

In May 2011, Chief and financial partner Tug Hill Inc. announced a deal to sell 228,000 net acres of land in the southwestern part of the Marcellus to Chevron Corp. That left the company with approximately 125,000 net acres in Bradford, Susquehanna, Tioga, Sullivan, and Wyoming counties in northeastern Pennsylvania. By that time, it had drilled 131 Marcellus wells. It planned to exit 2011 with three operated rigs drilling in the play plus multiple non-operated rigs controlled by other companies.

Cimarex Energy Co.

AVALON/BONE SPRING/WOLFCAMP

Cimarex Energy Co. has multiple unconventional targets in the Permian Basin, primarily in the Delaware Basin area in southeastern New Mexico. According to its 2Q 2011 report, it completed 71 gross, 56 net, wells in the basin in the first six months of 2011, completing 94% as producers. Most of those wells tapped the Avalon (First Bone Spring), Second and Third Bone Spring, Paddock, Abo, and Wolfcamp formations. Among recent horizontal Bone Spring wells, the Irwin 13 Federal 2H came in with a first-30-day average of 810 boe/d. The company said it was in the early evaluation stage of the Wolfcamp, Avalon, and Cisco/Canyon shales in the Delaware Basin. It had completed five Wolfcamp wells in the first half of 2011, raising its total to 12 wells with a 30-day average of 6.3 MMcfe/d of gas with 48% gas, 31% natural gas liquids, and 21% oil. In an August 2011 presentation, it said it had 125,000 acres in the Wolfcamp play, 160,000 acres in the Avalon, and 60,000 acres in

After participating in early development in the Barnett Shale, Chief Oil & Gas LLC sold most of its holdings in North Texas and moved to the Marcellus Shale play in 2006.

the Cisco/Canyon Shale. It had 45,000 net acres in southeastern New Mexico prospective for Bone Spring and was running seven rigs in that play.

CANA WOODFORD

Cimarex drilled and completed 86 gross, 32 net, wells as producers in its midcontinent region in the first half of 2011, according to the company's 2Q 2011 report. It had 22 gross, eight net, wells awaiting completion and produced an average 284.7 MMcfe/d of gas in 2Q 2011, up 15% from the same period a year earlier. Most of that drilling and production was in the Anadarko Basin and most of that activity was in the Cana Woodford play, where the company completed 71 gross, 23 net, wells. At the end of 2Q 2011, 22 gross, eight net, Cana Woodford wells awaited completion. Since it entered the Cana Woodford play in late 2007, the company participated in 257 gross, 100 net, wells. At the end of 2Q 2011, 214 gross, 79 net, wells were on production, producing 115 MMcfe/d of gas, a 53% gain from the 2Q 2010. The company holds 120,000 net acres in the play, including 64,000 acres in the core, and has between eight and 10 rigs at work. Its acreage has room for 2,200 gross, 730 net, wells and 4 to 5 Tcfe in resource potential.

GRANITE WASH

Most of the drilling activity by Cimarex in the Midcontinent was aimed at the company's Cana-Woodford play in western Oklahoma, but it also drilled to the Granite Wash and Morrow formations in the Texas Panhandle. During 2011, it planned to devote one or two rigs to Granite Wash activities.

Cinco Resources Inc.

EAGLE FORD

Cinco Resources Inc. works the Eagle Ford play in South Texas through a group of subsidiary companies, including Cinco Natural Resources Corp., Camden Resources LLC, and Sedna Energy Inc. Additionally, it operates a master services agreement as contract operator and manager of Cima Resources Inc., a company formed in 2010 by Yorktown Partners LLC to work the Eagle Ford play. Yorktown also funded Cinco when it was formed in 2002. Cinco had approximately 150,000 net acres of land in the play with proved reserves of 187 Bcfe and proved, probable, and possible resources of 703 Bcfe. Net production reached 25 MMcfe/d in May 2010, and Cinco operated 75% of that production. It operated a rig in the play for Cima in the second half of 2010. Cinco Natural Resources Corp. permitted an Eagle Ford well in Live Oak County in November 2010 and also has operations in Atascosa County.

Cinco Resources Inc. works the Eagle Ford play in South Texas through a group of subsidiary companies, including Cinco Natural Resources Corp., Camden Resources LLC, and Sedna Energy Inc.

Cirque Resources LP

BAKKEN

Cirque Resources LP, a Denver-based privately held company, has been an active driller in the North Dakota segment of the Bakken play with wells distinguished by colorful names including the Roustabout Stout 1-3H, Nut Brown 10-16H, and Harpoon Harvest 14-4H wildcats in McLean County. Among its Dimond Field wells in Burke County, the company fractured the Middle Bakken from 8,250 to 13,800 ft for an initial potential of 351 b/d of oil and 2 MMcf/d of gas. Its latest permit, according to IHS Inc., was the 16-4H Old Engine Oil, a remote horizontal wildcat in Mercer County, N.D., and only the second horizontal well permitted to Bakken in the non-producing county. The closest Bakken production is some 21 miles northwest in Dunn County.

NIOBRARA

Cirque assembled 400,000 net acres of land in two areas with Niobrara potential, including 250,000 acres in the northern Denver-Julesburg Basin. It farmed out 55% of that Denver-Julesburg acreage to Noble Energy, the biggest producer in Wattenberg Field. Wells listed by IHS Inc. for the company in the 12 months ending in August 2011 include a series of wells in Laramie County, Wyo., including the Quasimodo #34-16H, Hare Water Pup #3-16H, Marabou Muddler #7-1H, and a series of Samuelson wells in Silo Field. The company abandoned most of those locations.

Clayton Williams Energy Inc.

AVALON/BONE SPRING

Clayton Williams Energy Inc., a veteran Permian Basin operator, has specific Bone Spring potential in Warwink Field in Ward County in West Texas. In addition, it has potential in the formation through its Wolfbone play. The company acquired acreage in the Delaware Basin with future potential in the Avalon, Bone Spring, and Wolfcamp formations, it said in a May 2011 presentation. The company said it acquired acreage with potential production from those Delaware Basin properties through a farm-in arrangement with Chesapeake Energy. Under that deal, Clayton Williams can earn a 75% interest in 75,000 acres by drilling. It had four rigs working the area looking for Bone Spring and Wolfcamp pay and planned to expand activity later in 2011.

EAGLE FORD

Clayton Williams holds 173,000 acres of land in the Giddings Austin Chalk area, and 168,000 of those acres also are prospective for Eagle Ford production. The company had drilled two wells each in Burleson and Lee counties by May 2011 and was evaluating results for economic viability.

WOLFBERRY

The company's Wolfberry play is focused in Andrews County. By July 2011, it had drilled 128 wells on 80-acre spacing and 26 wells on 40-acre spacing. It had room for 80 wells on 80-acre spacing and 180 wells on 40-acre spacing. It produced approximately 2,800 b/d of liquids and 1.25 MMcf/d of gas from the properties during 2Q 2011, up from 1,600 b/d of liquids and 400 Mcf of gas in the same quarter a year earlier. It had

three rigs working the play but planned to divert two of those rigs. The company said its Andrews County property gave it a 38% return on investment with payout in 2.4 years from wells with 150 Mboe in gross reserves. The company has additional Wolfberry potential in Glasscock, Sterling, and Upton counties.

WOLFBONE

Reeves County, Texas, hosts Clayton Williams' early operations in the Wolfbone play. It leased 20,000 acres in the area and will add to that acreage through its farm-in arrangement with Chesapeake Energy. It earns a 75% interest in 640 acres for each well that it carries Chesapeake to the tanks. Clayton Williams is making a large front-end investment to acquire acreage and to build pipelines and other infrastructure. It said future activity would depend on drilling results. It had started drilling and completions on 13 wells by July 2011, had seven rigs working, and planned to add another four rigs. It also has Wolfbone potential in Loving County.

Concho Resources Inc.

AVALON/BONE SPRING/WOLFBONE

One of the biggest operators in the Permian Basin with 35 rigs on the payroll, Concho Resources Inc. has focused on the Avalon/Bone Spring combination as its prime play on its Delaware Basin properties. It has six rigs working the basin and expected to drill approximately 100 wells in 2011. The Delaware Basin provides 9% of its reserves and 15% of production on the 280,000 gross, 160,000 net, acres under Concho control. That acreage offers 1,464 drilling opportunities, 1,039 of them for horizontal wells. It had participated in 150 Bone Spring wells by August 2011 and produced 5,600 b/d of oil from the formation during 2Q 2011. It also has 332 vertical Wolfbone sites in the Delaware Basin.

Concho drills and completes wells at a cost of US $5 million to $7 million and gets EUR between 400 and 700 Mboe with wells posting a first-30-day initial potential of 400 to 1,200 boe/d with 4,000- to 4,500-ft laterals and eight to 13 frac stages.

WOLFBERRY

The Wolfberry in the northern Midland Basin is Concho's main target in the Permian Basin. During the past years, it acquired an additional 400 drilling locations in that play for $285 million, giving up its Bakken assets to concentrate on the Wolfberry. That acquisition gave it a working interest of about 50% in the play and gave it 49,000 net acres. That translates to 1,893 locations on 40-acre spacing, or 2,444 locations on 20-acre spacing. Concho had 15 rigs drilling in the play and planned to drill some 250 wells in 2011.

It can drill and complete a Wolfberry well at a cost between $1.6 million and $1.8 million to get wells with an initial-30-day potential of 95 to 125 boe/d and an EUR of 140 Mboe.

It also has Wolfberry and Wolffork (Wolfcamp and Clearfork) potential in the southern Midland Basin.

WOLFCAMP

The Wolfcamp Formation is a secondary target in Concho's Delaware Basin properties. The company can drill and complete a horizontal well at a total vertical depth of 11,000 to 12,500 ft for between $4 million and $6 million with initial-30-day initial potentials between 200 and 450 boe/d and EURs between 200 and 400 Mboe with five to 10 frac stages. It finishes the wells with eight- to 10-stage frac treatments.

ConocoPhillips Co.

AVALON/BONE SPRING

ConocoPhillips Inc. is working actively in the Avalon/Bone Spring play, but it hasn't fully evaluated the potential yet, according to the company's 1Q 2011 conference call.

BAKKEN

The company holds 460,000 net acres in the Bakken in Montana and North Dakota within its 4.6 million acres in the Williston Basin. In a March 2011 presentation, ConocoPhillips said its Bakken properties contained 400 MMboe of resource and more than 17,000 "high-value drilling opportunities." It completed recent wells with 10,000-ft laterals and 20-stage frac treatments. At the same time, it has increased EURs, reduced drilling times, increased frac efficiency, and lowered total cycle times. It anticipated production to reach 20,000 boe/d in 2011.

BARNETT NORTH

ConocoPhillips divested its acreage in the southern, gassy segment of the Barnett play to concentrate on 144,000 gross, 65,000 net, acres it acquired in the northern Barnett liquids-rich segment. In 2010, it produced 6 Mb/d of oil and 62 MMcf/d of gas from the Barnett, and the company planned more than 30 wells in 2011. Its properties contain some 200 million boe of resource, and the company expected production to reach 15,000 boe/d in 2011. It planned to invest US $400 million during the year in its Permian Basin and Barnett operations.

CARDIUM

The company has high expectations for its Cardium play in the Deep Basin area of the Western Canada Sedimentary Basin. Eight early horizontal wells have produced encouraging results, and ConocoPhillips has assembled 137,000 acres in the area. According to the company, the play looks a lot like the liquids-rich North Barnett Shale play in both production and liquids content. Part of the company's enthusiasm stems from its 1.7 Bboe in resource potential. It planned nine operated and six non-operated wells in the area in 4Q 2011.

EAGLE FORD

ConocoPhillips produced 3 Mb/d of liquids and 10 MMcf/d of gas from the Eagle Ford Formation in 2010, drilling more than 45 wells without a dry hole. High returns and predictable results made the Eagle Ford the company's top-priority play in the US. For 2011, it planned to raise its rig count from 11 at the beginning of the year and drill 150 wells. It planned 30,000 boe/d of production in 2011 with 75% liquids content. In a March 2011 presentation, the company said it was fine-tuning completions and that it would match its Eagle Ford wells against any in the industry. Even better, the company got into the play for $350 an acre. Now, it added, "We've seen offers north of $14,000 an acre." It holds more than 220,000 acres in the play. The company planned a $2.9 billion drilling program in 2011 for the US and Canada, and $1.4 billion of that will go to the Eagle Ford. Its Eagle Ford, North Barnett, and Bakken operations will use 63% of that capital program. Its average initial potential for five recent wells in June was 1,050 b/d of liquids and 235 boe/d of wet gas.

GRANITE WASH

The company held 40,000 net acres of properties in the Granite Wash play.

MONTNEY

ConocoPhillips lumped its Montney and Horn River Basin operations together. It didn't update activity in those plays in recent operations news, but said it had 363,000 acres of properties in the two plays.

NIOBRARA

The company signed a June 2011 agreement to buy up to 46,000 acres of leases in Arapahoe, Adams, Elbert, and Douglas counties in Colorado in the southern Denver-Julesburg Basin portion of the Niobrara Shale play from Lario Oil & Gas Co. ConocoPhillips will operate the leases and start developing after it acquires a 3-D seismic survey and drills test wells.

WOLFCAMP

ConocoPhillips holds 1 million acres of land with 700 MMboe in resources and more than 5,000 well sites in the Permian Basin, and it wants to expand its production above the 50,000 b/d mark. Most of that production comes from conventional resources and secondary and enhanced recovery in older fields, but it added 33,000 acres of properties in the Wolfcamp Shale play to its Midland Basin assets during 1Q 2011.

CONSOL Energy Inc.

MARCELLUS

The Marcellus Shale in Appalachia has treated CONSOL Energy Inc. very well during the past few years, and the company looks for even better treatment in the future. Its background in coal, coalbed methane, and shallower gas production gave it rights to some land prospective for the Marcellus. Operations started through its 83.3% ownership in CNX Gas, which had 186,000 net acres of Marcellus land and 15.7 MMcfe/d of gas production from five horizontal wells in the formation by April 2009.


(Photo courtesy of Continental Resources Inc.)

Continental Resources is currently active in the Bakken and the Niobrara liquids-rich plays.

CONSOL added to its position a year later with its US $3.475 billion acquisition of the Appalachian E&P business of Dominion Resources. The acquisition raised its Marcellus holdings to 752,336 net acres. In June 2010, it bought the 16.7% of CNX it didn't already own, and it had 140 Bcfe of gas in proved developed Marcellus reserves and 719 Bcfe in proved undeveloped resources with a potential resource of as much as 40.5 Tcfe. It had five rigs working the Marcellus in August 2011 when it sold a half interest in its Marcellus assets into a joint venture with Noble Energy Inc., the most active company in the Niobrara Shale play in Colorado. Under the agreement, Noble got a half interest in 663,350 net undeveloped acres in Pennsylvania and West Virginia for $1.07 billion and agreed to fund $2.13 billion of CONSOL's future drilling and completion costs, up to one-third of CONSOL's drilling and completions costs in the property, over eight years with a limit of $400 million in any single year. The price is equal to $9,650 per net acre. The acreage contains and estimated 7.4 Tcf for each interest owner with 400 Bcf in proven reserves at the end of 2010, 4,400 gross well locations, and potential for 600 MMcfe/d of gas in net production by 2015. The companies will increase the rig count in the play to 16 by 2015, according to an August 2011 CONSOL presentation. The purchase price includes associated gathering systems and a share of water rights. Some 570,000 acres with 3,700 horizontal locations are in the dry gas areas of the play, of which 95,000 acres and 630 locations are in the wet gas areas. The companies plan to drill 35 wells in 2011, 140 in 2012, 227 in 2013, 318 in 2014, and 354 in 2015.

UTICA

CONSOL's Utica properties are not part of its deal with Noble Energy. CONSOL holds approximately 200,000 acres of land prospective for Ohio Utica/Point Pleasant development, where it planned to spend US $35 million in 2011 to drill six exploratory wells. It also claimed credit as the first E&P company to announce a discovery in the Utica Shale. That October 2010 well in Belmont County, Ohio, flowed at an open-flow rate of 1.5 MMcf/d of gas for 24 hours from a 200-ft-thick Utica section with no stimulation. CONSOL planned to have one rig working in the Utica in October 2011. In September 2011, CONSOL said it signed a 50-50 joint venture agreement to develop the Utica in eastern Ohio. Under the agreement, Hess agreed to pay $59 million at closing and half of CONSOL's working interest obligations in drilling and completion costs up to $534 million. The deal was valued at $6,000 an acre. Hess will operate in the liquids-rich window of the Utica, approximately 80,000 aces in Belmont, Harrison, Guernsey, and Jefferson counties, and CONSOL will work in other areas, including Portage, Tuscarawas, and Mahoning counties in the oil window and in Noble County. The companies will average two rigs in 2011, 3 1/2 rigs in 2013, and flatten out at five rigs in 2016.

Continental Resources Inc.

BAKKEN

The industry has drilled some 4,000 horizontal wells to the Bakken Formation in the Williston Basin, and it's using 180 rigs to add more wells at a rate of 2,100 a year. Continental Resources Inc. is the biggest producer in that massive play. Continental's production rose to 27,177 b/d of oil in 2Q 2011, up 51% from the same quarter in 2010. By mid-2011, the company had assembled 901,370 net acres of land with Bakken/Three Forks potential in Montana and North Dakota. It added 9,300 acres in the 2Q 2011. Its North Dakota wells offered 603 Mboe in ultimate recovery, or as much as 4.8 MMboe on a section, with four wells each drilled to the Bakken and Three Forks formations. It credits the

North Dakota Bakken for 49% of its 421 MMbbl in company-wide resources, and the Montana segment of the play adds another 9%. Among recent operated activity, its Whitman 2-34H in North Dakota came in at 2,888 boe/d as part of the Hawkinson-Whitman ECO-Pad with four wells that tested for an average 1,804 boe/d per well. Its Big Sky 3-35H in Montana showed an initial potential of 1,163 boe/d, the company said in its 2Q 2011 report. Overall, the company had 3,497 well locations on 320-acre development and a potential 1.65 Bbbl in recoverable resource. An eight-well Eco-pad cost the company US $7.2 million and offered a 65% rate of return at an oil price of $110/bbl. It completed 78 gross, 21.9 net, wells in the Bakken in 2Q 2011.

NIOBRARA

Continental started drilling its second Niobrara well in 2Q 2011. The Marconi 1-1H is 12 miles south of the company's first well, the Newton 1-4H, which it completed in the same quarter. Results from the Newton well, the company said, confirmed that the Niobrara is a matrix-driven play, and the company can identify economic sites on that basis. The company holds 83,100 net acres in the Denver-Julesburg Basin, one-third in Colorado and two-thirds in Wyoming.

Cordillera Energy Partners III LLC

CLEVELAND

Cordillera Energy Partners III LLC's website says the company holds properties in the Cleveland/Marmaton play in western Oklahoma, but it doesn't describe any activity in 2011. This is a stacked pay area, and acreage prospective for Tonkawa also could be prospective for the Cleveland.

EAGLE FORD

The corporate website says the Eagle Ford Shale is one area of company focus, but it doesn't describe any property holdings or activity in South Texas.

GRANITE WASH

Cordillera holds 103,808 acres of land in the Texas Panhandle with 243 operated wells and 43 MMcfe/d of gas production. It operated three rigs in that area March 2011, all three working the Granite Wash in Hemphill and Wheeler counties. In a June report, the company said a recent Wheeler County, Texas, Granite Wash well, the A.C. Smith 41-2HB, reached 16,964-ft total depth with a 4,062-ft lateral at an average vertical depth of 12,680 ft. In one 24-hour period, the well tested for 17.33 MMcf/d of gas and 632 b/d of oil. The 1,220-Btu gas gave the company another 1,554 b/d of liquids. The company said it had 20 Granite Wash wells in six benches.

> **Cordillera has drilled or acquired more than 50 horizontal Tonkawa wells in the Texas Panhandle and western Oklahoma.**

TONKAWA

Cordillera holds 80,935 net acres in western Oklahoma where it has drilled 65 wells and produces 17 MMcfe/d of gas. Among recent wells in the area, it had three substantial producers from the Tonkawa Sand, according to a June 2011 press release. Its Grand 1-14HC in Ellis County, Okla., reached a 40-ft-thick Tonkawa section at a total vertical depth of 8,210 ft. The 3,962-ft lateral took the well to a total depth of 12,300 ft. It completed the well with 10 frac stages to produce 1,205 b/d of oil and 1.68 MMcf/d of 1,210-Btu/Mcf gas in 24 hours. The rich gas will produce another 166 b/d of liquids. The company completed the Oak 1-16HB horizontal well in the Tonkawa in the same county for 262 b/d of oil and 1.45 MMcf/d of gas after nine frac stages. In adjoining Mills County, Okla., its Glass 1-25HB tapped the Tonkawa for 568 b/d of oil and 2.48 MMcf/d of gas capable of producing another 244 b/d of liquids. At mid-year 2011, it operated four active rigs in the Tonkawa among the five rigs working western Oklahoma. Cordillera has drilled or acquired more than 50 horizontal Tonkawa wells in the Texas Panhandle and western Oklahoma.

Credo Petroleum Corp.

BAKKEN

Credo Petroleum Corp. holds some 8,000 gross, 6,000 net, acres of land prospective for Bakken and Three

Forks production on the Fort Berthold Indian Reservation in Mountrail, McKenzie, Dunn, and McLean counties in North Dakota. The property contains approximately 50 drillable spacing units. Credo does not operate the properties, since smaller operators often have trouble lining up drilling and completion services in the hot play. It holds property interests up to 51%. Seven Bakken producers have been drilled on Credo's property, and the company said, early in the year, that it expected to participate in 11 Bakken wells during the year. One of its wells, completed for 2,278 boe/d, set a record for company wells. By a June operations report, the company's estimate of 2011 wells dropped to nine. Its share of four horizontal wells, with interests from 1% to 3%, totals 140 boe/d. One of those wells, the Enerplus Ethan Hall, came in at 3,732 boe/d. The disadvantage of not operating, the company said, is that it has no control of the timing of the drilling program.

TONKAWA/CLEVELAND

Credo owns an average 33% interest in some 3,000 gross acres of properties in Lipscomb and Hemphill counties in the Texas Panhandle that are prospective for Tonkawa and Cleveland production. The company operated 12 vertical wells on the properties. The first horizontal well went to a 7,600-ft vertical depth with a 4,000-ft lateral and produced from the Tonkawa. The well was producing 180 boe/d in June 2011. The second well, drilled to the same depth, encountered sloughing shale at about 2,400 ft into the planned 4,000-ft lateral. The operator set pipe and fractured the well, which produced at a rate of 100 boe/d in June. Credo is the operator of the well.

Crescent Point Energy Corp.

BAKKEN

Crescent Point Energy Corp. completed six acquisitions to become the largest acreage holder in Viewfield Field, the biggest Bakken play in Canada. Along the way, it increased production from the southeastern Saskatchewan properties from 275 boe/d in 2001 to an expected 75,600 boe/d at the end of 2011. In an August 2011 presentation, the company said the field held 4.6 Bbbl of original oil in place, and only 1.3% had been recovered to date. While an independent source put proved and probable recovery at 8.2% of the oil in place, similar pools have offered 19% in primary production. Crescent set its net proved and probable reserves at 241 MMbbl from the Bakken, not counting additional recovery from waterflooding. The company has 1,000 net sections in the field with more than 3,800 net drilling locations. It diverted 40% of its 2011 capital program to drill 127 net wells. It also started a waterflood in the play with 17 injection wells converted to date. Primary recovery wells typically produce 210 b/d of oil through the first month, 60 b/d at 12 months, 35 b/d at 24 months, and 25 b/d at 36 months. EUR is 125 Mbbl of oil, or 146 Mboe. Wells give the company a 394% rate of return. The waterflood project uses one injection well with two offset producing wells. It started injecting in 1Q 2007, and Packers Plus fractured injection and production wells in 3Q 2003. The wells, including primary production, have a cumulative production of more than 300 Mbbl of oil. Water injection in five separate locations in the field proves the waterfloods work, the company said.

Crescent Point also has non-operated Bakken wells in North Dakota. In 2Q 2011, it participated in 4 gross, 0.6 net, successful wells. It started drilling its first operated well in July and anticipated results in 4Q 2011.

VIKING

Acquisitions of Wave Energy Ltd. and TriAxon Resources Ltd. in late 2009 gave Crescent Point a land position in the Viking light oil play in the Plato and Dodsland areas of southwestern Saskatchewan. At the end of 2Q 2011, the company held more than 95 sections of land in the two areas and planned to drill up to 20 gross, 16 net wells.

Crew Energy Inc.

CARDIUM

Crew Energy Inc. drilled one recent horizontal well to the Cardium Formation at Pine Creek, Alberta, and planned another Cardium horizontal well in 3Q 2011. It picked up Wapiti, Elmworth, and Kakwa Field properties on the Cardium Fairway in its acquisition of Caltex Energy Inc. The company planned up to five wells in the Wapiti area in the second half of 2011. Crew has 190 Cardium locations in the Caltex properties with 406 Mbbl of oil in proved and probable reserves.

MONTNEY

The company drilled four net wells to the Montney Formation in its Septimus area in 2Q 2011, all successful. A 1Q 2011 well came online at a rate of 11.5 MMcf/d of gas, while 2Q 2011 wells came in at seven-day rates of 3.5 MMcf/d each. The other two wells came in at 9.1 MMcf/d and 7.4 MMcf/d. Crew produced more than 6,400 boe/d from the field at the end of the second half of 2011. One (0.33 net) non-operated Montney well in the Tower area was being completed at the end of 2Q 2011. The company plans three to five more wells at Septimus in the last half of 2011. At the end of 2Q 2011, it produced 6,100 boe/d, 15% condensate, from Septimus, and the company planned to test the oil play in the area during 2011. Septimus holds some 2.7 Tcf of discovered petroleum initially in place. A typical Septimus 2.9-Bcfe-of-gas well produces 51.4 Mboe and offers a 40% rate of return with 20 bbl/MMcf of condensate and 4 bbl/MMcf of liquid petroleum gas. It also has Montney activity at Kobes, British Columbia. Crew completed analysis of a 3-D seismic survey in that area during 2Q 2011 where it holds 23 net sections of land and planned its first two horizontal wells in September and October. Crew also has land prospective for Montney in Portage Field where it controls 32 net sections. It tested two wells for 1.2 MMcf/d and 4.4 MMcf/d of gas, respectively.

VIKING

Crew drilled one well to the Viking Formation at Provost, Alberta, in 2Q 2011, and that well currently is being tested.

Crimson Exploration Inc.

EAGLE FORD

Crimson Exploration Inc. holds 6,700 net acres in the Eagle Ford play in South Texas with 5,500 acres in Zavala and Dimmit counties, 650 acres in Karnes County, and another 560 acres in Bee County. Its LM #1H in Karnes County came in at a gross rate of 995 boe/d, and the company has two horizontal wells producing in Bee County, according to a July presentation. The KM #1H well in the Zavala/Dimmit area was flowing back in July, and the LM #1H was producing. Some 90% of the company's Eagle Ford properties are held by production. In all, it has 71 Bcfe of gas in proved reserves and 59% proved developed with 23% of those reserves in liquids. Unproved unconventional resources add another 180 Bcfe with 83% liquids. Wells in the area produced 13 MMcfe/d in 2Q 2011, and the company dedicated US $32 million to drill 11 gross, 6.2 net, wells to the Eagle Ford in 2011. It operates one rig in the area. It has 172 drilling locations with $30 MMboe in net unproved potential.

The company controls some 15,400 gross, 10,000 net, acres of land prospective for the Niobrara Shale and J-Sand in Adams and Weld counties in the Colorado portion of the Denver-Julesburg Basin.

NIOBRARA

The company controls some 15,400 gross, 10,000 net, acres of land prospective for the Niobrara Shale and J-Sand in Adams and Weld counties in the Colorado portion of the Denver-Julesburg Basin. It holds 8 Bcfe of gas in proved reserves in the basin, 64% proved developed with 43% liquids content. All of its land is held by production. With $3.1 million assigned to the play for 2011, the company planned one gross, .6 net, wells. It has 178 unproved drilling locations with 40 Bcfe of net unproved potential in the basin with 21 locations and 3 MMboe in net unproved potential in the Niobrara on the 25% of the acreage the company had evaluated by mid-year 2011.

In February 2011, U.S. Energy said it entered into a participation agreement with Crimson in which U.S. Energy would acquire a 30% working interest in an oil prospect and associated leases in Zavala County. Under the agreement, that 22.5% net revenue interest would apply to 4,675 gross, 1,402.5 net, contiguous acres for cash and a commitment to carry costs on one well. After that, future drilling will be on a heads-up basis by the partners.

The target for the well is the Eagle Ford, apparently the KM Ranch well. The companies planned 14 fracture stages on the well, and they planned to use the well for budget planning for drilling in 2012.

Denbury Resources Inc.

BAKKEN

Denbury Resources Inc. took a big stake in the Bakken Shale play when it acquired Encore Acquisition Co. in March 2010. The Encore properties in the main fairway were in Williams, McKenzie, and Dunn counties in North Dakota, but the company had an extensional Bakken area in northeast Mountrail, Burke, and Ward counties. Denbury's specialty is EOR with carbon dioxide, and the Bakken properties fit into its business plan in two ways. First, it could use the, high-return Bakken property to finance early stages of EOR projects, and second, it could eventually use its enhanced recovery skills in the formation. It increased its Bakken proved reserves to 46.7 MMboe during 2010 and averaged 7,626 boe/d of production in 2Q 2011, up 33% from 1Q 2011 and up 69% from 2Q 2010. It had five rigs working the play in the first half and planned to add a sixth in 3Q 2011 and a seventh by the end of 2011. It completed 16 operated wells in the first six months of 2011. Denbury reduced its 2011 estimated average production from 8,700 to 8,400 boe/d because of weather delays in the first half of the year.

In an August 2011 presentation, Denbury said it had 417 MMboe of proved reserves in the Bakken with an 85% oil cut, another 276 MMboe in drilling potential, and a potential 567 MMboe more from EOR for a total of 1.25 Bboe from its 266,000 acres of Bakken properties. The company has carbon dioxide properties within easy pipelining distance from its North Dakota Bakken properties. As for economics, figuring 525 Mboe per well and a well cost of $7.5 million. After a 20% royalty, the company figured an $80 New York Mercantile Exchange (NYMEX) price, $17.83 in finding and development costs, $5.74/bbl in operating costs, and an average NYMEX differential of $10/boe to come up with a gross margin of $46.60/boe and an internal rate of return of 34% from the Bakken.

Devon Energy Corp.

ARKOMA WOODFORD

Devon Energy Corp. holds 43,000 net acres of land in the Arkoma Woodford play in eastern Oklahoma with a 32% average working interest. The land holds 400 producing wells with 13 Mboe/d in net production in 2Q 2011. Some 23% of that production was liquids. Reserves at the end of 2010 totaled 48 MMboe (19% liquids). Most of the company's acreage is held by production. It uses long lateral wells for production.

AVALON/WOLFCAMP

The company controls 200,000 net acres in the Delaware Basin in Texas and New Mexico prospective for the Avalon and Wolfcamp shales. At mid-2011 it had 25 wells producing 3 Mboe/d (50% liquids) and 2010 reserves of 4 MMboe (55% liquids). It spent US $77 million to drill and complete 19 wells in 2010 and planned to spend $145 million to drill approximately 70 horizontal wells in 2011 with three rigs at work.

BARNETT

Devon is the biggest property holder in the Barnett Shale play with 624,000 net acres, 7,000 risked locations, and 18 Tcfe of gas of net risked resource. Most of its properties are in the gassy part of the play, but in 2011 it expanded its gas processing capacity to 890 MMcf/d with a natural gas liquids (NGLs) capacity of 65,000 b/d. It produced 46,000 b/d of liquids in 2Q 2011. Devon drilled 460 wells in the Barnett in 2010 and planned 375 more in 2011.

The Cana Woodford area of western Oklahoma is a "leading growth area" for Devon. The company counts it as one of the most economic shale plays in North America.

BONE SPRING

Devon held 185,000 net acres in the Bone Spring play in the Delaware Basin with a 56% interest and 12 wells online at the end of 2Q 2011. Those wells produced 1 Mboe/d (89% liquids) and provided the company with 1 MMboe (83% liquids) in reserves at the end of 2010. New Mexico production is primarily from the First and Second Bone Spring while Texas production is mostly from the Third Bone Spring. The company spent $16 million on the play to drill 24 horizontal wells and planned to spend some $130 million to drill 65 additional wells with eight rigs working the play in 2011. It also was looking for additional acreage. The nine operated Bone Spring wells the company completed in 2Q 2011 averaged more than 700 boe/d.

CANA WOODFORD

The Cana Woodford area of western Oklahoma is a "leading growth area" for Devon. The company counts it as one of the most economic shale plays in North America. It doubled its acreage in the play and has more than half of the best acreage, the company said. The attraction is the liquids content, up to 100 bbl of NGLs per million cubic feet of gas. Condensate adds to the value. The company plans to double its Cana production to 250 MMcf/d by the end of 2011, including 14,000 bbl of NGLs and condensate. It holds some 11 Tcfe of gas of net risked resource on its 243,000 net acres with a 52% average working interest. That land contains 5,000 risked locations. It drilled 87 wells in 2010 and planned 255 more in 2011. It produced 189 MMcfe/d, including nearly 9,000 b/d of liquids, from 180 wells in 2Q 2011 from 2010 reserves of 175 MMboe (34% liquids).

CARDIUM

The Cardium and other formations give Devon production and opportunities for growth in Alberta and British Columbia in both the Deep Basin and Devon's central area. In all, it has 507,416 net acres with a 43% average working interest in 1,283 producing wells in numerous formations, primarily Cretaceous and Triassic. Cardium potential lies in the Deep Basin and the Ferrier area, where the company plans 18 wells in 2011. It only recently started testing Cardium light oil potential. The central plains of Alberta and Saskatchewan make up the Central region, where the Ferrier shows potential for Cardium production.

GRANITE WASH

Devon started drilling vertical wells in the Granite Wash play in the Texas Panhandle as early as 2005. It used those wells to design horizontal wells and drilled its first horizontal wells the following year. It now holds 63,000 net acres in the play and has 590 producing wells that produced an average 2 Mboe/d in 2Q 2011, including 200 b/d of oil and 730 b/d of NGLs. The company estimated a net risked resource of 200 MMboe from its 350 net well locations. It has five rigs at work in the play and planned about 55 wells in 2011.

MISSISSIPPI LIME/WOODFORD SHALE

Devon combines its Woodford Shale and Mississippi Lime plays in northern Oklahoma, where it holds 200,000 net acres. It planned to drill 12 to 15 horizontal and vertical wells in the area in 2011. The company considers the Mississippi Lime one of its new ventures in which it plans to add properties and acquire seismic data.

NIOBRARA

Devon holds a substantial position in the Niobrara play in the Powder River Basin of Wyoming, thanks to its widespread coalbed methane operations. Now the company is shifting its attention to the Niobrara Shale. It acquired acreage in the Niobrara in 2010 and planned to drill 10 wells to test its potential in 2011. At mid-year 2011, the company held 200,000 acres in the Powder River Basin and another 100,000 net acres in the Denver-Julesburg Basin.

TUSCALOOSA MARINE SHALE

The Tuscaloosa Marine Shale on the Louisiana-Alabama border is another new venture where Devon planned to acquire additional property and conduct seismic surveys. It holds some 250,000 net acres in the play and planned to drill or participate in three horizontal and vertical wells in 2011.

UTICA

Devon holds Utica Shale properties in Michigan and Ohio. It planned to drill or participate in four horizontal or vertical wells on its 300,000 net acres in Michigan and another four horizontal or vertical wells on its Ohio acreage. The company said it planned to raise its Ohio lease position to 150,000 acres.

VIKING

Devon's 887,250 net acres in southern Alberta and Saskatchewan give it plenty of opportunity to tap any number of producing zones. One of those zones with potential is the Viking, where it has between 1,000 and 2,000 possible drilling locations. It planned 19 wells to test that formation in 2011.

WOLFBERRY

Some 160,000 net acres of Devon land in the Midland Basin in West Texas are prospective for the Wolfberry liquids play. The company has an average 97% working interest in the properties with 196 wells producing from the Spraberry and Wolfcamp formations. Production reached 9 Mboe/d (91% liquids) in

Devon holds a substantial position in the Niobrara play in the Powder River Basin of Wyoming, thanks to its widespread coalbed methane operations. Now the company is shifting its attention to the Niobrara Shale.

2Q 2011 from 2010 reserves of 34 MMboe (85% liquids). It spent $202 million to drill and complete 89 vertical wells in the play in 2010 and planned to increase spending to $240 million to operate five rigs and drill approximately 135 vertical wells. It planned to acquire additional land and begin a 20-acre infill pilot drilling program. Devon drilled its first Wolfberry well in 2008 and has identified some 1,000 low-risk vertical drilling locations.

Dorchester Minerals LP

BAKKEN

Dorchester Mineral LP holds some 110,189 net acres in the North Dakota side of the Williston Basin where other operators, including Continental Resources, EOG Resources, Hess Corp. and Marathon Oil Corp. are developing the Bakken and Red River formations. Those properties also have potential production from the Three Forks/Sanish Formation. The company's net production at the end of 2010 was less than 200 boe/d from its interests in 100 producing and completed wells. It also had interests in 30 wells in various stages of completion and 19 wells proposed or permitted by operators. At that time, seven rigs were working on its property.

GRANITE WASH

Dorchester held 5,444 gross, 1,189 net, acres in Wheeler County in the Texas Panhandle with potential production from the Granite Wash.

MARCELLUS

The company held 25,172 net acres in Appalachia at the end of 2010 with potential production from shallow Upper Devonian; deeper Marcellus, Utica, and Devonian; and even deeper Trenton-Black River formations. Operators on the company's properties included Anadarko, Chesapeake, EOG, EQT, EXCO, Range, Seneca, Shell, and Talisman. It booked no reserves in the basin in 2010.

WOLFBERRY

Dorchester held 151,955 net acres of land throughout Texas including production from the Wasson and Denver Units in West Texas. Partners are developing the Wolfberry, and the company has additional expansion potential in the Delaware Basin.

El Paso Corp.

EAGLE FORD

El Paso Corp. is splitting its operations into the pipeline group and the E&P group, which will be called EP Energy Corp. The Eagle Ford Shale will be a flagship play for the new company as it is for El Paso's production operations. In a May 2011 presentation, El Paso said it raised its capex for E&P to US $1.6 billion as it added $300 million to Eagle Ford development in its central area La Salle and Dimmit counties in South Texas. It held 1,145 undrilled and unrisked Eagle Ford locations at the end of 2010 with additional properties in Atascosa, Frio, and Webb counties. By May 2001 it had drilled 34 wells, completed 24, and put 12 wells online in the central area, and at that time the average length of a lateral was 4,550 ft with a 16-stage frac treatment. Its productive capacity was 5.6 Mb/d of oil and 12 MMcf/d of gas. It had 570 locations in the central area alone with 200 MMboe of potential production on 120-acre spacing. By the time it made an August presentation, it had drilled 48 wells and completed 36, with 27 wells online, and was running three rigs in the play with plans. Its best well, the Hixon 1H, came in at about 1,200 boe/d. It had 10 wells that tested for more than 800 boe/d, 15 for 600 boe/d to 800 boe/d, and two wells that tested for less than 600 boe/d. Its productive capacity had grown to 7,700 b/d of liquids and 23 MMcf/d of gas. It calculated it would finish 2011 with production of 16,000 boe/d.

NIOBRARA

El Paso has properties in the Raton Basin of Colorado and New Mexico that are prospective for

Pierre/Niobrara, but the company doesn't list any activity in the area or any production from that zone. It also mentions unconventional opportunities in the Rocky Mountains without identifying its holdings.

WOLFCAMP

After the Eagle Ford, the company's prime liquids-rich play is the Wolfcamp in the Permian Basin. In its August presentation, the company said it was drilling wells with lateral legs more than 7,000 ft long, and it liked the economics. It also had drilled vertical wells and wells with 2,000-ft to 4,500-ft laterals on its properties in Reagan, Irion, and Crockett counties. Among its wells, the UL 43-22-1H, with a 3,600-ft lateral and a 13-stage frac treatment, tested for 393 boe/d, including 335 b/d of oil. Its UL 43 19-1H, with a 7,100-ft lateral, tested for 660 boe/d, including 575 b/d of oil. Its longer-lateral wells used 24- to 27-stage frac jobs, cost $7 million to $8.2 million to drill and complete, offered EUR of 440 to 500 Mboe, and promised internal rates of return from 30% to 40%.

The Montney is Encana's prime liquids shale play now that it has entered the commercial production stage.

Encana Corp.

BAKKEN/EXSHAW

Encana Corp. holds more than 1,800 sections of land in the Bakken/Exshaw play in Saskatchewan under a joint venture (JV) agreement.

CARDIUM

The company holds more than 200 acres of land prospective for the Cardium Formation under a JV agreement.

DUVERNAY

Encana ranks the Duvernay Shale play in the Simonette and Kaybob areas of Alberta among its promising new plays. It acquired some 190,000 net acres in the play for US $300 million, the company said in 1Q 2011. It drilled one well in 1Q 2011 and confirmed expectations that horizontal wells would achieve results similar to those of other operators in the area. By 2Q 2011, it held 365,000 net acres in the play and planned two more exploratory wells.

EAGLE FORD

An early 2010 presentation said Encana planned production from the Eagle Ford Formation in South Texas, but subsequent reports don't mention the popular shale, even as a new play for the company.

MONTNEY

The Montney is Encana's prime liquids shale play now that it has entered the commercial production stage. It holds 1.13 million net acres with a 1,700-wellsite inventory at Cutbank. That includes properties in West Cutbank, but that is a dry gas play. The play has some 70 Tcf of gas in place, a 12.5 Tcfe contingent resource with 4.6 Tcfe in economic contingent resources, and 1.8 Tcfe in proved reserves. Encana has brought in recent wells that have produced up to 10 MMcf/d for 30 days. It had 40 wells in 2010. The liquids-rich portion totals 495,000 net acres and another 380,000 acres in the Alberta Deep Basin. In 2Q 2011, the Montney produced 354 MMcfe/d, up from 250 MMcfe/d a year earlier. It planned to drill 49 net wells during the full year. In the first half of 2011 the Montney produced an average 344 MMcfe/d. Encana planned to produce more than 600 MMcfe/d from the formation in 2014. It had five rigs working the play.

MARCELLUS

In February 2010, Encana said it had approximately 19,000 net undeveloped acres in the Marcellus in Pennsylvania through a JV agreement, and it planned to evaluate the property during the year. By 2011, it no longer listed the Marcellus, even as a new play.

NIOBRARA

The Niobrara play in Colorado falls under the company's new-play category. It held 240,000 net acres of land in the Piceance Basin of northwestern Colorado and the Denver-Julesburg Basin in northeastern Colorado. Although the Piceance Mancos/Niobrara is

listed as a dry gas area, Encana said it has identified liquids potential and planned to test the opportunities with recompletion and drilling projects in 2011. Some 40,000 of those net acres lie in the liquids-rich Niobrara in the Denver-Julesburg Basin, and Encana planned to drill a horizontal test on its property in 2Q 2011 and two to four wells for all of 2011. If those wells are successful, the company has up to 175 drilling opportunities in the basin. In late September, it scheduled the #9113-2 D02 2104 HH horizontal Prairie Canyon member of the Mancos B test in Hells Hole Canyon Field in Rio Blanco County, Colo., and staked locations for two more horizontal Prairie Canyon tests.

Although the Piceance Mancos/Niobrara is listed as a dry gas area, Encana said it has identified liquids potential and planned to test the opportunities with recompletion and drilling projects in 2011.

TUSCALOOSA MARINE SHALE

In its 2Q 2011 conference call, Encana said it had captured more than 250,000 net acres in the Tuscaloosa Marine Shale play in Mississippi and Louisiana. It planned to evaluate the potential of the play during 2011.

UTICA/COLLINGWOOD

Encana collected some 425,000 net acres in the Utica/Collingood Shale play in Michigan under favorable terms and low prices. It acquired the property at about $200 an acre, and a single well can hold 7,500 acres. This still is a new play for Encana, and it planned to drill two vertical pilot wells in the northern oil play and two horizontal wells in the liquids-rich southern gas part of the play. Early wells show promise, the company said.

VIKING

Encana holds more than 200 sections of land prospective for the Viking in southern Saskatchewan under a JV agreement.

Endeavour International Corp.

MARCELLUS

Endeavour International Corp. took over approximately 50,000 net acres of properties in McKean and Potter counties in the northern Pennsylvania portion of the Marcellus Shale play from SM Energy Co. for US $110 million. The properties include three Marcellus wells producing between 3 MMcf/d and 4 MMcf/d of gas from an estimated 328 Mboe in proved and probable reserves and the 10.75-mile Potato Creek gathering system. Endeavour and SM Energy expected the transaction to close in 4Q 2011. The acquisition raises Endeavour's position in the play to 93,000 gross, 68,000 net, acres, including property in adjacent Cameron County. The company, with the Cohort Energy Co. arm of J-W Operating as the operator, has identified more than 300 drilling locations on the property. Endeavour had two horizontal wells in Daniel Field in Cameron County awaiting completion in August 2011. The company estimated potential recoverable gas at 650 to 800 Bcf net to Endeavour. The company's properties also have potential for shallower Genesee and deeper Utica production.

HEATH

As operator, Endeavour has a 25% working interest in more than 400,000 gross, 85,000 net, acres of land, mostly in Garfield and Rosebud counties in west-central Montana, prospective for production from the Heath Shale. It paid $4 million for its share. The company described the property as a "Bakken-like play, but shallower." It has 900 potential drilling locations. The companies had completed 2-D seismic mapping by August 2011 and planned a pilot test well in 3Q 2011. For the remainder of the year, it planned three or four vertical pilot wells and possible horizontal entries.

Energen Corp.

AVALON

Energen Corp. bought three properties in the Permian Basin in 2010 for some US $370 million to give it access to the Avalon Shale, Third Bone Spring, and Wolfberry formations. It plans to invest another $1.2 billion in coming years to develop the plays. The Avalon will receive less direct attention than the other two formations in the acquisitions, but at least in some of its properties it will have to drill through the Avalon Shale member of the First Bone Spring to reach the deeper Third Bone Spring. It reaches the Avalon at 8,500 to 9,000 ft at a completion cost for a horizontal well of $5.5 million. It is drilling three or four net wells in 2011 with EUR or 300 Mboe to 350 Mboe. It planned six additional wells in 2012 and seven more in 2013. Energen holds 110,000 net acres in the Avalon play in the Delaware Basin and has room for 340 potential locations in 320-acre spacing. By August 2011, it had drilled a step-out well that tested between 100 and 110 b/d of oil and between 400 and 600 Mcf/d of gas, but that well had completion and lift system problems.

BONE SPRING

In an August 2011 presentation, Energen said it dedicated four rigs to the Third Bone Spring in 2011 and double that count in 2012 and 2013. It planned 60 Bone Spring wells in 2012 and 2013. It will complete those wells at 11,000 to 11,300 ft with eight to 10 frac stages to get EUR between 400 and 450 Mboe from estimated net risked reserves of 250 to 300 Mboe per well. Recovery is 57% oil, 27% natural gas liquids (NGLs), and 22% gas. A well to the formation costs $7 million. Energen has 74,000 net acres in the play with 230 potential locations on 320-acre spacing. The stabilized initial potential for its 10 best wells in 2011 was 300 b/d of liquids and 900 Mcf/d of gas.

MARCELLUS

The company owns 200,000 net acres of leases in West Virginia but announced no plans for development of the properties.

NIOBRARA/MANCOS

Its coalbed methane properties in the San Juan Basin of northwestern New Mexico and southwestern Colorado give Energen access to 54,000 net acres of leases in the Niobrara/Mancos Formation in that basin.

WOLFBERRY

Energen planned 315 Wolfberry wells on its 26,000 net undeveloped leases in the Midland Basin. It planned 155 net wells in 2011 and 2012 and another 160 wells in 2013 with seven or eight rigs running through 2013. It harvests the Wolfberry with vertical wells and six to eight frac treatments between 7,500 and 10,500 ft. At a well cost of $2.1 million, wells offer an EUR of 155 Mboe consisting of 63% oil, 25% NGLs, and 12% gas. Energen said its model production rate was 55 b/d and 110 Mcf/d, but initial potentials on 54 producing wells have exceeded that model by 25% to 30%.

Energy Corp. of America

MARCELLUS

Energy Corp. of America started business in the Appalachian Basin and has had active operations there for 45 years. It owns more than a million acres of land from New York to Tennessee in the Appalachian Basin with its Eastern American Energy Corp. subsidiary with more than 15 Tcf of resource potential and more than 400 Bcf of proved reserves. Greene County, Pa., is the company's clear sweet spot in the play with 43 wells permitted, drilled, or drilling in mid-April 2011. In May 2009, it said it planned to drill 75 Marcellus horizontal wells in the next three years with an estimated recoverable resource of 1 Tcfe of gas in Greene County alone. The company also has properties with Marcellus potential in Clearfield in Pennsylvania and in Logan, Upshur, and Webster counties in West Virginia. It started the ECA Marcellus Trust in July 2010 with 14 producing horizontal Marcellus wells, according to an October 2010 article in Oil and Gas Investor magazine. It planned to drill 52 horizontal Marcellus wells in the following four years.

EAGLE FORD

Energy Corp. also entered a joint venture to develop Eagle Ford properties in South Texas.

Enerplus Corp.

BAKKEN

Enerplus Corp., a Canadian energy trust that incorporated in January 2011, put together an active development program focused on the Fort Berthold

Indian lands in North Dakota. It holds some 74,500 net acres in the Bakken play. In August 2011 it had four rigs working the play, including two walking rigs capable of pad drilling. It assigned US $230 million to the play for 2011 to drill 22 wells. It expected production to reach 12 Mboe/d by the end of 2012 from its proved and probable reserves of 22.4 MMboe. It expects production to grow to 20,000 boe/d in four years with additional upside potential in the Three Forks Formation. Some 90% of its leases are operated with a working interest of more than 90%.

Enerplus also has Bakken potential in the Freda/Skinner/Neptune Ratcliffe fields in Saskatchewan, but drilling results to date have been disappointing.

MARCELLUS

Enerplus acquired 110,000 net acres in the Marcellus Shale play and 60% of its property, 65,000 acres, is operated and lies in West Virginia, Maryland, and central Pennsylvania. It contains an estimated contingent resource of 2.3 Tcf of gas. The company has focused on delineation work in the area. Most of its 45,000 acres of non-operated land is in northeastern Pennsylvania, where it has a 20% working interest. Major non-operating partners are EXCO and Chief Oil & Gas. It budgeted $195 million on the Marcellus in 2011, mostly in the non-operated properties. In August 2011, it had nearly 60 gross wells in northeastern Pennsylvania, in Lycoming, Susquehanna, and Bradford counties, and 90% are outperforming the 6 Bcfe of gas type curve for the area. It had 169 gross wells, 12.5 net, awaiting completion or tie-ins to gathering systems. EXCO is running three rigs in northeastern Pennsylvania and expected to raise that number to five in 1Q 2012, all in Lycoming County, while Chief continued to run three rigs focused on Bradford and Susquehanna counties. Enerplus ran one rig with plans to drill five gross wells to delineate its resource. The company expected production of some 150 MMcf/d by the end of 2014 and planned to spend more than $800 million in the next four years. It sold a portion of its non-operated Marcellus properties for $568 million to give it a gain of $272 million.

MONTNEY

The company holds 28,000 net acres of undeveloped Montney land in the Cameron and Julienne Creek areas of Alberta, room enough for 50 to 150 horizontal drilling locations. Wells in the area show EUR of 3.5 to 5.5 Bcfe of gas per well. Enerplus bought and reprocessed 3-D seismic data for the area and licensed one well in 1Q 2011 but is uncertain about when it will drill the well.

DUVERNAY

Enerplus has 38,000 net acres in the Duvernay liquids-rich shale play, all undeveloped. It plans to delineate the potential but hasn't published a timetable.

EOG Resources Inc.

AVALON/LEONARD/BONE SPRING

EOG Resources Inc. combines the Leonardian-age Avalon Shale member of the First Bone Spring and the Second and Third Bone Spring formations in its reporting. It holds some 108,000 net acres in the play, mostly in Eddy and Lea counties in New Mexico, and had proven up 62,000 net acres by August 2011. It estimated 65 MMboe in potential reserves in New Mexico alone, and it continued to test acreage on the Texas side of the Delaware Basin for added potential. Drilling in Lea County suggested it could produce 300 Mboe per well with successful extensions into Eddy County. Its 11-well average in Lea County horizontal activity was 452 b/d of oil and 1.4 MMcf/d of gas in the first 30 days of production. It ran a one-rig program in the play in 2011 but planned to ramp up activity in 2012 as it used horizontal wells to reactivate existing fields previously produced by vertical wells.

BAKKEN

The Bakken/Three Forks oil play made EOG the biggest oil producer in North Dakota. It controlled 600,000 net acres in the play and ran a 10-rig drilling program in 2011 to drill a planned 106 gross wells. At the same time it confirmed better economics from longer laterals in the Bakken and Three Forks zones. The company's prime properties are in Parshall Field, the most prolific field in the play. Its Liberty LR #21036H well, with a 9,968-ft lateral, produced to sales at rates of 1,201 b/d of oil and 1.1 MMcf/d of gas. Its after-tax rate of return on those wells ranges from 40% to 50%, according to an August 2011 presentation.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BARNETT COMBO

During 2011, EOG, the biggest producer in the Barnett Combo, increased its property in the core area of the liquids-rich play to 195,000 net acres and moved into full development mode to make the play its second-largest liquids growth contributor, the company said. In late 2011, it ran eight rigs in the play and planned to drill approximately 230 net wells at an average cost of US $3 million per well and expectations of after-tax returns between 40% and 60%. Five wells in its Gaedke Unit tested at rates of 338 to 696 b/d of oil and 807 to 2.2 MMcf/d of rich gas while four wells in its Stoddard Unit tested for 777 to 918 b/d and 1.3 to 2.7 MMcf/d. The company estimated 370 MMboe in potential reserves after royalties from its properties. In a 2Q 2011 report, it said it continued to get successful drilling and completion results in the Montague and western Cooke County properties where it has several years of drilling locations in its inventory.

CLEVELAND

As part of its campaign to revive older vertically produced fields, EOG is working again in the Cleveland Formation in western Oklahoma. In a 1Q 2010 report, the company said it is developing its 60,000-acre position in Lipscomb County with horizontal drilling and enhanced completions to get economic rates of return. It found it increased recoverable reserves per well by a factor of four. At that time, it said the Appel 438 #5 and #6H started producing at rates of 1,000 and 840 b/d and 2.5 and 1 MMcf/d, respectively. Those properties also are prospective for Tonkawa production.

EAGLE FORD

The company has taken the largest position in the biggest oil discovery in 40 years in the Eagle Ford Shale. It holds 535,000 net acres in the oil window, another 26,000 net acres in the wet gas window, and 49,000 net acres in the dry gas window for a total of 610,000 net acres. Those properties hold potential reserves of 690 MMbbl of oil, 100 MMbbl of natural gas liquids (NGLs), and 661 Bcf of gas, or a total of 900 MMboe, although the company had booked only 135 MMboe in reserves at the end of 2010. A typical well offers 77% oil, 11% NGLs, and 12% gas. EOG is the largest oil producer in the play at 34 Mboe/d as of June 30, 2011, according to an August presentation. EOG is now working on improving recovery with reduced well spacing. EOG's enthusiasm for the play is reasonable; it gave the company an opportunity to invest $10 billion to $15 billion with an after-tax rate of return between 95% and 140%. At the same time, it is currently getting a 100% successful completions rate. It is running a 22-rig program in the play. Well performance is better in its eastern area with an EUR average of 460 Mboe net after royalties with 4,000-ft laterals. Initial potentials range from 800 to 1,600 b/d of oil plus rich gas. In the western area, it gets EURs of 430 Mboe with 5,000-ft laterals and initial potential production between 700 b/d and 1,200 b/d of oil plus rich gas.

MARCELLUS

EOG actively works its 210,000 acres of Marcellus land in Pennsylvania where it holds a 100% interest in 50,000 acres in the Bradford area and a half interest in 160,000 acres in Elk and Clearfield counties. It counts potential reserves of 3.3 Tcf of gas from those properties. In an August presentation, it said recent completions in Bradford County ranged from 10 to 15 MMcf/d and in Clearfield County from 7 to more than 9 MMcf/d. It planned to drill 30 wells on the property in 2011. Those northern Pennsylvania properties also could have potential for Utica returns.

NIOBRARA

The company has had encouraging drilling results of 169,000 of its 220,000 net acres in the Niobrara play in the Denver-Julesburg Basin. Even its flagship well, the Jake 2-10H in Hereford Ranch Field, still produces well. That well, drilled in late 2009, kicked off the Niobrara land rush in the basin. It produced at an average rate of 645 b/d of oil in its first month online and has produced at a stable rate of 250 to 300 b/d from 1Q 2011 through August. It is concentrating its activity on its 80,000-net-acre position in Hereford Ranch Field in northern Weld County, and recent drilling on two additional prospects on 89,000 additional acres has been encouraging. A typical well on its properties gives the company a mix of 82% oil, 12% NGLs, and 6% gas. Experience to date has shown EOG that typical wells produce at lower initial rates than some of its other liquids-rich plays but have a shallower decline curve.

WOLFCAMP

EOG operates 131,400 net acres of leases in the Wolfcamp play in the Midland Basin. It had proven up 47,000 of those acres by August 2011 with 14 horizontal wells. The area has multiple pay targets with a core-area – Irion and Crockett counties – potential of 40 MMboe. Early results from its Irion County property indicate EUR of 270 Mboe per well. Among 2011 wells, the University 40-A #0401H tested for 935 b/d of oil and 838 Mcf/d of gas. It also has Wolfcamp production in Reagan County.

Epsilon Energy Ltd.

BAKKEN

Epsilon Energy Ltd. holds a participating interest with operator Spartan Oil that seeks Bakken and Midale oil in Torquay, Ceylon, and Weyburn fields in the southeastern corner of Saskatchewan. Epsilon's share of the project includes 6,852 net acres with a potential of more than 52 locations at Ceylon, 7,761 net, acres with a potential for more than 48 locations at Weyburn, and 2,995 net acres with more than 18 potential locations at Torquay. At the end of August, the companies completed a Bakken discovery after weather delays and lease sales. The well showed an initial potential of 44 b/d of oil and appeared to be stabilizing at about 25 b/d. In an August presentation, the companies hadn't yet booked production or reserves from the properties.

MARCELLUS

The company holds 27,330 gross, 21,580 net, prospective acres for the Marcellus Shale in Pennsylvania and New York. Chesapeake is developing the 42-plus well locations under a 50-50 joint venture agreement. Chesapeake paid US $5 million up front and will carry Epsilon up to $95 million on the 11,600 gross acres of Pennsylvania properties, which produced 4 MMcf/d of gas in August 2011. Those properties also held potential for production from the Purcell Lime and Utica Shale. The properties hold 86.1 Bcf in proved reserves and another14.1 Bcf in probable reserves. Epsilon has 15,800 net acres in New York with 100 MMcf of proved gas reserves and more than 117 potential locations, but fracture treatments have been under a moratorium in that state. The New York properties also have potential for production from the Utica and Trenton-Black River.

MISSISSIPPI LIMESTONE

Epsilon developed a west-central Mississippi prospect in the Mississippi Brown Dense Limestone Formation. It holds interests in 8,591 net acres and is operator with a 51% interest within an area of mutual interest of 43,600 acres. The company completed a well in April 2011 without significant stimulation but hasn't booked production or reserves from the area.

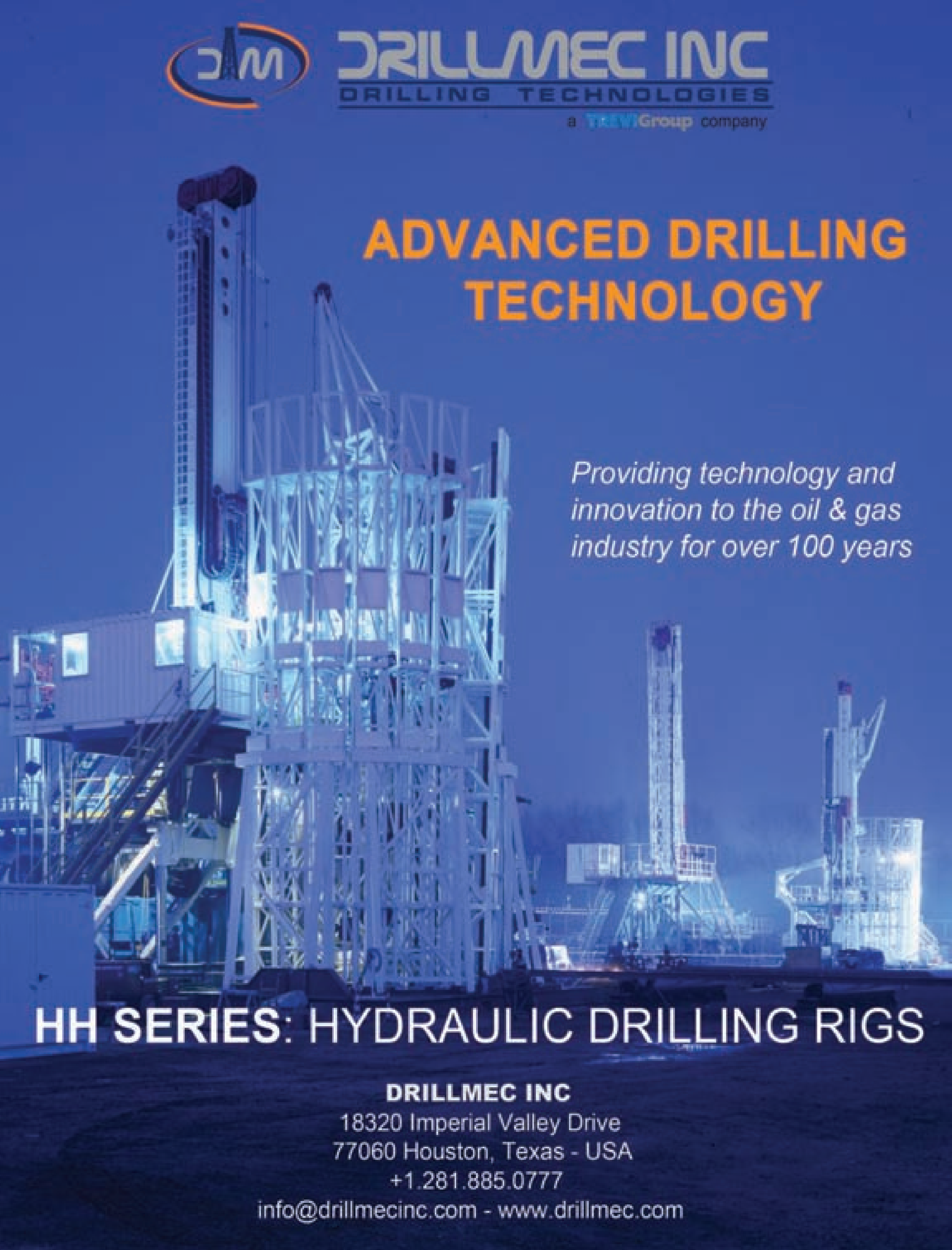
UTICA

Epsilon holds an elective 25% interest in some 920,319 gross, 191,850 net, acres of land in Southern Quebec, some of which is prospective for the Utica Shale. Gastem Inc. is operator of 64,831 gross acres in the St. Jean area in which Epsilon holds a 1.5% share. Epsilon also is operator of the Yamaska area, in which Epsilon holds a 5% share in 119,091 gross acres. Forest Oil is operator of the Yamaska area on the Gaspe Peninsula. Some of the Gaspe Peninsula, St. Jean, and Dundee properties in the St. Lawrence Lowlands are prospective for Utica production. Forest Oil tested two test wells for initial production rates up to 1 MMcf/d of gas and estimated 4 Tcf in resource potential at Yamaska.

EQT Corp.

MARCELLUS

EQT held approximately 520,000 acres prospective for Marcellus Shale production in Pennsylvania and West Virginia with proved reserves of 2.9 Tcfe of gas. It had 21.2 Tcfe in proved, probable, and possible resource and 20 Tcfe in resource potential in the play, according to an August presentation. The company's average well with a 5,300-ft lateral cost US $6 million and gave the company an EUR of 7.3 Bcfe. It planned 57 wells in southwestern Pennsylvania in 2011, 10 wells in northern Pennsylvania, and 33 wells to the Marcellus in northern West Virginia. The 100 wells in 2011 represented a sharp increase from the 30 wells in 2009 and 60 wells in 2010. It also tried a new frac design on 24 wells in 2011 that offered high initial potentials but cost $1.6 million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more. Overall, the Marcellus gave the company a 72% after-tax rate of return with a New York Stock Exchange price of $5/MMBtu and a return of more than 100% at a $6 gas price. Before the new design, the company conducted fractures in 300-ft stages with five clusters of perforations at 60-ft spacing. With the new design, it used 150-ft stages with five clusters of perforations at 30-ft spacing. The old design offered 15.66 frac events per acre compared to 48.33 frac events per acre with the new design. EQT's best well was the 590036 Phillips in Greene County, Pa., with an initial potential of 23 MMcf/d.

The company gave its wells three rankings using 5,300-ft laterals. One area, with 109,000 acres in Pennsylvania and 36,000 acres in West Virginia, gave the company 1,190 locations with 9 Bcfe EUR. A second area with 83,500 acres in Pennsylvania and 31,500 acres in West Virginia offered 940 locations with 7.4 Bcfe EUR. The third area, with 45,000 acres in Pennsylvania and 215,000 acres in West Virginia, gave EQT EUR of 6.4 Bcfe on 2,130 locations. In its 2Q 2011 report, ETT said it produced 47 Bcf, and the Marcellus accounted for 39% of that volume, up from 16% of the company's total volume in the same quarter a year earlier. Second-quarter Marcellus sales averaged 203 MMcf/d of gas, and the company expected to finish the year producing 285 MMcf/d from the formation.

UTICA

EQT also has Utica potential under its Marcellus properties, but it isn't actively working the play. It allocated $6.9 million to drill a Utica well in 2008 and spent another $1 million on the well in 2009. Then it plugged the well back and completed it as a horizontal Marcellus producer, according to the company's 2010 annual report.

EnerVest Operating LLC/ EV Energy Partners LP

CANA WOODFORD

EnerVest and its affiliate hold properties in western Oklahoma prospective for the Cana Woodford liquids play, but publicly available information doesn't list the extent of those properties or the operating arrangements.

EAGLE FORD

At one point, EnerVest Operating LLC and affiliate EV Energy Partners LP (EVEP) held a strong position in south-central Texas properties with Eagle Ford potential. In 2007, EVEP signed an agreement with Apache Corp. that gave Apache rights to some 400,000 acres of land in formations below the Austin Chalk, including the Eagle Ford and Pearsall shales. Those properties are in Brazos, Burleson, Grimes, Lee, and Washington counties. EnerVest and EVEP still operate the Austin Chalk properties.

GRANITE WASH

The companies hold more than 1,300 net acres in land prospective for the Granite Wash, Cottage Grove, and Cleveland formations in the Texas Panhandle, but other companies, primarily Sanguine Energy on a farm-out from Chevron, operate the properties. Horizontal tests to date have added a net 2 MMcf/d of gas to EVEP production.

MARCELLUS

In 2008, EnerVest and EVEP were among the top producers in Appalachia, with most of their production in formations shallower than the Marcellus. EnerVest held some 250,000 acres held by shallower production, and EVEP held another 35,000 acres with Marcellus production. In December 2009, the affiliated companies signed over access to 9,500 net acres of land in Harrison, Marion, Doddridge, Barbour, Upshur, and Randolph counties in north-central West Virginia, giving PetroEdge a 75% working interest in the acreage on each well it drilled and completed and a 75% interest in the total acreage if it spent US $33 million on drilling and related activity in four years. EnerVest and EVEP retained a 25% interest.

UTICA

The Utica Shale is one of the companies' most actively operated properties. They have a combined 780,000 net acres, mostly held by production in Ohio and largely acquired in the EnerVest takeover of Belden & Blake. EnerVest operates 60% of the property and EVEP holds 159,000 net working interest acres along with a 7.5% overriding royalty interest in some 240,000 net acres. The companies signed a long-term agreement that allowed Chesapeake to operate about 40% of the 780,000 in what the companies believe to be the sweet spot for Utica Shale in Ohio. EVEP kept the equivalent of a 7.5% override on 80,000 net acres and holds approximately 22,000 net working interest acres in the joint venture (JV). Chesapeake had five rigs testing the oil, natural gas liquids, and dry gas windows of the play in July 2011 with a few producing wells and several awaiting completion.

EnerVest is the operator for EVEP and an EnerVest institutional partnership on more than 400,000 net acres in the play in Ohio that doesn't fall under the JV. In that segment of the play, EVEP holds an average interest of some 33%, or 137,000 net working interest acres, and holds the equivalent of a 7.5% royalty interest on some 160,000 net acres. EnerVest permitted 10 wells and planned two or three Utica horizontal wells in 2011 and early 2012, but it preferred to learn from Chesapeake and other companies before undertaking a massive development project. EnerVest has data from more than 500 vertical wellbore penetrations in Ohio, including 1,560 ft of core from five wells and sidewall cores and cuttings from 12 wells. By late August 2011, all operators in the play had permitted 37 wells and had drilled or were drilling 17 wells. In its 2Q 2011 report, EVEP said Chesapeake had opened a data room to invite another partner into the JV.

EXCO Resources Inc.

MARCELLUS

EXCO Resources Inc. controls 847,000 gross, 379,000 net, acres in Appalachia with 140,000 net acres prospective for Marcellus Shale development. It had three rigs running at the end of 2Q 2011 and planned to add one or two more by the end of the year. It was completing six, 2.7 net, wells at that time on its northeastern Pennsylvania acreage. One well completed in early 2011 came in at 10.6 MMcf/d of gas from a 4,168-ft lateral. The company also is honing its skills in the play as it reduced the days to drill horizontal sections from 25 in 2Q 2010 to 15 days in 2Q 2011 with laterals of about 3,800 ft. About 60% of the company's Marcellus properties already are held by production from shallower zones. In 2010, it signed a joint venture agreement with BG Group plc on its Huron and Marcellus upstream and midstream assets. BG paid US $800 million in cash and agreed to spend $150 million in capital development in the Marcellus for interests in a group of companies that held half of EXCO's Appalachian assets, including more than 5,000 potential Marcellus drilling locations. In 2011, EXCO held property in 23 counties in Pennsylvania and 29 counties in West Virginia.

EXCO Resources Inc. controls 847,000 gross, 379,000 net, acres in Appalachia with 140,000 net acres prospective for Marcellus Shale development.

Exxon Mobil Corp./XTO Energy Inc.

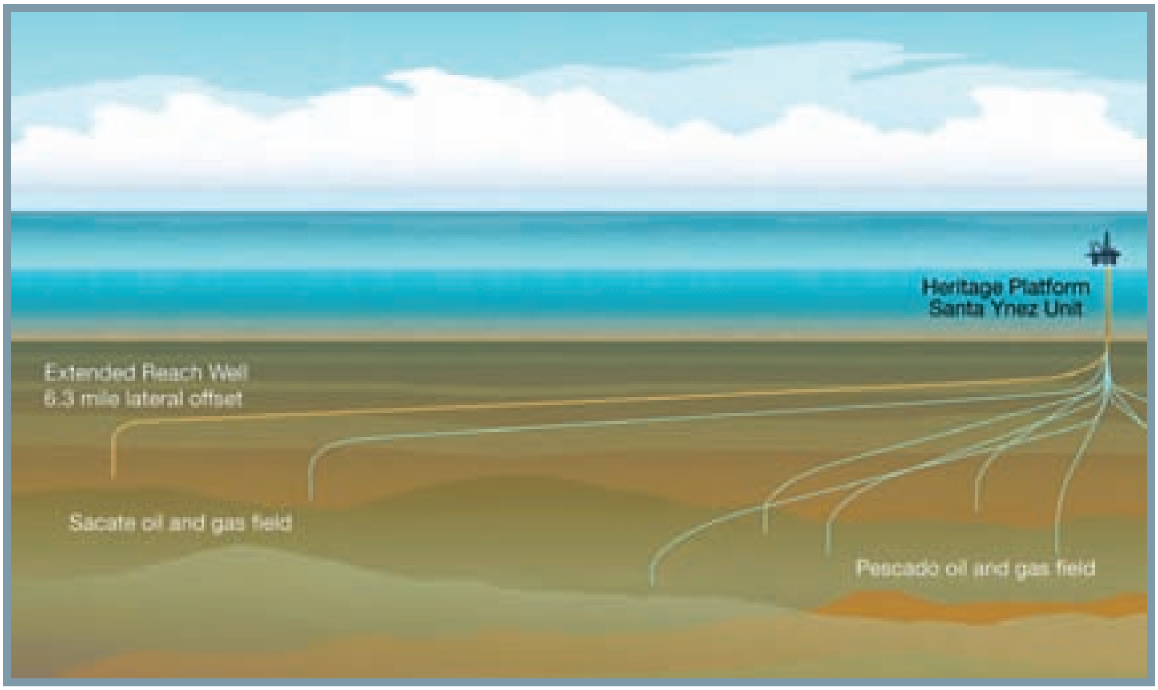
BAKKEN

When Exxon Mobil Corp. took over XTO Energy Inc., it also took over that company's 450,000 acres of leases in the Bakken Shale play, XTO's largest unconventional holding. Exxon Mobil does not break out individual plays in its operational reporting, but in a 3Q 2009 presentation, XTO said it was working three rigs in the Bakken and produced 13,800 boe/d with wells showing initial potential as high as 1,880 boe/d from the Bakken and the Three Forks/Sanish. At that time the company was moving toward longer laterals and more frac stages in its completions. It also was investigating the use of superpads. In early 2010, 27% of XTO's Bakken leases were in Elm Coulee Field in Montana. Its strongest North Dakota production came from Parshall and Ross Fields east of the Nesson Anticline. It expected to double its rig count to six during 2010.

CARDIUM

A January 2010 report by Newcrest division of TD Securities Inc. said Exxon Mobil Canada Ltd. was 30th in volume among producers from the Cardium Formation in Alberta with a production rate of 42 boe/d from four net wells. At the same time, the company ranked 16th among land holders with 110 net sections in the play. A 2011 Exxon Mobil presentation showed the company still held Cardium properties.

(Diagram courtesy of Exxon Mobil Corp.)



Exxon Mobil drilled the world's longest-reach well from a fixed production platform to develop the Monterey Formation offshore California.

EAGLE FORD

Exxon Mobil acquired 120,000 acres of leases in the Eagle Ford play in South Texas when it acquired XTO energy in June 2010. It drilled 15 wells in the play that year. One of those wells in the gas-prone portion of the play in Hawkville Field in Webb County tested for 5.7 MMcf/d of gas and 201 b/d of condensate.

MARCELLUS

The company's acquisition of XTO also gave it a significant footprint in the Marcellus Shale play. Exxon Mobil already had purchased 152,000 acres in the play from Linn Energy in 2008 and added 145,000 acres in Pennsylvania with a 2009 acquisition from Pennsylvania General Energy. In an October 2008 presentation, XTO said it held 280,000 acres in the Marcellus, and in May 2009 added that it had an inventory of 200 to 220 well locations in the Marcellus with a potential of 500 Bcfge in reserves. It also said its Marcellus production gave it a 70% internal rate of return at a natural gas price of $5/MMBtu. XTO's Pennsylvania properties were in Armstrong, Cambria, Columbia, Clarion, Clinton, Fayette, Westmoreland, Lycoming, and Indiana counties. It also had West Virginia activity in Boone, Barbour, Calhoun, Harrison, Marion, and Upshur counties.

MONTEREY

Exxon Mobil Corp.'s offshore California oil production offers a focused illustration of the current popularity and potential of the Monterey Formation onshore California. The company's Heritage offshore platform produces from Monterey in West Sacate, Sacate, Pescado fields with long-reach wells, according to a 2007 edition of *The Lamp* magazine. The company's Hondo, Harmony, and Heritage platforms off southern California have produced more than 450 million bbl of oil from the Hondo, Sacate, western Sacate, and Pescado fields since 1981. Exxon Mobil thought enough of the formation's capability that it installed the world's most powerful fixed-platform mounted drilling rig on the Heritage platform to take advantage of its Fast Drill drilling technology to develop the field with extended-reach wells. In April 2010, the company said it drilled the world's longest extended-reach well drilled from an offshore fixed platform drilling rig. It also was the longest extended-reach well drilled in North America. That well reached more than 6 miles horizontally at a depth of more than 7,000 ft below sea level. That single well, the company said, should produce an additional 5.8 MMboe from the field, enough to cover the annual energy consumption of more than 144,000 Californians for a year. Recent activity in the Monterey Formation in Sacate Field included the SA018 OCS P00193 drilled to an estimated total depth of 7,000 ft, according to IHS Inc. That well previously was a gas injection well. In the same field, it reported plans in July 2011 to drill the SA014 OCS P00326, also from the Heritage platform and also to the Monterey, IHS Inc. said. In adjoining Pescado Field, Exxon Mobil said in January 2011 it planned a re-drill, named the HE014 OCS P00183, to 18,514 ft in the Monterey. It started drilling in February with the Heritage platform rig and reached a total depth at 17,457 ft at a vertical depth of 8,389 ft. It perforated the well from 16,922 to 17,457 ft and was awaiting completion tools, according to an IHS report in August 2011.

Fidelity Exploration & Production Co./ MDU Resources Group Inc.

BAKKEN

The Fidelity Exploration & Production Co. subsidiary of MDU Resources Group Inc. holds some 90,000 net acres of Bakken/Three Forks properties in Montana and North Dakota with a potential 100 to 125 potential wells and a potential recovery between 250 and 500 Mbbl of oil. Its wells cost between US $7 million and $8 million to drill. The prime Bakken corridor for the company is in Mountrail County, N.D., where the 31-30H Hill tested at a five-day gross rate of 1,633 boe/d, and the Behr 16-21H tested at 1,216 boe/d for 30 days. Both were horizontal wells with 30-stage frac jobs. The company has 16,000 net acres in Mountrail County and added a second rig to its program there in April 2011, according to MDU's 2Q 2011 report. It drilled seven wells by August 2011 and had 45 operated wells at that time. It planned 15 wells for the year and 17 wells in both 2012 and 2013. It controls another 50,000 net acres in Stark County where the Three Forks is the primary target. It allocated $30 million to that prospect in 2011. Its remaining 20,000 net acres are in Richland County, and Three Forks also is the target there with an anticipated 250 to 400 Mbbl of oil EUR per well. It will drill its first appraisal well in that area in 2012.

HEATH

Fidelity has 80,000 net acres prospective for the Heath Shale in Rosebud County, Mont., where Cabot and Cirque also operate. Fidelity planned two appraisal wells in the area in 2011. The property offers between 40 and 200 potential well locations with expected gross EUR of 165 to 200 Mbbl of oil per well.

NIOBRARA

Fidelity has 50 to 200 potential net well locations on its 65,000 net acres with Niobrara potential in southeastern Wyoming. It planned four exploratory wells in 3Q and 4Q 2011, investing $5 million to $7 million per well with anticipated recoveries of 200 to 300 Mbbl of oil per well.

Forest Oil Corp.

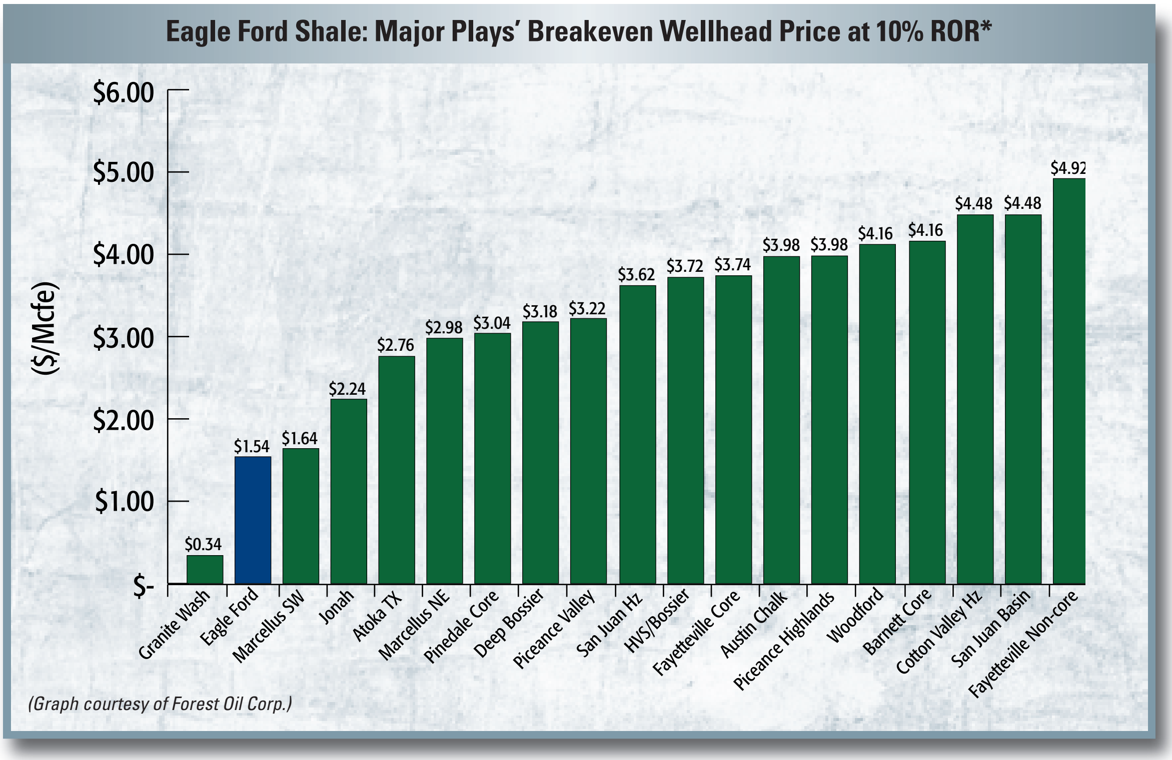
EAGLE FORD

Forest Oil Corp. continued to improve its position in the Eagle Ford Shale in 2Q 2011 as it sold 12,000 gross, 10,000 net, acres in the play but increased its overall acreage by 4,000 net acres to a total 113,000 net acres. It drilled four wells on its land in 2Q 2011 with initial potential rates averaging 747 boe/d. It also increased its capital allocation in the play to US $120 million. Its properties are in Gonzales, Lee, and DeWitt counties. At the end of 2Q 2011, the company ran two rigs in the play but planned to add another rig during 2011. At that time it had three proved undeveloped well locations and 1,015 other identified potential sites. It has an unrisked potential of a net 154 MMbbl of oil on its property.

GRANITE WASH

The company controls 169,000 gross, 103,000 net, acres of leases in the Granite Wash play in the Texas Panhandle. It drilled four wells in the play in 2Q 2011 with average initial potentials of 9 MMcfe/d of gas. Those wells had a liquids content of 46% of equivalent production, or more than 700 b/d of liquids. The company also had seven operated and eight non-operated wells in the formation that were awaiting completion. It expected to complete the wells in 3Q 2011. It has 259 proved undeveloped locations in the Granite Wash and 1,034 other identified locations. Half of Forest's capital budget for 2011 was aimed at the Granite Wash, where the company runs a six-rig drilling program. It planned to drill 40 operated wells in 2011. It has 36 wells with 9.7 MMcf/d of gross gas production and 2.1 Mb/d of gross liquids production and an unrisked

A chart assembled by Wall Street analysts shows NYMEX prices needed to achieve a pre-tax 10% rate of return exclusive of general and administrative, land, geological, geophysical, and infrastructure costs.



(Graph courtesy of Forest Oil Corp.)

potential of nearly 1.9 Tcfe of gas. Its properties are in Kelln, Canadian Southeast, Mendota Ranch, Buffalo Wallow, Camp South, and Frye Ranch fields.

UTICA

Forest was a pioneer in the Utica Shale play in Quebec, but it plans to turn those properties over to its Lone Pine Resources subsidiary as it spins that company off to shareholders. Forest discovered gas in the Utica in the St. Lawrence Lowlands in April 2008. At the time, it held 270,000 acres in the play with an estimated 4.1 Tcf of gas of potential recovery based on a 20% recovery factor. It also was the first company to drill horizontal wells in the play in 2008. It planned further drilling in 2010, but the Quebec government restricted drilling. It initially allocated $10 million for one vertical well in 2010.

WOLFCAMP

The Wolfcamp in Crockett County, Texas, is a new play for Forest, but the company has 57,000 gross, 48,000 net, acres to work with. It moved a rig into the play in June 2011 and planned to drill six wells in the second half of the year with a $50 million budget. It picked up the acreage at less than $1,000 an acre. If the play proves up, the company could begin full-scale development in 2012.

Gastar Exploration Ltd.

EAGLE FORD

Gastar Exploration Ltd. holds enough property on 160-acre spacing to drill 124 wells into the Eagle Ford/Woodbine, or Eaglebine, combination on its Leon and Robertson counties property in East Texas. To date, it drilled the Wildman #7H discovery well for an initial potential of 120 boe/d. The company anticipated EUR of 140 to 500 Mboe per horizontal well at a cost of US $6 million per well.

MARCELLUS

The company held 74,200 net acres that provided scale in the Marcellus play in Pennsylvania and West Virginia and a joint venture (JV) with Antinum Partners of the Republic of Korea that provided drilling funds, according to a September 2011 presentation. The company had three rigs operating in the play. Among its properties it held 6,700 net, 13,400 JV acres in Marshall and Wetzel counties in West Virginia.

When it comes to well stimulation,
are there products that are safer to use?
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What do *you* need?

It planned more than 95 wells in Marshal County with a $160 million drilling program in 2011 with horizontal wells drilled from pads. Gastar's contribution to that program is $27.8 million. It has 10,200 net, 20,400 JV acres in Pennsylvania. Within that area, the venture is involved in seven wells being drilled on the venture's 5,400 acres in Butler County by Rex Energy. The companies expect to drill 10 wells by the end of the year. They hold another 6,700 JV, 3,400 net-to-Gastar acres in Somerset and Fayette counties in Pennsylvania with development planned following 3-D seismic acquisition. Gastar drilled two vertical wells in West Virginia, starting in late 2009, and followed up with two horizontal wells. In September, the company said its Wengerd 1H and 7H wells produced an average combined gross 7.1 MMcf/d of 1,285 Btu/Mcf gas and 176 b/d of condensate for their first 30 days on production. In July, the company said the two wells produced at an initial combined rate of 15.5 MMcf/d of gas and 1,100 b/d of condensate. The company said it planned to put four additional horizontal Marcellus wells on production by the end of October and add at least three more by the end of the year. Overall, it planned 21 gross, 9.3 net, Marcellus horizontal wells in 2011, 14 operated, and the remainder operated by Rex. Gastar and Antinum each hold a 19.2% share in the Rex-operated wells. The company's agreement with Antinum called for a minimum of 12 horizontal wells in 2011 and 24 wells each in 2012 and 2013.

Gastar Exploration Ltd. holds enough property on 160-acre spacing to drill 124 wells into the Eagle Ford/Woobine, or Eaglebine, combination on its Leon and Robertson counties property

Gastem Inc.

MARCELLUS

Gastem Inc.'s Gastem USA subsidiary holds properties prospective for the Marcellus and Utica formations in New York. It has 32,000 acres of land in Broom, Delaware, Otsego, and Chenango counties in an 80-20 venture with Utica Energy LLC, formerly Covalent Energy. Covalent drilled two wells on the property in 2007, and Gastem earned its 80% by drilling a vertical well and adding stock and US $35,000 in cash in 2009. It received approval to fracture the Marcellus in the Ross #1 and the Upper Utica in Sheckels #1 in 2010. It used a small two-stage frac in the Ross well and recovered 120 Mcf/d of gas. It also conducted a 2-D seismic survey in Otsego County and an aeromagnetic survey over all of its properties. For 2011 and the future, the company said, further land acquisition and drilling programs are subject to well results, regulations, and funding.

UTICA

In addition to the Utica potential in New York, Gastem has a major presence in the Utica play in Quebec. In the Yamaska area, Gastem holds a 20% interest in 112,139 acres with partners Forest Oil, 60%, and Questerre, 20%. Gastem drilled two vertical wells in 2007, and Forest fractured a Utica well in 2007 and 2008. It drilled and fractured two horizontal wells in 2008, and Forest shot a 2-D survey in 2010. Forest plans to spin off its Canadian holdings into Lone Pine Resources, and further activity will depend on that company's decisions.

The company has a 16.575% interest in 92,039 acres in the St. Hyacinthe area with partners Canbriam, 68%, Forest 0.425%, and Suncor, 15%. This is a joint Gastem-Canbriam venture on a Suncor farmout with the Lorraine and Utica shales as targets. Two vertical wells were drilled in 2009 and one vertical and three horizontal wells in 2010. One horizontal well was stimulated that year, and the companies planned to stimulate the other two horizontal wells. That activity may be held up while Quebec finalizes fracturing regulations.

In the St. Jean East area Gastem and 12.5% partner Epsilon hold a half interest in 125,203 acres with Questerre, which has the other half interest. A program to test the Utica awaits government action.

At St. Jean North, Questerre holds an 80% interest and Gastem 20% in 53,953 acres. The St. Jean #1 was drilled to the Utica and stimulated in 2009.

That property is under review with no significant exploration spending planned.

Overall, until the government sets regulations for the Utica play, Gastem said it would concentrate on conventional targets.

GeoResources Inc.

BAKKEN

GeoResources holds 46,000 net acres, 32,200 operated, and continues to build its property position in the Bakken play in North Dakota and Montana. It has two dedicated rigs working on its operated properties and will add another in early 2012. The two rigs are working on the company's 25,000 net acres in Williams County where six wells were drilled and completed by early October 2011. It planned 10 to 11 gross wells in 2011. It partnered with Resolute Energy on an area of mutual interest in March 2010, but GeoResources retained a 47.55% working interest. The first four wells de-risked the acreage. The best well in that group, the Anderson 1-24-13H, tested at a 30-day average of 372 b/d of oil. Slawson Exploration operates on the company's 11,000 net acres in Mountrail County, N.D. It has four to five rigs working the area, and GeoResources holds an 8% average interest. Slawson also is evaluating the Three Forks Formation with two producers. GeoResources holds 10,000 net acres in Roosevelt and Richland counties in eastern Montana, 8,200 acres operated. In early October 2011, it had drilled and completed six gross Bakken wells. It also participated with Slawson on two wells and with Brigham Exploration on one well. It had participated with Slawson in more than 100 wells by October 2011. GeoResources is spending US $50.5 million on the Bakken in 2011.

EAGLE FORD

The company has 25,000 net acres in the Eagle Ford with 19,600 acres in Fayette County, 2,700 acres in Gonzales County, and a combined 1,700 net acres in Atascosa and McMullen counties. Recent drilling has de-risked the acreage and established commerciality, the company said in an August presentation. Two rigs worked the play in 2011, but the company and its area-of-mutual-interest partner will add a third and fourth rig in 2012. Four rigs would allow the companies to spud 21 to 24 gross wells in 2012. Ramshorn Investments, an affiliate of Nabors Industries, bought a half interest in the area by agreeing to fund the first six horizontal wells. GeoResources remains the operator. The companies planned to spud eight or nine (3.8 to 4.3 net to GeoResources) wells in 2011, and GeoResources dedicated $15.8 million to Eagle Ford activities in 2011. It drilled the first three in Fayette County in June and July 2011 and completed its fourth well in September and started a fifth well.

Goodrich Petroleum Corp.

EAGLE FORD

Goodrich Petroleum Corp. has 55,000 gross, 39,000 net, acres with an average 72.5% working interest in La Salle and Frio counties in its search for Eagle Ford pay. The company estimates 1% of its 464 Bcfe of gas in proved reserves lie in the Eagle Ford with 12% of its 7.3 Tcfe in unrisked potential resource. To reach that resource, it dedicated 56%, US $175 million, of its 2011 capex to the South Texas play. With 6,000-ft laterals, 100-acre spacing offers 550 gross, 390 net, drilling locations. In 2Q 2011, the company added four gross, 2.7 net wells in the Eagle Ford with five gross, 3.3 net wells awaiting completion. One of its better wells, the Burns Ranch 15H, tested for 1,155 b/d of oil and 570 Mcf/d of gas. It completed that well with a 9,200-ft lateral with 32 frac stages. Goodrich had two rigs at work in the Eagle Ford and deeper Buda Lime. It planned to drill five gross, 3.5 net, Eagle Ford wells on the southern half of its properties and eight gross, 5.5 net, Buda wells on the northern half.

TUSCALOOSA MARINE SHALE

Although it hasn't started drilling yet, Goodrich holds some 79,000 net acres of land acquired at a cost of $175 an acre in the emerging Tuscaloosa Marine Shale play on the border between the foot of Louisiana and Mississippi. It planned to begin drilling to the 100- to 200-ft section at 11,000 to 13,000 ft in the property in 2012.

Gulfport Energy Corp.

BAKKEN

Gulfport Energy Corp. doesn't list the Bakken Shale as part of its active portfolio, but its 2Q 2011 report said it produced 10,075 boe during the quarter from the Bakken and Niobrara combined.

NIOBRARA

The company holds 19,172 net acres of land on Craig Dome on the uplift between the Piceance and Sand Wash basins in northwestern Colorado. Eleven wells have penetrated the dome. The first well, drilled in 1987 with air and no stimulation, produced a cumulative 252 Mbbl of oil. The company expects to recover 103 and 143 Mbbl of oil, respectively, from the second and third Niobrara wells. Gulfport operates the property. It acquired 60 sq miles of 3-D seismic over the dome in the first half of 2011 and planned to process the results and begin drilling in the second half. Production should come from naturally fractured marlstones, called Buck Peak, Tow Creek, and Wolf Mountain benches, within the interbedded shales and calcerous shales. It contracted a rig planned to drilled three or four vertical wells starting in September 2011. Its capital cost is US $1.4 million per well with EUR of approximately 120 Mboe per well.

UTICA

Gulfport closed on 30,000 net acres in the Utica play in eastern Ohio by August 2011 and had commitments to raise that acreage position to 65,000 net acres. It planned to continue assembling acreage in the wet gas, condensate, and mature oil window of the play. It is trying to assemble land in Belmont, Carroll, Columbiana, Guernsey, Harrison, Jefferson, Monroe, and Tuscarawa counties in contiguous segments large enough to support 5,000-ft laterals. It planned to bring in one rig in 2012 to start drilling on its acreage.

WOLFBERRY

The Wolfberry in West Texas produced an average 829 boe/d from the company's non-operated 14,723 acres in 2Q 2011. Currently, it has 14.45 MMboe in proved reserves on 40-acre spacing, but that spacing only gives it access to 3% of the oil in place. It is testing 20-acre spacing to improve that number. It has four rigs running on the acreage. In August 2011, those rigs were drilling ahead on their 20th through 23rd gross, ninth through 10th net wells. It has identified more than 500 locations on 40-acre spacing, including 226 gross proved undeveloped locations, and has 9.5 MMboe in net probable reserves with 234 gross probable locations. It planned to drill 37 to 42 gross wells during the year with a net capex of $37 million to $39 million.

Utica Shale – Illustrative Development Economics

	UTICA SHALE(1) Low	UTICA SHALE(1) High	BAKKEN(1,2)	EAGLE FORD(1,2)
Well Cost ($MM)	$6.0	$6.0	$7.0	$5.5
Total Vertical Depth	7,500 – 9,500 Feet	7,500 – 9,500 Feet	10,000 Feet	11,000 – 13,000 Feet
Lateral Length	5,000 Feet	5,000 Feet	9,700 Feet	5,000 Feet
Frac Stages	12 Stages	12 Stages	25 Stages	15 Stages
OOIP per Section	36.4 MMBO	36.4 MMBO	9.0 MMBO	9.0 MMBO
Recovery Factor	5.0%	10.0%	4.0%	4.0%
Well Spacing	160 Acres	160 Acres	1,280 Acres	80 Acres
EUR per Well	455 MBO	910 MBO	720 MBO	595 MBO
Formation Thickness	140 Feet	140 Feet	100 Feet	100 Feet
POROSITY	8.0%	8.0%	5-8%	5-8%

(1) Statistics for the respective oil window
(2) Based on third-party operator sources

(Table courtesy of Gulfport Energy Corp.)

The emerging Utica Shale play in Ohio compares favorably with the established Bakken and Eagle Ford liquids-rich shale plays.


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Hess Corp.

BAKKEN

Hess Corp. predecessor companies found oil in North Dakota in 1951, drilled the first well, and named the Bakken Formation. With operations in the Tioga, Williston, Keene, Fryburg, and Newburg areas, it is the largest gas producer and third-largest oil producer in the state at more than 400 Mboe. It acquired American Oil & Gas and TRZ properties in 2010 to give it 252,000 acres and to raise its total to more than 900,000 acres. It produced 25 Mboe/d in 2Q 2011 and raised that rate to 34 Mboe/d in August 2011 with 18 rigs at work on its program. It expects to close out 2011 with average Bakken production of 40 Mboe/d and to raise production to 80 Mboe/d by 2015. It recently raised its completions to 38 frac stages.

Hess signed an agreement in early September 2011 for a 50-50 JV on 80,000 acres of CONSOL Energy prospective Utica Shale land in eastern Ohio.

EAGLE FORD

The company acquired 90,000 net acres of land in the Eagle Ford condensate window and planned 19 wells in 2011. It also holds interests in the Eaglebine (Eagle Ford/Woodbine) play in Texas and in Paris Basin shales in France through its relationships with Toreador and ZaZa Energy.

MARCELLUS

Hess Corp. held 80,000 net acres in the Marcellus play in 2009, most in Wayne County, Pa., and 50,000 of those acres as operator. That year it signed a 50-50 joint venture (JV) agreement with Newfield Exploration that covered 140,000 acres in Susquehanna and Wayne counties with Newfield as the operator. The company controls another 52,900 acres of Marcellus land outside of the partnership, and Hess is sole operator of that property. It planned four to six vertical wells on its operated properties in the first half of 2011. After that, the company said it would drill a number of horizontal assessment wells before drawing up a plan for development.

UTICA

Hess signed an agreement in early September 2011 for a 50-50 JV on 80,000 acres of CONSOL Energy prospective Utica Shale land in eastern Ohio. Under the agreement, Hess paid US $59 million up front and will pay half of CONSOL's working interest drilling and completion obligations up to approximately $534 million as both companies develop the acreage. The sale price equates to $6,000/net acre. Hess will operate the liquids-rich window in Belmont, Harrison, Guernsey, and Jefferson counties, while CONSOL will operate in Portage, Tuscarawas, and Mahoning counties in the oil window and in Noble County. The companies will average two rigs in 2012, 3-1/2 rigs in 2013, and flatten at five rigs in 2015. In September 2011, Hess bought Marquette Exploration LLC and other Utica Shale leases in Ohio to add another 85,000 net acres in that play for $750 million. The new leases are in Jefferson, Harrison, and Belmont counties. The company planned to begin appraising the properties in 4Q 2011. With the CONSOL agreement, Hess holds approximately 185,000 net acres in the play.

Kodiak Oil & Gas Corp.

BAKKEN

Denver-based Kodiak Oil Gas Corp. chose the Bakken/Three Forks play in North Dakota and Montana as its primary area of operations, and it is expanding both the area and the operations. It held nearly 110,000 net acres in the play in August 2011, but additions and planned additions raised that number to 155,000 net acres by mid-November 2011. In August 2011, it held 34,000 net acres in its Dunn County FBIR Field east of the Nesson Anticline. It had potential for 106 Bakken and 80 Three Forks wells in the area. The company took delivery of its fifth operated drilling rig in early October. All five rigs are drilling from pads, three in McKenzie County and two in Dunn County. It planned 29 gross, 16.7 net, wells in 2011. It assembled 10,000 net acres in its Koala Field in McKenzie

County with room for 31 Bakken and 23 Three Forks wells. Its Smokey Field in McKenzie County offers space for 38 Bakken and 25 Three Forks wells on 16,000 net acres. Its Grizzly Field in McKenzie County could support five wells in each formation on its 3,000 acres. Nearby East Grizzly in the same county, with 22,000 acres, had potential for 52 Bakken and 20 Three Forks wells. Kodiak planned four gross, 26 net, wells in the two Grizzly fields in 2011. Its Polar Field in Divide and Williams counties in North Dakota has 4,000 acres and room for nine Bakken and six Three Forks wells. In late October, the company said it paid US $235 million to acquire another 13,500 net acres in Williams County, north of its Koala Project, with operating rights for six gross, 4.6 net, producing wells, and three gross, 1.5 net, wells drilled and awaiting completion. Another well, 0.35 net well, is drilling and four more wells are permitted with locations built. Its only properties in Montana are in Sheridan County where it could drill seven wells into each formation on its 4,500 net acres. The company's long-lateral wells in Dunn County, assuming an EUR of 850 Mbo per well at a cost of $9 million and $95 oil would give the company a net present value, discounted at 10% a year, of $17.6 million, an 80% internal rate of return and payout in 15 months. By early October, the company produced between 7.5 and 8 Mboe/d from the Bakken and Three Forks and planned to build that production to 9 Mboe/d by the end of 2011. That doesn't include production from the planned Williams County acquisition.

Laredo Energy LLC

EAGLE FORD

Laredo Energy captured record production from the Eagle Ford at 40 MMcf/d of gas with the completion of two new wells, the company said in a July 2011 press release, and it planned three more wells be the end of August. The company had 25 horizontal wells on its 120,000 aces in Webb County, Texas, including 16 Eagle Ford wells. It also had production from the Austin Chalk, Olmos, and Escondido formations. Laredo managers have been working the South Texas area since 1982 and sold most of its assets, many prospective for the Eagle Ford Shale, three times. The managers rebuilt the company after each sale. In June 2011, the company said it signed an agreement to merge with Broad Oak Energy. Under the agreement, Broad Oak would operate as a subsidiary of Laredo. That merger would give Laredo an additional 10,000 net acres in the Eagle Ford play and some 65,000 acres in the Permian Basin.

Lario Oil & Gas Co.

BAKKEN

Lario Oil & Gas Co. holds more than 250,000 gross, 49,182 net, acres of leases with Bakken/Three Forks in North Dakota, Montana, and Saskatchewan and produced more than 3,000 b/d of oil, net, at mid-year 2010. At that time, the company had participated in or acquired interests in 155 producing Bakken/Three Forks/Sanish wells with working interests up to 50%. Its operating partners in the play included Brigham Exploration, EOG Resources, GeoResources, Murex, Northern Oil, Sinclair, Slawson, Whiting, and Zenergy. Much of its property was in Mountrail County in the Bakken sweet spot. In September 2011, the company was divesting its Canadian properties.

NIOBRARA

Lario held 46,000 acres of land in the southern part of the Denver-Julesburg Basin in Arapahoe, Adams, Elbert, and Douglas counties, but it sold those properties to ConocoPhillips in late July 2011. By that time, the company has permitted at least four horizontal wells south of the town of Watkins.

Lewis Energy Group LP

EAGLE FORD

Lewis Energy Group LP started working the Eagle Ford as early as 2002, and it has integrated the shale play with its traditional drilling to the Olmos, Escondido, and other zones in the area as it maintained its title as one of the most active and aggressive operating companies in South Texas. It earned its position. The company spent some US $25 million through 2005 unsuccessfully trying to make the Eagle Ford a profitable enterprise. In an interview with Steve Toon of Oilandgasinvestor.com in May 2011, President and CEO Rod Lewis said the company held 430,000 net acres in the area, and 230,000 acres have Eagle Ford potential. Most of the properties are in La Salle, Dimmit, and Webb counties. Between mid-2009 and May 2011, it drilled 69 horizontal wells to the Eagle Ford with 18 of those wells awaiting completion. At the end of the period, it produced 99 MMcf/d of gas that came from horizontal wells with 5,000-ft laterals with 14 to 17 frac stages in the dry gas zone where 60% of its properties lie.

Lewis Energy Group LP started working the Eagle Ford as early as 2002, and it has integrated the shale play with its traditional drilling to the Olmos, Escondido, and other zones in the area.

The company had 10 rigs working the area in the first half of 2011 but planned to add three more rigs in June. Lewis said dry gas wells come in at an average 5 MMcf/d of gas with wells in the rich-gas zone averaging 3 to 4 MMcf/d of gas and 250 b/d to 400 b/d of liquids. EUR is in the 5 to 7 Bcf of gas range. Lewis signed a roughly $200 million agreement in 2010 to take in BP as a 50-50 partner on 80,000 acres of Lewis land with Eagle Ford potential. BP earned its position by carrying Lewis on drilling and completion costs, but the companies drilled wells in the same area and compared results. In January, BP handed all the operation back to Lewis while it concentrated on leasing, geology, and engineering. BP's well costs were significantly higher, Lewis said.

Linn Energy LLC

BAKKEN

Linn Energy LLC moved into the Bakken play with the US $163 million acquisition from Concho Resources in early 2011 for non-operated working interests averaging 10% in some 17,000 net acres of land. The 28% proved developed properties produce 2,300 boe/d with 88% liquids. It holds 16 MMboe in proved reserves and some 800 horizontal drilling locations, according to an August 2011 presentation.

BONE SPRING

Although Linn did not list Bone Spring properties or development, it has properties in the Delaware Basin, specifically Leonardian-age carbonates. Typically, that means the Bone Spring Formation.

CLEVELAND

Linn bought into the Cleveland play in Lipscomb and Ochiltree counties in the Texas Panhandle and in Ellis County in western Oklahoma for $220 million. It bought the properties from Panther Energy Co. LLC and its affiliate, Red Willow Mid-Continent LLC, the oil and gas producing entities for the Southern Ute Nation. It acquired a non-operating position with 140,000 gross, 44,000 net, acres, 10 MMboe in proved reserves, and 2,700 boe/d in production. The reserves are 37% proved developed, containing 45% oil and 55% high-Btu gas. The property holds 170 producing wells and 165 proved undeveloped horizontal well locations.

GRANITE WASH

The company acquired some 70,000 gross, 50,000 net, acres of land in Hutchinson, Wheeler, and Hemphill counties in the Texas Panhandle and another 100,000 gross, 25,000 net, acres in Beckham and Roger Mills counties in western Oklahoma with actual and potential Granite Wash production. On its operated properties in the Greater Stiles Ranch area, Linn averages 19 MMcfe/d of initial gas potentials on its wells. In August 2011, it had 19 producing operated wells and 18 non-operated producing wells. It had another four operated wells in the drilling operation and seven non-operated wells drilling. The company had four operated wells awaiting completion with three operated wells and one non-operated well in some stage of completion. It planned 35 wells in 2011 with four rigs working the play's 200 horizontal locations. The wells produced 51 MMcfe/d in 2Q 2011, up from 36 MMcfe/d in 1Q 2011. Linn also was building a 63-mile gathering system and pipeline


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(Photo courtesy Marathon Oil Corp.)

Drilling continued at a fast pace in the Bakken Shale play in North Dakota, often with rigs in sight of each other. In the background, a completed well needs plenty of storage capacity.

and a water management system that would reduce its fresh water use by 50% to 60% with a water management system that recycles frac water.

UTICA/COLLINGWOOD

Linn has more than 266 Bcfe of gas in more than 1,300 wells in the Michigan Basin and upside potential for more reserves from the Utica/Collingwood Formation on more than 26,000 net acres of land.

WOLFBERRY

The company controls some 102,000 net acres, 88,000 net undeveloped acres, in the Permian Basin with the Wolfberry play as a prime target. It planned 130 wells in the play in 2011 using five drilling rigs, and it had 88 MMboe in proved reserves, 78% liquids. Production from the area was 12,500 boe/d.

Linn had 700 low-risk drilling and infill opportunities on the land and expected EUR between 100 and 160 Mboe per well. That would give the company a return between 50% and 100%.

Magnum Hunter Resources Corp.

BAKKEN

Magnum Hunter Resources Corp. holds 46,521 net acres of land in Burke and Divide counties in North Dakota and another 35,240 net acres in Tableland Field in Saskatchewan with potential for production from Bakken, Three Forks/Sanish, and Madison formations. Its properties contain 114 MMboe in net unrisked resource potential with 7.8 MMboe in proved reserves and 2.7 MMboe in proved producing reserves on June 30, 2011. It had 227 gross wells online in the basin and identified 486 net locations targeting the Bakken and Three Forks formations. In its 3Q 2011 report in October, the company said its Williston Hunter division reached 1,670 boe/d of production. It planned to produce 2,300 boe/d by the end of 2011 with an 87% oil content. It allocated US $70 million of its 2011 capital budget to that division with plans to drill 52 gross, 11.3 net Middle Bakken/Three Forks/Sanish wells, complete wells drilled in 2010, and install production facilities. It had one rig working its Canadian properties and five operating in North Dakota.

EAGLE FORD

The company held 24,872 net acres of land in the Eagle Ford, all in the oil window. Broken down, it had 17,978 acres in Gonzales County, 3,567 acres in Fayette and Lee counties, and 3,327 acres in Atascosa County. It planned to spend $75 million in 2011 to work some 1.3 MMboe in proved producing reserves and 4.5 MMboe in total proved reserves. It produced 900 boe/d in 2Q 2011 from nine producing wells. It still had another 198 gross, 89 net, drilling locations for the Eagle Ford, an unrisked net resource potential of 39 MMboe, and a total potential between 300 and 600 Mboe per well.

MARCELLUS

Magnum Hunter's northern Appalachian Basin properties included prospects for the Huron, Weir, Marcellus, and Utica. They included 54,048 net acres with 265 MMboe in resource potential. It had 290 locations in the Marcellus, and its primary target was liquids-rich Marcellus in northwestern West Virginia. On June 30, 2011, it had drilled and completed five wells, two each in Tyler and Wetzel counties in West Virginia and one in Monroe County, Ohio. It had three wells awaiting completion in Wetzel County and was drilling one well in Tyler County. The company, operating as Triad Hunter in the Appalachian Basin, has more than 2,000 wells that produce from the Huron, Weir, and Marcellus in Ohio, Kentucky, and West Virginia.

UTICA

The company said it had deeper potential for Utica production under some of Triad Hunter's Appalachian properties.

Marathon Oil Corp.

BAKKEN

Marathon Oil Corp. has seven rigs working its 410,000 net acres of land with Bakken potential in North Dakota but planned to raise its count to eight rigs by the middle of 2012. It currently produces 16,000 net boe/d but plans to finish the year at approximately 20,000 net boe/d and raise that to 33,000 boe/d by 2016, according to a September 2011 presentation. In had 28 gross operated wells awaiting stimulation in September and planned to fracture 50 wells by the end of 2011. Its property holds a potential for 2,000 to 2,250 gross wells and a 50% probability of a resource of some 300 MMboe. The company expects EUR of 350 to 580 Mboe per well with 30-day initial potentials from 325 to 700 boe/d. With well and facility costs of US $8.5 million, operating costs of $6 to $8/boe, and net development costs of $20 to $30/boe, it expects a before-tax internal rate of return of 14% to 27% on wells with 9,000-ft laterals and 30-stage fracture treatments.

EAGLE FORD

The company expects big things from its Eagle Ford properties. It spent $3.5 billion acquiring Hilcorp's assets in the play in a deal scheduled to close in November 2011. Marathon already had drilled four wells on its properties in Frio, Atascosa, and Wilson counties, and Hilcorp added property in Gonzales, Lavaca, DeWitt, Karnes, McMullen, Live Oak, and Bee counties and more leases in Atascosa County. With the Hilcorp property, Marathon will have 285,000 net acres in the play with 2,200 to 4,400 potential gross wells and a 50% probability of resource potential of 500 to 900 MMboe. For individual wells, it expects gross EUR of 300 to 1 MMboe and 30-day initial potentials from 325 to 1,650 boe/d. Its wells and facilities cost between $5.5 million and $8.1 million with operating costs of $3 to $4/boe and net developments costs of $15 to $25/boe. Marathon produced 7 Mboe/d in June 2011 with six rigs running and planned to ramp up to 11 rigs and 13 Mboe/d by year end. From that point, it planned to add one rig a month until it reached an optimal number. In an October 2011 presentation at Hart Energy's Developing Unconventional Gas conference, David Roberts Jr., executive vice president and CEO, said the company expected to produce at least 80,000 boe/d from the Hilcorp properties within five years with capex of $1 billion to $1.5 billion a year. It anticipated a before-tax internal rate of return of more than 100% in the condensate window, 43% to 50% in the volatile oil window, and 22% in the black oil window with a possibility of another 75 MMboe on 23,000 acres in the dry gas window.

In an October 2011 presentation at Hart Energy's Developing Unconventional Gas conference, David Roberts Jr., executive vice president and CEO, said the company expected to produce at least 80,000 boe/d from the Hilcorp properties within five years

MARCELLUS

In February, Triana Energy said it would partner with Marathon, working through a wholly owned subsidiary, to develop 82,000 acres in northern West Virginia and Fayette Co., Pa. Triana will drill four wells in 2011, and 132 wells on 43 pads will follow. Marathon said it held about 80,000 acres in Pennsylvania and West Virginia, up from 65,000 acres in 2008.

NIOBRARA

Marathon controls 180,000 acres of leases in the Niobrara play in Goshen and Laramie counties in southeastern Wyoming and Weld and Larimer counties in northeastern Colorado. It reported positive results from the two vertical wells it drilled, and it spud its first horizontal exploratory well in July 2011, all three in Weld County. It planned to add a second drilling rig by September 2011 as it continues to acquire seismic data. It planned to drill eight to 12 gross wells by the end of the year. In 2Q 2011, Marathon turned over a 30% working interest in its 180,000 acres to Marubeni Denver Julesburg LLC, a subsidiary of Japan's Marubeni Corp., for US $270 million, or $5,000 an acre. That money repaid Marathon for its original investment in the play. The property holds a potential for 600 to 800 gross wells with a 50% probability of resource potential between 50 MMboe and 60 MMboe. Wells show 30-day initial potentials of 200 to 300 boe/d and EUR of 250 to 300 Mboe. Wells and facilities cost $4.3 million with an operating cost between $6 and $8/boe and net development costs of $15 to $20/boe.

WOODFORD ANADARKO

The liquids-prone Woodford Shale in the Anadarko Bain, like the Eagle Ford, has gas, condensate, and oil windows extending from south to north. Recent wells include Marathon's Shi Randall, in which it has a 50% working interest. That well showed a 24-hour initial production (IP) of 9.3 MMcf/d of gas and 136 bc/d. Marathon has 126,000 net acres in the play with an average 55% working interest. The property has room for 1,800 to 2,000 potential gross wells with a 50% probability of resource of 300 MMboe. On its wells, Marathon anticipates EUR of 350 to 1 MMboe and 30-day IPs from 400 to 900 boe/d. It expects well and facility costs of $8 million a well, operating costs of $2 to $3/boe, and a net development cost of $10 to $15/boe. It ran five rigs in September 2011 and planned to add three more by the end of the year. It will ramp up to 50 to 60 net wells a year by 2013. The company planned to exit 2011 with 5,000 boe/d of production and reach a peak rate of 30,000 boe/d by 2015.

Murphy Oil Corp.

BAKKEN/EXSHAW

Murphy Oil Corp. moved into the emerging Bakken/Ekshaw light oil play in southern Alberta in 2010 and now holds 220,000 net acres in the play. By August 2011, the company had drilled four wells and spud a fifth. Among the four wells, two were producing, one was awaiting completion, and one was under evaluation. Murphy planned to keep one rig busy drilling six to nine wells in 2011.

EAGLE FORD

Murphy drilled 35 horizontal wells into the Eagle Ford Formation by August 2011. Of those, 25 were producing and the other 10 awaited completion. It planned 20 exploratory and 26 development wells during 2011 on its 220,000 net acres of land. That land is in Catarina Field in Dimmitt County; Tilden Field in Atascosa, McMullen, and La Salle counties; Nueces Field in La Salle, McMullen, and Webb counties; and Karnes Field in Karnes, DeWitt, and Wilson counties. The company produced 6 Mb/d of oil and 6 MMcf/d of gas in August with five rigs working and planned to add two more rigs by year end. Three of the working rigs were in Karnes Field and one each in Tilden and Catarina fields.

A Newfield rig in South Texas works the Eagle Ford Shale on approximately 335,000 acres controlled by the company.

(Photo courtesy of Newfield Exploration Co.)

MONTNEY

The company's 155,000 net acres in the Montney play, nearly all in British Columbia, played host to four to six rigs during 2011. It had properties in Tupper Main, with part of the field in Alberta, Tupper West, Groundbirch, Sundown, and Brassey fields. It had 81 wells producing more than 100 MMcf/d of gas at Tupper Main with all-in costs of $3.75/Mcf. It anticipated 305 Bcf of recovery from the wells, or 35 Bcf per well. Tupper West is in Phase I. It already has 40 wells producing more than 110 MMcf/d and expects a probable recovery of 900 Bcf of gas, or 3.3 Bcf per well. Murphy plans 275 wells in the first phase and another 244 wells in the second phase.

National Fuel Gas Co./ Seneca Resources Corp.

MARCELLUS

National Fuel Gas Co., working through its Seneca Resources Corp. oil and gas E&P arm, holds some 745,000 net acres of land and 8 Tcfe to 15 Tcfe of gas in risked potential resource in the Marcellus play in Pennsylvania and New York. It started producing the property in the Marcellus in 2008 and now has major programs in place. It will spend US $560 million to $600 million of its $600 million to $655 million capex in 2011 on the Marcellus and raise spending in the formation to $740 million to $820 million in 2012. It anticipated 62 Bcfe to 72 Bcfe of gas production from the Marcellus in 2011 and up to 101 Bcfe in 2012. Its 2012 Marcellus production could surpass total company production in 2011. Its eastern area in Tioga, Lycoming, and Potter counties in Pennsylvania included 55,000 acres with gross production of 120 MMcf/d from 39 producing wells in August 2011. It is drilling in two additional areas in the eastern area. It has a joint venture (JV) with EOG Resources on some 200,000 gross acres of land, mostly in Elk County in its western area. Both companies work the area. For example, EOG operates the Punxy area with 45 drilled wells and 25 producing wells that put out 36 MMcf/d. The JV planned 25 to 35 wells in 2011 and 35 to 45 wells in 2012.

MONTEREY

Seneca Resource produces some 1,800 boe/d from 216 active wells in the Monterey Shale in its South Lost Hills Field in the San Joaquin Basin of California.

UTICA

Seneca has acreage with Utica potential in Pennsylvania and Ohio, some under its existing Marcellus acreage. It spud one Utica well at Mt. Jewett in its western area in April 2011 and planned another in the nearby Henderson area in August. The company planned a third Utica test in its Tionesta area in 2012.

Newfield Exploration Co.

BAKKEN

Newfield Exploration Co., with some 150,000 net acres in the Williston Basin, operates properties in Big Valley, Catwalk, Westberg, Aquarium/Watford, and Lost Bear fields in North Dakota and in Richland, Sheridan, and Roosevelt counties in Montana. After drilling nine new wells, it increased its net production from the Bakken/Three Forks plays to 8,000 boe/d. It completed eight of the nine wells with lateral lengths of more than 9,500 ft and completed the nine wells for an average 2,100 boe/d at an average cost of US $9.8 million each. The Wiseness Federal 152-96-4-2H, with a gross 24-hour initial production rate of 5,200 boe/d in Westberg Field and drilled in 1Q 2011, is the company's best well to date. Newfield expected to complete 13 wells in 3Q 2011 and reach a total of 40 wells for 2011. It had drilled 40 total wells in the play by the end of June 2011. It has five rigs working the play. It anticipates an 80% internal rate of return at a gas price of $4/MMBtu and an oil price of $80/bbl.

The company has an additional 350,000 net acres of land in Glacier County, Mont., in the southern Alberta Basin that is prospective for the Lodgepole, Bakken, Sanish/Three Forks, and Nisku formations.

(Photo courtesy of Newfield Exploration Co.)

A drilling rig on a neatly designed location drills a horizontal well to the Bakken Formation in North Dakota.

That included some 156,000 net acres leased in 2009 from the Blackfeet Nation. It has drilled seven vertical and two horizontal wells in that play since 2010 and still is evaluating the potential.

EAGLE FORD

Newfield holds 335,000 net acres of land in the Maverick Basin in Dimmit, Maverick, and Zavala counties and planned to meet its drilling obligations and hold onto its leases by running one or two rigs in the play through 2011. By September 2011, it had completed 13 Eagle Ford wells, four wells to the Georgetown, and two more to the Pearsall gas shale. Gross production from the basin reached 6,500 boe/d. In the second half of 2011, activity targeted the southern portion of its property, about 50,000 acres, where it is drilling from pads to try to assess optimal spacing. It plans 40 wells in that area. Newfield has drilled wells in as few as seven days at an average cost of some $6.6 million with gross initial potentials from 400 to 1,400 boe/d in that area. It planned to spend $265 million in the basin in 2011.

GRANITE WASH

The company reached a record gross 190 MMcfe/d, 135 MMcfe/d net, of gas production from the Granite Wash in 2Q 2011, up from a net 110 MMcfe/d at the end of 1Q 2011. It planned to finish 2011 with a net 160 MMcfe/d. It maintained its four-rig program, in place since early 2009, with a focus on

Wheeler County in Texas. Overall, it completed 51 wells in the play since 2008 with gross initial potential production averaging some 16 MMcfe/d, including the 2001 program that has focused on the Marmaton DE and FG intervals of the Granite Wash. Those wells have averaged an initial 17 MMcf/d. The company planned 25 to 30 wells for 2011 to increase production by 25% over the previous year. It expects 40% internal rates of return from its wells. Newfield also is assessing 15,000 acres of property with Granite Wash potential in Oklahoma.

Success in the Niobrara Formation in Wattenberg Field prompted Noble Energy to add a fifth horizontal drilling rig in 3Q 2011 and raise its original estimate of 70 wells for the year to a new level of 85 in the Denver-Julesburg Basin.

Noble Energy Inc.

CLEVELAND

Noble Energy Inc. drilled or participated in 33 development wells in the Cleveland Formation in western Oklahoma in 2010. It holds properties in the Texas Panhandle as well. It did not update activity in the Cleveland in 2011.

MARCELLUS

The company signed an agreement in mid-August 2011 to create a 50-50 joint venture with CONSOL Energy Inc., with the acquisition of 314,000 net undeveloped acres of land with Marcellus Shale potential and 50 MMcf/d of gas production in southwestern Pennsylvania and northwestern West Virginia. The company will pay US $1.07 billion in three annual installments plus $2.13 billion in funding to carry one-third of CONSOL's drilling and completion costs in the development program with an annual cap of $400 million.

The purchase price equates to a discounted present value of $7,100 per net acre for the land. The deal also gives Noble a half interest in 70 MMcfe/d of existing Marcellus production and infrastructure for $219 million. The acres contain an estimated 7.4 Tcfe of risked resource, net to Noble, including 400 Bcfe of proven reserves at the end of 2010. The companies could drill 4,400 wells on the property with a potential net production for Noble of 600 MMcfe/d in 2015 with continued growth thereafter. The companies plan an increase from the four-rig count in 2011 to 16 rigs in 2015 with both companies sharing operations.

By mid-November, net production had grown the 70 MMcfge/d or double the August production rate. Noble expected a net production rate of 80 MMcfge/d by the end of the year.

NIOBRARA

Success in the Niobrara Formation in Wattenberg Field prompted Noble Energy to add a fifth horizontal drilling rig in 3Q 2011 and raise its original estimate of 70 wells for the year to a new level of 85 in the Denver-Julesburg Basin. The company also added all of Petro-Canada Resources' Rocky Mountain assets in the US, including properties in the central Denver-Julesburg Basin, to bring its total for the basin to more than 840,000 net acres, including 400,000 acres in giant Wattenberg Field, Noble's largest onshore property. The company had acquired 870 sq miles of 3-D seismic in the basin and planned to acquire another 420 sq miles in 2011. By mid-year 2011, it employed eight vertical and five horizontal rigs in the play and had drilled 485 vertical and 85 horizontal wells to produce a net 59 Mboe/d, more than half liquids. It produced 65 Mboe/d during 3Q 2011. At that time, it had completed 32 horizontal wells in the Denver-Julesburg Basin that yielded average 30-day initial potentials of more than 600 boe/d each. The company said its average vertical well offered a 40 Mboe EUR, its average horizontal well a 310 Mboe EUR, and the Gemini well, the best ever drilled in Wattenberg Field, an EUR of more than 700 Mboe.

By mid-November 2011, production from all formations in the basin had grown to 67 MMcfge/d, more than half of that content from liquids, and the company expected to double that production by 2016. Noble produced 14 MMcfge/d from the Niobrara with its 58 horizontal wells, up 20% from the end of the third quarter. It expected to increase its net production from horizontal wells to 70 Mboe/d by 2016.

NuVista Energy Ltd.

CARDIUM

NuVista Energy Ltd. sold its Cardium properties producing 250 boe/d in the Pembina area of the Alberta Deep Basin for US $37.2 million, or a pre-tax gain of $27 million, in April 2011. It retained Cardium potential in the Wapiti area with 145 gross contiguous sections in which it held a 65% working interest and potential for more than 500 horizontal wells. It participated in five operated and five non-operated wells to date and was evaluating well performance and drilling and completions technology.

MONTNEY

NuVista moved into the Montney play in the Wapiti area of the Alberta Deep Basin early in the play and assembled 144 net sections. It allotted US $70 million to its Wapiti Montney program for the 12 months beginning in July 2011 with spending devoted to validating leases and licenses and understanding the scope, costs, and recoverable reserve potential of the play. It spud its first horizontal well in the play in the company's north block in early July and planned to drill two wells in that block and one well in the south block during the 12-month period. It also planned to start construction on a compressor and dehydration plant on the north block. The company had some 400 potential horizontal well locations at Wapiti and booked 11 proved and probable well locations with 800 Mboe per well. Those wells would produce 28% liquids.

Oasis Petroleum LLC

BAKKEN/THREE FORKS

Former Burlington Resources senior managers created Oasis Petroleum LLC in 2007, targeted the Bakken and Three Forks, and embarked on a growth spree. From a land position of 175,000 net acres in 2007, it grew to 292,000 acres by the end of 2009 and to 303,000 net acres by mid-year 2011. That acreage is divided among its West Williston area in Richland and Roosevelt counties in Montana and Williams and McKenzie counties in North Dakota, its East Nesson area in Burke and northern Mountrail counties in North Dakota, and Sanish Field in central Mountrail County. Production started at 1,000 boe/d in 2007 in its original West Williston properties. By the end of 2009, it produced 1,109 boe/d from West Williston, 1,016 boe/d from East Nesson, and 792 boe/d from Sanish. By the end of 2Q 2011, production rose to 4,386 boe/d from West Williston, 1,975 boe/d from East Nesson, and 1,433 boe/d from Sanish.

In August 2011, company directors raised the company's capex budget to US $627 million from $490 million, including a drilling and completion budget increase to $527 million from $441 million. Some $22 million of that increase will go to increase frac stages to 36 from the previous level of 28 and $26 million to add an eighth and ninth drilling rig in 4Q 2011. It planned 53 gross wells with 36 stages during the year because each additional stage cost the company $120,000 and returned 12 to 25 Mboe at a finding cost of $5 to $10/bbl. The budget increase will allow Oasis to drill 60 gross, 45.9 net, wells in West Williston; 13 gross, 5.6 net, wells in East Nesson; and 3.9 net wells at Sanish. That's a sharp increase from 18.3 net wells in West Williston, 7.4 net wells at East Nesson, and 9.6 net wells at Sanish in 2010. Throughout its properties, Oasis identified 1,170 potential Bakken drill sites and 1,288 potential Three Forks sites. It planned to drill six to seven Three Forks wells in 2011, according to an August 2011 presentation.

Occidental Petroleum Corp.

BAKKEN

Occidental Petroleum Corp., after quietly gathering 20,000 net acres of properties in the Williston Basin since 2008, became a major operator in the basin with its US $1.4 billion purchase of another 180,000 net acres of land with Bakken and Three Forks potential in North Dakota in December 2010. The company did not disclose the name of the seller. At the time of the purchase, the properties produced 5.5 Mboe/d. Oxy said the property has a net risked resource potential of 250 MMboe, and it expected to raise production to at least 30 Mboe/d by 2017.

BONE SPRING

The company produces from the Bone Spring in Winkler County in Texas and from Corral Draw,

Oxy produced 201,000 boe/d, or 19% of its US output, from the Permian Basin in 2009, and it produced 20% of all the oil that came out of the basin.

Cotton Draw East, Lusk North, Mesa Verde, Pierce Crossing, Pierce Crossing East, Red Bluff, Red Tank, Red Tank East, and Shugart North fields in southeastern New Mexico.

MONTEREY

Occidental doesn't identify the Monterey Shale by name in its public announcements, but it did say in late 2010 that one-fourth of its California production came from shales, and the Monterey Shale lies beneath a substantial portion of its properties, including supergiant Elk Hills Field. The company produced an average 139,000 boe/d during 2010. It holds 1.6 million acres of land in the state, including 1.4 million net acres in more than 50 fields in the Ventura, San Joaquin, and Sacramento basins, including interests held by its Vintage Production California LLC affiliate. At least 870,000 acres have potential for shale production. Oxy said Elk Hills Field included a number of shale zones that compare favorably with the Bakken and Eagle Ford shales in organic content, gross thickness, depth, porosity, and permeability. Vintage drilled the 133 Ojai directional well into the Monterey Shale in Ojai Field in Ventura County in late 2010, according to IHS Inc. records. The parent company also said it was conducting a four-year development program to appraise the production potential of more than 20 Bbbl of oil in place in its shale acreage, including drilling and testing 10 to 15 wells a year and participating in the state's largest 3-D seismic survey with Venoco Inc. to identify shale sweet spots. In 4Q 2010, the company said it had 520 geologically viable shale drilling locations. It planned to drill 107 shale wells outside Elk Hills in 2011. Among the 28 exploratory wells planned in California in 2011, about half will go to unconventional zones.

WOLFBERRY

Oxy produced 201,000 boe/d, or 19% of its US output, from the Permian Basin in 2009, and it produced 20% of all the oil that came out of the basin. It is the largest oil producer on the Texas side of the basin and the second-largest oil producer in southeastern New Mexico. It also controls a large position in the Wolfberry play in the Midland Basin. Among its properties are more than 550 Wolfberry locations with potential production of more than 70 MMboe. Its largest Wolfberry project is the 250-well Dora Roberts Field in Midland County.

WOLFCAMP

Among its Permian Basin properties, Oxy produces from the Wolfcamp Formation from fields in Terrell, Glasscock, Pecos, Loving, Reeves, Ector, Andrews, Winkler, and Ward counties in Texas.

Painted Pony Petroleum Ltd.

BAKKEN

Painted Pony Petroleum Ltd. held 81,896 net acres, 128 net sections, of land prospective for Bakken production in southeastern Saskatchewan on June 30, 2011. According to an August 2011 presentation, that land is in Midale and Huntoon fields south of the massive Viewfield Field at Flat Lake and Weyburn. It planned 28 gross, 20.3 net, wells in the second half of 2011 with production projected at 1,422 boe/d. It drilled the Bakken discovery well in late 2010, and the well continued to produce at a rate of 175 b/d, 88 b/d net, after two months onstream. The company's proved and probable Bakken reserves reached 6.1 MMboe in Saskatchewan with a netback of about US $66/boe. It calculated potential reserves at 88 Mbbl/well of oil with initial potentials of 135 boe/d. With a drilling and completion cost of $1.6 million, the company anticipated a 117% rate of return on Crown land and 78% on freehold land at a January 2011 West Texas Intermediate price of $93.45, according to Sproule Associates.

MONTNEY

The Montney and Buckinghorse shales in northeastern British Columbia make attractive natural gas targets for Painted Pony with projects in the Blair/Town and Cameron/Kobes areas. The company holds 136,175 net acres in the area, including 4,200 net acres it picked up at the August British Columbia Crown land auction. It completed five gross, 2.3 net, wells and put them on production in 2Q 2011; three gross, 1.5 net, drilled from a single pad with one well each aimed at the Upper, Middle, and Lower Montney. All three wells were put on production. The Middle Montney well was the first horizontal completion in that zone. The company planned to drill nine gross, 5.6 net, wells in the second half of the year. It produced 2,171 boe/d, 97% gas, in 2Q 2011 and calculated proved and probable reserves of 477 Bcfe of gas (79 MMboe). It planned its first Buckinghorse stimulation by the end of the year. That formation overlies the Montney. A 2011 assessment put the company's contingent Montney resources at a net 2.1 Tcf. At a well cost of $6.1 million and an initial potential production rate of 6.3 MMcf/d per well, Painted Pony will get a 67% rate of return at a January 2011 New York Mercantile Exchange gas price of $4.65/MMBtu.

Paramount Resources Ltd.

BAKKEN

Paramount Resources Ltd. entered the Bakken play with its Summit Exploration subsidiary in 2002 and had 75,000 net acres near Medora in Billings County, N.D., with two rigs working at one time. It dropped back to one rig in 2009 and ceased activity during 2010 with production at 1,200 b/d of oil. In April 2010, the company signed a joint venture (JV) agreement with an unnamed US company that allowed that company to drill and carry Summit's costs for a half interest in 39,000 acres. The partner's three initial wells produced at only nominal rates, and the company started a fourth horizontal well in May 2011. Paramount also sold 6,000 net acres with Bakken/Three Forks potential in early 2011 that weren't under the JV agreement.

CARDIUM

The company picked up some properties with Cardium potential on the 132,300 gross, 104,000 net, acres of land it collected in its acquisition of ProspEx Resources Ltd. According to Paramount, that acquisition added more than 33 gross, 17 net, Falher, Cardium, and Montney locations.

MONTNEY

Paramount Resources holds patches of land with Montney potential in several areas of the Deep Basin segment of the Western Canada Sedimentary Basin. Part of that land came to the company through its May 2011 acquisition of ProspEx Resources Ltd. Among those 132,300 gross, 104,000 net, acres of properties were holdings with Montney potential in 22,500 net acres of land in the Birch area of northeastern British Columbia. In 3Q 2011, Paramount planned to complete a horizontal well drilled by ProspEx. On its existing properties, Paramount drilled two gross, 1.5 net, wells at Ante Creek to the Montney. The first well produced approximately 200 b/d gross, 100 b/d net, of oil, the maximum permitted rate, but it tested for 1,000 b/d plus solution gas. It planned to complete and tie a second well to production in 3Q 2011 and complete its third well later in the year. It has identified 42 additional well locations at Ante Creek. In its Kaybob area, Paramount recompleted one Montney well and drilled another with promising results. The company holds 100,000 acres of Montney rights in the Musreau/Resthaven area of the Deep Basin and planned five horizontal wells during 2011. It drilled the second of those wells in June. It said an offset well tested for 10 MMcf/d of gas from the Montney and estimated its land held more than 70 Bcf per section of original gas in place. At Kerr-Gold Creek, which produces Montney sour and Nikanassin sweet gas, the company holds about 95,000 net acres. Recent Montney wells tested from 9.6 MMcf/d to 13.4 MMcf/d, and the company has started drilling from pads with laterals up to 5,900 ft with 10- to 22-stage fracture treatments. Its Valhalla area produces from Doig and Montney, and the company has completed five wells to date and is expanding processing capacity.

VIKING

A JV operating partner on Paramount's southern Saskatchewan properties brought the initial three Viking light oil wells on production. Paramount will keep a post-payout interest of 45% in the wells. The company drilled 4 gross, 1.8 net additional wells in 2Q 2011 and were scheduled for completion later in 2011.

Petroleum Development Corp./ PDC Energy

MARCELLUS

Petroleum Development Corp., doing business as PDC Energy, formed a joint venture (JV) with Lime Rock Partners LLC. The PDC Mountaineer LLC JV drilled five horizontal Marcellus wells in 2010. The combination completed three of those wells and put them online in early 2011 and planned nine new horizontal wells for the year at a net development capex of US $46 million. By August 2011, the venture had drilled 10 vertical and 6 horizontal Marcellus wells with average 3,026-ft laterals and an average initial potential of 3.78 MMcfe/d of gas each with 3 to 6 Bcfe per well. By that time, the company planned to increase lateral lengths from 6,000 to 4,000 ft to look for higher production from its wells. In late September, the partnership agreed to acquire an estimated 90,000 net acres of prospective Marcellus land in Harrison, Taylor, Barbour, Upshur, Lewis, and Randolph counties in north-central West Virginia and another 10,000 net acres in Mingo and McDowell counties in southwestern West Virginia prospective for the Huron Shale for $152.5 million from Seneca-Upshur LLC. The property produces 5.4 MMcf/d from formations shallower than the Marcellus, and PDC Mountaineer will operate the new acreage. The acquisition will give the partnership net production of 24 MMcfe/d from the Marcellus and Upper Devonian from some 140,000 net acres of land with an estimated 2.2 Tcfe of net risked resource from approximately 610 gross horizontal Marcellus locations. PDC Mountaineer plans to continue operating one rig to drill 20 to 25 Marcellus wells a year starting in 2012. It will divest its 9,000 acres of Pennsylvania Marcellus land to fund the West Virginia program.

NIOBRARA

The company drilled its first horizontal Niobrara well in 4Q 2010 and completed it in early 2011 with a 16-stage frac treatment for 625 boe/d, but it had been working the Niobrara in the Denver-Julesburg Basin for about 10 years. The results from that first horizontal well were good enough that it scheduled 15 more for 2011. The company has a big advantage over many newcomer competitors. It had 1,572 gross operated wells in the basin with 67,900 acres of land of its 74,100 total net acres in the rich Wattenberg Field core. Those wells gave it a lot of well control data within the field. Overall, the company holds some 350 horizontal Niobrara locations and planned to spend $169 million in 2011 on 104 vertical and 16 horizontal wells.

WOLFBERRY

PDC Energy completed two key purchases in the Wolfberry Trend in the Midland Basin section of the Permian Basin in 2010 to add to its existing position. In October 2011, the company said it planned to sell its Wolfberry properties, along with other acreage, according to Wells Fargo LLC. The Wolfberry is the primary target on the acreage, but it has secondary potential from the Strawn, Bend, Devonian, and Fusselman formations. It has 74 gross operated wells on its 12,800 gross, 6,400 net acres of leases with 187 gross undeveloped locations. The company's 2011 plans called for capex of $64 million for 26 vertical wells and six recompletions. By August, it was drilling its 12th Wolfberry well and had put nine wells online. Its seven most recent wells at that time averaged a peak production rate of 167 boe/d each. In October, the company produced 1,400 boe/d from 23 MMboe in reserves on its Permian properties

UTICA

The Utica is a new play for PDC Energy. In early September 2011, it announced that it signed deals with multiple parties to gather acreage in the wet gas and oil windows of the Utica Shale play in southeastern Ohio. Those 40,000 held-by-production net acres are primarily in Noble, Monroe, Washington, Morgan, and Guernsey counties. The company will operate the properties and staked its first Utica well, which it planned to drill in 4Q 2011. It committed to drill two horizontal Utica wells in 2012 with an option to drill two more vertical wells that year. It will invest some $50 million to acquire the acreage and fulfill drill-to-earn obligations. It is pursuing opportunities to raise its net leasehold position in the play from 80,000 to 100,000 acres.

Penn Virginia Corp.

CLEVELAND/TONKAWA

At the end of the first half of 2011, Penn Virginia Corp. had 9,700 net acres of land in Washita County, Okla. At that time, it was drilling horizontal wells to the Granite Wash, but it held another 40,000 net acres with prospects for the Cleveland, Tonkawa, and Granite Wash. It started accumulating acreage in the area in 2006.

The company held some 13,900 net acres of land in the volatile oil window of the Eagle Ford Shale in Gonzales County, Texas, and operated the property.

EAGLE FORD

The company held some 13,900 net acres of land in the volatile oil window of the Eagle Ford Shale in Gonzales County, Texas, and operated the property. Its 12 existing wells produced a net 5,000 boe/d, including natural gas liquids (NGLs), according to a September 2011 presentation. It planned to finish the year producing 7,000 boe/d from the formation. Its first 12 wells tested for initial potentials between 582 and 1,921 boe/d, and it had 130 remaining locations. During 2011, it used three rigs with plans to drill up to 34 gross, 27.9 net, wells using US $226 million in capital spending. It entered the play in August 2010. The company continues to acquire acreage in the play, and that acreage also has potential production from the Austin Chalk. Penn Virginia expected a 10% rate of return on its wells at a West Texas Intermediate price between $45 and $59/bbl of oil. It planned to spend between $360 million and $380 million companywide, and 60% of that will go into the Eagle Ford.

GRANITE WASH

Penn Virginia has a joint venture (JV) with Chesapeake Energy on 9,700 net acres of land in Washita

County, Okla., with Penn Virginia operating about one-third of the wells. Chesapeake is doing all of the drilling in 2011, but Penn Virginia will resume testing in 2012 or 2013. The companies planed 20 gross, 8.7 net to Penn Virginia wells in 2011 with that company spending up to $88 million. The JV has about 80 well locations. Penn Virginia has another 40,000 net exploratory acres outside the JV, and that land also is prospective for Granite Wash development.

MARCELLUS

Although Penn Virginia holds more than 1 million acres of properties in Appalachia, it counts only 55,000 net acres in Pennsylvania in the Marcellus play, 35,000 acres in Potter and Tioga counties in northern Pennsylvania, and 20,000 net acres in southwestern Pennsylvania. It is the operator with an 87% average working interest. It has more than 200 gross locations in the play. Northern Pennsylvania is primarily in the dry gas window, and the company is trying to establish EUR of 4 Bcfe of gas per well. It drilled and tested three wells in Potter County in 2011, and those lines were scheduled to come online in September. It will focus on its northeastern acreage in 2012. It expected a 10% rate of return on production at a gas price of $3.84/MMBtu at Henry Hub.

PetroBakken Energy Ltd.

BAKKEN

PetroBakken Energy Ltd., a 59% subsidiary of PetroBank Ltd., has a reputation as a pioneer in the Bakken play in Canada. According to an August presentation, it drilled the first successful horizontal openhole well with a multistage frac completion in the Bakken; the first horizontal, 20-stage, openhole, multistage frac completion in Canada; and the first bilateral horizontal, open-hole, multistage frac completion. The technology makes economic sense. Two single laterals covering the same area as one bilateral well payout in 1.3 years. The bilateral pays out in less than 10 months. It said it was generating approximately US $125 million of free cash from its Bakken play in Canada in 2011. The company is working under a 10-year plan on its properties in southeastern Saskatchewan, drilling 90 wells a year for four years and 45 wells a year thereafter. It has more than 800 net Bakken drilling locations and planned 80 wells for 2011. Sixty of those wells will be horizontal bilateral wells. It holds more than 510 gross, 430 net, sections of land prospective for the Bakken. It also is investigating enhanced recovery from the Bakken with carbon dioxide injection that has showed improved recoveries in offset wells. It planned five pilot projects for 2011. It put its first well on injection in March 2011 and planned for more injectors in 3Q and 4Q 2011. It expected preliminary results from the first well in 4Q 2011.

CARDIUM

PetroBakken is the most active driller of horizontal Cardium wells and plans to make the Cardium the company's next major resource play after the Bakken. It holds 340 gross, 260 net, sections with 60% of its acres in West Pembina, 25% in East Pembina, and 15% in the Garrington and Lochend areas southwest of Edmonton in Alberta. It produced more than 12,000 boe/d from the formation in early August 2011 and planned to finish the year with production between 13,000 and 16,000 boe/d. The company planned 90 wells for 2011 and finished 42 of them in the first half of the year. Overall, it has 650 net locations in the play. Its Cardium wells pay out in 1.7 years with a West Texas Intermediate price of $75/bbl of oil and in 1.3 years with a $90 oil price. Production is 79% liquids.

MONTNEY

PetroBakken controls 120,000 net acres in four oil plays, the Nordegg, Montney, Duvernay, and Swan Hills, in northeastern British Columbia and planned four test wells in the second half of 2011. It also has property in the Horn River Basin but is waiting for higher gas prices to justify development there. The company's oil production comes from Monias Field where it holds 17 sections of land. It drilled two horizontal wells there in 1Q 2011 with one well coming onstream at 275 boe/d with 200 bbl of liquids per million cubic feet of natural gas. It expected the second well to come onstream in 3Q 2011. While success will determine the pace of future activity, PetroBakken activity now is focused on preserving its land position for future development.

Petro-Hunt LLC

BAKKEN

Petro-Hunt focused its technology on the Williston Basin as early as 1998 when it drilled its Otto Boss 18-1 in Williams County, N.D. That well was the first dual-whipstock re-entry out of 5 1/2-in. casing in North Dakota and, at 7,172 ft, was the longest lateral drilled out of a re-entry well. It also was the first four-lateral well in the state. It has drilled Bakken and Three Forks Sanish wells since 2006 when it tested its USA 2D-3-1H in Charlson Field for 729 b/d of oil and 785 Mcf/d of gas. In 2010, the company was acting as operator on a Bakken well in which Credo Petroleum held a 10% interest. That well tested for 1,267 b/d of oil and 1.24 MMcf/d of gas on the Fort Berthold Reservation. Recent activity includes the 14B-23-2H Lowenstein 28-58 discovery well that initially flowed 478 bbl of oil, 256 Mcf of gas, and 1,190 bbl of load water a day from the Middle Bakken with a 9,000-ft lateral and a 28-stage frac job. The company drilled the well from a pad on the southeastern flank of Bainville North Field, according to IHS Inc.

EAGLE FORD

Petro-Hunt permitted two Eagle Ford Shale wells in eastern Karnes County in South Texas in late 2010. The two wells were about 12 miles apart in the eastern part of the county, according to IHS Inc. In September that year, it commissioned Energy Spectrum Advisors Inc. to sell all of its interests in 11,607 gross acres in Karnes County, including rights to the Eagle Ford Formation. That property is in the oil and wet gas window. IHS Inc. does not show any activity by the company in the Eagle Ford over the past 12 months.

PetroQuest Energy Inc.

EAGLE FORD

PetroQuest Energy Inc. holds 4,300 gross, 2,300 net acres in the Eagle Ford play, 1,700 net acres in La Salle County and another 600 net acres in Dimmit County. In an August presentation, it claimed no proved reserves in the play, but it had an unrisked net potential of 16 Bcfe of gas. It planned three gross operated and one gross non-operated well in 2011. Its first well, in Dimmit County, yielded an initial production rate of 253 b/d of oil while its second and third wells in La Salle County were awaiting completion. The company allocated 13% of its 2011 capital spending to the Eagle Ford.

MISSISSIPPI LIME

The company acquired 28,250 acres of land in the emerging Mississippi Lime play in Pawnee County, Okla., in September 2011 for US $24.1 million. Those purchased acres, combined with PetroQuest's existing leasing program in the area, brought its acreage position to about 40,000 net acres. The properties included 50 boe/d of production and five saltwater disposal wells. After the closing, PetroQuest sold a half interest in the Pawnee property for approximately $24.5 million, leaving the company with approximately 24,000 net acres in Pawnee, Grant, and Kay counties in Oklahoma and Sumner County in Kansas. It continued to look for acreage in the area and planned to begin drilling in 4Q 2011.

The company acquired 28,250 acres of land in the emerging Mississippi Lime play in Pawnee County, Okla., in September 2011 for US $24.1 million.

NIOBRARA

PetroQuest holds interests in land in and south of the Silo Field area in Laramie County, Wyo. In an August presentation, it claimed 1 Bcfe of gas in proved reserves and 13 Bcfe in unrisked net potential resources in the play. It held a 25% non-operated working interest in some 20,000 gross, 5,000 net acres in the area. Activity includes an interest in the Simray Production Nevis #2, with an initial potential of 831 b/d of oil, and the SM Energy Polaris, with an initial production rate of 837 b/d, both in Silo Field. It also had an interest in a well near the Colorado border that tested for an initial 1,605 b/d.

Pioneer Natural Resources Co.

BARNETT COMBO

Pioneer Natural Resources set its sights on the Barnett play in 2007 and assembled 80,000 gross, 48,000 net, acres of land in Wise County, the original gas segment of the play and in Montague County where liquids-prone production is on production. It had some 120 Bcfe of gas in proved resources at the end of 2010 and more than 600 Bcfe of additional potential resource with more than 900 drilling sites. It put one rig to work drilling wells with average 3,400-ft laterals. It estimated ultimate recoveries at 320 Mboe per well with 16% condensate and 42% natural gas liquids (NGLs) in addition to gas production. The venture operates in McMullen, Atascosa, Live Oak, Bee, Karnes, and DeWitt counties. Only 20% of its properties are in the dry gas area of the play. Another 45% are in the lean condensate area with about 30% liquids and 20% condensate, and 35% are in the rich condensate area of 50% condensate and 20% NGLs. It produced 2 Mboe/d in 2010 and increased production to 5 Mboe/d in 1Q 2011 with 10 rigs online. It planned to produce 18 to 23 Mboe/d in the second half of 2011, 26 to 30 Mboe/d in 2012, and 40 to 45 Mboe/d in 2013. It planned to raise its rig count to 10 rigs in 2011, 16 rigs in 2012, and 14 rigs in 2013.

WOLFBERRY

The company, with 900,000 acres, holds more acreage in the Spraberry Trend than any other operator, and much of that land is prospective for the Wolberry (Wolfcamp, Dean, and Spraberry) as well. Pioneer's main activity is aimed at its Spraberry resources, but it drilled one horizontal well each to the Wolfberry in 3Q and 4Q 2011.

Plains Exploration & Production Co.

EAGLE FORD

Plains accelerated its activity in the Eagle Ford Shale with help from a decision by the board of directors to raise the company's 2011 capital spending budget to approximately US $1.5 billion from $1.2 billion, not counting deepwater spending. The Eagle Ford play will get 25% of that budget. The company has a net 5.5 drilling rigs working the play, up from the three rigs originally planned for the year. It sold approximately 4,400 boe/d net in July and plans to produce 10,000 boe/d by the end of this year. Plans call for production to reach 24 Mboe/d in 2015. Among recent wells, its Carmody #1 and #2 wells produced at a combined initial rate of 2,919 boe/d net to Plains. The company holds 58,700 net acres in the play on land between the oil and condensate windows. That land holds a net resource potential of 170 MMboe.

GRANITE WASH

The company worked five rigs on its 21,400 net acres of land in the Granite Wash play in the Texas Panhandle and expected to continue working at that level throughout 2011. It sold a net 13,620 boe/d in 2Q 2011, up 52% from 1Q 2010 and 139% from 2Q 2010. It expected to exit the year producing 17 boe/d and planned to reach more than 18 Mboe by 2015. The play has a net resource potential of 119.5 MMboe.

MONTEREY

Plains Exploration holds 86,000 net acres of land with Monterey potential in the San Joaquin, Los Angeles, and Santa Maria basins of California. It has production from all three basins and plans exploratory wells to the formation in 2011. In 2011, 1% of the company-wide capex budget of $1.5 billion was allocated to Monterey exploration.

Progress Energy Resources Corp.

MONTNEY

Progress Energy Resources Corp. worked up a plan for efficiency in developing the Montney play in the British Columbia Foothills that drew international attention. It concentrated its activities to avoid large numbers of scattered facilities, and it designed a system of drilling in pods – drilling locations in focused areas with a centralized processing plant capable of handling 50 MMcf/d of gas. It also identified six pods ready for commercial development in four stages. First, it will proceed with a test stage with one vertical and horizontal well. Next, it will begin a pilot phase of two to four more horizontal wells to refine costs and production. Third, it will go into full development with 15 to 20 additional horizontal wells to raise production to 50 MMcf/d of gas. Finally, it will build a maintenance phase to maintain production for 10 years. A typical pod will cost US $146.4 million for 23 wells and the processing plant.

> **Progress Energy Resources Corp. worked up a plan for efficiency in developing the Montney play in the British Columbia Foothills that drew international attention.**

That plan allowed Progress to form a 50-50 joint venture (JV) with Malaysian national oil company Petronas to develop the company's Altares, Lily, and Kahta properties in its North Montney area. The companies plan to use the production to build a liquefied natural gas (LNG) exporting plant, 80% owned by Petronas, on British Columbia's West Coast. Under the agreement signed in June 2011, Petronas will pay $270 million at closing and carry 75% of Progress' capex over the next five years up to $810.3 million in the 149,910 JV acreage. That acreage represents only about 20% of the Progress holdings in the area, which include some 700,000 net acres in British Columbia and 900,000 net acres of Montney rights in British Columbia and Alberta.

The companies plan approximately 80 wells with a 50 MMcf/d gas processing plant and a capital cost of some $5.04 billion over the next five years.

On its Altares pod, Progress planned to complete its first horizontal wells in 3Q 2011, move to initial development in 4Q 2012, and to full development in 3Q 2013.

It is producing about 6.5 MMcf/d net from its Kobes pod where it holds a 30% working interest. Progress operates the northern area while Talisman Energy operates the southern region. The companies drilled the first vertical well in 3Q 2009 and finished the pilot phase a year later. They completed initial development in 4Q 2010 and began full development in 1Q 2011.

Progress planned to complete a new 25 MMcf/d gas plant at its Gundy pod in 3Q 2011 as it entered the initial development stage with full development set to begin in 1Q 2012.

The Town South pod is the company's most mature development in the Montney with 50 MMcf/d of gas production, including initial Gundy volume, flowing into an expanded 50 MMcf/d gas facility. It went into full development phase in 1Q 2011.

Progress brought a 25 MMcf/d gas plant onstream at the Town North pod in April 2011 with full development planned for 3Q 2011.

The full development phase is scheduled for the Caribou pod in 4Q 2012.

The Caribou, Town, and Kobes developments lie on more than 650,000 net acres with best-estimated contingent resources of some 8.1 Tcf of gas. The Town area includes Town North and South and Gundy. The area currently holds 590 Bcfe of proved and probable reserves.

QEP Resources Inc. runs three operated rigs on its 90,000 net aces of land in the Bakken/Three Forks play in North Dakota where it has 71 proved undeveloped locations and 445 gross remaining drilling locations.

QEP Resources Inc.

BAKKEN

QEP Resources Inc. runs three operated rigs on its 90,000 net aces of land in the Bakken/Three Forks play in North Dakota where it has 71 proved undeveloped locations and 445 gross remaining drilling locations. A well with a lateral from 5,000 to 10,000 ft costs US $6.5 million to $9 million to complete and provides EUR from 350 to 750 Mboe. Initial potentials on shorter laterals average 998 boe/d, while longer laterals come in at an average 1.53 Mboe/d. The company's best well in the Bakken offered an initial potential of 2,650 boe/d, while two Three Forks wells tested for 1,448 and 1,347 boe/d, respectively. The plays offer QEP a net finding cost of $20.50/bbl of oil. It calculates 26.6 MMboe in proved reserves from the Williston Basin, and it is ramping up pad drilling for economy. It has two two-well pads, one four-well pad and plans a 10-well pad. By the end of the 3Q 2011, the company operated 20 producing wells in the play and had interests in another 79 producing wells operated by other companies. Bakken/Three Forks production averaged 4.1 Mboe/d in the quarter.

CANA/WOODFORD

The company holds 77,600 net acres in the Cana Woodford play in Oklahoma's Anadarko Basin and produced 45 MMcfe/d of gas during 3Q 2011. It runs three rigs in the play in which it holds a 20% working interest in the tier one part of the play and operates 52% of its potential investment. It has 3,450 gross potential locations and 103 proved undeveloped drilling sites. Production is predominately condensate and natural gas liquids (NGLs) on 18% of the company's land, significantly condensate and NGLs on 60% of its land, and dry gas on the remainder. Well costs to completion range from $8 million to $9.5 million and the company expects an EUR of 6.5 Bcfe with 25 to 130 bbl of liquids per million cubic feet of gas. It estimates its finding costs at $1.57/Mcfe. By the end of the 3Q 2011, the company had 22 operated producing wells and had working interests in 169 non-operated wells in the play.

GRANITE WASH

QEP has two Granite Wash segments in its inventory. It holds 25,300 net acres in the Texas Panhandle with potential for Granite Wash and Atoka Wash formations. It operated two rigs in that play in the first half of the year and dropped to one rig in the third quarter. A completed well costs $8 million to $9 million and yields and an EUR average of 5.2 Bcfe per well. Its best well, the Morrison 33 #5H, tested for 23 MMcfge/d. It has 36 remaining locations with finding costs of $2.19/Mcf. Including Oklahoma properties, QEP holds 38,900 net acres in what the company calls "Wash" plays in Wheeler County, Texas, and Roger Mills, Beckham, and Washita counties in Oklahoma. Its Roxanne 2-17H in Washita County tested for 660 bo/d and 5.46 MMcf/d. It has 52 remaining locations in this area with a 68% working interest. Wells in this area offer an average gross EUR of 7.1 Bcfe at a finding cost of $1.51/Mcfe. At the end of 3Q 2011, the company held interests in 50 producing horizontal Wash wells producing 38 MMcfe/d.

NIOBRARA

The company holds 82,600 net acres of land in the Denver-Julesburg Basin and another 55,000 net acres in the Powder River Basin with prospective Niobrara production. One QEP well, the Borie 16-4H in Colorado was plugged and abandoned.

Questerre Energy Corp.

BAKKEN

Questerre Energy Corp., after placing on hold its Utica development pending completion of environmental studies and government policy determinations, looks to its Bakken/Torquay light oil play at its Antler project in southeastern Saskatchewan for unconventional liquids cash flow. It holds more than 45,000 net acres in the Bakken/Torquay, and 95% of the acreage still is undeveloped. During 2010, 13 gross, 6.5 net, wells were drilled in the property, but extreme weather and a shortage of frac equipment limited completions, and only 10 gross, five net, wells were put on production. Results from those wells, however, persuaded the company to drill 20 gross, 10 net, wells in 2011, including infill wells and step-outs. In an August presentation, Questerre said it was refining drilling and completion techniques and improving production practices to increase recoveries and reduce costs. The company plans to increase production to 2,000 b/d while the strategic environmental assessment takes place in Quebec. It will double its rig count in Saskatchewan to two from the single rig run in 2011 and contract a frac crew for 2012. It planned 10 to 15 wells per rig in 2012. It also planned a waterflood project in 2012 with the potential to increase production by 8% to 20%. Those revenues could provide the company a source of capital for future development in Quebec, Questerre said.

UTICA

Questerre holds more than 1 million gross, 340,000 net, acres of land in the St. Lawrence Lowlands south of the St. Lawrence River with potential for production from the Utica and Lorraine shales. Now, a stakeholder committee is conducting a strategic environmental assessment of the results of Utica development and will turn its findings over to the government for action. Until then, the government will allow fracture treatments only on pilot projects. The company's land holds a potential 18 Tcfe of gas in recoverable resources in the heart of the Utica fairway, and it holds rights to the land until 2021. It started testing the Utica with its partner, Talisman Energy, in 2008 and 2009. The St. Edouard #1 well, with a 3,281-ft lateral, tested with an initial potential of more than 12 MMcf/d and a 30-day average flow of 5.7 MMcf/d. It scheduled completions on two more wells in 2011, completed a 3-D seismic program in the area, and participated in a Forest Oil-generated 2-D seismic program.

Quicksilver Resources Inc.

BAKKEN

Quicksilver Resources Inc. specializes in unconventional plays from the Barnett to the Horn River and from shales to coalbed methane. One of those specialties is the Bakken Shale on the Montana side of the Southern Alberta Basin, primarily in Glacier and Toole counties. It holds some 175,000 acres in the area with 100% of 119,000 net acres held by production from the Cutbank Sand. It works in a 300,000-acre area of mutual interest. Although it has no booked Bakken production yet from the formation at 4,000 ft, it is monitoring increasing industry activity in the area. The company also is looking at Bakken potential on its Horn River Basin properties in northeastern British Columbia. Coring has revealed good oil shows in the Bakken/Exshaw.

NIOBRARA

The company's Niobrara potential lies in its 210,000-net-acre position in the Sand Wash Basin of northwestern Colorado where it has identified a potential resource of 100 MMboe. It is in a joint venture in the area and planned eight to 14 vertical resource assessment wells in 2011. By August, it had drilled three of the wells and started completion activity. With success, the company said it could ramp up activity quickly.

WOLFBONE

Quicksilver described part of its holdings in the Permian Basin as the Wolfpack. The pack includes the Wolfcamp and Wolfbone (Wolfcamp-Bone Spring) plays in the Delaware Basin. It holds 125,000 net acres prospective for Bone Spring with a 75% net revenue interest, 75,000 net acres, mostly in Reeves and Pecos counties, and another 50,000 net acres in Presidio County in West Texas. It planned one or two recompletions in 2011 and one new drill.

RAM Energy Resources Inc.

MISSISSIPPI LIME

RAM Energy Resources Inc. is progressing on its development of properties in the Mississippi (Dense) Lime along the Kansas-Oklahoma border. According to its 2Q 2011 report, it completed modifications to its production facilities and saltwater disposal well in its Southern Surber area and started testing previously drilled wells that were shut in pending completion of the improvements. It is installing gas-power electric generation to power submersible pumps in its Surber #1-26 and Rickets #3-26 wells. It also planned a second saltwater disposal well. The Surber well, stimulated in March 2011, produced at about 108 boe/d at the end of 2Q 2011. It planned a slickwater frac on three additional wells. It drilled the Farmland #2-16 to the Bartlesville Formation in April and the Christensen #3-2 to the Arbuckle in its Central Mashunkashey area where it also has potential for production from the Mississippi Lime. RAM planned four wells to the lime in 3Q 2011 in the Surber area and the first horizontal well in the area in 2012. It also gathered additional seismic data in the area with results from processing and interpretation due in mid-September 2011.

Range Resources Inc.

AVALON/BONE SPRING

Range Resources Inc. has a big foothold in the Avalon/Bone Spring play in the Delaware Basin of Texas and New Mexico with a gross resource potential of 500 Bcfe to 1 Tcfe of gas, according to a company presentation. It did not release further details.

CANA WOODFORD

The company's Cana Woodford play in Major, Blaine, and Canadian counties in Oklahoma covers some 42,000 net acres. All of the company's 700 potential drilling locations are held by production from other zones. Range estimated gross resource potential between 1.1 Tcfe and 1.7 Tcfe of gas.

GRANITE WASH

Range hasn't taken an aggressive approach to its Granite Wash properties, primarily in Hemphill and Wheeler counties in the Texas Panhandle. It has 140 potential locations in the play with a net resource potential of 300 to 400 Bcfe of gas.

MARCELLUS

Range's activities in Appalachia essentially kicked off the monster Marcellus play, and it remains one of the largest leaseholders and owners of properties in the prime production areas within its 1.1-million-acre empire. That empire contains some 22 to 32 Tcfe (20 to 28 Tcf of gas and 409 to 545 MMbbl of liquids) in net unproven resource potential, and it plans to make the play self-funding by 2013. The company drilled 103 wells in the southwestern Pennsylvania wet gas area in 2009 and 2010 with an average EUR of 5.7 Bcfe per well. It cost US $4 million to complete wells with a 2,802-ft average lateral and nine frac stages for a finding and development (F&D) cost of 82 cents/Mcf. That offered Range a 79% return at a gas price of $4/MMBtu and a 134%

return with a $6 gas price. It drilled 38 more wells in its 2011 campaign by the end of June on its 550,000 net acres in the southwestern part of the play. That area has room for 5,000 wells on 80-acre spacing, assuming the company drills on 80% of its acreage. It has 240,000 net acres in the northeastern gassy part of the play where it brought five wells online by mid-February 2011. Average reserves totaled 6 Bcf for a well with a 2,573-ft lateral with nine frac stages. It brought six more wells online by July and planned another 27 wells in the area by the end of November. It also planned to test a horizontal well with a 4,500-ft lateral and 15 frac stages in late 2011. Range ended 2010 with production of more than 200 MMcfe from all of its Marcellus properties. It planned to double that production by the end of 2011 and add another 200 MMcfe/d by the end of 2012. It also planned to begin ethane extraction in 2013, a move that could add 500 MMboe of production potential, essentially doubling liquids potential.

MISSISSIPPI LIME

Range is working the Mississippi Lime in Kay and Noble counties in Oklahoma where it holds 60,000 net acres of land. It can complete wells there for $3.1 million for EUR between 400 and 500 Mboe, an F&D cost of $9.78/bbl on a 400-Mboe well and $7.89/bbl on a 500-Mboe well. That equates to a 60% return on the smaller wells and a 69% return on the larger wells. To date, EUR have averaged 485 Mboe with 2,197-ft laterals and 12-stage frac treatments.

UTICA

The company drilled and completed its first Utica well for a 4.4 MMcf/d of gas seven-day rate. Range expects its Utica properties, held by drilling in the Marcellus Shale, to produce dry gas. It plans two to four wells in next couple of years, but basically it will just watch the play.

WOLFCAMP/PENN

Range holds 90,000 net acres of land in the Penn Shale in the southern Midland Basin with a net resource potential of 170 MMbbl of oil and another 9,000 net acres in the Wolfcamp in the same area with a 20 MMbbl net resource potential.

Reliance Industries Ltd.

EAGLE FORD

Reliance Industries Ltd., India's largest publicly traded company, entered US shale plays with a purchasing spree during 2010. It entered a joint venture (JV) with Pioneer Natural Resources Co. and partner Newpek to get a 45% interest in the partners' Eagle Ford properties. That interest went to Reliance subsidiary Reliance Eagleford Upstream. Pioneer kept a 46% share of the properties and Newpek retained the remaining 9%. The venture holds 289,000 gross, 263,000 net, acres in the play. Reliance put up US $1.315 billion for its 118,000 net acres, paying $263 million upfront and carrying 75% of the other partners' costs for the remainder. The properties are in the core of the play with potential to drill more than 1,750 wells for a potential 10 Tcfe of gas, or 4.5 Tcfe net to Reliance.

Reliance Industries Ltd., India's largest publicly traded company, entered US shale plays with a purchasing spree during 2010.

At the time of the acquisition in mid-2010, the companies planned to drill 140 wells a year for the next three years. The agreement also gave Reliance production of a net 11 MMcfe/d from the five wells producing at the time. Pioneer is operating the properties, but Reliance has the option of taking on some operations when it chooses. Reliance and Pioneer also formed a midstream JV for a gathering system. In that deal, Reliance paid $46 million for a 49.9% share in the JV. In August 2011, the Reliance-Pioneer JV was producing 165 MMcf/d of gas and 13,800 b/d of condensate.

At the same time, Reliance was talking with Chesapeake Energy on an arrangement that would allow Reliance to take a share of Chesapeake's 600,000 acres in the Eagle Ford play, but that deal fell through.

MARCELLUS

Reliance signed an agreement to buy a 40% share of the Marcellus holdings of Atlas Energy Inc. in March 2010

(Photos courtesy of Rice Energy LLC)

Top photo: When space is tight, frac crews learn to work in crowded conditions, like the X-man well site. Bottom photo: A clean well site in Washington County, Pa., shows concern for the environment and helps keep friendly neighbors.

for $1.7 billion, or $14,000 an acre. As in the Eagle Ford deal with Pioneer, Reliance contributed $339 million in upfront money and agreed to pay 75% of Atlas' capital costs with the remaining $1.36 billion. The following month, the venture partners bought 42,344 acres in Armstrong, Clarion, Fayette, Indiana, Washington, and Westmoreland counties in Pennsylvania for $4,532 an acre. Following that purchase, the venture held 343,000 acres in the Marcellus Shale with a 206,000-net-acre share going to Atlas and the remaining 137,000 acres held by Reliance. Atlas, as operator, planned to drill more than 450 horizontal wells on the newly acquired acreage alone. Chevron Corp. later acquired Atlas with its JV agreement. Chevron drilled nine wells in 2Q 2011 for a total of 22 wells producing 51 MMcf/d of gas during the quarter.

In August 2010, Reliance signed another agreement to acquire a 60% interest in Marcellus Shale holdings in central and northeastern Pennsylvania from a 50-50 JV of Carrizo Oil & Gas and ACP II Marcellus LLC, an affiliate of Avista Capital Partners. Reliance bought Avista out of the partnership and added 20% of Carrizo's position. Reliance paid $392 million, including $340 million in cash and $52 million in capital carries on 75% of Carrizo's costs. The new JV held 104,400 net acres of undeveloped leases with Reliance holding a 62,600-net-acre share. That land holds a net resource potential of some 3.4 Tcfe from approximately 2,000 wells. In August 2011, the Reliance-Carrizo venture had put 15 wells into production and was in the final stages of building a pipeline to get its gas to markets.

Rex Energy Corp.

MARCELLUS

Rex Energy Corp. controls 63,100 net acres in Marcellus Shale in Pennsylvania, 63% in the liquids-rich sector. It holds 63,200 gross, 43,500 net, acres in its Butler-County-operated area, where it has a 70% interest with Sumitomo in upstream operations, and the Butler Midstream joint venture (JV) in which Stonehenge has a 60% interest, Rex holds a 28% share, and Sumitomo a 12% interest. It processed 28.4 MMcf/d of gas through the Butler County Sarsen plant in June 2011. Through the first half of 2011, it drilled 22 Marcellus wells, fractured 11 wells, and put 13 wells in service in the county. It also has three multiple-well pads on production. On June 30, it had 18 wells drilled and awaiting completion. It planned another six Marcellus wells in the second half of 2011. By mid-September, the company completed its three-well Behm pad with a five-day flow rate of 6.6 MMcfe/d of gas from the three wells.

On its non-operated properties in Westmoreland County, Williams Cos. drilled 14 Marcellus wells, stimulated eight wells, and put another eight wells online through June 30. By mid-September, Williams put the four-well Uschak #1 pad online with a five-day average flow rate of 3.3 MMcf/d of gas per well and an average 30-day flow rate of 2.7 MMcf/d per well. Both rates were constricted by offtake capacity. It planned to drill another eight wells, stimulate 18 wells, and put nine wells in service in the Marcellus. Average gross production from Williams' Marcellus wells in June reached 21.8 MMcf/d. Williams drilled three Marcellus wells in Clearfield County and placed another on service through June 30. Rex had 41,900, 16,600 net, acres in the Williams JV in which Williams had a half interest, Rex 40%, and Sumitomo 10%.

NIOBRARA

The company has 56,000 gross, 39,000 net acres in the Niobrara play, including 8,300 farm-in acres, all in the Niobrara oil window in the Denver-Julesburg Basin. In August 2011 it was completing the Steege 1-33H well and expected to fracture the Shapley 14-25 during 3Q 2011. It was evaluating its Herrington Farms #1H and the BJB #1H. Rex invested US $8.3 million on the Shapley and Steege wells and a total $14.2 million to drill two wells and complete three during 2011. At this point, Rex doesn't consider the Niobrara a true resource play.

UTICA

Rex has 83,500 gross, 57,900 net, acres in the Utica Shale, including its 43,500 net acres under the Marcellus in Butler County, where it drilled the #1 Cheesman to the Utica and planned completion in 2011. It also holds 11,000 net acres in its Ohio Warrior Utica Prospect where it plans to begin drilling and development in 2012. It has 80 net potential drilling locations in Carroll County, Ohio, and it is continuing to lease acreage. It allocated $41 million for Utica leasing capital.

Rice Energy LLC

MARCELLUS

Rice Energy LLC, founded by Daniel J. Rice III, energy portfolio manager for BlackRock Inc., started leasing in the Marcellus Shale in 2007 and gathered leases capable of supporting between 200 and 250 horizontal Marcellus wells. It has started drilling operations in liquids-rich southwestern Pennsylvania and gas-prone northeastern Pennsylvania with most of its operations in Washington County through its Rice Drilling B LLC affiliate. Part of its operations resulted from a farm-in arrangement with Denex Petroleum for drilling rights in Washington County. According to IHS Inc., the company had permitted, drilled, or completed 44 wells in Washington County, two wells in Fayette County, eight wells in Greene County, one well in Luzerne County, four wells in Lycoming County, and one well in Westmoreland County by mid-April 2011. In July 2011, it permitted the 4H Captain Planet in Washington County, a proposed horizontal well. It had started a pilot hold for the well in early September.

Rosetta Resources Inc.

BAKKEN

Rosetta Resources Inc. is working up a Bakken oil play in the Montana portion of the Southern Alberta Basin. It drilled 11 delineation wells within a 30- by 45-mile area and planned to complete a seven-well horizontal evaluation program in the same 300,000-net acre area in 2011. The company's property holds an estimated 6 Bboe in place with 1,500 potential drilling locations. To date, its horizontal wells have come in with an initial potential of 250 boe/d and 185 Mboe of EUR on 160-acre spacing. It estimated well costs at US $4 million. That would give the company a 21.3% rate of return with $85/bbl oil and 35.1% with $95 oil. Its finding and development cost is $27.46/boe. In early October 2011 activity, the company reported completing two vertical Bakken wells on the Blackfeet Reservation in Glacier County. One well tested for 447 bbl of oil and 298 Mcf of gas in 10 days and the other for 100 bbl of oil and 59 Mcf of gas in 10 days.

EAGLE FORD

Rosetta holds 65,000 net acres of leases in the Eagle Ford Shale play in South Texas, 50,000 net acres in the liquids-rich area and 15,000 net acres in the dry gas area. It holds a 100% working interest in most of that territory. In 2011, it was high-grading the play within a 9-by-11-mile Gates Ranch area where it holds 26,500 net acres in Webb and Dimmit counties. It produced an average 129 MMcfe/d of gas, about 46% liquids, from the field in 2Q 2011. It estimated 12.6 Tcfe of hydrocarbons in place at Gates Ranch and 10 Bcfe per well of recoverable resource. It planned to develop the field with 236 horizontal wells, possibly 441 wells with infill drilling, and it will test infill drilling in late 2011. It planned to concentrate development in the field through 2016 to recover 20% of the resource in place. Throughout the liquids-rich area, it had drilled 36 horizontal wells and had 450 remaining locations without counting infill drilling potential. Its 15,000 net acres with dry gas potential is concentrated in the Encinal area where it has an estimated 5 Tcfe of hydrocarbons in place. It completed four horizontal wells for 5 MMcfe/d of production. The company has 145 potential locations in the area, or three to four years of remaining inventory.

Samson Investment Co.

AVALON/BONE SPRING

Samson Investment Co., which also operates at Samson Lone Star LLC and Samson Resources Co., offered properties for sale in the Avalon/Bone Spring play in southeastern New Mexico, according to the October 20, 2010, issue of the PLS A&D Transactions newsletter. About 10,000 net acres were prospective for Avalon and Bone Spring in southeastern New Mexico. The gas-oil ratio in the area was 60-40.

BAKKEN

Samson Resources has a concentrated Bakken development program focused on Divide County in North Dakota. It has drilled new field wildcats in the area, according to IHS Inc., but most recent activity aims at development wells in Blooming Prairie, Candak, Forthun, and Ambrose fields. It also has Bakken production from Foothills Field in Burke County, N.D. Among its Blooming Prairie wells, it completed the 20-32-163-98H Ness, a horizontal Bakken well, for 379 b/d of oil and 502 Mcf/d of gas.

GRANITE WASH

Samson Lone Star LLC works the company's Granite Wash properties in the Texas Panhandle. Although the privately held company doesn't report its activities, it asked the Texas Railroad Commission to amend rules for the Granite Wash in Hemphill Field in Hemphill and Roberts counties, Mendota Northwest Field in Hemphill County, and Wheeler Northeast Field in Wheeler County. In February 2011 IHS Inc. said Samson Lone Star recovered gas at an initial rate of 18.7 MMcf/d with 240 b/d of condensate from its 404H Young Trust in southeastern Hemphill County. Its 513H Zybach in Wheeler County tested for 21.2 MMcf/d of gas with 717 b/d of condensate.

MARCELLUS

A February 2011 article in the Somerset Daily American newspaper in Somerset County, Pa., quoted Steve Trujillo, Samson Resources' operations and engineering manager for the Marcellus, who said the company held 120,000 acres of land in the county. He also said it had finished its exploration program in the county and was going into the appraisal stage on its properties. By that time, it had drilled five Marcellus wells in the region with two producing and tied into a pipeline. He also said the company planned 11 wells during 2011, but it was moving slowly since Somerset County is on the fringe of the Marcellus play. The company also holds Marcellus properties in Maryland. According to the September 2009 minutes of the State Geologic Mapping Advisory Committee, the company planned three or four wells on its 50,000 acres in Garret County at that time.

WOLFBERRY

Samson held 506 producing units with 417 proved undeveloped well locations in the Permian Basin and 368 well locations prospective for Wolfberry production in the Midland Basin. It held 137,000 acres in the Permian Basin in West Texas and southeastern New Mexico, but 10,000 net acres were prospective for Avalon and Bone Spring.

Samson Oil & Gas Ltd.

BAKKEN

Australia-based Samson Oil & Gas Ltd. has a fondness for unconventional plays, and its positions in the Rockies illustrate that fondness. In addition to activity in the Bakken and Niobrara shales, the company said it also has interests in activities in the Lewis and Baxter shales in southern Wyoming. It holds 3,303 gross, 1,200 net, acres in the Bakken play in North Stockyard Field in McKenzie County, N.D. where it had five producing wells and a sixth awaiting a fracture treatment in September 2011. Its Earl #1-13H started producing in March 2011 at an initial rate of 1,300 b/d of oil and averaged 520 b/d during July. It holds another 20,028 net acres in Roosevelt County, Mont., with two wells in 3Q and 4Q 2011. It purchased the properties from Fort Peck Energy Corp., the energy company of the Fort Peck Reservation, and that company has the option of backing into the play for one-third of the property and the first two wells. Samson also has an option to acquire another 20,000 acres of land on the reservation, and Fort Peck Energy can back into that property for a one-third interest, as well. Samson and Fort Peck Energy also have a 50,000 acre area of mutual interest where they plan to acquire additional leases. They expected to drill the first well, the Australia II, in October 2011.

NIOBRARA

Samson holds 17,489 net acres of land in Goshen County in southeastern Wyoming, which it calls its Hawk Springs project. It has no wells on the land yet, but it estimated ultimate recoveries of 413 Mboe from wells on the land. Halliburton Energy Services farmed into the property and will carry Samson on the first two wells on the land. The Defender US33 2-29H was drilling in September with plans for a 4,300-ft lateral at a depth of 7,450 ft. The second well will spud in November. It had tested production in the area as early as 2006, when the London Flats #1, the first well in the project, was drilled to the Niobrara. That well was marginal. Recently, exploration in Hawk Springs has focused on the Sharon Springs member of the Pierre Shale. In June 2010, Samson agreed to sell part of its Goshen County acreage to Chesapeake Energy Corp. for US $3,275 an acre. Samson is participating in two Chesapeake wells on that property.

SandRidge Energy Inc.

AVALON/BONE SPRING

SandRidge Energy Inc. once held some 43,000 net acres in the Avalon and Bone Spring reserves with no production and additional properties in Lea and Eddy counties in New Mexico. It sold a 40,000-acre parcel in December 2010 for US $110 million, or approximately 2,750 an acre. It had no production from those properties. A month later, it sold the Lea and Eddy County properties for $200 million. Those properties included 23,000 net acres producing 1,500 boe/d.

MISSISSIPPI LIME

Chesapeake Energy may have discovered the Mississippi Lime play on the Oklahoma-Kansas border in 2007, but SandRidge Energy took the lead in drilling activity. It holds 900,000 net acres and more than 4,000 locations and plans to raise it acreage holding to 1 million net acres. It has 14 rigs drilling horizontal wells to an average vertical depth of 6,000 ft with 4,000-ft laterals. Thousands of vertical wells supply extensive well control in the area, and the carbonate section is more than 250-ft thick. It expects to produce 300 Mboe to 500 Mboe/well at a cost of $3 million to get 52% crude oil from its wells. As an indicator of the company's feelings about the Mississippi Lime, it assigned 47% of its $1.55-billion E&P budget in 2012 to the play. By September 2011, it had drilled 121 wells, while the rest of the industry operators in the play drilled 165 wells. In its latest 20 wells initial potentials averaged 332 boe/d, and the company expected a 120% internal rate of return on its investment at September 2011 oil and gas prices. It has identified more than 3,400 potential drilling locations, and it planned to drill 135 horizontal wells in 2011. In September 2011, the company closed a joint venture agreement that gave the Republic of Korea's Atinum Partners Co. Ltd. a 13.2% non-operated interest in 860,000 SandRidge acres in the play, or approximately 113,000 net acres, for $500 million. The purchase included $250 million in up-front cash and $250 million in drilling carries.

WOLFBERRY

As part of its plan to spin off non-core assets to concentrate on its Mississippi Lime and central Permian Basin platform conventional development activities, SandRidge sold its Wolfberry assets in the Permian Basin in January 2011 for $155 million. The properties were producing 1,600 boe/d at the time.


(Photo courtesy of Shell Oil Co.)

A rig drills to the Marcellus Shale near Wellsboro and the Pennsylvania Grand Canyon.

Shell Energy North America LP

EAGLE FORD

The Shell Energy North America LP arm of Royal Dutch Shell plc started producing in South Texas in 1953, but it didn't enter the Eagle Ford play until its US $4.7 billion acquisition of East Resources in 2010, which gave it a strong position in the Marcellus Shale, as well. Now, it holds approximately 250,000 net acres in the Eagle Ford and Pearsall shales where it has gathered and processed additional 3-D seismic, conducted delineation drilling, and started drilling development wells. In a September 2010 presentation, the company ranked the Eagle Ford among its emerging plays with Groundbirch in the Montney Shale in northeastern British Columbia; the Marcellus in West Virginia, Pennsylvania, and New York; and the Haynesville in Louisiana.

MARCELLUS

Shell owned more than 700,000 gross, 650,000 net, acres of leases in the Marcellus play in West Virginia, Pennsylvania, and New York through its acquisition of East Resources for $4.7 billion in July 2010. Since that time, it has followed East Resources' lead in focusing its activities in Tioga County, Pa., but also extended its work to the fringes of the play to delineate its holdings. It also has a 50-50 joint venture with Ultra Petroleum in Potter County, Pa., and properties in Bradford, Forest, McKean, Butler, Lawrence, and Jefferson counties. It also got Northern Pipeline Co. from East Resources. That line includes some 400 miles of gathering system in Butler, Clarion, Forest, McKean, Venango, and Warren counties. It also included 100 miles of gathering line to the south through Pittsburgh to the West Virginia border and 60 miles in Lancaster, Chester, and Delaware counties in Pennsylvania. The company recycles nearly all of its produced fluids in its drilling and fracturing operations.

MONTEREY

Shell has an interest in Aera Energy LLC in California. Although that company doesn't broadcast that it produces from the Monterey Shale, it works in areas of the San Joaquin Basin of California that are prospective for the Monterey, specifically South Belridge and Lost Hills fields.

MONTNEY

The company purchased Duvernay Oil Co. in 2008 for $5.7 billion. That purchase gave the company some 450,000 acres in the Montney Shale at Groundbirch in northeastern British Columbia and in the Deep Basin of the Western Canada Sedimentary Basin. In 2011, the company was building a reclaimed water plant to reuse water from fracturing and drilling for its own operations and for non-drinking use by the city of Dawson Creek.

UTICA

East Resources also had Utica production when Shell bought the company in 2010. In addition to the 70,000 acres it acquired from East in Butler and Lawrence counties in Pennsylvania on the border with Ohio, Shell added another 30,000 acres by mid-2011 and started delineation drilling. Shell drilled the first Marcellus well in Lawrence County. That land is on the western edge of the Marcellus play and near the liquids-rich section of the Utica Shale in Ohio.

Slawson Exploration Co. Inc.

BAKKEN

Slawson Exploration Co. Inc., a division of Slawson Cos., entered the Williston Basin in the late 1980s and was the third operator to drill a horizontal well into the formation, according to an interview with Craig Slawson on Bakkenstocks.com. It often drilled through the tight Bakken on the way to deeper formations such as the Red River. In 1991, it had collected from 40,000 acres prospective for Bakken in Richland County, Mont., but low oil prices forced the company out of the play until 2003. Since then, the company has drilled some of the hottest areas in the Bakken, including Parshall and Ross fields in Mountrail County in North Dakota, many of those wells under agreements with Northern Oil & Gas Co. It acquired a half interest with Northern in 12,000 net acres of land in a November 2009 North Dakota lease sale, and Northern picked up half of 11,000 net acres in Slawson's Big Sky Bakken program in Richland County, Mont., and another 13,000 net acres from a half interest in Slawson's Anvil properties in Williams County, N.D., and Roosevelt County, Mont. In June 2011, Northern said it participated in a number of wells drilled by Slawson, including the Mustang #1-22H in Mountrail County with an initial potential of 1,829 b/d of oil. It also said Slawson made an important discovery in the Upper Bakken Shale on the edge of Elm Coulee Field in Richland County with the Rascal #1-18H with an initial test of 707 b/d of oil. It was the third successful test in the upper shale in the Big Sky/Lambert prospect.

NIOBRARA

The company started Niobrara play operations in the Denver-Julesburg Basin in northeastern Colorado through a 50-50 joint venture with Voyager Oil & Gas Inc. when Voyager farmed in to Slawson's 44,000 net acres in the basin in June 2010. By October that year, Slawson had drilled three wells on the acreage with completion costs of approximately $3.2 million per well. One well in the trio tested at a peak rate of 650 b/d of oil after a fracture treatment. By that time, Slawson had set surface casing on 22 additional wells high-graded from nearby well reports and from its own wells. Setting casing extended lease termination dates by a year. Slawson planned to drill the wells in 2011. By May 2011, Slawson had drilled six wells on the properties. At that time, Voyager said it would concentrate the rest of its 2011 capex on its Bakken properties in the Williston Basin.

In spite of an August 2011 sale of land in La Salle and Dimmit counties in Texas, the Eagle Ford Shale occupies the top spot on SM Energy's priority list.

SM Energy Co.

BAKKEN/THREE FORKS

SM Energy Co. boasts a strong presence in the Williston Basin and in the Bakken/Three Forks play with 204,000 net acres, including 85,000 net acres in its Raven, Bear Den, Gooseneck, and Divide fields in McKenzie and Divide counties. According to a September 2011 presentation, the company was running three rigs in Divide and Raven fields as it took advantage of a US $20-million increase in capital spending for the play to $190 million. It plans to spend between $185 million to $205 million on the play in 2012. The company's leaseholds straddle the Montana and North Dakota sides of the Williston Basin and a significant portion of that, mostly in Montana, is held by production. The company also planned to participate in a number of non-operated wells in 2011.

EAGLE FORD

In spite of an August 2011 sale of land in La Salle and Dimmit counties in Texas, the Eagle Ford Shale occupies the top spot on SM Energy's priority list. The sale gave the company $227.4 million and was one factor that allowed the company to raise its capital spending plans for the play to $795 million from a planned $500 million earlier in the year. It plans to spend between $670 million and $730 million in the play in 2012. After the sale, SM Energy retained 196,000 net acres in the shale. That figure includes 150,000 net operated acres, almost entirely in the rich gas window. It also held 46,000 non-operated acres in a joint venture with Anadarko Petroleum. SM Energy had held a 27% share in that partnership until it sold 12.5% to Mitusi of Japan. That left the company with a 14.5% interest. Anadarko planned to run 10 to 12 gross rigs on that acreage through 2011.

GRANITE WASH

SM Energy is running a single rig in its Granite Wash program in the first half of 2011 and planned to run one or two rigs through the year. All of the acreage is held by production. It dedicated $60 million to develop its properties in 2011 and planned to raise that figure to between $70 million and $75 million in 2012. In addition to its Texas properties, SM Energy had acreage in western Oklahoma with potential for Granite Wash production. That acreage also is held by production from other zones, and the company plans to monitor activity in the area.

MARCELLUS

The company acquired a non-operated position in the Marcellus play in the Appalachian Basin and is setting up partnerships with operating companies to test economic potential in under-explored parts of the play.

NIOBRARA

SM Energy holds 89,000 net acres in eastern Wyoming with potential for Niobrara production and planned to spend $25 million in 2011 to test that potential. Some 63,000 of those acres are in the Powder River Basin. It drilled three operated wells in 2Q 2011 with the Polaris well, in which the company held a 38% interest, testing for a seven-day average rate of 950 boe/d. It planned to complete the other two wells later in the year.

WOLFBERRY

SM Energy entered the Permian Basin in the 1990s, but it was an asset acquisition in late 2006 that gave the company access to the emerging Wolfberry play in the Midland Basin. It planned to spend $50 million in the basin to run one rig aimed at drilling down-spacing pilot wells to the Wolfberry and to test Mississippian potential. Its major Wolfberry assets are Sweetie Peck Field, which it operates, and its non-operated Halff East Field.

Southwestern Energy Co.

MARCELLUS

Already the dominant force in the Fayetteville Shale in Arkansas, Southwestern Energy Co. started leasing property in the Marcellus Shale play in 2007. By July 2011, it had put together a 173,009-net-acre position in Pennsylvania. It participated in 28 Marcellus wells with 18 successes and 10 in progress by June 30, 2011. A month later, it had three additional wells online in its Greenzweig area in Bradford County. Southwestern operated all of the wells on production. It produced 2.8 Bcf of gas in 1Q 2011 and bumped that number to 5.1 Bcf in 2Q 2011. By July, it was producing approximately 104 MMcf/d of gas. It planned to bring its second rig online in August for a Susquehanna drilling program. For all of 2011, it planned to participate in 40 to 45 operated wells. Southwestern said it would raise its rig count to four or five in 2012. The company's Ball Myer 1H well in Bradford County, with 19 frac stages in a 4,502-ft lateral, tested at a tubing-constrained rate of 7.8 MMcf/d of gas after 33 days on production. The company's previous horizontal wells had average laterals 3,900 ft long with 10 frac stages.

Statoil ASA

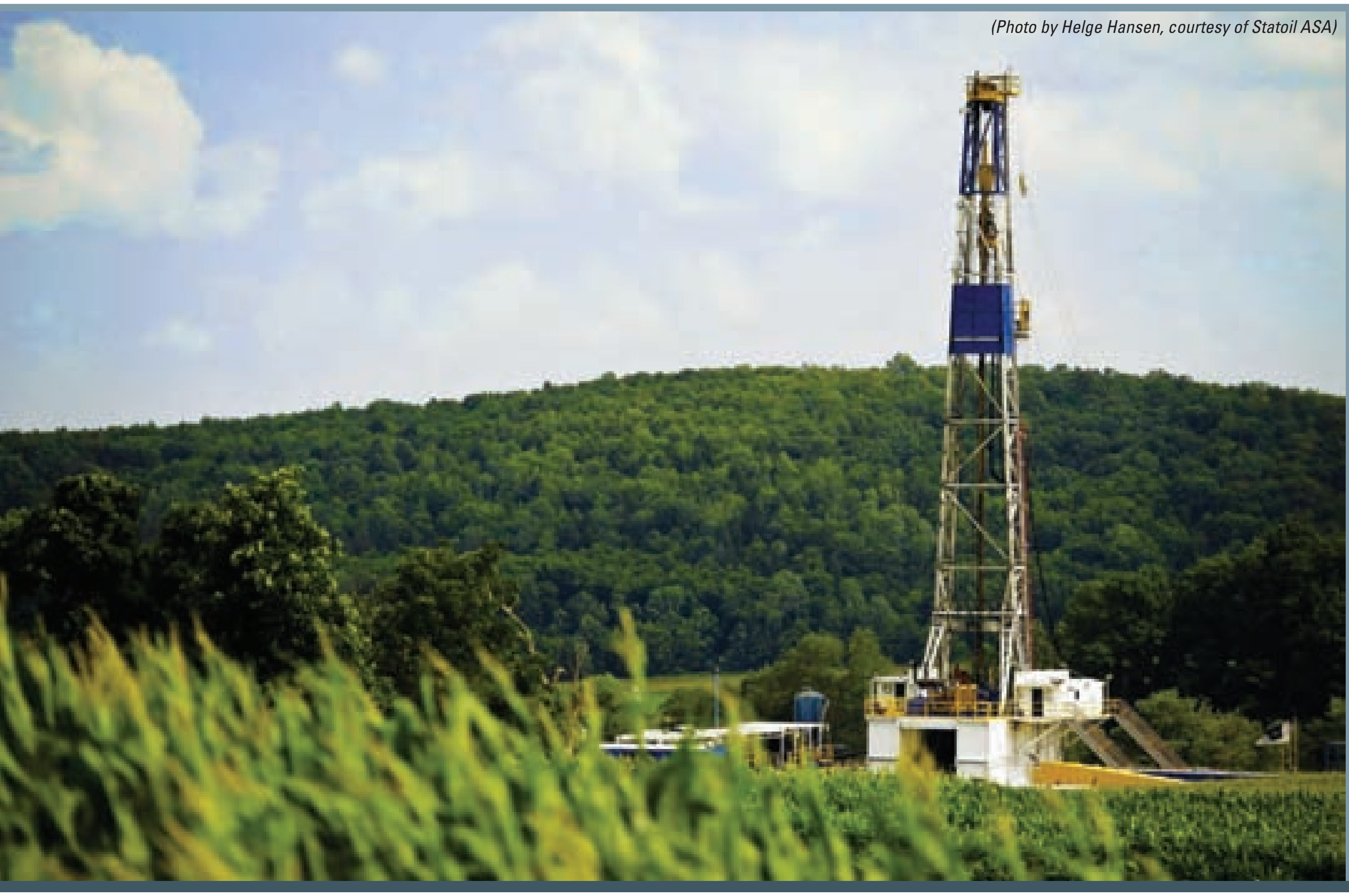
Statoil holds a 32.5% interest in approximately 1.8 million acres of land with Marcellus potential in Pennsylvania, West Virginia, and New York.

BAKKEN/THREE FORKS

In mid-October 2011, Statoil ASA signed a definitive agreement to merge with Brigham Exploration by offering Brigham shareholders US $36.50 a share for their stock, or $4.4 billion. The tender offer began at the end of October and the companies anticipated completing the deal in late 2011 or 2012. Brigham holds some 375,800 net acres in the Bakken/Three Forks play in North Dakota and Montana and has de-risked 235,200 net acres. Brigham produced more than 13 Mboe/d from its North Dakota and Montana properties in July 2011, and by 3Q 2011 it still held 94 undrilled locations in the Bakken and 1,299 undrilled locations in the Bakken plus Three Forks zones.

EAGLE FORD

Statoil ASA entered the Eagle Ford play in 2010 with separate agreements with Enduring Resources LLC and Canada's Talisman Energy Inc. Statoil signed a 50-50 joint venture agreement with Talisman to develop 37,000 Talisman acres in the play. Statoil got 18,500 net acres for $180 million. The venture partners then acquired the Eagle Ford assets of Enduring Resources, 97,000 gross acres, with 48,500 net to Statoil. The companies paid $1.325 billion, or $10,900 an acre, for that acquisition. On a net basis, Statoil acquired its 67,000 acres for $843 million to receive an estimated 550 million boe in



(Photo by Helge Hansen, courtesy of Statoil ASA) recoverable resources. The companies also have an option to acquire up to 22,000 additional acres. Under the agreement, Talisman will operate all the properties for the first three years. After that, Statoil will take over operations on half the acreage.

MARCELLUS

Statoil made its first big move into US shale plays in 2008 when it acquired 32.5% of Chesapeake Energy Corp.'s 1.8 million acres in the Marcellus Shale area of Appalachia. That property could support 13,500 to 17,000 horizontal wells drilled over the next 20 years. At that time, the companies planned to jointly explore opportunities for development of unconventional resources worldwide. The agreement covered more than 32,000 leases in Pennsylvania, West Virginia, New York, and Ohio, and Chesapeake planned to continue acquiring leases in the play. Statoil held the right to participate in any additional acreage up to a 32.5% share. That deal gave Statoil access to a potentially recoverable 2.5 billion to 3 billion boe. The company expected to see production rise to 50,000 boe/d in 2012 and at least 200,000 boe/d after 2020.

Stone Energy Corp.

BAKKEN

While a large part of Stone Energy Corp.'s operations lie in its Gulf of Mexico properties, the company has assembled approximately 35,000 net acres of land prospective for the Bakken Formation on the Montana side of the southern Alberta Basin.

EAGLE FORD

The company has approximately 2,000 net acres in the Eagle Ford play in South Texas. In recent activity, it held a non-operated 42.5% working interest in the Moczygemba #1H horizontal well that was flowing approximately 300 boe/d in September 2011 after early production of more than 800 boe/d. It planned to participate in another well before the end of 2011.

MARCELLUS

Stone Energy held some 14,000 acres in its Katie and Andie project areas in the Marcellus play in northeastern Pennsylvania, another 28,000 acres in its Christine area in west-central Pennsylvania, and 33,000 acres in the liquids-rich area of northern West Virginia in its Mary, Heather, and Buddy areas. It planned 19 horizontal wells at its Mary Foundation area and three horizontal wells at Heather. It planned to produce 10 to 15 MMcfe/d of gas in 4Q 2011 as it dedicated one-third of its US $500 million 2011 capex budget to the Marcellus. The company said it produced 13 MMcf/e from the Heather-Buddy area, and it started producing in the Katie area after a pipeline connection. In a 1Q 2011 report, Stone said it expected drilling efficiency to increase the number of wells drilled on its property from 21 to 24 in 2011 with 16 to 20 of those wells fractured and completed. Production should increase as pipeline connections are completed.

NIOBRARA

The company holds 10,000 net acres in the Niobrara play in southeastern Wyoming.

Sundance Energy Inc.

BAKKEN

The US arm of Australia's Sundance Energy Inc. had approximately 8,667 net acres in the Williston Basin on June 30, 2011, at a cost of US $279 an acre. That Bakken/Three Forks acreage contained 6.28 MMboe in proved reserves on Dec. 31, 2011, according to an August 2011 presentation. It had 4,230 net acres in the South Antelope prospect with 37 gross, 3.6 net, producing wells and 213 gross, 21.2 net, drillable locations. At the 1,527-net-acre Phoenix prospect, it had 15 gross, 1.7 net, producing wells and 86 gross, 8.7 net drillable locations. It held another 2,825 net acres at its Goliath prospect with 26 gross, 0.5 net producing wells and 263 gross, 4.7 net, drillable locations.

NIOBRARA

The company held 15,192 net acres of land prospective for Niobrara Shale production in Colorado and Wyoming, which it picked up at an average cost of $91 an acre. That included 9,600 net acres in the heart of the play with some acreage offsetting Silo Field in Wyoming and Hereford Ranch Field in Colorado. It planned initial development work on those properties in 4Q 2011. It leased another 5,600 acres of land in the Niobrara play in the North Park Basin of northern Colorado near an EOG discovery well. Sundance held another 40,000 net acres of land in the southern Denver-Julesburg Basin of Colorado, which it said was prospective for the Atoka, Cherokee, and Niobrara formations, but the property had been explored by August 2011. It planned a 3-D seismic shoot in 4Q 2011 to identify potential targets. That land includes the company's Arriba prospect in Lincoln County and the Spring Creek prospect in Kit Carson County.

Talisman Energy Inc.

BAKKEN

Talisman Energy Inc. held a substantial position in the Bakken play in Daniels County, Mont., and southeastern Saskatchewan, but it sold the properties in 2009 to Crescent Point Resources and the TOG Partnership affiliate of Tristar Oil & Gas Co. for US $565.6 million.

CARDIUM

The company has started developing its Cardium Formation properties in the Alberta Deep Basin. It planned to put 10 new wells onstream in 2011 on its 114,000 net acres in the oil window where it has 490 net well locations. Its 30-day initial production (IP) potentials averaged 120 boe/d. It held another 45,000 net acres with 90 net well locations in the Cardium wet gas window. It planned three wells there in 2011 among its 90 net well locations. Its EUR were 500 Mboe per well from wells with an average 30-day IP of 330 boe/d.

EAGLE FORD

Talisman controls 78,000 net acres in the Eagle Ford play in South Texas where it has an average 40% working interest in a partnership with Norway's Statoil. It estimated contingent resources of 3 Tcfe of gas (550 MMboe) with a full-cycle break-even point of less than $4/MMBtu. It has 750 net well locations in the play. EUR were running about 660 Mboe with 30-day IPs of 1,200 boe/d. The company ramped up its activity from four rigs in 2010 to 10 rigs in 2011 and put two dedicated frac crews to work. It drilled 10 gross, four net, wells in the play in 2Q 2011.

MARCELLUS

The Alberta-based company put together a land package of 223,000 net acres in the Marcellus play in northeastern Pennsylvania and southern New York. It classified the play as development-stage as it works toward 6 Tcfe of gas in contingent resource in Pennsylvania and another 4 Tcfe in New York. It has 1,850 well locations in Pennsylvania and planned to spend $800 million. It put 22 wells online in the play in 2009, ramped up to 99 wells in 2010, and planned about 100 wells in 2011. In the same years, production rose from 29 to 181 MMcf/d to an anticipated 350 to 400 MMcf/d average for 2011. EURs average about 5 Bcf per well with 30-day IPs of approximately 4 MMcfe/d.

MONTNEY

Talisman signed a 50-50 joint venture (JV) agreement with South Africa's Sasol in the first half of 2011 to develop part of Talisman's Montney properties where the companies will target some 10 Tcfe of gas in contingent resources in the Farrell Creek and Cypress areas, which they will develop as an integrated project. Sasol entered the play for $2.03 billion, consisting of $504 million in cash and $1.53 billion in funding commitments on 52,000 acres at Farrell Creek and 57,000 acres at Cypress. After Talisman put 20 wells onstream in 2010, the companies started the development phase at Farrell Creek in 2011 with another 25 wells in 2011. They expect EUR of 7 Bcfe per well and a 30-day IP of 6 MMcf/d. They put 10 rigs to work in 2011 to start developing 1,700 well locations. Overall, Talisman has 211,000 net acres in the Montney play, including the JV properties, another 10 Tcfe in contingent resources in the Heritage Montney area, and 13 Tcfe in other Montney properties, including Groundbirch. It has 4,300 well locations.

UTICA

Talisman's Utica Shale play is in the pilot phase with additional work pending regulatory decisions by the Quebec government. It controls some 756,000 net acres of land with Utica potential in the St. Lawrence Lowlands. Among tests, its average IP for vertical wells is 600 Mcfe/d of gas. Its St. Edouard horizontal well tested for 5.3 MMcfe/d, and its second and third horizontal wells still are under evaluation.

Ultra Petroleum Corp.

MARCELLUS

Ultra Petroleum Corp. started acquiring land in Pennsylvania in 2001 with plans to develop deeper plays and drilled its first well in 2005. Now, it holds 164,000 net acres centered on Potter and Tioga counties in northern Pennsylvania and another 96,000 net acres in the Clinton-Lycoming area. It had 75 producing wells in the northern area and 17 producing wells in the southern area with a total net risked resource potential of 9.5 Tcfge from 2,500 net wells. Its finding and development cost is US $1.62/Mcfge and the properties could yield $15.4 billion in future capital. It has seven drilling pads on the property and recent wells with an initial potential as high as 10.3 MMcfg/d. In September 2011, it was drilling on 110-acre spacing, but the company said it saw encouraging results from wells on 500-ft and 750-ft well spacing. The company brought 59 horizontal wells on line in the first 10 months of 2011 with an average initial production rate of 6.4 MMcfge/d. It anticipated bringing 106 gross, 53 net, Marcellus horizontal wells on line during 2011 with year-end cumulative production of 40 Bcfge. Since starting work in the play, the company has drilled 290 wells and brought 155 of them into production.

NIOBRARA

The company holds approximately 100,000 net acres of land in the Denver-Julesburg Basin targeting liquids-prone Niobrara production in its new ventures portfolio. It planned to drill and complete four vertical wells in 4Q 2011 and 1Q 2012 and begin a horizontal well evaluation program in 2Q 2012. If prospects turn out as planned, it will get 200 to 400 Mboe per well. It also planned to acquire additional land and seismic data.

Unit Corp.

BAKKEN

Unit Corp. planned to spend US $30 million on its 13,400 net acres in the Bakken play in the North Dakota section of the Williston Basin. That spending will go to support the company's 12% working interest in operating two to three rigs to drill 20 non-operated wells. Currently, it is working in Williams and McKenzie counties, but it also has property in Sheridan County, Mont., set aside for future drilling. Results from 1Q and 2Q 2011 indicate 628 Mboe in potential recovery per well with an 86% oil cut. Average cost to completion was $10 million for a horizontal well with a 9,000-ft lateral and 25-stage frac treatment.

GRANITE WASH

From 4Q 2010 through the 2Q 2011, Unit received first sales on 16 operated Granite Wash wells on its 36,000 net acres in the Texas Panhandle. Reserves on those wells average 4 Bcfe of gas with 47% oil and liquids and initial 30-day potential production of 6.6 MMcfe/d. It planned to run three to four rigs in the play to drill about 20 horizontal wells. Its $96 million in capex also would support another 16 non-operated wells. The company's cost to completion averaged $5.4 million with 4,000-ft laterals and 11-stage stimulation treatments.

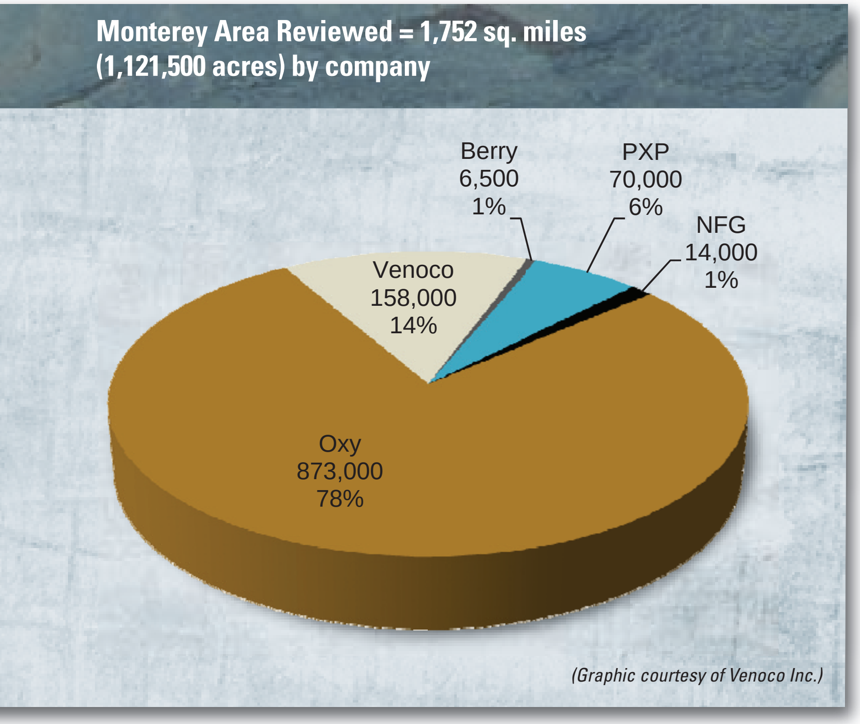
MARCELLUS

Unit's operations in Appalachia in September 2011 included the final stages of construction of a 16-mile, 16-in.-diameter pipeline and compression station in Preston County, W. Va., with a capacity of 220 MMcf/d of gas. It also started construction for a gathering system and compression station in Tioga and Potter counties in Pennsylvania with completion scheduled in 4Q 2011 or 1Q 2012. It also signed a letter of intent to build a 7-mile, 16-in.-diameter pipeline in Allegheny and Butler counties in Pennsylvania with completion scheduled for the first half of 2012.

Venoco Inc.

MONTEREY

Venoco Inc. started working the Monterey Shale, which it calls the nation's largest shale liquids play, in 2006 with its offshore properties in California. Both South Ellwood and Sockeye fields produce from the Monterey Shale, and South Ellwood has produced 53 MMboe from that formation, according to an August 2011 presentation. South Ellwood and Sockeye, along with its West Montalvo offshore



Oxy is the big gun in Monterey acreage. Venoco, in second place, is followed by Plains Exploration, Newfield Exploration, and Berry Petroleum.

field, which does not produce from the Monterey, accounted for 85% of the company's Southern California production. It has 72 MMbbl of oil of potential production from the Monterey at South Ellwood and another 17 MMbbl from Sockeye. It holds another 214,000 net acres onshore prospective for the Monterey, including 18,000 acres in Salinas Valley, 29,400 acres in the Santa Maria Basin, 8,400 acres at its Sevier location and 112,100 acres in the San Joaquin Valley. In addition, it joined Occidental Petroleum Corp., the largest landholder in the play, in shooting the largest 3-D seismic survey ever shot in California with the Monterey as the primary target. Onshore Monterey potential includes 175 MMbbl from Orcutt Field in the Santa Maria Basin, 550 MMbbl from sand facies in the Monterey at San Ardo Field, 86 MMbbl in its Elk Hills properties in the San Joaquin Basin, and another 13 MMbbl from North Shafter Field in the San Joaquin Basin. It already produces from the Monterey, or has Monterey potential held by production from other zones, on 46,000 onshore acres. It planned to spend US $100 million in 2011 for 15 wells onshore, including four vertical Monterey tests at Sevier and permitting for additional pads for 2012 activity and one vertical and one horizontal well in the San Joaquin Basin. It had one rig operating in the Monterey in 2Q 2011 and planned to add four more rigs by the end of 2011. The company planned to work six to eight rigs and spud 50 to 75 wells in 2012, most of them to delineate and develop its Sevier discovery.

Showing his confidence in the future of the company, CEO Tim Marquez offered in late August 2011 to buy all of the stock in the company that he didn't already hold at a 39% premium to the company's market price at the time of the offer.

Voyager Oil & Gas Inc.

BAKKEN

Voyager Oil & Gas Inc. controlled 30,000 net acres in a growing property position in the Bakken/Three Forks/Sanish play in North Dakota and Montana. It reached that position with the acquisition of 5,262 net acres on land in 2Q 2011 at an average price of $1,570 an acre. By the end of 2Q 2011, Voyager had 63 gross, 3.13 net, Bakken and Three Forks wells in the drilling, completing or producing stages, including 24 gross, 1.13 net, producing wells. By the end of 3Q, Voyager held production from 46 gross, 1.66 net, wells. The company planned to participate in six net wells to the two formations during 2011.

NIOBRARA

The company is participating with Slawson Exploration on a heads-up basis in a half interest in 21,000 net acres of land prospective for Niobrara production in Weld County, Colo., and Laramie County, Wyo., in the Denver-Julesburg Basin. Drilling on the properties started in late 2010, and by the end of 2Q 2011, Slawson had drilled six wells under the agreement, all in Weld County.

HEATH

Voyager also put together a 33,500-net-acre package in the Heath oil shale play in Garfield, Fergus, Musselshell, Petroleum, and Rosebud counties in Montana. It compared that play to the Bakken in the Williston Basin and said the Heath offered high porosity and significant natural fracturing.

WestFire Energy Ltd.

VIKING

Calgary, Alberta-based WestFire Energy Ltd. concentrated its activities on the Viking liquids shale play in southeastern Alberta and southwestern Saskatchewan through a series of attractive acquisitions. By July 31, 2011, it had assembled 155,000 net undeveloped Viking-prospective acres and saw significant upside potential on its properties by using waterfloods to increase recoveries from the current 5% to 10% of hydrocarbons in place to 15% to 20% of in-place resources. It drilled and completed 39 wells in the first half of 2011 with a 100% success rate, and all 39 were on production in mid-September, according to a company presentation. The company increased operation efficiency by drilling on pads. It held properties in the Redwater area of Alberta, at its West Central Saskatchewan location and at its Provost properties. Altogether, it held 244.5 net sections of Viking-prospective land with 1,160 net unrisked, 812 risked, locations; 71.4 MMboe of net unrisked, 52 MMboe risked, EUR potential; and 71,600 boe/d unrisked, 51,800 boe/d risked, potential production. It drilled 10 gross, 9.2 net, Viking wells in 3Q 2011 and established enough history from five wells to project an 85 boe/d first-month average production rate with a 95% oil cut. It also increased the number of frac stages on its horizontal wells to 20 from 15 for better recoveries. The company's acquisitions since December 2007 included Northern Challenger Exploration, K-Town Energy Ltd., five private companies in the Dodsland area of Saskatchewan, Racing Resources Ltd., Exceed Energy Inc., Provost Alberta Viking assets, and a strategic merger with Orion Oil & Gas Corp.

Whiting Petroleum Corp.

BONE SPRING/WOLFCAMP

Whiting Petroleum Corp., the 17th-largest producer in Texas in 2011, gets a small part of that production from the Bone Spring and Wolfcamp formations in its Big Tex Field on the Texas side of the Delaware Basin. The Bissett 9701, the company's first horizontal well in the field, was producing 788 boe/d on July 25, 2011. At that time, it had two rigs working the play with US $60 million set aside to drill 19 wells in 2011, according to an August 2011 presentation. The prospect area covers 83,303 net acres in Pecos, Ward, and Reeves counties, which the company acquired for $540 an acre.

BAKKEN

The company's Bakken/Three Forks/Sanish activity made it the second-largest oil producer in North Dakota with 13.7 MMboe produced in 2010. It held 75 MMboe in EUR at $12.91/boe and a resource potential of 127 MMbbl of oil, 11 MMbbl of natural gas liquids, and 70 Bcf of gas, or 148 MMboe. For 2011, the company planned 95 gross wells for $319 million at Sanish Field and 48 gross wells for $330 million at Lewis & Clark Field. Whiting controls 680,137 net acres in the Bakken Trend in Sanish, Tarpon, Cassandra, Hidden Bench, Lewis & Clark, and Big Island fields in North Dakota and Starbuck and Missouri Breaks fields in Montana. It was producing 31,161 boe/d from those properties and from interests in other fields on July 19, 2011. Among recent significant wells, the company's Norgard 21-13H at Hidden Bench tested for an initial flow of 3,065 boe/d, and its Smith 34-12TFH tested for an initial potential of 2,939 boe/d from Lewis & Clark Field.

NIOBRARA

Whiting assembled 75,701 net acres of land at $462 per net acre in its Redtail project in northern Weld County, Colo., north of Wattenberg Field, in the Denver-Julesburg Basin. It estimated recoveries of 38 MMbbl of oil and 24 Bcf of gas, or 42 MMboe, from its properties and planned to spend $62 million for 10 gross, nine net, wells in 2011. Its Wild Horse 16-13H discovery well, completed on June 16, 2011, with a 4,113-ft lateral and 21 frac stages, tested for 1,321 boe/d and averaged 454 boe/d during its first 30 days online.

WhitMar Exploration Co.

BAKKEN

Privately held WhitMar Exploration Co. formed a leasehold acquisition and drilling joint venture (JV) in the Bakken/Three Forks play on 52,000 acres of leases in WhitMar's Lego and Snow Goose prospects in

Sheridan County, Mont. In July 2011, the companies made an initial commitment to drill two horizontal wells and anticipated drilling the first well in 4Q 2011. WhitMar will keep a 25% interest in the venture.

MARCELLUS

The company parlayed a series of partnerships with experienced operating companies into a successful operation in the Marcellus Shale in Pennsylvania where it holds some 160,000 acres. In a JV partnership with XTO/Exxon, it completed the Brown #8520H for 5.2 MMcf/d of gas and the #8519H for 5.15 MMcf/d in June 2011 in Lycoming County, Pa. A May well in that program showed an initial potential of 6.25 MMcf/d of gas. WhitMar and partners Stone Energy and Carrizo tested their Loomis 2H well in Susquehanna County, Pa., for an initial potential of 9.2 MMcf/d in 2010 after completing their first two wells in the arrangement the previous month, one of those for 9.8 MMcf/d. It also started drilling the first well in a partnership with Encana Oil and Gas (USA) Inc. in July 2010, but after drilling two wells with poor results, the partners decided to discontinue activity in the prospect area in November the same year.

Williams Cos. Inc.

BAKKEN

Williams Cos. Inc. holds 89,420 net acres of land in the Bakken play with 23 MMboe in proved reserves. It calculated its proved, probable, and possible reserves at 185 MMboe, and during 2Q 2011, it produced 5.9 Mboe/d.

EAGLE FORD

The company has gathering assets in the Eagle Ford Shale play through an arrangement with Copano/Kinder Morgan.

MARCELLUS

Williams Cos. has both upstream and midstream assets in the Marcellus Shale. Its upstream assets, which it calls "an upstart presence," include 99,301 net acres of leases producing 12 MMcfe/d of gas. It holds an estimated 100 Bcf in proved reserves and 1.7 Tcf in proved, probable, and possible reserves in the trend. On the midstream side, it acquired the gathering assets of Cabot Oil & Gas in northeastern Pennsylvania and partners with Chevron on gathering product on that company's former Atlas assets in southwestern Pennsylvania. It is increasing capacity in both areas. In the southwest, it plans to double capacity to more than 900 MMcf/d. In the northeast, it plans to increase capacity from 400 MMcf/d in July 2011 to 1.2 MMcf/d by November 2012. Overall, it will increase capacity to 2 Bcf/d by 2013 and 2.75 Bcf/d by 2015 with plans to spend some US $4.25 billion in the Marcellus area through 2016.

TUSCALOOSA MARINE SHALE

The company has gathering assets that serve the emerging Tuscaloosa Marine Shale play.

In the Eagle Ford play, Hess spent US $15 million upfront and agreed to carry ZaZa for $800 million. The companies planned 30 wells in 2011, 100 wells in 2012, and 150 wells in 2013

ZaZa Energy LLC.

EAGLE FORD

ZaZa Energy LLC planned a merger with Toreador Resources with a closing set for 4Q 2011 to form a new company called ZaZa Energy Corp. ZaZa already had 123,000 gross, 12,300 net, acres in the Eagle Ford play and was acquiring more in 3Q 2011. It also held 80,000 gross, 59,000 net, acres in the Eagle Ford/Woodbine, or Eaglebine, play in East Texas and planned to raise that position to 100,000 acres. It operated three drilling rigs and planned to add two more by 1Q 2012. The company had drilled 17 operated wells through September 2011 and planned to drill 30 wells and complete 23 by the end of the year. ZaZa formed a 90-10 joint venture (JV) partnership with Hess Corp. in the Eagle Ford play with Hess holding a 90% interest. Hess also joined Toreador in a 50-50 JV to work 400,000 net acres of shale in the Paris Basin of France. In the Eagle Ford play, Hess spent US $15 million upfront and agreed to carry ZaZa for $800 million. The companies planned 30 wells in 2011, 100 wells in 2012, and 150 wells in 2013. ■

(Photo courtesy of Baker Hughes)

Today's Technologies Support Operator Goals

By Jerry Greenberg
Contributing Editor

New and existing tools can improve economics and give players a competitive edge.

Operators seek the latest drilling and completion technologies to reap economic and competitive advantages. Today, the technology of choice for a particular shale play might be the latest high-performing bits geosteering solution or a high-angle rotary steerable system. In other cases, operators may re-examine and employ shale technologies applied several years ago, such as multilateral technology.

Service companies have developed faster, more efficient stimulation techniques that can fracture multiple intervals at the same time. Several of these companies have developed a pinpoint fracturing method for more effective stimulation compared with plug and perforation, for example. One company developed an optical television viewer for formation imaging to provide high resolution images of rock fabric and fractures associated with the production of hydrocarbons.

A case study in technology solutions

Chesapeake Energy Corp. owns leading positions in the Barnett, Haynesville, Bossier, Marcellus, and Pearsall natural gas shale plays. The company is also an important player in the Granite Wash, Cleveland, Tonkawa, Mississippian, Bone Spring, Avalon, Wolfcamp, Wolfberry, Eagle Ford, Niobrara, Three Forks/Bakken, and Utica unconventional liquids plays.

Chesapeake recently achieved key production milestones and set new corporate all-time production records with gross operated production reaching 6.1 Bcfe/dwith its net production exceeding 3.45 Bcfe/d, including approximately 95,000 b/d of liquids. By the end of 2012 and 2015, the company plans to increase its net liquids production by 50% and 150% to more than 150,000 b/d and more than 250,000 b/d, respectively, while maintaining its net natural gas production at current levels. As recently as 2009, the company's full-year liquids production averaged only 32,000 b/d.

Chesapeake is targeting a development program with average drilling and completion costs of approximately US $5 million to $6 million per well. The company currently has five drilling rigs under contract in the Utica Shale play and plans to increase its operated rigs through 2014. Chesapeake expects to have 10 rigs under contract by year-end 2011, 20 rigs by year-end 2012, and 40 rigs by year-end 2014.

Due to its anticipated growth and the shortage of key services to the industry, especially in the liquids-rich plays, Chesapeake has purchased service companies and

Pictured far left: Baker Hughes' OptiPort fracturing system is conveyed downhole on coiled tubing.

An Oklahoma City employee works at Chesapeake's Reservoir Technology Center performing analysis on cores taken from unconventional oil and gas reservoirs.

(Photo courtesy of Chesapeake Energy)

(Photo courtesy of Chesapeake Energy)

An example of Chesapeake's vertical integration in the field: employees of Nomac Drilling, a Chesapeake subsidiary, work on a rig.

equipment. The company created a new subsidiary, Chesapeake Oilfield Services (COS), for these new assets.

The operator initiated its service company vertical integration strategy in 2001 with a $25 million investment to build and refurbish five drilling rigs. In the past 10 years, the company has built what it believes will become a top five US-focused oilfield service company. The goal is to provide premium services at attractive prices to its E&P operations while improving operating efficiencies, lowering costs, and serving as an inflation hedge. Including Chesapeake's 30% interest in Frac Tech International, the company has invested approximately $1.8 billion in its service companies and believes its service companies could be worth between $7 billion to $10 billion in 2012.

COS subsidiaries include:

- Nomac Drilling – the fourth-largest drilling contractor in the US with 114 operated rigs;
- Performance Technologies – a start-up pressure pumping company that had 60,000 hp in the field in October 2011. The company anticipates 140,000 hp by February 2012 and 300,000 hp by year-end 2012;
- Thunder Oilfield Services – a holding company for trucking, equipment rental, and rock excavation businesses;
- Compass Manufacturing – supplies natural gas compression packages and related production equipment to Chesapeake's wholly owned subsidiary MidCon Compression, the second-largest natural gas compressor provider in the US; and
- CHK Directional Drilling – a leading provider of integrated directional drilling and MWD services.

Chesapeake owns its own reservoir technology center in Oklahoma where the company analyzes cores using its proprietary Tight Rock Analysis equipment and processes. Data is available two to three weeks from when the core is received, allowing the Chesapeake to focus on areas with high rates of return in new and developing plays. According to the company, the quality of this data is confirmed through reservoir simulation, 3-D geocellular models, and matching historical well production, and it has led to a better understanding of how to proceed with optimal field development.

"We can speed up the rock identification process and keep that information confidential," said Steve Dixon, Chesapeake's COO. "The center also allows us to work on new techniques, new instrumentation, and better rock property measurements. A lot of the rocks that we are working with are tighter than conventional reservoirs, so a lot of the historic measurements may be outside the realm of other [technology centers]."

Similar to the reservoir technology center, Chesapeake's Engineering and Geoscience Technology Groups provide in-house expertise in reservoir modeling that precludes the need for third-party contracting of these services.

"As these plays mature, we can increase our understanding of the reservoir through modeling, including geocellular and reservoir models and simulations, to proceed with optimal field development.

"We are so active in so many plays that you can take the experience from one play to another," Dixon said, "so I think what we have is unique."

After determining in which plays to participate, signing leases, or owning properties where the company believes hydrocarbon activity is going to ramp up, COS can provide the company with rigs, rental equipment, and water management methods.

"We can, in a very short time, ramp up activity, and that has been another key to success for Chesapeake," Dixon said.

"During the summer of 2009, we had 17 rigs running in liquid-rich plays," Dixon said. "[In September 2011] we had 102 rigs."

Part of that shift is the result of reallocating rigs from dry gas markets to the oil and gas condensate plays. In the post 2008 recession, the company was running 94 rigs, but its total fleet is now at 175 operating units. It owns 114 rigs. Chesapeake has grown its fleet in part by acquiring drilling companies (Bronco Drilling is its latest purchase), but the company also has added newbuilds to its fleet, most of which work for Chesapeake.

The company trends toward the "plug and perf" method when it comes time to fracture the well. "Of the 175 rigs we have running," Dixon said, "maybe five of those wells would use a multiport completion system."

Chesapeake uses third parties for its stimulation activities, but it is building COS as a fracture stimulation company. Chesapeake planned to perform its first frac job under COS last October, and, as noted earlier, is planning to significantly build its pumping horsepower capacity by the end of 2012. While it may seem like it on the surface, the company is not trying to push out third party companies completely. According to Dixon, "We would do our own stimulation if there was a choke or bottleneck to our activity or if the margins are just too high that there is no reason why we couldn't do the job."

The operator often works for itself managing water resources for its many active plays. The Texas drought is a good example. The Edwards Aquifer, where most of the water for Eagle Ford is sourced, is still in good shape, Dixon said. However, the company is moving toward alternate water sources by testing brackish water found deeper than the aquifer and tapping that water that isn't used for public or irrigation consumption.

"This could allow us to use water that is slightly inferior but still works fine for fracing," Dixon said. "We really haven't had a problem with water in Eagle Ford as we are drilling on a lot of large ranches and the owners provide water. However, we are very sensitive to water sourcing issues. We are making every effort to maximize our reuse of produced water and to seek out alternative water sources that require minimal treatment. In some cases the brackish water may only have be run through a filtering process."

The company has focused on improving the environmental footprint of its hydraulic fracturing fluids. This effort has influenced the chemical additives purchased for COS. Additionally, the company works closely with its third-party stimulation contractors to improve their additives per Chesapeake specifications.

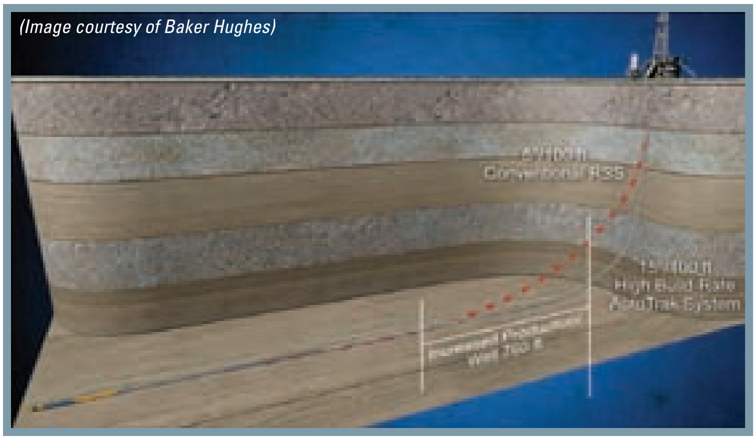
"We are working very hard on greening our fracturing chemicals, and we have eliminated or substituted a significant portion of our frac chemicals to make them greener," Dixon emphasized.

Throughout the industry, operators and service companies are all working hard pursuing solutions to the challenges of unconventional play development. Efforts focus on three key areas: drilling, stimulation, and water management.

DRILLING TECHNOLOGY

High-angle rotary steerables, CT fracture stimulation

Drilling with a rotary steerable system (RSS) has significant benefits. They include ROP, faster drilling in 3-D well profiles, more precise placement of the well into a reservoir's sweet spot, and production of a smooth well bore, which aides in casing running and completion design. It has been shown in some unconventional reservoirs that when using a RSS, an operator can drill the vertical, curve, and hori-



(Image courtesy of Baker Hughes)

With Baker Hughes' high build RSS, an operator can land the bit into the horizontal lateral quicker and potentially produce from an additional 760 ft of reservoir compared with a conventional RSS that delivers a dogleg severity of 5°/100 ft.

zontal sections in one run while also steering the well through any formation dips and faults to remain in the target formation.

Two service companies have developed their own iteration of a high-angle RSS capable of drilling 15-17°/100 ft while providing all the drilling advantages of a conventional RSS, plus a few more important benefits. For example, the operator can enter the lateral quicker, increasing the length of the productive horizontal section while remaining within the lease line.

Baker Hughes is testing its high-angle RSS and expects to launch the system in 1Q 2012. Field tests have been successful, according to the company.

"We drilled the vertical, curve, and lateral in some of these shales in one run, generally with an 8 ¾-in. hole size," said Paul Bond, Baker Hughes marketing director for Drilling Systems, US Land.

"I think we are at our technical limit as to how fast we can drill with conventional motor assemblies. With rotary steerable systems we are beating the technical limit of motors sometimes by a couple days on a seven- or eight-day well. I'm sure we are going to shave off even more time. What we will see is the ability to drill a six- or eight-well pad in only two months instead of three months," he said.

This particular system can drill up to about 17°/100-ft doglegs compared with 6°/100 ft with conventional RSS. The new system can drill a complex 3-D curve up to the landing point in the reservoir and then seamlessly switch to a mode that allows the drilling of the lateral with minimal tortuosity, according to the company. There is no requirement to trip to back off on the dogleg capability. The tool can drill a curve that meets the objectives in 3-D trajectory. When the curve is landed, the system can continue to drill a very straight lateral, Bond noted.

The system consists of a single-piece bottom-hole assembly (BHA) with a non-rotating sleeve that deflects the BHA against the side of the well bore. The company designed the system to work in different formations from soft to very hard or brittle. Additionally, the BHA is more flexible to manage the increased bending loads.

Multilateral well techniques

Halliburton believes multilateral technology could become more prevalent in shale plays as a quick and cost effective method to complete the development drilling plan with less rig time and lower cost than drilling an entire pad.

Typically when drilling development wells in a liquids-rich or dry gas shale play, an operator drills the wells from multiwell pads that could contain anywhere from six to 20 well slots. A six-well pad is a traditional number of development wells, primarily due to the smaller footprint as well as permitting issues in a particular region. The result is a "mass" of wells in all directions, depending on how close the operator is to the lease line. However, one way to "drill up" a pad, or to drill more wells from the pad, is multilateral well technology. The technique generally is thought of as an expensive method to drain several formations, to optimally drain a reservoir, to increase production, or to choke off a formation that is expected to produce more water than oil in the future.

However, Halliburton developed a multilateral technology in which only three multilateral wells would need to be drilled to take the place of a six-well pad, or a six-well pad could have a dozen wells.

Shales are no stranger to multilateral well technology as numerous wells in the Bakken, Granite Wash, Permian Basin, and others contain multilateral wells drilled in the early 2000s. Interest in multilateral waned in the mid- to late-2000s, but may be picking up again as operators look for an economic advantage. In fact, Halliburton is working with an operator

that was one of the early companies to use multilateral technology in the Bakken.

"There is interest," said Doug Durst, global multilateral solutions manager for Halliburton. "We are getting requests from operators to visit and tell them what we have to offer, so there is interest. We just don't know how strong it is yet. We think at some point it will grow simply because we believe we can make it cost effective. As long as operators can move past the risk factor, it could become more predominant," he added.

Essentially, a multilateral shale well allows the operator to drill two horizontal wells from the same location. When previously used, operators received better production results from the horizontals, according to Durst, and their drilling assemblies performed better. "Data published on drilling a single multilateral well versus drilling two single horizontal wells all had savings on the drilling and the completion side," Durst said. "Instead of drilling six wells on a pad, for example, you can drill three and get the same reservoir exposure and the same anticipated production. With multilaterals you not only save on rig time, fluid lines, and wellheads, but there are fewer trucks on the road, which reduces safety issues. All of those numbers go down because there is less surface penetration."

Key to a successful multilateral well is fracturing the two laterals. Typically when drilling a multilateral well with two horizontal sections, the operator will case and cement the bottom horizontal. If it does not case and cement back to the vertical well section, there may be an openhole section. Either way, the operator will run a liner with a multistage frac completion.

"The main branch, or the lower lateral, will always have some kind of liner, either cemented or uncemented," Durst explained.

An operator also will install a liner in the upper lateral. However, where the operator ties the liner in the upper lateral into the main vertical section there typically is no seal, and the operator is left with either an openhole section or a cemented liner that has been partially removed, Durst noted.

"Either way, there is no pressure integrity," he said. "The key is having the ability to isolate the junction so the pressure is being applied to the lateral and not the junction -- what we call a temporary Level 5 multilateral.

"In a shale play, you have to come back with a completion product that provides the ability to isolate one of the laterals while stimulating the other," Durst said. "You have to have the ability to selectively frac the laterals and isolate the junction so you don't expose it to any pressure."

When you selectively frac one lateral and isolate the other, do not give up any inside diameter, Durst said. This means the hardware components used t o isolate one lateral from the other do not restrict the inside diameter (ID). The operator can use conventional plug and perf techniques, drop ball sleeves, or coiled tubing techniques. The ID remains the same when going from a horizontal well bore to a multilateral.

"We also are using other products such as swellable packers and expandable liner hangers. An assortment of integration is going into these types of shale multilateral wells," Durst said.

Varying the approach

The brute force approach of multistage fracturing of horizontal laterals is not receiving as much value as operators would like from their wells, according to some industry insiders. Often, production logs indicate that fracture clusters do not perform as anticipated. Why don't they and what can be done to get more value from the fracture?

Halliburton analysis revealed that operators were drilling wells in unconventional reservoirs into a piece of stratigraphy within a particular rock section with no concept or input of what the geology actually was doing. Operators were targeting a particular zone but no matter what the rock property, it was getting treated exactly the same.

According to Halliburton, its DrillDOC tool helps produce an optimal well bore by using a dynamic downhole measuring system that allows the operator to transmit real-time high-speed data on weight, torque, and bending moment to characterize the transfer of energy from the surface to the bit. Data is transmitted to the surface via electromagnetic (EM) pulse, resulting in significantly more data at faster transmission rates. The DrillDOC tool also contains sensors to measure vibration of the BHA downhole to ensure the full movement of the BHA is measured through all aspects of the drilling process. The tool runs with Sperry Drilling's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Heating Frac Fluids on the Fly
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pressure-while-drilling tool, with measurements that compensate for pressure and temperature changes downhole to ensure the accuracy of the tool's measurements through a full range of temperatures and pressures in all conditions.

The tool features redundant measurement sensors in the event of a sensor failure. The operator can install multiple tools in the same BHA with real-time telemetry capability. As a result, the operator can run the tools below and above reamers or hole openers. Engineers can optimize drilling and reaming performance, maximize ROP, and reduce non-productive time based on the data acquired.

Optimizing stimulation procedure

"There is sometimes a disconnect between the geology, the well, and the stimulation process," said Jason Pitcher, global well placement solutions champion for Sperry Drilling. According to Pitcher, the company's sonic tool can obtain enough information to help stimulation engineers develop a better fracture program and make an impact on the completion. The tool can send the information while drilling the well and steering into the most productive rock or the operator can download the information after drilling operations. "The sonic tells the operator the ratio to determine a good rock from a fracture standpoint," Pitcher said.

"As a result, we developed a process called drill-to-frac where we can assemble gamma and sonic tools, drill the well, and steer according to the sonic properties. We are not so concerned about stratigraphy. We want to be within a 30-ft-thick window, for example, but what we really want to know is where to place a 6 ¼-in. well bore within that 30-ft window. It can make a big difference and big impact to the production results," Pitcher explained.

The company can use the sonic tool to place the well in fractureable rock, and then use the sonic data to fine-tune the completion and stimulation design.

The company is conducting pilot programs for several different operators in both liquids-rich and dry gas shale plays, and is looking at projects in Haynesville, Marcellus, Woodford, and Eagle Ford. While Halliburton is still running the drill-to-frac technique in pilot programs, the individual tools and software are commercially available.

High build rate rotary steering

Schlumberger developed its hybrid PowerDrive Archer high build rate RSS by pushing the envelope of RSS, according to the company. The high angle RSS is designed to help operators gain an increased amount of productive horizontal well sections over conventional RSS. The new tool, provided through PathFinder in North America, combines point-the-bit and push-the-bit steering and can drill the vertical, curve, and lateral sections in one run. The tool's internal pads push against an articulated sleeve pivoted on a universal joint to point the bit. It also enables open-hole sidetracking at any point in the well because of reduced dependence on wellbore contact. With all external parts of the RSS continuously rotating, even at such high dogleg severity (DLS), hole cleaning is improved, thus reducing the risk of stuck pipe. While the high-angle RSS has built curves at more than 17°/100-ft DLS with an 8 ½-in. bit in the Eagle Ford shale, this is not typical. Curves at 8-10°/100-ft DLS within the 8 ½-in. section are normal.

The high-angle RSS has been used in several North American shales including the Bakken, the Bone Spring-Permian, the Cana Woodford, the Eagle Ford, the Marcellus, the Niobrara, the Anadarko Basin, and the Cotton Valley.

"We are moving the technology into most of the liquids-rich plays in North America," said Dave Sobernheim, Schlumberger shale gas marketing communications manager and principal production engineer.

- In the Eagle Ford: Most operators drill wells in the Eagle Ford basin using conventional motors with a high percentage of slide intervals required to build curves up to 10°/100 ft. As a result, ROP is reduced along with the potential risk of casing running problems due to high wellbore tortuosity in the curve and lateral sections. On the other hand, continuous rotation greatly reduces micro doglegs and increases ROP by eliminating sliding intervals. In the Eagle Ford play, use of the company's high-angle RSS increased ROP by 85%, which consequently reduced the cost per foot by 27% compared to conventional motors. In a multiwell project, the RSS improved the average ROP in the curve, drilling 85% faster than conventional motors in

10 wells. The operator greatly reduced tortuosity in the curve and lateral and found for the first time that casing could be run to bottom without rotating, according to Schlumberger.

- In the Woodford Shale: Cimarex Energy planned to drill a well in the Woodford Shale in Oklahoma while reducing wellbore tortuosity experienced in four previous wells drilled in the field with a PDM. The operator used high-angle RSS to drill the Kappus 1-22H well. The high-angle RSS drilled the 8 ¾-in. curve section with an 8°/100-ft DLS, resulting in an 80% increase in ROP compared with the previous wells drilled with a PDM. The average ROP in the well curve section was 12.43 ft/hr compared with 6.65 ft/hr for the previous four wells. Wellbore tortuosity dropped 20% compared with the curve section of the closest offset well drilled with a motor. The quality of the curve section enabled the company to drill the 4,353-ft lateral section with a conventional RSS to TD in one run. Use of the two RSS saved the operator a total of 10 days.

(Photo courtesy of Schlumberger)

PowerDrive Archer high build rate RSS run by PathFinder with a Smith Bit in a North America shale play.

Shale-optimized steel-body PDC drill bits

Smith Bits, a Schlumberger company, designed the Spear shale-optimized steel-body PDC drill bit to improve the economics of shale plays. The Spear bit drills a curve and a long lateral hole section with a drilling motor or RSS while minimizing bit balling and short runs. According to the company it also improves ROP and enhances directional control. Conventional PDC bit designs target either the curve or the lateral section, but not both. Cuttings accumulate at the bottom of the well because there is no hydraulic energy at the drill bit. This impedes access to fresh rock and dramatically reduces ROP. Packed blades, plugged nozzles, and stuck or slippery drillstrings also can occur.

In the targeted applications, directional drillers use a steerable motor with a bent housing to steer the bit and achieve the desired DLS. A longer bit-to-bend length puts excessive torque on the motor and bit. The smaller makeup length of a Spear bit enables the operator to run the bits on a motor with a lower bend angle, which allows rotation and a high ROP in the lateral, while still achieving the desired build rates in the curve section.

"The Spear bit is optimized for the shales when we are drilling long laterals, which required changing some of the bit's dynamics," Sobernheim said. "The hydraulics clean debris from the bit face and help the cutter edges to be more exposed on the shale surface, which can help maximize ROP. The bit also has a bullet-shape body to allow cuttings to sweep around the bit and not clog the junk slot as well as allowing for greater blade height.

"Since it is made from steel," Sobernheim continued, "it is ductile enough to allow increased blade height and reduced blade width, thereby increasing the distance between the borehole and the bit body and improving the ability of cuttings to pass through the slots."

The greater area around the body allows the bit to pass over or through a cuttings bed without blade

(Photos courtesy of M-I Swaco, a Schlumberger company)

For the dewatering of water-based mud, the image on the left shows the clear fluid returned to the system and the image on the right shows the dewatered cuttings ready for disposal.

packing and nozzle plugging. To improve directional control, the drill bits use smaller (11 mm and 13 mm) cutters, with no adverse effect on ROP, according to the company. For more abrasive formations, the company said it can fit the bits with ONYX II PDC cutters that are more thermally stable, as well as more wear- and impact-resistant than other PDC cutters, both standard and premium.

Addressing NPT in the Eagle Ford

Operators working in the Eagle Ford Shale play have experienced costly NPT as a result of multiple runs needed to drill curve and lateral hole sections. An operator wanted a PDC drill bit that would increase ROP and total footage capabilities in the 8 3/4-in. curve and lateral hole sections while providing good directional control at maximum penetration rates. With this request, a familiar technological dilemma emerged. PDC bits designed for curve sections deliver strong build capabilities and predictable directional control, but often at the expense of acceptable ROP. Alternatively, bits intended for laterals produce high ROP but have fewer directional control capabilities. This technology gap required operators to choose between steerability performance and high ROP.

Smith Bits developed a specific Spear PDC bit for the Eagle Ford Shale drilling application with the following technology platform:

- Optimized hydraulics clean debris from bit face and expose cutter edges to formation maximizing ROP;
- Bullet-shaped body allows cuttings to sweep around bit and into junk slots;
- Reduced body diameter increases distance between the borehole wall, which permits the bit to pass over or through a cuttings bed without blade packing or nozzle plugging; and
- Bit's steel composition enables increased blade height and reduced width, which enlarges junk slot area.

The 8¾-in. SDi513 on a PathFinder steerable motor drilled 6,904 ft of curve and lateral hole section in one run at a record ROP of 64.83 ft/hr. This represents the fastest curve and lateral run for the operator in the Eagle Ford Shale play, according to the company. Based on a comparison with the best offset run, the Spear bit saved the operator $46,780 in rig time.

Green, high-performance drilling fluids

M-I Swaco has developed several environmentally friendly emulsion (non-aqueous) fluids and water-based muds (WBM). The company requires new fluids to be "green" and perform as well as previous fluids. Its general-purpose WBM, the Kla-Shield system, is a polyamine-based fluid enhanced for environmental performance over potassium chloride-based systems, but it is flexible enough to meet geological and performance requirements. It is used for drilling high-angle wells in reactive shale formations and is more tolerant to contamination with drill solids. It also reduces clay dispersion and hydration.

M-I Swaco developed the Envirotherm NT fluid for higher-temperature and higher-density WBM applications. The fluid can resist bottomhole temperatures over 425°F and has been used in bottomohole temperatures of more than 350°F.

"Normally when using a water-based mud in high-temperature and high-pressure areas, we have very good results using chromium-based products," said Catalin Aldea, M-I Swaco's director of new technology.

"This is not an environmentally friendly element. We developed a polymer water-based mud for high temperatures to improve the environmental footprint."

The company also has developed an oil-based mud (OBM) that uses a linear paraffin as the base fluid.

"In this fluid we also replaced the calcium chloride with an alternative salt that results in a more environmentally friendly oil-based mud," Aldea explained.

The OBM also is more biodegradable. Diesel OBM cuttings that are stored and allowed to biodegrade are more likely to contain much of the residual hydrocarbons.

"If you use a linear paraffin instead of diesel as the base fluid, most of the time hydrocarbons remaining on drill cuttings will biodegrade in a short time," he said.

The company performed a statistical analysis on about 1,000 Eagle Ford wells. It observed a large variation in total drilling days for similar well depths and trajectories.

"The total drilling days for similar wells and similar depths can vary by 20 days or less to 60 days or longer," said Quan Guo, advisor and manager, Industry Initiatives, M-I Swaco. "If you have shorter wells you can see oil-based mud or water-based mud did not make much difference. But with longer lateral wells, the oil-based mud reduces drilling days, in some cases by 20 days."

One of the reasons operators use OBM is for its lubricity, but the company has seen increased interest in making OBM even more lubricious. As a result, M-I Swaco developed two new OBM lubricants, Lube 776 and Lube 1017. They reduce torque, drag, and the potential for differential sticking by reducing the friction coefficient. In one field application, M-I Swaco observed rotary torque readings fall by as much as 33% after initial addition of the Lube 776 lubricant at 2% v/v. This lubricant also showed low foaming, greasing, and/or emulsion-forming potential, according to M-I Swaco.

Software for drilling fluid programs

M-I Swaco developed the Virtual Hydraulics software package for engineers to generate realistic, top-to-bottom snapshots of a well at any time and for different operations. The program is a multicomponent application for maximizing drilling fluid performance and minimizing overall costs of premium water, synthetic- and oil-based drilling fluid systems. The integrated software suite uses state-of-the-art models for hydraulics, mud rheology, temperature profiles, hole-cleaning performance, and surge/swab pressures that consider the effects of pressure and temperature on downhole fluid properties.

Wellbore stability is one issue related to drilling efficiency. Traditionally, geomechanical engineering addresses wellbore stability issues, Guo noted, but it really is the mud engineer and the geomechanics engineer who have the same objective.

"The mud engineer is on the drilling side, and he is the first to do something to mitigate issues. We added a wellbore stability module to the software for our mud engineers," Guo explained.

When a mud engineer sees drilling fluid-related issues, the software tells the engineer what kind of issue and what solution to implement. For example, the mud engineer will need to decide whether to increase the mud weight or add chemicals. If the cuttings coming to the surface look dry rather than reactive, it may be a mechanical issue rather than a chemical issue. The software will point to the root cause and suggest a solution. An engineer can make any changes in the mud on the fly.

Dry emulsifier for severe winter conditions

M-I Swaco also is formulating and developing emulsifiers for several applications. Operators use the Actimul RD dry emulsifier for OBM for extended reach drilling in extremely cold regions.

"All of our emulsifiers that go into oil-based mud have been in liquid form," Aldea said. "Traditionally they have performed well and kept a tight emulsion. But if you work in places like North Dakota, with extremely cold winter temperatures, you find yourself striving to get the liquid emulsifier out of the drum. As a result, we developed the dry emulsifier that comes in 25 lb bags for easy handling."

The emulsifier provides good mud properties, Aldea noted, and it also is working at slightly lower concentrations, so the logistics of handling the product is reduced.

The company engineered the Actimul RD dry emulsifier as a dry additive specifically to alleviate the problems associated with mixing liquid emulsifiers in cold weather and remote locations with restricted logistics. The dry emulsifier reduces costly logistic issues associated with the transport of heavy drum materials. An operator conducted a field trial to evaluate the dry emulsifier as a replacement for Megamul near Stanley, N.D., from Dec. 16, 2010, to Jan. 17, 2011. The company mixed approximately 1,500 bbl of 9.7 lb/bbl Megadril diesel-based fluid at a nearby M-I Swaco plant. The dry emulsifier retained all of the rheological properties as per specification at a lower emulsifier concentration. The operator reported no torque or drag while drilling the two sections. It then ran the 4 ½-in. production liner to bottom at 18,750 ft measured depth (8,907 ft total vertical depth) with no problems or issues. The company then drilled three more wells with this fluid system with good results. On these wells, a working concentration of 3 to 4 lbs proved adequate for delivering the required rheological/chemical parameters.

STIMULATION

Coiled tubing fracture stimulation

Operators have used BJ Services' OptiFrac coiled tubing fracing system in Canada with significant success. The system migrated to the US in 2011. Introduced in the summer of 2010 in Western Canada, operators have run OptiPort technology and fracture stimulated in excess of 2,500 coiled-tubing frac sleeves. In Canada, using OptiPort coiled-tubing frac sleeve technology, the company reduced the average treating time by 45%, or eight hours, and fluid usage per treatment by 30%, or 31,700 gal [120 m3], per well. BJ Services' most recent job was a 15-stage frac treatment performed in record time, according to the company.

This technology includes sand plugs, sand jetting to perforate the casing, coiled tubing, and hydraulic fracturing. In Canada, Baker Hughes used its BJ Services OptiPort ported collar, which allowed the company to pump the frac fluid and proppant into the formation. The ported collar with the BJ Services SureSet BHA seals allowed the sleeve to shift open. The fracturing process occurred down the annulus, between the casing and the coiled tubing. The method assured that the operator was isolated from the previous zone, which was a priority when completing a horizontal well.

OptiPort technology combines sliding sleeves like those found in ball-drop systems. However, the SureSet BHA, rather than sequentially sized balls, opens the sleeves. This allows for a virtually unlimited number of stages, according to the company, and leaves the coiled tubing in the well to perform a quick cleanout if required after a screen out.

"Because the fracturing job is pumped down the annulus, the operator has lower horsepower requirements," said Paul Bond, Baker Hughes marketing director for Drilling Systems, US Land. The smaller the zone being fractured the more emphasis can be focused toward optimal performance. With a 250-ft zone, for example, the fracture treatment may not contact the entire 250-ft interval. Instead of doing one 250-ft zone, the technology can more efficiently and effectively stimulate three 80-ft intervals. The result is better exposure to the rock.

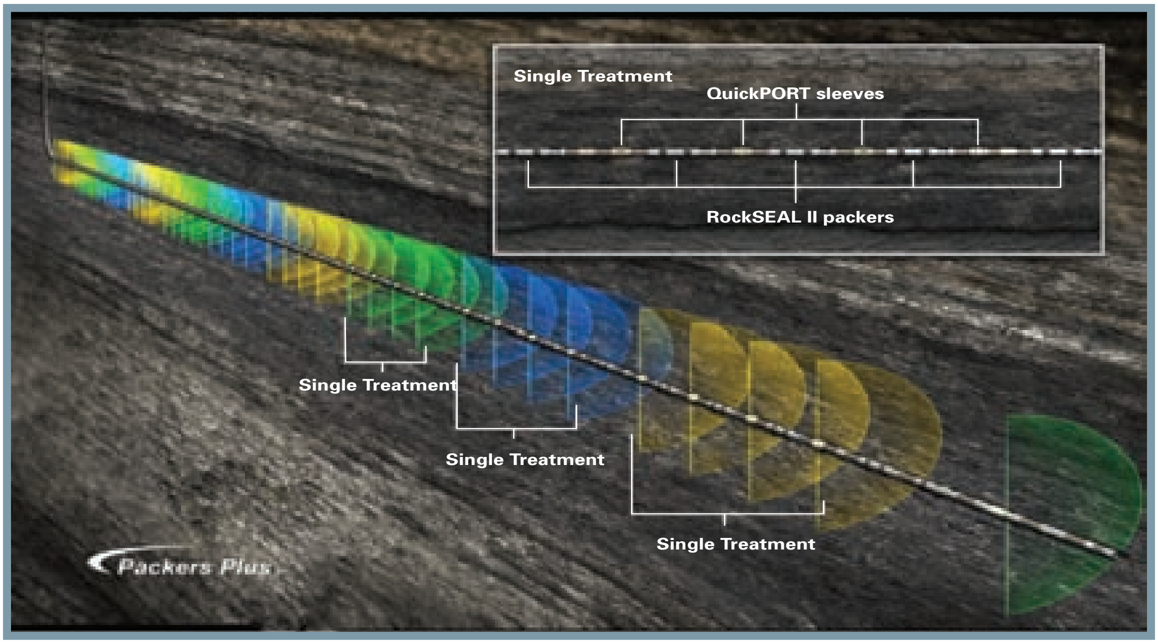
Increasing the number of frac stages

Operators have been using multistage fracture stimulation systems with good results, although not all operators have embraced the method. Packers Plus Energy Services in launched two multistage fracturing methods that have produced significant results while saving the operator time and increasing production, according to the company.

The QuickFRAC system is capable of fracturing 60 stages while pumping only 15 treatments at the surface, according to Packers Plus. Using limited entry diversion techniques and the company's proprietary technology, the system allows operators to fracture several isolated stages at one time through a batch fracturing method. For each treatment zone, the system includes a number of QuickPORT sleeves flanked by RockSEAL II packers, creating multiple, individually isolated stages within a single treatment zone. Actuation balls of increasing size activate each treatment zone, enabling several zones to be stimulated in succession with the biggest ball at the top. The company has run the system in the Bakken, the Horn River, the Montney, and other shales.

The appropriate size ball is dropped into the system and pumped down onto the seat. Fluid is pumped from the surface to pressure up the system and open the QuickPORT sleeves, allowing stimulation fluid to flow into the annulus. There are a variety of ball sizes available, allowing multiple rounds of fracture treatments to run in sequence. After the stim-

(Image courtesy of Packers Plus)



Packers Plus QuickFRAC multistage batch fracturing system enables simultaneous stimulation of multiple stages with a single fracture treatment at surface.

ulation is completed, the balls flow back and the system can be milled out.

"In terms of completion technology, the conventional way of doing multistage fracturing is the cemented liner plug and perf method," said Dan Themig, president of Packers Plus. "The difference is that it cases and cements the entire horizontal."

This cuts off any inflow from the horizontal, Themig said, so the operator must perforate, pump water and sand down the liner, set a bridge plug, and then move up the well bore and do it again.

"This method involves tripping in and out of the hole with coiled tubing or wireline and overdisplacing proppant, which we have avoided by having continuous pumping operations," he explained.

"We don't need a rig on site, and the system was pioneered for openhole completions so we don't need to cement, perforate, and run bridge plugs," Themig continued. "QuickFrac was developed to save time and costs and increase efficiencies, but it also results in better producing wells."

With this system, a single ball is dropped to simultaneously open three stages, for example. Each port has a nozzle restriction designed to allow a specific pumping rate. If an operator wanted to perform a 30-stage job, instead of being on location for several days to pump 30 individual stages, the system can pump 10 stages on the surface while delivering 30 stages downhole by dividing each interval into three specific stages. If each interval requires 20 bbl/min, on surface the operator would pump 60 bbl/min and each of the intervals would receive 20 bbl/min. An operator uses the same amount of proppant volume and can reduce the total time to frac the well by two-thirds, according to the company.

Most recently, the company launched its RepeaterPORT sleeve, a ball-actuated, hydraulically activated flow port that allows for more than one stage to be activated with the same size actuation ball. It is run in conjunction with a FracPORT sleeve with the same ball seat size. The operator runs each sleeve between two RockSEAL II packers. This allows the operator to isolate and selectively fracture specific zones of the well bore, as well as increase the number of stages available in the company's StackFRAC HD (high density) system.

A 30-stage system in the Bakken

Unconventional characteristics, including low average permeability (0.04 md) and porosity (5%), have responded well to horizontal drilling with multistage fracturing. Packers Plus has focused recent efforts on increasing lateral length and stage count to maximize recovery; however, this strategy introduces completion challenges. The difficulty lies in matching the longer lateral lengths with increased stage numbers to maintain the same stage spacing. Unfortunately, either technical or cost limitations often restrict producers.

An operator working in the Bakken Formation wanted to increase its stage number and ultimate production on a well in Mountrail County, N.D. Although various multistage fracturing technologies are available in the Bakken, the operator focused on openhole, multistage fracturing systems using mechanical packers, specifically the StackFRAC HD system. The trend of increasing stage density in the Bakken had pushed the limits of current StackFRAC HD systems. The operator required additional technological advancements to meet its needs.

The system was run into a well bore with a 9,525-ft lateral length and 19,740 ft measured depth (MD). It used a combination of FracPORT sleeve and RepeaterPORT sleeve stages with an average stage length of 310 ft to increase communication with the formation. The operator successfully fractured the system with over 2.6 million lb of proppant and a total slurry volume of 37,600 bbl. With 10 successful RepeaterPORT sleeves run in conjunction with 10 stages using the same size standard FracPORT sleeves, the operator achieved 20 stages. It ran 10 additional FracPORT sleeve stages to bring the total to 30. The success of the new RepeaterPORT sleeve in this well has encouraged the operator to use the technology for additional wells in the Bakken, according to the company, which has now fractured a 38-stage well.

CT for multistage fracturing

Use of coiled tubing (CT) during fracturing and stimulation of long horizontal laterals can provide several advantages over other stimulation services. Conventional processes using a cluster perforating strategy can result in a considerable level of fracture generation and proppant placement uncertainty. Engineers designed CT fracturing to place one fracture at a time, removing the uncertainty and ensuring accurate fracture and proppant placement. An operator can stimulate a horizontal lateral with CT with less pumping horsepower, in some cases up to half the horsepower, of a conventional stimulation process, according to some industry experts. This substantially reduces the footprint. Stimulation with CT takes less time and requires less water, all of which add up to improved stimulation effectiveness, greater efficiency, and less risk.

"CT fracturing is simply the functionality of two flow paths. Depending on the stimulation treatment requirements, it may be necessary to pump the frac down the tubing, the annulus, or possibly both," said Fraser McNeil, Halliburton's global product champion for Pinpoint Stimulation. "One of our processes, CobraMax DM service, for downhole mixing calls for pumping a concentrated sand slurry [liquid sand process] up to 20 lb/gal down the tubing and a clean fluid at a high rate down the annulus. We actually mix them downhole."

Downhole mixing enables real-time manipulation of rate and proppant concentration in response to treatment pressures, allowing for mitigation of screenouts and other unplanned events. If the operator sees a screenout developing, it would shut down. If a CT unit was standing by, the operator would position it over the well for cleanout, which results in significant downtime.

"With real-time control downhole, if the operator sees a screenout occurring, it would reduce or eliminate the pumping rate down the tubing, which is the concentrated sand slurry, and then maintain or increase the rate down the annulus, which is the clean fluid. This can potentially cure the screenout, allowing pumping to continue as planned," McNeil explained.

Additionally, McNeil noted, if the operator was unsuccessful in avoiding a screenout, having CT in the hole allows the sand to be reverse circulated out immediately before moving to the next zone. For example, if the operator was near the beginning of the treatment schedule and hadn't pumped much of the frac away, it could clean out the sand, pull up a few feet, reperforate and pump the fracture treatment.

"In a CobraMax DM service job in the Eagle Ford we have demonstrated the level of efficiency possible," McNeil said. "The time between the screenout occurrence and hydrajetting the next zone was as little as 1 ½ hours compared to a few days or more using conventional methods."

The CT-based fracturing service enables placement of a virtually unlimited number of fracturing stages, and is applicable to horizontal, cased, cemented, and unperforated well bores, according to the company. The service includes a BHA that features a Hydra-Jet TS [trip saver] tool designed to perforate all intervals using a single tool, and a mixing sub designed to ensure that a homogenous slurry is achieved downhole. Real-time downhole changes to the proppant concentration help maximize stimulated reservoir volume and connectivity to the fracture network.

In deep reach wells where CT may limit the operation, the operator can deploy fracturing processes using the PowerReach service.

"PowerReach allows us to continue with CT functionality when the CT has reached its limits in a particular well," said Ralph McDaniel, chief global advisor for Hydraulic Workover, Snubbing and Well Control for the company's Boots & Coots service line. "Typically, CT is limited in its depth because only so many feet can be put onto a reel. Within the industry it is typically less than 15,000 ft."

Road restrictions also constrain the weight of the load, which also limits the amount of CT that can be delivered to a well site. With PowerReach service, the lower CT weight easily can be transported on most roads.

"With this service, we can add another 12,000 to 14,000 ft of CT on top of jointed pipe," McDaniel continued. "We run the jointed pipe first to at least the heel and then add the CT. That gives us CT to the toe."

This setup provides the operator with a larger unit. Now it is a 20,000 to 25,000 ft CT unit up from a 12,000 to 14,000 ft CT unit. The operator also can run larger pipe, from 2 ⅜-in. to 3 ½-in. CT.

The service uses a unique downhole valve developed to use CT and jointed pipe under live well conditions. The operator can actuate the safety valve with hydraulic pressure from the rig floor or with pressure between blowout preventers, and can cycle open and closed the valve as many times as desired. The 5-ft-long tool features enhanced debris isolation at the flapper. The metal-to-metal sealing flapper eliminates issues with elastomeric seals for maximum chemical compatibility. The safety valve provides contingency well pressure isolation to allow disconnecting the CT from the jointed pipe in hybrid CT/hydraulic workover unit operations. Operators primarily use it at the junction of the jointed tubing CT hybrid unit, but also as part of the downhole BHA to control the well when running or retrieving jointed pipe.

When using the system for fracturing, the hydraulic workover unit snubs the jointed pipe segment of the hybrid string into the well bore to the desired distance. Upon completion, the operator brings the CT unit and frac equipment on location and implements the frac operation. The workover unit handles all movement of the hybrid string. The operator can use the system to perform fracturing treatments using dynamic fluid diversion, sand plugs, or straddle packers to isolate fracturing intervals.

The PowerReach system also can be beneficial in milling applications and cleanouts in deep reach horizontal wells. An operator completed the deepest horizontal well to 20,332 ft MD by milling out plugs using 2⅜-in. CT and jointed pipe. It did not use mechanical or chemical aids to achieve this depth.

Fracturing 30 intervals in the Marcellus Shale

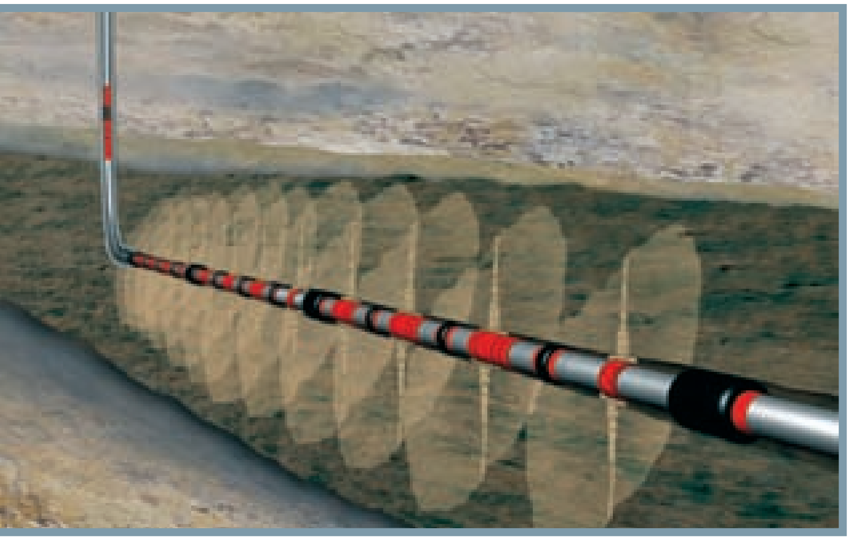
An operator, recognizing that conventional methods place less priority on the effectiveness of the stimulation treatment or the risks involved in recovering from unplanned events, was looking for a method to hydraulically fracture 30 intervals in the Marcellus Shale. Halliburton recommended deploying the CobraMax DM service as it offers a low-risk, operationally efficient service while optimizing the stimulation treatment, according to the company. Highlights of the multistage fracturing process demonstrated in this case history include:

- Performed 30 fracture stages and two cleanouts with only one trip in hole;
- Pumped 4 million lb of proppant through tools on a single job;
- Averaged 37 bbl/min per interval;
- Reduced time between treatment stages to about


(Photo courtesy of Halliburton)

The CobraMax DM service is used in W. Va., for hydraulic fracturing in the Marcellus Shale.

(Image courtesy of Halliburton)



Halliburton's RapidFrac stimulation system can be used in cemented or openhole completions.

40 minutes compared to 4 hours per stage using the conventional plug and perf method, which requires a trip in and out of the well;

- Demonstrated ability to achieve reservoir diversion by increasing net pressure and dilating and propagating natural fractures in the reservoir;
- Proved the ability to completely avoid a screenout and continued pumping into the same fracture;
- Used less than half of the hydraulic horsepower typically used on conventional jobs in the area; and
- Used with PowerReach system to reach the long horizontal well bore.

Replacing plug and perf

Service companies that provide stimulation and completion services are developing methods that can fracture multiple stages at the same time while providing highly accurate placement of fractures with seemingly unlimited sleeves per interval. Halliburton launched its RapidFrac system in 2011 following successful field tests.

"The driver for this system was primarily to have a more direct replacement for the plug and perf method," said Todd Broome, the company's product manager for horizontal completions. "The issue with plug and perf is being able to complete the well in clusters with several intervals and several entry points into the formation. The RapidFrac sleeve and system allows the operator to frac in clusters."

The system provides some of the same benefits as plug and perf, but also has the ability to pump continuously with no wireline service requirement. The system uses several RapidFrac sleeves and a Delta Stim Lite sleeve within a single interval, exposing the reservoir to multiple fracture points. An operator can use up to six fracture points within an interval isolated by packers and up to 15 zones for the completion, although this could be extended.

One of the RapidFrac's benefits is its delayed opening of the sleeves, Broome noted. "The ball goes through and activates these sleeves and lands on a more conventional sleeve. The operator pressures up and shears the baffle. A pressure response is visible at the surface. We believe that delayed opening enables a good pressure response at the surface, which is one of the keys to the system's success," he said.

The operator initiates the sleeves with a specific diameter ball that is immediately released, it lands on the next sleeve downhole, and finally lands on the baffle of a standard ball-opened frac sleeve. The operator may open multiple sleeves to allow treatments through the sleeves simultaneously, per interval. This increases the total number of sleeves per well to over 90 for the 4 ½-in. size completion. The delay mechanism in the RapidFrac sleeve ensures the operator opens the standard frac sleeve before opening any of the RapidFrac sleeves in a given interval. Each sleeve has ports that the operator can plug to tailor every sleeve to specific flow requirements to maximize the stimulation treatment.

The Delta Stim Initiator sleeve allows for an interventionless stimulation treatment and serves as the toe opening sleeve in a Delta Stim completion. The operator activates the initiator sleeve using tubing/casing pressure that exceeds a predetermined sheer pinned value. The sleeve uses an air-chambered sleeve that operates off of absolute tubing pressure. Once opened, the operator can use the sleeve to stimulate the first zone and/or as the flow path to pump the first ball down to the lowest zone comprising the other sleeves.

An operator conducted the first 4 ½-in. field trials in the Bakken Shale. Operators also have installed a 5 ½-in. cemented system in the Eagle Ford and a 4 ½-in. completion in the Niobrara. In the Bakken, the operators completed intervals using the system in half the time of a plug and perf technique, according to the company. Initial production information from the second well indicated a significant production increase compared to an offset well completed with a combination of frac sleeves and plug and perf technology, the company noted.

"There are several values gained with our system in addition to time savings," Broome said. "With a sleeve-type system the operator is displacing less, so less proppant is pushed away from the well bore. Also, the operator can move the pumping equipment onto the next well quicker to move through the backlog of wells requiring stimulation. Wells can be brought online faster.

"Additionally, with the well charged up with the fracture fluid pressure, the operator can use that to clean the well quicker because it doesn't dissipate as much compared with plug and perf systems."

To date operators have used the system in openhole completions. However, some operators still want to use cement as an isolation system rather than swellable or mechanical hydraulic packers used presently. Consequently, the company conducted field trials in the Eagle Ford for cementing the system in place. Using packers is the preferred method because it gains access to naturally occurring fractures rather than effectively sealing off those types of fractures when cementing the casing.

Cutting pumping time

Williams wanted to improve its completion time in the Bakken Shale by reducing well stimulation time without losing the multipoint entry approach and high performance of the plug and perf technology that it was using. Halliburton recommended the RapidFrac system. According to the Halliburton, Williams reduced the number of people necessary on site. Instead of a complete wireline crew, the completion system required only one person to supervise ball-release sequences. The operator pumped balls downhole in a small volume of proppant-free fluid. This reduced water consumption and other issues associated with pumping large equipment downhole.

Williams adjusted the number of ports per cluster to ensure equal flow to every sleeve, allowing the equivalent of two stages to be fractured together. It increased the pump rate from the standard 30 bbl/min to 40-50 bbl/min, which allowed the operator to achieve greater fracture stimulation and reduced the stimulation cycle time to two days instead of four days for a comparable offset well. The operator saved about 3,700 bbl of water running the system compared with plug and perf. Additionally, the well increased production in the first 15 days of operation.

Increasing production, reducing costs

Schlumberger provides several different fracturing methods, including its Falcon multistage stimulation fracturing system for uncemented cased hole applications, nZone multistage fracturing system for cemented applications, and the HiWAY flow-channel hydraulic fracturing service, which operators have used successfully in several shale plays, including the liquids-rich Eagle Ford area. One of the company's newest offerings is its Falcon multistage stimulation system, which it acquired with the Smith acquisition.

"Falcon was a system Smith was developing and we continued to develop it, working to get it completed quicker and into the market," said George Waters, unconventional completions technical manager for Schlumberger. "It is an uncemented packer system with ball drop port collar opening, similar to other systems on the market today. However, our system has the option of using swell packers or mechanically set packers."

The system uses hydraulically set or swellable packers to isolate frac zones during the stimulation in horizontal, deviated, and vertical wells. Installing the system in uncemented completions allows the operator to fracture up to 20 stages continuously with the use of gradually larger diameter balls dropped from the surface that seat in and shift open ball-actuated port collars. Operators no longer need wireline, perforating guns, coiled tubing drillouts, and cementing, which minimizes operation time, costs, and risks.

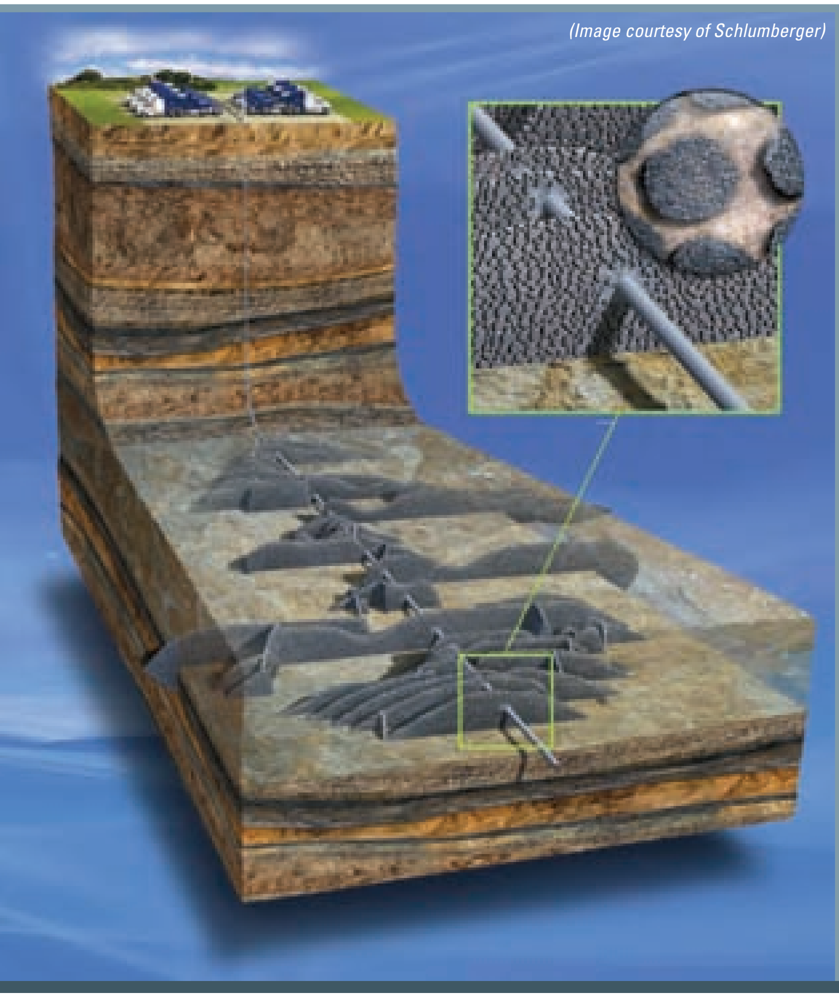
The system features large exit ports for greater flow area, a ball-seat design that facilitates flowback of balls during fracture cleanup, and pressure and temperature ratings of 10,000 psi and 300°F, respectively. Use of the system can result in higher production. Reduced fracture pressure due to a greater formation contact provides full wellbore access and improved flow near the well bore, the company said. Eliminating the need to pump down frac plugs and perforating guns, as well as reducing equipment and personnel requirements, also reduces water usage. This system reduces environmental impact.

"The industry consensus is that most operators want to move away from the traditional plug and perf stimulation technique," said Kyel Hodenfield, vice president, unconventional resources for Schlumberger. "Clients want to move to intervention-less systems where wireline intervention is not required. That also provides an opportunity to shorten the stage length.

"Instead of shooting four perforation clusters and setting one plug," Hodenfield continued, "the Falcon system is controlled from the surface by dropping a ball. The system provides the opportunity to perform the job with less horsepower at the surface because we are fracturing a smaller interval of the reservoir each time. Instead of utilizing 10 pump trucks, the job could utilize five pump trucks."

Smaller stimulation stage lengths can be beneficial to operators. Larger stages with multiple perforation clusters grouped together can fail. For example, an operator could frac five or six perforations at the same time with 25,000 hhp or more only to discover later that only two of the five perforation clusters are actually producing.

HiWAY flow-channel hydraulic fracturing technique is designed for horizontal completions.



(Image courtesy of Schlumberger)

"Maybe all five of the perforated intervals could have been productive," Hodenfield explained, "but when the clusters are combined, only two of the perforation clusters took the majority of the fluid and proppant, thus limiting the fracture stimulation in the other three perforation clusters.

Schlumberger designed its nZone cemented completion system to allow unlimited number of stages to be fracture stimulated in a single, continuous operation. The system also allows multiple fracture treatments without incremental reduction in borehole ID, facilitating normal cementing operations. The valves are key to this approach and must be spaced at least 10 ft apart. There is no limit to how far apart they can be, according to the company. The flow area through the valve is equivalent to the flow area of 4 ½-in. casing. Schlumberger has run the system in horizontal, vertical, and deviated wells with DLS up to 25°.

During the completion process the operator fractures the deepest interval without any intervention. Internal casing pressure applied to the lowest nZone valve causes the rupture discs to burst, which opens the deepest sleeve. Pumping fluid through the specially designed slots on the sleeve allows communication to the formation through the cement sheath, and the well is ready for the fracture treatment. At the end of the fracture treatment, the operator drops a dart into the borehole and seats it on the lowest valve, sealing off the formation below. It applies pumping pressure when the dart seats causing the next valve sleeve to shift open, exposing the next stage of the formation for treatment.

Channel fracturing

Schlumberger offers its channel fracturing flow-channel hydraulic fracturing technique in its HiWAY system, which involves mixing fibers, crosslinked gel, and proppant to create channels through the fracture network to enhance fracture conductivity. Rather than leaving fracture flow dependant on proppant pack conductivity, this method creates stable, open channels for hydrocarbons to flow through, increasing the effective fracture conductivity. In areas in which fracture conductivity is not limiting, the method also provides for improved production by increasing the effective area of contact with the reservoir, according to the company.

Four items are critical to the success of the technique:

- A pulsing technique is used to create the chan-

nels. Operators use specialized equipment on the surface to alternately pump slurry and clean fluid, creating the pulses very rapidly;
- The fibers used in the pulses keep the proppant from homogenizing into a continuous proppant pack;
- Fit-for-purpose perforation strategies promote creation of the channel network; and
- The geomechanical modeling that goes into understanding where this technique is applicable and where it is not. The fibers prevent everything from collapsing and assure the channels stay in place during the closing of the fractures.

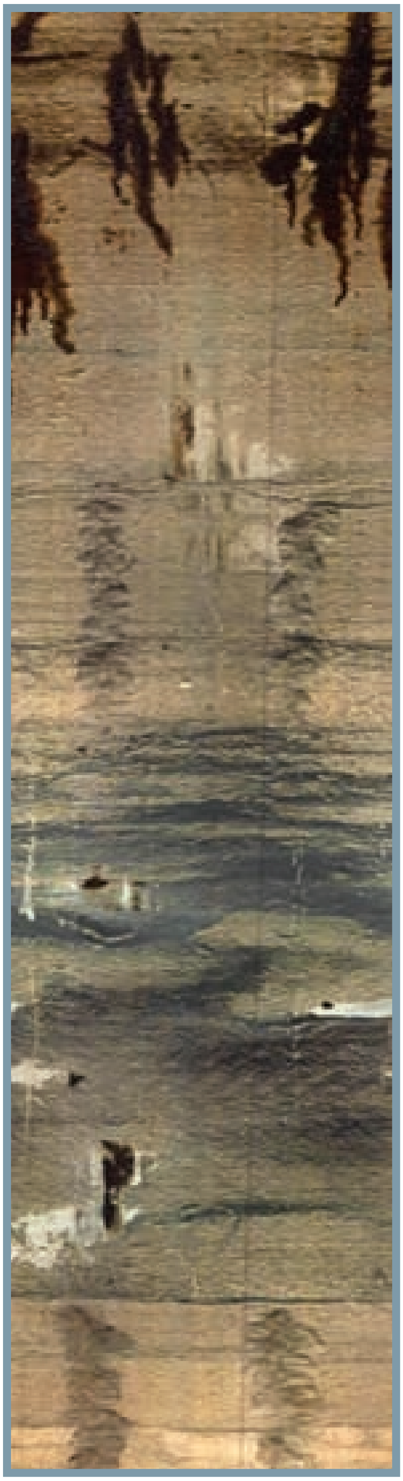
Understanding the spacing of the channels, the width of the channels, and how it is related to the geomechanics of the well is another key aspect.

The technique involves a unique combination of placement methods, materials engineering, completions techniques, and process control equipment, the company said. A proprietary fiber, which maintains the structures from surface to reservoir until the fracture has closed and the *in-situ* stress of the rock takes over, ensures the stability of the flow channels. The productivity of the fracture is decoupled from the actual permeability of the proppant used. Rather than flowing through the proppant pack, hydrocarbons flow through stable, open channels, meaning infinite fracture conductivity. Crushing, fines, fluid damage, multiphase flow, and non-Darcy effects eliminate traditional losses in proppant pack conductivity, ensuring more fluid and polymer recovery.

Less water and proppant

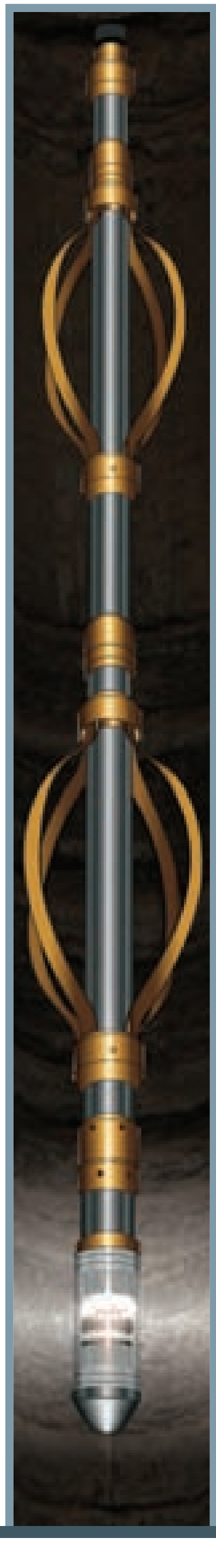
Working in the Eagleville Field in South Texas, a large operator continually aimed to improve production from the Eagle Ford Shale, which is mainly comprised of limestones and shales with 7% to 10% porosity, 200-600 nD, 8,000-10,000-psi reservoir pressure, and 4.1 to 8.4 million psi Young's modulus. Operators generally have stimulated this section of the Eagle Ford Shale using multistage horizontal completions with high-rate slickwater treatments. Such treatments require millions of gallons of water and millions of pounds of proppant per well. The ongoing expansion of fracturing activity in the Eagle Ford further constrains the limited availability of water and proppant.

(Images courtesy of Superior Well Services)



In this single OPTV well image log, multiple features can be observed including oil saturation, borehole breakout and stress orientation, natural fracture strike and dip and lithostratigraphic units.

The OPTV tool assembly in run mode.



The operator chose to evaluate the flow-channel hydraulic fracturing technique for the stimulation of wells in the Eagleville Field in a four-well study. It stimulated two wells with the flow-channel technique, and simultaneously stimulated the other two wells with the conventional method. The operator drilled the wells treated with the flow-channel technique from a single pad in opposite directions. It drilled the other two wells in opposite directions from a single pad 3,500 ft away and parallel to the first two wells. The average lateral length for each pair of wells differed by only 1%.

During the first 60 days after stimulation, the wells treated with the flow-channel technique produced an average of 26,535 bbl of condensate with 30.1 MMcf of associated gas. The wells treated conventionally produced an average of 18,555 bbl of condensate with 18.7 MMcf of associated gas. The average wellhead flowing pressure for the wells treated with the flow-channel technique was 2,156 psi versus 1,916 psi for the conventional wells. The flow-channel technique increased condensate and gas production by 43% and 61%, respectively, while delivering higher flowing pressures. The operator reduced the amount of water and proppant used per well by 58% and 35%, respectively, to obtain these results. It saved more than 10,000,000 gal of water and 2,600,000 lb of proppant in the two wells stimulated with the flow-channel fracturing method.

High-resolution downhole images

In any formation, conventional or unconventional, liquids-rich or dry gas, operators strive to find the optimal stimulation plan to frac the most productive zones and avoid those zones with natural fractures or those that could result in water production. Companies offer MWD and LWD services with options such as gamma ray resistivity, azimuthal resistivity, magnetic resonance, and nuclear services to pinpoint the most productive fractures. Superior Well Services has turned to high-resolution optics to see the inside of the well bore to determine the best zone for fracturing.

The Optical Televiewer (OPTV) is a formation imaging system that exhibits unique, high resolution images of rock fabric and fractures, according to Superior. The company applied OPTV in an air-filled borehole to obtain high resolution, color images of formations associated with the production of hydrocarbons. An operator also can use the OPTV in a well bore previously filled with fluid after blowing out the fluid as long as the well is not producing hydrocarbons. The technology is particularly well suited to shale reservoir evaluation.

The OPTV works best when air drilling a well. It also is useful in a clear fluid hole environment and can be used in liquids-rich shale plays where the operator needs to locate and discern with nearly pinpoint precision exactly where the oil zones lie. OPTV is helpful in very thin discontinuous oil plays such as fractured dolomitized carbonates. Operators can run it downhole in vertical well bores on wireline, coiled tubing, or jointed pipe. The company also has used it in horizontal applications in the Lower Huron play, which is typically air drilled.

"We recently have been successful in the Knox Formation," said Matt Blauch, director of product development for Superior Well Services. "We are able to identify exactly where oil is seeping and see features that you can't see with any other method, even to the point that it might be worthwhile to drill a vertical pilot hole just to be able to run that technology."

The 5-ft-long, 11-lb tool essentially uses camera technology with a visual image that is adapted to the interpretive software component to measure orientations, to conduct fracture analysis and orientation, and to locate oil shows in shales. While another company developed the camera technology for use in the mining industry, Superior developed hardware and other impedance-lowering technologies for the OPTV to be used on standard 12,500 ft multi-conductor wireline units and similar technologies. OPTV acquires data in horizontal wells using tractor mechanisms to convey the OPTV tool to 12,500 ft total measured depth of horizontal hole.

The OPTV probe provides continuous, detailed, and oriented 360° images of borehole walls. Operators can interpret such images at the well site to analyze dip, strike, frequency, and fracture aperture. An OPTV survey can replace or augment coring in development projects. OPTV offers much greater flexibility and convenience for data interpretation than low-resolution, conventional borehole video or imaging survey offers. The real-time aspect of the direct image data enables selection of sidewall-core and perforation points.

Some completion benefits include stage-design development and minimum/maximum stresses

(breakouts and induced versus natural fractures) determination. OPTV does not require any inferences from an electrical (or acoustic) measurement before making geologic inferences; the end-user is able to interpret a direct rock image.

"OPTV would typically replace or augment [formation evaluation tools]," Blauch said. "You can run both, but we have found [OPTV] to be as instructive and at a lower cost."

The OPTV is optimal in wells that are air drilled because the operator can see the hydrocarbon influx and influx of natural gas.

"The bubbling gas also is of interest in picking your completion zones because you actually can see the productive zones," Blauch said.

However, operators can use OPTV when drilling fluid is used depending upon the fluid's clarity.

"Even if the well is drilled with mud, you can circulate out the hole, basically blow it down with nitrogen, and then run the camera as long as the hole is not filling with hydrocarbons or fluids," Blauch said.

Air-drilled wellbore imaging

A large US independent operating company was using horizontal air drilling technology and drilling several laterals off a single pad to maximize production and avoid the added expense of drilling with fluid. The operator selected lateral azimuth directions based on information gathered from existing vertical producing wells and geologic analysis of the fracture systems. Not wanting to load these laterals with fluid, the operator sought high-quality imaging log data to confirm geologic modeling; interpret fully the fracture systems encountered; distinguish open, naturally producing fracture systems from nonproductive systems (comparing the images to basic open air-hole hole logging suites and spinner logs); aid in completion and stimulation design; and determine location and azimuth of future lateral placements.

The operator's initial planning included a risk/benefit exercise between geology and drilling the holes on air, then loading the hole with fluid to obtain the desirable geologic wireline logging imaging conveyed on drill pipe or coiled tubing. The company developed the application of tractor-conveyed OPTV. The company and the tractor company jointly developed the adapters for this conveyance.

Before logging horizontally, the operator wished to compare the OPTV with a traditional micro-resistivity imaging device using a vertical pilot hole drilled through the target formations. The operator ran both tools over the same intervals and the quality of images compared. The operator was satisfied that the OPTV image quality run in air was superior to those obtained by the micro-resisitvity device run in fluid, especially in identifying the fractures. The horizontal project proceeded as designed with the horizontal section drilled and logged on air.

Job participants estimated that using the OPTV system to obtain required images from an air-filled borehole yielded savings of 48 hours of rig time, US $10,000 in fluid and removal, and $25,000 in wireline logging, conveyance, and interpretation. The operator also avoided formation damage and associated risk using this method.

WATER MANAGEMENT

Managing water resources crucial in some regions

Water is a major cost of the drilling and production process, from sourcing and transporting fresh water; treating flowback and produced water for re-use or reinjection; trucking costs (a large expense, not to mention wear and tear on local roads); trucking to disposal sites; and the cost of disposal itself. One company has taken several of its water management solutions and bundled them into a service that can be tailored to an operator's specific needs. Options include choosing the type and amount of services, as well as establishing the potential for more or less permanent water management facilities in particular regions such as the Eagle Ford, the Niobrara, the Permian Basin, Midcontinent as well as in Canada.

It is the operator's responsibility to contract for each of the services including water suppliers, haulers, tank suppliers, and disposal companies. Halliburton aims to provide and manage all of these services and serve as the operator's primary supplier, which includes handling all aspects of water management, from fresh water to final water disposal.

While none of the water management technologies presently included in the company's total solutions service is new, the concept of bundling them as a complete service is a new business strategy. The company is working on developing new technologies to

SHINING STAR

ENERGY

TORNADO VENTURE SEIS, LP

Sondra L. Grohman, President

EAGLE FORD SHALE

"A South Texas Legacy"

(Photo courtesy of M-I Swaco, a Schlumberger company)

Two parallel, twin-filter pods in series provide redundancy and capacity for water management.

enhance its present water management solutions and to support the complete service. It is investing in recycling, storage, and disposal technologies, and permanent wastewater treatment facilities. The facilities will accept water from operators and condition it for reuse or dispose it as needed. As part of the process, the company will use its CleanWave and Clean Stream services to condition fracture flowback and produced water, making the combined stream usable for wellsite operations. Halliburton will use mobile CleanWave service units at the well site and in permanent facilities.

The company's Water Solutions projects are under way in the Permian Basin, the Rockies, South Texas, and North Dakota. Halliburton was scheduled to begin operations from a water management facility in South Texas to serve operators in the Eagle Ford Shale and the surrounding area during 4Q 2011. The industry expects other facilities to begin operations in North America in 2012.

"This service can help assure operators that they can complete their shale wells on schedule and with an improved environmental profile of recycling and reusing as much water as possible while reducing their dependency upon fresh water," said Clay Terry, water solutions manager.

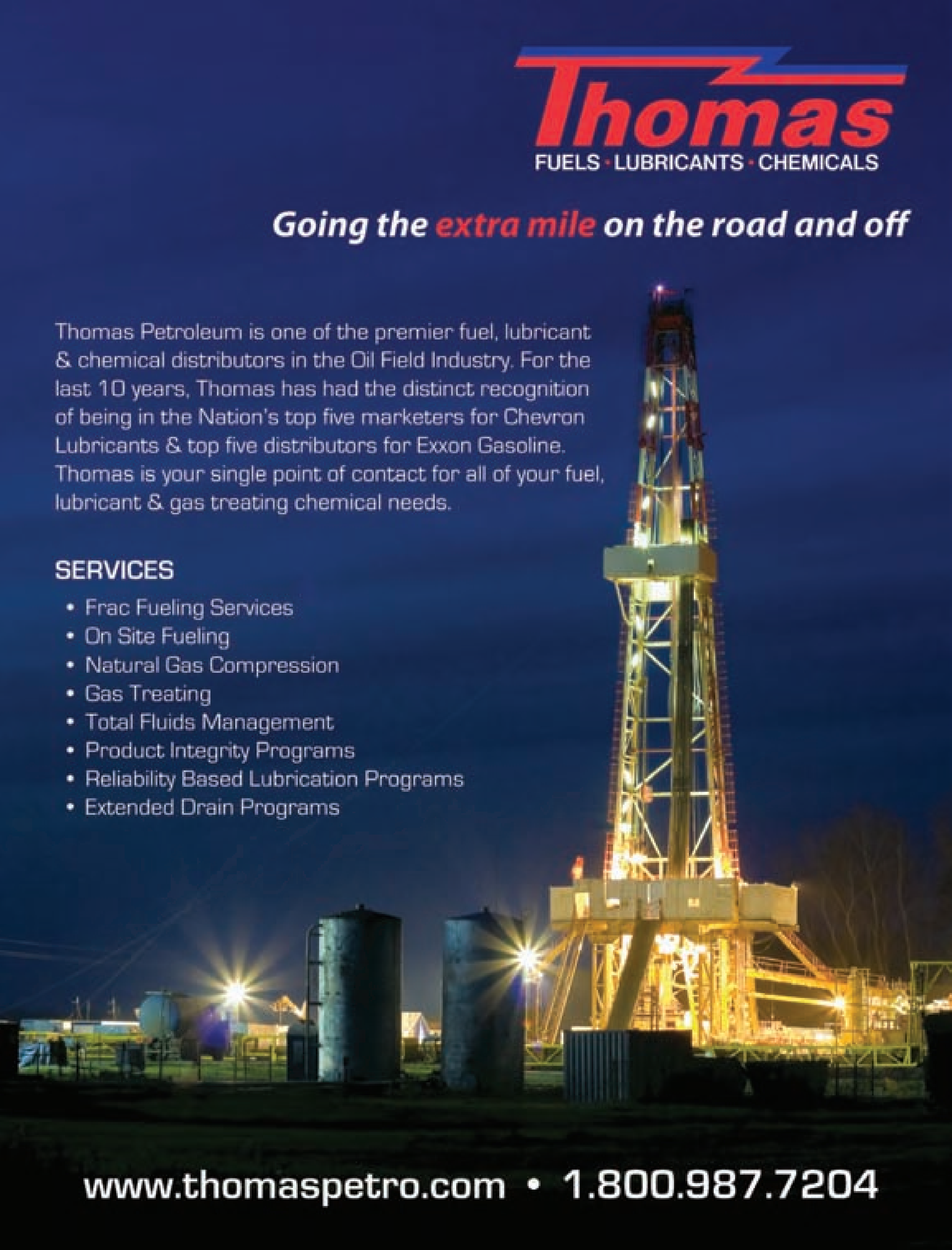
"Treating flowback water is a principal tenet of our water solutions strategy," Terry said. "The use of brackish water for drilling and completion purposes is also a focus.

"The idea of integrating these for purposes of providing an overall service network specifically for driving some of the cost out of the system is another benefit to operators. With multistage stimulation treatments for horizontal completions using 10 to 15 times as much water as a vertical well, there are significant additional costs associated with the logistics of water supply and disposal throughout the process," Terry explained. "We believe there is an opportunity to provide a costs savings of 25% to 30% along with using environmentally prudent technologies."

Accomplishing that kind of savings requires at least a three-prong attack:

- Water treatment and recycling existing water;
- A mechanism for cost avoidance by recycling and reducing the amount of disposal fluids and the disposal component of water management; and
- Unconventional water transportation methods.

"Eliminating as many inefficiencies of trucking as possible is one of our objectives," said Mark Ritchie, global operations manager with the Water Solutions Group. "Use of other transport methods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such as pipelines and staging of water storage elements in various locations, in some cases augmented by trucking, are other objectives.

"We see the infrastructure on county and other public roads becoming a mounting problem and the idea of taking as many trucks off the road where possible is attractive to us," Ritchie said. "If you look at the entire water supply chain, between 50% and 70% of the water costs is transportation."

Emphasizing that the company is not targeting only the trucking industry nor is it trying to completely eliminate its use, Richie noted that there are opportunities to drive significant costs out of each water management supply chain component. Having all parts of the water solution is a major piece of the company's water management business strategy, he said. "We are not a trucking company, so we will partner with interested parties geographically located to maximize our logistical support and to participate in the development of that solution."

One alternative to reduced trucking is a pipeline network, the complexity of which would depend on the scale of operation. For example, there are some plays and some operators in those plays that have sufficient surface access to large lease holdings that could support in ground infrastructure for a long-term water management solution.

"Traditional subsurface pipelines may be a component of that," Ritchie said. "However, most of the projects would entail temporary above ground pipeline networks."

Whether below or above ground, a pipeline network could be difficult to accomplish. Surface ownership can be very complicated in some areas. Small parcels of land with individual land owners in close proximity to municipal areas could complicate the idea of surface pipelines. There also are regulatory hurdles including rights-of-way, roadway crossings, public corridors, and proximity to wildlife areas or wetlands.

"There are complicating factors," Ritchie said, "and the use of specific design routes for surface pipelines may or may not eliminate them all."

Providing mobile water treatment

M-I Swaco focuses its water treatment capabilities on providing mobile technology to treat frac flowback water. Presently, its filtration technology removes certain micron-size particles from the water, and its reclamation technology uses chemical treatment to remove constituents dissolved in the water such as calcium, magnesium, iron, and barium. Operators have used the M-I Swaco Aqualibrium water treatment technology in numerous unconventional and conventional basins.

"Frac flowback water in the liquids-rich shale plays may require a bit more treatment to remove the oil and grease from the flowback or produced water," said Brad Billon, director of oilfield water management for M-I Swaco. "We are investigating and evaluating new and innovative technologies that will allow for cost effective reuse of frac flowback or produced water.

"We are also developing and evaluating several disinfection technologies that will provide an environmentally friendly way to disinfect frac water," Billon added.

According to the M-I Swaco, one Marcellus operator was fracing up to five wells per week using an average of 150,000 bbl of water per frac job. Total flowback from the five wells was about 112,500 bbl/week. The operator was committed to reuse 100% of the flowback water, conserving fresh water resources and reducing the number of trucks on the road. The operator used the Aqualibrium filtration system, designed to remove the total suspended solids up to the operator's mandated 20-micron desired size, to treat the flowback. The process treated up to 1.8 MMbbl of flowback and produced water with 99% of the water recycled.

According to the company, in another case, an operator's 10-stage frac job would use 100,000 bbl of water. The project required installing an onsite water tank farm, purchasing and trucking water from a local town with only 100 bbl/load capacity, flowing back 10% to 30% of the frac fluid over a 10-day period, and transporting and disposing of the flowback water. The operator wanted to remove contaminants that could cause scaling, reduce total suspended solids to prevent formation damage, reduce total dissolved solids, and minimize disposal volumes. The company treated 10,414 bbl of reclaimed frac water with 99% water recovery and 125 bbl of semi-wet solid waste. The average daily processing rate during a 12-hour span was 3,000 bbl with the maximum daily processing rate of 3,850 bbl of reclaimed fluid, significantly reducing the operator's costs. ■

California Dreamin': The Monterey Shale

By Kelly Gilleland, Contributing Editor

The largest US oil shale play presents unique challenges.

California has always been America's land of dreams and opportunities, and when it comes to unconventional plays, the Monterey Shale is true to form. With several hundred billion barrels of oil estimated in place and a conservative estimate of 15 Bbbl of recoverable oil – two-thirds of the country's total shale reserves – the Monterey is luring exploration much like the state's Gold Rush did in the 1800s, and with similar "feast or famine" results.

What perplexes geologists is the age old conundrum: We know it's there, how do we successfully produce maximum quantities? The Monterey Shale presents a unique set of challenges in this regard, said Venoco Inc.'s Michael Edwards, vice president of corporate and investor relations. "The Monterey Shale contains world-class source rock and is the largest US oil shale play, and one of the oldest, producing since the late 1800s. In effect, it's the oldest 'emerging' play around. Almost all of the oil in conventional California oil fields – which have an expected ultimate recovery of 38 billion barrels – has been sourced from the Monterey. However, the geology is certainly complex and complicated."

Schlumberger's principal petrophysicist for Data & Consulting Services, Jeffrey Little, agreed. "The Monterey differs from other unconventional reservoirs in North America in that the complications of the lithology are tremendous," Little said. "The different phases of quartz or diatomite require careful and precise technologies and some considerable patience in order to get a handle on what you are dealing with. The Monterey group is a fairly complex mixture of depositional source material and requires a few additional measurements just to be able to characterize the mineralogy in any particular area. We end up solving for more complex mineralogy in the Monterey than in a shale environment like the Gulf Coast, simply because of the different quartz phases present, largely due to digenetic alteration which occurs across the Monterey Formation."

The Monterey is the source rock for conventional reservoirs such as the Kern River and Elk Hills fields, with API gravity anywhere from 6° to more than 30°. The oil can be sweet or sour, and well depths generally run between 6,000 and 14,000 ft. However, it is the unconventional potential that is garnering much of the industry's focus, especially as new tools and technologies are being developed to deal with the challenges of porosity and permeability in shale plays. Hydraulic fracturing hasn't been demonstrated to be necessary in the Monterey, as Mother Nature has already fractured the rock. However, locating precise intervals using horizontal drilling has proven to be difficult. Instead, the majority of the development wells have been vertical because they contact the entire gross Monterey interval, which can be from 2,000 to over 8,000 ft thick in the San Joaquin basin. Large, mud-acid jobs clean up mud that is lost into and clogs the matrix of the natural fractures.

(Photos by Lowell Georgia)

The sun rises behind Venoco Inc.'s Platform Holly in the Santa Barbara Channel. California's Miocene Monterey Shale was rediscovered at Holly in 1969; the shale produced in the early 1900s in the Santa Maria Basin.

The basic depositional setting is a rifting phase in shallow marine Miocene, between five to 17 million years old – much younger than the traditional 300 million-year-old structures associated with other shale reservoirs. "Opal-A exists in the Monterey in several different forms, due to the depth of burial and the diagenetic alteration as it gets deeper and heated up," Little explains. "With continued alteration, opal-CT precipitates and porcelainite is formed, and as the alteration continues it becomes the stable endmember chert. So you start with a lot of porosity – maybe 60% – and then as it transitions, it gets squashed down to 0%."

One of the first questions that explorers try to ascertain is whether the hydrocarbon biomarkers indicate migration or self-sourced depositions. Little said the reservoir appears to be self-sourced and contains kerogen in varying quantities throughout the whole Monterey group. The play is primarily oil, but associated gas is also prevalent, although not as much as in shale plays elsewhere in the country.

"The Monterey is very much a different beast," added Russell Lockman, Production Enhancement Operations manager at Halliburton. "The biggest challenge is that it is not a resource play, but a structural play, and requires the use of a multitude of techniques in every case. The Monterey is both an offshore and onshore play, and spans a huge area. What is effective in the upper part isn't necessarily effective in the lower part, and factors like the amount of natural fracturing can lead to loss circulation and stability issues. With each well, we really need to know where in the structure the target is being placed before we can figure out what technologies we need to use, and even then, success is often not duplicated from one area to the next."

In the current economic environment, the potential is outweighing the challenges, and it's not just a play for the majors – although several, including Occidental, Chevron, Exxon, and Shell are actively involved in both exploration and production. Aggressive independents like Venoco are also in an excellent position to take advantage of the enormous potential that has been identified in this play. Venoco's multiyear, multiwell drilling program targeting the Monterey Shale within the 304,000 gross, 214,000 net, acres it holds across three basins – the Santa Maria, Salinas Valley, and San Joaquin – as met with mixed success so far, but the results continue to be encouraging. The company is currently operating one rig in its Monterey Shale play and is waiting on drilling results to determine activity levels in 2012.

On a warm day, oil seeps into boot prints on a surface exposure of the Monterey Shale along California's coast.

"We are shoring up our development plans for the Sevier discovery and have been in contact with the agencies to ensure we have a clear path forward to develop this discovery," said Venoco's Chairman and CEO Timothy Marquez. "We were pleased to see the recent US Energy Information Administration's assessment of emerging resource plays, which confirms a lot of what we've been saying about the Monterey's resource potential. Not only is the Monterey Shale the largest overall play, it also dwarfs all other individual US oil shale plays."

Venoco is looking to increase its acreage in the Monterey, although it admits that acquiring acreage in the area can be a challenge. Much of the mineral rights have been under lease or held by production for years and the negotiations can be time consuming.

"Even though this is an older play, there is still a lot of potential," Edwards said, "and we aim to take advantage of it." ■

Focusing on Liquids-rich Returns

By Nissa Darbonne
Contributing Editor

Producers have turned their attention to their horizontal liquids-rich prospects and are tapping all means necessary to improve profit margin from these capital-intense wells.

Producers across liquids-rich shale plays are improving their economics the obvious way: making higher-performing wells. But they are also tackling the cost side as well as the market value of their assets and the product they are making via myriad – and at times surprising – methods from experimenting with completions and building their own service company operations to signing ethane supply contracts and capturing the wide, new Brent/WTI spread.

In August, Tudor, Pickering, Holt & Co. Securities Inc. (TPH) analysts looked at play break-even costs as WTI was ticking down to US $80 and Brent down to $100. Their figures are based on a 10% after-tax, internal rate of return (ATIRR). "It's not an exact science by any means," the team reports, "but it gets us in a pretty good ballpark and helps to define, especially on the margins, which basins are most profitable at any oil price, and more importantly, which basins will start to feel the pain first if we see a lack of global demand, pushing commodity prices lower."

In plays where there is associated gas, the analysts used a 14:1 gas:oil price ratio. In the conventional Permian, they report, wells make a 10% ATIRR at between $50 and $76 a barrel; in the Eagle Ford oil window, $48 to $80; the Mississippi Lime, $53 to $64; the unconventional Permian, $44 to $72; the Bakken, $40 to $65; Niobrara, $30 to $85; Granite Wash, $49 to $55; Eagle Ford condensate window, $40 to $66; and Southern California, $27 to $41.

Marcellus. Rehan Rashid, managing director and group head, energy and natural resources research, for FRB Capital Markets, notes that Marcellus dry- and wet-gas production is 3.5 Bcf/d and, at that rate and based on proved, probable, and possible reserves, the formation could produce for 400 years.

But operators with more than 2,000 Marcellus wells made to date are still drilling. Based on that, Rashid forecasts production could peak at 25 Bcf/d by 2025 – if there is sufficient demand to support a profitable price for that much gas. At that rate, the play would be mostly produced out in 40 years, if production performance is not enhanced and no additional reserves are booked, such as from the Upper Devonian and Utica and from New York state.

Producers across liquids-rich shale plays are improving their economics the obvious way: making higher-performing wells. But they are also tackling the cost side as well as the market value of their assets and the product they are making via myriad – and at times surprising – methods.

The net present value (NPV) Rashid estimates of the Marcellus' potential may be $75 billion at a long-term average margin of $2/Mcf and a 15% discount rate for the 500 Tcfe of estimated base-case recoverable reserves. At the standard 10% discount rate, the implied value would be around $150 billion, he added.

"We believe the recovery factor should ultimately increase to as much as 50%, which would still be materially below conventional recovery factors of 70%, and would imply recoverable reserves of 720 Tcfe, peak production of 35 Bcf/d, and a valuation level of $145 billion," Rashid said.

Eagle Ford. For the liquids-rich Eagle Ford, Rashid estimates its worth is at least $85 billion and as much as $200 billion. The low-case number is based on current first 30-day initial production (IP) rates and estimated ultimate recovery (EUR) per well; the high case, on if producers' improvement in tapping the resources is similar to advancements shown in the Barnett and Fayetteville plays as E&Ps have worked those over the years.

"Our analysis indicates that every doubling of cumulative wells drilled in other shale plays has yielded a 15% to 23% improvement in productivity as measured by increases in the average 30-day production rate," Rashid said. In the Barnett, each time the number of wells drilled has doubled in the past, the average first 30-day IP has improved 17.5%, he said, noting that in the Fayetteville, it was 23.1% each time; the Bakken, 15.6%; and the Haynesville, 15%.

At the current pace of drilling the Eagle Ford, with some 140 rigs at work, he forecasts the well count will double every 12 to 15 months. He then compared the outlook for the Eagle Ford to what has been demonstrated in the Bakken, which is also oil-rich, and the flow of oil is more complicated than that of gas, which is a smaller molecule.

"Assuming the Eagle Ford learning curve follows the same 15.6% path as the Bakken and taking into account the current and forecasted rig count, we would expect the 30-day average IP rates in the oil window to increase to 850 boe/d by 4Q 2012 and to 1,100 boe/d by the end of 2015," he said.

This would be improved from the average 585 boe/d that was posted at year-end 2010.

Niobrara vs. Bakken, Eagle Ford. For the Niobrara, wells cost less than in the Bakken and Eagle Ford, but they make less after-tax return on investment, according to Jessica Chapman, a TPH analyst and lead author of the Niobrara study. There might be more original oil in place (OOIP) in the Niobrara (30 MMboe/sq mile, including chalk and marl/shale intervals) than in the Bakken (10 MMboe to 15 MMboe) but less than in the Eagle Ford (30 MMboe to 50 MMboe).

But, in the Niobrara, when considering OOIP in the "B" chalk bench only, which is thicker and has better porosity than two other chalk benches (A and C), the TPH group estimate 5 to 10 MMboe – or less OOIP/sq mile than in the Bakken or Eagle Ford.

Niobrara wells can cost less, however, because the formation is at a shallower depth than the Bakken and Eagle Ford, and there are more oilfield services available in the area, Chapman said. A Niobrara well in the D-J Basin area can cost $3.5 million to $5.5 million, drilled and completed, compared with $6 million to $9 million in the Eagle Ford and $7 million to $12 million in the Bakken.

Using $60 to $100 oil and $4 to $6 gas, an average Niobrara well in the gassier Wattenberg Field area may return 10% to 45% plus on the dollars invested, 15% to 60% plus in oilier sweet spots outside Wattenberg and 0% to 15% in marginal areas outside Wattenberg, she noted.

"These returns compare to 15% to 80% plus in the Eagle Ford oil window and 15% to 200% plus in the Bakken," Chapman said. If the operator is able to tap a large, natural fracture system, the Niobrara return may improve significantly to between 100% and 200%-plus.

"It's early days," she concluded. "We think the Niobrara now is where the Bakken was in 2005 as far as knowing which drilling and completion techniques work best and where the sweet spots and edges of the play are. A play in its infancy means more risk but potentially greater reward."

Drilling, completion efficiencies

One of the means by which producers are achieving greater economics across liquids-rich plays is via further experimentation with well placement, drilling, and completions. At Petrohawk Energy Corp., which discovered the Eagle Ford play in 2H 2008 and became the onshore US operating group of BHP Billiton Ltd. this summer, the team has been modifying completion and production.

In the Eagle Ford, several wells that had an average IP of 6.2 MMcf of gas and 240 b/d of condensate were put on a more restricted 19/64-in. choke. The decline

rate of each appeared to be more gradual than that of wells on a normal choke, Petrohawk noted.

The company also has been testing Schlumberger Ltd.'s new MP7 (HiWAY) flow-channel fracturing technique. Early indications from this were that production increased an average 37% from Eagle Ford gas and gas liquids wells and 32% from condensate-rich wells. The tests further suggested that EUR per well was between 25% and 90% higher when using the pilot frac method.

In the Bakken, Continental Resources Inc., which founded the play in 2004, began testing the HiWAY completion technology this year. Although it was unable to disclose the results at the time of publication, Jeff Hume, Continental president and chief operating officer, said, "What I can tell you is that both of the fracs we've executed have gone off flawlessly...We do have plans to do several more of those and look at the results." The completions cost with this method is maybe 5% more, he said. "You're running more fiber gel in there."

Deeper Three Forks. Meanwhile, Continental is also testing the deeper Three Forks Formation that sits below the Bakken. In August, the company's Charlotte 2-22H was being drilled to the second of four oil-bearing dolomite Three Forks benches about 50 ft below the first bench, which has been the traditional target. Hume said, "The first bench...(has) proven to be very uniform and quite widespread. The second bench from our studies looks to be equally uniform and widespread in its development...In the end, what all this means is that there's more oil in place in the Three Forks than we had previously perceived, and this has got to translate into increased recoverable reserves for this field in the future."

Sand instead of ceramic. In the Eagle Ford, Pioneer Natural Resources Co. was testing the use of sand in its fracs instead of ceramic proppant, saving $700,000 per well, "which is very significant, if you look at the future drilling campaign," Tim Dove, Pioneer president and COO, said. On the first 10 wells, performance after sand was similar to that of direct offset wells in which ceramic had been used. "So the idea this year is that in about 30% of our wells, we'll be using white sand."

Shorter laterals, Marcellus. In the Marcellus, which is known for its dry-gas bounty but increasingly for

Single-Well IRR v. Oil, Gas Prices

Single-Well IRR v. Oil Price*									
Play/Window	$60	$70	$80	$90	$100	$110	$120	$130	$140
Barnett/Liquids	36.2%	49.4%	65.4%	84.7%	107.8%	135.6%	169.0%	209.2%	257.8%
Barnett/Gas	22.4%	23.8%	25.3%	26.7%	28.3%	29.8%	31.5%	33.1%	34.8%
Marcellus/Liquids	67.2%	71.8%	76.5%	81.5%	86.7%	92.2%	98.0%	104.0%	110.3%
Marcellus/Gas	67.2%	67.2%	67.2%	67.2%	67.2%	67.2%	67.2%	67.2%	67.2%
Eagle Ford/Liquids***	46.4%	62.2%	81.1%	103.8%	131.0%	163.6%	202.5%	249.3%	305.6%
Eagle Ford/Gas	25.8%	25.8%	25.8%	25.8%	25.8%	25.8%	25.8%	25.8%	25.8%
Single-Well IRR v. Gas Price**	$3.00	$3.50	$4.00	$4.50	$5.00	$5.50	$6.00	$6.50	$7.00
Barnett/Liquids	39.9%	44.3%	49.1%	54.2%	59.7%	65.4%	71.6%	78.2%	85.2%
Barnett/Gas	4.2%	7.6%	11.2%	15.4%	20.0%	25.3%	31.1%	37.6%	44.8%
Marcellus/Liquids	16.2%	24.1%	33.8%	45.5%	59.7%	76.5%	96.7%	120.6%	149.3%
Marcellus/Gas	7.5%	14.5%	23.6%	35.1%	49.4%	67.2%	89.1%	116.1%	149.3%
Eagle Ford/Liquids**	40.4%	47.2%	54.5%	62.6%	71.5%	81.1%	91.7%	103.2%	115.7%
Eagle Ford/Gas	(1.0%)	0.6%	4.9%	10.3%	17.2%	25.8%	36.5%	49.4%	64.8%

** Oil price at constant $80/bbl*
*** Gas price at constant $4.50 MMBtu*
**** Excludes condensate or natural gasoline*

As crude oil prices grow, the profit from liquids-rich gas plays improves; however, the price of the dry gas or methane is unchanged. Meanwhile, profit from liquids-rich gas plays improves as dry-gas prices improve, as well, meaning the liquids are a bonus no matter the oil or gas price market. *(Source: FBR Capital Markets)*

"There is plenty of water for fracing in Ohio, the topography is less challenging than Marcellus' hills and mountains of West Virginia and Pennsylvania, and labor is plentiful."

*— **Aubrey McClendon**, Chesapeake chairman and CEO*

its liquids-rich gas window, Range Resources Corp. is using relatively shorter laterals – the average among Range's wells is 2,800 ft – and fewer frac stages – eight or nine – than many other operators. Jeff Ventura, Range president and COO, notes that the average EUR for its Marcellus wells and those of eight other companies reviewed recently by Goldman Sachs analysts is the same: 5.7 Bcfe each.

"Many of those companies drill significantly longer laterals and pump more stages," Ventura said. "Yet the average EUR is the same. That implies that, versus the average, the rock quality of what we're drilling is better. It also suggests that if we complete with more stages, we can increase the ultimate recovery of our wells. Of course, the key is to optimize the rate of return of the project, not the EUR of a particular well."

Range is in an internal race to hold its roughly 1 million Marcellus acres by production. According to Ventura, by keeping its cost down, the company is able to drill more wells and hold more acreage while generating an excellent rate of return. Range's wells cost about $4 million each, generating 105% rate of return at $5 gas. Even at "$4 gas forever," Ventura said, it's 74%. "It's not optimal (than longer laterals and more stages), but it's pretty darn good."

Longer laterals, Marcellus. Under less pressure to hold by production (HBP) its Marcellus leasehold, EQT Corp. has 3.4 million acres in Appalachia mostly as a legacy position. Dave Porges, EQT chairman, president and CEO, says that when drilling for both well economics and to hold acreage, "it is probably true that shorter laterals make more sense because what you want to do, in that circumstance, is touch as many of those leases as possible."

Early entrants to the play that secured five-year lease terms will be approaching expirations in 2012 and 2013. But if able to drill solely for top well economics, "we are absolutely convinced that longer laterals are better, at least up to 9,000 ft, which is as far as we've drilled to date," Porges said.

Meanwhile, Cabot Oil & Gas Corp. has reported the largest Marcellus wells to date, and each had more frac stages than the Range standard: First 24-hour production from a pair came in at some 30 MMcf each, with 21 and 26 frac stages and lateral lengths of between 5,000 and 6,000 ft. The company's average well previously IP'ed 16 MMcf, and the newest wells suggest an EUR of at least 15 Bcf per well.

The wells cost some $7.5 million to $8 million each. "This sort of type curve should generate acceptable economics with gas as low as $2," Biju Perincheril, equity analyst for Jefferies & Co. Inc., said.

Utica economics, JVs, RTs

Well economics also can be improved via financial engineering besides drilling and completions engineering. Chesapeake Energy Corp.'s Nick Dell'Osso, executive vice president and CFO, says shareholders are getting the company's 13.2 million of undeveloped acres at zero cost as a result of joint ventures the company has set up on its shale plays. He estimates the acreage holds 18 Bboe of risked, unproved reserves. "Pretty remarkable opportunity for value," Dell'Osso said.

Chesapeake has JV'ed acreage in the Fayetteville, Haynesville, Marcellus, Eagle Ford, and Niobrara and recently divested the balance of its stake in the Fayetteville to BHP. At the time of publication, the company was working to JV the 1.25 million acres it has put together – for between $1.5 billion and $2 billion – over Utica, in which it drilled the first four horizontal discovery wells this year.

Aubrey McClendon, Chesapeake chairman and CEO, likens the Utica to the Eagle Ford in that it has a dry-gas window in the east, liquids in the middle, and oil in the west, but the rock quality and the location is better, making it economically superior, he said.

McClendon added that there is plenty of water for fracing in Ohio, the topography is less challenging than Marcellus' hills and mountains of West Virginia and Pennsylvania, and labor is plentiful.

There is also the Ohio River, "so if we need to barge oil out tomorrow, we can do that," he said.

Also making it a good play for Chesapeake is that a great deal of the acreage it has amassed is HBP. "We went in early and made deals on deep rights with a lot of shallow producers," McClendon said. Net revenue interest is mostly the standard 85%. Terms on other leases is five years with an option for a five-year renewal, "so we feel like we'll have no trouble getting it all HBP and won't have to be in as big a rush as we were on the Barnett or the Haynesville, although we certainly do have more acreage here that we do need to get HBP."

The Utica JV may be between $12,000 and $16,000 an acre, suggesting the 1.25 million acres are worth between $15 billion and $20 billion to Chesapeake shareholders. "That's a big number to be sure," McClendon said, "but we believe we understand the hydrocarbon potential under our acreage and we also know a fair amount about how to create and extract value from a play such as this."

The royalty trust. Chesapeake also will monetize a portion of its gas liquids-rich Granite Wash position in the Midcontinent in a royalty trust, which it was planning to IPO at the time of publication. The RT is an especially useful means of raising capital without selling an asset when in a hot market for income-producing securities.

"Similar to a VPP (volumetric production payment), there's a reversion of some tail interest here," Dell'Osso said. "There's some beneficial tax treatment associated with it...(And) you're selling well bores only, and you're selling them within a defined depth."

The RT is particularly interesting in the Granite Wash region of stacked pay. Above the many Granite Wash benches are the oily Tonkawa, the gas liquids-rich Cleveland or Marmaton and other pay; beneath it is the long-plied deep gas in Morrow and Springer that drillers are not currently targeting at sub-$6 gas prices.

According to Dell'Osso, "these (VPPs and RTs) are very discreet monetization vehicles, and they allow us to capture value for projected production at a very low discount rate and, frankly, beat out what you would get in the A&D market if you were to go sell this asset, where you'd have to give up all the upside drilling associated with it and not get a whole lot more value for it."

NPV via neighboring M&A

The value of unconventional resource acreage is further being proved by other deal-making in the plays. Pioneer's Scott Sheffield, chairman and CEO, points to BHP's $15.1 billion deal for Petrohawk this summer in which the Australian conglomerate acquired more than 1 million net acres in the Eagle Ford and Haynesville as well as in the Permian Basin. "Obviously, it's nice to see people paying $23,000 per acre right next to our (Eagle Ford) acreage," Sheffield said.

Meanwhile, Marathon Oil Corp. plans to pay $24,800 a net acre for Hilcorp Resources Holdings LP's 141,000 over the Eagle Ford in a deal that was set to close at the time of publication. EOG Resources Inc.'s Mark Papa, chairman and CEO, points to this as well as the BHP deal as independent testament to leasehold value in the South Texas play, which EOG began accumulating in 2008 for as little as some $450 an acre. EOG's leases are mostly in the Eagle Ford's oil window, so Papa says its value is even greater.

"We believe EOG's 561,000 net acres have a higher average geologic and product quality than this transaction," Papa said of the Marathon deal. As for the Petrohawk deal, "both the size and quality of our acreage significantly surpasses the Petrohawk position," he said.

Range's Ventura says of deals like that of BHP-Petrohawk, "What it tells you is that NAV (net asset value) really matters. And at the end of the day, the companies that can drive up their NAV on a most cost-efficient basis, on a per-share basis, are the ones who are going to be the big winners. And that's all we're focused on."

Neighborly derisking. Ventura adds that neighboring drilling in the Marcellus play is further proving the value of its own leasehold. In the southwestern play, some 500,000 of Range's 550,000 net acres have been derisked by it and others' combined 1,000 wells by mid-year 2011.

"Assuming that 80% of the acreage will be drilled and as the development will be on 80 acres, we would then have 5,000 wells to be drilled in the southwest, considering only the Marcellus Shale (and not the Upper Devonian and Utica)," Ventura said.

Getting >WTI, HH

In the midst of head-turning amounts of new US oil production from old onshore basins is the curious case of the WTI/Brent spread.

Paul Sankey, energy analyst for Deutsche Bank, forecasts the double-digit Brent/WTI spread phenomenon will continue into 2013 at least, which is the expected start date of the 500,000 b/d Canada-to-Gulf Coast Keystone XL pipeline. Into 2014, the spread should narrow into single digits, particularly as Libyan production is fully restored, he said.

From the Eagle Ford, E&Ps such as Pioneer and Anadarko Petroleum Corp. are working on putting their oil on barges off the Texas Coast, exposing it to the waterborne Louisiana Light Sweet (LLS) spot price that is more like that of seaborne or Brent-priced oil.

The prize is huge. At EOG, for each $1 change in the wellhead price the company gets for oil and condensate and the related change in the NGL price, it makes some $24 million more or less in net income and $36 million more or less in operating cash flow, according to Tim Driggers, EOG vice president and CFO.

In seeking more of the nearly Brent price for its Bakken oil, EOG expects to rail most of this production to Louisiana instead of Cushing by 2012. “If those differentials exist next year, we’ll be railing every possible barrel we can to (Louisiana) as opposed to Cushing,” Papa said.

Greg Armstrong, chairman and CEO of Plains All American Pipeline LP, notes that Eagle Ford and Bakken oil is light. Potential new oil supply from the Utica Shale play in Ohio is light, too. “And so you’re talking about probably an aggregate – no matter whose story you believe – of at least over 1 million barrels a day of (new), very light product. And it’s going to change the dynamics in (a refining) industry that’s been gearing up for heavy or sour product.”

Better than HH. Range, which discovered the Marcellus play in 2007, fetched an averaged $5.73/Mcfe for its 3Q 2011 production, up 15% from 3Q 2010, as it was making wetter gas and NGL and oil prices were higher. For its dry gas, it received $4.51/Mcf; for its NGLs, $49.52/bbl; and for its oil, $81.70/bbl.

The company’s gas is higher Btu and it is also near the premium US Northeast market rather than Henry Hub (HH) in South Louisiana. To further capture a higher premium for its wet gas, Range has been working for several years to sell the ethane to end-users. In September, it signed its first deal – to ship ethane to Nova Chemicals Corp. in Sarnia, Ontario, on Lake Huron, via the new Mariner West pipeline. First sales are expected in 2013. Range also is discussing selling ethane to petrochemical plants on the Louisiana coast as well as in Europe via seaborne shipments launched from the Atlantic coast as part of the Mariner East project.

Ethane Supply & Demand Model* (Mbbl/d)

	Est. Capacity	2011E	2012E	2013E	2014E	2015E	2016E	2017E
Build-Up Of Ethane Supply								
Ethane Supply (Jan 2011)	900	900	900	900	900	900	900	900
+ w/Likely and Possible Projects		951	1,010	1,151	1,284	1,284	1,284	1,284
Build-Up Of Ethane Demand								
Ethane Demand (Jan 2011)	926	926	926	926	926	926	926	926
+ w/Likely and Possible Projects		948	1,012	1,059	1,097	1,139	1,272	1,344
Estimated Ethane Over/(Under) Supply		3	(2)	92	187	144	11	(60)

** Aug. 23, 2011.*
*** To be determined.*
Notes: Analysis assumes ethane comprises 45% of new NGL fractionation capacity and an operating rate of 90%.

Ethane supply from NGLs produced from the Eagle Ford and other plays across the US is projected to grow 44% by 2014. Demand may grow faster but again exceed supply by 2017. *(Source: Wells Fargo Securities LLC estimates from company reports and EIA and Hodson Report data.)*

The Tightly Held Monterey Shale

California's enormous, century-long-known Monterey Shale potential has been barely tapped, but several new leaseholders are aiming to grab some of the prize.

The potential for producing more bounty from the Monterey Shale, which contains 15.4 Bbbl of technically recoverable oil, may be enough for legacy producers in Southern California to step out of their held-by-production (HBP) comfort zones and re-enter the California permitting process.

"The state's permitting process for drilling and production operations on non-HBP fee acreage is in most cases daunting," said Bruce Berwager, COO for Santa Barbara, Calif.-based small-cap Underground Energy Inc. "The majority of operators from other parts of the country have quicker and easier access to prospective lands and, as a result, have focused their respective budgets away from California in the past."

But, this is oil — evermore the prize among both small independents and majors in a 24:1 gas:oil price environment. And, this is onshore US oil, particularly attractive as operating in the US offshore and in foreign countries is increasingly hostile.

And, even more compelling: This is Southern Californian oil, which is priced more like seaborne crude, such as Brent, which has been trading at US $15 or more higher than that of mid-continental North American — or West Texas Intermediate (WTI)-priced-oil for the past year.

"California imports about two-thirds of its oil from waterborne sources and produces the rest in-state," Berwager noted. "As such, our locally produced oil competes with world oil prices rather than WTI."

Monterey wells in the naturally fractured areas of the rock that is pervasive in the state may be economic at as little as $20 WTI, which is about $43/bbl in Southern Californian refinery dollars.

The state's permitting process can be onerous, though. Mike Wracher, vice president, exploration and Sacramento Basin, for longtime Southern California operator Venoco Inc., said, "Many operators don't think they can play in California, but those of us who have worked our entire careers in California know it's not that bad and we've been able to pick up 170,000 net acres over the past three or four years.

"So, obviously you can do it, you just have to know how."

Compared with above-ground revolt against drilling in New York state and elsewhere, particularly to hydraulic fracturing, the Monterey might be a more favorable operating environment these days. Wracher said, "The jury is out about whether fracing is even going to be useful in the Monterey. So that has kept us off the radar screen from that debate."

Why not frac it?

Wracher explains that the Monterey is pretty brittle and the tectonically active nature of the state's subsurface has resulted in a great deal of natural fracturing. The company fraced some Monterey wells but found that well economics did not improve meaningfully; simple perforating and acidizing in completions may be all that is necessary, he said.

Produced for more than a century from simple vertical wells and without the benefit of 3-D seismic, the shale has given up more than 2 Bbbl of oil to date. Major oil companies such as Chevron Corp., the Aera Energy LLC operating unit of Royal Dutch Shell, and Exxon Mobil Corp., have focused in the past on development of existing fields and not on new exploration.

Steven Marshall, president of Bakersfield, Calif.-based Western Energy Production LLC, which has leased more than 100,000 net acres over Monterey, said, "And therein lays the opportunity for us and other companies to acquire some open acreage in a relatively small amount of time."

To get in on the play, joint ventures and outright acquisitions are necessary as most of the leasehold is owned by majors or has been leased by others, such as Venoco, Underground, and Western Energy, in the past few years.

While the Monterey Shale is some five times bigger in technically recoverable reserves than the Bakken, Venoco's Wracher calls it the granddaddy of all the US shale plays "because it really was the first one that was developed back in 1902. All these other shale plays really have originated in the past 15 years."

Because of the legacy positions of major oil companies in Southern California, the area hosts few operators like that of new plays, such as the Marcellus, Eagle Ford, and Bakken.

Marshall says, "Competition for us would be healthy. At this phase of the game, we need some outside forces. We're moving to the drilling phase and the drilling and completion data throughout the play will be helpful to each company and to development of the overall potential itself."

— Nissa Darbonne

From the nearby Utica shale play, more gas liquids are expected as Chesapeake reported three horizontal discoveries in the wet-gas window in September, IP'ing between 980 b/d and 1,425 b/d of liquids. According to Irene Haas, senior equity analyst, E&P, for Wunderlich Securities Inc., "Utica is very much a midstream story. If successful, we expect the Utica to generate as much if not more NGLs than the neighboring Marcellus trend."

Besides from Appalachia, more gas liquids are coming out of the Eagle Ford as well as from the Cleveland/Marmaton, Granite Wash, and western Mississippi Lime plays in the Anadarko Basin in Oklahoma and the Texas Panhandle.

Bentek Energy LLC reports that, as the center of US NGL production is shifting away from the Gulf of Mexico, "the increased distance of much of the new production from 'fractionator alley' and the petrochemical markets along the Gulf Coast is driving new midstream investments in pipelines, gas-processing plants, and other facilities necessary to support increasing NGL volumes."

For example, Bentek forecasts NGL production out of the Greater Anadarko Basin will increase 60% by 2020. End-users' appetite for the NGLs is whet as NGLs are a less expensive feedstock than crude oil derivatives. Jim Teague, Enterprise Products Partners LP executive vice president and COO, noted, "In the past 12 months alone, approximately 100,000 to 150,000 barrels per day of heavy (crude) cracker feedstocks have been replaced with light-end (NGL) feedstocks."

Michael Blum, Wells Fargo Securities LLC senior research analyst covering MLPs, continues to expect strong demand for ethane as more crackers are put online. Total supply may reach 1.3 MMb/d in 2014, he said, while demand reaches 1.1 MMb/d. However, proposed newbuild ethylene plants by The Dow Chemical Co., Chevron Phillips Chemical, and LyondellBasell in 2016-17 may bring the ethane market back into undersupply, thus driving the price back up.

Building in-house services

Far north, Newfield Exploration Co. has slowed its development of a new liquids-rich play – the Montana Bakken in the southern Alberta Basin – as the area is particularly service equipment-poor, which is made worse because "anything within 150 or 200 miles of (North Dakota's) Williston Basin hears the giant, sucking sound of the basin's gravitational pull," Lee Boothby, Newfield chairman, president, and CEO, said.

At Pioneer, to reduce cost and the number of wells in the "waiting on completion" or WOC column, it has been building its own pressure-pump-

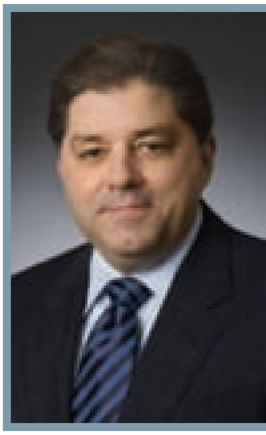
2011 Eagle Ford Transactions, Plus Selected $1 B-Plus Deals

Date Announced	Buyer	Seller	Transaction Value ($MM)	Net Acres	$/Net Acre
6-30-11	Undisclosed	Forest Oil Corp.	$110	10,000	$11,000
6-29-11	Mitsui & Co. Ltd.	SM Energy Co.	$735	39,000	$17,403
6-20-11	JGC Energy Development	Tritech I LLC	$65	6,300	$10,317
6-13-11	Statoil ASA, Talisman Energy	SM Energy Co.	$225	15,400	$14,610
6-1-11	Marathon Oil Corp.	Hilcorp Energy Co.	$3,500	141,000	$24,823
3-21-11	KNOC	Anadarko Petroleum	$1,550	96,000	$16,146
10-10-10	Talisman/Statoil	Enduring Resources	$1,325	97,000	$10,900
10-10-10	CNOOC Ltd.	Chesapeake Energy	$2,160	200,000	$10,800
3-28-10	Royal Dutch Shell	Harrison Ranch	$1,000	95,300	$12,015
6-24-10	Reliance Industries	Pioneer Natural Resources	$1,145	100,000	$10,000
Median, All Deals, Beginning 1-14-10			$180	35,000	$9,865

Marathon Oil Corp.'s purchase of Hilcorp's Eagle Ford position holds the high-water mark for transactions in the play. BHP Billiton Ltd.'s $15.1 billion bid for Petrohawk Energy Corp. approaches it; however, the deal includes Haynesville Shale gas and Permian Basin acreage as well as Eagle Ford. *(Source: Tudor, Pickering, Holt & Co. Securities Inc.)*

Newfield Exploration Co. has slowed its development of a new liquids-rich play … as the area is particularly service equipment-poor, which is made worse because "anything within 150 or 200 miles of (North Dakota's) Williston Basin hears the giant, sucking sound of the basin's gravitational pull."

*— **Lee Boothby**, Newfield chairman, president and CEO*



ing fleets. Six are at work in its Sprayberry play in West Texas and in the Eagle Ford – where it has a combined 20,000 liquids-rich locations to drill – and two more were expected to be on the job by year-end for combined hydraulic horsepower (HHP) of 225,000. The fleet makes the company the No. 15 operator of pressure-pumping in terms of HHP.

"Vertical integration has been a much better benefit than we ever imagined," Sheffield says. "The decisions we made back in 2009 to buy into those businesses, we're seeing tremendous returns that allow us to keep capex down significantly over the next several years."

In the Eagle Ford, where Pioneer's average lateral length is about 5,500 ft and EURs are some 6 Bcfe each, wells can cost $7 million to $8 million, but Pioneer is saving $1.7 million by fracing its own wells. On an annual basis, the savings is $460 million compared with the cost of hiring HHP under a long-term contract; if compared with the spot price for pressure pumping, the savings is $715 million.

Meanwhile, the HHP represents additional book value to Pioneer shareholders. Would Pioneer consider selling the service business? "I guess if somebody offered $3.5 billion, we have to strongly consider it – five times the $715 million number – but, right now, with the savings that we have, the growth in it and the benefits we're seeing, we just don't see it," Sheffield said.

Also, demand for HHP only continues to grow faster than supply. Industry-wide, more than 2,000 wells are WOC, according to a Halliburton Co. count. Michael Bodino, managing director and head of energy research for Global Hunter Securities LLC, says demand for HHP in the Lower 48 entering 2011 was at least 13.6 million, while existing and anticipated new supply in 2011 totaled 11 million.

"The demand for (HHP for) the international shale plays is developing now," Sheffield said. "It's all coming out of the US market too, so it's going to be tight for a long time."

Mining its own sand. At the EOG, Eagle Ford and Bakken cost creep in 2011 has been 8% to 10% over 2010, Driggers said. The company, which is in nearly every unconventional resource play in North America, has been supplying its own sand to its Barnett completions from a Texas mine for some time.

In 2011, a new Wisconsin mine was added. That and other efficiencies are to save it some $1 million per well, according to Driggers, or possibly $400 million company-wide just for the sand. With the savings, EOG expects its Eagle Ford average well cost, for example, will be some $5.25 million in 2012, down from $6 million or more this year.

Operating rigs. Chesapeake is also reducing its exposure to service-cost inflation. The company operates some 115 rigs or two-thirds of what it has working for it on any given day, saving some 20% compared with what other operators pay for third-party drilling. It is building 150 oil-hauling trucks and was expecting its first 250,000 HHP of pressure-pumping fleet at the time of publication. McClendon expects to continue to grow these business units. "Remember, we need about probably 1 million horsepower a day," he said.

Conventional services. In the Mississippi Lime in northern Oklahoma, however, developer SandRidge Energy Inc. notes some of this liquids-rich, horizontal, conventional resource play's many advantages. Rigs needed are among the abundant, conventional, 1,000-hp type and, for completions, only 10,000- to 12,000-HHP pressure pumping – in great contrast to the 40,000 HHP needed in deeper, tighter unconventional plays. Proppant is simple sand.

Tom Ward, SandRidge chairman and CEO, noted, "The entire industry has moved to tight, deep plays that require high-pressure drilling and completions. Consequently, there is an abundance of low-pressure equipment...So we have an excess capacity of equipment when other people don't." ■

High Liquids Yield from US Oil Shales Shifts Production, Price Curves

The rapid commercialization of liquids-rich unconventional plays is shifting oil production back on land, but at what price and for how long remains to be seen.

Over the next few years, onshore US oil production is set to be one of the most significant and dynamic contributors to non-OPEC supply growth. The discovery and rapid development of unconventional tight and shale reservoirs in North America, especially those with extensive liquids windows, is shifting US production from high-risk offshore frontiers back on land.

According to research by Barclays Capital, the past 24 months have seen a tangible acceleration in unconventional drilling activity and the fast-track commercialization of these resources such that the US oil industry now stands at the doorstep of one of the most exciting developments in recent history. With burgeoning shale gas supplies depressing gas prices on the domestic front, companies are emphasizing their desire to tap more liquid-rich reserves in unconventional basins, with a significant portion of this output set to come in the form of condensate and natural gas liquids (NGLs), rather than crude oil.

By year-end 2011, the trend toward accelerated drilling in the US oil shale plays like the Bakken and Eagle Ford had showed no signs of abating; however, according to Barclays Capital, whether drillers will face a new learning curve in crude oil or continue to improve on natural gas production results depends on a number of challenges the industry, particularly the independents paving the way in exploiting these shale reservoirs, must address.

Editor's note: This article contains information excerpted from Barclays Capital June 21, 2011, research report, "US Oil Shales—The End of WTI?" by James R. Crandell and Amrita Sen. For further information about Barclays Capital Research, please visit ***Barclayscapital.com***.

Drilling: Where, when, and how much?

The accelerated pace of unconventional shale development in the US has fueled buoyant expectations for domestic oil production, with the larger part of that volume making its way to the Cushing, Okla., hub – or effectively backing out crude demand from Cushing. This shift to oil drilling has been steady and relentless, though not surprising, according to Barclays Capital.

Meanwhile, the West Texas Intermediate (WTI) oil price benchmark has experienced a downward pull because of accelerated oil shale development as a number of independents have either redirected or increased capital onshore.

With Cushing at the forefront of this production shift, new oil development in an area referred to by oil analysts as PADD II is located largely in the mid-continent US. While production growth from these reservoirs is not significant yet, Barclays Capital maintains that it has been dramatic for the localized market around PADD II, depressing WTI prices relative to other light, sweet crude oil benchmarks. Unheard of until recent months, WTI prices have widened to discounts of more than $20/bbl versus Brent.

While some of the increase in oil drilling reflects better economics in drilling for oil versus natural gas, some of it also reflects strong economics in oil that are attracting more and more rigs that had been idled previously. Rig counts as of June 2011 point to a push toward oil drilling amid the influx of shale gas supplies currently weighing down gas prices. In the past 24 months, the gas rig count declined from 992 to 879 rigs – a 113 rig loss over the past two years – against a 333 rig gain in the oil rig count.

As budgets and portfolios have begun to favor oil over gas, Barclays Capital does not believe producers have shifted completely away from volumetric production growth, whether it comes from oil or gas. Much like gas, the longer run viability of oil shales remains to be seen.

Unconventional challenges, constraints

With the oil rig count rising on a steady, linear basis, increases in oil drilling introduces more volatility (both upward and downward) to US production trends. Oversupply in the Midcontinent will depend on factors such as pipelines, refineries, imports from Canada, and demand in the US. But the biggest factor in the next few years for WTI differentials is US midcontinent crude oil production, with unconventional oil production playing a leading role in higher output.

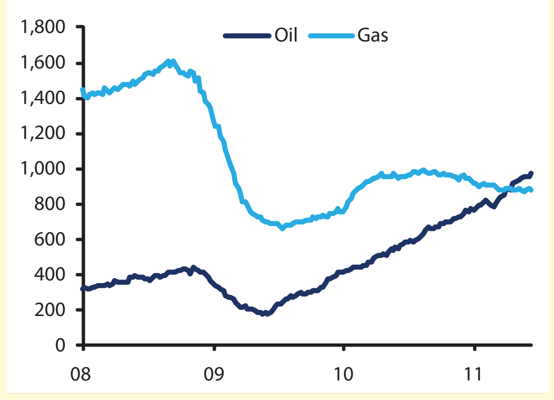
Production gains in the region are unlikely to evolve without widespread challenges, however. According to Barclays Capital, there are various constraints that may both slow the growth rates and pose serious impediments to future unconventional resource development not just in Cushing but throughout the US, including steep decline rates following initial high production, infrastructure buildouts keeping pace with the number of wells being drilled in shorter time, and, assuming the geology exists on a wide scale, whether the technology can be replicated to other similar reservoirs at a similar cost.

In the more immediate future, infrastructure is likely to be the biggest constraint that the shale play areas face as the midstream industry has failed to keep up with the pace of production growth, and near-term success of oil shales depends on infrastructure buildout. Depressed WTI values already have increased shipments by truck, train, and barges, but while these volumes are likely to continue to increase, they remain small in relation to growth in production.

This is evident in Cushing where, due to a lack of longer pipelines to transport crude to the Gulf Coast, a short-term fix to add short-haul capacity to tie-in to existing systems has created a bottleneck in the region.

Plans to eventually expand infrastructure to increase takeaway capacity in key regions such as in North Dakota and in South Texas are burgeoning, however, with rail capacity in particular booming. With pipeline additions more expensive and with no new southbound pipes from Cushing planned until 2013 or beyond, shipments of oil through tankers, although small, have already doubled from a year ago to approximately 100,000 b/d, especially in North Dakota. Pipeline projects also are gathering momentum. In 2011, midstream companies have announced a series of new pipeline projects in the Eagle Ford Shale and have committed more than $1 billion to add 940,000 b/d of pipeline capacity by year-end 2012.

Oil and gas-directed rig count



(Source: Baker Hughes, Barclays Capital)

The oil rig count has increased on a steady, linear basis, with two main constraints to it moving consistently higher – the availability of high horsepower rigs and oil acreage being scarcer than gas acreage.

In addition to near-term supply constraints, concerns on air quality, carbon emissions, groundwater, spent shale disposal, land reclamation, and other environmental issues associated with the development of oil shale from hydraulic fracturing are challenging swift industry commercialization. A study is currently being conducted by the EPA assessing the environmental impact of fracing with initial findings due in 2012 and final recommendations to be made in 2014.

The way ahead

The time line from discovering a promising liquids-rich shale play to commercial production has become astonishingly compressed, and from emergent to core in two years has been the story for most of the American shale plays.

According to Barclays Capital, the key unconventional plays to watch in the early stage of development are the Bakken and Eagle Ford shale plays. The firm projects that US liquids production from these locations will expand at a rate of 200,000 b/d to 250,000 b/d in the coming years, with the bulk of this growth coming from the Bakken (100,000 b/d) and Eagle Ford (70,000 b/d). ■

(Photo courtesy of Chesapeake Energy Corp.)

Unconventional Resource Developments Drive Future Production

By Skip Simmons
Contributing Editor

Midstream asset modifications and newbuilds are key.

With the current price difference between oil and natural gas, many producers have identified the "oilier" plays within their resource portfolio as the focal point of their capital spending and development activities. Plays with development potential for crude oil, condensate, and hydrocarbon-rich natural gas are very active, while dry gas development has slowed in many unconventional resource areas – save for hold-by-production or other lease requirements – but will be back when natural gas prices are more supportive and/or operators shift back to their dry gas play opportunities.

As the developments in the oilier plays occur, producers concurrently are implementing midstream infrastructure facilities. Those facilities consist of oil gathering and transmission pipelines, oil trucking and rail facilities, oil storage and terminal facilities, condensate stabilization and storage facilities, gas gathering and processing, natural gas liquids (NGL) pipelines and storage facilities, fractionators, NGL trucking and rail facilities, and NGL products pipelines. Because these facilities require significant capital investment, midstream operators generally offer fee-for-service contracts in return for reserve dedication and/or term contractual commitments. In addition, midstream operators often implement facilities in phases, which coincide with upstream operators' development timing and resultant actual production capability.

For some unconventional resource areas where operators previously developed conventional resources using vertical wells and completion techniques, operators now are using horizontal drilling techniques, which result in unconventional resource access. In these cases there is significant historical data regarding the areas overall drilling and completion efforts, which allows operators to use existing vertical wells to support horizontal offsets. Also, pad locations and drilling and production support facilities are generally in place, and ample local service companies are available to support them. Existing midstream gathering infrastructure usually is available to support these new initial developments and can be enhanced or supplemented as needed.

A brief description of various North American unconventional resource areas follows. Various data tables referenced therein include descriptions of modifications to existing area midstream infrastructure and/or the various newbuilds in process to assure that developing supplies can reach their desired markets. Resource areas are listed alphabetically and some are combined geographically (though certainly not geologically).

Avalon Shale/Bone Springs (Permian Basin)

These two unconventional plays are in the greater Permian Basin in southeastern New Mexico and West Texas. The Permian Basin has been one of the oldest and largest US domestic supply areas, providing billions of barrels from traditional vertical wells over its history. As a senior area, the Permian region still has more than 150,000 wells, provides 72% of the oil produced in Texas, and 13% of annual US domestic oil production.

Drill pipe delivered to a rack near a drilling rig stands ready to make an Eagle Ford hole.

Table 1. Permian area: various infrastructure supporting Avalon Shale and Bone Springs (Leonard Shale) development efforts

Midstream assets	Operator	Capacity (g) mmcf/d (l) (bbls/d)	Existing (E) Expansion (X)	Timeline
Dagger Draw gas processing and treating plant	Agave Energy Company	(g) 35,000 (est)	E	In-service
Red Bluff gas gathering system		(g) 50,000 (est)	E	In-service
Red Hills gas processing and treating plant + 30-mile NGL pipeline		(g) 60,000 (l) 25,000	X	2 Q 2012
West Texas LPG Pipeline LP (WTLPG)m – Interstate and Intrastate facilities	ChevronPhillips (80%) Atlas Pipeline Partners (20%)	(l) 230,000	E	In-service
Upstream crude oil gathering arrangement by WTLPG for proposed delivery to DCP Sandhills Pipeline	WTLPG (for DCP Midstream)	(l) varies with shipper nominations	X	2 Q 2013
Las Animas gas gathering systems (possible conversion to wet gas system and plant additions)	Crestwood Midstream Partners LP	(g) 50,000 (est)	E	In-service
Artesia, NM plant	DCP Midstream LLC [Spectra Energy (50%) ConocoPhillips (50%)	(g) 74,000	E	In-service
Artesia Plant Expansion		(g) 100,000	X	2 Q 2012
Re-activate Zia, NM Plant		(g) 42,000	E	In-service
Eunice, NM plant		(g) 105,000	E	In-service
Antelope Ridge, NM plant		(g) 30,000	E	In-service
Linam Ranch, NM plant		(g) 175,000	E	In-service
Linam Ranch expansion		(g) 50,000	X	2 Q 2012
Hobbs plant		(g) 40,000	E	In-service
Connecting pipeline between Southeast NM gathering system and West Texas gathering system		(g) varies (flexibility)	X	2011
Proposed DCP Sandhills NGL Pipeline from Permian Basin to Mont Belvieu	DCP Midstream Sandhills Pipeline LLC	(l) 120,000	X	2 Q 2013
Chaparral NGL Pipeline to Mont Belvieu	Enterprise Products Partners	(l)150,000 (estimated)	E	In-service
Trinity Pipeline 8-in. (convert from CO_2 to crude oil service)		(l) 54,000	X	4 Q 2011
35-mile crude pipeline from HEP gathering facilities to Holly/Frontier refinery in NM	Holly Energy Partners (HEP)	(l) 35,000	E	In-service
HEP Pipeline expansion – NM		(l) 35,000	E	In-service
HEP Pipeline expansion – NM	Holly Energy Partners (HEP)	(l) 25,000	X	2 Q 2012
Reactivate and convert 70-mile, 8-in. to crude oil service in NM ; multiple delivery connections	Nuevo Midstream LLC	(g) 50,000	E	In-service
141-mile Ramsey gas gathering system, re-activate JT processing facility and fractionators; new 8- in. NGL products pipeline		(g) 20,000	E	In-service
Reeves County, TX plant		(g) 20,000	X	2011
Reeves County plant expansion	Occidental Petroleum	(l) 225,000	E	In-service
Crude gathering system	Oxy USA WTP LP	(g) 240,000 (l) 10,000	E	In-service
Indian Basin gas processing plant (sour), Eddy, NM	Plains All American LP*	(l) 225,000	E	In-service
Various Permian crude area gathering systems		(l) 65,000	X	4 Q 2011

(Tables by Hart Energy)

Table 1 Continued

Midstream assets	Operator	Capacity (g) mmcf/d (l) (bbls/d)	Existing (E) Expansion (X)	Timeline
Bone Springs crude and condensate	Targa Resource Partners (63%)	(g) 280,000	E	In-service
gathering + storage	Chevron USA (37%)	(l) 20,000+	E	In-service
3,100-mileVersado gas gathering system, NM, including:	Targa Resource Partners	(g) 200,000	E	In-service
Monument gas plant		(g) 150,000	E	In-service
Eunice gas plant			E	In-service
Saunders gas plant			E	In-service
1,300-mile West Seminole and Puckett gathering systems in TX, including:		(g) not available	E	In-service
Sand Hills processing plant				

** Note: Occidental Petroleum's midstream investment includes a 35% ownership of Plains All American (PAA) LP.*

The Avalon/Bone Springs (Leonard) play occupies a large area in Lea and Eddy counties in New Mexico and Reeves, Loving, Ward, and Culbertson counties in Texas. The play has completion potential in multiple horizons and could lead to significant volumes in future years. A significant amount of older and in some cases idled gas and oil gathering and gas processing plant infrastructure generally exists in the area. Where previous infrastructure exists, the expected magnitude of new upstream developments has created the need for new facilities and/or modification for oil transportation as well as the ability to process any associated gas streams. In other cases, parties are proposing to implement newer, more efficient facilities, especially on the gas processing side. Table 1 lists existing area facilities as well as announced projects specifically supporting the Avalon and Bone Springs development efforts. Table 2 lists the major crude oil pipelines in the region that currently route crude to local markets, exit northward to the Cushing, Okla., trading hub, or provide for eastward flow to refinery markets in other Texas areas. Additional proposed regional crude oil facilities complementing these assets also are included.

With a current bottleneck for crude oil transportation at the Cushing, Okla., trading hub – partially caused by some volumes from the Permian Basin that producers are routing northward to Cushing – some pipeline developers are considering a number of pipeline projects directly from Cushing to the greater Houston area as well as potential projects into Houston directly from the Permian. It is too early to determine which projects are likely to win out and how and when the constraint situation at Cushing, Okla., will be resolved. The ultimate solution, however, should result in at least one pipeline from each originating area and a potential re-alignment of overall regional crude oil flows occurring at or near the same time that Eagle Ford Shale crude volumes begin ramping up and entering the greater Houston area.

The El Paso Pipeline, Transwestern Pipeline, Natural Gas Pipeline (NGPL), and Northern Natural Gas (NNG) are principal transporters of area processing plant residue/dry gas volumes to interstate markets. Oasis Pipeline receives volumes into its intrastate system from Texas locations while Public Service Co. New Mexico (PNM) receives volumes into its intrastate system from New Mexico locations. The Waha trading hub provides for regional gas price determination and trading opportunities.

Alberta Bakken/Exshaw Shale (Canada)

With success in the Bakken Basin to the southeast and the Cardium Basin to the north, oil industry players now are looking at the Southern Alberta

Table 2. Permian area: major crude oil transportation systems

Midstream assets	Operator	Capacity (g) mmcf/d (l) (bbls/d)	Existing (E) Expansion (X)	Timeline
Basin crude oil pipeline – Colorado City, TX to Cushing, OK	Plains All American LP*(87%) Enterprise Products Partners LP (13%)	(l) 400,000	E	In-service
Basin Pipeline expansion		(l) 50,000	X	1 Q 2012
Mesa Pipeline – crude oil Midland-to-Colorado City (WTGP connection)	Plains All American * (63%) Sunoco Logistics (37%)	(l) 320,000	E	In-service
Mesa Pipeline expansion		(l)100,000	E	In-service
West Texas Gulf crude pipeline (WTGP) to Mid-Valley Pipeline and Gulf Coast	Plains All American * (40%) Sunoco Logistics (60%)	(l) 300,000	E	In-service
West Texas Gulf expansion		(l) 100,000	X	3 Q 2012
Amdel crude pipeline (sour) – Midland, TX to Nederland , TX	Sunoco Logistics	(l) 27,000	E	In-service
White Pipeline – Amdel Pipeline to Alon refinery in Big Springs, TX		(l) 40,000	E	In-service
Proposed Magellan Pipeline reversal and conversion, Crane, TX to Houston & Texas City refineries	Magellan Midstream Partners	(l) 200,000	X	2 Q 2013
Centurion pipeline from Midland, TX to Cushing, OK	Occidental Petroleum	(l) 175,000	E	In-service
EM crude pipeline (PRIVATE) Midland, TX to Corsicana, TX to Beaumont, TX	Exxon Mobil	(l) 215,000	E	In-service

** Note: Occidental Petroleum's midstream investment includes a 35% ownership of Plains All American (PAA) LP.*

Basin, sometimes referred to as the Exshaw play. With only limited development to date on both sides of the border and in the midst of ongoing land/lease acquisition efforts, information on early successes and expected potential has been sparse. Geologically, the play lies at the southern Alberta/northwestern Montana border and is said to resemble the neighboring Bakken play in many ways. Much like in the Bakken, industry must expand existing area infrastructure as ongoing play development potential is determined.

Current oil production in the area runs southward into the US where it combines with Montana sources and runs via the Glacier Pipeline to area refineries at Billings and/or Laurel, Mont., or via the Cenex Pipeline LLC facility to the Cenex refinery at Laurel, Mont. At Billings, operators can route crude to other markets south in Wyoming via interconnections with Plains All American's Beartooth pipeline. In addition, Kinder Morgan's Express crude oil pipeline is nearby and has a total capacity of 280,000 b/d. Though considered a principal conduit from other source regions in Alberta and transporting a variety of mixed crude oil batches, this facility is "within reach" if Alberta Bakken development potential merits future connection.

Associated with the Deep Bakken oil production, operators must gather and process natural gas. A recent commercial arrangement between Encana Corp. and Pembina Pipeline Corp. provides that Pembina invest in the expansion of area facilities to increase Encana's NGL capabilities. Encana, according to the commercial arrangement, is incenting the expansion of three area plants: its partially owned Resthaven plant, to yield total NGLs of approximately 12,000 b/d; Pembina's Musreau plant, to yield 5,000 b/d; and a new plant at Gordondale that a third party will build to process 120 MMcf/d of gas, to yield an additional 3,000 to 4,000 b/d. Pembina

Table 3. Bakken area: crude oil aggregation and pipeline export capabilities (includes rail facilities)

Crude Pipeline and/or truck/rail facility	Operator	Capacity (bbls/d)	Existing (E) Expansion (X)	Timeline
Butte Pipeline	True Companies	120,000	E	In-service
Belle Fourche		50,000	X	2011
Butte		30,000		
Enbridge ND System	Enbridge North Dakota Pipeline	185,000	E	In-service
Added truck & rail facilities at Berthold, ND		30,000 (est)	X	2011-2013
Portal Pipeline reversal		25,000	E (modify)	In-service
Bakken area Expansion/optimization		120,000	X	Jan. 2013
Platte Pipeline	Kinder Morgan	143,000#	E	In-service
Bakken North/Wescana reversal	Plains All-American*	50,000	X (modify)	
Robinson Lake Pipeline		18,000	E	In-service
Ridgelawn, MT rail propane storage		400 rail car holding track	X	3 Q 2011
Ross ND NGL rail and transloading facility		94 rail car holding track	X	3 Q 2011
15-mile crude pipeline from Stanley, ND to Ross, ND crude rail, storage, and transloading facility		55,000	X	4 Q 2012
High Plains Pipeline, gathering, and truck terminal	Tesoro Logistics	60,000	E	In-service
Refinery expansion	Tesoro Refining	10,000	X	Mid-2012
Stanley ND rail facility	EOG Resources	60,000	E	In-service
Tioga ND rail facility	Hess Corp.	120,000	X	Mid-2012
Williams County, ND rail facility	Rangeland Energy LLC	72,000	X	1 Q 2012
New Town, ND rail facility	Dakota Transport Solutions	20,000	E	In-service
Trenton ND Railport	Savage Companies	72000	X	2 Q 2012
Bakken Oil Express, Dickinson, ND	Lario Logistics LLC	100,000	E	In-service
Various ND locations	various	30,000	E	In-service
Proposed: Keystone XL MarketLink lateral	TransCanada	100,000	X	2014 **

 # Platte not included in either total as it also currently receives Canadian crude from Express Pipeline
** Note: Occidental Petroleum's midstream investment includes a 35% ownership of Plains All American (PAA) partnership.*
*** Depends upon whether Keystone XL receives US regulatory approval to implement the pipeline*

also has agreed to build a 27.3-mile NGL pipeline lateral from the Resthaven plant to its existing Peace River NGL pipeline system. Pembina operates three gas processing plants in the area as a part of its Cutbank complex (Cutbank, Musreau, and Kakwa) with a total raw gas processing capability of 410 MMcf/d. These investments represent a growth in its regional capabilities. The Cutbank complex delivers residue gas receipts into the Montana Power gas system.

Bakken Shale

Stretching across portions of both the US and Canada, this vast shale play has been one of the lead attractions in the unconventional game. Set within the Williston Basin, this play stretches across approximately 200,000 sq miles and holds about 2 Bbbl of recoverable reserves. Bakken is one of the "oilier" shale plays with significant potential. Oil production from the overall Williston Basin region, which includes conventional supplies, has grown rapidly, exceeding 450,000 b/d as of year-end 2010. More recent production results for June 2011 show volumes remaining reasonably steady at 425,000 b/d, as some developments experienced weather delays (unseasonal rains and subsequent area flooding) while others are awaiting midstream infrastructure implementation. Those implementations include oil gathering and transmission pipelines, gas gathering facilities and connections to gas processing plants, NGL pipelines, and rail terminal and storage facilities. Operators have aggressive, multiyear resource development plans and expect to continue those plans despite recent delays. Table 3 provides a high-level summary of the various types of regional midstream infrastructure that is in place or being implemented to meet current and future needs.

Currently, operators are flaring some of the natural gas in the Bakken region as they focus on capturing crude oil value. However, North Dakota's Oil & Gas Division recently advised that although over 130 MMcf/d is being flared in the region, operators still are capturing more than 95% of the commercial value of the Btu being flared. This means that the operators are capturing a significant quantity of the higher Btu NGL components of propane, butane, and natural gasoline and send it to market via truck or rail. Regulators generally grant a one-year waiver that allows gas to be flared; at that point, operators must reapply and justify any continuation. Operators will reduce flaring significantly as additional processing plants and NGL facilities come online in the future, which also will allow operators to capture any remaining economic values.

The Alliance Pipeline System is an interstate gas pipeline that begins in Canada and traverses the Bakken area. It is a hydrocarbon-rich gas pipeline system and cannot accept dry gas volumes. Alliance USA, which has a capacity of 1.5 Bcf/d, currently is receiving about 80 MMcf/d of rich gas from Bakken sources via the Prairie Rose Pipeline System, and producers expect it to receive up to an additional 120 MMcf/d when a future connecting lateral comes online near Hess' Tioga, N.D., processing plant. Northern Border Pipe Line (NBPL) and Williston Basin Interstate Pipeline (WBIP) also are able to receive dry gas volumes and route such to available markets. Collectively, these systems potentially have available capacity of up to 2 Bcf/d of natural gas, but a major portion of that capacity may alternatively be sourced from Canada.

Cana Woodford (or Anadarko Woodford)

The Cana Woodford development is in west-central Oklahoma, just west of Oklahoma City,with wells in this area producing condensate/NGLs in addition to natural gas. Other eastward portions of the Woodford Shale represent a dry gas play. Because the Cana Woodford gas is hydrocarbon-rich, it needs processing prior to delivery to area takeaway pipelines. Some of that area infrastructure exists as it supported previous vertical conventional wells, but industry may need to enhance it to handle the area's growing gas needs.

OneOk Energy Partners is an active Cana-area midstream provider. It is currently constructing more than 230 miles of NGL pipelines that will expand the partnership's existing Mid-Continent NGL gathering system in the Cana-Woodford and Granite Wash areas by connecting to three new third-party natural gas processing facilities under construction and to three existing third-party natural gas processing facilities that are expanding. Producers expect these investments to add 75,000 to 80,000 of NGLs. To accommodate such, OneOk also will expand its Arbuckle NGL pipeline from 160,000 to 240,000 b/d and is implementing additional downstream fractionation at its Mont Belvieu, Texas, facility.

Though significantly damaged by a tornado in late May 2011, Devon's 200 MMcf/d Cana gas processing plant is now restored, and Devon will expand the plant's capability to 350 MMcf/d and 27,000 b/d of NGL/liquids capability by 4Q 2012. Atlas Pipeline Partners' Velma (Okla.) system gathers Woodford area volumes. Its 100 MMcf/d high-pressure Madill-to-Velma (MTV) pipeline, completed in the summer of 2009, is approaching full capacity, and volumes continue to increase. To keep pace with this growth, Atlas Pipeline will expand its Velma system by adding a 60 MMcf/d cryogenic plant, thereby increasing total processing capacity to 160 MMcf/d. This facility should be operative by mid-2012. Atlas also is increasing its residue gas delivery capability into NGPL as well as adding an additional delivery capability into the Enogex LLC intrastate pipeline.

Cardium/Pembina (Alberta)

The conventional Cardium oil play runs throughout much of west-central Alberta, and the nearby Pembina Field play is an excellent source of light crude. The region is a sandstone geological play and has been producing oil and gas from traditional vertical wells for several years. Operators previously discounted the Cardium potential as adjacent geologi-

Table 4. Midcontinent US: Facilities supporting rich gas gathering and processing in Cleveland Shale, Granite Wash, and Tonkawa areas

Gas gathering, processing plant, NGL capability	Operator	Capacity (g) Gas (mcf/d) (l) NGL's (bbl/d)	Existing (E) Expansion (X)	Timeline
Indian Creek gathering and processing	Crestwood Midstream Partners LP	(g) 36,000	E	In-service
Gathering & plant expansion		(g) 60,000	X	2012
East Panhandle Gathering system	Eagle Rock Energy Partners LP	(g) 100,000 (est)	E	In-service
Phoenix/Arrington Ranch plant		(g) 50,000	E	In-service
Plant expansion		(g) 50,000	X	2011
Roberts County, TX plant		(g) 25,000	E	In-service
Canadian plant		(g) 25,000	E	In-service
Red Deer plant		(g) 20,000	E	In-service
Woodall plant		(g) 60,000	X	2012
Clinton, Ok plant	Enogex Gas Gathering LLC Enogex Gas Products LLC	(g) 120,000	E	In-service
Wheeler, TX plant		(g) 120,000	X	2012
Custer, OK plant		(g) 200,000	X	2013
South Canadian plant		(g) 200,000	X	Late 2011
Elk City gathering system and (2) plants	Enbridge Pipelines (Texas Gathering) LP	(g) 370,000	E	In-service
Anadarko gathering system and (6) plants		(g) 1,050,000	E	In-service
Allison plant		(g) 150,000	X	2011
Ajax plant		(g) 150,000	X	2013
Arapaho plant	Mark West Energy Partners LP	(g) 160,000	E	In-service
Arapaho expansion		(g) 60,000	X	2011
Beaver plant	Penn Virginia resource Partners LP	(g) 100,000	E	In-service
Sweetwater II plant		(g) 60,000	E	In-service
Spearman plant		(g) 60,000	E	In-service
Antelope Hills plant		(g) 20,000	E	In-service
Antelope Hills expansion		(g) 50,000	X	2012
Hemphill/Mendota, TX gathering system and processing plant	Superior Pipeline Company LLC	(g) 100,000	E	In-service

cal formations contained more oil. They determined that this area was uneconomical to develop with then-current capabilities. Today's horizontal drilling expertise, new completion techniques, and higher oil prices have led to a renewed industry interest. Because of previous area development, this also may provide for development of the Cardium play on existing leases. Use of existing regional infrastructure should also be a bonus to overall development efforts.

Cardium has light-grade oil, thus previously developed aggregation and crude- gathering systems will continue to serve the new Cardium developments. Residue/dry gas from the region is gathered into the TCPL Alberta gas system where it is routed/priced against the AECO Hub regional price.

Granite Wash

The Granite Wash, a heterogeneous series of sands, shales, and siltstones that has yielded production since the late 1950s, subsides in southwestern Oklahoma counties of Beckham, Roger Mills, Custer, Washita, and Greer as well as the Texas Panhandle counties of Gray, Wheeler, Roberts, and Hemphill. (The former is often referred to as the Colony

Table 5. Midcontinent US - NGL/liquids pipelines for routing NGLs to downstream fractionation

NGL Pipeline	Operator	Capacity (I) NGL's (bbl/d)	Existing (E) Expansion (X)	Timeline
Skelly-Belvieu Pipeline	Enterprise Products partners (50%)	(I) 60,000	E	In-service
	Chevron Pipeline Company (50%)	(I) 17,000	X	4 Q 2012
Mid-America Pipeline (MAPCO) Conway South NGL Pipeline	Mid-America Pipeline Company LLC	(I) unavailable	E	In-service
Arbuckle Pipeline	OneOk Energy Partners LP	(I) 140,000	E	In-service
Expansion		(I) 80,000	X	2012
Sterling I NGL Products Pipeline				
Expansion		(I) 15,000	X	Late 2011
Sterling III NGL Pipeline (proposed)		(I) 193,000	X	2013
Southern Hills NGL Pipeline (proposed)	DCP Midstream LLC	(I) 150,000	X	2013
Texas Express NGL Pipeline and gathering systems (proposed)	Anardarko Petroleum Enterprise Products Partners Enbridge Energy Partners	(I) 280,000	X	2013

Granite Wash, while the latter is referred to as the Texas Panhandle Granite Wash.) The play has strong NGL and liquids potential though completed zones may vary significantly in oil and gas pay quality. The saturation of liquids, however, is what makes it one of the more attractive and economic unconventional plays today.

Several of the area's gas gathering systems have evolved over the years and are above or near the developing Granite Wash trends in both Texas and Oklahoma. With today's developments, gathering and processing system operators are finding they must re-tool and add to their existing infrastructure to accommodate the expected Granite Wash resource output. Table 4 provides an overall listing of area gathering systems, processing plants, and proposed expansions. Table 5 provides an overview of area NGL pipeline facilities that support these processing activities.

ANR Pipeline Company, Centerpoint Energy Gas Transmission, El Paso Natural Gas, Natural Gas Pipeline of America (NGPL), and Northern Natural Gas interstate pipelines receive dry/residue gas. Intrastate pipelines include OneOk Westar Gas (Texas) and Enogex Pipeline LLC and OneOk Gas Transmission (Oklahoma).

Eagle Ford

In mid-2010, the upstream development of the liquid-rich portion of the Eagle Ford play took off with the epicenter in Karnes and Gonzales counties, Texas. Following the successes in those two counties, operators concentrated their efforts on the liquid-rich portions along the so-called geological border between the condensate and oil zones in Dimmit, La Salle, McMullen, and Live Oak counties. Since March 2011, activity also has increased in Frio, Atascosa, and Zavala counties, which lie exclusively within the oil zone.

With crude oil, condensate, associated (i.e., hydrocarbon-rich) gas, and traditional dry gas all present in the developing product mix, operators are implementing numerous projects to provide needed gathering capacity and access to downstream markets. In many cases, truck and rail services currently are providing for interim movement of crude oil and/or condensate production until near-term and longer-term pipeline infrastructure becomes available. Where possible, operators are using existing area natural gas facilities to manage any gas production until they can make long-term arrangements. Looking ahead, regulators will eliminate many of today's short-term infrastructure constraints for liquids, gas liquids, and gas by mid-

Table 6. Eagle Ford: Crude oil/condensate transportation facilities

Crude oil/condensate pipeline	Operator	Capacity (bbl/d)	Existing (E) Expansion (X)	Timeline
Crude oil processing facility/topping unit	Blue Dolphin Energy Co.	(I) 15,000	E	In-service
Pettus-to-Corpus Christi crude pipeline	Koch Pipeline Company LP	140,000	E	In-service
Expansion into Karnes County		120,000	X	Late 2012
Crude gathering facilities		120,000 (est)	E	In-service
NuStar's products pipeline reversal and conversion to crude/condensate service	NuStar Logistics LP	50,000	E	In-service
55-miles of additional pipeline to provide for waterborne crude at Corpus to be routed to Valero Three Rivers' refinery		20,000	X	2 Q 2012
Reversal of existing crude oil pipeline from Corpus Christi to Three Rivers, TX		200,000	X	2 Q 2012
Crude pipeline from new truck terminal in San Antonio, TX to local NuStar refinery		15,000 (est)	X	1 Q 2012
65-mile pipeline and truck loading facilities from Gardendale Hub to NuStar's terminal near Three Rivers, TX (new)	NuStar Logistics LP/ TexStar Midstream Services LP	120,000	X	3 Q 2012
Unit train offloading and crude storage facility, St. James, Louisiana	NuStar Logistics LP, EOG affiliates	(I) 70,000	X	2 Q 2012
Crude gathering pipeline and truck loading facilities (new)	El Paso Midstream Energy Partners, LP	70,000	E	In-service
143 –mile crude pipeline to connect to Rancho Pipeline, Sealy , TX (new)	Enterprise Products Partners LP	340,000	X	2 Q 2012
80-mile crude pipeline connection to Gardendale Hub (new)		200,000	X	1 Q 2013
95-miles crude gathering laterals and truck terminal facilities		Not available	X	1 Q 2013
Arrowhead crude pipeline extension	Harvest Pipeline	50,000	E	In-service
140-mile crude/condensate pipeline from Gardendale Hub to Corpus Christi terminals (new)	Harvest Pipeline	100,000	X	2 Q 2012
Crude gathering pipeline to Valero refinery, Three Rivers, TX (new)	Harvest Pipeline/ Valero Refining	70,000	X	Late 2011
Eagle Eye crude and condensate gathering system to Gardendale Hub (new)	Velocity Midstream	120,000	X	2012
130-mile crude/condensate pipeline to Corpus Christi area	Plains All American Pipeline LP	300,000	X	4 Q 2012
170-mile condensate pipeline from Cuero, TX to Deer Park, TX (convert portion of existing gas pipeline to liquids service)	Kinder Morgan Energy Partners	300,000	X	3 Q 2012
Port of Corpus Christi – marine terminal and storage expansion	Martin Midstream	300,000 storage	X	4 Q 2011
Pipeline from Flint Hills terminal, Corpus Christi to Ingleside marine terminal	Koch Pipeline Company	200,000	X	3 Q 2012

2013, when operators should be able to receive full value for the majority of their products.

Primary infrastructure developments are under way near crude oil, condensate, and hydrocarbon-rich gas plays. Tables 6 and 7 provide information on the various infrastructure proposals.

A number of gas processing facilities and NGL pipelines already are present in the coastal areas of south and southeast Texas. Some fractionators are in place and provide purity products for use in the nearby coastal industries. However, pipelines transport processing plant output -- referred to as y-grade or NGL mix -- to Mont Belvieu, Texas, for fractionation and storage. The Eagle Ford developments are adding significant volumes of hydrocarbon-rich gas, which must be processed each day to capture full NGL value as well as make the residue gas marketable. Operators have proposed a number of major projects that will integrate some existing area facilities with a number of converted pipelines, new gas processing plants, and NGL pipeline additions.

Marcellus

The Marcellus/Devonian Shale plays underlay portions of six northeastern states covering 95,000 sq miles, but the majority of the Marcellus Shale area development to date has been in West Virginia, Pennsylvania, and New York. Amid the current industry rush to develop unconventional liquids plays and in spite of an overall lower gas-pricing environment, Marcellus Shale gas development still remains a profitable venture. With consistent drilling activity targeting both dry gas and high-Btu gas liquids, the Marcellus area continues to require new infrastructure and market access.

For the moment, operators are extracting higher-end hydrocarbons from the area's rich gas streams and are marketing them via truck or rail facilities. Operators are returning extracted ethane to the gas stream and marketing its Btu as natural gas. With ongoing development, available ethane will exceed acceptable regional pipeline and storage gas quality levels and operators will have to remove it from the gas stream and route it to its potential markets. Industry has presented a number of major infrastructure projects/solutions; only recently have any of those projects received the necessary commitments from shippers and/or markets to advance to development stage.

With some treating and/or dehydration, operators are ready to market dry gas volumes in other portions of the Marcellus play. Producers are implementing a number of dry gas gathering systems in the area to provide such capability. With many of the area pipelines already sourced from other supply areas, Marcellus gas must compete for its portion of available market share. Located near its desired markets, Marcellus gas enjoys a significant fuel advantage over competing long-haul receipts from other areas. Marcellus volumes also are strategically located to access incremental pipeline capacity expansions, incremental markets, and significant regional gas storage, often commanding a market premium over competing supplies. Producers pipe some of the Marcellus production into eastern Canada to seek markets and storage there, reversing historic import quantities to the US, which have declined due to recent higher tolls on the TransCanada Pipeline system impacting volumes traditionally received from Alberta.

Today's horizontal drilling and completion techniques are providing economical results. As in other areas where operators previously developed conventional resources, significant data are available to assist operators in optimizing their more recent unconventional efforts.

A wide variety of historical midstream pipeline infrastructure exists in the overall Marcellus region, but operators must implement many new projects to manage the increasing Marcellus receipts. Columbia Gas Transmission, Dominion Transmission, Inc., Equitrans Pipeline, Millennium Pipeline, National Fuel Gas Supply, Tennessee Gas Pipeline, Texas Eastern Transmission, and Transcontinental Gas Pipeline interstate pipelines run through the area. Industry is implementing numerous gathering systems in the region and/or modifying portions of assets from these pipeline companies to perform a gathering-like function. Table 8 lists gathering systems focused on hydrocarbon-rich gas service and area processing plants that remove NGLs from the gas streams.

Table 7. Eagle Ford: Rich gas gathering, gas processing, and NGL pipelines

Gas gathering, processing plant, NGL capability	Operator	Capacity (g) mcf/d (l) NGL's (bbl/d)	Existing (E) Expansion (X)	Timeline
58-mile gas gathering line to Houston Central plant	Copano Energy LLC	350,000	X	4 Q 2011
Houston Central gas processing plant and fractionator		(g) 700,000	E	In-service
Plant expansion and fractionator expansion		(g) 400,000 (l) 22,000		2013
Trunkline Gas will convert 165 miles of existing gas pipeline to rich gas service for DCP	DCP Midstream Partners LP	(g) 1,000,000 (est)	E	In-service
130-miles of gas gathering facilities into the Trunkline Gas header system		(g) 400,000 (est)	X	2012
(5) existing DCP area plants will connect to header and be able to process available gas		(g) 800,000	E	In-service
Eagle gas processing plant (new)		(g) 200,000	X	3 Q 2012
700-mile Sand Hills NGL Pipeline from Permian Basin to Mont Belvieu (routed to collect Eagle Ford NGLs, as well)		(l) 120,000	X	2 Q 2013
117-mile EFG Gas Gathering system (various areas)	Eagle Ford Gas Gathering JV: Kinder Morgan Energy Partners/Copano Energy LLC	(g) 500,000	E	In-service
Modified KM Texas pipeline to gather gas to Copano's Houston Central gas plant and fractionator		(g) 600,000	E	In-service
Modified KM Tejas pipeline to gather rich gas to Point Comfort gas plant and/or Williams Markham gas plant		(g) 375,000	X	Late 2011
56-mile EFG Crossover pipeline project connecting KM Texas pipeline to KM Tejas pipeline		(g) 400,000	X	Late 2011
Houston Pipeline gathering and processing capability at EM King Ranch plant	Energy Transfer Partners LP	(g) 200,000	E	In-service
50-mile Dos Hermanos gathering pipeline		(g) 400,000	E	In-service
83-mile Chisholm lateral to ETP LaGrange processing plant		(g) 100,000	E	In-service
160-mile Eagle Ford Rich pipeline (REM) – gathers gas to Chisholm Pipeline		(g) 600,000	E	In-service
70-mile REM extension to Jackson, County, TX		(g) 600,000	X	2013
Jackson County processing plant (new)		(g) 600,000	X	1 Q 2013
130-mile NGL pipeline from Jackson County plant to Mont Belvieu, TX fractionator		(l) 340,000	X	2013
Existing rich gas gathering and processing system in south and southeast Texas	Enterprise Products Partners LP	(g) 1,500,000	E	In-service
86-mile pipeline connecting existing Shoup and Schilling gas plants		(g) 400,000 (est)	E	In-service
142-mile expansion of existing rich gas system from White Kitchen, TX to Yoakum, TX		(g) 1,000,000 (est)	E	In-service
62-mile White Kitchen lateral		(g) 200,000	E	In-service
46.5-mile White Kitchen lateral extension to Caterina area		(g) 200,000 (est)	E	In-service

As these gathering systems bring more supply into the area interstate pipelines, they are working with shippers to determine where received volumes will flow. Some expansions provide additional downstream market access, while others are routing northward, either to liquid market points like Leidy storage or to the US/Canadian border where volumes can displace historical imports into the US and/or flow into Ontario to seek markets there.

Unique to the Marcellus area, hydrocarbon-rich gas contains high levels of ethane. After removing certain NGL components, plant operators are currently returning ethane to the gas stream and are blending down gas volumes prior to delivery to interstate pipeline systems. This increasingly is more problematic as overall area volumes grow. Producers have proposed a number of ethane solutions, most involving piping the excess ethane away from the region. A recent commitment to Mariner West Pipeline and a downstream sales contract between Range Resources and Nova Chemical at Sarnia could anchor the Mariner West project for at least a portion of future regional ethane sales. Table 9 shows other potential projects. Industry also is proposing to locate petrochemical plants (i.e., ethane crackers) in the Marcellus region to benefit from a local, long-lived feedstock. Royal Dutch Shell has proposed one such site, a US $1 billion facility that would crack 60,000 to 80,000 b/d, roughly 50% of the expected ethane quantities needed to be evacuated in future years. Negotiations continue on all of these solutions and timing for such.

Mississippi Lime(stone)

The Mississippian oil play runs along the north-central Oklahoma/south-central Kansas border. Oklahoma counties of Woods and Alfalfa have been quite active due to Chesapeake Energy and SandRidge Energy Corp.'s development efforts. The play is relatively shallow at depths of 5,000 to 6,000 ft and

Table 7 Continued

Gas gathering, processing plant, NGL capability	Operator	Capacity (g) mcf/d (l) NGL's (bbl/d)	Existing (E) Expansion (X)	Timeline
Yoakum gas processing plant (new)		(g) 600,000 (l) 60,000	X	1 Q 2012
69-mile dry gas pipeline from Yoakum plant to Wilson gas storage/market		(g) 1,000,000	X	1 Q 2012
127-mile NGL pipeline to Wilson NGL storage and connecting to existing NGL pipeline to Mont Belvieu fractionators and storage		(l) 60,000	X	1 Q 2012
Mont Belvieu fractionator addition 1		(l) 75,000	X	2012
Mont Belvieu fractionator addition 2		(l) 75,000	X	2013
Cuervo Creek rich gas gathering pipeline	Meritage Midstream Services LLC	(g) 150,000	X	Late 2011
400-mile gas gathering and condensate recovery facilities (new)	Regency Energy Partners LP	(g) 100,000 (est) (l) 26,500	X	Ongoing, to 2014
Tilden treating plant expansion		(g) 20,000	X	
Gregory processing plant	Southcross Energy	(g) 135,000	E	In-service
Woodsboro plant (new)		(g) 200,000	X	2 Q 2012
25-mile pipeline and related gathering system (new) and convert existing dry gas system to rich gas service		(g) 120,000	E	In-service
Atascosa and McMullen Counties' rich gas gathering system & Three Rivers area delivery header	TexStar Midstream Services LP	(g) 50,000 (est)	X	2013

includes highly permeable carbonate. Today's horizontal drilling and completion techniques are providing economical results. As in other areas where operators previously developed conventional resources, significant data are available to assist operators in optimizing their more recent unconventional efforts.

The challenge in the area is that operators produce vast amounts of water with the oil, and operators must re-inject the water via disposal wells. Upper-

Table 8. Marcellus area: rich gas gathering systems, gas processing plants, NGL-related facilities

Gas gathering, processing plant, NGL capability	Operator	Capacity (g) mcf/d (l) NGL's (bbl/d)	Existing (E) Expansion (X)	Timeline
140-mile gas gathering system, WV	Caiman Energy LP	(g) 600,000+	E	In-service
Ft. Beeler, WV processing plant I		(g) 120,000	E	In-service
Ft. Beeler II expansion		(g) 200,000	X	4 Q 2011
Ft. Beeler III expansion		(g) 200,000	X	4 Q 2012
NGL pipeline, fractionators, truck, rail		(l) 12,500	X	4 Q 2011
& barge facilities		(l) 15,000	X	4 Q 2012
Line 1570 Marcellus project, WV	Columbia Gas Transmission	(g) 300,000	E	In-service
TL-404 project	Dominion Transmission	(g) 300,000	E	In-service
Hastings Extraction plant		(g) 180,000	E	In-service
Natrium, WV gas processing plant and fractionator		(g) 200,000 (l) 36,000	X	4 Q 2012
Sunrise project WV/PA	Equitrans, LP	313,560	X	2 Q 2012
Gathering JV: Eureka Hunter Pipeline	Eureka Hunter Pipeline LLC/	30,000	E	In-service
	DCP Midstream LLC	170,000	X	2012-2013
Eureka Hunter Pipeline, WV (extension to Mobley plants)	Magnum Hunter Resources Corporation	320,000	E	2 Q 2012
Liberty gathering system, WV	Mark West Liberty Midstream and Resources LCC/	(g) 270,000	E	In-service
Liberty gathering system, PA	NiSource Midstream Services	(g) 165,000		
Majorsville WV gas processing plant		(g) 360,000	E	In-service
Houston, PA gas processing plants I, II, III	Mark West Liberty Midstream and Resources LCC Partners: The Energy & Minerals Resource Group (40%) Mark West Energy Partners(60%)	(g) 355,000	E	In-service
Houston, PA fractionators and truck/rail facilities, and NGL connection to TEPPCO		(l) 60,000 (full)	X	3 Q 2011
		(l) 27,000 (propane)	X	4 Q 2011
		(l) 10,000 (butane)	X	4 Q 2012
		(l) 75,000 (ethane)	X	4 Q 2012
		(l) 50,000 (rail loading)		
Thomas Russell processing plant (renamed to Mobley 2)		(g) 200,000	X	3 Q 2012
Mobley I WV processing plant		(g) 120,000	X	2 Q 2012
Siloam, KY fractionator	Mark West Energy Partners LP	(l) 24,000	E	In-service
Gathering, PA	Nisource Midstream Services	(g) 100,000	E	In-service
Gathering, WV		(g) 250,000	E	In-service

level completions in the wells appear to yield less water and oil, while the more-attractive lower-level completions yield significant quantities of water, sometimes as much as 6:1, water-to-oil/liquids.

With historical vertical well production, existing area midstream infrastructure is in place to manage currently developing levels of oil production. Operators aggregate oil production on lease and truck it to market and/or pipeline facilities.

The Hiland Partners' Eagle Chief gathering system consists of 609 miles of gathering pipelines and 35,000 Mcf/d of gathering and processing capacity. Atlas Pipeline Partners' WestOk gathering system has thousands of miles of regional gathering and three gas processing plants – Chester, Waynoka, and Chaney Dell – with total processing capability of 228 MMcf/d. Gas gathering systems aggregate associated hydrocarbon-rich gas volumes and route it to local plants for processing. Atlas plans to expand its Waynoka plant by 200 MMcf/d. The company expects the expansion to be completed by 2Q 2012. OneOk Field Services is also one of the area's major players with thousands of miles of regional gas gathering and multiple gas processing plants.

Monterey Shale

California's Monterey Shale is an area that is very fractured by nature. As the Monterey Shale varies across regional fields and even within potential completion zones within the field, several operators are using seismic analysis to further their knowledge and to focus their future efforts to the most attractive areas within their portfolio. Production from shale in the region is not new, but developing California shale using unconventional techniques appears to be a significant change.

Most of California's developments are producing both oil and gas. As the natural gas is associated with the oil production, producers must process it to remove hydrocarbons/NGLs prior to selling the gas. Therefore, numerous special-purpose gas processing plants exist at the field level throughout the region, and trucking and rail facilities route any produced NGLs to local area markets.

Various area gas processing plants primarily deliver residue gas to the Southern California Gas Transmission's pipeline system where producers direct it to a specific intrastate market or aggregate and sell it at the SoCal city-gate pool. Producers can nominate and administer their gas themselves or can appoint an agent to do so on their behalf. Because of close proximity to market, gas must always remain pipeline quality, or it is immediately shut in.

All of the natural gas produced in California is consumed in California, and California also imports significant quantities by pipeline from the Rockies,

Table 9. Marcellus area: ethane evacuation and other potential ethane infrastructure solutions

Proposed ethane project	Operator	Capacity (l) bbl/d	Expansion (X)	Timeline
Marcellus Ethane Pipeline (involves use of a line of Tennessee Gas Pipeline)	El Paso Midstream Services	(l)	X	On Hold
Enterprise Ethane Pipeline (involves use/conversion of an existing Enterprise TE products pipeline)	Enterprise products Partners LP	(l) 125,000	X	1 Q 2014
Cochin: Marcellus Lateral pipeline (MLP)	Kinder Morgan Inc.	(l) 25,000-150,000	X	2013
Mariner West – pipeline delivery to Sarnia, Ontario (partial use of existing Sunoco pipeline)	Mark West Liberty Midstream & Resources LLC/ Sunoco Logistics Partners LP	(l) 50,000	X	2 Q 2013
Mariner East – pipeline delivery to East Coast and ship to US Gulf Coast		(l) 50,000	X	2 Q 2013
Blending project Phase 1: Use dry gas, Laurel Mountain Midstream	Williams Partners LP	(g) 450,000 (l) 32,500	X	2012-2013

Canada, the San Juan Basin, and the Permian Basin. Connections to imports at Mexico's Costa Azul LNG terminal are also available, but cargos have generally been limited as LNG seeks better pricing, primarily in Asian markets. Gas storage facilities in northern and southern California provide additional tools for the market to manage the various produced and imported pipeline gas sources to match overall market needs.

Oil pipeline operators in California have developed an extensive, if not fully integrated, oil gathering and transportation system that routes in-state and coastal offshore oil production to various area refineries. In-state production falls short of California's daily crude oil needs, so operators have imported oil from Alaska and foreign sources in the past.

In-state production has declined over time as has Alaska production; thus, regional oil imports from foreign sources have increased to meet the demand. Therefore increased in-state crude oil production from the Monterey Shale will be welcomed.

The California crude oil pipeline transportation system includes San Francisco Bay area refineries and terminals; Kern County/Bakersfield area refineries and supply aggregation points; Santa Barbara area receipts; Ventura area receipts; and Los Angeles area refineries and terminals. The overall California crude pipeline system is significantly more complex with numerous crude pipeline systems paralleling one another and/or integrating into the larger regional nodal concept. Numerous field gathering systems and oil processing plants, as well as offshore systems that deliver crude at various shore-based terminals, also are integrated therein. Various truck terminals complement the network. Added complexity enters on the delivery side as customers desire terminal/storage access and/or delivery point flexibility as the pipeline assets near the targeted refineries.

Table 12 lists a number of the region's major oil pipeline operators, their routes, estimated daily capacities, and currently published tariff rates.

Montney

The Montney Shale in Alberta is an unconventional tight gas/shale distributed over an area extending from north central Alberta to the northwest of Fort St. John in British Columbia. It is primarily a gas play, with major portions of the area providing hydrocarbon-rich natural gas to support overall development economics. At current natural gas prices, most of the development is focused on these rich gas portions of the play. The principal producing area of the play is the south Peace region, where operators are implementing or augmenting major midstream gathering, processing, and pipeline facilities to assist in further development. The Montney has been a key asset area for the Encana Ltd/Petro-China joint venture. Shell Canada Ltd. also is a significant player in the area. Table 10 provides a listing of the various midstream infrastructure facilities used to support Montney development activities.

Spectra Energy's BC Pipeline (formerly West-Coast Energy Inc.), 1,700 miles of natural gas transmission pipeline that can transport 2.4 Bcf/d of natural gas, provides dry/residue gas service in the area. The pipeline delivers gas to southern British Columbia markets as well as into the Seattle area at Sumas, Wash.

An interconnection to NGTL's Alberta system at Gordondale routes limited gas volumes eastward into the NGTL system. TCPL recently has extended its NGTL Alberta system into the Dawson Creek area. This 36-in. Groundbirch Mainline Project has capacity of 1,100 MMcf/d and is expected to be fully contracted by 2014.

Niobrara

The deep Niobrara Shale play is primarily an oil play. It underlies portions of the lower Powder River Basin in southeastern Wyoming, the North Park Basin in northeastern Colorado, and the Denver-Julesburg (D-J) Basin in northeastern Colorado and southwestern Nebraska.

> **Primarily, producers have routed crude oil production within and from the region by truck and rail, but new Niobrara supply quickly has outpaced the limited regional demand and available transportation capacity.**

With numerous shale operators seeking more involvement in liquids-related plays, the Niobrara — much like the larger Bakken Shale to the north and the Eagle Ford Shale to the south — is experiencing an increase in interest and activity. Early Niobrara development evolved near the growing Wattenberg oil and natural gas developments in northeastern Colorado and has slowly migrated outward from there as operators have methodically attempted to scope the Niobrara's overall potential.

Though operators have focused most of the recent development on oil and liquids, the acreage has both gas and liquids potential.

Primarily, producers have routed crude oil production within and from the region by truck and rail, but new Niobrara supply quickly has outpaced the limited regional demand and available transportation capacity. As a result, light crude production from the Niobrara is forcing producers to seek new infrastructure to provide access to markets elsewhere. In response, in 2009 SemCrude LP, a subsidiary of Tulsa-based SemGroup Corp., completed a regional crude-oil pipeline to exit Colorado, the first built in many years. SemCrude (51%), Plains All American Pipeline LP (34%), Western Gas Partners LP (10%), and Noble Energy (5%) co-own the 50,000 b/d White Cliffs Pipeline.

Table 10. Montney area: Canadian midstream assets supporting Montney Shale developments

Gas gathering, processing plant, NGL disposition	Operator	Capacity (g) Gas (mcf/d) (l) NGL's (bbl/d)	Existing (E) Expansion (X)	Timeline
Dawson gas plant	ARC Energy Trust	(g) 60,000	E	In-service
Dawson expansion		(g) 60,000	X	4 Q 2011
Septimus Pipeline lateral to Alliance mainline	Aux Sable Canada LLC	(g) 200,000 (est)	E	In-service
Septimus gas plant B.C.		(g) 50,000	E	In-service
Gathering system and gas plant – Gordondale area	AltaGas Ltd.	(g) 120,000	X	4 Q 2012
Younger "deep-cut" processing plant and fractionator, Taylor B.C.	AltaGas Ltd./ Provident Energy	(g) 750,000	E	In-service
Groundbirch sweet/sour gas plant	Monterey Exploration	(g) 28,000	E	In-service
Groundbirch gas plant	PenGrowth Energy Trust	(g) 28,000	E	In-service
Younger Septimus pipeline	Provident Energy LTD	(g) 300,000	X	4 Q 2011
Groundbirch Montney gas plant	Shell Canada Ltd. (from Dunernay Oil)	(g) 75,000	E	In-service
Groundbirch Montney phase 2 expansion	Shell Canada Ltd.	(g) 55,000	E	In-service
Groundbirch Montney phase 3 expansion		(g) 80,000	E	In-service
Groundbirch Montney phase 4 expansion		(g) 100,000	X	2012
Interconnection to NGTL Groundbirch pipeline: dry gas	Spectra Energy Midstream	(g) 500,000	X	4 Q 2011
Expansion capacity on T-North system (from Ft. Nelson)		(g) 170,000	X	2 Q 2012
South Peace River gas gathering system (rich gas to McMahon plant)		(g) 220,000	X	4 Q 2011
Dawson area sour gas plant implementation		(g) 100,000	X	4 Q 2011
		(g) 100,000	X	1 Q 2013
Bissette gathering pipeline		(g) 225,000	E	In-service
Highway gas plant		(g) 140,000	E	In-service
Re-activate Aitken Creek gas plant		(g) 82,000	X	Not available
McMahon gas plant		(g) 750,000	E	In-service
Jedney 1&2 gas plants		(g) 140,000	E	In-service

Table 11. Permian area: infrastructure supporting Wolfcamp and Wolfberry developments

Midstream Asset	Operator	Capacity (g) mmcf/d (l) bbls/d	Existing (E) Expansion (X)	Timeline
3,100-mile West Texas (Midkiff) rich gas gathering system	Atlas Pipeline Partners LP	(g) 300,000	E	In-service
Consolidator processing plant		(g) 150000	E	In-service
Expansion skid/cryo		(g) 60,000	X	3 Q 2011
Benedum gas processing plant		(g) 45,000	E	In-service
Glasscock County processing facility, restart Patriot fractionators, NGL truck loading and rail facilities	Crosstex Energy LP/ Apache Corporation	(g) 20,000 (g) 50,000	X X	4 Q 2011 2 Q 2012
West Texas gathering systems	DCP Midstream LLC	(g)	E	In-service
Benedum processing plant (jointly-owned)		(g) 36,000	E	In-service
Fullerton processing plant		(g) 70,000	E	In-service
Goldsmith processing plant		(g) 160,000	E	In-service
Pegasus processing plant		(g) 100,000	E	In-service
Spraberry processing plant		(g) 60,000	E	In-service
(Restart) Roberts Ranch processing plant		(g) 75,000	E	In-service

Table 12. Representative listing of oil pipeline systems operating in California

Operator	Pipeline size	From	To	Capacity bbl/d	Tariff Rate per barrel
Pacific Pipeline System LLC	8-16 in.	Bakersfield area gathering	Mainline points	125,000	$1.05-$1.55
Pacific Pipeline System LLC	16 in.	Bakersfield area	Los Angeles area	105,000	$1.12-$1.52
Pacific Pipeline System LLC	20 in. (heated/insulated)	Bakersfield area	Los Angeles area	130,000	$1.61-$1.71
ExxonMobil Pipeline Company (PRIVATE)	16 in. (heated/insulated)	Bakersfield area	Los Angeles area/ Torrance	120,000+	No 3rd party use
Crimson Pipeline Company	10-20 in.	Ventura various	Los Angeles area/ various	150,000+	$0.63-$0.74
Crimson Pipeline Company	various	Aggregation: Ventura area	Ventura station	150,000+	$0.187- $0.275
Plains All-American Pipeline Company	30 in. (heated/insulated)	Santa Barbara area	Kern/Bakersfield	300,000	$2.53
Plains All-American Pipeline Company	30 in. (heated/insulated)	Santa Barbara area	Sisquoc station (north to Santa Maria refinery)	150,000	$2.35
San Pablo Bay Pipeline Company	20 in. (heated/insulated)	Bakersfield	SF Bay area	145,000	$1.34
Chevron Pipeline Company	18 in (heated/insulated)	Bakersfield	SF Bay area	120,000+	$0.88 - $1.25
ConocoPhillips Pipeline Company	8-16 in. (partially heated/insulated)	Coast and Valley Systems	SF Bay area	240,000	$0.64-$0.73

The companies gather, transport, store, market, and distribute Rockies-area crude through the White Cliffs Pipeline and its Cushing, Okla., storage facility. Today, the 526-mile, 12-in.-diameter White Cliffs Pipeline is the only pipeline to move oil out of the Denver-Julesburg Basin and directly into the oil trading hub at Cushing.

Development efforts in the Wyoming portion of the Niobrara are just beginning to pick up with operator activity and announcements.

Kinder Morgan (affiliates) recently announced a project to convert the Pony Express Pipeline from its existing dry gas service back to its original crude oil service. As the pipeline currently is operating in interstate (regulated) gas pipeline service, Kinder Morgan Interstate Pipeline must seek approval from the Federal Energy Regulatory Commission (FERC) to abandon gas service via the pipeline prior to restoring the line to crude service. Assuming approval, another Kinder Morgan affiliate would carry out the conversion and extend the pipeline from its existing terminus near Kansas City to provide delivery service to the Cushing, Okla., trading hub. When completed in 2014, producers expect the converted and extended pipelines to provide 210,000 b/d of crude oil transportation service from Guernsney, Wyo., -- where it expects Bakken crude oil supplies to be seeking area exit capacity -- to the Cushing trading hub. Enroute, the new Pony Express crude pipeline would be near potential Niobrara area completions, and Pony Express may be able to provide a future crude oil transportation exit option for Niobrara operators.

The Colorado portion of the Niobrara appears to have a higher associated-gas potential than the Wyoming portion. Existing Colorado area gas processing facilities and NGL pipelines have focused on area conventional resource development in the past, thus the Niobrara Shale offers further utilization and new opportunity. Development efforts in the Wyoming portion of the Niobrara are just beginning to pick up with operator activity and announcements.

Although residue gas from the various regional plants runs to various pipelines and local gas distribution companies, the producers either truck NGLs to local markets for consumption or export them via the D-J Basin lateral into the Overland Pass pipeline system enroute to Conway, Kansas. DCP Midstream Partner's purchase of the Wattenberg Pipeline and its connection to downstream storage and fractionation at Conway also provide a needed transportation option for NGLs seeking to exit the Rockies and Bakken regions.

Utica

If you could take the best aspects of the Marcellus and Eagle Ford shales and roll them together, what would you get? According to optimistic operators opening up this new play, the Utica Shale promises the best of both worlds. Like the Marcellus, the Utica Shale has low finding and development costs and positive price differentials due to proximity to markets. And like the Eagle Ford, it has three distinct commodity zones, including a rich mix of natural gas liquids and condensate.

The Utica Shale covers a very large geographical area, extending from Ohio through Pennsylvania, into New York, and crossing the border into Quebec. In fact, the Utica lies several thousand feet below the Marcellus Shale formation in much of the indicated region. Because of the common footprints, many costs such as lease, road enhancement, surface location, and water management, are likely to decrease where Marcellus activity has already occurred or will occur in the future. In addition, the Utica extends westward into Michigan, where discussions of recent Ohio activity have piqued considerable interest in that state.

With a focus on the eastern Ohio portion of the shale, Chesapeake Energy, after several horizontal well results, indicates that the Ohio Utica Shale may have multiple source regions within the play (i.e., an oil zone, a wet gas/condensate play, and a dry gas play) and thus is comparable to the Eagle Ford Shale. Initial discussions propose that the Ohio Utica may produce more NGLs than the Marcellus, providing significant uplift potential to bolster development economics in the current lower US gas price path.

As much of the current Marcellus development has essentially bypassed Ohio, producers are just now considering midstream infrastructure needs for potential Utica development. Interestingly, some of the Marcellus infrastructure developments have occurred along the Ohio River and may find that they have dual purposes in the future. For example, Dominion Energy has announced that its proposed Natrium, W.Va., gas processing plant complex is positioned to manage added hydrocarbon-rich gas from the Ohio Utica developments as well as those already contracted from the Marcellus area. Producers expect the 200 MMcf/d processing plant with fractionation capability of 36,000 b/d of NGLs to be in-service by late 2012. At that point, expansion of the facility to process up to 400 MMcf/d and fractionate 59,000 b/d of NGLs is an expansion option. The extensive facilities of another Dominion affiliate, East Ohio Gas Co. – an intrastate pipeline/utility in Ohio – would assist in gathering the hydrocarbon-rich gas in Ohio and deliver it into the Dominion interstate pipeline for ultimate deliveries to the Natrium, W.Va., complex.

For the New York portion of the Utica and, for that matter, the Marcellus area, proposed new rules for drilling have potential developers concerned. Expected to be finalized early next year, the state would impose an off-limits buffer around its various waterways due to environmental concerns about the effects that drilling could possibly have on regional water supplies. The probable buffers – much larger than neighboring, industry-friendly Pennsylvania – appear to have negated some existing leases and would break up many contiguous lease areas.

Wolfcamp/Wolfberry (Permian Basin)

The Wolfberry region centers around Midland, Texas. The play principally runs north-to-south through Andrews, Martin, Ector, Midland, and Upton Counties and picks up again eastward, once again running north to south in the counties of Howard, Glasscock, and Sterling. Permian operators have long considered the Spraberry geological trend a desirable target. Operators have known of the Wolfcamp for many years, but the Spraberry offered more attractive production at a lower drilling cost (i.e., depth). As previous operators often drilled slightly into the Wolfcamp when completing the Spraberry, the Texas Railroad Commission has allowed co-mingling of production from these two zones. When operators discovered that the Wolfcamp Formation – lying just below the Spraberry – also could be produced using current technology and techniques, overall area strategy and development dynamics began to change. The so-called Wolfberry play represents a 2,000 to 3,000 ft geological interval from the top of the Spraberry to the bottom of the Wolfcamp, with the Wolfcamp representing approximately 50% of that zone. As operators have focused more to the Wolfcamp, they also have determined that there are other pay zones, including the Dean Formation that lies between the Spraberry and the Wolfcamp.

> **When operators discovered that the Wolfcamp Formation – lying just below the Spraberry – also could be produced using current technology and techniques, overall area strategy and development dynamics began to change.**

The overall regional play has historically been a sweet crude oil play with some levels of associated gas. As operators have produced from the Spraberry zone for many years, existing oil gathering, gas gathering, and processing plants are present in the region and will be supportive of these new area efforts. Table 11 provides a listing of various area facilities that are assisting in Wolfcamp/Spraberry development activities.

Major area crude oil transportation facilities are essentially the same as those listed in Table 2. However, producers require unique gathering systems to gather the Wolfberry oil volumes into those regional pipelines. Trucking facilities also are in use where gathering by pipeline is not the optimum solution.

Area gas pipelines include El Paso Gas, Enterprise Texas Intrastate, and Northern Natural Gas. ■

Additional Information on Unconventional Resources

For details on the top 20 liquids-rich plays and more, consult the selected 2011 sources below.

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SHALE GAS

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**A printing error by Hart Energy resulted in the omission of an image and copy from a Schlumberger advertisement in the 2011 Eagle Ford Playbook. Hart Energy regrets the error.*

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