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Energy Companies To Watch

SPRING 2014

HARTENERGY

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Energy Companies To Watch

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UPSTREAM EXECUTION

As one looks out to the balance of 2014, rarely has it been harder to keep up with the pace of events unfolding throughout the industry. Company strategies are being formulated and tested, and results are drawing scrutiny from the sometimes short-term judgments of the marketplace as well as the more measured views of long-term investors.

For E&Ps, execution is of paramount importance, as the industry increasingly moves to what some call "hydrocarbon manufacturing." Acreage positions have been amassed, drilling in favored basins has long been underway, and now comes a multitude of questions focused on the ability of E&Ps to leverage size and scale through cost-cutting and greater efficiencies.

Few E&Ps advertise acreage that is not "core," but is it possible to further consolidate blocky positions in key plays? On drilling and completion techniques, are longer laterals more cost-effective, and are completions more effective if they incorporate techniques such as reduced cluster spacing?

Along with extensive downspacing tests of acreage, these and a host of other factors will combine to produce an optimal development plan. This may involve pad drilling, batch completions and other methods to achieve economies of scale. And while such plans may be more typical of large-cap producers, they provide a guide to the direction in which the industry as a whole is headed.

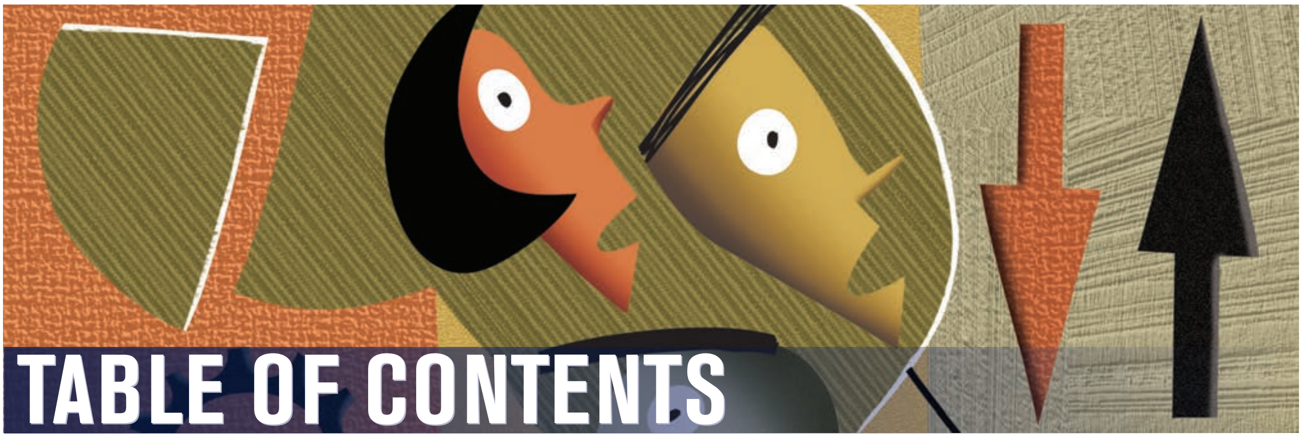
It's about execution, achieving incrementally more for a given capex dollar.

Key issues often involve projected capex, well count and output targets. As production history lengthens, confidence in well type curves for major basins is also a critical factor. Ideally, costs per unit will be trending lower as production ramps, and initial costs of entering a basin, including infrastructure costs, are now in the rearview mirror.

But, of course, every E&P team has its own story to tell. Each management has a unique approach in terms of tackling its challenges and opportunities. What are targeted internal rates of return? And how does capex compare to cash flow, implying a certain level of outspend/underspend of cash flow? Critically, what is the one most important thing investors should know about a company?

Here are insights on companies operating in the fast-evolving E&P sector of today.

—Chris Sheehan, CFA, Senior Financial Analyst



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With one exception, most of the minimum-lot purchases of these E&P stocks cost less than $3,000 while price-performance expectations for many are +100%.

ARABELLA EXPLORATION INC. ....OTCQB: AXPLF ....arabellaexploration.com 20

BONANZA CREEK ENERGY INC. ....NYSE: BCEI ....bonanzacrk.com 22

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MILLER ENERGY RESOURCES INC. ....NYSE: MILL....................millerenergyresources.com 26

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INVESTMENT THEMES TO WATCH

EIGHT THEMES WILL SHAPE THE E&P INVESTMENT WORLD IN 2014.

As 2014 shapes up, Robert W. Baird & Co. Inc. expects eight key themes to shape the oil and gas investment landscape this year. These include E&Ps' shift to manufacturing mode; capital destruction becoming a thing of the past; increasing expectations to "show me the money"; basin economics continuing to drive investment; oilfield services and costs remaining a near-term E&P tailwind; significant offshore expansion internationally and in the Gulf of Mexico; M&A pushed further out; and Northeast infrastructure bottlenecks.

E&Ps' shift to manufacturing mode. Since shale-mania first captivated investors, much of the focus has been on who captured how much land and where, followed by well-watching. However, we think 2013 was the beginning of a shift toward development and scale and expect this trend to continue in 2014 as E&Ps enter manufacturing mode to prove up their acreage after the land grab.

Now that acreage is largely held by production and more infrastructure is in place, E&Ps are using pad drilling to focus on efficiency and scale. Longer laterals, more frac stages and more proppant are combining to increase well productivity while reducing costs. As a result, we expect a continued high correlation between production and the number of wells drilled vs. rig counts. In addition, producers are conducting downspace tests to optimize development patterns and have begun to investigate secondary-recovery methods with a goal to maximize resource recovery.

The "promised land" of unconventional oil and gas development is the point at which scale and efficiency gains combine to drive per-unit costs lower, capital turnover (recycle ratios) higher and expanded returns. We think the industry is finally on the verge of harvesting the fruits of its initial investments in maintaining land positions, infrastructure build-outs, and the technical advancement and march up the learning curve that has characterized the past several years.

In our view, those producers with cored-up, blocky positions in the leading plays will see outsized benefits as this phase unfolds. We think those with a strong track record of thoughtful operations and execution, combined with deep inventory positions, will likely shine particularly bright into 2014 as the "haves" and the "have-nots" will continue to stand out even more than in recent years.

Some would argue that given the incentive for E&Ps to drill their best acreage first, acreage quality could suffer going forward, thereby eroding efficiency gains. We are monitoring the interplay between these two variables but ultimately think it is too early to make a call, given technical drilling and completion innovations, increased infrastructure capacity and ongoing HBP requirements.

Generally, we think additional take-away capacity in key basins could provide more near-term drilling opportunities in the highest-returning portions of major plays. Thus, in our view, it's still too early for the degradation of acreage quality to impact 2014 results. Nonetheless, the topic should stay in focus for 2015 and beyond.

Is capital destruction becoming a thing of the past? When the shale boom initially took off, companies focused on increasing acreage footprints and drilling to hold acreage. Additionally, E&Ps spent primarily on exploration drilling to delineate what acreage would ultimately be economic and which completion methods worked best. All of this led to consistently inefficient operations, low returns and significant capital outspending.

Management teams today are now placing greater emphasis on returns. In addition to the drilling efficiency improvements outlined above, returns are improving as companies can now drill their best wells as opposed to drilling to hold acreage or test the science. We are now several years into the gas-to-liquids transition with very little capital being spent on dry gas drilling outside of the Marcellus. With this shift behind us, the majority of capital is dedicated to high-return liquids plays.

As areas with the best economics continue to move into manufacturing mode, companies will be capable of generating >30% free cash flow. In turn, these producers will recycle cash flows back into their best areas. A better understanding of the sustainability of growth and the magnitude of margins possible in pure manufacturing mode, coupled with a diminishing need for outside capital, should over time drive best-in-class E&Ps to trade at multiples well beyond their historic range, in our opinion.

In addition to the evolving trends in operations, balance sheets are generally pressured after years of levering up to fund acreage acquisitions and exploration drilling leaving many E&Ps with limitations. In that same regard, we have seen consistent equity offerings from the sector resulting in many companies being labeled as "serial issuers," causing their stocks to trade at discounted multiples.

In the 2000s, Wall Street was happy to fund this dilution. However, recent offerings have garnered less favorable reactions, as the positive growth impact from these capital raises was less clear. Companies that demonstrate how incremental capital will accelerate growth should continue to be rewarded in spite of the dilution.

Companies with alternative means of internally funding capital programs are also highly regarded, given a more comprehensive and sustainable funding plan. MLP IPOs and major asset sales are examples of such alternatives, with the former particularly well regarded given the immediate mark to market of assets that are typically undervalued in an E&P's portfolio, coupled with the funding repeatability driven by asset dropdowns or LP unit monetization.

"Show me the money." Investors have been patient with producers that have been meaningfully outspending cash flows to capture leaseholds and to delineate their acreage

Basin Economics: Well Return and Breakeven Analysis–Key Inputs

Key Inputs	
Gas Price	$4.50
Oil Price	$85.00
NGL Price	$34.00
Discount Rate	10%

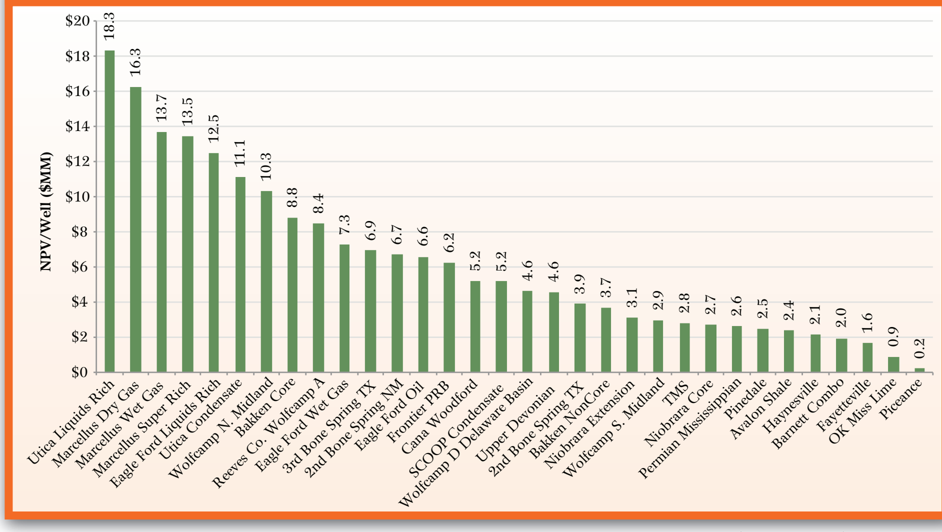
	Returns			Commodity Splits			Key Well Inputs						Expenses			Commodity Pricing					
Type Curves	NPV/ Well	IRR	Pay-back	% Gas	% Oil	% NGL	"EUR (Bcfe)"	"EUR (Mboe)"	IP (MMcfe/d)	b-factor	Well Cost ($MM)	NRI	Prod'n Tax	Vari-able LOE	Trans-port & Other	Gas Price	Oil Price	NGL Price	Gas Diff	Oil Diff	NGL Diff
Utica Liquids Rich (AR)	18.3	92%	1.1	74%	4%	22%	19.9	3,317	23.0	1.3	11.3	80%	5.0%	0.15	1.00	$4.50	$85.00	$34.00	5%	-10%	-60%
Marcellus Dry Gas (COG)	16.3	175%	0.7	100%	0%	0%	16.0	2,670	18.0	1.3	6.5	85%	3.0%	0.20	0.55	$4.50	$85.00	$34.00	-5%	0%	-60%
Marcellus Wet Gas (RRC)	13.7	109%	1.0	52%	1%	47%	12.3	2,050	10.2	1.6	6.1	85%	3.0%	0.20	0.50	$4.50	$85.00	$34.00	-5%	0%	-60%
Marcellus Super Rich (RRC)	13.5	100%	1.1	43%	6%	51%	10.9	1,820	9.0	1.6	6.4	85%	3.0%	0.20	0.50	$4.50	$85.00	$34.00	-5%	0%	-60%
Eagle Ford Liquids Rich (PXD)	12.5	94%	1.1	40%	35%	25%	7.2	1,200	9.0	1.4	7.5	80%	5.5%	0.55	0.33	$4.50	$85.00	$34.00	0%	3%	-60%
Utica Condensate (AR)	11.1	60%	1.5	49%	34%	17%	8.1	1,348	10.2	1.2	10.0	81%	5.0%	0.25	1.00	$4.50	$85.00	$34.00	5%	-3%	-60%
Wolfcamp N. Midland (PXD)	10.3	63%	1.5	18%	70%	12%	5.1	850	6.0	1.5	8.0	85%	5.0%	1.00	0.66	$4.50	$85.00	$34.00	-6%	-3%	-60%
Bakken Core (KOG)	8.8	44%	2.2	7%	93%	0%	5.1	850	12.0	1.8	9.0	82%	11.5%	1.00	0.33	$4.50	$85.00	$34.00	0%	-10%	-60%
Reeves Co. Wolfcamp A (XEC)	8.4	42%	2.2	20%	60%	20%	6.0	1,000	7.8	1.4	10.0	75%	5.0%	1.10	0.40	$4.50	$85.00	$34.00	-4%	0%	-60%
Eagle Ford Wet Gas (SM)	7.3	51%	1.9	56%	6%	38%	8.0	1,333	8.7	1.5	6.7	80%	5.0%	0.40	0.25	$4.50	$85.00	$34.00	2%	-4%	-60%
3rd Bone Spring TX (XEC)	6.9	62%	1.5	17%	75%	8%	3.6	600	5.7	1.3	6.4	75%	6.0%	1.10	0.40	$4.50	$85.00	$34.00	-4%	0%	-60%
2nd Bone Spring NM (XEC)	6.7	57%	1.7	9%	84%	7%	3.0	500	4.0	1.4	6.1	82%	6.0%	1.10	0.40	$4.50	$85.00	$34.00	-4%	0%	-60%
Eagle Ford Oil (CRZO)	6.6	42%	2.2	14%	75%	11%	3.2	540	3.8	1.3	8.0	80%	5.5%	0.45	0.30	$4.50	$85.00	$34.00	0%	4%	-60%
Frontier PRB (SM)	6.2	23%	4.5	30%	70%	0%	6.0	1,000	7.4	1.5	14.0	80%	9.0%	1.00	0.40	$4.50	$85.00	$34.00	0%	0%	-60%
Utica Dry Gas (Eclipse)	5.8	27%	3.8	100%	0%	0%	12.0	1,993	16.5	1.6	10.5	80%	5.0%	0.10	0.50	$4.50	$85.00	$34.00	0%	0%	-60%
Cana Woodford (XEC)	5.2	39%	2.4	65%	7%	28%	7.5	1,245	7.6	1.3	6.5	81%	4.0%	0.75	0.40	$4.50	$85.00	$34.00	-5%	0%	-60%
SCOOP Condensate (CLR)	5.2	26%	4.1	39%	24%	37%	7.1	1,190	5.7	1.6	9.0	83%	9.0%	0.70	0.40	$4.50	$85.00	$34.00	0%	-3%	-60%
Wolfcamp D Delaware Basin (XEC)	4.6	26%	3.9	47%	23%	30%	7.2	1,200	7.7	1.5	8.7	75%	5.0%	1.00	0.20	$4.50	$85.00	$34.00	-4%	0%	-60%
Upper Devonian (REXX)	4.6	29%	3.7	64%	0%	36%	7.7	1,285	4.3	1.8	6.0	85%	4.0%	0.60	0.60	$4.50	$85.00	$44.20	-5%	0%	-48%
2nd Bone Spring TX (XEC)	3.9	39%	2.4	27%	60%	13%	3.0	500	4.8	1.5	5.1	75%	6.0%	1.10	0.40	$4.50	$85.00	$34.00	-4%	0%	-60%
Bakken NonCore (WLL)	3.7	26%	3.9	10%	90%	0%	3.0	500	9.0	1.6	7.5	83%	11.5%	1.00	0.33	$4.50	$85.00	$34.00	0%	-10%	-60%
Niobrara Extension (NBL)	3.1	33%	3.0	12%	80%	8%	2.1	345	3.0	1.5	4.7	80%	6.5%	0.83	0.40	$4.50	$85.00	$34.00	-5%	-5%	-60%
Wolfcamp S. Midland (AREX)	2.9	28%	3.6	23%	58%	19%	2.7	450	3.2	1.4	5.4	76%	6.0%	0.80	0.20	$4.50	$85.00	$34.00	-3%	-5%	-60%
TMS (GDP)	2.8	16%	7.3	5%	95%	0%	3.0	500	4.0	1.4	13.0	82%	0.0%	1.00	0.67	$4.50	$85.00	$34.00	0%	5%	-60%
Niobrara Core (BCEI)	2.7	34%	2.8	24%	57%	19%	2.1	356	2.9	1.4	4.0	80%	6.5%	0.83	0.40	$4.50	$85.00	$34.00	-5%	-5%	-60%
Permian Mississippian (SM)	2.6	18%	6.3	7%	93%	0%	2.6	440	3.8	1.5	9.0	80%	6.5%	0.90	0.40	$4.50	$85.00	$34.00	-4%	0%	-60%
Pinedale (QEP)	2.5	28%	3.7	77%	5%	18%	4.6	767	5.9	1.6	4.2	85%	6.0%	0.40	0.60	$4.50	$85.00	$34.00	-5%	0%	-60%
Avalon Shale (XEC)	2.4	21%	4.8	25%	60%	15%	3.0	500	5.4	1.3	7.3	78%	5.0%	1.20	0.40	$4.50	$85.00	$34.00	-4%	0%	-60%
Haynesville (CRK)	2.1	17%	6.6	100%	0%	0%	7.2	1,200	9.6	1.4	8.8	78%	6.5%	0.20	0.20	$4.50	$85.00	$34.00	0%	0%	-60%
Barnett Combo (PXD)	2.0	32%	3.1	42%	16%	42%	2.4	400	2.7	1.5	2.9	80%	5.8%	0.35	0.40	$4.50	$85.00	$34.00	0%	-4%	-60%
Fayetteville (SWN)	1.6	29%	3.6	100%	0%	0%	3.0	500	2.5	1.6	2.5	85%	7.0%	0.30	0.30	$4.50	$85.00	$34.00	0%	0%	-60%
OK Miss Lime (SD)	0.9	17%	7.4	63%	29%	8%	2.2	369	1.6	1.7	3.0	80%	7.0%	1.17	0.50	$4.50	$85.00	$34.00	0%	0%	-60%
Piceance (WPX)	0.2	14%	11.0	80%	2%	18%	1.2	200	1.2	1.6	1.4	85%	5.0%	0.40	0.60	$4.50	$85.00	$34.00	-5%	0%	-60%

Source: Robert W. Baird estimates

positions in recent years. Ideally, we would like to see E&P companies continue to re-deploy their free cash flows into drilling projects and accelerate production growth, assuming these projects can generate higher rates of return. However, we wonder if investor sentiment may soon shift toward cash returns.

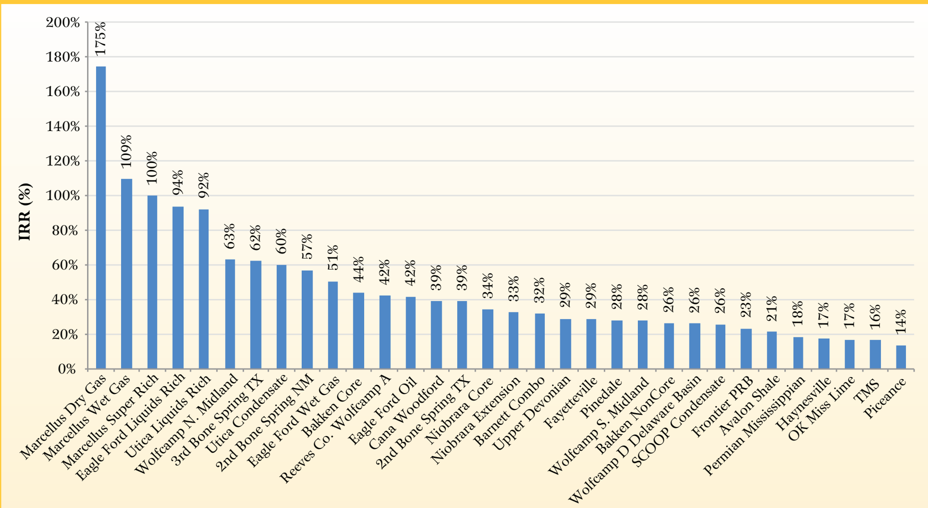
While each operator is at a different phase of basin development and maturity, some have reached the stage where they can begin thinking about returning cash to shareholders via dividend increases and share repurchases. We believe these options would become increasingly attractive for companies that believe they will not get credit for additional growth going forward.

Exhibit 2: Well Economics–NPV/Well



Source: Robert W. Baird estimates

Exhibit 3: Well Economics–IRR



Source: Robert W. Baird estimates

Basin economics continue to drive industry investment. We performed a comprehensive well return and breakeven analysis to better understand capital allocation decisions and comparative returns across basins. Our analysis covers 33 type curves spanning all of the major U.S. onshore plays with each type curve based on corporate data but also generally representative of average returns for the area. In Exhibit 1 we outline the type curves and key assumptions that went into each well economic model.[1]

As highlighted in the charts, the results were generally consistent with expectations in that oilier plays outperformed gas as a whole, with the exception of the prolific Marcellus (Exhibits 2 and 3). Top-returning basins include Appalachia (both Marcellus and Utica), Eagle Ford, Permian, and Williston, while less prolific gas basins (Rockies, Haynesville, Barnett), high-cost plays (Miss Lime, TMS), and more peripheral acreage in otherwise good basins rounded out the bottom of the return list. Not surprisingly then, the highest-returning basins are those where the majority of rigs are deployed and where E&P investment is occurring (Exhibit 4).

We continue to view economics and resource life as the key differentiator among the E&P group. Operators with scale in and leverage to the top plays will garner premium valuations, in our view. That said, we prefer E&Ps with meaningful leverage to liquids-rich plays at the current strip, but believe core areas of the Marcellus will rival even the most efficient liquids-rich wells.

We also estimated the commodity prices at which returns in certain plays come under pressure via breakeven analysis (Exhibit 5). Current front-month WTI of >$100/bbl is accommodative for all of the U.S. onshore plays we analyzed, though higher-cost plays come under pressure in the $80 to $90/bbl range. Lower-returning plays and more peripheral acreage break even at $70 to $80/bbl, while the core liquids plays are still economic below $70/bbl and lower for those with substantial gas contributions. Therefore, we think capital budgets are subject to reevaluation at sub-$85 crude while budget cuts and slowed activity are likely on a sustained pullback below $80/bbl.

On the gas side, Appalachian drilling remains economic at sub-$3/MMBtu, while less prolific plays break even at $4 to $5/MMBtu and higher for certain Rockies plays. Producers are likely reevaluating economics at the current strip while waiting for a sustained rally in the $4.50 to $5/MMBtu range to meaningfully redeploy capital.

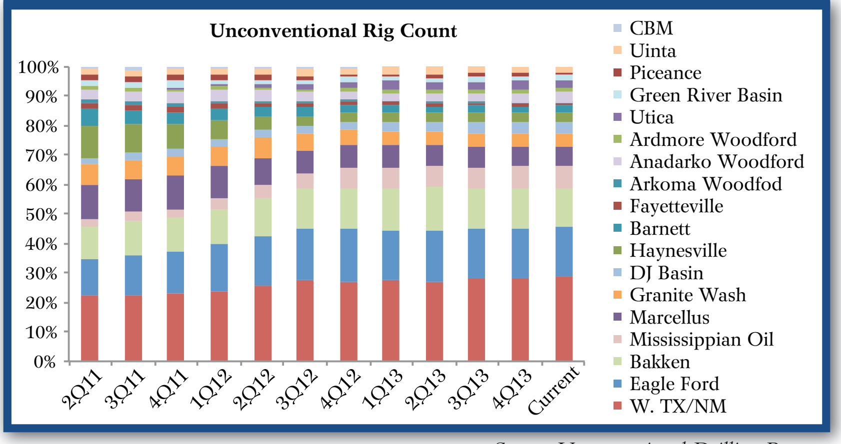
OFS and costs remain a tailwind for E&Ps near term. In response to unprecedented demand in 2010-2111, OFS providers undertook massive capital expansions that led to a wave of deliveries coincident with the decline in natural gas prices entering 2012, essentially creating excess supply that persists today.

The current environment has remained largely unchanged over the past year: a knife-fight with heavy crowding as servicers have redeployed their footprints into the "hot" basins in conjunction with the equally intense bidding environment in the sparse basins as servicers compete for shares of a smaller pie. While technological advances that have ramped up service intensity have finally brought consumable inventories down to near supply-and-demand parity, and we can soon expect consumable equipment orders to better reflect activity levels, other advances in service intensity have effectively extended the excess capacity situation.

The conversion of 12-hour to 24-hour pressure pumping fleets has expanded total virtual supply of horsepower, all accomplished without significant equipment capex investments. Combined with the relatively low barriers to entry due to the commoditized nature of North American services, very few, if any, U.S. land-levered equipment providers have expressed the expectation of meaningful upticks in orders. Nonetheless, a solid start to first-quarter 2014 and the gas supply situation have some providers starting to make modest incremental investments and hoping for price increases in the second quarter, although we believe pricing will be constrained.

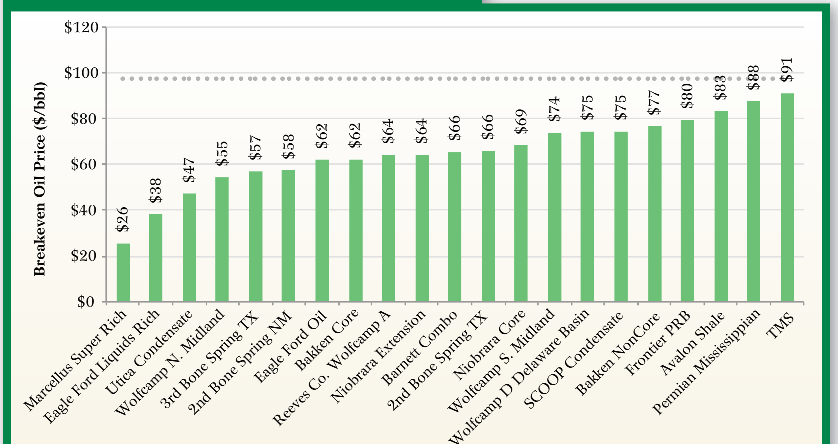
Significant offshore expansion internationally/GOM. In contrast to both OPEC and non-OPEC conventional crude production's expected decline over the next several decades, rising crude oil production from deepwater, tight and other unconventional resources will drive an overall increase in supply in order to

Exhibit 4: Rig Deployment Correlates To High-Returning Basins



Source: Unconventional Drilling Report

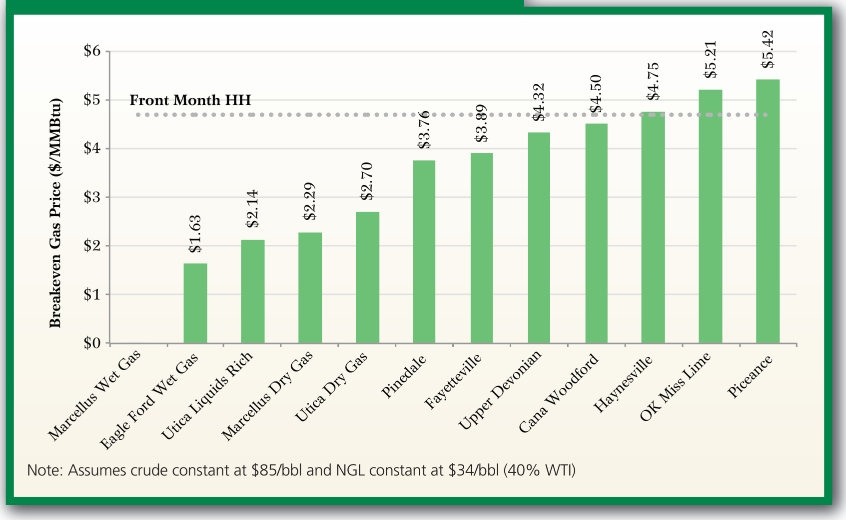
Exhibit 5: Breakeven Economics Oil



Note: Assumes gas constant at $4.50/MMBtu; NGL price varies at 40% WTI

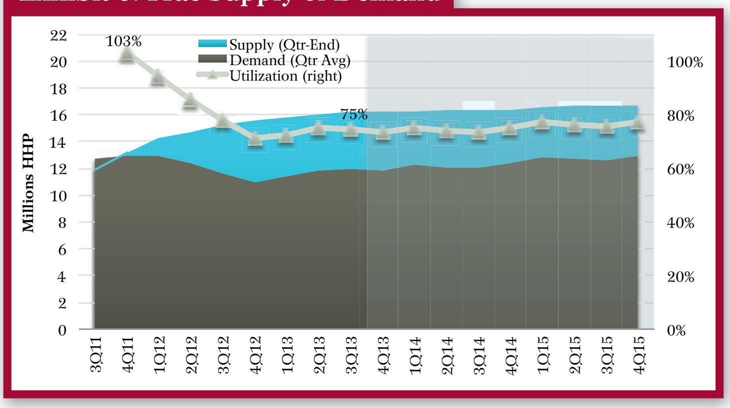
Source: Unconventional Drilling Report

Exhibit 5: Breakeven Economics Gas



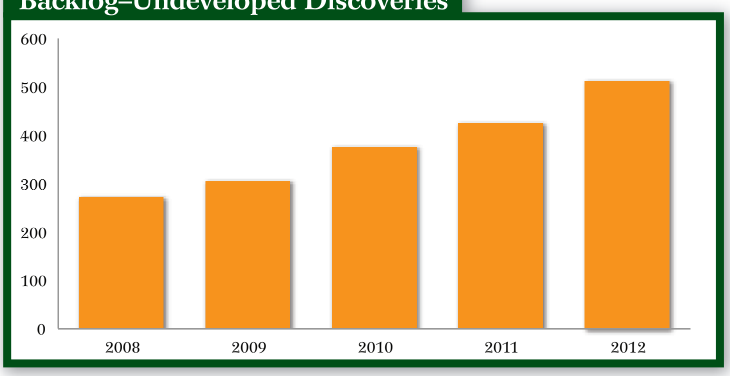
Source: Robert W. Baird estimates

Exhibit 6: Frac Supply & Demand



Source: PacWest Consulting Partners, Robert W. Baird

Exhibit 7: Deepwater Fields Backlog–Undeveloped Discoveries



Source: OII Presentations, IHS Petrodata, Robert W. Baird

meet projected energy demands. As production from these resources is heavily technology-driven, the increasing importance of these sources has wide-reaching implications across the equipment and services space.

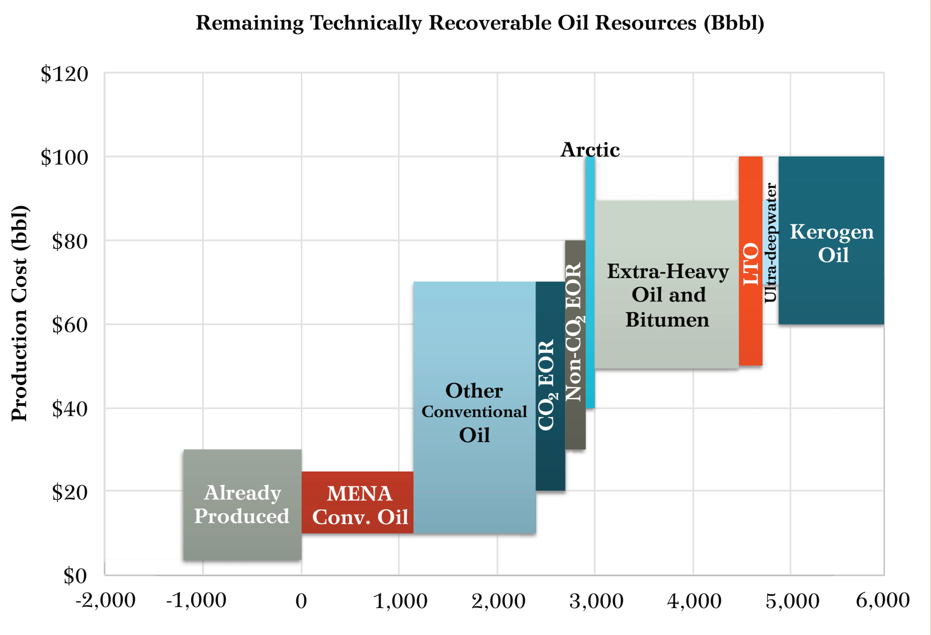
Sustained crude prices at about $100/bbl have bolstered the search for deepwater resources, driving record backlogs (Exhibit 7). With significant numbers of additional deepwater and ultra-deepwater floating rigs coming online over the next few years, we expect companies to start utilizing these additional resources to develop the growing backlog. In turn, we believe the corresponding increase in offshore installations is the single biggest catalyst for equipment names. While the services companies will benefit from the equipment side, there are multiple other avenues for growth in these offshore markets throughout the life cycle of the fields.

Importantly, shallow and deepwater fields, which comprise the upper half of the IEA's "other conventional oil" category in Exhibit 8, are not only important sources of supply to meet the next several decades of energy demand, they also provide attractive economics at current commodity price levels, often requiring breakeven crude prices in the $50-to-$60 range. Moreover, viewed aggregately with ultra-deepwater, about 80% of the offshore field backlog is viable at $80 crude.

Meanwhile, in addition to the onshore unconventional oil plays (Permian, Bakken, Eagle Ford), the Gulf of Mexico also represents a key domestic asset for the U.S. While not yet surpassing pre-Macondo levels, 2012 saw 463 MMbbl of crude oil produced in the U.S. GOM (average rate of 1.27 MMbbl/d), representing nearly 20% of total U.S. oil production. The EIA projects average production to increase to 1.45 MMbbl/d by 2014 as post-Macondo projects approach peak production levels, thereby providing margin tailwinds to the subsea installation space.

M&A gets pushed further out. While 2013 M&A and joint-venture activities seem to have cooled off with fewer deals than 2012, we expect to see continuing M&A activity in the E&P sector, likely in the form of more asset transactions rather than corporate deals. The main drivers underpinning this view include 1) private-equity activity supporting high corporate valuations, 2) small-cap optimism on resource estimates, and 3) integrateds still plagued

Exhibit 8: Oil Production Costs By Resource Category



Source: IEA, Robert W. Baird

Utica. Take-away capacity could be strained until mid- to late 2014, when a significant backlog of projects come online, although smaller gathering and compression projects could potentially fill the gap in certain areas. Longer term, we expect sufficient capacity build-out to key demand centers on the Gulf Coast and metropolitan areas in the Northeast as well-capitalized MLPs continue deploying capital to high-return projects.

The largest risk to the Northeast build-out, in our opinion, is the degree to which capital markets remain accommodative. Despite sufficient take-away capacity, seasonal demand swings create the potential for large shifts in differentials. With winter demand met by local production, we can expect summer differentials to widen. Although we initially expected these seasonal swings to have a positive impact on gas storage in the Northeast, we have yet to see any significant sentiment change for natural gas storage overall.

by questionably timed deals. However, we continue to believe larger companies' deep pockets, relative cost of capital advantage, and scale advantages will ultimately be required to develop shale plays.

For context, North American onshore acquisitions from upstream producers in 2013 (both E&P and upstream MLPs, private and public) totaled 81 transactions for about $40 billion in value, according to IHS Herold, a significant reduction from 112 transactions for some $87 billion in value from 2012.

Northeast infrastructure. Midstream operators continued to spend on infrastructure to support burgeoning wet and dry gas from the Marcellus and

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[1] *The underlying flat commodity pricing scenario employed was $4.50/MMBtu for natural gas, $85/bbl for crude, and $34/bbl for NGL (40% of WTI) with differentials applied thereafter if applicable.*
[2] *The Northeast exhibits the largest seasonal demand swings of any other U.S. market. Bentek estimates range from 10 Bcf/d to 25 Bcf/d in peak demand.*

THE FASHION WINDOW OPENS FOR IPOS

EXPLORATION AND PRODUCTION COMPANIES FOCUSED ON PREFERRED BASINS ARE PUSHING HARD TO TAKE ADVANTAGE OF THE POTENTIAL PUBLIC MARKET PREMIUM.

By Chris Sheehan, CFA

Predicting what will stay in style is notoriously difficult. But the resurgence of energy initial public offerings could run for the next year or more, especially for E&P issuers in "fashion-window" basins where public company valuations are handily surpassing comparable valuations being achieved in private asset transactions. And, in many cases, after a quick check of other options, E&Ps are making a beeline to the IPO window while it stays open.

The fashion-window analogy is one used by Brad Hutchinson, managing director at Barclays, when pointing to the basins that have given birth to some of the most noteworthy recent IPOs. He cites the Marcellus and Utica, with the much-anticipated launching of the Antero Resources Corp. and Rice Energy Inc. IPOs, as well as the Permian Basin, birthplace of several successful IPOs, including Athlon Energy Inc., RSP Permian Inc. and, in late 2012, Diamondback Energy Inc.

"Basin fashion windows do change over time, but today they have more staying power than what we were seeing five years ago," says Hutchinson, part of the Barclays team that led the offerings for Antero Resources, Rice Energy and Athlon Energy.

And there is no mistaking the valuation uplift characterizing the three basins currently in vogue—and providing a strong impetus for players in those basins to turn to the IPO market.

"If based on 2014 estimates the median E&P is trading at 5 to 6 times EV/EBITDA [enterprise value to earnings before interest, depreciation and amortization], those three basins are commanding multiples at a much higher level," says Hutchinson. "Relative to having a management team build up a company and then sell it into the private market, the multiple difference in going to the public markets in those three hot areas is at least an additional two turn of EBITDA, if not more, in terms of value."

This is illustrated perhaps most vividly by the Antero Resources IPO, which was priced at an EV/EBITDA multiple of 9.3 times and has traded up to around a 13 multiple of 2014 EBITDA estimates.

Other metrics similarly support a significant valuation uplift if E&Ps decide to go public. Based on an analysis of Wall Street estimates of E&Ps' net asset value (NAV), divided by the acreage held by an E&P in a given play, public values in the Marcellus/Utica are as high as $30,000 to $40,000 per acre, according to Barclays data as of February. This compares to $10,000 to $13,000 per acre for private transactions, or just one-third of the public value on a midpoint to midpoint basis.

A similar disparity is seen in the Permian Basin. Estimates of public values for E&Ps operating in the Delaware side of the Permian fall into a range of $15,000 to $40,000 per acre as compared to just $4,000 to $10,000 per acre in private transactions. On the Midland side, public values of $30,000 to $55,000 per acre compare to private deals spanning $20,000 to $40,000 per acre, but whose median transaction value—at $20,550 per acre—is closer to the bottom of the range.

"A lot of management teams are looking at these IPO valuations and—seeing the arbitrage—are considering becoming a public company instead of just selling the assets and moving on," says Hutchinson. With the strength of the IPO market, he is increasingly seeing instances of managements who "built and sold several times before now going public," such as the RSP Permian team.

Mike Bock, principal at Denver-based Petrie Partners, sees momentum building in the IPO pipeline.

In part, this reflects a roughly 10% year-over-year lift in the enterprise values of public E&Ps through the end of January, widening the premium over private transaction valuations. In addition, he points to the positive impact of the Antero Resources IPO, which within weeks raised a public entrant to the $16- to $17-billion enterprise value attained by such peers as Range Resources Corp. and Cabot Oil & Gas Corp.

Mike Bock
Principal
Petrie Partners

"The value arbitrage favors IPOs these days," says Bock. "People got a sense of it with the Antero IPO, and then it was reinforced by the Rice Energy transaction." With E&Ps now waiting for year-end audited financials, and the effect of confidential filings afforded under the JOBS Act, "there will be a little bit of a lag until the next wave. But if the valuations are still there, you'll see a lot of activity."

Valuations by Petrie Partners compare enterprise values per thousand cubic feet equivalent per day (Mcfe/d) of flowing production for public companies to transaction values per flowing Mcfe/d for private deals. One caveat is the difficulty in comparing "core of the core" valuations in public companies with the often-mature production valued in private asset transactions, particularly in the Marcellus.

Not surprisingly, the Marcellus exhibits the widest disparity, with public companies trading at $20,387 per Mcfe/d of production versus $6,817 per Mcfe/d for private transactions, Petrie data show. In the Permian, public companies are valued at $32,907 per Mcfe/d of production versus $24,383 for private asset transactions. Public companies in the Williston also have an edge, trading at $23,002 per Mcf/d versus private asset transactions at $17,179, according to the data.

So how hard are E&Ps in favored basins pushing to take advantage of the public market premium?

Barclays' Hutchinson says a "dual-track process" of examining the merits of both an IPO and an asset sale is being pursued by some—but not most—E&P clients. "Most of these right now are running hard to the hoop—straight to the IPO market—especially those in the Midland Basin."

And what of E&Ps on the Delaware side of the basin? "Activity is moving south now. Could there be emerging players there? I think so," Hutchinson says.

Petrie Partners, whose suite of investment-banking services includes an IPO advisory service, offers varied avenues for E&Ps to pursue that are tailored to their specific circumstances. (The firm advised Cheniere Energy late last year, when its subsidiary Cheniere Energy Partners LP Holdings LLC undertook an IPO that was upsized to 36 million shares and raised gross proceeds of $720 million.)

With the valuation uplift seen by some public markets, coupled with the leverage often used in successful oil and gas developments, incentives for private-equity-backed managements to take the public route are such that "even the most reluctant anti-IPO management teams really have to consider going public, and at the end of the day, may have to embrace it," says Bock.

For those with greater urgency to achieve liquidity—and heightened concerns that the IPO window

Public Market Vs. Private Market Arbitrage

Comparison Of Wall Street NAVs To Private Market Transactions

	$/Acre	
	Wall Street NAVs	**Private Market Transactions**
Permian-Midland Basin	$30,000-$55,000	$20,000-$40,000
Permian-Delaware Basin	$15,000-$40,000	$4,000-$10,000
Marcellus/Utica	$30,000-$40,000	$10,000-$13,000
Eagle Ford	$15,000-$55,000	$10,000-$35,000
Bakken	$10,000-$25,000	$5,000-$25,000
Niobrara/Wattenberg	$9,000-$15,000	$4,000-$5,000

Note: Wall Street NAVs represent value of undeveloped acreage (proved undeveloped reserves plus additional undeveloped value by acreage). Private market transactions represent value of undeveloped acreage after adjusting for current production valued at $60,000 per flowing barrel of oil equivalent.

"INVESTORS WANT TO PUT TOGETHER THEIR OWN PORTFOLIOS INSTEAD OF HAVING A PORTFOLIO IN AN E&P COMPANY."

—Brad Hutchinson

could shut before they get through—a backup strategy involving a dual-track process may be in order.

"It takes time to execute an IPO. If I want to be liquid, and the IPO window shuts, I want to have a dual-track process underway rather than a serial process in which I then have to start on an asset sale," says Bock. "If I don't have as much time pressure, it probably is better to go straight to an IPO."

Of course, not all basins have been equally blessed with the market appeal currently needed to execute a successful IPO strategy.

"If you're not in one of the fashion-window basins, which change over time, you're not necessarily looking at an arbitrage between a multiple in a public and private market," says Hutchinson. "In a lot of the other areas, it behooves you to take a look at private dispositions in the acquisition and divestiture market versus an IPO."

Craig Lande, managing director with RBC Richardson Barr, is aware of E&Ps in both camps. He notes there is a handful of E&Ps that have made, or are considering making, confidential filings with the Securities and Exchange Commission (SEC) in preparation for an IPO, as well as a similar number that are testing the asset market in their region while striving to keep an open mind as to which of the alternatives to pursue.

Of the latter, "some are looking at an asset sale, and if they don't get a strong-enough valuation, they are certainly prepared to head to the public market in light of how strong the valuations are there," Lande says. He notes, however, that an IPO may not be the first choice among many private-equity-backed management teams. "Some people will likely quietly run asset processes to see if they can get a strong-enough number to keep them from going public. But with private equity, they know the IPO route is always an option."

Which path will be taken by those testing both markets?

"It wouldn't surprise me if, of the four or five E&Ps that I know about, maybe two end up going public, while maybe one or two get bought," Lande says. "And, given how fast the IPO window has been known to close, maybe the IPO window shuts on someone else—they just don't make it in time."

Lande cites areas in the core of the Permian where an expected valuation discrepancy has been substantially eroded, on a dollar-per-acre basis, between public and private transactions. "If you're in the right zip code in the Permian, you have the possibility to get taken out at a significant premium that may very well mitigate a public valuation."

In particular, he points to a "core-of-the-core" asset being sold in the Midland Basin, where the seller "can pick and choose which route it wants to go. Potentially, you could see them get such an attractive asset valuation that they'll never need to consider going public."

On the other hand, in basins such as the Eagle Ford, the arbitrage is working in reverse for public E&Ps, with public valuations lagging asset transactions. Lande points to public valuations in the Eagle Ford of $27,800 per acre, which significantly trail such recent purchases as Devon Energy's acquisition of the GeoSouthern Energy Corp. assets, at $46,600 per acre, or Baytex Energy Corp.'s purchase of Aurora Oil & Gas Ltd., at $54,300 per acre, according to RBC Richardson Barr data.

With the heightened interest in the public route, what are common characteristics of E&Ps teeing up an IPO? A consensus viewpoint is that the market is rewarding "focus," meaning E&Ps operating in a single or just two basins.

"Right now, the market is giving a higher multiple to concentrated strategies," observes Hutchinson. "Investors want to put together their own portfolios instead of having a portfolio in an E&P company."

In addition, "you've got to be in the core of the fashion-window basins; you can't be in the periphery," he says. "And you have to have a deep inventory of locations to drill in your key area. I think a line of demarcation is you have to have seven or eight years of inventory. More than that is helpful, but if it's less, you may start getting questions about depth of inventory."

How long favorable conditions will persist for IPOs is heavily dependent on broader market conditions, but Hutchinson expresses confidence in the 2014 outlook. "There's definitely visibility for this year, and maybe it's the next 12 to 18 months.

However, with a lull in activity pending year-end audited financials and reserve reports—plus delayed disclosure due to confidential filings with the JOBS Act—IPO candidates are more difficult to track down.

In the Marcellus/Utica, Eclipse Resources has indicated it is considering an IPO, possibly around midyear. And in the Permian, Parsley Energy LLC has said it expects to undertake a public offering in the second quarter, subject to the SEC review process. Private-equity backers of the two E&Ps are EnCap Investments and Natural Gas Partners, respectively.

In addition, another half-dozen or more E&Ps are mentioned as possible IPO candidates, several of which are Permian-focused. IPO offerings may be typically $400- to $600 million from issuers that would subsequently have an enterprise value of $2- to $4 billion or higher.

On a somewhat larger scale, Aubrey McClendon, founder of American Energy Partners LLC, has a history of taking companies public. Having already raised $1.2 billion in private equity through affiliate American Energy–Utica LLC, the latter recently closed on a $750-million offering of seven-year, 3.5% convertible subordinated notes. The notes are convertible into the first qualified registered public offering of shares by American Energy–Utica, using an agreed formula specifying the conversion ratio. American Energy holds approximately 260,000 net acres in the southern portion of the Utica.

What could derail resurgent IPO activity?

"Looking back over the last three decades, these things go in cycles," says Bock, with issuers with the higher-quality assets typically leading the way. "I think investors already recognize that they're paying up for some of these companies relative to what they would fetch in the asset market. That psychology could creep into the market. There will be a little more resistance to paying up for the next IPO, and public market demand could wane."

And longer term, after the IPO trend plays out?

"After a wave of IPOs, at some point I think we're going to see a period of consolidation," Hutchinson says. "Within basins, there are public companies with very similar acreage positions that should probably be combined to achieve operational efficiencies, as well as synergies in administrative costs under a single management team. The point is that there are consolidation opportunities that can maintain that basin-centric strategy, which is what the market wants."

But such a consolidation is another story—one for the A&D book. ■

SMALL-CAP UPSIDE

WITH ONE EXCEPTION, MOST OF THE MINIMUM-LOT PURCHASES OF THESE E&P STOCKS COST LESS THAN $3,000 WHILE PRICE-PERFORMANCE EXPECTATIONS FOR MANY ARE +100%.

By Nissa Darbonne

With some E&P stocks at nearly $200 a share, such as those of Pioneer Natural Resources Co. and EOG Resources Inc., what's a small-portfolio manager to do? Given small caps with assets ranging from Kansas, West Texas and North Dakota to the U.K. North Sea, securities analysts aren't short on investment ideas.

Oil and Gas Investor polled several of them for their favorites for 2014 and dove into the research reports of several more for their views. In just two weeks approaching press time, one of these stocks—that of Eagle Ford operator Penn Virginia Corp.—hit and then proceeded to exceed a Jefferies LLC analyst's target price.

Here's a look at 15 of the top picks, beginning with **Synergy Resources Corp.**, whose shares grew 64% in 2013 to close the year at $9.26. At press time, they had pushed on to $10.35.

Irene Haas, E&P analyst for Wunderlich Securities Inc., said the production-growth story is just beginning for the roughly $800-million-market-cap E&P. She had a Buy on the stock (NYSE Market: SYRG) and a $14 target in February.

Headquartered within Wattenberg Field in Platteville, Colorado, Synergy was formed as a private company in 2007 and went public in August 2008 in a merger with a fellow, nascent E&P, Brishlin Resources Inc. The latter had one shut-in well; the former, $2.2 million in cash from private investors and 640 acres of leasehold in Weld County.

The stacked oil pay of Wattenberg Field was being developed vertically at the time, primarily in the Codell, Niobrara and J sand. Ed Holloway and Bill Scaff, Synergy's co-chief executive officers, were aiming to do the same.

Synergy has grown to operating 283 wells and holding nonoperated interest in 75. Net proved oil and condensate reserves were 7 million barrels in August 2013; proved gas, 40.7 billion cubic feet.

But captivating the equity market today is its new horizontal program, launched in May 2013 with five wells at its Renfroe pad. Later in 2013, it followed with the completion of six horizontals at its Leffler prospect. Its production this past fall averaged 3,200 barrels of oil equivalent (BOE) a day, up

Small-Cap Stocks To Watch

	Market/Ticker	Price*	Rating	Target	Analyst
Approach Resources Inc.	Nasdaq: AREX	$22.27	Buy	$42	Haas
Clayton Williams Energy Inc.	NSYE: CWEI	$97.00	Buy	$110	Haas
Emerald Oil Inc.	NSYE Market: EOX	$7.66	Buy	$12	Trimble
Endeavour International Corp.	NYSE: END	$4.86	Buy	$10	Dingmann
Gastar Exploration Inc.	NYSE Market: GST	$6.73	Buy	NA	TPH
Goodrich Petroleum Corp.	NYSE: GDP	$13.62	Buy	$30	Dingmann
Jones Energy Inc.	NYSE: JONE	$15.62	Outperform	NA	Tameron
Midstates Petroleum Co. Inc.	NYSE: MPO	$4.41	Buy	$12	Dingmann
Penn Virginia Corp.	NYSE: PVA	$15.15	Buy	$15**	Perincheril
PetroQuest Energy Inc.	NYSE: PQ	$4.70	Outperform	$8	Rashid
Rex Energy Corp.	Nasdaq: REXX	$18.21	Outperform	$25	Anderson
Rice Energy Inc.	NYSE: RICE	$24.00	Buy	$32	Dingmann
Ring Energy Inc.	NYSE Market: REI	$14.04	Outperform	$20	Anderson
RSP Permian Inc.	NYSE: RSPP	$27.80	Buy	$30	Chandra
Synergy Resources Corp.	NYSE Market: SYRG	$10.35	Buy	$14	Haas

**On March 1, 2014. **On Feb. 19, 2014.*

Irene Haas
E&P Analyst
Wunderlich Securities Inc.

from just 1,658 a year earlier. It expects to be producing between 9,000 and 10,000 BOE a day by August 31—the end of its 2014 fiscal year.

Its $189-million capex plan for fiscal 2014 includes $150 million for 34 operated and five non-operated horizontals in the field with roughly half of these landed in Codell, about 40% in Niobrara B and the balance in Niobrara C.

Meanwhile, J. Ross Craft is working to rid **Approach Resources Inc.**'s shares of a market perception that its future is gas-weighted. "[Potential investors] look at us as a whole and say, 'Your Wolfcamp is different from everyone else's because everyone else's has a higher percentage of oil production,'" the president and chief executive says.

"Instead, our Wolfcamp is the same but, when we report total production for the company, we have more than 600 gas wells mixed in it."

Approach had been drilling those gas wells in Canyon, Strawn and Ellenburger underlying Wolfcamp since 2004. "Drilling those 600 wells is how we came across the Wolfcamp and came up with the concept of going sideways in it," he adds.

A couple of vertical, research wells were drilled in 2010; a first horizontal, in early 2011. Of its 166,000 net acres in the Midland Basin, Wolfcamp underlies all of it and Approach has de-risked 107,000 acres to date for Wolfcamp pay. Most of it is HBP by the deep-gas wells.

The company is landing laterals in the Wolfcamp's A, B and C zones—69 of them to date in B, eight in A and four in C.

Fiscally, Approach is set to drill its position without a joint-venture or other capital partner. The company raised $250 million in a debt issue in 2013 at 7% interest. It had also built an oil pipeline, connecting the play to larger pipe, and sold its share of it for $109 million net—a 600% return on investment in less than a year.

Yet, the roughly $870-million-market-cap E&P's stock performance disconnected from that of other Wolfcamp leaders in fourth-quarter 2013. "The market views us a little skeptically now; I believe that, if we meet guidance, our stock price will come back," says Craft.

E&P analyst Haas had a Buy rating on Approach shares (Nasdaq: AREX) and a $42 target in mid-February while the shares were about $20.

WATCH THESE TOO

Haas also recommends **Clayton Williams Energy Inc.** on which she had a Buy and target of $110 in February when the stock was about $93. She noted that, after the company provided guidance on expectations from its Wolfbone play in the Delaware Basin, "the stock went on a tear." Shares (NSYE: CWEI) bolted from about $68 to $84 in just two trading days. In early March, they were $97. Its market cap had grown 43% in one month from about $840 million to $1.2 billion.

Haas noted that the company's fourth-quarter production averaged 14,900 BOE a day from across its portfolio, which includes Austin Chalk and Eagle Ford. Its expectations for 2014 are for making between 16,400 and 17,400 a day.

"The company plans to run two rigs in the Delaware Basin, targeting Wolfcamp A, B and C. In addition, it plans to have two rigs running in the Eagle Ford. We look for a steady stream of drilling catalysts from it and its competitors in the southern Delaware Basin in 2014," she concluded.

Several analysts also cited **Emerald Oil Inc.**, which had a $500-million market cap in early March. Curtis Trimble, senior analyst for Global Hunter, had a Buy on the shares (NSYE Market: EOX) and a $12

Neal Dingmann
Managing Director of E&P
and Oilfield-Service Research
SunTrust Robinson Humphrey Inc.

"WE BELIEVE THE HENRY HUB SPOT MARKET IS IN THE BEGINNING STAGES OF TURNING INTO A PREMIUM MARKET."

—Rehan Rashid

target while they were about $7.50. With a recent 20,800-net-acre purchase, Emerald has 85,000 net prospective for Bakken pay. The company funded the $75-million acquisition with half from its $140 million of cash on hand and half from its $75-million bank facility. Its 2014 exit rate is expected to be 4,250 BOE per day, up from the 1,870 it was making in the third quarter of 2013.

Trimble reported, "The prospective value added through this transaction … provided the catalyst for our [upgrade]. With the increased depth of its acreage portfolio, we expect the company to add a fourth drilling rig in September."

Rehan Rashid, E&P analyst for FBR & Co., had an Outperform rating and $8 target on **PetroQuest Energy Inc.** shares (NYSE: PQ), which had improved from about $3.70 to $4.70 during February, taking its market cap from about $234 million to $300 million.

"We believe the Henry Hub spot market is in the beginning stages of turning into a premium market," Rashid reported in late February, "as we expect Gulf Coast/Southeast-area demand growth to exceed the current supply-growth outlook. Within our small-cap coverage group, PetroQuest … provides the best exposure."

He noted the company's Thunder Bayou, conventional-reservoir prospect may resemble "the highly successful La Cantera project and could be worth as much as $2.25 per share." Besides its Gulf Coast potential, PetroQuest's exposure to the Woodford shale in the Midcontinent "is underappreciated and could ultimately be worth $7 per share." And its work in the Cotton Valley and Mississippi Lime "could get incrementally de-risked as the year progresses …," he concluded.

Neal Dingmann, managing director of E&P and oilfield-service research for SunTrust Robinson Humphrey Inc., had a Buy on **Goodrich Petroleum Corp.** and $30 target on the stock (NYSE: GDP) that was $13.62 in early March. The company's market cap had more than doubled in the second half of 2013 upon strong well results in the Tuscaloosa Marine shale play. It tumbled in February as Goodrich reported its Weyerhaeuser 51H continued to trouble it and it missed its fourth-quarter production estimate.

Dingmann reported, "There is a good chance the [well] can be remedied, causing it to flow sufficiently and the next few wells … are likely to be solid. However, despite our optimism still about the TMS play, production has been slower to develop than we previously forecasted and we are lowering our production estimates, cash-flow estimates and ultimately our price target [from $40] as a result."

The TMS wells have been challenging in part due to their depth combined with the lateral length; fishing equipment out of the hole has been difficult. Dingmann reported, "Hopefully, by bringing a unit in to drill out the permanent frac plug, Goodrich will be able to fully un-restrict the well.

"Going forward the next wells … will all be landed below the rubble zone and all will use [naturally dissolving] carbonate frac plugs … . We look for results from a couple of the new Goodrich wells relatively soon."

With a $3-billion market cap in early March just five weeks after its IPO, **Rice Energy Inc.** (NYSE: RICE) exceeded the traditional E&P small-cap definition but public float is about $1 billion. Dingmann initiated coverage of it with a Buy and target of $32 in February. The Marcellus- and Utica-focused E&P had priced at $21 each in January; the shares were worth $24 in early March.

Dingmann reported that Rice's position in Tier 1 acreage in Appalachia is "in what we believe to be some of the most economic areas of the Utica and Marcellus, with the company continuing to aggressively add assets.

"Though having a relatively short track record, Rice has been a leader in early-stage shale development, attaining over 200 [million cubic feet

equivalent of daily] production faster than any other Marcellus operator, while reducing drilling and completion costs per foot by nearly 60% in the past several quarters."

Also newly public, **RSP Permian Inc.**'s market cap was $2.2 billion in early March after IPOing 20 million shares at $19.50 in January. Subash Chandra, E&P analyst for Jefferies LLC, initiated coverage with a Buy rating and $30 target on the shares while they were $25.85. By early March, they had grown to $27.80.

Chandra reported, "RSP Permian offers investors exposure to the Permian Basin, specifically the northern Midland Basin where … multipay potential is emerging. RSP's acreage position could lead to commercial development from … as many as five reservoirs."

A pure-play operator in the basin, he noted, RSP has 33,933 net acres and 1,169 potential well locations for middle and lower Spraberry and Wolfcamp A, B and D. "Each zone yields solid economics but the Wolfcamp A and B are the best of the bunch with an IRR [internal rate of return] of some 37%."

Meanwhile, with **Gaster Exploration Inc.**'s market cap of $390 million, analysts at Tudor, Pickering, Holt & Co. Securities Inc. had a Buy on shares in mid-February while the stock (NYSE Market: GST) was $6.73. The price had just soared from $5.38 to $7.06 in seven trading days upon news of Magnum Hunter Resources Corp.'s 32.5-million-cubic-foot-equivalent Utica gusher near Gastar's acreage.

"Gastar plans to spud a short-lateral Utica test well in April but lateral [length is] likely to increase under full development," the TPH analysts reported. "The Utica deepens as you move east, so Gastar's acreage should have [yet] higher pressure and deliverability … ."

If estimated ultimate recovery (EUR) is 14 billion cubic feet for a Magnum Hunter-type well, costing $12 million, then the analysts expect upside to Gastar shares of between $1 and $2 if making 20 of these wells and more than $3 if making 50, which is what Gastar expects to drill, they reported.

Also in the Utica and Marcellus, **Rex Energy Corp.** shares (Nasdaq: REXX) have a favorable outlook from E&P analyst Reed Anderson with Northland Securities Inc. He had an Outperform rating and $25 target in February while the stock was $18.21. Anderson noted that Rex had a small fourth-quarter earnings miss due to higher costs but "we are encouraged by the company's execution as Butler County [Pennsylvania] results continue to look solid and downspacing tests in the Utica provide near-term catalysts."

The company expects a second-quarter production increase of up to 18% and a further increase in the third quarter of up to 30%. Anderson concluded, "With continued operational efficiencies, solid results and an improving natural-gas [price] environment, Rex looks well positioned for a strong 2014."

David Tameron, senior analyst for KeyBanc Capital Markets Inc., had an Outperform on Midcontinent-focused **Jones Energy Inc.**, which IPOed 12.5 million shares in July at $15 each. In early March, the $771-million-market-cap E&P's shares (NYSE: JONE) were $15.62.

Tameron had expected the dive, noting the company's disappointing update on production and reserves guidance. " … For what it's worth, the Street—us included—likely got ahead of itself with elevated growth expectations with a small-cap name … ."

That aside, Tameron reported, "Jones Energy offers investors relatively low-risk, producing assets alongside an attractive growth profile and exploration upside potential. Management has solid operational experience, in our view, and a track record as a low-cost operator."

Meanwhile, SunTrust's Dingmann had a Buy on **Midstates Petroleum Co. Inc.** and $12 target for the shares (NYSE: MPO), which were $4.41 in early March for a market cap of $302 million. The Midcontinent and Gulf Coast operator's fourth-quarter results were "mostly in line with estimates when factoring in weather," he reported, which had affected producers in several U.S. basins in December.

The stock was $5.93 at the time and Dingmann had expected it to decline due to the production report. He noted, however, that "the high end of 2014 production guidance also looks in line with current estimates and a bit better when adding back production [that was] curtailed."

Endeavour International Corp., which operates in the Haynesville, Marcellus, Rockies and abroad, was also on Dingmann's Buy list. The analyst had a $10 target on the stock (NYSE: END), which was $4.86 in early March for a market cap of about $230 million. He noted in late February that problems appeared to be nearly resolved with getting one Endeavour well in the U.K. North Sea to come online and with getting a second well back on production.

"While first-quarter cash flow and earnings are likely materially impacted, it appears the company can manage liquidity until production begins to materially ramp again soon. We see the shares continuing to rebound as cash flow rebounds with various incrementals ahead."

At Northland, Anderson liked Kansas and Permian operator **Ring Energy Inc.** with an Outperform and target of $20 while the shares (NYSE Market: REI) were $14.04. In early March, they were $13.79 for a market cap of $325 million. Anderson reported that Ring's fourth-quarter production that averaged 696 BOE per day was in line with estimates. Meanwhile, "its drilling program in the Permian continues at a solid pace. Drilling is expected to begin on its Kansas acreage in February and a second rig in the Permian is planned to arrive at midyear."

He also noted that the company's December production was more than 800 BOE per day. "Bottom line, Ring appears to be executing on its operational plans, which we find encouraging … . We look forward to an updated reserve report that will likely be available in the coming months and should illustrate strong growth attributable to its 2013 development program."

As for **Penn Virginia Corp.**, Jefferies analyst Biju Perincheril put a Buy and $15 target on the shares (NYSE: PVA) in mid-February when they were $12.91. The stock soared in the following seven trading days to $15.15 by early March for a market cap of $990 million. At the time of the report, the Eagle Ford operator had missed earnings estimates due to postponed completions of several new wells. But, Perincheril noted, production is to grow some 38% this year.

"[Its] Eagle Ford acreage increased to some 80,000 net acres, up from 67,000 reported in early November." Meanwhile, it now has 1,125 drilling locations, up from 895, "of which only about 280 are currently booked as proved undeveloped locations.

"This provides several more years of reserve growth visibility," he concluded.

ARABELLA EXPLORATION INC.

OTCQB: AXPLF | ARABELLAEXPLORATION.COM

JASON HOISAGER is the CEO of Arabella Exploration Inc., a company that is actively acquiring and developing assets in the Delaware Basin of West Texas. Prior to Arabella, Hoisager was an independent landman planning strategic land purchases, identifying investment partners, acquiring leases and marketing to operators seeking entry into the resource plays of North and West Texas. He attended Texas Tech University, where he studied finance and accounting.

Describe the strategy that drives the company, and how you will implement it this year.

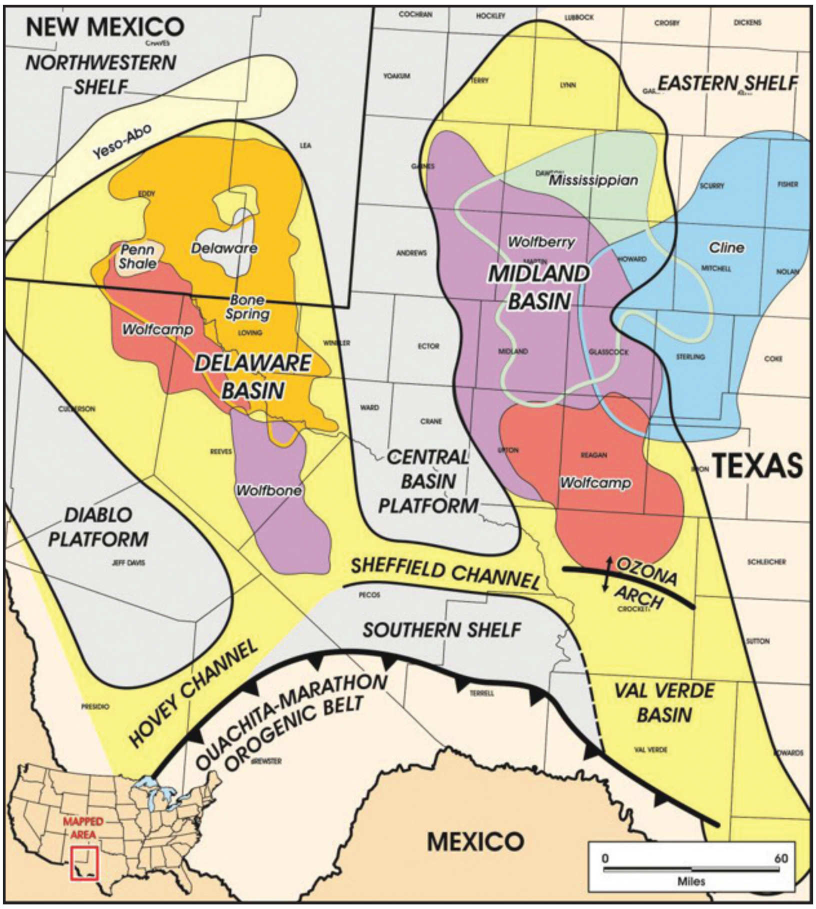
Our strategy is to drill our lowest risk locations and increase our net barrels of oil equivalent per day (BOEPD) as much and as quickly as possible.

How have high oil prices and low gas prices affected your business?

We get all of the benefit of the commodity environment for oil with little downside risk from low gas prices as we produce very high Btu gas that sells for a premium, recently as high as $7 per thousand cubic feet (Mcf).

Will you expand into any new basins or plays? Why or why not?

Not at this time. We are currently the only public pure-play Southern Delaware Basin company and we are focusing right now on our core asset area where we can exercise the highest expertise.



Abrabella Exploration is a pure-play Delaware Basin-focused company with all acreage in the oil fairway of the Wolfbone play.

Which projects will yield the best return for the company this year?

Horizontal Wolfcamp drilling, because the return on investment is highest. Given the productivity of the targets on our current drilling plan, we should see excellent returns. In addition, with our technical abilities, we will evaluate well re-entries for single and multilateral completions, allowing us to increase returns on existing wells.

What is your projected budget for the current year and how does it compare to prior years? What are the primary drivers?

For 2014 we will be doubling our efforts. We drilled five wells in 2013 and plans for this year are to drill at least 10 new wells with more than $30 million to be deployed.

Are you constrained by midstream capacity?

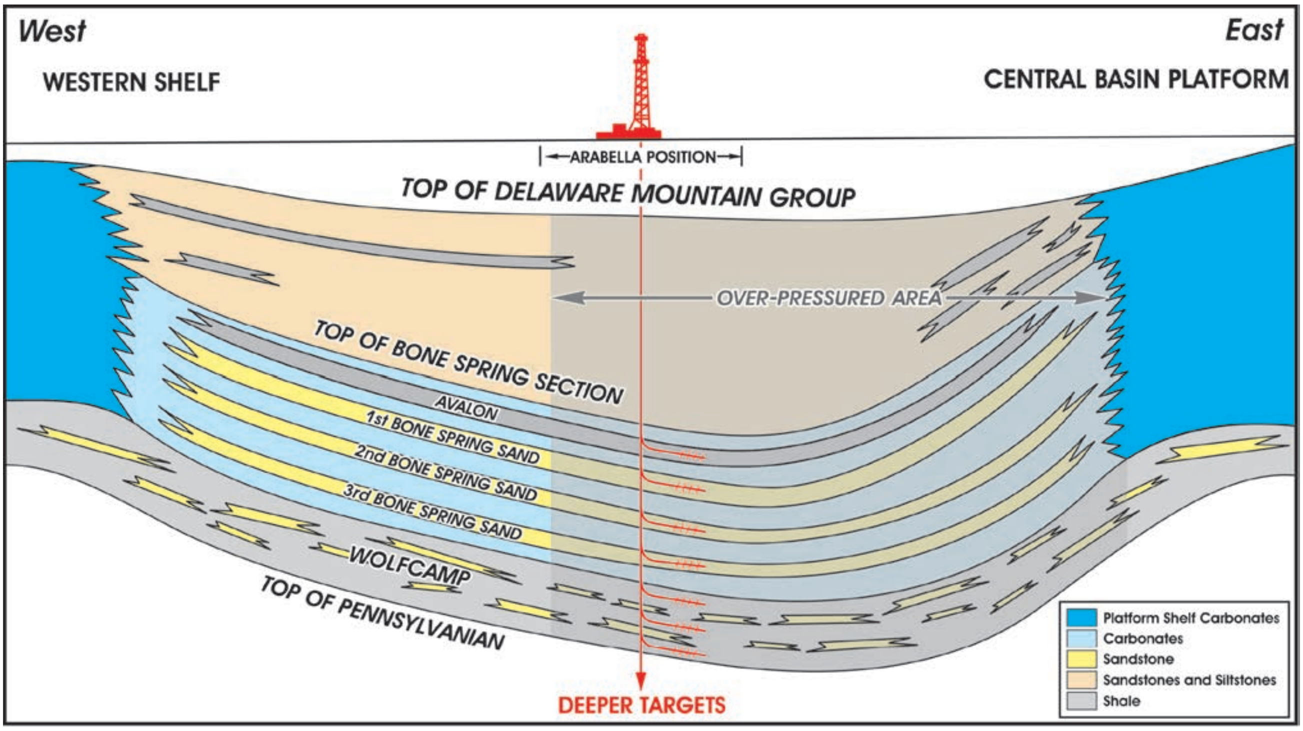
No, that is one of the benefits of operating in an established basin. There is existing infrastructure from past development and so we can access new reservoirs with existing midstream capacity largely in place.

Do you foresee any acquisitions this year?
Perhaps we will consider growth through new leaseholds in areas that complement our existing assets and build on our knowledge base and expertise in the play.

What are you experiencing regarding well costs now that your drilling plans are ramping?
With the refinement of our drilling techniques and ability to take advantage of existing infrastructure, we believe we can reduce our overall well cost this year by more than 20%.

What is the greatest challenge you face this year?
Like many of our peers, our biggest challenge is having access to capital to take advantage of opportunities.

What is the one thing you want investors to know?
We have a very strong operational team with superior technical expertise, experienced senior management and a strong board that provides knowledge and guidance. By adding those key components to an asset base that we see as the best developing basin growth opportunity in the U.S. today, we are focused on driving shareholder value.



Arabella's position is in the heart of the overpressured, stacked pays of the Delaware Basin with the potential for high-liquids-producing wells out of multiple pay zones.

BONANZA CREEK ENERGY INC.

NYSE: BCEI | BONANZACRK.COM

MARVIN CHRONISTER, interim president and CEO, is an independent investor, energy finance and operations consultant, owner of Enfield Cos. and has more than 38 years of experience in the oil and gas industry. He has previously held senior management positions with Deloitte, Kidder Peabody, Merrill Lynch, and in industry. In addition, he has also served on several boards of directors of both public and private companies.

Describe the strategy that drives the company and how you will implement it this year.

Bonanza Creek is focused on execution. We firmly believe that hitting our targets quarter after quarter builds trust and results in value accretion to our shareholders. We are fortunate to have assets that are predictable and perform within a tight range of expectations. What I find particularly compelling is the opportunity to fund significant oily production growth in Wattenberg Field using oily cash flow from Arkansas. The company benefits from significant leverage to a top-tier asset while at the same time benefiting from the stability and diversification that comes from having a second core area.

Our strategy is to prudently pursue growth rates in the top quartile of our peers by accelerating the horizontal development of the Niobrara and Codell formations in Wattenberg, today one of the premier oil resource plays in the U.S. Together with Arkansas, we forecast increasing production approximately 50% over 2013. We can accomplish these excellent growth rates while maintaining a strong balance sheet and less than 2x net debt to EBITDA.

Top quartile production growth is expected to continue into the future as our Wattenberg Field asset contains approximately 1,800 horizontal locations identified in the Niobrara B and C benches and in the Codell formation. Having drilled more than 100 horizontal wells to date, we feel confident that we have de-risked these reservoirs across the areal extent of our acreage position. We currently operate four rigs in the field and the 2014 development plan incorporates further downspacing, delineation of the Niobrara C Bench and Codell and application of extended-reach laterals.

How have high oil prices and low gas prices affected your business?

In 2013, 72% of our sales volumes and 89% of our revenues came from oil and NGLs. Also during the year, before the effects of hedging, we realized $71.45 per barrel of oil equivalent (BOE) in revenue with a resulting cash margin of approximately $52 per BOE. To protect our current and future capital programs, we actively hedge our oil volumes targeting $90 floors with a combination of collars and swaps.

Will you be expanding into any new basins or plays? Why or why not?

We have a concentrated position in the oil and liquids-weighted part of Wattenberg Field where economic returns are among the most attractive in the U.S.; at our current drilling pace we have approximately 15 years of inventory. We remain opportunistic and aggressive about expanding our position in Wattenberg Field and view that as our first priority. We are in the fortunate position to be very selective without the need to make acquisitions outside of our core areas. That said, we screen opportunities across the U.S. to stay knowledgeable about the market.

Which projects will yield the best return for the company this year?

Our success over the past few years is primarily due to the continuous expansion of the Wattenberg Niobrara/Codell play. Well costs of $4.2 million and an oil-weighted EUR of 313 MBOE achieve internal rates of return over 60% at a $90 WTI oil price, at the lease level and before income tax. A review of comparative basin economics confirms that the

Wattenberg Niobrara yields some of the highest rates of return in the country.

What is your projected budget and how many wells is that targeting, and how does it compare to 2013?
Our 2014 capital budget contemplates investing a range of $575 million to $625 million, approximately 85% dedicated to Wattenberg Field. We expect to drill 121 operated horizontal wells, including our standard 4,000-foot laterals in the Niobrara B Bench, wells in the Niobrara C Bench and Codell, extended-reach laterals and significant downspacing tests in multiple zones. Altogether, this plan increases wells drilled in Wattenberg by nearly 70% during 2013. In Arkansas, our plan is largely the same as it was last year, drilling wells targeting the Cotton Valley sands at 10-acre spacing, as well as drilling additional wells to test five-acre spacing.

Are you constrained by midstream capacity at all?
Gas processing capacity in the D-J Basin was stretched in the past year due to the dramatic increase in production volumes. As a result, all the operators in the basin have been affected by high line pressures, which have primarily impacted production from older vertical wells. However, with the addition of incremental processing capacity and compression facilities, we have seen line pressures significantly decline over the past several months and expect that the worst of the line pressure issues are behind us. We project that gas-processing capacity in the D-J Basin will nearly double by the end of 2014, staying ahead of forecasted growth.

On the crude oil side, expansion of the White Cliffs pipeline and increased utilization of rail will expand takeaway capacity out of Wattenberg Field during 2014.

Do you foresee any acquisitions this year?
We have an underleveraged balance sheet, substantial dry powder to take advantage of attractive opportunities and a track record of buying right. We appreciate the compelling economics of our current asset base and are opportunity driven as we seek out the most accretive opportunities for our shareholders.

What is the greatest challenge you face this year?
Managing Bonanza Creek's industry-leading growth. Bonanza Creek has grown substantially in production and personnel over the past few years and it is imperative to keep the culture that is responsible for that success. We have hired a lot of exceptional talent over the past couple of years and believe that Bonanza Creek is a place where people can thrive and fulfill their potential.

What is the one thing you want investors to know?
Bonanza Creek is fortunate to possess many advantages for our investors including an oily asset base with strong cash margins, exceptional growth potential and nearly 15 years of operating experience in Wattenberg Field. With high returns and short investment payback, we add incremental layers of cash flow each quarter that are highly accretive to shareholder value. Bonanza Creek is able to maintain one of the strongest balance sheets among our E&P peers while aggressively developing the company's substantial, and expanding, investment portfolio.

Any final comments or thoughts?
We are committed to maximizing shareholder value and have done this effectively since the first Bonanza Creek company in Wattenberg in 1999 and since becoming public in 2011. In 2012, Bonanza Creek was recognized as the top-performing E&P stock with over $1 billion in market capitalization, receiving *Oil & Gas Investor*'s "Excellence Award" for Best Corporate Performance. In 2013, the company was awarded the Corporate Growth Award by the Association for Corporate Growth, for its excellence in growth strategies. I believe we can expect another transformational year for the company in 2014. Wattenberg Field continues to expand and impress, and we are adding significant amounts of incremental production and cash flow that return outsized value to our shareholders. We are proud to be a significant contributor to the U.S. domestic energy renaissance and are excited about our future.

ENERJEX RESOURCES INC.

OTCQB: ENRJ | ENERJEX.COM

ROBERT WATSON JR. has served as the CEO of EnerJex Resources since it was transformed at the end of 2010. EnerJex is an independent exploration and production company focused on the acquisition and development of oil and natural gas properties in the mid-continent. The company owns leases covering approximately 100,000 acres focused in the D-J Basin and has identified more than 500 low-risk drilling locations on its existing properties. EnerJex's assets are characterized by shallow long-lived oil production and its large acreage footprint exposes the company to deep emerging oil resource plays.

Describe the company's transformation.

EnerJex was launched in early 2007 with a business plan focused on aggregating and exploiting shallow oil properties in Eastern Kansas where the market is highly fragmented. This region is dominated by small operators that do not have the financial resources necessary to achieve critical mass and economies of scale. EnerJex was initially funded with debt, and after successfully executing its business plan, the company was poised to list its shares on a major exchange and complete a large equity offering during mid-2008 when the market was robust.

Unfortunately EnerJex was unable to complete these plans before the capital markets and oil prices collapsed, and its business languished until the company was transformed at the end of 2010 through a comprehensive transaction. Through this transaction, EnerJex's board of directors and management team were reconstituted, its balance sheet was improved through the conversion of debt into common stock at $0.80 per share, it received an injection of equity capital, and it acquired additional assets located in South Texas and Eastern Kansas.

What has EnerJex accomplished since?

We have successfully turned the company around and become very profitable while demonstrating significant growth in oil production and reserves. During the past few years we have spent a lot of time high-grading EnerJex's asset portfolio in Kansas by divesting non-core assets and increasing the company's exposure to its most attractive projects. Through that process, EnerJex significantly decreased its unit operating expenses and executed a number of successful drilling programs. These assets are 100% oil and have an economic life of approximately 50 years, so they provide an excellent platform from which we can continue to grow while expanding into higher impact projects. And that is exactly what we accomplished recently through the acquisition of Black Raven Energy.

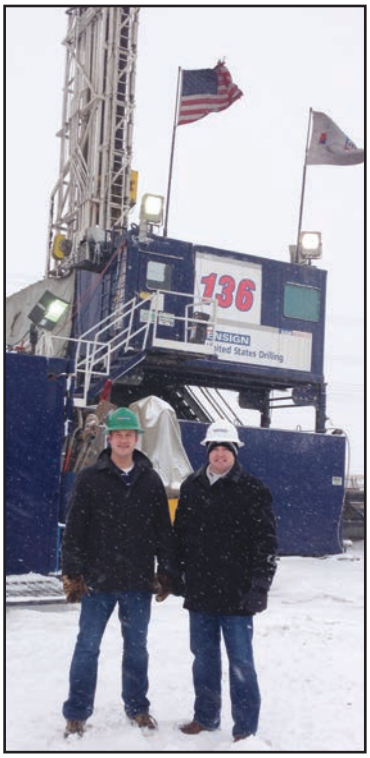
What did the company gain through its acquisition of Black Raven Energy?

EnerJex gained a substantial asset base located in the Denver Julesburg (D-J) Basin of Northeastern Colorado including two core projects. The first consists of a 100% working interest in approximately 20,000 acres covering the majority of Adena Field, which is the third largest oil field ever discovered in Colorado behind Rangely and Wattenberg, having produced 75 million barrels of oil and 125 billion cubic feet of natural gas. This acreage was unitized in 1956 by the Union Oil Company of California (Unocal) and produced more than 20,000 barrels of oil per day at its peak.

Nearly all of the producing wells in Adena Field were temporarily abandoned or shut-in during the mid-1980's when oil prices collapsed, and Unocal sold the field to a small operator shortly thereafter. Only a small number of wells have been produced since that time and approximately 130 wells are currently idle, of which we have already identified roughly 75 wells to be re-activated in the J-Sand formation or recompleted uphole in the D-Sand formation. Since completing the acquisition, we have already re-activated or re-completed approximately half a dozen wells and all of them have met or exceeded our expectations. We plan to aggressively bring this field back to life throughout 2014.

Describe the other D-J Basin assets.

The company was fortunate to have acquired a substantial natural gas asset right before prices started to



EnerJex's CEO Robert Watson Jr. and Director Atticus Lowe onsite at Adena Field observing drilling operations during a blizzard.

escalate in late 2013. This asset consists of more than 50,000 acres that have been high-graded from an original position of 380,000 acres based on seismic analysis of which EnerJex owns 114 miles of 2-D and 165 square miles (105,000 acres) of 3-D data. We have identified more than 150 high-ranked Niobrara drilling locations on our acreage based on 3-D seismic analysis which has historically yielded success rates of approximately 90% in this play. In addition, the company's acreage is well situated with direct access to the Cheyenne Hub market in immediate proximity to the 1,679-mile Rocky Mountain Express pipeline and the 436-mile Trailblazer pipeline.

EnerJex also acquired an overriding royalty interest of approximately 6% in nearly 200 natural gas wells in addition to approximately 20 wells that are owned and operated by the company. We have recently begun working over a number of these wells which contributed minimal production during the past year, and we are very pleased with the initial results. In the current natural gas price environment we believe this play is very attractive, and we are making plans to begin developing this asset.

In addition, EnerJex gained exposure to deep oil resource plays that are being pursued by a number of larger competitors. Numerous exploration wells have recently been permitted, drilled, and tested on trend with our acreage that target unconventional oil production from Paleozoic (Permian-Pennsylvanian and Mississippian) carbonates and shales. Primary targets include the Marmaton, Cherokee, Morrow, Atoka, Virgil, and Admire formations. Unconventional oil production is also being targeted in the Cretaceous Greenhorn formation. We are closely monitoring industry activity in this area and believe that success has already been demonstrated to the south of our position by companies such as Nighthawk Energy and Weipking-Fullerton Energy. A very high percentage of our acreage is held by production, so we can continue focusing on the low-hanging fruit while these plays develop.

Does the company have any other meaningful assets that you haven't mentioned?

EnerJex also owns assets in South Texas where we produce oil from the Olmos formation. Unfortunately the booming Eagle Ford Shale play has made it very difficult and less attractive for us to develop these assets due to service constraints. However, the Olmos formation has recently been exploited through horizontal drilling by other operators such as Swift Energy, and we are currently evaluating this potential along with other prospects that the company has in this area. EnerJex also owns 15% of Oakridge Energy, which owns oil and gas interests along with a large undeveloped real estate project in Durango, Colorado.

What has been the most frustrating aspect of EnerJex's turnaround for you?

By far the most frustrating thing has been the lack of stock price appreciation during the last three years. I think EnerJex has created a tremendous amount of value by increasing production, reserves and cash flow, and unfortunately this progress has not been reflected in our stock price. In my opinion we are trading at a substantial discount to the value of our existing reserves. Our team has been focused on managing the business and creating value for our stockholders, and I believe these efforts will ultimately be rewarded as we continue to execute.

EnerJex has a very small market capitalization of $55 million compared to the size and scope of its assets, and insiders own a substantial portion of the company. We have repurchased six million shares of stock during the past three years, which is unusual for a company of our size, and that is a testament to our value-oriented philosophy. We approach the value creation process with an intense and critical focus on growing our production, reserves, and cash flow in a manner that is accretive to shareholders on a per-share basis.

MILLER ENERGY RESOURCES INC.

NYSE: MILL | MILLERENERGYRESOURCES.COM

SCOTT M. BORUFF has served as a director and CEO since August 2008. Prior to joining Miller, Boruff was a licensed investment banker. He was a director from 2006 to 2007 of Cresta Capital Strategies LLC, a New York investment-banking firm that closed transactions totaling $150 million to $200 million. He specialized in structuring of direct financings, recapitalizations, M&A, and strategic planning with an emphasis in oil and gas. He was a commercial real estate broker for more than 20 years. Boruff holds a BS in business administration from East Tennessee State University.

Describe the strategy that drives the company, and how you will implement it this year.

We are focused on development and step-out drilling in Alaska close to our existing infrastructure. We have a team that has operated in the Cook Inlet for more than 20 years. We will continue to implement our strategy in the coming year by drilling PUD and step-out targets identified by previous well tests and 3-D seismic.

How have high oil prices and low gas prices affected your business?

One of the many benefits of operating in Alaska, in addition to attractive state drilling rebates, is that both the oil and natural gas markets have been strong. Prior to this year we have focused on oil drilling where we receive ANS-based pricing (which is similar to Brent pricing). This year we closed a gas-focused acquisition with a fixed contract at $7 per thousand cubic feet (Mcf). The development of our existing oil assets and the purchase of natural gas-focused assets are indicative of the strong commodity markets in Alaska and demonstrate management's commitment to investing in projects with exceptional rates of return, whether gas or oil. Going forward, we anticipate that our production will be approximately 80% oil and 20% gas.

Will you expand into any new basins or plays? Why or why not?

Our core area of expertise is in Alaska where our capital budget is focused, and also in Tennessee, where we are drilling horizontal wells. We are primarily focused on expanding in Alaska; however, we are always looking at acquisitions in other areas where we might find opportunities with strong rates of return and that require a relatively low upfront purchase price.

Which projects will yield the best return for the company this year?

Given that we currently receive 35% to 60% of every dollar we spend drilling in Alaska back from the state, and because we already have substantial infrastructure in place,

Miller Energy's Osprey Platform is part of its Cook Inlet midstream infrastructure.

our Alaska projects will undoubtedly yield the best rates of return.

What is your projected budget for the current year and how does it compare to prior years? What are the primary drivers?

We expect to spend somewhere in the range of $180 million this year, of which we expect to receive a meaningful portion back from the state. Our capital budget has been accelerating every year as we continue to add great drilling projects in which to deploy capital. In the process, we have been able to secure expanded financing at lower interest rates, with world-class capital partners such as Apollo and Highbridge.

The Kustatan Production Facility in Alaska is a state-of-the-art midstream asset that Miller Energy purchased.

Are you constrained by midstream capacity?

Not for the foreseeable future … our midstream assets include our Osprey Platform, and our processing facilities at Kustatan and West McArthur River. These were built by a prior owner at a cost of more than $300 million and they are state-of-the-art facilities. Our midstream infrastructure has the capacity to support many times our current production level and is a great competitive advantage for Miller.

Do you foresee any acquisitions this year?

Yes—in fact, we have several letters of intent out for assets in Alaska and have also acquired additional acreage in Tennessee. We expect to continue to acquire additional assets throughout this year and into the foreseeable future.

How much are you hedged?

We have hedged more than 2,000 barrels of oil per day in the near term at prices from $108 to $94, details of which can be found in our SEC filings and presentations. We have hedged with straight swaps against Brent crude to date. We like to hedge a high portion of our net production to insure our cash flow against commodity price movements. Our gas is effectively 100% hedged as it is sold under a fixed contract at $7/Mcf.

What is the greatest challenge you face this year?

Our greatest challenge perennially has been managing costs as we execute our drilling plan. That said, state tax credits mitigate any increases in capex and we have learned to be increasingly efficient as we drill. For example, in our next West McArthur River project, we intend to use an existing wellbore (WMRU-2A) to minimize costs to access a new development drilling location. The message here is that, with each well we drill, we gain additional information and experience that we put to immediate work in subsequent efforts.

What is the one thing you want investors to know?

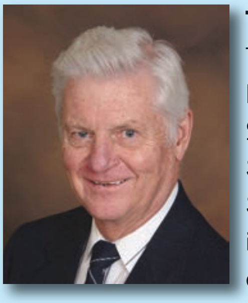
With its exceptional assets and the unusually favorable regions in which we operate, Miller is an established company with a long operating history. We're very proud of our success to date, but we think the best is yet to come.

Any final comments or thoughts?

We appreciate the chance to share some details about our company, and if anyone would like additional information, they are welcome to visit our website at millerenergyresources.com.

TORCHLIGHT ENERGY RESOURCES INC.

NASDAQ: TRCH | TORCHLIGHTENERGY.COM



TOM LAPINSKI is CEO and chairman of the board and has served in that capacity since Torchlight's inception in 2010. He co-founded Torchlight Energy Inc., Torchlight Energy Resources' wholly owned subsidiary, and led the transition to the public company in November 2010. Since 2002 he has engaged in consulting work globally in the oil and gas space. From September 1996 to June 2002, he was president of Stephens Energy International of The Stephens Group LLC. He spent more than 30 years in senior positions with Amoco Corp. both internationally and domestically (Midcontinent) before retiring. He holds a degree in geophysical engineering from the Colorado School of Mines.

Describe the strategy that drives the company, and how you will implement it this year?

We focus on liquids production and really consider our efforts to be exploitation rather than exploration projects. We only participate in areas with known geology and production. We seek out partnerships with established creditable companies that are almost always relationship based and provide entry into developmental projects where success is highly repeatable.

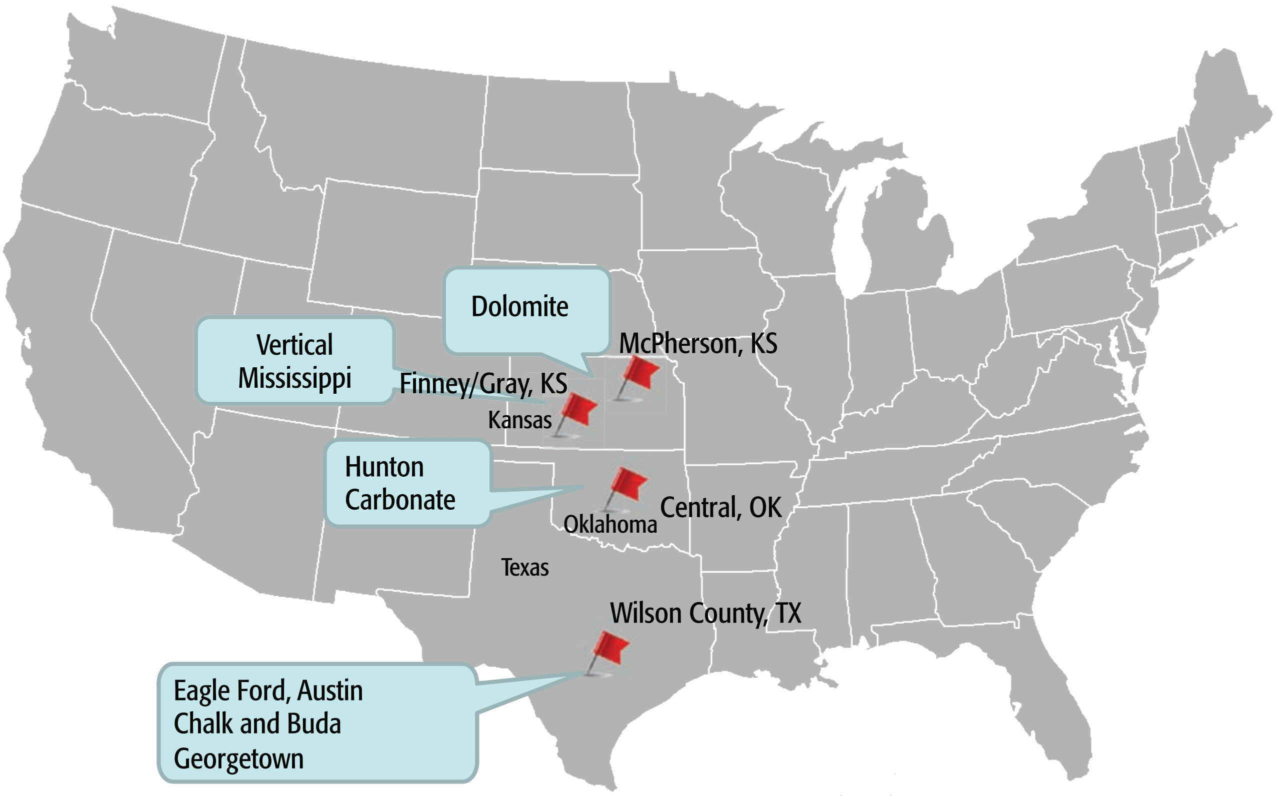
A good example of how we will implement our strategy is that we recently entered into two partnerships that provide for explosive growth with proven and experienced operators, Husky Ventures in Oklahoma and Ring Energy in Kansas. With both partnerships we have large acreage positions and are actively growing those positions.

How have high oil prices and low gas prices affected your business?

We focus on liquids-rich projects; however, if the economics were good on a natural gas project, we would consider that as well.

Will you be expanding into any new basins or plays? Why or why not?

We are opportunity driven and we will let the opportunities dictate where we go next. That said,



we are basically a Midcontinent player, but we are open to looking for opportunities elsewhere if the economics are strong enough.

What is your projected budget, how many wells does it include, and how does it compare to 2013?
Our projected capital expenditure budget for 2014 is approximately $36 million. We estimate that we will participate in close to 100 wells by the end of 2014. Our exit for 2013 on a net production basis and gross wellbore basis was approximately 1/10 of what we expect to accomplish this year.

Are you constrained by midstream capacity?
No, where we are now involved there is established production and facilities are there. There have been millions in developmental dollars spent by our partners, which has paved the way for infrastructure in our core asset areas. We reap the benefit of this minus the cost.

Do you foresee any acquisitions this year?
As mentioned, we are opportunity driven, in fact, a good example is that we have recently entered into an "area of mutual interest" and lease program with our partners covering 92,000 additional acres offsetting our existing efforts.

Do you employ a hedging strategy?
We are not currently employing any hedges. We will, however, be looking to pursue one once we achieve the production levels where it is more impactful, later this year.

What is the greatest challenge you face this year?
We have a very aggressive drilling program scheduled for 2014 and 2015 and our biggest challenge is to not let the program drive us, but that we drive the drilling program. This will mean being smart on where we drill and capitalizing on the wells that make the most impact.

What is the one thing you want investors to know?
Very simply that our company has a tremendous opportunity runway in place. Our future drilling inventory on existing assets is more than 1,000 new well locations and growing.

Any final comments or thoughts?
I would reiterate that we are focused on proven, established plays with multiple pay zones. We are currently developing proven opportunities on de-risked assets, we are cash-flow positive and expect to be covering all development out of cash flow by the third quarter of 2014. We keep to a disciplined M&A strategy where we acquire projects with strong economics that offer under-one-year paybacks. We have a proven management team with more than 175 years combined experience and large acreage positions with nearly 50,000 combined gross acres in proven and producing areas and growing. ■

AN INVESTOR'S GLOSSARY

Like many businesses, the oil and gas industry has terms, units of measure, abbreviations and other lingo that may be unfamiliar. Here are the basics.

HYDROCARBONS

Coalbed methane (CBM)–Recoverable volumes of gas from development of coal seams (also known as coal seam gas, or CSG).

Conventional gas resources–Generally defined as those associated with higher permeability fields and reservoirs. Typically, such a reservoir is characterized by a water zone below the oil and gas. These resources are discrete accumulations, typified by a well-defined field outline.

Dry natural gas–is fairly pure methane gas. It is natural gas that remains after 1) the liquefiable hydrocarbon portion has been removed from the gas stream (i.e., gas after lease, field, and/or plant separation); and 2) any volumes of non-hydrocarbon gases have been removed where they occur in sufficient quantity to render the gas unmarketable. Note: Dry natural gas is also known as consumer-grade natural gas.

Liquefied natural gas (LNG)–Natural gas (primarily methane) that has been liquefied by reducing its temperature to -260 degrees Fahrenheit at atmospheric pressure. Once a liquid, it can be more readily transported by ship to end-use markets, then regasified for movement through a pipeline.

Shale gas–Natural gas produced from wells that are open to shale formations. Shale is a fine-grained, sedimentary rock composed of mud from flakes of clay minerals and tiny fragments (silt-sized particles) of other materials. The shale acts as both the source and the reservoir for the natural gas.

Tight oil–Tight oil plays are those shale plays that are dominated by oil and associated gas, such as the Bakken shale in North Dakota.

Tight gas–Recoverable volumes of gas and condensate from development of very low permeability sandstones.

Unconventional gas resources –Reservoirs in which oil or gas do not flow without the aid of fracturing technology. The main categories are coalbed methane, tight gas, and shale gas, although other categories exist, including methane hydrates and coal gasification.

West Texas Intermediate oil (WTI or Cushing)–A crude oil produced in Texas and southern Oklahoma that is light (low density) and sweet (low sulfur). It serves as a benchmark or "marker" for pricing a number of other types of crude streams. It is physically stored and traded in the domestic spot market at Cushing, Oklahoma, the primary oil trading hub in the U.S. Nymex prices are referenced at Cushing as well, for paper trades. Nymex, the New York Mercantile Exchange, is a futures market in which a seller promises to deliver a given quantity of a commodity at a specified place, price, and time in the future. Oil, natural gas and other related commodities are traded on Nymex.

Wet gas–includes all the natural gas liquids (see below) and typically has a higher Btu (British thermal unit) content of at least 1,500 Btu.

COMMON MEASUREMENTS

M is the Roman numeral for a thousand. Production of 67 Mcf of gas per day is 67,000 cubic feet. **MM** represents a million, so production of 67 MMcf of gas per day is 67 million cubic feet per day. **B** represents a billion, thus production of 67 Bcf of gas per day is 67 billion cubic feet. T represents a trillion, so proved reserves of 2 Tcf of gas are 2 trillion cubic feet of gas.

Bbl represents a barrel, or 42 gallons of oil. Production of 80 Mbbl of oil per day is 80,000 barrels.

Cf represents cubic feet and is usually the measurement of natural gas, as in "a well produces 2.5 MMcf per day."

Cfe represents cubic feet of gas equivalent. It is usually the measurement of the mathematical combination of natural gas and oil or gas liquids, ranked together by heating content or Btu value. The conversion is usually 10,000 or 6,000 cubic feet of gas per one barrel of oil or gas liquids. (The ratio usually reflects the recent market value of 1 Mcf of gas in comparison with 1 barrel of oil or gas liquids.)

Thus, 10 MMcfe is 10 million cubic feet of gas equivalent. If the true mixture is 50% natural gas and 50% liquids (oil or gas) and the mathematical rate is 10:1, then 10 MMcfe consists of 5 MMcf of gas and 500 barrels of oil or gas liquids.

BOE–is barrels of oil equivalent. It is usually the measurement of a mathematical combination of natural gas and oil or gas liquids. The conversion is usually 10,000 or 6,000 cubic feet of gas per one barrel of oil or gas liquids. Thus, 10 MMBOE is 10 million barrels of oil equivalent. If the true mixture is 50% natural gas and 50% liquids (oil or gas) and the conversion rate is 10:1, then 10 MMBOE consists of 500 Bcf of gas and 5 million barrels of oil or gas liquids.

Cf/d–is cubic feet of gas per day. Another abbreviation of this is cfpd.

AN INVESTOR'S GLOSSARY

Bbl/d–is barrels of oil per day or barrels of gas liquids per day. Another abbreviation is bpd.

Btu–a British thermal unit, measures stored energy, primarily used to describe the heat content of natural gas. One million Btu is generally the equivalent of 1,000 physical cubic feet; however, some natural gas contains fewer or more impurities than others and therefore has a higher or lower stored-energy content and, thus, market value. Natural gas is traded on Nymex in Btu rather than cubic feet.

FIELD TERMINOLOGY

A **dry hole** occurs when no oil or gas is found in the well, or the quantity of oil or gas that was found is insufficient to justify the expense of bringing the well into production.

A **delineation well** or appraisal well is drilled near a discovery well. It helps define the boundaries of the oil or gas reservoir, and assists in deciding whether to incur additional spending to drill more wells to fully develop the field and produce the oil or gas. A delineation or appraisal well can be deemed a dry hole.

A **development well** is drilled where there has been a discovery, as a result of an exploratory well, and is usually drilled after delineation or appraisal. Oil or gas is produced from this well. A development well is rarely a dry hole.

Downstream Refining, distribution and retailing of oil and gas products.

EUR or estimated ultimate recovery–is the amount of oil or gas estimated to be produced over a well's lifetime, prior to plugging and abandoning the well because it is no longer economic to produce.

An **exploratory well** is drilled to find oil or natural gas where none has been produced before.

A field is an area that contains a single reservoir or related reservoirs with the same geological structural feature or stratigraphic condition. It may contain dozens or hundreds of wells.

Fracture stimulation (frac job)–Also called hydrofracing. An operation that involves large pumps that inject, at high pressure, many gallons of water or other fluids, and pounds of proppant (sand or ceramic) down the well casing and out into the formation. The mixture fractures the rock so oil or gas can be released through the fractures and flow up the well bore.

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Horizontal drilling–Drilling a horizontal section in a well (used primarily in a shale or tight oil well), typically thousands of feet in length.

Midstream–Downstream of the wellhead, including gathering, gas and liquids processing, and pipeline transportation.

Net pay–is the thickness of productive oil- or gas-saturated rock that has been encountered during drilling. A company may drill a 15,000-foot well and encounter 300 feet of net pay in several intervals of 100 feet each, for example. The development well is designed to produce only from the net pay.

Permeability–The capacity of a rock to transmit fluids. A tight rock, sand or formation will have low permeability and thus, low capacity to produce oi or gas, unless the well can be fracture-stimulated to increase production.

A **play or trend** is an area or region where there is a great deal of drilling and production activity and involves a group of geologically related fields and prospects. A play is a set of known or postulated oil and gas accumulations sharing similar geologic, geographic, and temporal properties, such as source rock, migration pathway, timing, trapping mechanism, and hydrocarbon type. A play differs from an assessment unit; an assessment unit can include one or more plays. A play is often used to refer to a natural gas accumulation, i.e., a natural gas shale play, an oil play.

Porosity–The volume of small to minute openings in a rock that allow it to hold fluids.

A **prospect** is a lease or individual well that may be drilled because geology indicates it will probably be productive.

Prospective acreage–is where there are geologic, seismic and/or other reasons to believe the subsurface may contain oil or gas. Drilling will be necessary to form a conclusion.

Proved acreage–is where the existence of oil or gas has been proven by drilling exploration and appraisal wells.

Proved reserves–are reserves of oil or gas that can be economically produced under current economic conditions and commodity prices, and given current technologies, within five years, according to complex guidelines in force by the Securities and Exchange Commission (SEC).

Proved developed reserves–are reserves that can be expected to be recovered through existing wells, with existing equipment and known operating methods.

PUDs–Proved undeveloped reserves that may be soon drilled and placed into production using existing technologies, recovered from new wells on undrilled, proved acreage, or from existing wells where a relatively major expenditure is required for completion.

Reservoir–A porous and permeable subsurface formation that contains oil or gas and is surrounded by rock that separates the oil or gas contents from other reservoirs.

Seismic–An earthquake or earth vibration including those that are artificially induced.

Stripper well–A gas well that produces 6 Mcf a day or less, or an oil well that produces 10 barrels a day or less. Thousands of such wells are found in 29 producing states. (See National Stripper Well Association at nswa.us.)

Upstream–Oil and gas extraction, including exploration, leasing, permitting, site preparation, drilling, completion, and long-term well operation.

Wellbore–That part of a well that is below the surface. Hole diameters vary with the type and purpose of wells.

AN INVESTOR'S GLOSSARY

OFFSHORE TERMS

Deep water–is water greater than 1,000 feet or 305 meters deep.

FPSO–Floating production, storage and offloading vessel, a ship that collects oil production, stores it, then offloads it into tankers that take it to shore.

Floater–Nickname for any offshore drilling rig that floats as opposed to being moored to the sea floor.

Jack-up rig–A self-contained combination drilling rig and floating barge, fitted with long support legs that can be raised or lowered independently of each other. The first one was built in 1954.

Outer Continental Shelf–Offshore federal domain divided into lease blocks that may be leased at periodic federal lease sales under a sealed bid system. Such leasing began in 1954. These blocks are from 3 to 230 miles offshore. (Waters less than 3 miles from shore are owned by the states and are called state waters.) There are more than 7,500 leases on the OCS.

Platform–Either a drilling or production facility offshore.

Shallow water–is less than 1,000 feet or 305 meters deep, according to definitions of the U.S. Dept. of the Interior, which manages offshore activity through two agencies: the Bureau of Ocean Energy Management (BOEM) and Bureau of Safety and Environmental Enforcement (BSEE).

Ultra-deepwater–is water deeper than 5,249 feet or 1,600 meters. Companies are now able to drill in water up to 10,000 feet deep, with wells going as deep as 27,000 feet below the subsea surface.

INTERESTS AND CONTRACTS

Gross acres or gross wells–are the total acres or wells in which a working interest is involved. Net acres and net wells are calculated by factoring in working interest. For example, if a company's working interest in 100,000 acres is 30%, then its ownership is 30,000 net acres. If the company's working interest in 100 wells is 45%, then its ownership is 45 net wells.

Farm-in or farm-out–is an agreement in which the owner of a working interest in an oil and gas lease gives some or all of that interest to another party (company) that will drill on the leased acreage. The party farming out the working interest usually retains a royalty or reversionary interest from the party that is farming in.

Royalty interest–is the right to receive a specified amount of the gross income or production from a mineral property. A royalty interest, as opposed to a working interest, is not charged with the costs of exploration or development drilling, or operation, and is therefore treated as a nonoperating interest for federal income tax purposes.

Working interest–is the percentage of ownership that the company has in a joint venture, partnership, consortium, project, acreage or well. A working interest owner pays his share of the well drilling and operating costs, and shares in the cash flow.

NATURAL GAS LIQUIDS

Compression–To move natural gas through pipelines, it must be compressed to save space and push it further down the pipeline. Most gas is compressed at 1,000 psi (pounds per square inch).

Frac spread–A measure of profitability for processing plants. It's the difference between the sales price of natural gas liquids (the processing output) and the cost of natural gas (the processing input).

Natural gas processing plant–Facilities designed to recover natural gas liquids from a stream of natural gas that may or may not have passed through lease separators and/or field separation facilities. These facilities control the quality of the natural gas to be marketed. Cycling plants are classified as gas-processing plants.

NGLs or natural gas liquids–Usually measured in barrels rather than in cubic feet. Six marketable products are produced from the natural gas stream at the wellhead. These are separated at a gas-processing plant. During times of high gas demand, the Btu content of ethane may be more valuable left in the natural gas stream, rather than being sold as a separate product.

The components of NGLs are: ethane (chiefly used to produce ethylene in petrochemical plants); propane, used as a heating source and some vehicle fuel; butane, sold as bottled fuel or as a petrochemical feedstock; isobutane, used as a petrochemical feedstock; LPG or liquefied petroleum gas, and used as fuel; and natural gasoline, an NGL with vapor pressure between that of condensate and LPG. It is used as a feedstock for nylon, plastics and cosmetics. LNG is liquefied natural gas.