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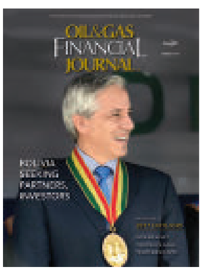

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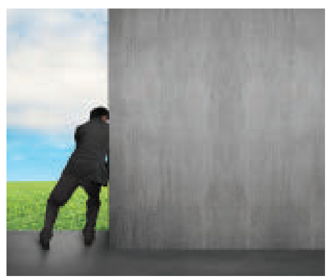

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Get up-to-date news and featured content on OGFJ.com daily. Wood Mackenzie forecasts the investment cycle will show the first signs of growth in 2017 since 2014 and final investment decisions (FIDs) will double, compared with 2016. Get details here. The Texas petroleum economy recently reached the two-year contraction point, according to the Texas Petro Index, a service of the Texas Alliance of Energy Producers. Read more here. This, and much more, every day, on OGFJ.com.

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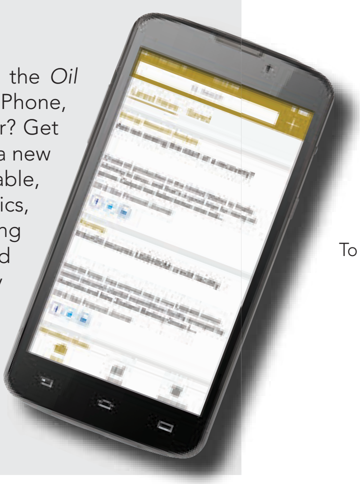

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Data breaches and cyber-attacks

DON STOWERS
CHIEF EDITOR – OGFJ

CYBER-ATTACKS CURRENTLY cost businesses approximately $400 billion a year globally, and experts at SAP predict the costs will reach $90 trillion by 2030. That's right "trillion" – with a "t." To counter this threat, SAP says oil and gas companies should focus on prevention, detection, and resiliency. There is an urgent need to take proactive measures to reduce vulnerabilities and protect data at all points.

To any who doubt the value in guarding against data breaches and intrusions in their organization, I suggest they talk to President Hillary Clinton.

A new survey from Accenture reveals that one in three cyber-attacks results in a security breach, and the number of cyber-attacks is on the rise, say experts on the topic. Despite this increasing threat, there is still a struggle to convince corporate executives of the seriousness of the problem and to take the necessary steps to prevent attacks that could be disastrous for their companies.

"To any who doubt the value in guarding against data breaches and intrusions in their organization, I suggest they talk to President Hillary Clinton."

Reports from various sources have pointed out that the energy sector is lagging behind other industries in protecting databases and control systems from attack. Oil and gas companies face the threat of security breaches that could damage their reputations, cause major business disruptions, and result in huge financial losses.

Writing in this issue of OGFJ (pgs. 38-39), Philip Bezanson and Carolyn Robbs Bilanko of Bracewell LLP say that data breaches can trigger investigations by the US Federal Trade Commission, the US Securities and Exchange Commission, the US Department of Justice, and state regulatory agencies, as well as class-action lawsuits and shareholder derivative actions.

"The inevitability of cyber-attacks behooves directors and officers at oil and gas companies to allocate adequate funds and time to implement cyber security risk-management strategies that protect sensitive business information and property and minimize the company's legal exposure," write Bezanson and Bilanko.

In their article, "Legal liability from cyber-attacks," the attorneys offer tips on how energy companies can mitigate their legal liability from such attacks.

The Accenture survey revealed the lack of effectiveness of current security efforts by many companies and the inadequacy of existing investments in security. The length of time it takes to detect these security breaches often compounds the problem, as more than half of respondents disclosed that it takes months to detect sophisticated breaches, and as many as a third of all successful breaches are not discovered at all by the security team.

"Cyber-attacks are a continual operational reality across every industry today, and our survey reveals that catching criminal behavior requires more than the best practices and perspectives of the past," says Russell Thomas, Canadian cyber-security lead for Accenture. "There needs to be a fundamentally different approach to security protection, starting with identifying and prioritizing key company assets across the entire value chain. It is also clear that the need for organizations to take a comprehensive end-to-end approach to digital security – one that integrates cyber defense deeply into the enterprise – has never been greater."

Cyber threats come from inside the organization as well as from outside hackers. Malicious insiders sometimes steal, manipulate, and destroy data, which has caused companies to invest in forensic data analytics (FDA) tools to investigate incidents and manage risk. An EY survey of 665 executives concluded that internal fraud risk ranks highest among their concerns at 77%, followed by cyber breach or insider threat risk at 70%.

David Stulb, EY's global leader of Fraud Investigation & Dispute Services, advises: "For organizations, the threat of cybercrime is an everyday reality, posing a dynamic and relentless challenge. This means that boards and senior management need to incorporate FDA as a critical component of their risk management and compliance programs. This is especially critical given the current regulatory enforcement environment and market reaction to instances of alleged corporate fraud, bribery, and cyber breach."

In an article in the November issue of OGFJ, "Cyber-attacks on the rise," Udi Edry, CEO of Nation-E in Santa Clara, Calif., says that, "As cyber-security continues to advance at an incredible pace, it is matched by the incessant efforts of hackers to mount perilous attacks against global corporations, government agencies, and local industrial enterprises." He suggests that oil and gas infrastructure may be the "new battlefront" in the war against terrorism.

Edry notes an upswing in investment by key industry players in cyber protection for energy-related critical infrastructure and installations.

In 2012, a malware cyber-attack on Saudi Aramco was responsible for overwriting the hard drives of as many as 30,000 work stations of Saudi Aramco and RasGas. The attack apparently was intended to stop oil and gas production in Saudi Arabia and prevent the flow of the country's oil and gas resources to international markets. Fortunately, it was not successful. But the next time a cyber-attack is launched against a petroleum company, the consequences could be dire if the company isn't properly prepared to defend itself. OGFJ


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When stakeholders resist

WHAT HAPPENS WHEN STAKEHOLDERS SUPPORT THE END GOAL BUT REJECT YOUR APPROACH?

BRENDAN SMITH, NORTH HIGHLAND, HOUSTON

THESE HAVE BEEN CHALLENGING TIMES in the oil and gas industry. The new reality of $50 per barrel oil has required significant internal changes in most industry players to become leaner and meaner. This survival strategy for a downturn mandates change, and lots of it, for businesses.

Most change management efforts are focused on countering resistance and building advocacy for the end-state of the change. For instance, we often deal with resistance to new technology, redesigned business process or new operating models. This is a Type One resistance or the first kind of resistance firms are likely to experience.

But, what happens when stakeholders are optimistic about those end-states, but are resistant to the way the change is being implemented? This Type Two or "second" kind of resistance happens when stakeholders instead reject your messaging, the implementation approach, or your sponsor, but still support the end goal change, indicating change management is the problem.

Here are a few examples of this phenomenon and suggestions for how leaders in the oil and gas industry (and change managers in particular) might respond:

Scenario: I don't really understand it. Stakeholders will tell you the change sounds like a great idea, has a noble goal, and is something we really need. Most employees, shareholders and other impacted persons are all on board with making the tough choices to survive in a low commodity price environment. But, they have no idea what the end-state is going to look like. Downsizing may be tangible, but many of the complex restructuring efforts that are undertaken are frustratingly vague. So, even when the goal and the benefits are obvious and exciting to stakeholders, what the real future-state will look like is often still a mystery in their eyes. This can be especially true when introducing new operating models or business processes that are conceptual at the start of the transition effort and not yet fully defined.

Solution: Keep it simple, use analogies for complicated concepts, and get someone from the operations side to sit with you and translate technical terms or concepts. Part of the problem may be the overuse of jargon, especially technical terminology. Whenever possible, put communications in the vernacular used by stakeholders and illustrate the solution in the user's operational context. Also, this can be an occasion where a graphic might be a more effective medium to communicate the future state. After all, a picture is worth a thousand words.

Scenario: I don't like how you're doing this. Change deals in the human dimension. People don't like when change is imposed upon them. You may hear feedback from stakeholders such as "I've not been included, consulted, or involved." Or worse, you might hear employees or business partners say that "You treat me like I'm stupid." These kinds of comments may be indicative of serious gaps in the communications and engagement components of your implementation approach. In essence, the issue may be the approach you're using to achieve the change vision, and not necessarily the end goal itself.

Solution: Increasingly, change managers are taking a more democratic approach to change management activities. In this sense, there is a move to involve stakeholders more fully in the design of solutions and, particularly, in the application of change management. This approach means that rather than imposing change on stakeholders, they instead become engaged in creating and living the change. Such an approach can help alleviate resistance that may be coming from how you're implementing the change.

Scenario: I don't trust you! In this case, your sponsor or leader may be the risk. Clearly if you're hearing comments around a lack of trust in your change leaders, it means somebody got burned before and there's some unfortunate history there. Your sponsor is the face of the change and if they are a source of mistrust and resistance, you have a real problem. Sometimes an individual can be the tangible focus of resistance even if there's more hostility built up regarding organizational cultural issues that are personified by the sponsor. Again, stakeholders might like the goals of the change, but they don't necessarily like the leaders of the change.

"Take a very close look at the resistance or change challenges you face in your transformation. You might be surprised by the nature of stakeholder pushback. A few simple adjustments to how you are implementing the change management efforts might easily pivot things in your favor and help your business weather the volatile downturn energy environment."

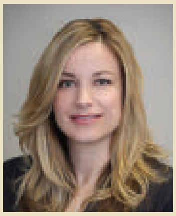
Solution: The obvious solution is to change the sponsor. This may not be a palatable solution because that sponsor might truly be the right person for the job (they know the solution, have the bandwidth, and are skilled at getting things done). As an alternative, you might consider introducing some other faces for the change. You can deploy change agents/change ambassadors/change liaisons who can supplement the sponsor by being additional visible faces of the change who could counter any resistance to the personality of the sponsor. Your sponsor still needs to be the leader and the one who can marshal resources for the change, but by supplementing with change agents you can put other faces in front of stakeholders who can mitigate this risk. You may also need to examine what the organization's history has been regarding transformation efforts and whether those have soured employees.

Take a very close look at the resistance or change challenges you face in your transformation. You might be surprised by the nature of stakeholder pushback. A few simple adjustments to how you are implementing the change management efforts might easily pivot things in your favor and help your business weather the volatile downturn energy environment. OGFJ

ABOUT THE AUTHOR

Brendan Smith is a management consultant with North Highland in Houston. He has more than 23 years of consulting experience and is an expert in the fields of organizational transformation, change management, program management, communications, strategy, and organizational design. Smith has led multiple large-scale transformation initiatives over his career across domains including transportation, human resources, acquisition/purchasing, facilities management, and information technology in industries such as healthcare, defense, government, aerospace, chemicals, and energy.

Oilfield service pricing on the move



MIKAILA ADAMS
EDITOR – *OGFJ*

OILFIELD SERVICE companies, like exploration and production companies, have been battered by the industry downturn, offering deep concessions to customers to stay afloat. Some didn't manage. One hundred and ten North American oilfield services providers filed for bankruptcy from the beginning of 2015 to December 2, 2017, according to Haynes & Boone. For the rest, 2017 may offer a glimmer of hope as oil prices steady and E&Ps cautiously, but optimistically, advance drilling and production plans.

For our January issue, EY's Deborah Byers told me there'd likely be "a lot of pressure" on service companies to "deliver some of the efficiencies and price reductions that they've given up as concessions" when the market revives in 2017. Efficiencies, sure, but what about price concessions? Service companies will have to ratchet up prices. When and how much? Much of what I've heard is rooted in supply and demand, and it is starting to take shape.

"Oil service pricing is rapidly moving higher in North America due to a lack of available equipment and labor," Evercore ISI analyst James West told me via email in late January. "The bottom was established in 3Q with pricing rapidly moving up to start this year as E&P companies struggle to secure equipment necessary to provide the production gains they promised their shareholders."

In keeping with that sentiment, Wood Mackenzie reported in late January that service costs will increase in 2017, but not to 2014 levels. Offering a few specifics, WoodMac said its "base case well cost inflation is 10% with pressure pumping and proppant poised for the strongest recovery. A risk to the upside comes down to region and price. Firms with assets in West Texas could realize greater margins, and have already felt a labor/equipment pinch in Q4 2016 driven by demand. Expect inflation to rise as South Texas and Williston Basin assets compete for resources in a $55-$60/bbl price environment."

Further, WoodMac points to 20% cost inflation on pressure pumping, "underpinned by increasing frac intensity and job size on the demand side, as well as cannibalization and lack of repair/maintenance on the supply side. Downside to our view is 1) more IPOs like Keane Group flooding the market and 2) more stacked equipment re-instated rather than retired (we assume roughly 30% of peak horsepower exits permanently in our base case)."

The proppant market saw "pricing power" already in 2016, WoodMac said, noting inflation expectations of approximately 15% in 2017, as proppant demand is likely to "increase heavily in 2017 on account of 1) continued gains in rig count and subsequent fracking, 2) continued DUC drawdown (30% lower breakevens compared to new wells), and 3) flat to rising proppant loading. As demand, and inevitably prices, for low-cost proppant rises, we expect more operators to draw from a supply of competitively priced medium to high-cost proppant."

Drillers may see "a modest cost inflation of up to ~10%," backloaded to H2 2017. WoodMac views pricing power for this group "limited" as "1) more long-term contracts from 2014 are rolled off into spot market pricing and 2) excess high-spec rig capacity is not fully absorbed until late-2017. With rig efficiencies improving during the downturn, operators appear to be less concerned about rising day rates."

E&Ps are discussing the issue and various scenarios. From a late January stint in Dallas and Midland during which Evercore ISI analysts met with Permian E&Ps and FTSI, a private pressure pumper, a glimpse of thoughts on the matter: "From an operator perspective, we heard a range of expectations regarding service cost inflation with one operator acknowledging the inevitable, another highlighting how increased efficiencies (piping water, pad drilling, bigger wells) can offset inflation, and another claiming that better well performance (through diverters, longer laterals, higher proppant) can offset the brute impact of cost inflation." RSP Permian gave "the most intellectually honest response," the analysts said, when it offered that "after oil increased by +20% it's only natural to expect service costs to rise by a similar magnitude, and that is acceptable given per well NPVs would increase on an absolute basis."

In late January, Seaport Global Securities (SGS) analysts met with various E&P companies in Denver, and the takeaway was similar. "Overall, a hyper focus and consistent message on service costs – a 10% increase YoY was expected from just about everyone," they said. As expected, the companies will keep an eye on costs. Synergy Resources told SGS that it will strive to "offset some upcoming service cost inflation with savings from incremental operational efficiencies," SGS reported, noting a "new benchmark on a recent 12K ft. lateral, TD'ed in a record 7.4 days."

Going back to the WoodMac report, price increases will mean different things to different E&Ps. "When activity increases, being vertically integrated offers insulation from spikes in service pricing. Oasis Petroleum and Pioneer Resources have their own pressure pumping fleets; EOG and Southwestern Energy have their own sand mines. Companies like these will be shielded, to some extent, from extreme re-inflation driven by service supply shortages," the firm said.

E&P companies are strategizing to offset the costs. What about investors? "For investors looking for a tangible moment when they can expect the return of service cost inflation, we would focus on the rig count. We believe there are about 800 of the latest generation drilling rigs in the marketplace today. A ramp in activity toward that level would embolden service companies to seek stronger pricing for services," offered Mizuho Securities USA Inc. in a mid-January note. As of this writing, the US rig count reported by Baker Hughes was 712. OGFJ

BRIEFS

CHEVRON TO SELL INDONESIAN, PHILIPPINES GEOTHERMAL OPERATIONS

Chevron Corp. subsidiaries have entered into a sales and purchase agreement with Star Energy Consortium to sell Chevron's Indonesian and Philippines Geothermal assets.

In Indonesia, Chevron subsidiaries operate the Darajat and Salak geothermal fields in West Java. In the Philippines, company subsidiaries have a 40% equity interest in the Philippine Geothermal Production Co. Inc., which operates the Tiwi and Mak-Ban geothermal power plants in Southern Luzon.

WOODMAC: NEW PROJECTS IN THE UPSTREAM INDUSTRY TO DOUBLE IN 2017

Wood Mackenzie forecasts the investment cycle will show the first signs of growth in 2017 since 2014 and final investment decisions (FIDs) will double, compared with 2016.

Malcolm Dickson, a principal analyst for Upstream Oil and Gas for Wood Mackenzie, said: "2017 will demonstrate how efficient the oil and gas industry has become; showing projects in better shape all round."

According to Wood Mackenzie's global upstream outlook for 2017, confidence will start to return to the sector, with exploration and production spend set to rise by 3% to US$450 billion. Though a corner is being turned, this is still 40% below the heady days of 2014. At the forefront of the revival will be US tight oil. Costs will continue to fall in 2017, though only marginally. But for all the pain of the downturn, a leaner industry is starting to emerge.

Capex deflation has averaged 20% over the past two years. With service sector margins wafer thin, Wood Mackenzie believes there's now only room for small reductions and capital costs are expected to fall by an average of 3% to 7%.

According to Wood Mackenzie, the five things to look for in 2017 are:

- Global investment will rise, reversing two years of severe decline.
- FIDs will double and deep water is back on the agenda.
- Costs will bottom out as an efficiency boom takes hold, but more work is required.
- Fiscal rules need to improve to attract scarce investment.
- Rise in global investment in 2017 after two years of severe decline

"The global investment cycle will show the first signs of growth in 2017, bringing the crushing two-year investment slump to a close," said Dickson.

US tight oil, and the Permian basin in particular, will lead the way, distinguished by low breakevens, scale and flexibility. US Lower 48 spend is set to grow by 23%, to US$61 billion, with upside if oil prices rise strongly and US Independents are emboldened by a Trump presidency.

Number of project FIDs to double

Wood Mackenzie predicts the number of FIDs will rise to more than 20 in 2017, compared with nine in 2016. This is still well short of the 2010-2014 average of 40 a year. But these are generally smaller, more efficient projects, and capex per barrel of oil equivalent (boe) averages just US$7 per barrel, down from US$17 per barrel for the 2014 projects.

"Companies will get more bang for their buck as development incremental internal rates of return (IRR) will jump from 9% to 16%, comparing 2014 to 2017," said Dickson. "This is in part a result of a shift in capital allocation away from complex mega projects towards smaller, incremental projects in the Canadian oil sands and deep water."

A leaner industry has emerged from the downturn

"Nowhere is the mantra 'doing more with less' more evident than onshore US. There has been a dramatic increase in efficiency in the sector, exemplified by the drillers, who are managing to complete wells up to 30% quicker," he added.

Wood Mackenzie says as the tight oil sector heats up further, the spectre of cost inflation looms in 2017. But any increase in costs may well be offset by further efficiency gains in earlier-life plays. For example, there's still potential for a further improvement in drilling speed of 20% to 30% in some early-life tight oil plays.

Deepwater will spring back to life in 2017, but more cost cutting is needed in long run

Deepwater FIDs will be a leading indicator the tide is turning. The best development assets will hold their own against tight oil, especially as more risk-averse tight oil operators start to screen opportunities under higher discount rates.

According to Wood Mackenzie's global upstream outlook, projects slated for FID in 2017 are largely looking good, but the longer-term deepwater pipeline is more challenged. Of the 40 larger pre-FID deepwater projects, around half fail to hit 15% IRR at US$60 a barrel.

"The industry has selected the best projects to optimize and take forward. In 2017 it will have to turn its attention towards optimizing the next wave of developments to get them sanction-ready," said Dickson.

Fiscal terms will need to improve to attract scarce investment

Graham Kellas, senior vice president of global fiscal research at Wood Mackenzie, said: "Some governments will be tempted to increase tax rates, but those with uncompetitive fiscal regimes will have to make changes to ensure they can attract still-scarce new capital. Getting the risk-reward balance right will be a critical factor in attracting scarce investment capture in 2017, even for resource-rich hotspots such as Iran and Mexico."

2016 OFFSHORE-DISCOVERED LIQUIDS 90% LOWER THAN IN 2010

Rystad Energy concludes that the 2016 total offshore-discovered liquids resources reached only slightly below 2.3 billion bbl, 90% lower than in 2010. This drop is most significant to the overall decline in discovered volumes; in fact, total global discovered volumes (oil & gas combined) are at an all-time low since the 1940s.

In 2016, the average liquid content in the discovered resources was merely ~40%. Even more tellingly, the replacement ratio* for liquids in 2016 was below 10%. For comparison, the replacement ratio for liquids in 2013 was as high as ~30%.

There are a few key countries that influenced offshore discovered liquids development:

- Brazil – The country experienced a new 'golden age' thanks to multi-billion bbl discoveries made in the beginning of this decade. Among the largest discoveries Lula (formerly known as Tupi), Libra and Buzios stand out. Combined, these discoveries hold ~20 billion barrels of liquids. All of the large discoveries made in Brazil in the past decade are located in the large pre-salt basins, especially Santos and Campos. However, the success story from 2010 did not repeat itself as 2016 approached. This is due to a combination of factors such as limited capital to develop projects that were previously discovered or local content regulations, among others.
- Norway – The offshore exploration on the NCS showed disappointing results in 2015 and 2016, with no discovery surpassing 100 million bbl of discovered resources. In fact, since the discovery of Johan Sverdrup in 2011, there has not been another sizeable discovery made on the NCS. Exploration results were particularly discouraging given the number of exploration wells in the region, which remained relatively stable within the range of 45 to 65 exploration wells per year, since 2010.
- US – In GoM, the discovered volumes have remained relatively stable compared to the development in other offshore regions.
- Russia – In Russia, the largest discovery in the past years was Universitetskaya, discovered in 2014. This discovery could potentially hold over 2.3 billion barrels of resources, of which ~1 billion bbl are liquids alone. Russia continues to be dependent on foreign technologies to be able to develop its offshore discoveries, especially in the arctic areas. At the same time, exploration activities in offshore arctic regions are currently on hold due to sanctions and generally less interest in the investment-heavy exploration due to low oil price.
- Angola – The past five years have been positive for Angola in terms of exploration results. In 2016, there were three significant discoveries made: Golfinho (operated by Sonangol), being the only large oil discovery; and Katambi and Zalophus (operated by BP and Sonangol, respectively), being the largest gas discoveries.
- Guyana – Exploration results in Guyana were particularly encouraging in 2015, with the 1 billion bbl discovery – Liza. Liza was the largest oil offshore discovery made in that year, representing ~30% of the total offshore discovered liquids in 2015.

Rystad Energy expects the exploration activity to slowly pick up from 2018, allowing for more discoveries towards the end of this decade and beyond. At the same time, some of the recent license awards could open new prospective exploration regions, e.g. the deepwater license award in Mexico.

*The replacement ratio measures the amount of discovered resources during the year relative to the amount of liquids product in the same year globally. It disregards the production start-up date for the discoveries.

COBALT NOTES PRELIMINARY APPRAISAL WELL RESULTS AT NORTH PLATTE

Cobalt International Energy Inc. has completed drilling operations on the North Platte #4 appraisal well. Preliminary results indicate that the well encountered approximately 650 feet of net oil pay, which is greater than the approximately 550 feet of net pay found in the North Platte #3 appraisal well. The North Platte #4 initial appraisal results also indicate high quality Inboard Lower Tertiary Wilcox reservoirs on the eastern flank of the North Platte field.

Cobalt is currently evaluating log data, fluid samples and pressure information and is preparing for a geologic sidetrack to further analyze the extent of the eastern flank. Cobalt, as operator, owns a 60% working interest in North Platte. TOTAL E&P USA Inc. owns the remaining 40%.

BRIEFS

EXXONMOBIL MAKES DISCOVERIES OFFSHORE GUYANA

ExxonMobil has encountered positive results from its Payara-1 well offshore Guyana. Payara is ExxonMobil's second oil discovery on the Stabroek Block and was drilled in a new reservoir. The well was drilled by ExxonMobil affiliate Esso Exploration and Production Guyana Ltd., and encountered more than 95 feet of oil-bearing sandstone reservoirs. It was drilled to 18,080 feet in 6,660 feet of water. The Payara field discovery is about 10 miles northwest of the 2015 Liza discovery.

In addition to the Payara discovery, appraisal drilling at Liza-3 has identified an additional, deeper reservoir directly below the Liza field, which is estimated to contain between 100-150 million oil equivalent barrels.The Stabroek Block is 6.6 million acres. Esso Exploration and Production Guyana Ltd. is operator and holds 45% interest in the Stabroek Block. Hess Guyana Exploration Ltd. holds 30% interest and CNOOC Nexen Petroleum Guyana Ltd. holds 25% interest.

BRIEFS

MULTIFUELS ACQUIRES GAS PIPELINE SYSTEM IN CENTRAL TEXAS

Multifuels Midstream Group LLC, a portfolio company of Warren Equity Partners, recently purchased 124 miles of high pressure gas pipeline in Central Texas from a large publicly traded master limited partnership, and will repurpose the pipeline with new pipe construction; new interconnects including gas measurement and pressure regulation. The completed pipeline system will serve end use customers in the Bastrop to Hallettsville, TX corridor, via an anchor long term contract. The new construction is expected to be completed by end of 2018. The acquisition is Warren Equity Partners' first add-on to its Multifuels platform investment, which was closed in January 2016 in partnership with Multifuels LP.

DCP MIDSTREAM TO DROP DOWN ALL REMAINING ASSETS TO DPM FOR ~$3.85B

DCP Midstream LLC (Midstream), a 50/50 joint venture between Phillips 66 and Spectra Energy (owners), and DCP Midstream Partners LP, signed and closed a transaction combining all of the assets and debt of Midstream with DPM, creating the largest natural gas liquids (NGL) producer and gas processor in the United States with a pro-forma enterprise value of approximately $11 billion. Under terms of the transaction, Midstream has contributed subsidiaries owning all of its assets to DPM, plus $424 million of cash, in exchange for approximately 31.1 million DPM units ($1.125 billion) and DPM assuming $3.15 billion of Midstream debt, for an estimated transaction multiple of approximately eight times based on current commodity strip prices. The cash proceeds of $424 million contributed to DPM will be used to repay its revolver, fund its growth projects or prefund repayment of DPM debt maturing in December 2017. The owners have retained their 50/50 joint ownership of DCP Midstream LLC, which owns the incentive distribution rights (IDRs) and 38% of the outstanding DPM general and limited partner units. To support a minimum 1.0 times distribution coverage ratio, the owners have agreed, if required, to provide IDR givebacks up to $100 million annually through 2019 which provides downside protection for LP unitholders.

DJ Basin expansion

DPM will construct a new 200 MMcf/d cryogenic natural gas processing plant (Mewbourn 3) in the DJ Basin, its tenth plant in the basin, projected to be in service by the end of 2018. Additionally, DCP collaborated with several key producers to form a cooperative development plan which provides a framework to add another 200 MMcf/d plant by mid-2019. Together, these projects will increase capacity by 50% to 1.2 billion cubic feet per day. DPM will also complete the next phase of its Grand Parkway low pressure gathering project and associated compression expansions by the end of 2018.

DPM is in the process of constructing additional field compression and plant bypass infrastructure that will add approximately 40 MMcf/d of incremental capacity during the summer of 2017. The new plants will connect to the Front Range Pipeline, one-third owned by DPM, for NGL takeaway to Mont Belvieu, Texas. Total capital investment for the plant and associated gathering is expected to be up to $395 million.

Sand Hills Pipeline expansion

DPM will expand NGL takeaway capacity on Sand Hills Pipeline by 30%, or 85,000 barrels per day (b/d) to 365,000 b/d, through the addition of four pump stations and a pipeline loop (Sand Hills expansion) to meet NGL production growth from owned and third party plants in the Delaware Basin. Total capital investment for the Sand Hills expansion is approximately $70 million, with an expected in-service date in 4Q17. The newly combined DPM owns two-thirds interest in Sand Hills and Phillips 66 Partners owns the remaining one-third interest and each will fund their proportionate share of the expansion.

Sand Hills provides NGL takeaway capacity to the Mont Belvieu market from both owned and third party plants in the Permian Basin.

BofA Merrill Lynch acted as financial advisor, Bracewell acted as legal counsel and Gibson, Dunn & Crutcher acted as special tax counsel to DCP Midstream, LLC. Evercore acted as financial advisor and Andrews Kurth Kenyon and Richards, Layton & Finger acted as legal counsel to the Conflicts Committee of DPM's Board of Directors.

SENDERO MIDSTREAM TO BUILD GATHERING, PROCESSING SYSTEM IN EDDY COUNTY, NM

Sendero Midstream Partners LP, a privately held company owned by Energy Capital Partners, has secured long-term producer commitments and funding from Energy Capital Partners for the construction of a natural gas gathering and processing system located near the city of Carlsbad in Eddy County, New Mexico.

Sendero's facilities will consist of both low and high pressure gas gathering pipelines, a 130 MMcf/day cryogenic processing plant and a natural gas liquids takeaway pipeline. The newly constructed midstream assets are expected to begin operations in 3Q17.

PLAINS ALL AMERICAN TO ACQUIRE PERMIAN GATHERING SYSTEM FOR $1.2B

Plains All American Pipeline LP has entered into definitive agreements to acquire a Permian Basin crude oil gathering system for approximately $1.2 billion. PAA also announced it had entered into definitive sales agreements totaling $380 million, which includes two pending transactions aggregating approximately $310 million and the completion of a third transaction in January 2017 for approximately $70 million.

Permian Basin acquisition

Concho Resources Inc. and Frontier Midstream Solutions LLC entered into separate agreements with Plains All American Pipeline LP to sell 100% of their respective ownership interests of Alpha Holding Company LLC, the owner of the Alpha Crude Connector system (ACC).

In 2014, Concho and Frontier formed the ACC joint venture to construct a crude oil transportation system in the northern Delaware Basin. Concho owns 50% of the joint venture with an option to purchase Frontier's ownership interest at a predetermined multiple of invested capital. After adjusting for debt and working capital, Concho expects to receive net cash proceeds from the sale of approximately $800 million. As of December 31, 2016, Concho's net investment in ACC was approximately $130 million.

ACC, which is the first large-scale crude oil gathering system in the northern Delaware Basin, includes a 515-mile gathering system as well as crude oil storage facilities, truck terminals and multiple receipt points. The pipeline system became operational in late 2015, and at that time, Concho commenced a 10-year crude oil acreage dedication and transportation agreement. After the transaction's close, the dedication and transportation agreement will remain in place.

The acquisition and pending sale transactions are subject to customary closing conditions, including receipt of regulatory approvals, and are expected to close during the first half of 2017. Simmons & Company International, Energy Specialists of Piper Jaffray, served as exclusive financial advisor, and Vinson & Elkins served as legal advisor to Concho.

Asset sale, partnership

PAA also executed definitive agreements to sell two non-core assets for aggregate proceeds of approximately $310 million. Such transactions include the Bluewater gas storage facility in Michigan and a non-core pipeline segment located in the Midwestern US.

On January 18, 2017, PAA completed the sale of an undivided 40% interest in a segment of the Red River Pipeline to a subsidiary of Valero Energy Partners LP for approximately $70 million. The undivided interest conveyed represents 60,000 barrels per day on the segment of the pipeline extending from Cushing, Oklahoma to Hewitt, Oklahoma near Valero's refinery in Ardmore, Oklahoma. PAA retained an undivided 60% interest in the Hewitt Segment and a 100% interest in the remaining portion of the pipeline that extends from Ardmore to Longview, Texas, where it connects with various pipelines, including PAA's newly constructed Caddo pipeline that extends to refinery markets in Northern Louisiana.

NGL ENERGY PARTNERS CLOSES MURPHY ENERGY ASSET DEAL

NGL Energy Partners LP has closed on the previously announced acquisition of certain assets of Murphy Energy Corp. The assets include the Port Hudson, Louisiana Terminal, which is a natural gas liquids terminal that supports refined products blending, and the Kingfisher, Oklahoma Facility, which is a natural gas liquids and condensate facility. The combined purchase price of the assets was approximately $51 million.

The Port Hudson Terminal is located near Baton Rouge, Louisiana, and is in proximity to other refined products infrastructure along the Colonial Pipeline. The terminal consists of four truck unloading bays and eight pressurized storage tanks with total capacity of 720,000 gallons. Cash flows are supported by long-term supply contracts.

The Kingfisher Facility is a natural gas liquids and condensate facility located in Kingfisher, Oklahoma and connects to the Chisholm NGL Pipeline and the Conway Fractionation complex. The facility has multiple truck unloading stations, 450,000 gallons of storage capacity, a methanol extraction tower and a 5,000-barrel per day condensate splitter. The facility is supplied by production from regional gas processing plants and producers. Crude oil from this facility is also expected to be delivered to Cushing via the Glass Mountain Pipeline extension into the STACK play. NGL Energy Partners LP is a 50% owner in Glass Mountain Pipeline.

ZENITH ENERGY TO MARKET, DEVELOP MIDSTREAM ASSETS IN MEXICO

Zenith Energy LP, an international liquids and bulk terminaling company, has signed an agreement with a company in Mexico to market and develop existing logistics assets for oil storage and distribution in Mexico. The agreement provides for the use of certain facilities in Mexico of CEMEX S.A.B. de C.V., a global building materials company. Zenith has been awarded the rights to develop these sites for fuel and LPG storage and distribution. CEMEX's facilities in Mexico include more than 90 storage and distribution locations, in both inland and coastal cities, most of them connected to the Mexican railroad network.

BRIEFS

PLAINS ALL AMERICAN TO EXPAND PERMIAN BASIN CRUDE TAKEAWAY CAPACITY

Plains All American Pipeline LP is expanding the capacity on its Cactus pipeline from McCamey to Gardendale, Texas to approximately 390,000 barrels per day. The expansion will allow PAA to move increasing production volumes from the Permian Basin to Corpus Christi and other delivery points along the system. The expansion includes manifold and metering enhancements at its origination station which are anticipated to be completed in the third quarter of 2017.

The Cactus pipeline is a 310-mile, 20-inch crude oil pipeline and is capable of transporting crude oil from the Permian Basin to the PAA/Enterprise Products Partners Eagle Ford Joint Venture (Eagle Ford JV) Pipeline. The Eagle Ford JV Pipeline has a capacity of 660,000 barrels per day and serves the Three Rivers and Corpus Christi markets directly and can supply the Houston-area market through a connection to the Enterprise South Texas Crude Oil Pipeline.

Restructuring activity to rise in 2017

SURVEY: BANKRUPTCIES WILL INCREASE OR REMAIN THE SAME AS 2016

ALIXPARTNERS, a global advisory firm, has released the results of its 11th annual North American Restructuring Experts Survey. This year's survey, which represents the opinions of 207 senior-level restructuring experts, indicates there will likely be more restructuring activity in 2017 than last year with 78% of respondents saying the number of bankruptcies will increase or remain the same as 2016. This comes after 2016 saw a rebound in the number of business bankruptcies after many years of decline.

"In addition to retail and oil and gas, we are seeing increased restructuring activity in shipping and energy/utilities," said Lisa Donahue, managing director at AlixPartners and global leader of the firm's Turnaround & Restructuring Services practice.

"As the year came to a close, 2016 will be remembered for some of the most impactful global events on record that not even the most well informed experts could have predicted," she said. "But the changes brought upheaval and opportunities for the restructuring community to contribute its skills. We expect this to continue in 2017."

INDUSTRIES TO WATCH IN 2017

In the United States, the top industries predicted to face distress in 2017 are retail (67%), oil and gas (57%), and health care (31%). Outside of the US, oil and gas (55%), maritime and shipping (40%), and retail (35%) are the three most-cited sectors.

The retail industry began 2017 under the spotlight after an uptick in bankruptcies in the sector in 2016. Several high-profile apparel retailers filed for bankruptcy last year and as consumers continue to migrate online for purchases, retailers are under continued stress to adapt their operations to the changing environment.

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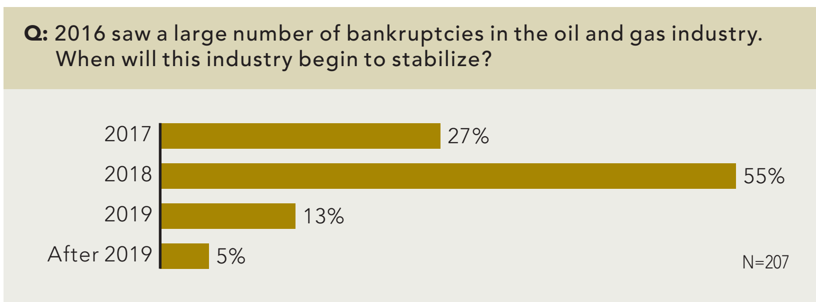
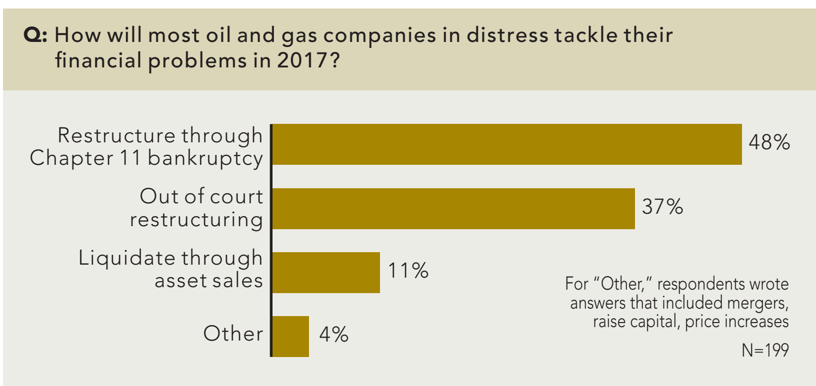
F1: RESTRUCTURING EXPERTS PREDICT THE OIL AND GAS INDUSTRY WILL STABILIZE DURING 2017 AND INTO 2018



F2: HALF SAY MOST OIL AND GAS COMPANIES WILL RESTRUCTURE THROUGH CHAPTER 11 BANKRUPTCY



> *"Our survey respondents are saying that the challenges that oil and gas companies have faced for the past several years are not expected to subside this year. Oil and gas was the industry with the most corporate bankruptcies in 2016, and this could continue into 2017. It does not appear that there will be significant increases in oil prices in 2017. Given the high fixed costs and debt load of many oil and gas companies, this may push more firms to pursue restructurings." – Jim Mesterharm, AlixPartners*

The oil and gas industry saw a large number of bankruptcies and restructurings in 2016, and 55% of respondents feel the industry will not stabilize until 2018. Forty-eight percent of respondents predict companies in the industry will resolve their financial problems through Chapter 11 proceedings while 37% percent say companies in the sector will conduct out-of-court restructurings. Oilfield services is the sub-sector predicted to have the most restructurings, followed by offshore drilling.

"Our survey respondents are saying that the challenges that oil and gas companies have faced for the past several years are not expected to subside this year," said Jim Mesterharm, managing director at AlixPartners and co-head of the firm's Turnaround & Restructuring Services practice for the Americas.

"Oil and gas was the industry with the most corporate bankruptcies in 2016 and this could continue into 2017," he said. "It does not appear that there will be significant increases in oil prices in 2017. Given the high fixed costs and debt load of many oil and gas companies, this may push more firms to pursue restructurings."

GLOBAL OUTLOOK

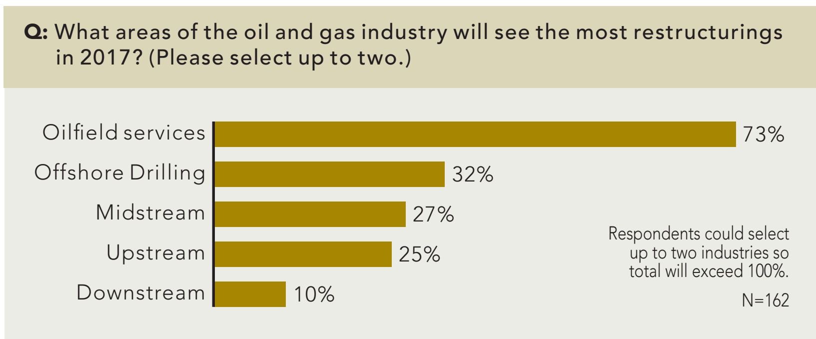
According to the experts surveyed, restructuring activity is expected to increase outside of the US as well, with 57% of survey respondents believing 2017 will see an increase in activity over 2016 and 40% believing the level of activity will remain at the same level.

Survey respondents expect the United Kingdom to see the most restructuring activity in 2017, followed by Italy. Most experts think the Brexit vote will lead to more restructurings in the UK (68%), while 28% think Brexit will have no impact.

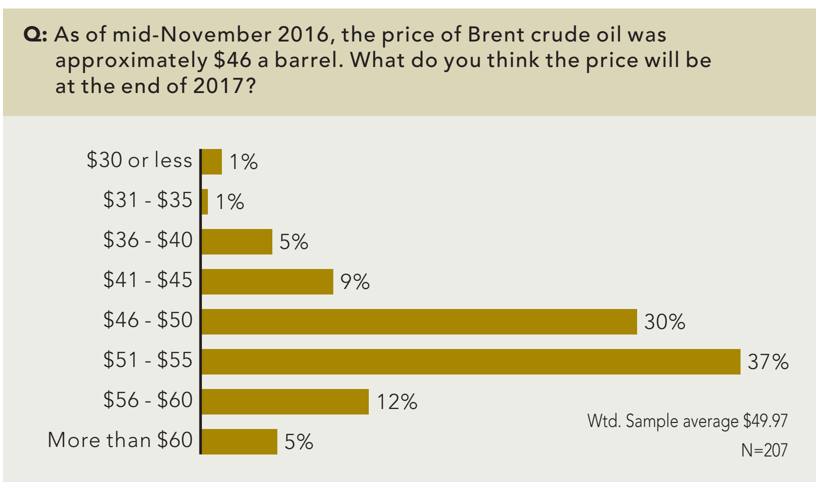
ABOUT THE NORTH AMERICAN RESTRUCTURING EXPERTS SURVEY

The North American Restructuring Experts Survey reflects the opinions of 207 senior-level North American-based corporate restructuring experts. The survey, which was conducted online from November 22 through December 9, 2016, highlights the evolving state of the restructuring industry and forecasts developments over the next 12 months. The survey polled senior attorneys, investment bankers, lenders, hedge fund managers, and other restructuring professionals across the United States. OGFJ

F3: OILFIELD SERVICES IS EXPECTED TO BE THE OIL AND GAS SUBSECTOR WITH THE MOST RESTRUCTURINGS IN 2017



F4: $49.97/BBL AT THE END OF 2017



North American Shale breakeven prices

WHAT TO EXPECT IN 2017

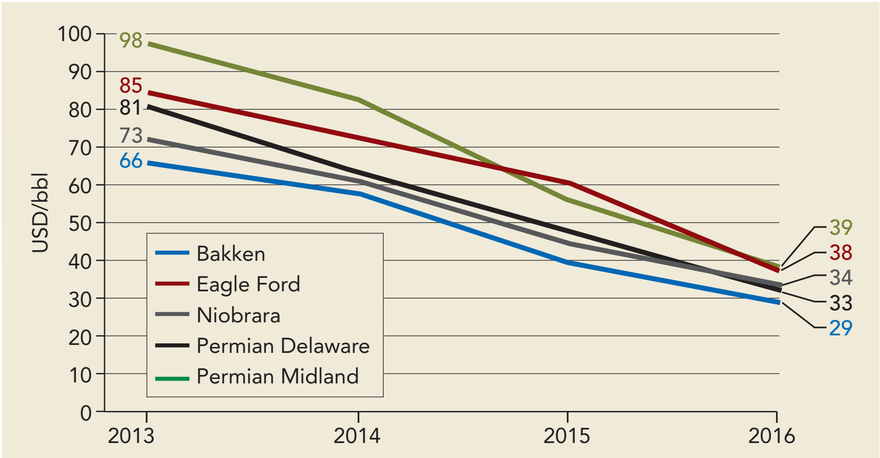
SONA MLADA, RYSTAD ENERGY

THE YEARLY DROP in breakeven prices across North American shale plays is likely to bottom in 2016. Understanding the drivers behind the continuous decrease in breakeven prices is crucial in forecasting the impact in 2017 and beyond. This article examines how the breakeven prices developed both on the wellhead level and on the acreage level, as well as how much of the observed reduction is sustainable in the future.

Since 2013, the average wellhead breakeven price (BEP) for key shale plays has decreased from US$80/bbl to US$35/bbl. This represents a decrease of over 55%, on average. As Figure 1 indicates, the wellhead BEP decreased across all key shale plays, with the Permian Midland experiencing the largest decrease, falling by over 60% from US$98/bbl in 2013 to US$38/bbl in 2016 (for horizontal wells only). Due to a higher average royalty, different decline profile and hydrocarbon split, the Eagle Ford experienced one of the highest wellhead BEP among the main shale oil plays in 2016.

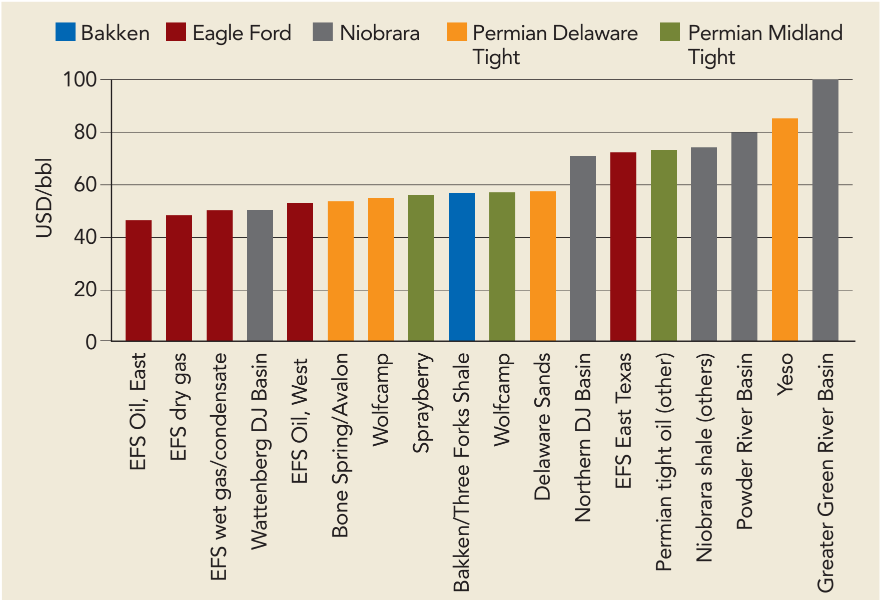
There are several reasons behind the observed drop in BEP. The drop is partly attributable to structural changes such as improved well performance (which can be measured by improvements in the EUR) and the improved efficiency gains (which can be measured by the effect of lower drilling and completion cost, a result of more effective operations). Another set of drivers behind the falling BEP can be referred to as plummeting oil price. With clear cycles describing the petroleum industry historically, the cyclical changes experienced from 2014 will be reverted with an oil price recovery. Among the key cyclical drivers for the shale wellhead BEP are high grading (measuring the effect of operators focusing their drilling operations in the best acreages) and lower unit and production costs.

F1: DEVELOPMENT IN WELLHEAD BREAKEVEN PRICES FOR KEY SHALE PLAYS



Source: Rystad Energy NASWellCube

F2: AVERAGE WTI BEP FOR NEW SHALE WELLS PER PLAY



Source: Rystad Energy UCube

Even though the wellhead BEP is often considered the "raw" or "initial" breakeven, this is not the actual breakeven realized by the companies. If we include the effect of facility costs and the price discounts, we can compare the average acreage BEP across main shale plays, expressed in WTI price. As Figure 2 indicates, in this comparison, the different zones of the Eagle Ford Shale (EFS) – namely the East Oil zone, Dry Gas zone and Wet Gas/Condensate zone, have lower WTI BEP compared to the Permian Delaware's Bone Spring/Avalon or Wolfcamp formations.

es or Energen, have relatively high BEP compared to their peers. For both operators this is a result of a high BEP for Wolfberry operations in the Permian Midland Basin.

Even though the BEPs have fallen across the shale plays due to the factors described, the most important question to answer is how much of this change is sustainable. Rystad Energy studied and quantified the different cyclical and structural drivers of the changing BEP and arrived at the conclusion that if all of the cyclical effects are reverted when the oil price starts recovering, the BEP might grow by 62% over the next couple of years for US shale plays.

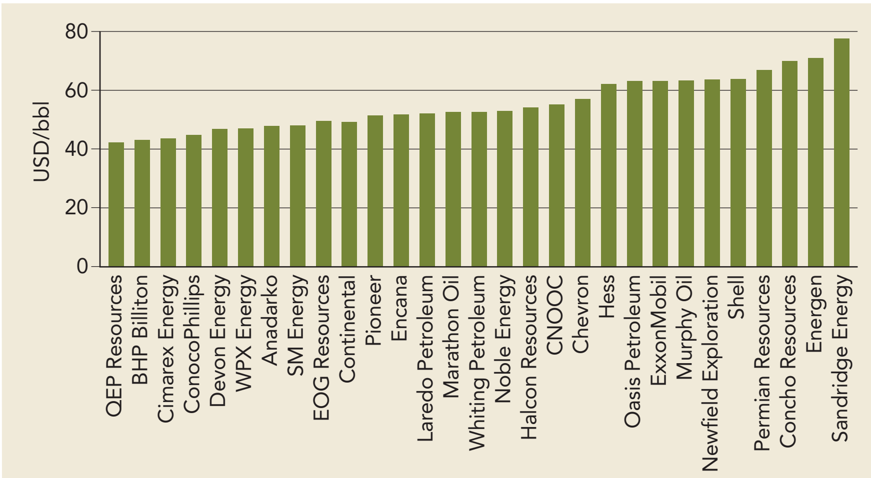
As we enter 2017, it is important to look into whether the shale operators are ready for a growth in the current year. Activity-wise, in the main shale oil plays (EFS, Bakken, Permian and Niobrara), there are approximately 335 horizontal rigs drilling currently. This represents a nearly 100% increase compared to the bottom rig count in May 2016 at 168 Hz rigs for the same plays. While in the Bakken play

"Activity-wise, in the main shale oil plays, there are approximately 335 horizontal rigs drilling currently. This represents a nearly 100% increase compared to the bottom rig count in May 2016 at 168 Hz rigs for the same plays."

Note that the differences between the WTI BEP and the wellhead BEP are play-specific and can be within the range of 10-15 dollars.

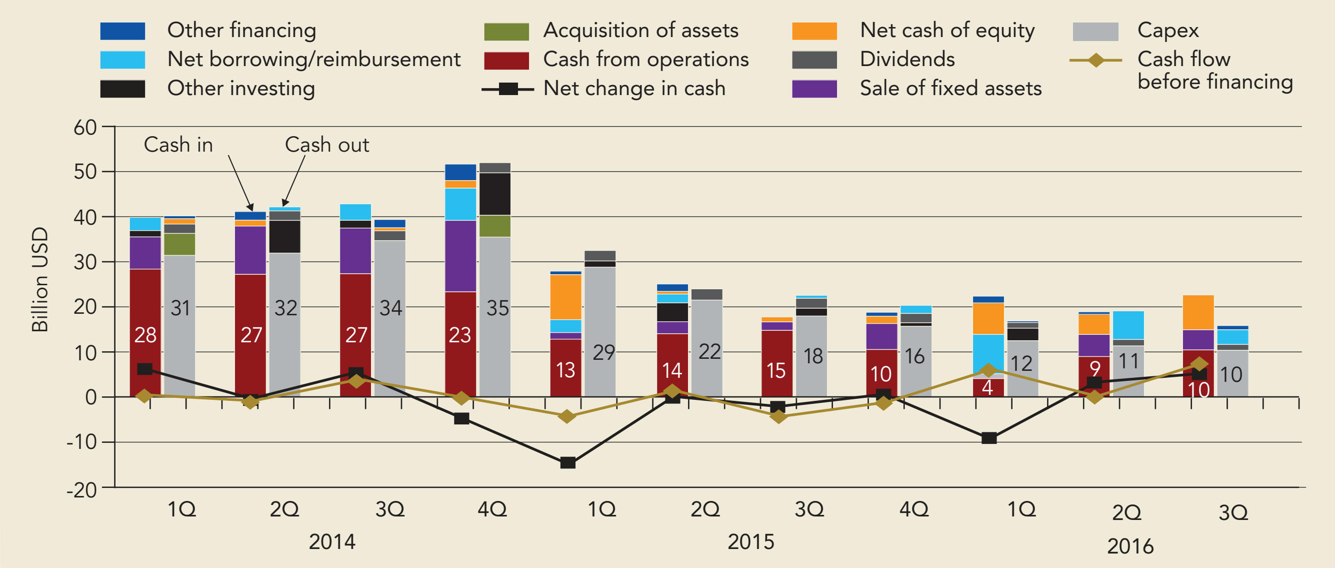
Among the shale companies with the lowest average BEP (expressed in WTI) for new shale wells, QEP Resources scores as the company with the lowest BEP (see Figure 3). This is driven primarily by the low BEP in the company's Bakken Shale acreage, particularly in the South Antelope Area. ConocoPhillips scores as the major company with lowest BEP, driven by the acreage in the East Oil zone of its Eagle Ford acreage. Some Permian-focused companies, e.g. Concho Resourc-

F3: AVERAGE WTI BEP FOR NEW SHALE WELLS PER COMPANY



Source: Rystad Energy UCube

F4: SHALE PEER GROUP'S REPORTED CASH FLOW BREAKEVEN



Source: Rystad Energy NASReport

the rig count has somewhat stabilized and remained relatively flat over the past couple of months, we have observed a growing trend in the Eagle Ford Shale over the last weeks of 2016. For both plays, however, the total current number of rigs stands close to 1/5 of the peak that occurred in 2014. At the same time, we observe a significantly different development for the Permian plays. Here, both plays are currently at a similar level in terms of number of running Hz rigs as they were in March 2015, or about 65-70% of the peak activity from 2014.

The shale operators are also entering 2017 with a more balanced cash flow from shale operations, our analysis indicates (see Figure 4). In Q3 2016 the cash flow from operations was $10 billion, with an average WTI of 44.8 $/bbl. This means that for the first time the investments did not exceed the cash from operations for the shale companies. The shale companies have been able to reduce the imbalance between cash from operations and investment from $16 billion in Q1 2015 to zero in Q3 2016 with a considerable reduction in investments. For 2017, Rystad Energy forecasts an average WTI oil price of $60/bbl, which implies a 40% improvement in the cash from operations. This improvement in the cash flow will result in higher investments by shale operators. **OGFJ**

ABOUT THE AUTHOR

Sona Mlada is a senior analyst at Rystad Energy. Her main responsibility is the analysis of upstream E&P activities in North America, with a specific focus on shale asset modeling. She is the project manager for the monthly North American Shale Report, and is also responsible for analyzing global discoveries and estimating recoverable resources. She holds a degree from the University of Economics in Bratislava, Slovakia, including a graduate exchange program at Universidad de Granada, Spain.

Bolivia's Vice President Álvaro García Linera (left) is shown with Evo Morales, who has served as President of Bolivia since 2006.

Bolivia seeking partners, investors

SOUTH AMERICAN NATION HOPES TO BECOME PREMIER GAS, ENERGY SUPPLIER

FOCUS REPORTS

EDITOR'S NOTE: In an exclusive interview for Oil & Gas Financial Journal, the Focus Reports editorial team interviews Álvaro García Linera, Vice President of Bolivia, who discusses the country's plans, goals, and steps the South American nation is taking in hopes of becoming a premier supplier of gas and energy to Latin America and the world.

OIL & GAS FINANCIAL JOURNAL: This year marks the tenth anniversary of President Evo Morales' nationalization of hydrocarbon resources in Bolivia. From your perspective, what have been the results of this action?

ÁLVARO GARCÍA LINERA: The first result was the improvement of the country's income, which is reflected in increased investment in sectors such as infrastructure, health and education, which was an old debt that the government had with the people to improve all these aspects.

The second result was increased diversity in hydrocarbon activities in Bolivia because we began to venture into the industrialization of gas. This year we brought a urea and ammonia plant, and in four years we plan to launch a polypropylene and polyethylene plant. Depending on the fluctuations of the market in the next 10 years, we are contemplating the production of ethylene using soft plastics.

The third result has been an increase in foreign investment into Bolivia, thanks to the political and social stability that the country has achieved. This new environment has encouraged companies already present to extend or renew their contracts and has promoted the increase of new foreign companies coming to Bolivia. This action has increased the overall foreign investment in the country.

In the past, the regimen of property and distribution of profits were badly proportioned, creating injustice and political instability. Companies were able to generate very high profits, but with great risks. Now that we have stabilized the country, we have created an environment that is predictable, stable, and plannable in terms of investment and profits for foreign companies.

OGFJ: Currently, Bolivia has a nine-year plan to become the heart of energy for Latin America. This plan requires an investment of $32 billion according to Yacimientos Petrolíferos Fiscales Bolivianos (YPFB). This rather large sum is equivalent to the annual gross domestic product of the country. How does the government plan to finance this project?

GARCÍA LINERA: The government will directly fund more than 50% of the project and will have a lower percentage of foreign investment. This is a nine-year plan, in which each year the government will invest approximately $2.5 billion of GDP, leaving about $10 billion to finance.

The remaining part will be financed with the profits from gas activities, plus the country's international reserves that represent 50% of GDP, being the highest in Latin America. In addition, we have $12 billion dollars in resources of the Pension Fund Administrators (AFP) and $22 billion in private savings in banks. When these resources are added, it creates a strong financial backing that allows the government to finance the plan directly or through credit.

OGFJ: Where will Bolivia acquire the technology for this project?

GARCÍA LINERA: The technology will be acquired abroad, in part by the government of Bolivia, but also leaving room for foreign investment. We are committed to acquiring the best technology available.

In the case of the urea and ammonia plant, we hired the Korean company Hyundai. For the polypropylene plant, we are evaluating several suppliers from the United States, Italy, Germany, Spain, and Japan among others. In the upcoming months, we will decide which company to choose, taking into account the technology and price. We know that at this time we are not able to generate this technology internally, so will absorb that of the world leaders until we can produce it in Bolivia.

OGFJ: Bolivia is a country with only 10 million inhabitants. However, it has a huge infrastructure downstream, a field that so far is under-industrialized. What are the objectives for these infrastructures?

GARCÍA LINERA: Clearly, the Bolivian market is very small, and the large industrial investments that we have done do not go accordingly with the domestic market. The small and medium investments are directly aimed for domestic consumption. However, the giant investments in gas, oil, electricity, mineral smelting, lithium, and atomic energy are oriented for the international market.

In the case of lithium, Bolivia has 40% of world reserves of this element that is essential for car batteries. In the same way, we want to participate in the creation of energy by nuclear fusion, which occupies deuterium from water, and tritium from lithium. The goal is to achieve an inexpensive technique of fusion of the two atoms to generate electricity. This project is very promising for Bolivia, since no other country in the world has such a large reserve of lithium.

This is a very promising project for Bolivia because we are the country with the highest lithium reserves in the world. This is a plan of at least 20 years, but we must prepare now to not only sell the raw material, but also to incorporate added value. Our goal is to partner with countries that are currently working on developing these technologies to work together in the future.

OGFJ: In order to develop all of these projects, it is vital for Bolivia to have partners. How does the government of Bolivia build these partnerships in such a fluctuating continent such as South America, where governments often change from one political pole to the other?

GARCÍA LINERA: Bolivia has shown itself to be serious towards its commitments, regardless of the type of government that has signed the commitment. In the case of Brazil, when Bolivia signed the gas contract, the Brazilian government was extreme right, and when government changed, we kept the contract unalterably. The same case has been with the gas contract to Argentina and the recent change of government.

In the foreign market, Bolivia has been very serious in fulfilling its commitments, regardless of both internal and external political fluctuations. Bolivia was on the verge of a civil war that almost led to a divided country, but the contracts were never interrupted.

The nationalization that took place in Bolivia was very modern. It was achieved through negotiations with all the companies that were present in the country. We got them to stay in the country and even received more companies.

Regardless of the variations and political cycles, contracts must be respected. Today, we represent the economy with higher economic growth on the continent, after Panama. This growth, according to the World Bank, would exceed by 2% the growth of Panama if we had access to the sea.

Today we offer foreign investors a stable political situation and clear laws, thus facilitating the vision of the results of such investments. We are a country very interested in the nationalization of our resources, but we also understand the importance of globalization.

OGFJ: Bolivia has very favorable political stability. However, its neighbors do not. How important it is for Bolivia to send its gas frozen or by other means to more distant and industrialized countries?

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GARCÍA LINERA: This is the ideal scenario because one of the limitations for foreign investment in Bolivia the lack of access to the sea. As of now, we are using the proximity to Brazil and Argentina for the sale of gas, which is a great advantage.

We are working on making Bolivia run only on renewable energy. Thus, all the energy produced by hydroelectric or thermoelectric means is left for export.

Currently, Bolivia produces 60 million cubic meters of gas per day, of which the domestic market consumes 12. This leaves 48 million cubic meters of gas for export, and this number is expected to increase in the coming years. Companies that deliver gas for electricity also receive the export price, as this gas will be sold in the form of electricity to Peru, Brazil, and Argentina.

Argentina has resources, but it also needs energy and Brazil needs 2,000 megawatts each year. Thus, Bolivia has invested in a large-capacity power plant to convert gas into electricity.

Even with these measures, we are not reaching our full potential, so we are exploring the feasibility of freezing the gas and send it to other countries. At the moment we are working on agreements with Peru to gain access to the sea, not only to export frozen gas, but also to serve as a connection between Brazil and China.

Nowadays, Brazil exports to China about $70 billion per year in goods, and imports $40 billion per year. Our plan is to build a railway with European or Chinese investment that connects Brazil to a Peruvian port, forming a corridor that allows for the free movement of these goods. Once this corridor is done, the next step would be to export the frozen gas through it, solving the landlocked issue.

OGFJ: All these mega projects that Bolivia is working require a high level of technology and human capital with such knowledge. What is Bolivia doing to ensure this human capital in the country?

GARCÍA LINERA: We have started from the basics to deal with this need. After Cuba, we are the country in Latin America that invests more in education. We invest 13% of the state budget in education versus 6% in the rest of the continent. The results have begun to appear, but we still have a way to go. For now, we are absorbing knowledge abroad as fast as possible.

We have a free project for masters and doctorates abroad with the agreement of satisfactory results and to work for the country for four to six years. This way we increase the technical education of the population. We have followed the footsteps of other countries such as India and Ecuador, by sending young people abroad to learn and then apply their knowledge in the country. We know this is a long-term investment, but eventually this will generate an added value to the resources of Bolivia.

In the short term, we are working with foreign companies in the country to accelerate training. Bolivia does not require foreign companies to hire a certain amount of Bolivian personnel, but they discover quickly the benefit of having domestic employees working for them.

OGFJ: In recent years, the oil and energy sector has been severely affected, making companies more cautious when selecting a country to invest in. What would you tell the readers of Oil & Gas Financial Journal about Bolivia?

GARCÍA LINERA: In these times of uncertainty, Bolivia is the ideal place to invest because it has sustainable economic growth, clear laws, secured markets, and political and social stability. There are very few countries with such characteristics in the continent, and our country is one of them. Bolivia represents profitability, stability, and predictability, putting us in an enviable position at a time of global uncertainty.

OGFJ: Thank you very much for your time today.

"In the past, the regimen of property and distribution of profits were badly proportioned, creating injustice and political instability. Companies were able to generate very high profits, but with great risks. Now that we have stabilized the country, we have created an environment that is predictable, stable, and plannable in terms of investment and profits for foreign companies."

Recent events help shape oil prices

HAS A NEW WORLD ECONOMIC ORDER BEEN LAUNCHED BY THE US ELECTION?

MIKE ISSA, GLASSRATNER ADVISORY & CAPITAL GROUP, IRVINE, CALIF.

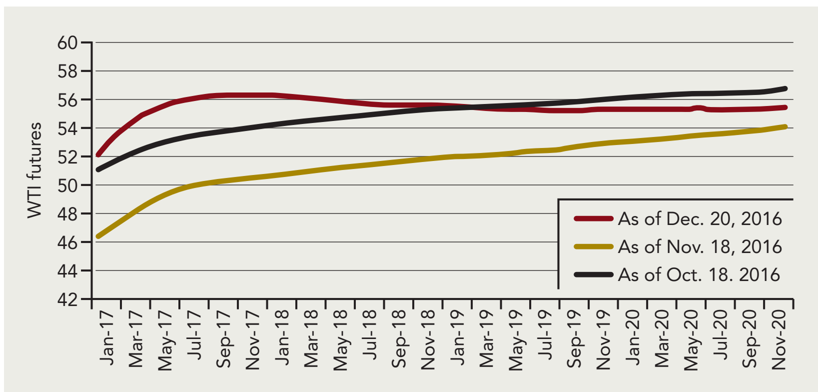
IN THIS INCREASINGLY complicated world, it is useful to fall back on an examination of the three things that matter for our industry: supply, demand, and currency exchange rates. There are several meaningful headwinds and perhaps several crosswinds that have occurred since we wrote about Brexit for the August issue of Oil & Gas Financial Journal. The US election, OPEC's intentions versus their reality, and the seeming direction of Brexit are the key influences for this reflection and comment. The markets clearly believe that Trump can deliver on much of his campaign platform with Republican control of both houses in Congress and have traded up based on that perception. People want to believe that OPEC can actually deliver on and honor a production curtailment program. And, Brexit continues to evolve in potentially adverse ways.

WHAT ARE THE MARKETS TELLING US ABOUT THE SHOCKING TRUMP VICTORY AND HOW WILL IT REALLY PLAY OUT?

The markets clearly interpret the Trump win as a victory for capitalism, with an attendant reduction in taxes, and fiscal stimulation that will accelerate US GDP growth. In the wake of the election, US interest rates have trended up (from 1.8% to 2.3% (CNBC, 2016)); equity markets have risen to new highs (CNBC, 2016; Bloomberg, 2016), and the US dollar has been on a tear against the euro and against a basket of world currencies (CNBC, 2016).

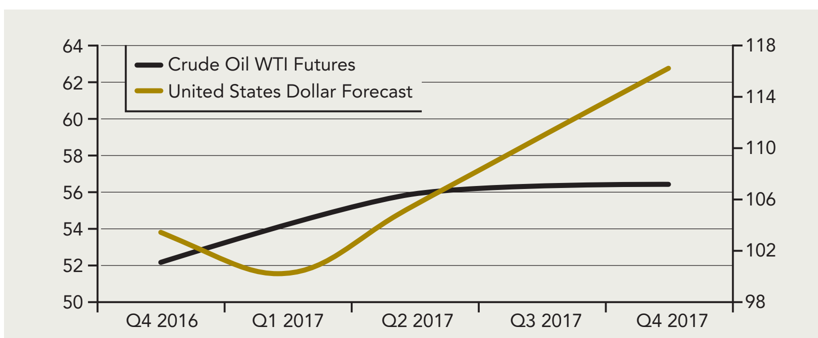
- Clearly the rising strength of the dollar is proving to be a considerable headwind for crude pricing because of the historical inverse relationship, and the fairly high degree of negative correlation. In a yield-starved world the prospect of investing in a safe-haven currency and receiving higher yields would be expected to support further strength in the dollar. It is a challenge to imagine a robust increase in crude prices in concert with continuing strengthening of the US dollar. Note that the entire crude futures price curve shifted down immediately post-election, reflecting the consensus view that the strength of the US dollar will continue to have a measurable impact on crude (See Figures 1 and 2). Interestingly, our analytics suggest that the correlation between the USD and crude began to weaken significantly in late 2016. Note that the crude futures curve is very flat five years out. The weakening correlation between the USD and crude suggests other forces at work in the crude pricing model.
- Note carefully that there is perhaps as much as 5.7 billion barrels in storage currently (Oil Sands Magazine, 2016). We estimate that approximately 10% of the amount in storage is true excess supply, perhaps 500-600 million barrels. There is no possible shift in demand that can absorb that surplus in the short run. However, the production decline curve, in concert with crude prices that do not promote substantial incremental production, will make this a self-correcting problem in the intermediate term, however painful the interim might be.
- Some will make the case that the post-election US economy, and perhaps the world economy, will experience acceleration in GDP growth with an attendant increase in

F1: CRUDE OIL WTI FUTURES CONTRACTS, 2017-2020



Source: All Futures Contracts for Crude Oil WTI (Barchart.com, 2016)

F2: CRUDE OIL WTI FUTURES VS. USD FUTURES



Source: All Futures Contracts for Crude Oil WTI (Barchart.com, 2016);
US Dollar Forecast (Trading Economics, 2017)

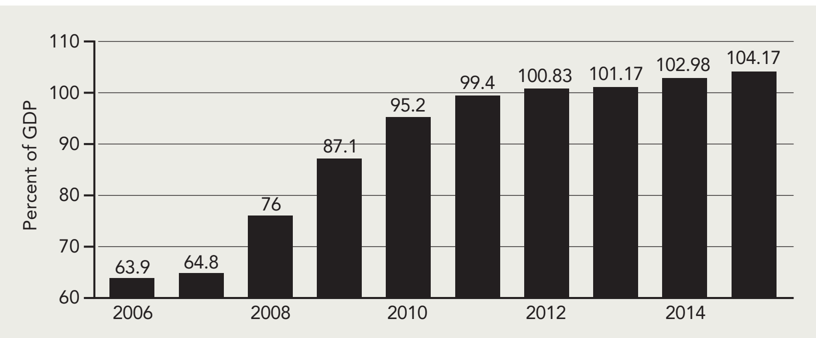
demand for crude. It is far from clear that this can actually occur.

- It's mathematically impossible for Trump to spend all the money he promised on the campaign trail without destroying the US budget and bond ratings.
  - US sovereign debt in inflation adjusted dollars as a percentage of GDP is nearly double the level of 2006, just prior to the Obama administration taking office (See Figure 3).
  - The 2015 federal budget deficit was $439 billion, equal to 2.5% of GDP (Congressional Budget Office, 2016).
  - As of CY 2015, the US GDP growth rate was 2.6% (Bureau of Economic Analysis, 2016). According to an article in the Financial Times, the sustainable growth rate for the United States is 1.5% (Smithers, 2015). Warren Buffet recently commented that 2% is toward the high end of the range of sustainable US GDP growth.
  - 2015 GDP was $17.9 trillion, and is forecast to hit $18.3 trillion by the end of 2016 (Trading Economics, 2016).
  - As of August 2016, the budget deficit is projected to be $590 billion for FY 2016 (Congressional Budget Office, 2016). This puts the budget deficit at 3.2% of GDP for 2016. Compare this to the estimated GDP growth of 2.6% in 2016 (Trading Economics, 2017).
  - The US debt as of October 2016 was $19,805.7B (US Treasury, 2016). Note that if/when interest rates increase by 1%, annual interest expense will increase by $198.1 billion – an increase of 33.4% of the projected 2016 budget deficit (Center on Budget and Policy Priorities, 2016). Note that the Obama administration missed or ignored a huge opportunity to fund out long on our sovereign debt and fix interest rates at generational lows for decades into the future. Instead, the average maturity of US treasury has peaked at about six years, the same as circa 2002 (US Department of the Treasury, 2016). We can't resist the temptation to note that many more well-managed nations and large companies executed this exact strategy, issuing debt with maturities of up to 100 years at fixed rates. (Barron's, 2016; Wall Street Journal, 2016).
  - The significance of the statistics above is that budget deficits as a percentage of GDP cannot outpace the GDP growth rate in perpetuity. The deficit gets to the point of no return as a result of the compounding of a perpetual shortfall. The best solution to this imbalance in any nation is more robust growth in GDP, which is easy for politicians to say but harder to execute. (See Figure 4)
  - Monetary policy has clearly reached the limit of its ability to stimulate further growth in the US economy. Fiscal policy, while somewhat effective in the short run, is unsustainable in the long run when sovereign debt levels are already high (George Mason University, 2010). Note further that fiscal policy also contributes little to long-term GDP growth (International Monetary Fund, 2014). The US markets reaction suggests that the "smart money" is betting that tax reductions (see Laffer Curve comments below) and infrastructure spending will be stimulative to the economy and that GDP growth will accelerate.

Laffer Curve Research

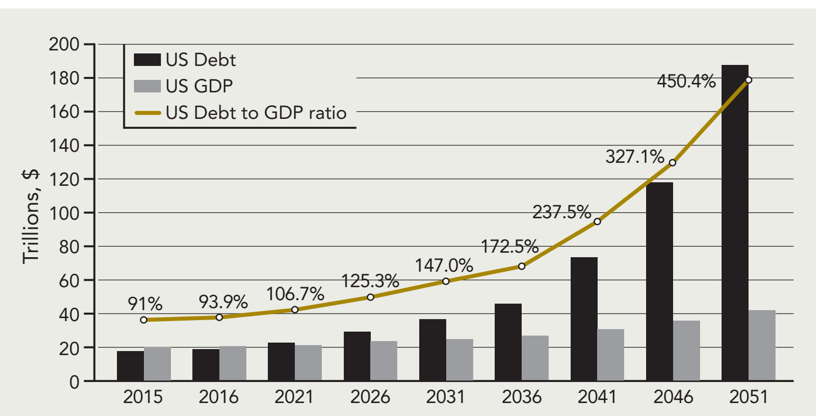
- Christina Romer and her husband David Romer (both Economics professors at UC Berkeley) found that the optimal tax rate to maximize revenue is 33% in a paper titled "The Macroeconomic Effects of Tax Changes: Estimates Based on a New Measure of Fiscal Shocks" that was published in The American Economic Review in June of 2010 (Vol. 100, No. 3).

F3: US SOVEREIGN DEBT AS A PERCENT OF GDP



Source: Trading Economics, US. Bureau of Public Debt (Trading Economics, 2016)

F4: US DEBT TO GDP RATIO FORECAST AT CURRENT PRICES



Assumptions: Interest rate 1.8%; sovereign debt growing at 3%; GDP growing at 1.5%

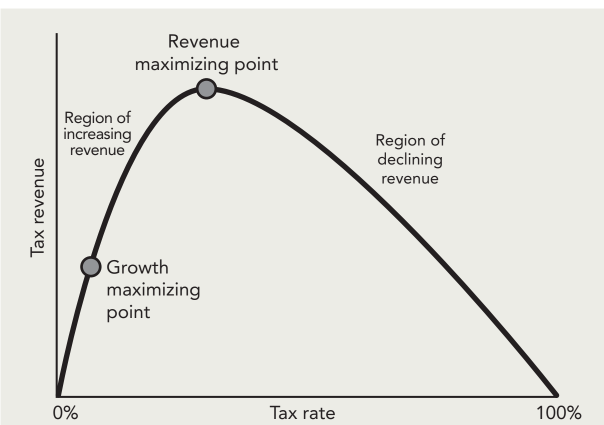
"It is hard to see a meaningful improvement in crude pricing or in the health of the industry in the next few years. In fact, it is hard to rationalize any degree of upward slope of the crude futures curve with the currently known facts..the current futures curve flattened considerably since early November as the market came to this realization."

- Additional research shows that, as tax rates get closer and closer to the revenue maximizing point, the economic damage becomes very significant (Mitchell, A Primer of the Laffer Curve, 2014). Nations should actually want to be at the growth-maximizing point of the Laffer Curve (Mitchell, 2010). (See Figure 5.)
- Romer and Romer found that for every 1% that taxes rise (as a percent of GDP), GDP falls about 3% (Ricochet, 2012).
- The Romer's reiterated that there are significant disincentive effects of higher tax rates in their rebuttal to Gerald Friedman's proposed policies during Bernie Sanders' economically flawed (dare we say nonsensical) campaign rhetoric in 2016 (Romer & Romer, Senator Sanders's Proposed Policies and Economic Growth, 2016).
- While it is reasonable to expect that GDP growth will respond positively to this stimulus, the timing, duration and magnitude of the response is uncertain. Lead time will be required to implement tax cuts and infrastructure spending, since Congressional action is required. More time will then elapse before the economy then begins to respond. Clearly this time line from concept to measurable results will be years, perhaps 2-3 years, rather than months.

OPEC'S INTENTION VS. REALITY

- The markets reacted positively to OPEC's "agreement in concept" for the collective curtailment of production at their 170th Meeting on September 28th. Crude immediately traded up from $44.65 to $47.07 (US Energy Information Administration, 2016), but the increase was only temporary.

F5: THE LAFFER CURVE



Source: Forbes.com (Mitchell D.J., The Laffer Curve Shows that Tax Increases are a Very Bad Idea, 2012)

- After the 171st Meeting, which took place on November 30th, 2016, OPEC actually agreed to a specific allocation of the curtailment. A production curtailment was exactly the right thing for OPEC to attempt and is clearly in the economic best interest of OPEC's members. Since the meeting, crude oil has climbed to nearly $53. An OPEC production cut of about 4% has resulted in a lift in crude pricing of roughly 10%, clearly a positive economic outcome for OPEC members if it holds.
- However, OPEC members have historically "tended to cheat" when given quotas for production. According to the Financial Times, parties to any such agreement will inevitably cheat on their production allocation (Financial Times, 2016). Former Saudi-oil minister Ali Al-Naimi confirmed this at an event in Washington at the beginning of December (Forbes, 2016).
- The simple facts are that at these prices, a number of OPEC members are in desperate straits for cash and literally can't pay their bills. Note that Saudi just floated a $17.5B bond offering, because they need the money (Wall Street Journal, 2016). Venezuela is dead flat broke (CCC credit rating-second lowest rating among all rated countries) to the point of insurrection (Bloomberg, 2016).

WORLD OIL SUPPLY & DEMAND EFFECTS BASED ON NOVEMBER OPEC MEETING

- At the 171st OPEC meeting, OPEC nations agreed to the allocations of oil production curtailment as shown in Table 1.
- Although Russia is not a member of OPEC, it has also agreed to curtail its production by 600 tb/d starting on January 1, 2017 (Forbes, 2016).
- Note that OPEC accounts for about 40% of the world's oil supply, and Russia and OPEC combined account for slightly over 50% of the world's oil supply (International Energy Agency, 2016).
- World Oil Supply started to outpace Demand in 2014 (IEA, 2016), leading to the currently estimated 5.7B barrels of oil in storage.
- Note that the curtailment deal with Russia and OPEC is only in effect for six months (OPEC, 2016).

BREXIT UPDATE

- Our Brexit update is also mixed in terms of its implications for our industry. We originally said that Brexit stood to adversely impact the GDP of the UK, the world's fifth-largest economy, and to strengthen the US dollar, which is inversely related to movements in crude pricing. Clearly the strength of the dollar has played out as expected, with considerable additional lift resulting from the US election. This is a strong headwind for crude pricing that looks as though it has legs, perhaps for some number of years. Brexit's impact on the UK GDP is a more nuanced topic.
  - Various pundits have observed that the other shoe for GDP has not yet dropped; implying that perhaps it won't drop at all. This is easily explained. British exports have been robust exactly because the GBP hit a 31-year low in

T1: OPEC-14 CURTAILMENT ALLOCATION, BEGINNING JANUARY 1, 2017

Agreed crude oil production adjustments and levels[1] (tb/d)

Member country	Reference production level	Adjustment	Production level effective Jan. '17	Δ in output
Algeria	1,089	-50	1,039	-4.6%
Angola	1,751	-78	1,673	-4.5%
Ecuador	548	-26	522	-4.7%
Gabon	202	-9	193	-4.5%
Indonesia[2]	—	—	—	—
IR Iran[3]	3,975	90	4,065	2.3%
Iraq	4,561	-210	4,351	-4.6%
Kuwait	2,838	-131	2,707	-4.6%
Libya	—	—	—	—
Nigeria	—	—	—	—
Qatar	648	-30	618	-4.6%
Saudi Arabia	10,544	-486	10,058	-4.6%
UAE	3,013	-139	2,874	-4.6%
Venezuela	2,067	-95	1,972	-4.6%
Total	**31,236**	**-1,164**	**30,072**	**-3.7%**

[1]Reference base to crude oil production adjustment is October 2016 levels, except Angola for which September 2016 is used, and the numbers are from secondary sources, which do not represent a quota for each member country. [2]Indonesia suspended its membership [3]Iran is the only country allowed to increase input based on the agreement
Source: Organization of the Petroleum Exporting Countries, 2016

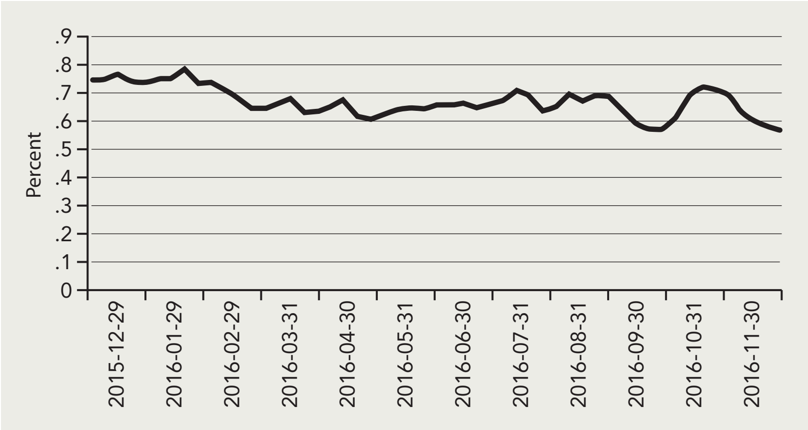
October of 2016 of $1.18 (CNN, 2016), making UK goods substantially cheaper on world markets (Wall Street Journal, 2016). Exports have surged and this growth has stabilized UK GDP for now (The Telegraph, 2016). When Leave is actually negotiated between the UK and the EU, clearly the exit will have penalty clauses which will include trade tariffs. A virtual certainty is that the UK will no longer participate in the EU as part of the member free market system. Any tariffs set by the EU will erode the current UK export price advantage. A simple way to contemplate this is to reflect on which UK exports a user might be willing to pay a 20%+ premium to continue to buy post-Leave. Jaguar or Range Rover? No thanks. If and when the UK export volume tanks, so will their GDP. The UK's exports of goods and services has hovered around 30% of GDP for the past five years (UK Office for National Statistics, 2016).

- Prime Minister May actually said on several occasions that she intended to concentrate on immigration issues more than the trade issues in the exit negotiations. If one wanted to concoct the scenario that is likely to do the maximum damage to the overall UK economy, this is probably it. Fortunately for the UK, Parliament has asserted their privilege to be involved in the exit negotiations, which was upheld by the High Court on November 3rd, 2016 (The Independent, 2016). A Supreme Court judge, Lady Brenda Hale, has suggested that even a "simple Act of Parliament" would not be sufficient to trigger Brexit, potentially delaying the move for two years (Merrick, Theresa May dealt fresh blow as Supreme Court judge signals major delay on starting Brexit, 2016). The Supreme Court threw a further hurdle in the way when it ruled that Scottish and Welsh governments can intervene in the triggering of Article 50 on November 18th, 2016 (Merrick, Brexit: Fresh blow for Theresa May as Supreme Court rules Scotland and Wales can intervene in Article 50 triggering, 2016).
- Also fortunately, someone has apparently warned May of the potential economic storm that is brewing and the Prime Minister has expressed support for cuts in the corporate tax rate and attendant economic stimulation as a partial mitigation against the likely Brexit-driven economic decline.

TAX CUTS IN THE US AND THE UK

- Theresa May "officially endorsed a move by Britain's previous Conservative government to lower the main corporate tax rate to 17% by 2020, from today's 20%" (Wall Street Journal, 2016).
- She "stopped short of endorsing her predecessor's further recommendation—made after the Brexit vote—to go down to 15%" (Wall Street Journal, 2016).
  - Assuming that the UK goes forward with Leave, it is very likely to have a meaningful adverse impact, conceivably disastrous, on the economy of the UK with collateral damage to the EU. The ripple effect of this could be more severe than anyone presently anticipates. We note in passing that the UK Central Bank owns 13% of the ECB (Europa, 2016), which may be the last safety net for Greece and perhaps for several other EU "have-not" members.

F6: LONG-TO-SHORT RATIO (COMMERCIAL), CRUDE FUTURES CONTRACTS



Source: Commodities Futures Trading Commission Reports, 2016

Ripple effects and OECD forecasts

- The procedures and goals outlined by May would put the country on a timetable to exit "not just from the EU, but from the preferential terms of access to EU markets on which investors, both foreign and domestic, rely" (Financial Times, 2016). While the EU currently takes almost half of the UK's exports, the UK will "not be deemed a credible negotiating partner until its EU deal is finalized. By March 2019, then, the UK is likely to find itself without preferential access to any EU markets" (Financial Times, 2016).
- The United States is the largest single investor in Britain, and many firms consider it the gateway to free trade with the EU-28. Brexit would be "bad for the UK, it would be bad for Europe, it would be bad for the world, including the United States," Angel Gurría, secretary general of the OECD, said in a recent interview (Washington Post, 2016).
- In September, the OECD downgraded the UK economy's 2017 GDP forecast by 1% (from 3% to 2%) (Sky News, 2016), and held it at 2% in their November 28th update (OECD, 2016). Other pundits have forecast an actual drop in UK GDP rather than merely a decline in the GDP growth rate.
- As a result, OECD's forecast for the combined GDP of its 36 members – most of which are developed economies – has decreased to 1.7% for year-end 2016 (down from 2.2% for CY 2015) (OECD, 2016).

POSSIBLE "FREXIT"

- France is the next big western democracy with a presidential election pending. The country's presidential election is upcoming in May.
- Marine Le Pen is running on a platform appealing to voter concerns over immigration and globalization. She advocates radical measures including "an exit from the EU, a tightening of asylum criteria, and a ban on the wearing of the Islamic veil in all public places." (Financial Times, 2016).
- Le Pen's election now begins to seem more plausible after Trump's win in the US. In a statement on November 9th, she is quoted as saying: "This election should be interpreted as the victory of freedom. Let's bet that it will give another reason for the French, who cherish freedom so much, to break with a system that hampers them." (Financial Times, 2016).

CONCLUSION

For the reasons outlined, it is hard to see a meaningful improvement in crude pricing or in the health of the industry in the next few years. In fact, it is hard to rationalize any degree of upward slope of the crude futures curve with the currently known facts. Note that the crude futures curve flattened considerably since early November as the market came to this realization. (See Figure 6.) Having said that, absent a global economic cataclysm, all gluts burn off. Prices eventually revert to the mean and life goes on. The crude futures chart tends to reflect this, even if the reasons are not always well understood at the time. We are hopeful for the economies of the US and the world post-election. It is incontestable, although not universally acknowledged, that capitalism works and that socialism does not. The US political landscape now appears to favor the side of capitalism again. Having said that, there does not seem to be a compelling reason to play the crude trade on the long side at present.

In fact, the risk-reward ratio may favor the hedge-sell side of the trade based on the supply overhang, Brexit complexities and their potential for disaster, and the new world economic order that was just launched by the US election, with a currently raging US dollar as an unintended consequence. OGFJ

ABOUT THE AUTHOR

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The shale/price balancing act

DOMESTIC PRODUCTION REPRESENTS THE MARGINAL BARREL OF PRODUCTION FOR THE FORESEEABLE FUTURE

DEBORAH BYERS AND VANCE SCOTT, EY, HOUSTON

WILL US SHALE production serve as a natural cap on crude prices for the foreseeable future? We believe it will — and the resulting compressed price cycles will require oil and gas companies to make significant changes in strategy in order to compete effectively.

There is no question shale plays — through the ongoing application of technology innovations and cost improvements — have disrupted the traditional supply curve. The industry has always been cyclical in nature, but those cycles have typically been long ones, usually featuring multiple years of higher-than-normal prices followed by sharp drops and long recoveries. For example, after the price of oil crashed in 1985, it stayed relatively low for more than 15 years before beginning its upward trajectory.

Shale changes the game. Because of its abundance, the number of economically rational operators involved, its short development cycle and its ability to deliver returns quickly, US shale will likely represent the marginal barrel of production, at least in the medium term.

To be certain, there will still be other resource plays with the ability to impact both global supply and pricing. Like OPEC, for example, deciding to pull back production in an effort to push prices upward. And geopolitical disruptions are always a possibility in an industry that operates in many challenging locations.

Today, many shale operators are completely capable of drilling profitably when the price of oil is relatively low. And — for now — there is enough capacity in the marketplace, in terms of labor, equipment and associated supplies, to ramp up production quickly if prices warrant it. This capacity is also greatly enhanced by the significant efficiency gains in the drilling and completion process that is much more akin to a manufacturing process, something the nimble operators have exceled at exploiting.

When prices move above the economic break-even point — most likely in the neighborhood of $45–$50 a barrel — US operators will react quickly, locking in the economics via volume hedging, deploying the necessary capital and producing to that volume.

As US shale producers respond to price signals, their time from decision-to-drill to first oil is now around 12 months — compared with the much-longer lead time conventional plays require to come online (and with far less project risk).

With quick ramp-up, US shale production will rapidly close any gaps in supply and keep prices from gaining too much upward momentum. Then, as prices fall again, producers will pull back on drilling — or drill but allow wells to remain uncompleted — until the next supply shortfall. These wells remain in inventory and can cycle back even quicker within a three- to six-month time horizon.

As a result, the oil market clearing price will be set by US shale. This quick response means the commodity price cycle will likely be compressed, compared with historical trends. And we'll see more time spent in the trough versus the highs.

Ultimately, US shale will set a natural balancing point.

SHALE STILL ATTRACTIVE

While this may not sound like an exciting business model, US shale is still an attractive investment opportunity for a number of reasons.

For starters, the US remains one of the few places in the world where investors own the rights to underlying resources. That, of course, incentivizes rights owners to allow drilling and reduces project risk due to lack of governmental involvement.

Second, shale drilling is low-cost, and getting lower. The typical authorization for expenditure on a shale well is less than $5 million, and producers continue to peel away significant costs from production while increasing volumes — a trend that has picked up pace during the recent downturn.

Third, shale drilling has short cycle times, less than two months in many cases. Some companies have reduced to fewer than 20 days from start of drilling to production. That allows shale producers to be much more responsive to market pricing.

And fourth, a typical shale well can achieve payback in approximately 1.5 years. That significantly de-risks projects by allowing producers to use hedging to lock in favorable economics.

Compared with offshore wells, for example, shale wells require less project lead time and less up-front capital expenditures, and cash inflows begin much sooner. And although shale's steep well decline rates require additional wells to be drilled on an ongoing basis, stretching out capex over time allows producers to adjust the scope of their projects as market conditions change — drilling more if prices are high and canceling new wells if prices decline.

"There is no question shale plays — through the ongoing application of technology innovations and cost improvements — have disrupted the traditional supply curve...Shale changes the game. Because of its abundance, the number of economically rational operators involved, its short development cycle and its ability to deliver returns quickly, US shale will likely represent the marginal barrel of production, at least in the medium term."

Finally, the industry may get a shot in the arm from energy policies if President Trump holds true to his campaign promises. This could come in the form of regulatory policy as well as comprehensive tax reform. Companies are well-advised to retune their legislative efforts as this unfolds.

OPTIONS FOR PRODUCERS

In this new environment, producers that find themselves with a relatively high-cost portfolio have two options. They can find ways to take out costs and make existing opportunities more profitable, or shift a portion of their portfolio to lower-cost production such as shale.

That latter option may be easier in the longer term. Onshore drilling inventory in the US today is in short supply, and expensive. Companies can find "great rock" for shale drilling, but they will pay handsomely for it.

However, as the lower-for-longer price environment adds stress to the industry, an uptick in transaction activity is inevitable, and there may be increased opportunity to acquire shale reserves with favorable terms in the next few years. Research shows, for example, independent shale producers with a focus in one major basin have outperformed those with scattered assets, which may eventually cause some companies to consider selling or swapping assets to streamline their operations — providing new M&A opportunities.

Companies currently involved in shale will also need to change — adopting and refining an operational model that is better suited to unconventionals, with flexible, timely decision-making and constant portfolio rebalancing. The top-down, centrally planned approach that works well for huge, complex projects hinders shale production and leads to suboptimal capital deployment decisions.

STEPS TO SUCCESS

Risk mitigation in managing portfolios will be key for conventional oil and gas producers learning to compete in a world where prices fluctuate from $40 to $60 (and spend more time at the lower end of that range).

That is especially true for portfolios with large numbers of deepwater or onshore conventional assets, particularly those that will require complex, high-cost projects to reach production.

The first step is improving the ability to accurately identify the risk-adjusted return of every project in their portfolios. Today, too many companies utilize a rudimentary approach to planning that fails to incorporate all actual project risks involved in developing the resource.

For example, some studies show as many as 60% to 65% of capex projects in the oil and gas industry run overschedule and over budget, significantly reducing the economic value the project will deliver. That's an issue with both planning and execution, but properly identifying those risks up-front can help companies avoid painful — and expensive — lessons.

Obviously, the more technically complex the project, the more risk it carries. The same holds true for projects in regions where tax, royalty and local content laws can change rapidly. But companies don't always incorporate these risks fully into their pre-drilling analysis.

Reducing reservoir risk is another critical success factor. Conventional onshore and offshore projects require more sophisticated modeling and simulation analyses than shale opportunities. Companies must fine-tune their decision-making capabilities by properly characterizing reservoirs earlier in the process to eliminate the need for expensive and time-consuming planning and design to accommodate a wide range of outcomes.

These decisions are often impacted by the human factor, too. A team that believes in a project will overlook obstacles and push to drill, even when risks are high. Reducing the human factor can help companies pursue the right projects with the maximum opportunity for financial viability.

Another critical success factor will be employees. In this short-cycle environment, producers will need to develop a more flexible business model to eliminate the hire/fire scramble related to pricing changes. Smart companies will develop a core team of employees at the bottom of a cycle and utilize contractors and temporary employees as prices rise and activity increases. Notably, this will require companies to step up their employee training and knowledge transfer activities so they are ready and able to move quickly when prices rise.

Finally, integrated companies must learn to maximize the built-in advantage of being involved in both upstream and downstream. In a low-price environment, integrated companies often outperform independents because they capture value from the wellhead to the customer. For example, integrated companies can utilize the product knowledge embedded in the organization to help upstream personnel understand how various types of crude can be blended and what specific refiners focus on. Understanding the hydrocarbon value chain can lead to an upside of 10 to 25 cents a barrel in the marketplace, which can add up substantially over time. As a result, in the future, we may see trends turn away from the separation of upstream and downstream assets, with more midsized companies forward-integrating into LNG and petrochemicals to improve the economics of their upstream production.

OTHER OPPORTUNITIES

The growth of shale as the marginal barrel of production could also open up opportunities around the globe.

For example, governments that rely heavily on petrodollars may reach the realization that heavy taxes and royalties are hampering investments in their country, as capital continues to flow to US shale with its relatively stable regulatory climate and other benefits.

Rethinking their fiscal regimes to spur new investment — and recapture much-needed revenues — would open up new markets for oil and gas companies and make previously uneconomic projects viable again. This could, in the long term, fundamentally reset the cost structure of deepwater and conventional drilling in some countries.

Still, the days of outsized returns are likely over. With prices remaining relatively stable for at least a decade, and supply being plentiful, even big discoveries won't deliver huge premiums. When there are plenty of opportunities to drill, but no financial incentive to do so, undeveloped reserves aren't nearly as valuable.

FUNDAMENTAL CHANGE

Some in the industry still believe the price of crude will soon run back up to the $100-a-barrel threshold. But those believers lack a full appreciation for how the fundamental structure of global supply has changed in recent years.

With US shale leading the way, there is long-term stability of supply — and the opportunity to increase production as needed to smooth out shifts in demand. This new era presents a challenge for domestic producers, certainly. But it is also an opportunity for executives to rethink their business model and create lean, agile and responsive organizations that can compete effectively at any price. OGFJ

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The views reflected in this article are the views of the authors and do not necessarily reflect the views of the global EY organization or its member firms.

Compensation trends

REWARDING EMPLOYEES IN THE CURRENT OPERATING ENVIRONMENT

JOSHUA ROSS, AON HEWITT, HOUSTON

MOST COMPANIES in the oil and gas industry use the first quarter of the year to reward employees for their efforts from the previous year in the form of base pay increases, bonuses, and stock grants. However, after two years of depressed commodity prices following the collapse of crude prices in the fourth quarter of 2014, the oil and gas companies continue to adjust their annual spending practices to align with the current operating environment.

Aon conducted a study of more than 60 US-based petroleum-related companies during the fourth quarter of 2016 to capture trends in compensation for the industry going into the new year. In aggregate, more than 140,000 US employees in the oil and gas industry are represented in our research, with participants spanning multiple sectors, including upstream (38%), midstream (36%), oilfield services and equipment providers (15%), and others (11%), such as integrated oils, downstream refining, and petrochemicals. In addition, participants include companies of all sizes based on 2015 revenues, including 20% of participants with revenues between $5 billion and $30 billion; 45% $1 billion and $5 billion; and 35% with less than $1 billion in total revenues.

Year-end business performance is the single most important contributing factor to funding employee bonus pools and other discretionary spending for oil and gas firms. While the industry continues to respond to fluctuations in global and domestic benchmark commodity prices, approximately 75% of organizations were able to forecast their year-end business results in relation to their financial goals. Among those organizations that chose to forecast year-end results, approximately 32% performed below target, 34% performed at target, and 34% performed above target financial performance year. As expected, oilfield services and equipment providers were the most pessimistic about meeting financial objectives, with 66% of participants indicating below target performance. However, upstream producers were more upbeat, with approximately 60% of organizations indicating expected financial performance to be above target levels for the year.


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While most companies did not resort to such drastic measures as reducing base salaries in 2016 (97%), actual base pay increase budgets have been reduced over the past two years, with 44% of firms reporting a salary freeze in place during 2016, including 75% of upstream producers. Most companies (94%) did not report plans to freeze base salaries in 2017. However, companies did indicate that reduced base pay increase budgets are likely to be spread across fewer employees, focusing dollars on high performers, field populations in highly productive geographic areas and key contributors to company success.

Across all participants, projected base pay increase budgets average 2.7% to 2.8% of current base salary payroll, with executives and field employees slightly higher than corporate staff. However, projected base pay increase budgets do vary by industry segment. Midstream organizations maintain a median budget of 3.0%, but upstream producers fall closer to 2.0% at the median. Most oilfield service and equipment providers indicated plans to freeze base pay levels in 2017.

VARIABLE PAY

Despite the downturn in commodity prices, the oil and gas industry continues to outpace general industry in projected spending on variable pay for their non-executive population, reflecting the importance of aligning industry employees with the company's financial success to drive individual and team performance. According to research collected by Aon, oil and gas companies are projected to spend an average of 18.6% of payroll annually for non-executive variable pay salaried exempt employees, which mainly consists of annual bonuses.

However, the average company across general industry spends 12.8% of payroll on variable pay for salaried-exempt employees. The higher spend on variable pay among oil and gas companies is mainly driven by the larger proportion of salaried-exempt employees in the petroleum business with deep technical expertise and the impact of these employees on business results compared to general industry.

It is important to note that while 27% of all participants were unsure of their financial performance for the year, 40% of upstream producers remained unsure at the time of our research, indicating many firms are taking a wait-and-see approach to finalizing funding for their employee bonus pools and other discretionary spending in 2017, with several firms indicating an expectation of delaying base pay increases for at least a few months from the previous year.

LONG-TERM INCENTIVES

A long-term incentive, or equity compensation, is highly prevalent throughout the oil and gas industry beyond solely executives in the board room. While executives will receive a significant portion of their total direct compensation in equity, even at lesser values, it continues to serve as a retention device that aligns employees with the financial success of the company.

Most companies began planning for their 2017 long-term incentive grants in the fourth quarter of 2016. Long-term incentive practices vary significant by company due to corporate structure, share availability and company culture; however, the following trends exist:

- Upstream producers often grant long term incentives to employees below the management level to key contributors in technical disciplines, with half the sector granting shares to employees at all levels in the organization.
- Privately held companies generally will restrict access to long-term incentives higher in the organization than publicly traded companies, as vehicles are either more complex or cash-based.
- For publicly traded companies, the predominant form of equity compensation is a mix of time-based restricted stock and performance-based restricted stock, with executive compensation more heavily aligned with performance-based restricted stock.
- Since many performance-based restricted stock grants vest based on performance relative to peer organizations, executives of companies with better relative performance may see significant value delivered despite depressed market values for investors.
- Vesting periods for time-based vehicles will vary between three and five years from the date of grant, generally vesting in equal tranches throughout the vesting period.
- Performance-based grants generally will vest on a cliff date, where performance is assessed through a lookback period.

During 2016, many upstream producers, mainly due to their historic granting practices, ran into the conundrum of insufficient shares or a dilution rate that may alert investor watchdog organizations to sustain historic granting practices. According to our research, in the fourth quarter of 2016, upstream producers were significantly more likely to adjust their methodology for determining long-term incentive grant values for employees in 2016, with 41% employing some alternative methodology to reduce the number of shares required.

Most organizations employed some discretion by managers on who should receive grants, while others chose more quantitative ways of using fewer shares, while some organizations chose to utilize an alternative cash-based vehicle, despite not knowing how long prices would stay depressed and knowing three years from now, these grants will come due.

> *"Despite the downturn in commodity prices, the oil and gas industry continues to outpace general industry in projected spending on variable pay for their non-executive population, reflecting the importance of aligning industry employees with the company's financial success to drive individual and team performance."*

Other adjustments that upstream producers deployed in their grant valuations included:

- Maintaining the same level of dilution from outstanding shares as the previous year
- Reducing eligibility for grants
- Using a historical or average stock price from an earlier period
- Reducing prevalence of grants
- Fixed dollars budget

Long-term incentive compensation continues to be an important element in the overall rewards for employees in the oil and gas industry. As equity valuations improve with the global landscape, companies have to remember the impact of these awards on employees nearing retirement and key successors to their roles.

Organizations throughout the industry have to remain nimble and focused on the timing of execution. Much of this timing requires talent to be engaged in the process, understanding how each organization can maximize on movements in the market and capitalizing at the right time. Rewards programs are just one lever to use to engage employees, and with budgets more constrained, organizations often need to find different tools to help them achieve their results.

Developing stretch roles for high-performing employees to further their knowledge and capabilities; investing in employee development and mentorship programs; and employee recognition can all have as great, or even greater, impact than monetary rewards on employees' overall satisfaction and engagement. OGFJ

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Midstream agreements in a stressed environment

A POST-SABINE ANALYSIS

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COVENANTS RUNNING with the land or executory contracts? A mere two years ago, few pondered the legal characterization of gas dedications contained in the thousands of gathering, processing and transportation contracts between oil and gas producers and their midstream counterparties. Today this issue is of profound importance to the US energy industry. Since the beginning of 2015, more than 85 US oil and gas producers have sought bankruptcy protection in the wake of plummeting commodity prices. At the forefront of these bankruptcy proceedings—most notably in the legal cases of Sabine Oil & Gas Corp. and Quicksilver Resources Inc. —producers and midstream companies have squared off over whether the dedications in gathering and processing agreements are real property interests, and therefore immune from the reach of the bankruptcy court, or executory contracts that may be jettisoned through the restructuring process.

The domestic shale boom has resulted in markedly increased domestic oil and gas production and a surge in the associated oil and gas infrastructure. Over the last decade and a half, midstream companies have collectively invested billions of dollars in developing the infrastructure necessary to gather, process and transport domestic oil and gas. In exchange, these midstream companies contract with producers for a promise of payment based on the volume of oil and gas gathered, processed or transported, and dedications of the underlying oil and gas interests/mineral interests and associated acreage. The fees charged to producers under the gathering and processing contracts are designed to provide midstream companies, over a period of time, a return of and on their capital investment.

From the midstream perspective, gas dedications operate as security by burdening the oil and gas interests, thereby binding all successors to the terms of the original bargain. Midstream companies have historically undertaken the large capital investments, and their lenders have financed these midstream projects, with the understanding that these dedications are real property interests that bind successors to the mineral interests. That is, regardless of any change to the leasehold ownership, any hydrocarbons produced from the subject acreage remain

"The midstream sector has posited that judicial determinations that dedications are not covenants running with the land or equitable servitudes, and therefore subject to rejection in a bankruptcy proceeding, will have negative consequences to producers and consumers."

dedicated to the midstream company and subject to the terms of the gathering and processing contracts. Midstream companies have traditionally filed memoranda of the agreements in the real property records to put potential transferees on notice of the dedication. This is because producers routinely transfer or otherwise divest themselves of all or a portion of their mineral interests after granting the dedication to the midstream company.

The midstream sector has posited that judicial determinations that dedications are not covenants running with the land or equitable servitudes, and therefore subject to rejection in a bankruptcy proceeding, will have negative consequences to producers and consumers. The Gas Processing Association, a midstream trade association, has stated that such "a determination would threaten the sanctity of thousands of bargained-for agreements between midstream companies and their producer counterparties; would undermine investor confidence in midstream companies, raising the cost of capital to invest in infrastructure; would force midstream companies and producers to include more costly assurances in their contracts, such as, reservation charges, secured collateral or other guarantees; and would undermine the market in which mineral interests are transferred by threatening the dedications that underpin midstream investments."

In Sabine, the only court case thus far to rule on the characterization of dedications, Sabine sought court approval to reject four of its midstream contracts. In a landmark ruling, US Bankruptcy Judge Shelley Chapman determined the gathering and processing contracts between Sabine and its midstream counterparties were executory contracts—not real property interests—and could therefore be rejected. The judicially authorized rejection of the four gathering and processing agreements is estimated to have saved Sabine as much as $115 million.

There is currently an ongoing appeals process in the Sabine case. And it is further important to note that the Sabine decision is not binding precedent. Therefore, another court interpreting a different midstream agreement is free to reach a different conclusion.

In other producer bankruptcies where the covenant running with the land issue has been raised, most notably Quicksilver Resources Inc. and Emerald Oil Inc., the producers and their midstream counterparties have been able to work out commercial resolutions to re-negotiate existing gathering and processing agreements. The commercial agreements have prevented further court rulings on the issue.

Sabine's rejection of the Nordheim and HPIPP contracts enhanced its prospects for a successful restructuring; and other financially strapped producers will undoubtedly seek to leverage this uncertainty into more favorable commercial arrangements with their midstream counter-parties. This may take the form of using the bankruptcy process to reject existing midstream agreements. Or it may lead parties to renegotiate existing midstream agreements. Either way, the possibility of an outright rejection or renegotiation of existing midstream agreements creates substantial uncertainty for the midstream industry.

Additionally, financially solvent producers can expect new challenges in their commercial negotiations with midstream service providers. With the enforceability of dedications in question, midstream companies are more likely to seek additional assurances in their contracts, such as, minimum volume commitments, reservation charges, secured collateral or other financial commitments.

Doubt over whether midstream agreements are as secure as parties previously believed is but one of the consequences of the current oil bust. And this consequence has the potential to fundamentally change the way producers and their midstream counterparties analyze the risk involved in the large scale midstream infrastructure projects that transport oil and natural gas across the nation. OGFJ

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Legal liability from cyber attacks

HOW TO MINIMIZE YOUR COMPANY'S LEGAL EXPOSURE FROM DATA BREACHES

PHILIP J. BEZANSON AND CAROLYN ROBBS BILANKO, BRACEWELL LLP, SEATTLE

CYBER ATTACKS have become commonplace, and the threats they pose continue to evolve. Although the most high-profile attacks have typically involved theft of personal, financial, political, or business information that could be sold at a profit or used for competitive damage or public embarrassment, there are additional dramatic implications for energy companies.

The energy sector, along with other manufacturing and infrastructure institutions, bear the risk that hackers could access company databases and control systems for the malicious purpose of causing mayhem, tangible business disruption, or destruction to people and property.

Oil and gas companies face the specific threat of environmental-, religious-, and political-cyber-terrorists targeting upstream, midstream, and downstream sites. Such attacks endanger expensive company equipment, the environment, and the lives of on-site company personnel.

Whatever the type of attack, the monetary and reputational consequences can be significant. Data breaches often trigger investigations by the US Federal Trade Commission, the US Securities and Exchange Commission, the US Department of Justice, and state regulatory agencies, as well as class-action lawsuits and shareholder derivative actions. The modern inevitability of cyber attacks behooves directors and officers at oil and gas companies to allocate adequate funds and time to implement cyber security risk-management strategies that protect sensitive business information and property and minimize the company's legal exposure.

Here, we offer five tips on how energy companies can mitigate their legal liability from cyberattacks.

IDENTIFY AN INCIDENT RESPONSE TEAM IN ADVANCE

Since company employees are often the first to detect or learn of a cyber attack, all company personnel should be trained to immediately escalate the issue to the chief information security officer (CISO) (if the company has one) or the general counsel (GC). The CISO or GC should then immediately notify and mobilize the incident response team (IRT). While there may be a tendency to "wait and see" what details emerge before giving such notice, it is critical to elevate the issue immediately so the IRT can begin searching for the access point of the breach and assessing the damage.

The IRT should include the company's top executives (including a CISO, if possible), legal counsel, relevant IT support, and personnel who are able to convey updates to employees, business partners, investors, regulators, and other potential internal and external stakeholders.

Once the IRT has an initial grasp of what transpired (or is still taking place), the company may need to bring in external support. This includes notifying the board of directors, engaging outside legal counsel, hiring a forensic investigation firm, notifying the company's insurers, and contacting law enforcement. (Today, the FBI is considered the lead federal agency for investigating cyber attacks, but local law enforcement and/or other governmental agencies may be appropriate depending on the type of attack.) The company also may want to engage a call center to handle the inevitable surge in customer calls and a PR firm to coordinate communications with the media.

If personal information of the company's employees and/or clients may have been compromised, contact a credit or personal identity theft monitoring company immediately. Companies that are frequently targeted by cyber-attackers should consider signing retainer agreements with such entities. By listing the names and contact information of these external entities in the company's incident response plan, the company will be able to immediately receive the support it needs to address and mitigate the damage from cyberattacks.

REVIEW YOUR INSURANCE POLICIES

Insurers now offer a variety of policies that cover losses stemming from cyber attacks. Coverage options vary by insurer, but may include notification costs, forensic investigation costs, legal defense costs (including attorney fees, judgments, and/or settlements), regulatory response costs (including attorney fees and/or settlements with the government), revenue due to lost business, and ransom/extortion payments.

Oil and gas companies facing threats to their physical property and equipment also should review their property and criminal insurance policies for coverage in the event of a cyberattack. Insurance policies for company directors and officers should also be available in the event that litigation and/or governmental investigations ensue.

STAY UP-TO-DATE ON REGULATORY OBLIGATIONS

Laws pertinent to cyber security are rapidly being passed and then expanded, both domestically and abroad. In the US, 47 states and four territories currently have security breach notification laws. (Alabama, New Mexico, and South Dakota do not.) While these laws (and their associated penalties) vary by state, they generally require companies to disclose data breaches of personal information to affected individuals, in writing, within a short period of time. Some states have exemptions for encrypted information and companies working with law enforcement. Additionally, publicly traded companies that experience a cyber attack may need to file a Form 8-K under US securities laws, which require disclosure of "material events" to shareholders within four business days. Because disclosure obligations can be complicated and highly fact specific, companies experiencing a cyber attack should immediately consult experienced disclosure counsel for guidance on whether a filing is warranted.

As many oil and gas companies commonly operate outside of the US, they also need to stay informed about rapidly changing foreign legislation. For example, while Alberta is currently the only province in Canada with a mandatory breach notification law for private companies, federal regulations are on their way. In mid-2015, Canada passed the "Personal Information Protection and Electronic Documents Act" (PIPEDA). When the law comes into effect, it will require organizations to report to the Privacy Commissioner of Canada (and, generally, to affected individuals and certain third parties) any breach of security safeguards that are reasonably believed to create "a real risk of significant harm to an individual." To the extent that a company operates abroad, it should hire local or international counsel (including translators, if necessary) to keep it abreast of new or changing laws relating to cyber security.

IMPLEMENT AND UPDATE COMPANY DATA PRESERVATION AND DESTRUCTION POLICIES

While health care and financial institutions may be the most obvious examples of companies storing private customer information subject to cyber theft, oil and gas companies also store sensitive data along the lines of confidential business plans, information about proprietary technology and research, and private employee and customer information. Limiting the amount of sensitive data stored by the company is a clear way to limit the risk of it being breached. Thus, implement company policies that securely dispose of data that is no longer needed. This may include an automatic email deletion policy, standard deletion of employee and customer information upon termination of the relationship, or other policies prompting review and potential deletion of files that have not been accessed after a certain period of time.

If your company outsources storage of its data to a third party, ask in-depth questions about their security policies, request secure destruction of data as appropriate, and clearly address liability for potential security breaches in your contract.

"If personal information of the company's employees and/or clients may have been compromised, contact a credit or personal identity theft monitoring company immediately. Companies that are frequently targeted by cyber-attackers should consider signing retainer agreements with such entities."

Also note that individuals and companies are required to preserve relevant documents and evidence once they reasonably anticipate litigation stemming from an event, including from a security breach. Thus, upon discovering a cyber attack, a company may need to implement a company-wide litigation hold, which requires temporarily pausing the company's data destruction policies.

PRACTICE

As with all company policies and procedures, employees will not follow an incident response plan unless they a) know they exist and b) know how to follow them. Employees should receive annual training on how to recognize threats and how to report them. The IRT should do a full run-through of the company's incident response plan at least once a year so employees can knowledgeably and rapidly respond in the event of a real breach. In training, use realistic examples and provide feedback to instill best practices. Companies can take additional steps to protect themselves by expanding response plans to include oversight if and when vendors, joint venture partners, or other commercial allies fall victim to a cyber attack.

While cyber attacks are increasingly sophisticated, companies that anticipate and plan for them will be ready to react, thereby mitigating their liability and losses in the lawsuits and government investigations that follow. OGFJ

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India's gas hydrates

COMMERCIAL PRODUCTION IS STILL A DECADE AWAY, BUT NGH ARE A POTENTIAL GAME-CHANGER FOR INDIA

MANISH VAID, OBSERVER RESEARCH FOUNDATION, NEW DELHI

THE UNITED STATES GEOLOGICAL SURVEY (USGS), which is involved in natural gas hydrate (NGH) research in India and Japan, has assisted the Indian Oil Ministry in discovering highly enriched accumulations of NGH in the Bay of Bengal. This discovery is the first of its kind with a potentially producible large accumulation of gas hydrates in the Krishna Godavari Basin, off India's east coast.

Hydrate Energy International (HEI) has estimated India's NGH resource potential at 933 trillion cubic feet, which could represent a global energy game changer, provided the technologies for gas production from hydrate reservoirs are established techno-economically.

While research and development organizations around the world are defining and developing multiple techniques to explore and exploit natural gas hydrates, the Indian government is mulling production testing for some of these reserves.

The biggest incentive behind accelerating research and development of NGH is its abundance, which surpasses all other global fossil fuels combined. Therefore, this resource could become an energy game-changer for the world, solving the energy woes of a number of countries, such as India, which currently must import a high percentage of their fuel supplies.

The second biggest motivation for developing NGH is that they are widely distributed in marine surroundings, where 99% of global inventory is located. The remaining 1% is present in the permafrost in Arctic regions.

India would do well to develop its own NGH reservoirs and fast-track its NGH program to deal with its increasing energy demand, uncertainty of its supplies, and urgent need to reduce greenhouse gases (GHG). However, like other countries, India, too, is in a nascent stage of developing its NGH resources, in part due to economic and technical challenges.

WHAT ARE NATURAL GAS HYDRATES?

The term NGH is used interchangeably with "methane hydrate," "gas hydrate," and "clathrate." These are solid ice-like combinations of water and methane formed naturally under the conditions of high pressure and low temperature, known as the Gas Hydrate Stability Zone (GHSZ). In addition to such conditions, the presence of organic carbon can ensure the availability of NGH in the region. It is estimated that gas hydrates account for about one-third of the world's mobile organic carbon.

Natural gas hydrates are formed in two main regions, the Arctic and in the ocean (see Figure 1). In the Arctic, NGH are formed where cold air temperatures create thick zones of permanently frozen soils, or permafrost, at a depth of about 300 to 400 meters (1,000 to 1,300 feet) below the land surface.

In the case of an ocean or deep inland lakes, when methane and water combine at high pressure and low temperature generated by 300 to 500 meters (1,000 to 1,600 feet) or more of overlying water, NGH are formed. However, in both the cases, the high concentration of the deposits as well as its safe recovery plays an important role in NGH occurrences. Further, in a marine environment, NGH exist in deep water, shallow water depths, and even in warmer sea-bottom temperatures, depending on the precise chemical composition.

In the Gulf of Mexico, for instance, NGH have been found at shallow water depths and high temperature waters of 20 degrees centigrade (68 degrees Fahrenheit). This can happen due to the presence of ethane in the gas mixture, providing more stability and making the existence possible in warmer waters with lower pressures. Thus, a gas mixture that contains just 10% ethane makes an NGH stable at 6 atmospheres (atm) with 60 meters (200 feet) of water column. This contrasts with 100% methane hydrates, which are stable only at pressures exceeding approximately 40 atmospheres with a 400-meter (1,300-foot) water column.

NGH have not been extensively studied due in part to their occurrence in relatively inaccessible polar and marine environments. It wasn't until the 1970s when the existence of NGH was confirmed by industry drilling in Arctic permafrost. Marine NGH were confirmed in the 1980s during scientific expeditions, including that of the Deep-Sea Drilling Program's R/V Glomar Challenger. Figure 2 shows various locations at which NGH have been recovered and or confirmed to date.

According to Arthur H. Johnson of HEI, US, the global resource potential of gas hydrates is vast, indicating 43,300 trillion cubic feet of reserves, of which about 50% is expected to be technically recoverable.

FROM PROBLEM TO POTENTIAL

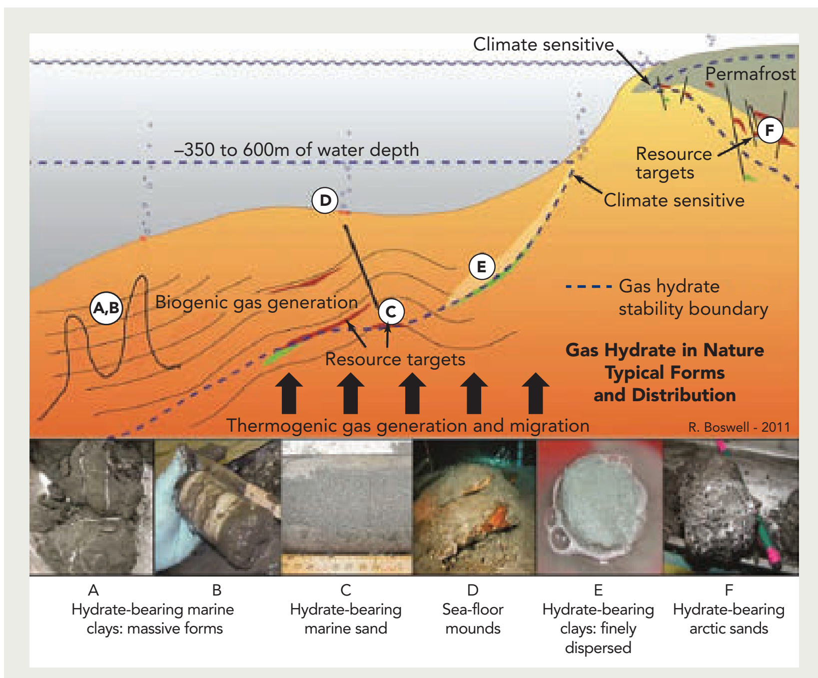
NGH are volatile compounds that are stable in the extreme cold and tremendous weight of deep water. However, when natural gas hydrates are built up inside the drill column of a well, they become extremely dangerous. Destabilized heat and lower pressure can prompt NGH to expand quickly to 164 times their volume leading to an explosion, as occurred with BP's Deepwater Horizon rig in the Gulf of Mexico rig on April 20, 2010. This resulted in loss of life and an estimated three million gallons of crude oil pouring into the Gulf and endangering the marine ecosystem. NGH have long been regarded as a drilling hazard, going back to the 1930s, when the hydrates formed blockages in oil and gas pipelines.

But growing energy demand, climate concerns, and a desire to shift towards cleaner fossil fuels have changed the interpretation of NGH as a potential energy resource of the future. However, producing NGH and effectively converting them to energy in an environmentally safe manner remain a significant challenge.

In this regard, technology will have to play bigger role in tapping into this potentially huge energy resource. Just as technology helped create a shale boom in the United States, it will have to do so to enable the exploitation of gas hydrates. NGH are found mainly in difficult terrains such as in deep and ultra-deep waters and in the Arctic, so new technologies will prove crucial in their development.

However, the considerable rewards of releasing methane from the NGH fields must be balanced with risks. This warrants more stringent efforts towards mitigating the inherent risks associated with developing NGH. The challenge therefore, also pertains with respect to uncontrolled release of methane from hydrate formations into the atmosphere,

F1: TYPES OF GAS HYDRATE DEPOSITS



Source: US Department of Energy

which could result in leakage and make NGH extraction inefficient and uneconomical. According to the report, titled, "Frozen Heat: A Global Outlook on Methane Gas Hydrates" published by the United Nations Environment Program in 2014, gas hydrate dissociation might amplify future warming, ocean acidification, and oxygen loss.

However, recent studies also suggest that circulation of cold seafloor water near exploration or production activities is sufficient to dramatically reduce the risk of NGH-induced sediment instability, besides the usage of other refrigeration techniques. This significantly reduces the environmental risk character of the NGH resources.

Bringing down the cost of producing natural gas from NGH fields is yet another challenge. At the nascent state of current technologies and level of expertise available, extracting gas hydrates is a very costly affair, making its commercial production unlikely for the next 10 to 15 years, barring a quick technological breakthrough.

Darren Spalding and Laura Fox of Bracewell in London, in an article titled, "Challenges of Methane Hydrates" published in the May 2014 issue of Oil and Gas Financial Journal, estimated the cost of producing gas from methane hydrates in the range of US$30 to US$50 per million British thermal units (MMBTUs). This enormous cost, according to the International Energy Agency (IEA), can be brought down significantly between US$4.70 and US$8.7 per MMBTU once efficient practices and processes are developed.

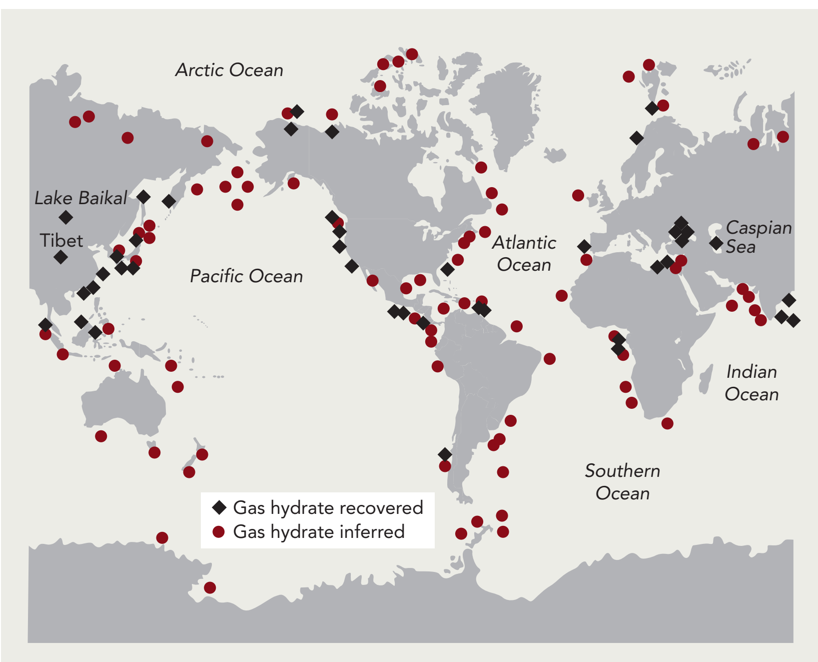
After realizing the resource potential of NGH, the world is now evolving fast from viewing this energy source as a problem to developing ways to manage the same. This can support the global efforts in shifting towards cleaner fossil fuel in a big way as an alternate fuel to oil and coal, thereby reducing emissions from GHG significantly.

Given the poor energy endowments of major importing countries such as Japan, India, and South Korea and the need to shift towards cleaner fossil fuels such as natural gas, several countries have initiated NGH programs. The US Department of Energy (DOE) has so far played a leading role in NGH research, followed by Japan, which initiated a research program in the mid-1990s.

However, NGH research is still at the research stage with no commercial production so far established anywhere in the world. In this regard, several production research and development studies have been carried out at places such as the Mallik site in Canada's Mackenzie Delta and the Nankai Trough off the southern coast of Japan, under their respective programs.

In the United States, the NGH program is operated by the DOE, whose major focus has been the Gulf of Mexico. In addition, the DOE, along with the USGS and Japan, are working to evaluate potential drilling locations and develop viable project structures.

F2: GLOBAL OCCURRENCES OF GAS HYDRATES



Source: Map compiled by USGS

GAS HYDRATE PROGRAMS IN INDIA

In India, gas hydrate programs were initiated in 1996 by the Gas Authority of India Limited (GAIL) under the auspices of the Ministry of Petroleum & Natural Gas (MoPNG). Built on the results of the US Department of Energy's first national NGH program of 1982, the National Gas Hydrate Program (NGHP) was restructured under the Directorate General of Hydrocarbons (DGH).

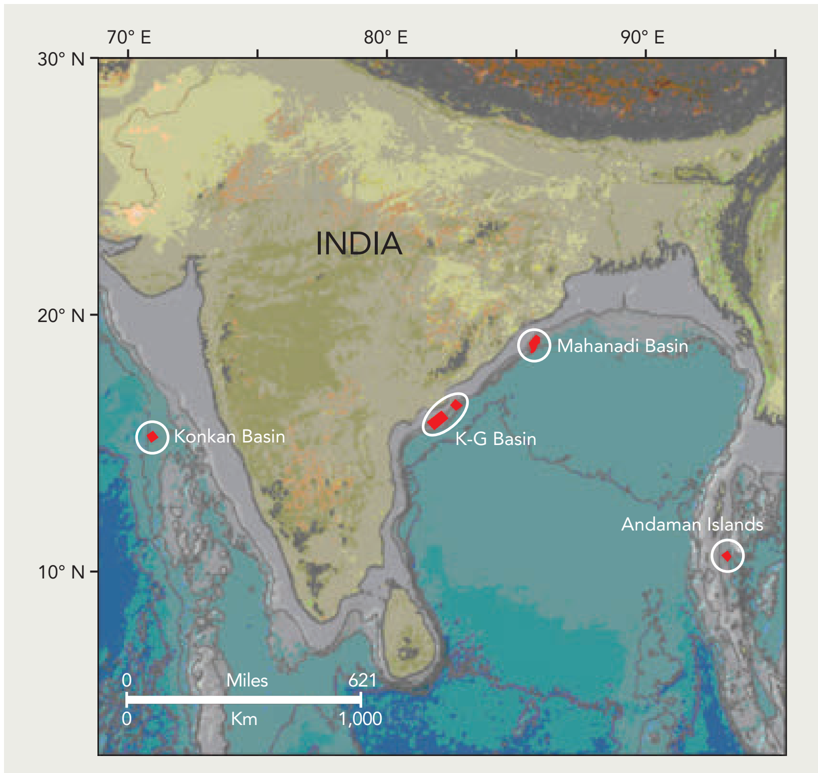
National upstream companies such as Oil and Natural Gas Corporation Limited, GAIL, Indian Oil Corporation Limited and Oil India Limited, and national research institutions such as the National Institute of Oceanography (NIO), the National Geophysical Research Institute (NGRI), and the National Institute of Ocean Technology (NIOT) were entrusted to reanalyze the resource potential of NGH along the Indian shelf followed by technology development for safe production of gas from NGH.

Further, MoPNG and DGH have signed MoUs with agencies such as the USGS, the US-DOE (under renewal), the US-Minerals Management Services (now Bureau of Ocean Energy Management) (under renewal), Japan Oil, Gas and Metals National Corporation (JOGMEC), GFZ-POTSDAM, Germany and IFM-GEOMAR, Germany.

NGHP carried out its Expedition-01 in 2006 in which the presence of significant quantities of NGH has been established in the Krishna Godavari (KG), Mahanadi, and Andaman basins. Under this expedition no assessment has been made on the potential of gas hydrates in this region. However, Hydrate Energy International has estimated the NGH potential in India at 933 TCF.

Under this phase, 21 sites were drilled in four areas – the Kerala-Konkan Basin, west coast; the Krishna-Godavari Basin, east coast; the Mahanadi Basin, east coast; and the Andaman Sea (see Figure 3).

F3: NGHP - EXPEDITION-01 AREAS



Source: USGS, ICICI Securities

The Expedition-02, approved by the Steering Committee in 2015, has been tasked to identify sites which would ideally have (1) sand dominated gas hydrates occurrence, (2) reasonably compacted sediments and (3) occurrence of free gas below the gas hydrate stability zone. Under this expedition, drilling and coring operations were carried out by a state-of-the-art Japanese vessel, called Chikyu, hired for exploring for gas hydrates in the KG basin, which drilled 40 wells.

The Steering Committee has also approved the fund sharing of the expenditure of NGHP Expedition-02. Based on the results of this phase, further surveys and geo-scientific studies will be planned to identify suitable locations for carrying out pilot production testing in NGHP Expedition-03.

Earlier, under the Ministry of Earth Sciences (MoES), a comprehensive research-oriented gas hydrates program was launched emphasizing the scientific and technological development with objectives like, understanding the nature of distribution of gas hydrates in marine sediments; developing techniques for detection and quantification of gas hydrates; identifying promising sites on regional scale and estimating the resource potential and monitoring environmental perturbation during harvesting of gas hydrates. During the previous financial year 2015-16, the Government of India allocated Rs. 1179 crore to the MoES for Oceanography Research and Meteorology, including research on NGH.

CONCLUSION

In his speech at Petrotech-2016, Indian Prime Minister Narendra Modi once again emphasized the need to increase India's domestic oil and gas production and to reduce import dependence while striving towards a gas-based economy. The accelerated NGH program of India is a step forward in this direction. As with the technological developments that helped launch the shale boom in the US and saw rapid expansion in the span of a single decade, global NGH research and production could follow suit.

Notably, unlike above the ground complexities of shale production, NGH deposits have physical properties and reservoir settings that appear conducive to production using conventional hydrocarbon recovery methods. Thus, production testing of NGH may lead to direct supply of gas the existing infrastructure in place. However, the evaluation of future NGH will certainly depend on social, economic, environmental, and political considerations, besides addressing scientific and technical bottlenecks, particularly with regard to its environmentally safe extraction and transportation to the existing natural gas infrastructure and markets.

For the immediate future, it is important that the government continues to push harder for NGH research through sufficient funding and active participation of the hydrocarbon industry. Given certain constraints, commercial production is still at least a decade away. This allows India concurrently to augment its other non-conventional energy sources, such as shale gas and coal-bed methane (CBM) in addition to conventional domestic energy sources in its pursuit of energy security goals. OGFJ

ABOUT THE AUTHOR

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The views expressed in the article are that of the author.

Adverse possession

THE LAWS IN TEXAS, AND IN THE OIL PATCH, GET TRICKY

ANDREW ZEVE, AUSTIN LEE AND WILLIAM MOSS, BRACEWELL LLP, HOUSTON

THE MOST BASIC EXAMPLE of adverse possession is when a landowner fences in land that belongs to a neighbor. This is trespassing, but if a long enough period of time passes without the neighbor bringing a trespass claim, the trespasser can acquire title by adverse possession. Texas law complicates things a bit by having four separate adverse possession statutes – depending on various factors, the time period is three years, five years, 10 years, or 25 years. Tex. Civ. Prac. & Rem. Code 16.024-16.028.

In the oil and gas industry, adverse possession can be even trickier. A property owner can have title to both the surface and mineral estates in a given tract of land, or these estates might be severed and owned separately. Further, a number of different property interests can be created from the mineral estate—working interests, royalty interests, overriding royalty interests, non-participating royalty interests, among others, each of which can be owned in various undivided percentages by multiple owners. Some of these interests can be adversely possessed, and some cannot. A brief discussion of each is below.

SURFACE AND MINERAL ESTATE, NOT SEVERED

This one is easy. If the surface and mineral estate have not been severed, then they can be adversely possessed together. Possession of the surface of an unsevered estate for the requisite period of time vests title in both the surface and mineral estates. Carminati v. Fenoglio, 267 S.W.2d 449, 453 (Tex. Civ. App.—Fort Worth 1954, writ ref'd n.r.e.) ("Where there has been no severance of mineral estate from the surface, the ordinary rules of adverse possession apply.").

SURFACE ESTATE, SEVERED FROM THE MINERAL ESTATE

Here, the surface estate can be adversely possessed (as in the example above where land gets fenced in). Importantly, if the mineral estate has been severed from the surface estate, possession of the surface alone will not constitute adverse possession of mineral estate. Natural Gas Pipeline Co. of Am. v. Pool, 124 S.W.3d 188, 193 (Tex. 2003).

MINERAL ESTATE

A mineral estate can be adversely possessed. "Generally, courts across the country, including Texas courts, have said that in order to mature title by limitations [i.e. adverse possession] to a mineral estate, actual possession of the minerals must occur. In the case of oil and gas, that means drilling and production of oil or gas." Pool, 124 S.W.3d at 192-93. Interests in the mineral estate are typically characterized as either working interests or leasehold interests, each of which consist of the right to produce the minerals under a given tract and the obligation to bear the costs of exploring for and developing such minerals. As such, the "title" obtained to the mineral estate via adverse possession is discussed below with respect to the various types of "Working Interests" and "Leasehold Interests."

ROYALTY INTEREST

Royalty interests, in their simplest form, are cost-free interests in production from the mineral estate under a given tract of land and, once created, are owned separate from, and are carved out of, the mineral estate that they burden. Assume that a producer pays royalties to an individual for a number of years under the belief that the individual had a royalty interest in the mineral estate in a given tract of land. The producer then learns that the individual actually owns no royalty interest in that tract. When the producer stops paying the individual, the individual claims that she has title to the royalty via adverse possession—is she correct? Nope. Because a royalty interest is non-possessory (i.e. the royalty interest entitles you to a cost-free share of production when and if it is produced from the subject tract, but gives the holder thereof nothing to possess until that production is obtained, nor does it entitle the holder to any right to go onto the subject tract and cause that production to occur, the rules of adverse possession do not apply as nothing is being possessed, adversely or otherwise. Sun Oil Co. v. Madeley, 626 S.W.2d 726 n.6 (Tex. 1982); Coates Energy Trust v. Frost Nat'l Bank, 2012 Tex. App. LEXIS 9718 at *26-27 (Tex. App.—San Antonio Nov. 28, 2012, pet. denied); Saunders v. Hornsby, 173 S.W.2d 795, 797 (Tex. App.—Amarillo 1943, no writ). It should be noted that this is the case even in the circumstance where the owner of the royalty interest has the right to take its royalty share of production "in kind" because the royalty owner's right to that production is still inherently void of the right to go onto the tract and cause that production to occur (and thus is still non-possessory). See Saunders, 173 S.W.2d at 797 (holding that a plaintiff who had wrongfully received royalty payments could not adversely possess a royalty interest, stating "appellant merely converted to his own use the oil and gas that had already been produced by the Gulf Production Company and did not affect that which remained in the ground….").

NON-PARTICIPATING ROYALTY INTEREST (NPRI)

An NPRI is a royalty interest carved out of the mineral estate but it is differentiated from other royalty interests in that it lacks certain rights, such as the executive right to lease the subject mineral estate and the right to collect bonus and delay payments from any such lease. Just like a royalty, an NPRI cannot be adversely possessed because it is non-possessory.

OVERRIDING ROYALTY INTEREST (ORRI)

An overriding royalty interest is a royalty interest that is carved out of a leasehold interest (and thus only survives as long as the underlying lease is in effect), and a leasehold interest can be adversely possessed (see below). That said, an ORRI is not possessory—it is a type of royalty interest and is void of the right to go onto the tract in question and cause production to occur. There is no Texas case law specifically discussing if an ORRI can be adversely possessed, but it seems likely that adverse possession does not apply. See generally Portwood v. Buckalew, 521 S.W.2d 904, 919 (Tex. Civ. App.—Tyler 1975, writ ref'd n.r.e.) (finding that claim of adverse possession of overriding royalty interests failed because there was no actual possession of the mineral estate). Other states considering the issue reached this conclusion. See Connaghan v. Eighty-Eight Oil Co., 750 P.2d 1321, 1324 (Wyo. 1988) (holding that an ORRI cannot be adversely possessed and citing Texas cases—including Portwood—holding that receipt of royalty payments is not a basis for adverse possession of a royalty).

LEASEHOLD INTEREST/OPERATED WORKING INTEREST

Unlike a royalty, a working interest (whether occurring through ownership of the mineral estate or through ownership of a lease of the mineral estate) is a possessory interest (i.e. the owner of that interest has the right to enter onto the subject tract and cause production to occur) and can be adversely possessed. For example, assume a lease has a cessation-of-production clause and expires due to production from the lease ceasing without additional operations being conducted or delay rentals being paid for the requisite period stated in the lease. What if the (now former) lessee drills new wells and pays royalties on the same terms as the lease after the lease terminated? The lessee is clearly trespassing on the mineral estate by taking minerals it has no right to take. If enough time passes without complaint, the lessee can acquire title to the mineral estate through adverse possession. The scope of this title is limited: "The lessees acquired the same interest that they adversely and peaceably possessed, that is, the oil and gas leasehold estates as defined by the original leases." Pool, 124 S.W.3d at 199.

NON-OPERATING WORKING INTEREST

Where there are multiple working interest owners that are all entitled to produce minerals on a given tract, the parties typically enter into a joint operating agreement (JOA) that designates one working interest owner as the operator and the rest as non-operators of the area covered by the JOA (Contract Area). The operator drills and maintains the wells while the non-operators share in the costs and revenues based on the percentage interest each non-operator owns in the Contract Area. Assume, for example, that a non-operator is believed to own a 10% working interest. What if, after 10 years of this non-operator receiving and paying joint interest billings under the JOA and receiving revenue based on a 10% working interest, the operator determines that the non-operator actually owns only an 8% working interest? Has the non-operator adversely possessed the extra 2%? This is a difficult question. As seen above, the Texas Supreme Court made clear in the Pool case that a working interest owner can acquire title to a mineral estate (working interest or leasehold interest) by adverse possession by taking oil and gas out of the ground. But a non-operating working interest is not taking oil and gas out of the ground—it is not possessing anything. A non-possessory interest such as a royalty interest is not subject to adverse possession, and a non-operating working interest is similar to a royalty interest because it is non-possessory. On the other hand, although the non-operating working interest holder is not taking the minerals from the ground, he/she is paying the costs of the operator to do so unlike a royalty owner, and the designation of another working interest owner as the "operator" under the JOA simply allows for a coordinated arrangement for developing the Contract Area. There is no Texas case law directly on point as to whether a non-operator can adversely possess a non-operated working interest or leasehold interest, so it's hard to be certain how a court would rule on an adverse possession claim made by a non-operating working interest owner. OGFJ

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Tillerson seals Exxon legacy with Bass deal en route to Washington

ANDREW DITTMAR, PLS INC., HOUSTON

DC ISN'T THE ONLY AREA in the United States with January fireworks as upstream deal activity kicked off with a bang in the Permian and Eagle Ford. Early 2017 deal markets are being driven by multi-billion-dollar moves by Sanchez Energy, Noble Energy and even the granddaddy of them all, ExxonMobil. Just through the first three weeks of 2017, US upstream markets have already racked up $14 billion in deals, or 20% of the 2016 total.

After patiently biding its time, Exxon finally jumped into the market and scooped up companies owned by the Bass family including operating firm BOPCO for $5.6 billion in equity plus a $1.0 billion cash sweetener that kicks in starting in 2020. The deal was reportedly negotiated personally by Rex Tillerson with members of the Bass family. The Bass family companies are principally focused on the New Mexico portion of the Delaware Basin, where they have leased up 250,000 net acres in large, contiguous blocks that are largely held by production. Exxon estimates the resource potential for these assets to be 3.4 Bboe, which more than doubles Permian resources owned through shale subsidiary XTO.

This deal is notable on the seller side as well. The Bass family of Fort Worth is one of the most distinguished in the Texas oil industry with roots stretching back to the early days of wildcatting. Perry Richardson Bass joined his uncle and legendary wildcatter Sid Richardson in discovering the giant Keystone field in West Texas along with other finds around the world. The family has subsequently diversified outside of oil and gas with investments as widespread as Disney and, in recent years, Blue Bell ice cream. Notably, the Bass family followed another famous oil family, the Yates, who also sold their New Mexico Permian position for $2.5 billion in EOG Resources equity. It is remarkable that in just a few months, two of the longest running Permian family oil-built fortunes decided to sell/partner with two of the best run companies to ensure their futures.

Just one day before the Exxon deal with Bass, another sto-

PLS INC. MONTHLY DEAL MONITOR – *12/17/16 - 1/16/17*

SELECT US UPSTREAM TRANSACTIONS

Date Announced	Buyer	Seller	Value ($MM)	Asset Location	Deal Type	O/G
17-Jan-17	ExxonMobil	Bass Family Companies	$5,600	NM Permian: Delaware Unconv.	Corporate	Oil
16-Jan-17	Noble Energy	Clayton Williams	$3,225	TX Permian: Delaware Unconv.	Corporate	Oil
12-Jan-17	Sanchez Energy; Blackstone Group	Anadarko Petroleum	$2,300	South Texas: Eagle Ford	Property	Oil
12-Jan-17	WPX Energy	Panther Energy II; Carrier Energy	$775	TX Permian: Delaware Unconv.	Property	Oil
12-Jan-17	PLS Confidential	Synergy Resources	$71	Colorado: Niobrara	Property	Oil + Gas
10-Jan-17	Parsley Energy	PLS Confidential	$650	TX Permian: Midland & Delaware	Property	Oil
3-Jan-17	Venado Oil & Gas	SM Energy	$800	South Texas: Eagle Ford	Property	Oil
22-Dec-16	Alta Resources	Anadarko	$1,240	Pennsylvania: Marcellus	Property	Gas
20-Dec-16	Covey Park	Chesapeake	$465	N. Louisiana: Haynesville	Property	Gas
20-Dec-16	KLR Energy Acquisition Corp.	Tema Oil & Gas	$400	TX Permian: Delaware Unconv.	Corporate	Oil
		Total	$15,526			

SELECT GLOBAL MIDSTREAM TRANSACTIONS

Date Announced	Buyer	Seller	Value ($MM)	Asset Location	Deal Type	Asset Type
4-Jan-17	DCP Midstream Partners	Spectra Energy Corp.; Phillips 66	$3,851	US: Diversified	Corporate	Gathering & Processing: Gas
3-Jan-17	Tallgrass Energy Partners	Tallgrass Development	$140	US: Rockies	Asset	Oil Terminals & Gas Pipeline
20-Dec-16	Alberta Investment Management	EnLink Midstream	$190	US: Eagle Ford & Marcellus	Corporate	Gathering & Processing: Gas
		Total	$4,181			

Prepared by PLS Inc. For more information, email memberservices@plsx.com
Validity of data is not guaranteed and is based on information available at time of publication.

ried Permian independent rode off into the sunset when Clayton Williams agreed to sell itself to Noble Energy for $3.2 billion. Clayton has assets across the Permian, but the core of its portfolio and the reason for interest from Noble is 71,000 net acres located in the Southern Delaware Basin primarily in Reeves County. The acreage is well positioned in an oily portion of the county and near active drilling activity. The quality of the acreage is reflected in Noble's adjusted acquisition price of just over $32,000/acre, right in line with other core southern Delaware deals.

While Clayton Williams' (Claytie to industry veterans) roots in the Permian don't date back quite as far as the Bass family, the company still has a notable 35-year-plus legacy riding the booms and busts of the oil business. After dropping below $7/share in March, Claytie found a top and sold off at a remarkable $138.97/share.

These sales don't mean all family-run independents are cashing out in this boom though and some are even doubling down. Sanchez Energy partnered with Blackstone (50/50) to buy out Anadarko's interest in a massive Eagle Ford asset located mostly in Dimmit and Webb counties. Named Comanche by Sanchez, the asset covers 155,000 net acres (318,000 gross) and has net production of 67,000 boe/d. Sanchez knows this area of the Eagle Ford perhaps better than anyone from its experience drilling the nearby Catarina project, which it acquired from Shell in 2014. Sanchez also leased 110,000 net acres north of Comanche and has now leap-frogged to the third largest Eagle Ford acreage holder, behind EOG and Lewis Energy.

Teaming up with Blackstone plus getting funding from the firm's credit arm GSO Capital Partners allowed Sanchez to take down an asset substantially larger than its market cap. In turn, Blackstone was able to pick up an interest in a world-class asset in conjunction with an experienced operator. The two companies will be joined in the Eagle Ford by new non-op partner and KKR portfolio company Venado Oil & Gas, which bought out SM Energy's stake for $800 million one week earlier.

Both Anadarko and SM Energy have been very active in deal markets as they focus their portfolios on core projects with the highest returns. For SM, this means selling Bakken assets in addition to Eagle Ford to raise capital for drilling up the Midland Basin properties it acquired in the second half of 2016. Anadarko, meanwhile, also reached an agreement in late December to sell its Marcellus position to Alta Resources for $1.2 billion. Moving forward, Anadarko is focused on its core Delaware Basin, DJ Basin and Deepwater Gulf of Mexico assets.

Deal activity in the midstream and oilfield service sectors has been more subdued after they went through a major period of consolidation recently. FMC Technologies was able to complete its 50-50 merger with Technip to form a combined subsea powerhouse firm. OGFJ

SELECT INTERNATIONAL UPSTREAM TRANSACTIONS

Date Announced	Buyer	Seller	Value ($MM)	Asset Location	Deal Type	O/G
19-Jan-17	Sound Energy	Oil & Gas Investment Fund	$234	North Africa: Morocco	Property	Gas
16-Jan-17	Inpex	Abu Dhabi Nation Oil Co.	-	Middle East: UAE	Property	Oil
9-Jan-17	Total	Tullow Oil	$900	Africa: Uganda	Acreage	Oil
4-Jan-17	Undisclosed	Kelt Exploration	$75	Canada: Montney	Property	Oil + Gas
2-Jan-17	PetroRio	Fundo Brascan de Petroleo	-	South America: Brazil	Acreage	Oil + Gas
25-Dec-16	Delek Group	Dana Petroleum	$53	Norway: North Sea	Property	Oil + Gas
23-Dec-16	Trident Exploration	Undisclosed	$17	Canada: CBM	Property	Gas
24-Dec-16	ONGC Videsh	Gujarat State Petroleum	$995	India	Property	Oil + Gas
		Total	$2,273			

SELECT GLOBAL OILFIELD SERVICE TRANSACTIONS

Date Announced	Buyer	Seller	Value ($MM)	Asset Location	Deal Type	Asset Type
17-Jan-17	Tenova	FMC Technologies	Undisclosed	US: Pennsylvania	Asset	Materials Handling
6-Jan-17	Dril-Quip	OilPatch Technologies	$20	US: Texas	Corporate	Offshore Riser Systems
5-Jan-17	Schlumberger	Summit Partners	Undisclosed	UK: Aberdeen	Corporate	Downhole Tools
3-Jan-17	Undisclosed	Magnum Hunter	Undisclosed	US: Texas	Asset	Well Drilling Services
26-Dec-16	Rosneft	Sistema	$67	Russia	Asset	Drilling Rigs
		Total	$87			

3Q16: Still not back to zero, but improving

DON STOWERS, *EDITOR – OGFJ*
LAURA BELL, *STATISTICS EDITOR – OIL & GAS JOURNAL*

THREE MONTHS AGO, we said that total revenue and net income for the OGJ150 group of US-based companies had finally come out of a two-year tailspin and had begun to show improvement. As we look at the results for this group in the third quarter of 2016, this is still the trend. Revenues and income continue to improve, although the companies as a group continue to bleed red ink.

With crude prices moving into the $50 to $60 range and remaining steady, operators have been able to adjust their operations to this new reality. As a result, well-managed companies are leading the way to profitability again. Shale producers operating in the Permian and Delaware basins of West Texas and southeastern New Mexico for the most part have been the top performers recently, although several other plays are starting to show signs of life as well. There has even been M&A activity in plays such as the Cotton Valley in East Texas, the Haynesville in northwest Louisiana, and the Eagle Ford in South Texas, some of this triggered by private capital, which is finally making some long-awaited moves into upstream and midstream deals.

Total revenue for the group inched up by nearly $10.4 billion (8%) from the previous quarter and stood at $127.7 billion by quarter's end. However, that figure was down approximately $17.8 billion (12%) compared to the same period in 2015. The

SOME KEY CHANGES FROM PREVIOUS QUARTER

How company appeared on last quarter's list	Why change?	How company appears on this quarter's list
Memorial Resources Development Corp.	Merged with	Range Resources Corp.

THE TOP 20 IN NET INCOME AND STOCKHOLDERS' EQUITY*

Rank	Company	Net income, $1,000	Rank	Company	Stockholders' equity, $1,000
1	ExxonMobil Corp.	2,889,000	1	ExxonMobil Corp.	177,010,000
2	Chevron Corp.	1,301,000	2	Chevron Corp.	147,952,000
3	Penn Virginia Corp.	1,146,614	3	ConocoPhillips	36,456,000
4	Devon Energy Corp.	1,007,000	4	Occidental Petroleum Corp.	22,296,000
5	California Resources Corp.	546,000	5	Hess Corp.	20,915,000
6	Halcon Resources Corp.	475,568	6	Marathon Oil Corp.	18,922,000
7	Antero Resources Corp.	238,255	7	Anadarko Petroleum Corp.	15,912,000
8	Kinder Morgan CO_2 Co. LP	217,000	8	EOG Resources Inc.	11,798,312
9	Consol Energy Inc.	161,075	9	Pioneer Natural Resources Co.	10,431,000
10	Ultra Petroleum	98,407	10	Devon Energy Corp.	10,061,000
11	Rice Energy Inc.	74,413	11	Noble Energy Inc.	9,845,000
12	Energen Corp.	53,314	12	Antero Resources Corp.	7,980,282
13	Exco Resources Inc.	50,936	13	Apache Corp.	7,949,000
14	QEP Resources Inc.	50,900	14	Range Resources Corp.	5,460,813
15	Newfield Exploration Co.	48,000	15	Murphy Oil Corp.	5,085,588
16	W&T Offshore Inc.	45,928	16	Whiting Petroleum Corp.	4,604,019
17	Triangle Petroleum Corp.	29,847	17	Continental Resources Inc.	4,260,698
18	Pioneer Natural Resources Co.	22,000	18	QEP Resources Inc.	3,635,100
19	Callon Petroleum Co.	21,139	19	WPX Energy Inc.	3,634,000
20	Matador Resources Co.	12,047	20	Energen Corp.	3,172,127
	Total	**8,488,443**		**Total**	**527,379,939**

*Based on 3rd quarter ended Sept. 30, 2016

THE TOP 20 FASTEST GROWING COMPANIES[1]

3rd quarter rank by total assets	Company	Stockholders' equity — Most recent quarter ($1,000)	Stockholders' equity — Preceding quarter[2] ($1,000)	Change, %	Net income — Most recent quarter ($1,000)	Net income — Preceding quarter[2] ($1,000)	Change, %	Long-term debt — Most recent quarter ($1,000)	Long-term debt — Preceding quarter[2] ($1,000)
106	Sabine Royalty Trust	4,718	3,291	43.4	8,527	5,854	45.7	0	0
79	PrimeEnergy Corp.	69,195	65,333	5.9	4,716	4,290	9.9	3,143	93,008
32	Energen Corp.	3,172,127	3,116,231	1.8	53,314	36,759	45.0	19,000	551,245
1	ExxonMobil Corp.	177,010,000	176,875,000	0.1	2,889,000	1,681,000	71.9	28,916,000	29,499,000

[1]Based on 3rd quarter ending Sept. 30, 2016, unless otherwise noted. Companies were selected on the basis of growth in stockholders' equity from previous quarter. Only companies with positive net income for both quarters were considered. Companies were not considered if they had a decline in net income, were subsidiaries of another company, or became public within the last year. [2]Based on previously reported data.

8% growth in revenue from the prior quarter is about half the 18% revenue growth seen in the second quarter of 2016, so it would be a mistake to assume this is a linear recovery.

Here is a quick look at total revenue for the OGJ150 group of companies for the past eight quarters:

3Q16 – $127.7 B
2Q16 – $117.3 B
1Q16 – $100.2 B
4Q15 – $123.9 B
3Q15 – $145.5 B
2Q15 – $159.3 B
1Q15 – $145.2 B
4Q14 – $198.1 B

As you can see, total revenue for the group bottomed out in the first quarter of 2016 and has improved in the two subsequent quarters.

Similarly, here is a glimpse at net income figures for the group for the past eight quarters (brackets indicate a net loss):

3Q16 – [$1.03 B]
2Q16 – [$17.11 B]
1Q16 – [$18.94 B]
4Q15 – [$58.45 B]
3Q15 – [$47.27 B]
2Q15 – [$28.51 B]
1Q15 – [$15.17 B]
4Q14 – $2.52 B

The last quarter that showed a positive net income was the fourth quarter of 2014, and that was a fairly modest amount – $2.5 billion. We've had seven consecutive quarters of net losses. Losses for the group peaked in the third and fourth quarters of 2015. It's been a long, slow road to recovery – and we're not quite there yet. At least not as of Sept. 30, 2016. In the coming weeks, we'll see what the final numbers were in the fourth quarter and for the year. Reports are starting to come in as of this writing (late January).

Net income remains in negative numbers, although the improvement seen during the third quarter of 2016 was significant. The group showed a net loss of slightly more than $1.0 billion for the quarter compared with a net loss of $17.1 billion in 2Q16. Year over year, the $1.0 billion loss looks even better than the $47.3 billion loss in the 3Q15. So the movement is in the right direction, but we're still not back to zero.

By press time for this issue, only 108 of the 135 publicly traded companies included in the OGJ150 Quarterly Report had reported their financial results to the US Securities Exchange Commission. Of these companies, only 34 reported a positive net income for the third quarter. However, this is up from the 20 companies that reported a positive net income in the previous quarter.

ExxonMobil once again led the way as the top company in net income with $2.9 billion in reported income. For the previous quarter, the Irving, Texas-based company had $1.7 billion in net income. XOM was followed by Chevron Corp. at $1.3 billion; Penn Virginia Corp. at $1.1 billion; Devon Energy at $1.0 billion; California Resources Corp. at $546 million; Halcon Resources Corp. at $476 million; Antero Resources Corp. at $238 million; Kinder Morgan CO2 Co. LP at $217 million; Consol Energy at $161 million; and Ultra Petroleum at $98 million.

The producers showing the biggest losses for the quarter were (in order): Chesapeake Energy – $1.2 billion; ConocoPhillips – $1.0 billion; Anadarko Petroleum – $747 million; Southwestern Energy–$708million;WhitingPetroleum–$693 million; Apache Corp. – $559 million; Seneca Resources Corp. – $453 million; Sandridge Energy – $404 million; Breitburn Energy Partners LP – $365 million; and Hess Corp. – $317 million.

In all, 68% of the 108 reporting companies had a net loss for the quarter. That is down from 81% that reported a net loss for the previous quarter. Also, in the last quarter five companies reported losses in excess of $1 billion. For the 3Q16, only two companies (Chesapeake and ConocoPhillips) reported losses greater than $1 billion.

THE TOP 20 IN SPENDING*

Rank	Company	Capital, exploratory spending, $1,000
1	Chevron Corp.	14,100,000
2	ExxonMobil Corp.	12,603,000
3	ConocoPhillips	3,870,000
4	Anadarko Petroleum Corp.	2,618,000
5	Occidental Petroleum Corp.	1,845,000
6	EOG Resources Inc.	1,781,547
7	Hess Corp.	1,764,000
8	Devon Energy Corp.	1,659,000
9	Pioneer Natural Resources Co.	1,387,000
10	Apache Corp.	1,281,000
11	Noble Energy Inc.	1,164,000
12	EQT Production	1,090,033
13	Antero Resources Corp.	1,009,851
14	Marathon Oil Corp.	983,000
15	Chesapeake Energy Corp.	980,000
16	Concho Resources Inc.	926,922
17	Continental Resources Inc.	878,928
18	Murphy Oil Corp.	781,668
19	Newfield Exploration Co.	692,000
20	Rice Energy Inc.	681,741
	Total	**52,096,690**

*Based on year-to-date Sept. 30, 2016.

THE TOP 20 IN TOTAL REVENUE*

Rank	Company	Total revenue, $1,000
1	ExxonMobil Corp.	58,677,000
2	Chevron Corp.	30,140,000
3	ConocoPhillips	6,516,000
4	Devon Energy Corp.	4,233,000
5	Occidental Petroleum Corp.	2,733,000
6	Chesapeake Energy Corp.	2,276,000
7	EOG Resources Inc.	2,118,504
8	Anadarko Petroleum Corp.	1,893,000
9	Apache Corp.	1,438,000
10	Marathon Oil Corp.	1,229,000
11	Hess Corp.	1,196,000
12	Pioneer Natural Resources Co.	1,186,000
13	Antero Resources Corp.	1,116,503
14	Noble Energy Inc.	910,000
15	Southwestern Energy Co.	651,000
16	Seneca Resources Corp.	607,977
17	Continental Resources Inc.	526,199
18	EQT Production	502,546
19	Murphy Oil Corp.	500,533
20	California Resources Corp.	456,000
	Total	**118,906,262**

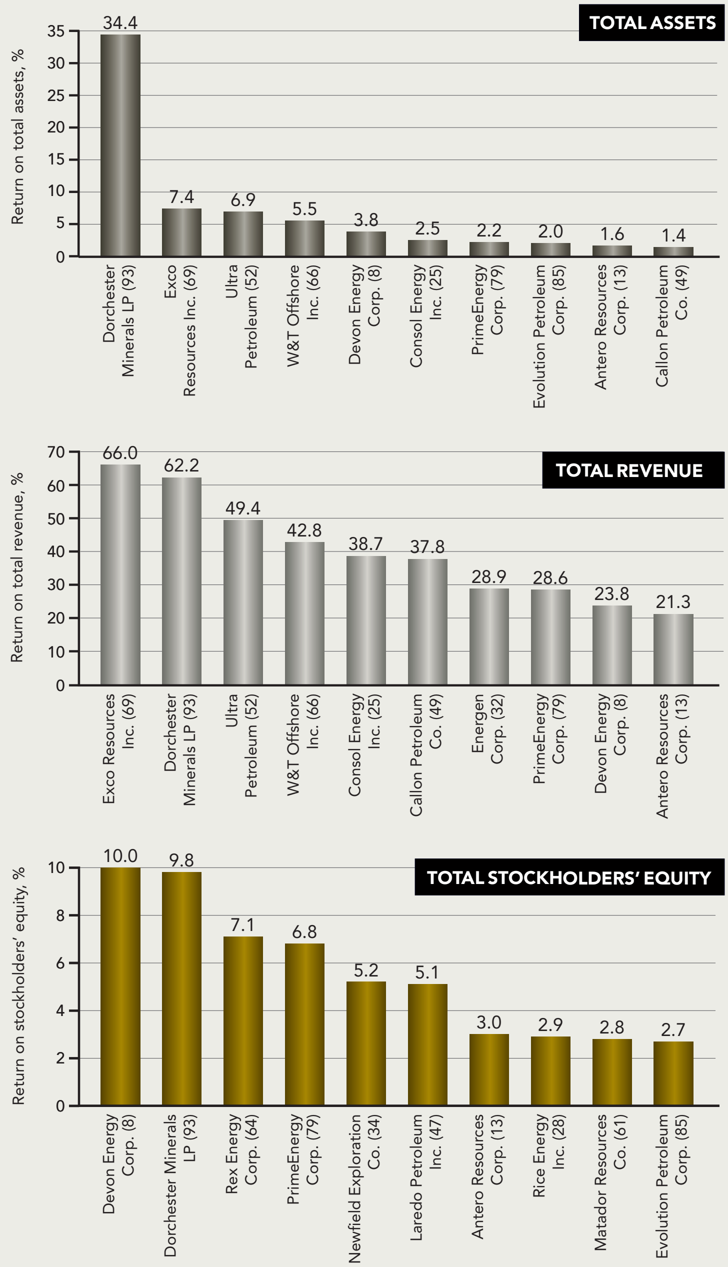
*Based on 3rd quarter ended Sept. 30, 2016

THE TOP 20 IN ASSETS — MARKET CAPITALIZATION[1]

Rank	Company	Market capitalization, $1,000
1	ExxonMobil Corp.	361,923,393
2	Chevron Corp.	194,289,218
3	ConocoPhillips	53,860,521
4	Anadarko Petroleum Corp.	34,911,360
5	Occidental Petroleum Corp.	55,724,625
6	Hess Corp.	16,977,221
7	Marathon Oil Corp.	13,391,070
8	Devon Energy Corp.	23,095,996
9	EOG Resources Inc.	53,309,318
10	Apache Corp.	24,234,152
11	Noble Energy Inc.	15,475,420
12	Pioneer Natural Resources Co.	31,507,984
13	Antero Resources Corp.	7,466,120
14	Continental Resources Inc.	19,460,964
15	Chesapeake Energy Corp.	4,863,834
16	Concho Resources Inc.	17,720,204
17	Range Resources Corp.	9,575,143
18	Murphy Oil Corp.	5,234,882
19	Whiting Petroleum Corp.	2,531,776
20	EQT Production[2]	12,545,686
	Total	**958,098,890**

[1]As of Sept. 30, 2016. [2]Parent company data.

TOP COMPANIES IN RETURN ON...*



*Includes companies whose accounting methods vary. Excludes companies whose results were inflated by identifiable extraordinary gains. Excludes royalty trusts. Numbers in parentheses indicate rank by total assets.

YTD CAPITAL SPENDING

Year-to-date capital spending in the third quarter of 2016 stood at approximately $63.3 billion, down about 48% from the $121.9 billion in the third quarter of 2015. This represents a spending cut of nearly half of expenditures, year over year, in the same quarter. So oilfield services companies, drilling contractors, and equipment manufacturers are obviously still not happy with volumes at this point.

TOTAL ASSET VALUE

Total asset value for the OGJ150 group of companies has fallen by $116 billion (8%) since the third quarter of 2015. It currently stands at a little more than $1.2 trillion. The decline from the previous quarter was less than 1%.

STOCKHOLDERS' EQUITY

In another sign that the economic recovery in the oil patch may be approaching, stockholders' equity rose slightly in the third quarter to $547 billion, an increase of about $1.2 billion from the second quarter. Although this represents less than 1% growth, at least it is not negative. However, producers still have a long way to go. At this point in 2015, stockholders' equity stood at about $614.5 billion. Therefore, we have experienced about a 10% decline in stockholders' equity since then.

Memorial Resources Development Corp., which appeared on last quarter's list, merged with Range Resources Corp. and is no longer listed separately.

There were no "fastest-growing companies" to report for this quarter. OGFJ

Rank by total assets 3Q16	Company	Total assets $1,000	Stockholders' equity Rank	Stockholders' equity $1,000	Total revenue Rank	Total revenue $1,000	Net income Rank	Net income $1,000	YTD Capital & expl. spending Rank	YTD Capital & expl. spending $1,000
		3rd Quarter ending Sept. 30, 2016								
1	ExxonMobil Corp.	339,386,000	1	177,010,000	1	58,677,000	1	2,889,000	2	12,603,000
2	Chevron Corp.	259,863,000	2	147,952,000	2	30,140,000	2	1,301,000	1	14,100,000
3	ConocoPhillips	94,284,000	3	36,456,000	3	6,516,000	107	(1,026,000)	3	3,870,000
4	Anadarko Petroleum Corp.	45,417,000	7	15,912,000	8	1,893,000	106	(747,000)	4	2,618,000
5	Occidental Petroleum Corp.	41,630,000	4	22,296,000	5	2,733,000	96	(241,000)	5	1,845,000
6	Hess Corp.	34,459,000	5	20,915,000	11	1,196,000	99	(317,000)	7	1,764,000
7	Marathon Oil Corp.	32,310,000	6	18,922,000	10	1,229,000	93	(192,000)	14	983,000
8	Devon Energy Corp.	26,813,000	10	10,061,000	4	4,233,000	4	1,007,000	8	1,659,000
9	EOG Resources Inc.	25,554,921	8	11,798,312	7	[1]2,118,504	92	(190,000)	6	1,781,547
10	Apache Corp.	23,149,000	13	7,949,000	9	1,438,000	103	(559,000)	10	1,281,000
11	Noble Energy Inc.	22,469,000	11	9,845,000	14	910,000	89	(143,000)	11	1,164,000
12	Pioneer Natural Resources Co.	16,325,000	9	10,431,000	12	1,186,000	18	22,000	9	1,387,000
13	Antero Resources Corp.	14,629,253	12	7,980,282	13	1,116,503	7	238,255	13	1,009,851
14	Continental Resources Inc.	13,865,252	17	4,260,698	17	526,199	88	(109,621)	17	878,928
15	Chesapeake Energy Corp.	12,523,000	96	(932,000)	6	2,276,000	108	(1,154,000)	15	980,000
16	Concho Resources Inc.	11,570,634	31	1,194,583	21	[2]430,548	84	(51,146)	16	926,922
17	Range Resources Corp.	11,327,259	14	5,460,813	24	413,207	81	(41,971)	32	339,446
18	Murphy Oil Corp.	10,394,015	15	5,085,588	19	500,533	64	(16,176)	18	781,668
19	Whiting Petroleum Corp.	10,065,744	16	4,604,019	45	129,225	104	(693,055)	25	434,794
20	EQT Production[3]	9,222,067	—	—	18	502,546	68	(22,010)	12	1,090,033
21	WPX Energy Inc.	7,446,000	19	3,634,000	33	251,000	95	(219,000)	24	440,000
22	Linn Energy LLC[4]	7,402,948	99	(1,582,359)	26	385,665	94	(198,365)	45	179,332
23	QEP Resources Inc.	7,275,200	18	3,635,100	27	382,400	14	50,900	26	411,200
24	Southwestern Energy Co.	6,890,000	33	1,123,000	15	651,000	105	(708,000)	27	391,000
25	Consol Energy Inc.[5]	6,537,210	—	—	23	416,191	9	[6]161,075	63	48,746
26	California Resources Corp.	6,332,000	90	(493,000)	20	456,000	5	546,000	66	45,000
27	SM Energy Inc.	5,785,433	28	1,847,915	28	[2]352,660	80	(40,907)	21	492,794
28	Rice Energy Inc.	5,587,992	23	2,530,450	35	[2]198,920	11	74,413	20	681,741
29	Cabot Oil & Gas Corp.	5,531,921	21	2,863,250	30	310,429	60	(10,260)	37	245,033
30	Oasis Petroleum Inc.	5,398,261	25	2,387,504	38	177,311	77	(33,942)	31	340,314
31	Denbury Resources Inc.	4,816,801	37	847,344	32	253,985	72	(24,590)	46	176,631
32	Energen Corp.	4,569,124	20	3,172,127	37	184,385	12	53,314	33	314,581
33	Cimarex Energy Co.	4,538,747	26	2,333,282	29	335,717	62	(12,818)	22	485,114
34	Newfield Exploration Co.	4,213,000	36	916,000	25	392,000	15	48,000	19	692,000
35	Kinder Morgan CO_2 Co. LP[7]	4,211,000	—	—	31	310,000	8	[8]217,000	—	—
36	BreitBurn Energy Partners LP	4,189,854	39	[9]677,871	43	133,569	100	(364,600)	60	59,001
37	Parsley Energy Inc.	3,756,472	24	2,462,594	44	132,665	47	(1,641)	28	385,076
38	Diamondback Energy Inc.	3,525,680	22	2,835,295	42	142,131	42	(600)	38	241,609
39	Freeport McMoran Inc.[5]	3,462,000	—	—	22	427,000	98	(289,000)	47	160,000
40	PDC Energy	3,417,280	27	1,986,060	39	164,030	70	(23,309)	29	353,722
41	Gulfport Energy Corp.	3,075,843	30	1,725,120	36	194,023	91	(157,296)	23	441,128
42	RSP Permian Inc.	2,974,820	29	1,840,186	53	93,621	31	985	41	207,437
43	Unit Corp.	2,481,191	32	1,189,576	41	153,408	71	(24,022)	49	154,558
44	Memorial Production Partners LP	2,473,740	44	420,525	57	74,222	76	(32,866)	61	50,534

Rank by total assets 3Q16	Company	Total assets $1,000	Stockholders' equity Rank	Stockholders' equity $1,000	Total revenue Rank	Total revenue $1,000	Net income Rank	Net income $1,000	YTD Capital & expl. spending Rank	YTD Capital & expl. spending $1,000
		3rd Quarter ending Sept. 30, 2016								
45	Sandridge Energy Inc.	1,886,504	100	(2,675,521)	50	104,056	101	(404,337)	44	186,452
46	EV Energy Partners LP	1,766,376	35	[9]922,321	63	51,372	66	(19,230)	79	14,266
47	Laredo Petroleum Inc.	1,756,448	49	187,101	40	159,734	21	9,485	35	276,735
48	Vanguard Natural Resources LLC	1,545,885	93	(736,819)	46	126,285	97	(245,368)	62	49,190
49	Callon Petroleum Co.	1,527,604	34	1,100,719	60	55,927	19	21,139	51	122,698
50	Clayton Williams Energy Inc.	1,436,952	50	182,780	61	55,438	90	(148,776)	59	62,331
51	Carrizo Oil & Gas Inc.	1,420,507	84	(205,359)	48	111,177	87	(101,174)	30	346,245
52	Ultra Petroleum	1,420,231	101	(2,895,921)	34	199,253	10	98,407	43	189,511
53	Legacy Reserves LP	1,392,446	82	[9](118,950)	55	83,540	54	(4,303)	69	27,966
54	Halcon Resources Corp.[10]	1,351,048	51	132,836	51	102,454	6	475,568	40	236,906
55	Bill Barrett Corp.	1,335,553	42	509,179	65	50,553	73	(26,186)	54	93,704
56	Seneca Resources Corp.[11, 12]	1,323,081	—	—	16	607,977	102	(452,842)	36	256,104
57	Stone Energy Corp.	1,235,507	91	(519,661)	52	94,427	86	(89,635)	42	200,622
58	Bonanza Creek Energy Inc.	1,224,397	55	84,756	67	49,325	78	(34,902)	65	47,491
59	Eclipse Resources Corp.	1,202,991	40	609,335	62	54,479	74	(26,801)	55	92,204
60	Sanchez Energy Corp.	1,185,119	94	(761,144)	47	114,807	85	(66,262)	39	241,323
61	Matador Resources Co.	1,177,693	43	437,794	54	88,733	20	12,047	34	288,175
62	Approach Resources Inc.	1,122,581	41	573,463	73	23,749	59	(9,073)	76	17,299
63	Synergy Resources Corp.	992,619	38	833,061	72	26,244	67	(19,241)	56	82,318
64	Rex Energy Corp.	925,273	57	76,138	70	[2]34,039	25	5,415	64	48,640
65	Comstock Resources Inc.	885,512	85	(220,023)	66	50,330	75	(28,476)	68	41,142
66	W&T Offshore Inc.	832,597	92	(677,997)	49	107,403	16	45,928	71	24,062
67	Chaparral Energy Inc.	826,003	97	(1,027,008)	58	65,847	55	(5,491)	52	119,994
68	Midstates Petroleum Co. Inc.	695,692	98	(1,533,090)	59	64,193	79	(38,384)	50	129,072
69	Exco Resources Inc.	685,991	95	(837,590)	56	77,186	13	50,936	57	70,455
70	Swift Energy Co.	445,448	56	83,324	64	50,591	33	394	48	155,809
71	Northern Oil and Gas Inc.	410,372	89	(476,060)	69	45,109	82	(45,619)	58	66,931
72	Contango Oil & Gas Co.	383,660	46	251,455	74	19,576	61	(12,485)	74	19,849
73	Earthstone Energy Inc.	333,476	45	273,093	81	10,593	53	(3,900)	78	15,272
74	Penn Virginia Corp.	306,866	48	187,454	71	33,010	3	1,146,614	77	15,359
75	Gastar Exploration Inc.	299,967	83	(161,072)	79	13,003	36	(178)	67	43,175
76	Resolute Energy Corp.	294,871	87	(339,141)	68	47,419	65	(18,856)	53	98,313
77	Mid-Con Energy Partners LP	280,624	52	115,547	78	13,966	50	(2,421)	81	5,111
78	Ring Energy Inc.	227,334	47	211,895	85	7,829	56	(5,944)	72	22,345
79	PrimeEnergy Corp.	213,927	58	69,195	76	16,499	26	4,716	80	11,701
80	Panhandle Oil and Gas Inc.[13]	198,135	53	115,192	82	10,151	32	737	83	3,986
81	PetroQuest Energy Inc.	174,369	86	(236,810)	75	17,094	69	(22,021)	73	22,084
82	Abraxas Petroleum Corp.	162,742	63	23,022	77	13,976	52	(3,260)	70	24,632
83	Black Hills Corp.[5]	158,970	—	—	83	9,639	58	(8,828)	—	—
84	Yuma Energy Inc.	97,427	61	49,607	90	3,600	49	(2,115)	86	2,588
85	Evolution Petroleum Corp.[14]	92,878	59	68,283	86	7,594	28	1,817	82	4,819
86	VOC Energy Trust	87,502	54	[15]87,502	92	1,696	29	[16]1,530	—	—
87	Goodrich Petroleum Corp.	82,079	88	(410,699)	87	7,243	63	(13,986)	84	3,498

Rank by total assets 3Q16	Company	3rd Quarter ending Sept. 30, 2016 — Total assets $1,000	Stockholders' equity — Rank	Stockholders' equity — $1,000	Total revenue — Rank	Total revenue — $1,000	Net income — Rank	Net income — $1,000	YTD Capital & expl. spending — Rank	YTD Capital & expl. spending — $1,000
88	Lucas Energy Inc.[17]	71,329	65	17,741	99	895	83	(50,805)	90	970
89	Triangle Petroleum Corp.[18]	55,657	81	(106,074)	—	0	17	29,847	75	19,413
90	Lilis Energy Inc.	53,710	66	17,115	96	1,224	57	(8,147)	85	3,418
91	Reserve Petroleum Co.	36,784	62	31,994	93	[21]1,673	34	113	88	1,268
92	Spindletop Oil & Gas Co.	24,966	64	18,152	98	1,089	35	(103)	91	929
93	Dorchester Minerals LP	19,296	60	[9]68,064	80	10,679	23	6,647	—	—
94	US Energy Corp.	18,654	73	3,578	91	1,867	39	(265)	94	121
95	Mexco Energy Corp.[17]	15,993	68	8,844	102	581	37	(238)	93	268
96	Cross Timbers Royalty Trust	11,509	67	[15]10,068	94	1,514	30	[16]1,300	—	—
97	Glori Energy Inc.	11,093	77	(2,205)	97	1,119	51	(2,477)	87	1,301
98	San Juan Basin Royalty Trust	11,017	69	[15]8,144	89	4,543	27	[16]4,030	—	—
99	Royale Energy Inc.	10,065	78	(2,538)	105	319	43	(619)	89	1,054
100	Apache Offshore Investment Partnership	9,628	70	7,583	104	331	38	(240)	97	38
101	EnerJex Resources Inc.	9,560	80	(15,296)	103	474	48	(1,694)	98	17
102	Daybreak Oil & Gas Inc.[19]	9,307	79	(11,498)	106	234	46	(1,039)	99	1
103	Tengasco Inc.	8,638	74	3,533	95	1,242	45	(908)	92	305
104	FieldPoint Petroleum Corp.	8,498	76	(1,187)	101	662	44	(630)	95	97
105	Adams Resources & Energy Inc.[5]	7,459	—	—	100	863	41	(543)	—	—
106	Sabine Royalty Trust	5,624	71	[15]4,718	84	9,046	22	[16]8,527	—	—
107	Houston American Energy Corp.	4,303	72	4,258	107	40	40	(370)	96	92
108	Permian Basin Royalty Trust	2,783	75	[15]644	88	6,556	24	[16]6,244	—	—
—	American Eagle Energy Corp.[20]	NA	—	NA	—	NA	—	NA	—	NA
—	American Natural Energy Corp.[21]	NA	—	NA	—	NA	—	NA	—	NA
—	Armada Oil Inc.[22]	NA	—	NA	—	NA	—	NA	—	NA
—	Avalon Oil & Gas Inc.[23]	NA	—	NA	—	NA	—	NA	—	NA
—	Blacksands Petroleum Inc.[23]	NA	—	NA	—	NA	—	NA	—	NA
—	Cubic Energy Inc.[24]	NA	—	NA	—	NA	—	NA	—	NA
—	Dune Energy Inc.[25]	NA	—	NA	—	NA	—	NA	—	NA
—	Emerald Oil Inc.[25]	NA	—	NA	—	NA	—	NA	—	NA
—	Escalera Resources Co.[26]	NA	—	NA	—	NA	—	NA	—	NA
—	GeoPetro Resources Co.[23]	NA	—	NA	—	NA	—	NA	—	NA
—	Humble Energy Inc.[23]	NA	—	NA	—	NA	—	NA	—	NA
—	Hydrocarb Energy Corp.[23]	NA	—	NA	—	NA	—	NA	—	NA
—	Magnum Hunter Resources Corp.[27]	NA	—	NA	—	NA	—	NA	—	NA
—	Miller Energy Resources Inc.[23]	NA	—	NA	—	NA	—	NA	—	NA
—	Pegasi Energy Resources Corp.[23]	NA	—	NA	—	NA	—	NA	—	NA
—	Petron Energy II Inc.[23]	NA	—	NA	—	NA	—	NA	—	NA
—	Pioneer Oil & Gas[23]	NA	—	NA	—	NA	—	NA	—	NA
—	PostRock Energy Services Corp.[28]	NA	—	NA	—	NA	—	NA	—	NA
—	Quicksilver Resources Inc.[25]	NA	—	NA	—	NA	—	NA	—	NA
—	Red Mountain Resources Inc.[23]	NA	—	NA	—	NA	—	NA	—	NA
—	Sabine Oil & Gas[29]	NA	—	NA	—	NA	—	NA	—	NA
—	TN-K Energy Group Inc.[23]	NA	—	NA	—	NA	—	NA	—	NA

Rank by total assets 3Q16	Company	Total assets $1,000	Stockholders' equity Rank	Stockholders' equity $1,000	Total revenue Rank	Total revenue $1,000	Net income Rank	Net income $1,000	YTD Capital & expl. spending Rank	YTD Capital & expl. spending $1,000
		3rd Quarter ending Sept. 30, 2016								
—	United American Petroleum Corp.[23]	NA	—	NA	—	NA	—	NA	—	NA
—	Venoco Inc.[23]	NA	—	NA	—	NA	—	NA	—	NA
—	Warren Resources Inc.[23]	NA	—	NA	—	NA	—	NA	—	NA
—	Wexpro[23, 30]	NA	—	NA	—	NA	—	NA	—	NA
—	Zaza Energy Corp.[23]	NA	—	NA	—	NA	—	NA	—	NA
	Total	**1,206,960,792**		**546,970,960**		**127,668,664**		**(1,031,984)**		**62,303,409**

NA = Not Available. *Annual data reported in OGJ150, Sept. 5, 2016, p. 24. [1]Net operating. [2]Operating. [3]Subsidiary of EQT Resources Inc. [4]Filed Chapter 11 bankruptcy May 2016. [5]Oil and gas operations only. [6]Before income taxes. [7]Subsidiary of Kinder Morgan Inc [10]Before depreciation, depletion and amortization. [9]Partner's equity. [10]Filed Chapter 11 bankruptcy July 2016. [11]Subsidiary of National Fuel Gas Co. [12] 4th quarter. [13]4th quarter. [14]1st quarter. [15]Trust corpus. [16]Distributable income. [17]2nd quarter. [18]3rd quarter Oct. 31. [19]2nd quarter Aug. 31. [20]Filed Chapter 11 bankruptcy May 2015. [21]Filed Chapter 11 bankruptcy. Aug. 2015. [22]Filed Chapter 7 bankruptcy Aug. 2015. [23]Not filed at press time. [24]Filed Chapter 11 bankruptcy Dec. 2015. [25]Filed Chapter 11 bankruptcy Mar. 2015. [26]Filed Chapter 11 bankruptcy Nov. 2015. [27]Filed Chapter 11 bankruptcy Oct. 2015. [28]Filed Chapter 11 bankruptcy Apr. 2016. [29]Filed Chapter 11 bankruptcy July 2015. [30]Effective Sept. 2016, merged with Dominion Resources Corp.

THE OGJ150 COMPANY INDEX

Rank by total assets 3Q16	Company	Headquarters city
82	Abraxas Petroleum Corp.	San Antonio
105	Adams Resources & Energy Inc.	Houston
—	American Eagle Energy Corp.	Littleton
—	American Natural Energy Corp.	Tulsa
4	Anadarko Petroleum Corp.	The Woodlands, Tex.
13	Antero Resources Corp.	Denver
10	Apache Corp.	Houston
100	Apache Offshore Investment Partnership	Houston
62	Approach Resources Inc.	Ft. Worth
—	Armada Oil Inc.	Dallas
—	Avalon Oil & Gas Inc.	Minneapolis, Minn.
55	Bill Barrett Corp.	Denver
83	Black Hills Corp.	Rapid City, S.D.
—	Blacksands Petroleum Inc.	Houston
58	Bonanza Creek Energy Inc.	Denver
36	BreitBurn Energy Partners LP	Los Angeles
29	Cabot Oil & Gas Corp.	Houston
26	California Resources Corp.	Los Angeles
49	Callon Petroleum Co.	Natchez, Miss.
51	Carrizo Oil & Gas Inc.	Houston
67	Chaparral Energy Inc.	Oklahoma City
15	Chesapeake Energy Corp.	Oklahoma City
2	Chevron Corp.	San Ramon, Calif.
33	Cimarex Energy Co.	Denver
50	Clayton Williams Energy Inc.	Midland, Tex.
65	Comstock Resources Inc.	Frisco, Tex.
16	Concho Resources Inc.	Midland, Tex.

Rank by total assets 3Q16	Company	Headquarters city
3	ConocoPhillips	Houston
25	Consol Energy Inc.	Canonsburg, Penn.
72	Contango Oil & Gas Co.	Houston
14	Continental Resources Inc.	Oklahoma City
96	Cross Timbers Royalty Trust	Ft. Worth
—	Cubic Energy Inc.	Dallas
102	Daybreak Oil & Gas Inc.	Spokane, Wash.
31	Denbury Resources Inc.	Plano, Tex
8	Devon Energy Corp.	Oklahoma City
38	Diamondback Energy Inc.	Midland, Tex.
93	Dorchester Minerals LP	Dallas
—	Dune Energy Inc.	Houston
73	Earthstone Energy Inc.	The Woodlands, Tex.
59	Eclipse Resources Corp.	State College, Penn
—	Emerald Oil Inc.	Denver
32	Energen Corp.	Birmingham, Ala.
101	EnerJex Resources Inc.	San Antonio
9	EOG Resources Inc.	Houston
20	EQT Production	Pittsburgh
—	Escalera Resources Co.	Denver
46	EV Energy Partners LP	Houston
85	Evolution Petroleum Corp.	Houston
69	Exco Resources Inc.	Dallas
1	ExxonMobil Corp.	Irving, Tex.
104	FieldPoint Petroleum Corp.	Austin, Tex.
39	Freeport McMoran Inc.	Phoenix
75	Gastar Exploration Inc.	Houston

Rank by total assets 3Q16	Company	Headquarters city
—	GeoPetro Resources Co.	San Francisco
97	Glori Energy Inc.	Houston
87	Goodrich Petroleum Corp.	Houston
41	Gulfport Energy Corp.	Oklahoma City
54	Halcon Resources Corp.	Houston
6	Hess Corp.	New York
107	Houston American Energy Corp.	Houston
—	Humble Energy Inc.	Paron, Ark.
—	Hydrocarb Energy Corp.	Houston
35	Kinder Morgan CO2 Co. LP	Lakewood, Colo.
47	Laredo Petroleum Inc.	Tulsa
53	Legacy Reserves LP	Midland, Tex.
90	Lilis Energy Inc.	Denver
22	Linn Energy LLC	Houston
88	Lucas Energy Inc.	Houston
—	Magnum Hunter Resources Corp.	Irving, Tex.
7	Marathon Oil Corp.	Houston
61	Matador Resources Co.	Dallas
44	Memorial Production Partners LP	Houston
95	Mexco Energy Corp.	Midland, Tex.
77	Mid-Con Energy Partners LP	Dallas
68	Midstates Petroleum Co. Inc.	Tulsa
—	Miller Energy Resources Inc.	Knoxville, Tenn.
18	Murphy Oil Corp.	El Dorado, Ark.
34	Newfield Exploration Co.	The Woodlands, Tex.
11	Noble Energy Inc.	Houston
71	Northern Oil and Gas Inc.	Wayzata, Minn.
30	Oasis Petroleum Inc.	Houston
5	Occidental Petroleum Corp.	Los Angeles
80	Panhandle Oil and Gas Inc.	Oklahoma City
37	Parsley Energy Inc.	Austin, Tex.
40	PDC Energy	Denver
—	Pegasi Energy Resources Corp.	Tyler, Tex.
74	Penn Virginia Corp.	Radnor, Penn.
108	Permian Basin Royalty Trust	Dallas
—	Petron Energy II Inc.	Dallas
81	PetroQuest Energy Inc.	Lafayette, La.
12	Pioneer Natural Resources Co.	Irving, Tex.
—	Pioneer Oil & Gas	South Jordan, Utah
—	PostRock Energy Services Corp.	Oklahoma City
79	PrimeEnergy Corp.	Houston

Rank by total assets 3Q16	Company	Headquarters city
23	QEP Resources Inc.	Denver
—	Quicksilver Resources Inc.	Ft. Worth
17	Range Resources Corp.	Ft. Worth
—	Red Mountain Resources Inc.	Farmers Branch, Tex.
91	Reserve Petroleum Co.	Oklahoma City
76	Resolute Energy Corp.	Denver
64	Rex Energy Corp.	State College, Penn
28	Rice Energy Inc.	Canonsburg, Penn.
78	Ring Energy Inc.	Midland, Tex.
99	Royale Energy Inc.	El Cajon, Calif.
42	RSP Permian Inc.	Dallas
—	Sabine Oil & Gas	Houston
106	Sabine Royalty Trust	Dallas
98	San Juan Basin Royalty Trust	Ft. Worth
60	Sanchez Energy Corp.	Houston
45	Sandridge Energy Inc.	Oklahoma City
56	Seneca Resources Corp.	Williamsville, N.Y.
27	SM Energy Inc.	Denver
24	Southwestern Energy Co.	Spring, Tex.
92	Spindletop Oil & Gas Co.	Dallas
57	Stone Energy Corp.	Lafayette, La.
70	Swift Energy Co.	Houston
63	Synergy Resources Corp.	Denver
103	Tengasco Inc.	Greenwood Village, Colo.
—	TN-K Energy Group Inc.	Crossville, Tenn.
89	Triangle Petroleum Corp.	Denver
52	Ultra Petroleum	Houston
43	Unit Corp.	Tulsa
—	United American Petroleum Corp.	Austin, Tex.
94	US Energy Corp.	Riverton, Wyo.
48	Vanguard Natural Resources LLC	Houston
—	Venoco Inc.	Denver
86	VOC Energy Trust	Austin, Tex.
66	W&T Offshore Inc.	Houston
—	Warren Resources Inc.	Denver
—	Wexpro	Salt Lake City, Utah
19	Whiting Petroleum Corp.	Denver
21	WPX Energy Inc.	Tulsa
84	Yuma Energy Inc.	Houston
—	Zaza Energy Corp.	Houston

EXXONMOBIL TO DOUBLE PERMIAN RESOURCES WITH $6.6B BUY FROM BASS FAMILY

Exxon Mobil Corp. will more than double its Permian Basin resource to six billion barrels of oil equivalent through the acquisition of companies owned by the Bass family of Fort Worth, Texas, with an estimated resource of 3.4 billion barrels of oil equivalent in New Mexico's Delaware Basin. ExxonMobil will make an upfront payment of $5.6 billion in ExxonMobil shares, and a series of additional contingent cash payments totaling up to $1 billion, to be paid beginning in 2020 and ending no later than 2032 commensurate with the development of the resource. The acquired companies, which include the operating entity BOPCO, hold about 275,000 acres of leasehold, and production of more than 18,000 net oil equivalent barrels per day, about 70% of which is liquids. This includes about 250,000 acres of leasehold in the Permian Basin, the bulk of that in contiguous, held-by-production units in the New Mexico Delaware Basin, with more than 60 billion barrels of oil equivalent estimated in place. In a note to investors, Jefferies said the transactions "appear to offer good value to Exxon," noting that "Assuming $40k/flowing barrel and no value to the acreage outside the Delaware Basin, the initial price paid is equivalent to about $19.5k/acre. This is an attractive price relative to other recent transactions in the broader Permian that have averaged near $33k/acre (excluding the EOG acquisition of Yates Petroleum). Including all future potential contingent payments on an undiscounted basis brings the transaction to $23.5k/acre."

NOBLE ENERGY TO ACQUIRE CLAYTON WILLIAMS ENERGY

Noble Energy Inc. has agreed to acquire Clayton Williams Energy Inc. for $2.7 billion in Noble Energy stock and cash. The deal includes 71,000 contiguous net acres in the core of the Southern Delaware Basin in Reeves and Ward counties in Texas (directly adjacent to Noble Energy's existing 47,200 net acres). In addition, there are an additional 100,000 net acres in other areas of the Permian Basin. 80% average working interest in the Southern Delaware position, with more than 95% of the acreage operated. The acreage includes 2,400 identified Delaware Basin gross drilling locations that target the Upper and Lower Wolfcamp A zones, along with the Wolfcamp B and C. The average lateral length of the future locations is 8,000 feet. Total estimated net unrisked resource potential on the acreage is over 1 billion barrels of oil equivalent in the Wolfcamp zones, with upside potential in other zones. Noble Energy's outlook is to increase production on the acquired assets from 10 MBoe/d currently (70% oil) to approximately 60 MBoe/d in 2020 in the company's base plan. The acquired Delaware Basin acreage is largely undedicated to third-party oil and gas gathering and water systems, and approximately 12,500 acres are dedicated from a third-party operator. Existing midstream Delaware Basin assets include over 300 miles of oil, natural gas, and produced water gathering pipelines. Clayton Williams Energy shareholders will receive 2.7874 shares of Noble Energy common stock and $34.75 in cash for each share of common stock held. In the aggregate, this totals 55 million shares of Noble Energy stock and $665 million in cash. The value of the transaction, based on Noble Energy's closing stock price as of January 13, 2017, is approximately $139 per Clayton Williams Energy share, or $3.2 billion in the aggregate, including the assumption of approximately $500 million in net debt. Noble intends to fund the cash portion of the acquisition through a draw on its revolving credit facility. As of the end of 2016, the company's $4 billion facility was completely undrawn. The company also anticipates retiring outstanding debt of Clayton Williams Energy assumed as part of the transaction at or following the closing. Noble expects this, along with general and administrative cost elimination, will result in annual cost synergies to the company of approximately $75 million. Funds managed by Ares Management LP, which owned approximately 35% of the outstanding shares of Clayton Williams Energy as of December 31, 2016, have entered into a support agreement to vote in favor of the transaction. Following completion of the transaction, shareholders of Clayton Williams Energy are expected to own approximately 11% of the outstanding shares of Noble Energy. Closing is expected in the second quarter of 2017 and is subject to customary regulatory approvals, approval by the holders of a majority of Clayton Williams Energy common stock, and certain other conditions. "Valuing existing production of 10 MBoe/d (70% oil) at $35M/Boe/d and assigning $0 for 100M net acres located outside of the SDB core (primarily in Glasscock and Sterling counties, TX) implies a purchase price of ~$40M/acre. Deducting $600MM for midstream assets suggests $31M/acre, in line with recent transactions in the basin," said Stifel analysts after the announcement.

WPX INCREASES DELAWARE BASIN INVENTORY

WPX Energy has agreed to pay $775 million to Tulsa, OK-based Panther Energy Company II LLC and Carrier Energy Partners LLC to acquire assets Permian Basin assets that would increase the company's Permian operations to more than 120,000 net acres. The acquisition includes approximately 6,500 Boe/d (55% oil) of existing production from 23 producing wells (17 horizontals), two drilled but uncompleted horizontal laterals, 18,100 net acres in Reeves, Loving, Ward and Winkler counties in Texas and 920 gross undeveloped locations in the geologic sweet spot of the Delaware Basin. WPX expects the incremental cash flow from the purchase to fund the existing two-rig program on the acquired acreage. This will bring WPX's rig count in the Permian to seven. WPX plans to close the cash transaction using a combination of proceeds from an equity issuance and cash on hand. Including the Panther transaction, WPX has added approximately 32,000 net acres in the core of the Delaware Basin at an average cost of $18,600 per acre since its purchase of RKI Exploration and Production in August 2015. The average cost excludes flowing production. On a pro forma basis, WPX is now targeting 30% oil growth and 25% overall production growth in 2017, along with a targeted net debt/EBITDAX ratio at the lower end of the company's previously announced range of 2.0x to 2.5x by year-end 2018. The forecast targets 52,000-56,000 barrels of oil per day in 2017. This estimate includes nine months of production associated with the bolt-on purchase. Tudor, Pickering, Holt & Co. acted as financial advisor to WPX on the Panther and Carrier bolt-on transaction.

ANADARKO SELLS EAGLE FORD ASSETS TO SANCHEZ ENERGY AND BLACKSTONE FOR $2.3B

Anadarko Petroleum agreed to sell its Eagle Ford Shale assets in South Texas for approximately $2.3 billion to Sanchez Energy Corp. and Blackstone Group LP. Anadarko's sponsored MLP, Western Gas Partners LP, will continue to own and operate its midstream assets in South Texas and is expected to benefit from drilling commitments made by the buyers in conjunction with the transaction. The divestiture includes approximately 155,000 net acres primarily located in Dimmit and Webb counties. At the end of 4Q16, sales volumes from these properties totaled approximately 45,000 barrels of liquids per day and approximately 131 million cubic feet of natural gas per day. The transaction is expected to close in the first quarter of 2017, subject to customary closing conditions and adjustments. Anadarko Petroleum received approximately "$34,400 per flowing barrel which reflects its operatorship premium to the $29,365 per flowing barrel that SM received for its recent divestiture (includes midstream," noted Cowen and Company analysts in a note to investors following the news. The deal price "appears in-line with investor expectations following SM's recent deal," the analysts said, noting expectations for Anadarko to end the first quarter of 2017 with over $6 billion in cash "providing it with the flexibility to accelerate drilling beyond 12% - 14% 5-yr oil CAGR or to add opportunistically to its core plays."

PDC ENERGY EXPANDS PERMIAN FOOTPRINT WITH DELAWARE BASIN DEAL CLOSE

On December 30, 2016, PDC Energy Inc. closed on a deal to expand its Permian Basin footprint, acquiring approximately 4,500 net acres in Reeves and Culberson Counties, Texas, from Fortuna Resources Holdings LLC, for approximately $118 million in cash. PDC's working interest in the acquired leasehold is 100% and PDC expects to operate 100% of the properties. The acquired properties are concentrated in the company's central acreage block contiguous with the company's acreage from the recently closed acquisition of approximately 57,000 net acres in Reeves and Culberson Counties. Current net production associated with the acquisition is approximately 300 boe/d. Also included is a drilled, but uncompleted (DUC) horizontal well, and a salt water disposal well. Assuming $35M/Boe/d for 300 Boe/d, said Stifel analysts in a note following the announcement, the implied purchase price is ~$24M/acre, in line with recent purchases in the area, they continued. PDC Energy estimates the acquired acreage contains 75 gross one-mile horizontal drilling locations, based on four wells per section in each of the Wolfcamp A, B and C zones. Financing is expected to come from existing cash and PDC's $750 million credit facility, the analysts said, noting that the company's balance sheet "remains strong as we project YE17 and YE18 debt/EBITDA of 1.4x and 1.0x and 2017 and 2018 interest coverage of 15.9x and 17.8x."

REX ENERGY AGREES TO SELL OHIO UTICA WARRIOR SOUTH ASSET

Rex Energy Corp. has agreed to sell its Ohio Utica assets in the Warrior South Area to Antero Resources Corp. for net proceeds at closing of approximately $30 million. Included in the sale are 14 gross wells and approximately 4,100 net acres in Guernsey, Noble and Belmont Counties in Ohio; the assets are currently producing approximately 9.0 Mmcfe/d. Rex Energy expects to use the proceeds from the sale to pay down the revolving line of credit and for general corporate purposes. to close in the first quarter of 2017, subject to customary closing conditions and required approvals. Upon the closing of the transaction, the company has received approval from its bank lenders to maintain the existing $190 million borrowing base under its revolving credit facility. Stifel analysts said the deal is "better than expected," the purchase price implying a value of "$3.3M/Mcfe/d for the production and no unproved acreage value." Upon close, expected in 1Q17, Rex Energy's bank lenders have agreed to maintain the company's credit facility's $190 million borrowing base.

SCHLUMBERGER ACQUIRES PEAK WELL SYSTEMS

Schlumberger has acquired Peak Well Systems, a specialist in the design and development of advanced downhole tools for flow control, well intervention and well integrity. Schlumberger acquired Peak from growth equity investor Summit Partners and the company's founders and management team.

KREWE ENERGY MAKES COQUILLE ACQUISITION, SEES CAPITAL INVESTMENT

Covington, LA-based Krewe Energy LLC, a privately held oil and gas exploitation and development company, has completed the acquisition of additional working interest in the Coquille Bay Field, which it operates in Plaquemines Parish, Louisiana, giving Krewe approximately 100% interest in the field. Krewe Energy was formed by Houston, Texas-based Sage Road Capital together with Krewe Energy's founders, Tom De Brock and Barry Salsbury. Additionally, Krewe Energy recently received a new investment from Coral Reef Capital to recapitalize the company and further support its growth. Financial terms of the transaction were not disclosed. Coral Reef Capital is a New York-based private investment firm that focuses exclusively on private equity investments in the natural resources sector.

SM ENERGY PLANS DIVIDE COUNTY ASSETS SALE

SM Energy Co. has engaged Tudor, Pickering, Holt & Co. to run a formal bid process for sale of the company's Divide County area assets in the Williston Basin. Assuming an acceptable offer is received, the company expects to close the sale transaction around mid-year of 2017. Associated December 2016 production for the Divide County assets was 10,700 Boe/d.

AVAD SEES EQUITY COMMITMENT FROM PEARL ENERGY INVESTMENTS, NATURAL GAS PARTNERS

AVAD Energy Partners LLC (AVAD), a newly formed oil and natural gas production company based in Dallas, TX, has raised $77.5 million of equity commitments from lead investor Pearl Energy Investments, Natural Gas Partners (NGP) through its affiliate NGP Natural Resources XI LP, and management. AVAD is focused on acquiring and developing conventional oil and gas properties in the US. John Davis, AVAD's CEO, previously co-founded Alpine Gas Company LLC. Tom Quigley, senior vice president, will head the acquisition, evaluation, and development efforts of AVAD. He has over 25 years of engineering experience, having previously worked at Alpine, NSAI, Exxon, Hunt Petroleum Corp. and Encana Oil and Gas USA Inc. Crystal Blackstone, vice president, has worked for 25 years alongside David and Quigley as an analyst at NSAI, Hunt and Alpine.

GREENWELL ENERGY SOLUTIONS ACQUIRES EXCLUSIVE ENERGY SERVICES

Greenwell Energy Solutions, an independent specialty provider of completion and production services for the upstream energy industry, has acquired Exclusive Energy Services. Exclusive provides highly-automated, Data Acquisition System mixing plants that enable optimal chemical mixing and delivery for coil tubing, work-over and frac jobs.

SWIFT ENERGY SETS 2017 CAPITAL BUDGET

Swift Energy Co. has set its 2017 capital budget and expected production. Swift Energy's net operational capital budget for 2017 is expected to be in the range of $85 - $95 million. The company plans to run one rig in the Eagle Ford to complete twelve wells in 2017. Specifically, the company expects to complete nine wells (not including three wells drilled and completed in late 2016) in its Fasken field in Webb County, drill and complete two wells on its AWP acreage in McMullen County, and drill and complete its first well in Oro Grande in LaSalle County. All drilling activities will target the Lower Eagle Ford. Swift expects to spud the Oro Grande appraisal well in 2Q17. The anticipated capital budget is inclusive of the aforementioned completions as well as associated drilling activities, infrastructure, and other discretionary expenditures. The company expects production for 2017 to be 47.5 - 49.5 Bcfe with gas making up approximately 85% of total production. The 2017 capital budget is expected to be funded primarily through internally generated cash flows and, to a lesser extent, available borrowings on the credit facility. As of January 20, 2017, Swift had hedges in place for over 70% of expected natural gas and crude oil production at average weighted prices of $3.10 and $48.10, respectively.

W&T OFFSHORE APPROVES 2017 CAPITAL BUDGET

The board of directors of W&T Offshore Inc. approved a 2017 capital expenditure budget of $125 million, excluding potential acquisitions. The company has also provided production and expense guidance for 2017 and expects total production in 2017 to be approximately 4% higher than the mid-point of the company's expected production in 2016. The company currently anticipates drilling six to eight wells during 2017 in the Gulf of Mexico in a program that is expected to be generally balanced between exploration and development projects and between wells located on the shelf and in the deepwater. The 2017 capital plan includes completing the Ship Shoal 349 "Mahogany" A-18 well, which was drilled to total depth in late 2016 and put on production in mid-January, and the drilling and completion of three additional wells in the Mahogany field. Each of these projects is expected to achieve a rate of return in excess of 100%, with a relatively quick payback. The plan also includes the drilling and completion of two wells at the Ewing Bank 910 field, which are expected to average a rate of return in excess of 100%, with an average projected payout in approximately one year. Additionally, the 2017 plan includes performing between 20 and 25 recompletions at a cost of approximately $26 million. Approximately two-thirds of the entire capital budget is directed at projects that will come on line and start producing in 2017.

LUCAS ENERGY ENTERS PERMIAN

Lucas Energy Inc. has entered into an agreement with a privately-held, Houston, Texas-based oil and gas holding company to acquire a leasehold position in the Permian Basin in Texas. Lucas Energy will purchase the initial lease comprised of 16,322 gross, 3,630 net, mineral acres, and the parties have agreed to form an area of mutual interest (AMI) on the Central Basin Platform. Lucas will operate the properties and own a 90% working interest and the partner will hold a 10% working interest in the initial leases and all subsequently acquired leases. The initial cash consideration paid by Lucas Energy is $1.43 million, in exchange for access to the partner's regional, technical database and the company's 90% interest. As additional leases are acquired under the AMI, the company will pay the partner its lease acquisition costs and grant an incentive overriding royalty interest. Upon meeting certain acreage acquisition goals based on size and location of the properties, Lucas Energy will also issue to the partner 200,000 unregistered shares of its common stock and pay the partner an acreage fee based on the total leasehold and brokerage costs.

OPITO MOURNS LOSS OF CHIEF EXECUTIVE DOIG

OPITO, the global oil and gas industry skills, standards and workforce development organization, is deeply saddened to confirm the death of its chief executive **David Doig.** Doig, 57, who was based in Dubai, suffered a heart attack on December 31st and later passed away peacefully in hospital in Fife, Scotland.

John Taylor, chairman of OPITO, said: "David was a vocal champion of OPITO, a much-respected industry leader, a firm advocate of social responsibility; and a trusted colleague and friend to many. His straight-talking approach, determination and passionate belief that all oil and gas workers regardless of their job role, their employer or their nationality should be able to travel to work and return home safely at the end of the day, helped drive positive change in countless countries around the world and inspired great loyalty among those who knew him. His loss is sorely felt by us all. Our thoughts are with David's wife, Gillian, and his family at this difficult time."

Born and raised in St Andrews, Scotland, David was educated at Madras College. With an early background in engineering, he worked on major offshore projects in the North Sea for more than 25 years before moving onshore in 1994 to lead on maintenance support contracts as a business unit operations manager with KBR. He joined OPITO's in 1999 as head of the audit team and worked steadily to broaden his knowledge and experience, including returning to education to complete an MBA with the Open University.

Doig was appointed chief executive in spring 2005, then Group CEO following the creation of OPITO International in 2009 where he forged new relationships and advised governments, NOCs, IOCs and contractors on workforce development strategies.

Boney

BONEY NAMED PARTNER AT OPPORTUNE

James (Jim) Boney was named a partner at Opportune LLP. Boney will continue his focus on providing outsourcing services to Opportune's upstream and midstream clients. He has led outsourcing services at Opportune since its acquisition of PetroAcct LP in 2009. Boney's background, spanning more than 40 years, includes extensive experience in the financial management of oil and gas exploration and production companies. He specializes in transactional process and reporting, land administration, production allocation and reporting, system conversions and implementation, technical research and joint venture compliance review. Before forming PetroAcct LP in 1999, Boney served as controller of Transco Energy Co.'s oil and gas E&P subsidiaries.

DACHES JOINS LILIS ENERGY AS CFO

Lilis Energy Inc. has appointed Joseph C. Daches, CPA, as its new executive vice president, CFO, and treasurer. Daches has over 20 years of experience in directing strategy, accounting and finance in primarily small and mid-size oil and gas companies. Prior to joining Lilis Energy, Daches held the position of CFO at Magnum Hunter Resources (MHR) where he concluded his tenure by guiding MHR through a restructuring and upon emergence was appointed co-CEO by the new board of directors. Daches holds a Bachelor of Science in accounting and is a licensed CPA in Texas. Lilis Energy is a San Antonio-based independent oil and gas exploration and production company that operates in the Permian's Delaware Basin and in the Denver-Julesburg Basin.

GARDERE WELCOMES FIVE TO MEXICO CITY OFFICE

Gardere Wynne Sewell LLP has added two partners and three associates to the firm's international trade practice in Mexico City. The group joins Gardere from Carrasco, García Abogados, S.C. and Trade Law Consultores, S.C. Partner Marcos Carrasco-Menchaca provides advisory and consulting services related to international trade, customs, free trade agreements, customs litigation and taxation on foreign trade, as well as rendering services in international contracting and administrative litigation. Carrasco is currently an advisor on foreign trade for major multinational and national companies in the retail, fashion, oil and gas, automotive, auto parts and manufacturing industries. During President Vicente Fox's administration (2000-

2006), partner Alejandro Nemo Gómez-Strozzi served as the undersecretary of economy in charge of foreign investment, standards and trade remedies. In addition, he has previously led the Mexican Investigative Authority regarding trade remedies in the Ministry of Economy. Gómez focuses on international trade, antidumping, customs, foreign trade and Mexican administrative law. Miguel Angel Concha-Fuentes, Luis Jahir Contreras-Guadarrama and Alberto Santillán-Gaitán are joining Gardere as associates. Concha is a foreign trade and customs attorney who specializes in customs and administrative litigation, customs advisory and unfair international trade practices, primarily dumping. In addition, Contreras provides advisory and consulting services related to foreign trade, customs and free trade agreements. Santillán specializes in advising and consulting on international trade and taxes on foreign trade, as well as customs and administrative litigation.

DOUGLASS JOINS BAKER BOTTS LONDON

James Douglass, a lawyer who specializes in the development and financing of energy and infrastructure projects, has joined Baker Botts in London as a partner. Douglass has over 24 years of experience and has been involved in ground breaking projects across the power, oil and gas, and infrastructure sectors. He obtained a Bachelor of Laws from the University of Queensland, Australia, and is qualified to practice in Queensland, England & Wales, and Hong Kong.

CISARIK ELECTED CHAIRMAN OF THE TEXAS PIPELINE ASSOCIATION

James A. Cisarik, Enterprise Products Holdings LLC's senior vice president of government affairs and public relations, has been elected chairman of the Texas Pipeline Association (TPA). TPA is the largest state trade association in the country that solely represents the interests of the intrastate pipeline network. From February 2003 to January 2014, Cisarik served as a senior vice president of Enterprise, where he had primary responsibility for the oversight of the company's intrastate natural gas pipelines and projects derived from LNG and other natural gas business development. Prior to joining Enterprise, Cisarik was a senior vice president of Coral Energy LLC, and from 1997 to February 1999 was vice president, market development of Tejas Energy LLC. He graduated from the University of Texas with a bachelor of business administration degree in petroleum land management.

WILLKIE ADDS ENERGY AND COMMODITIES PARTNERS IN WASHINGTON

Energy and commodities lawyers Paul J. Pantano, Jr., and Athena Yvonne Eastwood have joined the Washington office of Willkie Farr & Gallagher LLP. They were formerly partners at Cadwalader, Wickersham & Taft LLP. Pantano, Jr. represents energy companies, commodity and swap dealers, financial institutions, brokerage firms and trade associations in a wide variety of transactional, regulatory, investigative and litigation matters. He regularly represents clients in investigations and regulatory matters before the Commodity Futures Trading Commission (CFTC), the Federal Energy Regulatory Commission (FERC) and commodity exchanges. Prior to entering private practice, he was a trial attorney in the Division of Enforcement of the CFTC. Eastwood represents energy companies, agricultural cooperatives, commodity and swap dealers, financial institutions and brokerage firms in regulatory, legislative, transactional and investigative matters involving commodities and derivatives before the CFTC and commodity exchanges. She has extensive experience with respect to all aspects of implementation of the Dodd-Frank Act and its impact on end-users, swap dealers, futures commission merchants, commodity pool operators and commodity trading advisors.

LATHAM & WATKINS ADDS TWO ENERGY REGULATORY PARTNERS

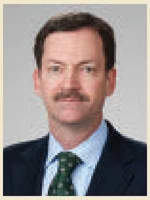
Patrick Nevins and **Eugene Elrod** have joined the Washington, DC office of Latham & Watkins LLP as partners in the firm's energy - oil and gas industry group and the eenergy regulatory and markets practice. Both energy lawyers focus on natural gas, LNG, and oil matters, particularly oil and gas transportation regulation at the Federal Energy Regulatory Commission. Nevins and Elrod joined Latham from Hogan Lovells and Sidley Austin, respectively. Nevins received his BA in Economics from University of Virginia, graduating with distinction, and his JD from Georgetown University, graduating magna cum laude and receiving an Order of the Coif. Elrod received his AB from Dartmouth College, graduating cum laude, and a JD from Emory University Law School.

TWO JOIN STEELHEAD LNG EXECUTIVE LEADERSHIP TEAM

Steelhead LNG has appointed two new members to its executive team. Paul Sullivan, formerly senior vice president of Global LNG and Floating LNG (FLNG) at Worley Parsons Group, has been appointed vice president, projects. Sullivan has had a long career in

Douglass

Cisarik

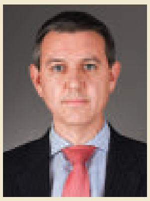


Nevins

Elrod


Craw


Bonebrake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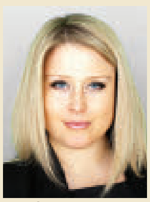
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engineering and construction, with more than 25 years managing liquefied natural gas import and export projects. He previously led the FEED group at British Gas, where he was involved in the development, from concept to implementation, of the company's liquefaction and regasification projects. Gerry Peereboom has been appointed vice president, integration. Peereboom has more than 38 years of international experience on major oil, gas and LNG projects for companies such as Noble Energy, BP and Amoco. Peereboom was president of Atlantic LNG in Trinidad when it was developed for BP/Amoco in the mid-1990s. He then served as President of Tangguh LNG for BP, based in Indonesia. Peereboom will lead the schedule, risk assessment and risk mitigation across the company, while playing a key role in the ongoing structuring of the midstream and interface with Steelhead LNG's upstream partner, Seven Generations Energy. He will also oversee the development and application of Steelhead LNG's environmental stewardship best practices. Both Sullivan and Peereboom will be based out of Steelhead LNG's corporate headquarters in Vancouver, British Columbia.

OPOL MAKES EXECUTIVE TEAM APPOINTMENTS

The Offshore Pollution Liability Association Limited (OPOL) has appointed **Jacquelynn Craw** as a new managing director. OPOL also confirmed the reappointment of its current chairman, Colin Wannell. Craw succeeds Niall Scott as managing director, who held the post since 2011. Scott stepped down at the end of December. Craw has previously served on OPOL's board and is a consultant to international law firm CMS Cameron McKenna. She was formerly general counsel of Fairfield Energy Ltd. She has 25 years of experience working with major oil and gas companies including Shell and Talisman Energy. Wannell spent the first part of his career as an insurance professional holding senior positions in BP's insurance department. He was called to the Bar in 2001 (Inner Temple) and practiced as an employed barrister working in BP's legal department where he specialized in international trade law. He retired from his position in BP's legal department as managing counsel oil trading and regulation (Europe) in January 2016. Wannell was BP's nominated director of OPOL for more than 20 years. He was elected to serve as chairman in 2008, a position he held until his retirement from BP. Since then, he has continued to serve OPOL in the capacity of an independent chair at the invitation of the board. Wannell continues to practice law as a consultant providing legal services to commodity trading houses. He is also a director of a Guernsey based risk management services provider (Thorndon Holdings Limited).

BONEBRAKE JOINS LAZARD AS A MANAGING DIRECTOR

Kevin Bonebrake has joined Lazard Ltd. as a managing director, financial advisory. Based in Houston, he will advise companies in the oil and gas sector on mergers and acquisitions and other financial matters. Bonebrake has more than 12 years of energy-sector advisory experience, with a focus on North American independent exploration and production companies, majors and national oil companies. He joins Lazard from Morgan Stanley, where he was most recently a managing director in the firm's Global Natural Resources practice within the Investment Banking Division. Between 2003 and 2009 he worked for Salomon Smith Barney/Citigroup as a member of its Global Energy Investment Banking team.

C&C RESERVOIRS APPOINTS FAROPPA CHIEF GEOSCIENTIST, SVP

C&C Reservoirs has appointed **James Faroppa** as chief geoscientist and senior vice president, services. Faroppa brings over 20 years of operator experience to C&C Reservoirs and has worked on a broad range of geological plays, basins, and countries, from onshore unconventional to deep-water oil and gas discoveries. Before joining C&C Reservoirs, Faroppa served as vice president, geosciences for Murphy Oil. Prior to Murphy, Faroppa worked for Kosmos Energy as vice president, Sub-Saharan Africa and BG Group. Faroppa received an MBA from Duke University in 2007. C&C Reservoirs is a global, analogs-based software and services company with offices in the US, the UK, and China.

PETERSON NAMES FORBES TO LEADERSHIP TEAM

International energy logistics provider Peterson has appointed **Sarah Forbes** as director projects and innovation. The appointment follows an investment by Peterson in Core29, the project management and consultancy business founded by Forbes in Aberdeen in 2012. Forbes has 15 years' industry experience in a number of senior roles focused on implementing innovative business systems and supporting organizations deliver improved efficiency and cost reductions through technology. Forbes will continue as a director of Core29 with Jaye Deighton, strategy delivery director, assuming a key operational role within the company.

COMPANY/ADVERTISER INDEX

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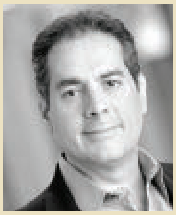
Engaging top independent talent



GENE ZAINO
MBO PARTNERS

IN THE LAST FIVE YEARS, the independent workforce has grown more than five times faster than traditional means of employment – across all industries – contributing $1.15 trillion annually to the economy. Within the oil and gas industry, the rise in independent workers is no different. Accenture estimates that in the oil and gas industry, as much as 77% of the workforce resides outside the core organization.

Call them freelancers, independent contractors, or consultants, these workers are Americans of all skill, education, and income levels who look regularly to independent work for income, opportunity, and satisfaction. According to MBO Partners' workforce survey, there are over 40 million independent workers, which includes 16.9 million in full-time positions. By 2021, that number is expected to grow to 48.9 million.

But efficient and compliant engagement of this fast-growing talent pool is not without unique challenges for the oil and gas industry. Executives should consider the following four key topics to engage with and retain top independent talent.

ADAPT TO CHANGING WORKFORCE DEMOGRAPHICS

Many industries are seeing a changing of the guard as older workers seek retirement and Millennials become the largest percentage of the workforce. The oil and gas industry is no exception. Richard D. Slack, president and CEO of Oildex, calls it a "talent crisis," stating, "We know that Millennials are the most promising group of workers to take the reins in our industry, but we are challenged by needing to provide them with the experience and training to take our industry – one that competes globally – into the future."

For companies looking to engage independent workers, this shift is a multi-step process. First, it means adapting workforce practices and engagement models to keep pace with changing workforce demographics. This may mean updating systems to become more technologically friendly for digital native Millennials or providing necessary training to get younger workers up to speed. This may also mean creating new independent and part-time opportunities for Baby Boomer workers who offer valuable knowledge and skills, but no longer have the desire to work full-time.

This is not an easy task, and requires creating a nuanced and compliant contingent workforce program to properly classify and engage this new talent. It also means keeping pace with regulatory changes as well as remaining a nimble organization for the talent itself.

SPECIALIZATION IS KEY

In the oil and gas industry, many roles require specific specializations and certifications. Finding contractors with the right set of skills and experiences is challenging, but not impossible. On the whole, independents tend to be more experienced and specialized than their traditionally employed counterparts. Sixty percent of independent workers offer a specialized skill that requires certification, special training, or education, and the average tenure for those working full-time is more than double the average of traditional employees, making this cohort a great resource for oil and gas executives looking to update their HR and staffing models.

LEVERAGE TECHNOLOGY TO ENGAGE AND RE-ENGAGE WORKERS EFFECTIVELY

Today, many oil and gas companies rely on word-of-mouth, referral, and even phone calls to friends to find top talent. However, systems like MBO Partners' own MBO Connect™ allow companies to develop private talent pools to easily find, engage, and re-engage top independent talent. These programs allow companies to reduce costs associated with time to fill, recruitment, and even training, as workers placed in the talent pool are already known to your organization and its policies. MBO's proprietary worker engagement and classification models also ensure compliant engagement and streamlined management of independent talent, meaning fewer burdens on HR and legal departments, ultimately leading to cost savings.

BECOME A CLIENT OF CHOICE

Oil and gas executives must understand how best to utilize these independent workers. Using a service such as MBO Partners ensures that talent is not only engaged compliantly, but that workers are provided with the tools they need to spend time focused on the tasks that matter to your company's bottom line – not worrying about things like invoicing, payment, and where their next gig is coming from.

Independent workers choose independence because they can control their own schedules and have more flexibility in their work. Sixty-five percent are satisfied with their chosen profession, suggesting that independence will continue to grow. By making it easy for both the worker and the client, savvy oil and gas companies can become a client of choice for top independents in the industry.

In 2017, it will be increasingly important for companies to make it easier for top independent talent to work with their organizations and to make it cost-effective and streamlined for the company itself to do business with independent talent. **OGFJ**

Gene Zaino is CEO of MBO Partners. An expert in the contract workforce market, he has appeared in various publications, including Forbes, Harvard Business Review, and The Wall Street Journal. He has also appeared on CNN and CNBC. Zaino holds a BSE degree (cum laude) from the University of Pennsylvania's Wharton School of Business.