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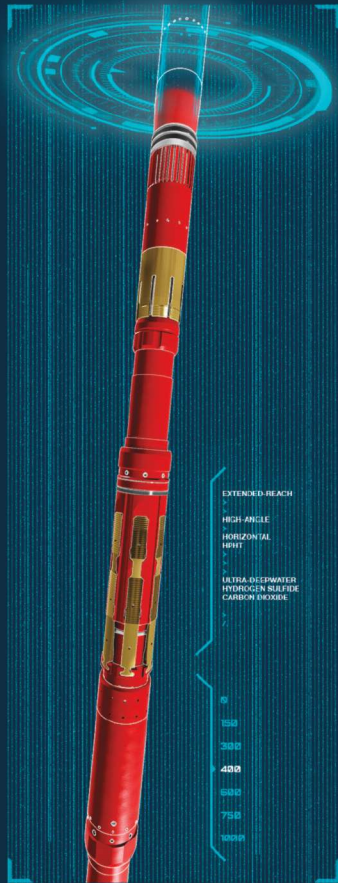
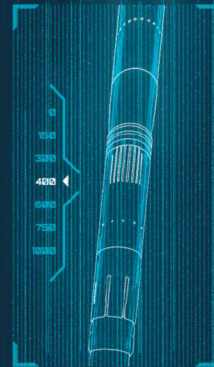
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**COMING NEXT MONTH** The August issue of **E&P** will showcase new advancements in IOR/EOR technology. Other features include borehole geophysics and well testing, shale drilling optimization, proppants, and subsea trees, and the unconventional report will highlight Argentina. The issue will also include an expanded section on the North Sea to celebrate its 50th year as an oil-producing province. As always, while you're waiting for your next copy of **E&P**, be sure to visit **EPMag.com** for the latest news, industry updates and unique industry analysis.



**ABOUT THE COVER** A Weatherford hydraulic fracturing crew continues operations at Newfield Exploration's Knauss 1H-1X well in Kingfisher County, Okla. Left, Egypt's offshore has produced a succession of substantial gas discoveries, including BP's Atoll find in the East Nile Delta, drilled by the *Maersk Discoverer* semisubmersible earlier this year. (Photo by Tom Fox; left, source: Maersk Drilling. Cover design by James Grant)

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**Tata Petrodyne farms in on Tanzania licenses**

Tata Petrodyne Ltd. will farm in on the Pangani and Kilosa-Kilombero licenses in Tanzania under an agreement with Swala Oil and Gas (Tanzania) Plc.

**OAO Gazprom Neft pursues Bazhenov Shale extraction**

OAO Gazprom Neft, the oil arm of Russia's state-run gas exporter, said commercial production from its Bazhenov Shale formations could start in three years amid U.S. sanctions limiting the transfer of fracking technology.

**Searcher completes PSDM reprocessing in Carnarvon Basin**

Searcher Seismic and Fugro Multi Client Services completed the Dropbear Ultracube 3-D reprocessing project, which is the broadband prestack depth-migrated (PSDM) reprocessed Willem 3-D seismic survey originally acquired in 2006 in Western Australia's Carnarvon Basin.

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**Forecast sees surge in output from ultradeep fields**

*By Velda Addison, Associate Online Editor*

An energy consultancy predicts production from the world's ultradeepwater fields will increase from about 6.5 MMboe/d to about 10.2 MMboe/d by 2021.

**EAGE 2015: Collaboration is king**

*By Rhonda Duey, Executive Editor*

The industry faces serious challenges. Yet engineers say the hurdles can be cleared with a more unified effort.



**EAGE 2015: E&P industry faces expanded horizon of risks**

*By Mark Thomas, Editor-in-Chief*

The upstream industry is already inherently risky, but its continued expansion into new areas is exposing it to a wider array of nontechnical issues and threats.

**Big Data gives operators advantages in hotly contested plays**

*By Scott Weeden, Senior Editor, Drilling*

The industry can benefit quickly by approaching Big Data from the place of maximizing value by minimizing complexity.

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# Good advice or just Wonderland?

"I give myself very good advice. But I very seldom follow it."

So uttered Lewis Carroll's forlorn fictional character Alice during her adventure down the rabbit hole in Wonderland, in a book that many of us have probably read at one time or another.

The saying came to me, however, in the slightly less fantastical surroundings of the recent European Association of Geoscientists and Engineers meeting in Madrid, Spain, as I sat listening to a panel of six preeminent experts. This annual exploration and geo-fest is always well worth attending, and the panelists concerned (including three international operators) all gave great presentations and commentary in the forum focused on nontechnical risk in all its forms.

However, when each was asked to give an (admittedly) very quick closing comment on what they thought their audience should take away with them as a lasting thought, all came out with different perspectives—but they were less than inspirational.

One flagged up the risk of the upstream industry being too short term-focused and said that it needed to retain a long-term view. Another voiced the importance of the industry "continuing to reinvent itself" to remain attractive to potential new recruits. Other points mentioned were the increasing influence of government take on the E&P sector's plans, the industry's "patchy knowledge" within companies that needs to be brought together through better collaboration and a need in today's climate not to underestimate "even the smallest shareholder."

These are admirable and wise words, of course. But surely this is something we've all heard many times before. If we as an industry need to be reminded that we should take a long-term view of things, then we are in deep trouble, as indeed we would also be if the oil and gas business is not aware of the need to constantly reinvent itself to keep pace with the rest of industry generally.

My belief is, of course, that we are all very aware of the above points. These are things that anyone in the E&P sector should bear in mind every day and almost certainly does.

So all of the advice, therefore, is welcome but—like Alice—I'm not sure we should take it. When times are tough—and they still very much are—we look to the movers, thinkers and shakers in our industry for insight and inspiration to help us continue to look forward rather than over our shoulders.

Several times this year at various events I've had the distinct impression that a succession of VIP speakers have wanted to make more positive and aggressive comments but have felt obliged to stay on safer ground, hamstrung perhaps by the fear of sounding too upbeat or not saying "the right thing" in the eyes of their advisers and—heaven forbid—their investors.

But surely, as industry leaders in their own right—the reason they've usually been invited to speak, after all—that's a real waste of an opportunity.

As Alice also said, "Curiouser and curiouser!" I'd echo that; we're all curious to know what our industry leaders are thinking rather than be spoon-fed safe advice. So come on speakers, speak up! **E&P**

# Technology, workforce keys to industry's success

Meeting global energy challenges will require connecting science, safety and society.

Duco de Haan, Lloyd's Register Energy

Oil prices are one of the most pressing challenges of the energy industry today. In a larger context, technology developments that help improve productivity, reduce costs and enhance quality are today's pressing issues. Spiraling costs of E&P in the industry are threatening to price-differentiate energy plays in different geographies. It is clear the current cost base cannot be sustained. This is a crucial time for the industry. It is precariously balanced between long-term success and failure, and the choices that are made in the next few years will determine whether it has a future or not. So initiatives that nurture technical innovation can no longer be an afterthought for business or government; they must be central to any organization's strategy for sustainable growth and market leadership. They are central to growth, too.

Even in an industry as regulated as offshore oil and gas exploration, there is always room for improvement. Identifying these opportunities is best accomplished by adopting a holistic rather than prescriptive set of safety regulations that focus on technology as well as training, taking into account the roles that equipment, systems and processes, and people all play in building and maintaining a safety culture. In the last 18 months the debate has gathered momentum on how industry needs to continue to address the challenge of driving

EOR with aspirations of moving from 40% to 70% on recoverable reserves. Lloyd's Register's Energy Technology Radar has helped draw out these key issues and trends from personnel in the oil and gas industry.

Some of the findings:

1. Innovation is drawing on a range of technologies rather than any single breakthrough;
2. A variety of technologies look set to have a high impact in the coming years relating to extending the life of existing assets;
3. The near-term impact of automation on remote and subsea operations is identified as firms seek to cope with challenging environments; and
4. HP/HT drilling and multistage fracking are expected to have a major impact but are expected to be fully deployed from 2020.

Going forward into the future, technology will be an enabler. Business challenges such as the issues around safety, the environment and costs indicate that the industry needs to embrace technology even more. Development and adoption of technology are also going to require a lot more collaboration because the cost of doing development work and adopting technology is significant.

## Commodity prices

The current economic issues around the sustainability of a truly global energy mix and the supply of oil has been known for a little while, but no one could have pre-

Technology will continue to be an enabler in the oil and gas industry.

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dicted the sudden scale of fall-off in the oil price frenzy. The fall in the oil price and the effects of increasing geopolitics across the world have called into question a number of things the industry has taken for granted. Most obvious is the availability of finance and consequently the future of large energy infrastructure projects. However, some of the best operators can now profit at far lower prices because they're learning how to drill wells more efficiently and how to increase production at lower costs with more accurate fracking, better targeting of the oil and gas sweet spots and spacing wells more closely together.

The current price environment is very much like a severe stress test to determine which companies have their finances and operations in order. Those that spent too much to lease equipment to drill or have high operating costs are most likely to suffer. If prices stay low into next year, providers of drilling services and oilfield gear will need to cut prices to retain customers, moves that will help preserve oil company margins; operators will demand higher levels of integrity from their contractors on equipment, systems and personnel. Crew competence and specific training to reduce downtime and the heavy costs associated with equipment failure will be of critical importance to tomorrow's winners. Manufacturers will have to review their equipment designs for functionality and failure and make adjustments based on new requirements.

One of the difficult questions is to address the best strategy to remain relevant and hedge any job loss risk during downturns. One of the key factors is competition. Oil and gas companies affected by the drop-off in the oil price have strong incentives not to pull back on drilling activities. These companies will be reluctant to let go of their core talent and especially their highly trained and experienced wellsite employees.

Another issue is how to win the war for talent in the next decade. Senior executives need to understand the transformation taking place in the world of work. Increasingly, work is ceasing to be a place and more a state of mind. For large numbers of people, it can happen at any time of day and in any place. Executives who understand this and equip their organizations to survive in this new world will be the ones still leading successful oil and gas companies in the next 30 years. During market downturns, collaboration across industry is critical to share best practice and evolve joint ventures, and this should not be hampered by the focus on cost reduction. It is important for the oil and gas industry to reach out to other sectors, like the automotive sector, where cars are made from parts manufactured by suppliers, enabling industrialized manufacturing.

## Young professionals

The use of data is going to change how we do things in the future. But it will mean new ways of working, new collaborations and how we think about different disciplines. Chemical engineers will work with civil and electronic instrumentation engineers, who will be working with mathematicians looking at algorithms and using statistical analysis. Technology is exciting, and the industry is on the start of the development curve to be leaner and more efficient. There are different mindsets across the industry, and it is going to require very different thinking to create the smarter and sustainable oil and gas industry of tomorrow's world.

The new generation of engineers, in particular, have had experiences as customers that influence their expectations in other business dealings, such as their interactions with their employers. That means that, as well as cost savings and productivity benefits, digital communication capabilities are becoming a key weapon in recruiting and retaining talent. Gone are the days when an employee enthusiastically received a new work laptop and mobile phone. Today's employees often have more information communications technology at their personal disposal than they are given at work, and IT departments are increasingly seen as a limitation to their needs rather than an enabler.

Organizations must understand the best way to enhance communication capabilities for their employees. For most companies this will not involve handing out tablets or iPads to each employee, but it should involve, at a minimum, setting up internal social networking and knowledge share sites. This approach will have the added benefit of increasing productivity as processes previously requiring several stages are completed in one or two stages.

Likewise, organizations need to look at the complete package that they offer new workers. Reward is part of this, but what employees are engaged with, the environment in which they work and the opportunities for growth and development are fundamental. There is a clear trend that the engineers of tomorrow are less motivated simply by the financial rewards; the ethics and the ethos of an organization are equally important.

Technology is helping to rapidly advance education and training to ensure the availability of the necessary skilled people. Lloyd's Register Foundation has an important role to play in meeting the global energy challenges, connecting science, safety and society. It is an exciting time for anyone interested in energy to join the industry. **E&P**



## Q&A

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# Bullish view from Down Under

'It is when we face challenges that we achieve great innovation and growth,' says BHP Billiton Petroleum president.

Mark Thomas, Editor-in-Chief

**B**HP Billiton Petroleum's Tim Cutt is clearly something of a motor racing enthusiast. The president of the Australian oil and gas major used the analogy of his country's leading Formula One racing driver, Daniel Ricciardo, and his Red Bull team's pit crew as an example of how the upstream industry will adapt, survive and thrive in the current oil price downturn.

Cutt compared the racing crew's performance with advances made by the oil and gas sector while presenting to delegates at the annual Australian Petroleum Production & Exploration Association (APPEA) conference in Melbourne, Australia. "In the 1960s race car crews were able to have a pit stop completed in under a minute. Today Formula One teams achieve this in under three seconds.

"We have been applying the same methodology in our shale operations and have some great examples of success: Taking rig moves from eight days to three days, reducing frack pump maintenance from eight hours to 15 minutes, and today we have lowered our drilling costs by 50%. In addition, exploration and conventional business over the past 12 months has reduced time to load and analyze seismic data by 80%."

## Facing challenges

"It is when we face challenges that we achieve great innovation and growth," Cutt said. "We must continue to deliver economic sources of oil supply, and driving productivity improvements to lower costs will help to ensure

long-term price stability. We need to work collaboratively with governments and regulators to achieve appropriate policy reform."

As the price recovers over the next two years, he said, people will get a little more active. U.S. shales bringing on more volume will help to offset some of the price pressure.

Cutt went on to admit he was more bullish than many of his peers on oil prices recovering, having experienced two previously significant oil slumps on world markets. "Volatile oil prices are nothing new," he said, referring to accelerated production from non-OPEC members

during the 1980s that plunged prices by almost half to less than \$20/bbl and caused a steady decline between 1980 and 1985.

"In 1986 OPEC changed its strategy. Rather than enduring production cuts, it maintained and later increased its output. This drove prices down and allowed OPEC to steadily regain market share. Following more than a decade of flat prices and significant industry consolidation, the supply overhang subsided and prices did indeed recover. I expect to see a parallel outcome in today's market, but with a much more rapid cycle time," he said.



**The Red Bull Racing team's pit crew is seen in action on Australian driver Daniel Ricciardo's Formula One car. According to BHP Billiton Petroleum's president, Tim Cutt, the oil and gas industry needs to achieve leaps in performance equivalent to those achieved by Formula One pit crews, which have reduced stops from just under a minute in the 1960s to just three seconds today. (Source: Red Bull Racing)**

## Supply-demand overhang

Cutt added that supply conditions had been relatively tight over the past 10 years, and the industry had responded by increasing investment and exploration. "This led to several sizable discoveries in Brazil and the opening of the U.S. shale industry, which has grown by a staggering 3 MMBbl/d of crude and condensate over the past four years," he pointed out.

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With supply currently exceeding demand by 1 MMbbl/d to 2 MMbbl/d of oil, Cutt said the world needed to “work off the overhang” before prices stabilized over the next year.

While significant reductions in U.S. shale activity had emerged as the biggest contributor to global production cuts as a consequence of oversupply, Cutt went on to say that average yearly demand for petroleum liquids was expected to grow by more than 1 MMbbl/d per year.



**Tim Cutt, president, petroleum and potash, BHP Billiton Petroleum**  
(Source: BHP Billiton Petroleum)

“On top of this, the petroleum industry must offset an annual base decline of approximately 3 MMbbl/d to 4 MMbbl/d. This means there is a gap of approximately 4 MMbbl/d to 5 MMbbl/d of effective demand that must be met with liquids production.”

He continued, “The question of where future supply will come from is very important, especially considering the declining trend of oil discoveries in recent decades. Annually the world consumes over 30 Bbbl of oil. On average, over the past decade, the industry has been finding less than half that amount each year on a recoverable basis.

“In the past four years discoveries were less than 10 Bbbl per year, and in 2014 they amounted to less than 6 Bbbl. That’s one-fifth of current consumption. This is a staggering trend and represents an opportunity and a responsibility,” he said.

This task was given added urgency, he said, by forecasts that by 2020 between 8 MMbbl/d and 10 MMbbl/d would be required to meet this demand at the steepest part of the cost curve.

### Future opportunities

Fellow Australian operator Woodside Petroleum’s CEO Peter Coleman continued the theme of urging the industry to adapt or else. He warned during APPEA’s opening plenary session that the industry will miss out on future opportunities in the oil and gas space if it doesn’t start to think outside the box and challenge conventional methods of operating.

Coleman said the industry shouldn’t automatically expect the next wave of industry investment to occur in brownfield operations. “The discussions around expansion and brownfield developments ... I think we need to be careful about those discussions,” he said. “I think it will come if we earn it.”

Despite natural gas being expected to fulfill 2% to 3% of energy demand per annum for the next 20 years, with demand predominately stemming from Asia, Coleman stressed that Australia’s proximity to that continent would not be enough on its own to secure lucrative opportunities to fulfill that demand. “We can’t sit here with our projections and think simply, just because energy demand growth is going up, that we have the right to fill that demand growth. We have to earn it by making sure we are competitive in our cost offering,” he said.

### Transition period

With Australia well on its way to becoming an LNG force to be reckoned with, Coleman said the challenge for Australian LNG is the ability to shift from a project constructor and builder to an LNG “trader, marketer and producer.”

“We [Australia] are moving beyond being a constructor, developer. Are we ready as a country for that and as companies for that?” he said.

While low oil prices were forcing some companies into hibernation and cost conservation mode, Coleman stressed that investment in the sector was still pushing ahead and reiterated that Australia was competing on a global stage. “If



**Peter Coleman, CEO, Woodside Petroleum**  
(Source: Woodside Petroleum)

we get stuck in this mode of ‘Well, we wouldn’t invest so nobody in the industry will invest’ and we come to conferences and talk about how we won’t invest, that’s not great. The Chenieres in this world go out and invest. The Freeports go out and invest.”

In May Woodside finalized terms with the above-mentioned Cheniere Energy relating to its purchase of gas from the Texas-based Corpus Christi liquefaction project after a positive final investment decision on the two-train project.

Coleman urged the need to think outside the box. “My point is we keep trying to predict the future as being something that is rational and stable. The reality is the industry has a history of about every 10 years fundamentally changing the business model, whether that is deepwater or 3-D seismic or shale gas. I think we need to look forward and really challenge ourselves and say ‘We really don’t know what the future looks like, but do we need to play?’” **E&P**

*Editor’s Note: Article compiled with assistance from Hart’s Oil & Gas Investor Australia editors Dale Granger and Lauren Barrett.*



# Service cost retrenchment

The carnage in oil services pricing nears the end.

**Richard Mason, Chief Technical Director**

**W**ell stimulation pricing, the largest casualty in the current energy downturn, may be nearing bottom. At press time rig count was flattening after publicly held operators removed an estimated \$80 billion in spending in just six months, a majority of which was formerly allocated to oilfield services.

Hart Energy's *Industry Revenue Model* indicates monthly revenue is down 44% to \$22 billion from last fall's peak based on current production times average monthly commodity prices for crude oil, natural gas liquids and natural gas. Add it up—or rather subtract it out—and it means oil and gas operators, both public and private, will have about a quarter billion dollars less domestically to reinvest or distribute as royalties or other payments in 2015. The figure may actually be greater since the industry was significantly outspending cash flow on a cushion of high-yield debt in the 2011 to 2014 era. Now operators are committed to living within cash flow out of necessity.

For the services sector, it means fewer rigs, fewer wells and less demand for well stimulation, which had been in the midst of capacity expansion when the floor dropped out of oil prices in late 2014.

Per-stage pricing for well stimulation services followed suit, dropping from \$80,000 to \$90,000 for standard plug and perf in fourth-quarter 2014 to the mid-\$50,000 range in second-quarter 2015, according to Hart Energy telephone surveys.

Well stimulation firms are operating at or below cash operating costs. Some smaller companies have gone out of business or been consolidated. Regional fleet effective capacity dropped significantly. Effective capacity is estimated at half of late 2014 levels in the Bakken, for example. In other markets, the churn is still underway, and well stimulation players tell Hart Energy they

just don't know a definitive number yet and won't until the smoke clears, which they expect to happen in the third quarter.

Furthermore, stimulation companies tell Hart Energy surveyors that pricing won't go much lower as they choose to idle equipment and lay off crews rather than work unsustainably at a loss. Some bigger players are reportedly operating below cash operating cost regionally as they seek marketshare and attempt to cover the deficit by bundling multiple wellsite services for customers.

Well stimulation companies have seen pricing drop about 35%, while completion-related bulk commodity materials like raw sand are down 20%. As noted last month, Hart Energy surveys show drilling rig day rates declined 25%. Currently operators can get a 1,500-hp AC-VFD Tier I rig from \$16,500 to \$21,000 a day, depending on the market, though demand for rigs of any kind is spotty.

The reduction in pricing for oilfield services would be a windfall for oil and gas operators if they were more active in the field. Publicly traded operators now claim that they can achieve acceptable rates of return at

\$65 oil and would get active with a sustained price between \$65/bbl and \$75/bbl. Unfortunately, crude oil pricing remains about \$10/bbl below the \$65 sustained that operators say they need, partly due to regional differential discounts.

By the time the cycle troughs—and that trough appears imminent—oil and gas operators will see a 25% reduction in well costs. Those savings appear to be split 40% to 60% on a capital efficiency vs. secular pricing basis. That ratio will be worth watching in the future because the portion of well cost reductions attributable to the secular downturn will not be permanent and may jump more than anticipated when operators return to the field, only to find the deficit in experienced manpower and equipment capacity on the services side can only be solved by an increase in pricing. **ESP**

- **Well stimulation pricing down 35%**
- **Well stimulation providers at cash cost as firms idle equipment and release crews**
- **Pricing for well stimulation approaching bottom**
- **Operator overall well costs down 25%**



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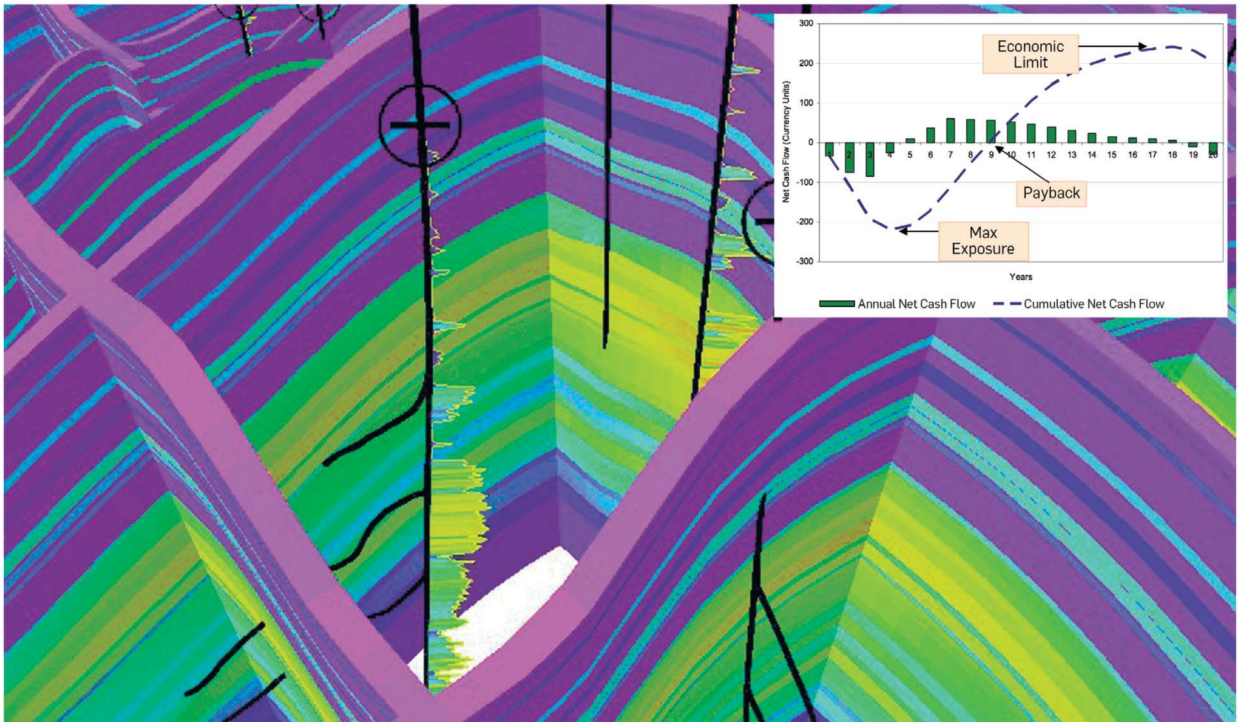


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# Women at the helm

An all-female management team is one thing that sets this new company apart from its peers.

The energy industry isn't always an easy place for women who want to have families and lay down roots—frequent transfers can make that challenging. But most women don't respond by starting their own companies.


Claire Jennings established seismic contractor WGP with her father in 1994. When the company became a public limited company and decided to relocate, she took a year off and then started Aqua GeoProjects in May 2014. Some of her friends came along for the ride, and the company is now believed to be the first all-female managed marine seismic project management company in the world.

Joining Jennings, who is managing director of the company, is Kerry Thain, project manager; Kelly Richards, public relations and quality manager; and Emma Cox, marketing manager. Between them, they have more than 35 years of global marine experience. "All of the women at the helm of the business have real-time operational experience in the marine geophysical sector and work in the field overseeing international projects not usually supported by women. And these are not your typical industry locations, ranging from the Arctic circle to Azerbaijan to Panama," Jennings said.

Jennings is not setting her sights on being the next CGG or WesternGeco. The company specializes in niche market services and seeks smaller scale operations in emerging areas where bespoke solutions are more often required that need to be cost-effective, reliable and scaled to fit the project budget.

This is in part because of the growth of WGP. Jennings wanted to get "back to our roots" to provide services that wouldn't necessarily be available from larger contractors.

Jennings said that during her time off, opportunities began cropping up in 3-D, transition zone and 2-D in



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South America. She had some funds set aside, and she began to build the company, which formally announced itself in April 2015. During 2014 and 2015 she made contacts and deals with several international businesses, she said.

"I never considered myself to be an entrepreneur, but other business associates tell me I am," she said.

"However, I do know I'm good at coming up with ideas and making decisions. With any successful business, it's all about relationships, collaboration and focus. You have to know your key market, and stick with it!"

So how does the all-female management team compare to a more traditional male-led organization? "I think women are far more able to multitask and look at the bigger picture," Jennings said. "Men are quick thinkers and quick decision-makers. They go out there and get the job done, moving from one objective to the next. All-male teams usually deliver results, but there is sometimes a lack in human/nonbusiness interaction."

However, she's not taking a "No men allowed" approach.

"We certainly don't rule out as the company grows expanding into a balanced and mixed team of both men and women," she said. "There is no doubt that a mixed team brings its benefits." **ESP**

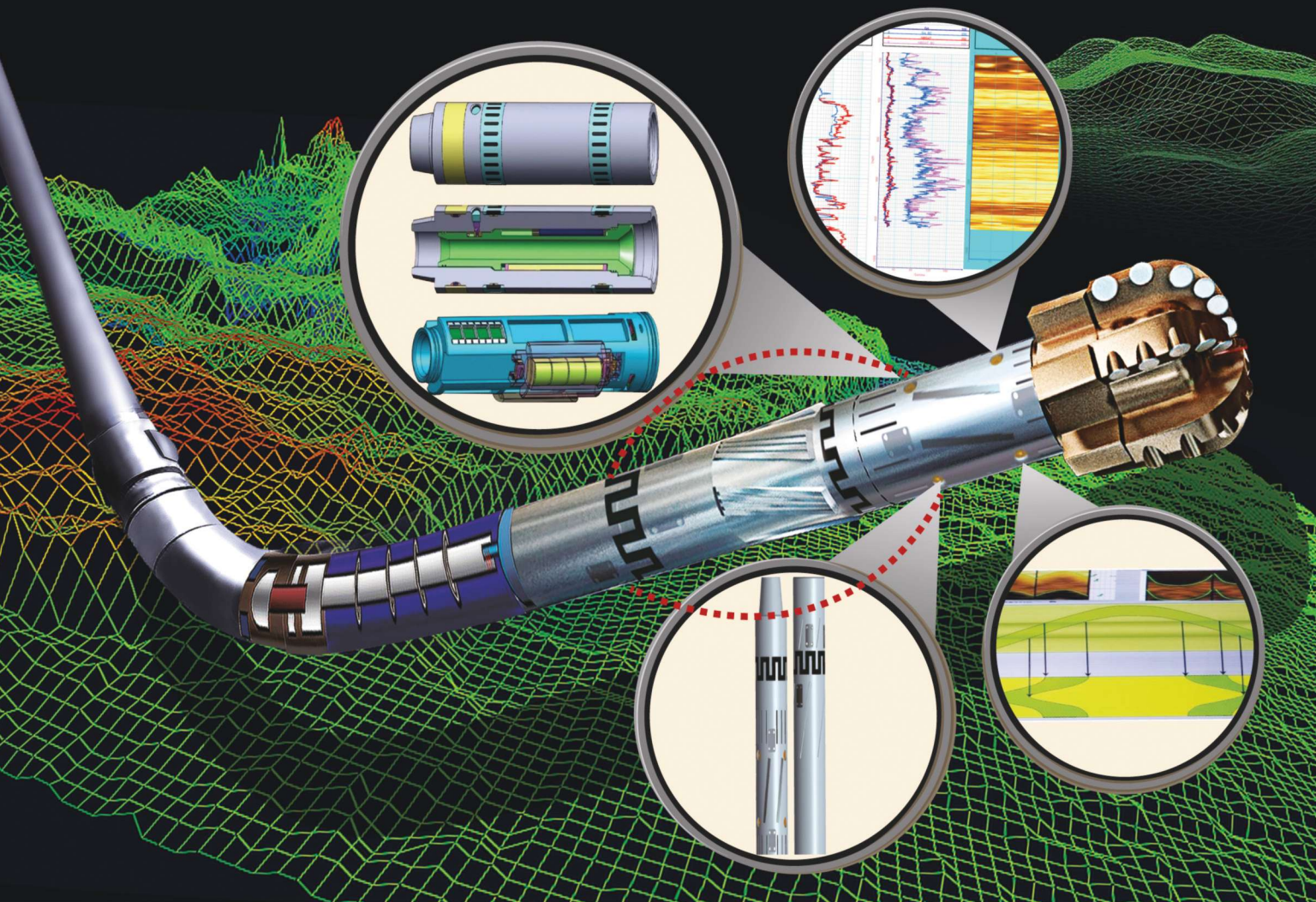


**Kerry Thain, Kelly Richards and Emma Cox joined Claire Jennings to make up what is believed to be the first all-female managed marine seismic project management company. (Source: Aqua GeoProjects)**



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# Drilling tidbits: New Macondo area drilling, boosting onshore rig fleet

LLOG tackles new well in Mississippi Canyon Block 252. Pioneer Natural Resources is adding rigs in the Permian and Eagle Ford plays.

Sevan Drilling's semisubmersible *Sevan Louisiana* is about to spud what will be the most closely watched well in the Gulf of Mexico (GoM) since the *Deepwater Horizon* disaster five years ago. That is because the rig will be testing the same formation where BP encountered its problems—Macondo—for LLOG Offshore Exploration.

The Associated Press (AP) reported May 13 that LLOG planned to start drilling the Macondo Formation in June. The permit to drill the well on Mississippi Canyon Block 252 was approved April 13 by the Bureau of Safety and Environmental Enforcement.

According to the May 13 AP article, federal regulators divided the block in 2014. BP still has 270 acres around its Macondo well. LLOG now has the remaining 5,490 acres in the block where it will drill.

The *Sevan Louisiana* is under contract to LLOG through second-quarter 2016.

Rick Fowler, LLOG vice president for deepwater projects, told AP that the company was committed to making sure an event like the *Deepwater Horizon* blowout does not happen again.

That would be the prudent way to do business.

For both onshore and offshore operators, another prudent way of doing business is to high-grade the drilling fleets. Offshore drilling contractors are either retiring or cold-stacking rigs. Onshore, the majority of operators are high-grading their fleets and taking advantage of lower day rates.

In its first-quarter 2015 report, Sevan Drilling said, "During the quarter, the market has seen very little new fixture activity, and the new contracts that have materialized are at significantly lower day rates. In order to manage this downturn, rig owners are stacking or scrapping older rigs, and new-build deliveries are being delayed."



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The company has deferred the delivery of the *Sevan Developer* until October 2015. The delay can be extended for four additional six-month periods through October 2017 at the company's option. The company has three of its rigs under contract, but the rig in the yard does not have a contract, thus the delay.

Another example is Pioneer Natural Resources, which just sold its 50.1% in its Eagle Ford midstream business for about \$1.1 billion. This will help the company ramp up its rig fleet.

Scott D. Sheffield, Pioneer chairman and CEO, stated in a press release, "We will re-initiate horizontal drilling in the Lower Spraberry Shale interval. Starting in July, we will add an average of two horizontal rigs per month in the northern Spraberry/Wolfcamp through the remainder of 2015 as long as the oil price outlook remains positive. During the first-quarter 2016, we are planning to add another eight horizontal rigs. This rig ramp-up will bring our total horizontal

count to 36 rigs, which is essentially the same as our horizontal rig count prior to the oil price collapse in late 2014/early 2015."

There are some good signs for the drilling industry. Let's keep those rigs working. **ESP**



**The *Sevan Louisiana*, which is under contract to LLOG Offshore Exploration, was expected to spud a well in June in the Macondo Formation.**

(Source: Sevan Drilling)

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# Fizzy frack

CO<sub>2</sub>-energized fracturing fluids prove the fizzy gas' utility goes beyond soda pop.

Unconventional reservoirs provide a unique set of challenges like low permeability and very low porosity that require stimulation to be economically viable. The addition of CO<sub>2</sub> or nitrogen to water-based fracturing fluids energizes the system, delivering improved well productivity and other benefits.

"Besides the water savings, which can be upward of 80% per well, there are other benefits," said Murray Reynolds, director of technical services for Ferus. "You're sourcing much less water, and you tend to be able to pump smaller-sized fracture treatments vs. slickwater, in particular."

According to Reynolds, CO<sub>2</sub> foam-based systems inherently carry proppant better into the fracture and hold it in the upper portion of the fracture, creating a better and more conductive propped fracture and resulting in better production over the life of the well. This increased flowback is due to the pumping of the CO<sub>2</sub> downhole into the formation as a high-density liquid.

"Once it enters the formation, as it warms, it expands into a gas. One gallon of liquid CO<sub>2</sub>, when it warms to 89 F [31 C], starts to expand and—at standard temperature and pressure—becomes 542 gallons of gas," he said. "The huge expansion that occurs in the reservoir helps to flow out not only load fluids that you pumped in there but also any hydrocarbon or water liquids in the reservoir."

While the use of CO<sub>2</sub> and nitrogen in fracturing is a proven approach in the Western Canadian Sedimentary Basin, its acceptance in the U.S. has been delayed, possibly due to a number of perceived challenges, namely availability, cost and logistics.

"Probably the biggest drawback is availability in certain areas as transporting over long distances is costly," Reynolds said. "Several of our Canadian CO<sub>2</sub> plants are located right in field locations, so the transporta-



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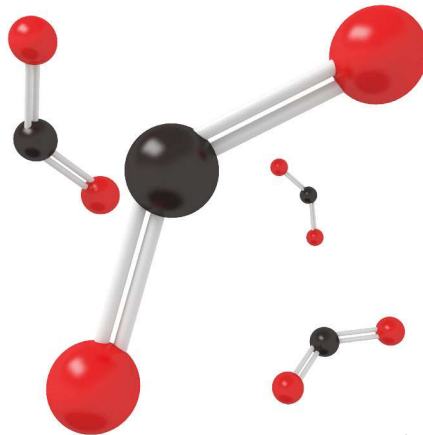
tion is over short distances, easily done and logistically easy. In the U.S. and Canada, there are thousands of small emitting plants that could quite easily have a CO<sub>2</sub> recovery unit put on them."

Reynolds noted that in developing a market, Ferus looks for local high-emitting sources like fertilizer plants or ethanol plants for gasoline as candidates for recovery units as these sources produce pure CO<sub>2</sub> as a byproduct.

"Another perception is cost. Yes, one barrel of CO<sub>2</sub> is more costly than one barrel of freshwater," he said. "However, when you add up all the other costs associated with water such as transport, flowback of water, trucking of flowback water, and either recycling or disposal of that flowback water, then it becomes very competitive,"

he said. "Of course, not all of the treatment fluid is typically CO<sub>2</sub>. It's usually 70% to 80% quality CO<sub>2</sub>, so there's a small aqueous water portion of the fluid. Certainly you're reducing those water-related costs significantly."

Statoil recently awarded Ferus with a service agreement to supply the CO<sub>2</sub> and provide transportation, logistics, storage, and onsite supervision for the Statoil test occurring later this year in the Bakken Shale. For more information about the Statoil test, be sure to check out "Energized fracturing comes to the Bakken" in this month's cover story. **ESP**



*Jennifer*

WELL STIMULATION

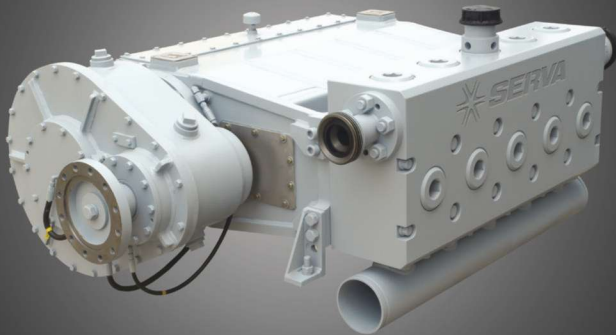


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# UK North Sea suffering consequences

The U.K. sector of the North Sea is, as the British would say, in a spot of bother.

**Steve Sasanow**, Contributing Editor

Companies across the industry here in the U.K. are desperately trying to find a way to revive a sector that has become moribund. Get your dictionaries out—that means “close to death.”

Of course, even if newfield investment slumps more than it already has—currently estimated at 50%—production will continue here for decades yet. But much of what is estimated to be extractable (more than 20 Bboe in reserves) would remain in the ground. In this case, the recommendations in last year’s report by the estimable Sir Ian Wood for “maximum economic recovery” from the sector would be unachievable.

Close observers of activity here will look at both the industry and the government and say they are only getting what they deserve. From the government’s perspective, it has always seen the oil and gas sector as no more than a cash cow—the 1980s Conservative government of Margaret Thatcher paid the cost of large-scale unemployment caused by closing steel mills, coalfields and shipyards with tax revenue from offshore production—and little has changed in 30 years.

The current Conservative government slapped on an extra 12% two years ago on the already punitive supplementary corporation tax (SCT) charged on the U.K. oil industry. When Chancellor of the Exchequer George Osborne withdrew the add-on in the March budget but left the rest of SCT in place, the industry groveled and said, “thank you, thank you.” With long-term production in decline, however, there may be precious little more revenue to collect.

The U.K. industry, as is often the case elsewhere,

does not know how to fight its corner. It accepts missives from environmental and government agencies without putting forward reasoned arguments for why it does things.

I remember being at a press conference years ago when the industry wanted to drill in the eastern Gulf of Mexico but was prevented from doing so by a combination of environmental and tourism interests. The then-president of Chevron threw up his hands, saying the industry could not win the PR battle. It was a pathetic response from a multibillion-dollar industry.

The Wood report pushed for a new regulator—now the Oil and Gas Authority (OGA)—which it sees as the savior of the U.K. sector. Why? Will OGA have more teeth than its predecessors?

While no government—except Saudi Arabia—has any influence on the oil price, only treasury-backed changes in rules will make any difference.

First, as the oilfield adage goes, you only make money by drilling wells. The U.K. government has to allow, as the Norwegians do, the write-off of drilling costs to

make exploration activity less risky. And OGA has to have the authority to force operators to undertake more well intervention work to get the most out of existing fields.

The former is unlikely unless the industry can better explain why it needs it, and the latter will require more force of will. Can it happen? Possibly, but it is not where I am putting my money. At present, only rising demand and oil price, plus cost reduction, can save the U.K. sector. **ESP**

*Steve Sasanow is the editorial director for Hart’s Subsea Engineering News and can be reached at [sen@hartenergy.com](mailto:sen@hartenergy.com).*

Close observers of activity here will look at both the industry and the government and say they are only getting what they deserve.



# Operators win completion game with lower costs, greater efficiency, more production

Although demand for completion services has declined at about the same rate as the price of oil, the need for technology to counterbalance cost reductions remains strong.

Scott Weeden, Senior Editor, Drilling

The pressure is on for operators, whether it is from lower oil prices hammering the bottom line, pressure pumping crews onshore providing the best hydraulic fracturing for the lowest cost or dealing with HP/HT in ultradeepwater wells in the Gulf of Mexico (GoM). How operators react to the pressure will determine how well they survive the downturn.

Some operators have taken the route of waiting for higher oil prices to return. In an April 23 article, Bloomberg Intelligence pegged the inventory of wells waiting to be completed at 4,731 wells. Even with the cost of tools and services being reduced by 30% to 40%, some plays still are not attractive.

The companies that continue to drill and complete wells are counting on technology to make those wells cost-effective and highly efficient by saving time and reducing risks. Service companies are hearing operator after operator emphasize greater efficiencies across the board.

Lowering costs is only part of the equation.

There is a current debate in the industry about the value of refracking. Some companies are convinced that refracks are of little or no importance, while other operators that have been pursuing shale plays for quite some time see a benefit to refracking wells considered understimulated.

Regardless of which side of the argument a company is on, the focus is on technology to

provide the final solution for effective completions. For example, Statoil is hoping some technology being used in Canada will have an impact in the U.S. The company will be using CO<sub>2</sub> as a fracturing fluid in a Bakken well later in 2015. If it delivers the success that Statoil is expecting, the company could switch how it stimulates wells with a goal of using less water.

The quest for lowering costs offshore would have even greater impact given how much companies have to spend on offshore projects.

Offshore, the industry knows that new technology will be needed for ultradeepwater completions. The Lower Tertiary in the GoM has the industry buzzing, but operators are delaying projects in the face of \$55 oil. The play is estimated to contain as much as 40 Bbbl of oil. But the challenges drive the costs up.

HP/HT, 3,050-m (10,000-ft) water depths, 10,670-m (35,000-ft) wells, low recovery factors and the need for artificial lift are just some of the challenges that technology will need to address.

Systems that mitigate risks—whether onshore or offshore—and technologies that meet the challenges will produce the winners in this game.

In the following pages, *E&P* delves into some of the technologies that the industry is using in these areas. **ESP**

# Even with low oil prices, technology still drives efficiency, cost savings

Service companies with technology that impacts efficiency, cost and risk are seeing an increase in customers.

**Scott Weeden, Senior Editor, Drilling**

Fewer wells are being drilled, yet oil and gas production remains at very high levels, with natural gas and crude oil storage heading for record volumes. Operators continue to push for even greater cost reductions in tools and services than the 20% to 30% that have already occurred.

How do service companies deliver improved production in the face of those lower costs? The answer is technology.

Operators continue to focus on saving time, decreasing costs and reducing risks. “What they are looking for are ways to make the well completions more efficient and cost-effective,” explained Garrett Frazier, director of sales and marketing, Magnum Oil Tools.

“The operators are looking for efficiencies. They’re looking for the ability to understand that they’ve stimulated the wellbore to the best of their ability,” Joe DeGeare, president, U.S. sales and operations, NCS Multistage LLC, told *E&P*.

Dan Themig, president and CEO, Packers Plus Energy Services, speaking at Hart Energy’s DUG Permian Conference May 20, said, “There’s a huge upside in driving efficiencies in our industry. One thing I think we sometimes overlook is effectiveness of our existing completion practices. Driving costs down is only part of it. Our goal is to move those cumulative curves up as well.”

When service companies provide the technology to meet those efficiencies and effectiveness, operators will be looking for that technology, even in a down market.

## Reducing well interventions

To paraphrase the movie *Field of Dreams*, “If you build it, they will come.” Magnum Oil Tools worked to develop a dissolvable plug for hydraulic fracturing. In 2012 the company brought its experience in zonal isolation to the table, partnering with Kureha Corp. and utilizing its

unique material to develop a dissolvable line of completion tools. In March 2013 Magnum launched the first of these products, which was called the Fastball—a dissolvable frack ball for sliding-sleeve completions.

On the heels of the Fastball’s introduction, further R&D resulted in the release of the Magnum Vanishing Plug (MVP), a dissolvable frack plug used in plug-and-perf (PNP) completions. The MVP

eliminates the plug drill-out process, enabling operators to save significant time, money and risks associated with well intervention.

“Instead of waiting for coiled tubing [CT] to drill out the plugs, clean out the well and then take it to production, all an operator has to do is pump that last frack, change out the frack valve on location to a production tree and send the well straight to production,” he explained.

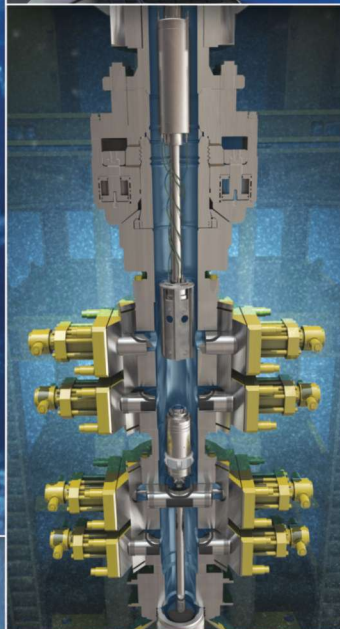
“This is certainly a step-change technology. We just released it in October 2014. We’re really starting to push a lot of products. We’re still in a hiring mode in that service department to satisfy all the demand,” Frazier said.



**Packers Plus field hands prepares the e-PLUS Retina system for running in the well. (Source: Packers Plus)**

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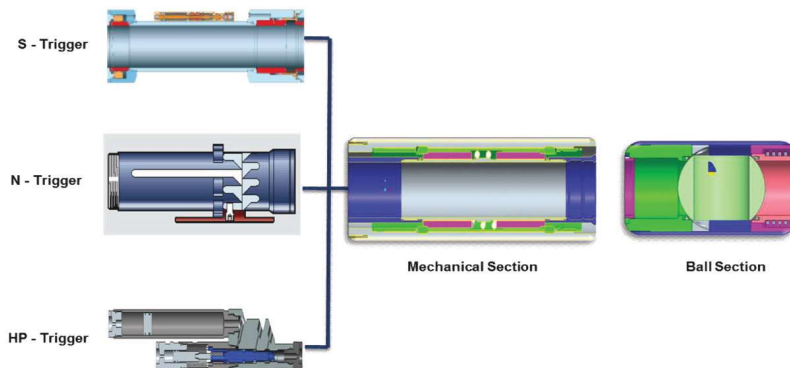
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**The third generation of isolation valves, called FORTRESS, is more debris-tolerant and offers new mechanical triggers for flexibility in design. (Source: Schlumberger)**

“Thousands of stages per month are still being fracked even in this downturn, and operators are looking for significant ways to optimize their operations,” he continued. This new technology is completely eliminating the well intervention process, and operators are reporting that these benefits are invaluable.

At the time of the MVP launch in October 2014, approximately one month before the crash in oil prices, potential savings of eliminating CT were substantially higher than in today’s market. However, Frazier noted, “Even though the pricing has declined on the cost of the CT operations by somewhere around 50%, Magnum’s dissolvable technology continues to make advances in more efficient and cost-effective completions.”

### Forty stages in 24 hours

Costs and time on the drilling side have been reduced considerably. The biggest cost in bringing a well into production is for completion. On the efficiency side, how quickly can the completion work be accomplished?

NCS Multistage completed an 87-stage well in the Powder River Basin in Wyoming for Devon Energy Corp. in less than one hour per stage. All the fracks were single-point injection using NCS Multistage’s CT frack system. The company set a record with 40 fracks in 24 hours with an average of 36 minutes per stage, DeGeare said.

Casing sleeves were run and cemented as part of the production casing string. The frack-isolation tool was run on CT to open each sleeve—in a single CT run.

“When compared with [PNP], which was used on nearby wells, we saved them several days of work,” he added.

What operators are doing “is looking at new technologies to have better conductivity to the wellbore and have the assurance that they have stimulated the wellbore at every point of injection,” he explained.

With this technology NCS Multistage also reduced the footprint in the frack spread by reducing the required horsepower on location by about two-thirds. “All of that adds to their bottom line. We’re gaining new customers all the time. Last month we worked for six new customers. This month we’ve got another three or four new customers. We just finished our first well in the Marcellus, and we’ve just delivered equipment to do a Utica well,” he continued.

“With our system, when we’re done with the frack we can put the well on production. We’re saving operators several days by putting production online more quickly,” DeGeare said.

### Three new strategies for effectiveness

Being able to make an impact on poor cluster efficiency is a goal of many operators. Themig discussed three technologies that could impact reservoir effectiveness.

The first is rapid execution strategy, which involves generating fracture complexity to affect rock mechanics of the reservoir. Painted Pony Production Ltd., for example, improved its type curve from 142 MMcm to 382 MMcm (5 Bcf to 13.5 Bcf) in the Montney play in Canada. The rapid execution strategy involves drilling a pair of parallel horizontal wells. One lateral is quickly fractured and shut in with no flowback. The second lateral is then fracked. The goal is to create complex fractures between the two laterals. Openhole completions respond particularly well to this method, he explained.

A second strategy is to ensure flawless execution. Packers Plus introduced its e-PLUS Retina monitoring system to collect and analyze real-time data that can detect a ball that fails to launch or double-shift on a stage, he continued.

The third strategy is the use of dual and triple laterals from the same wellbore. “It is possible to design wellbore construction to do downspace drilling from existing wellbores. This can include dual laterals,” he emphasized.

### Evolving isolation valve technology

In long laterals debris can be a problem in activating isolation valves. For the past five years Schlumberger has been developing a debris-tolerant isolation valve that provides both modularity and flexibility.

“We’ve installed more than 1,800 isolation valves in more than 40 countries and 44 clients. We have a diverse portfolio of valves, and we are on our third generation of isolation valves, which is called the FORTRESS pre-



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mium isolation valve,” said Ali Adlene Arraour, product line manager for safety and isolation valves, Completions, Schlumberger.

“It has become very clear that our clients are aiming for longer reach, deeper wells with more clusters and different laterals. The use of this kind of isolation valve becomes a necessity,” he emphasized.

More than one year was spent debris-testing the new valve. “We compared the actuation force required to open a valve between our old generation and new generation. This helped us modify our design, especially for the ball and mechanical sections. By doing the debris test, we found that the activation force for the old generation valve in a debris-filled well required more than 123% activation force. The new FORTRESS design greatly reduced this requirement to only 15%,” added Alaa Fouad, isolation valves product champion, Completions, Schlumberger.

What the designers did was eliminate more passes that may cause debris to settle out. They reinforced the design by creating a full-bore ball valve. Now the tool is

more stable and debris-tolerant, Arraour said.

“We recently closed out a project in the Middle East of over 100 valves used with an electric submersible pump completion. We saw 100% success on the installation,” he continued.

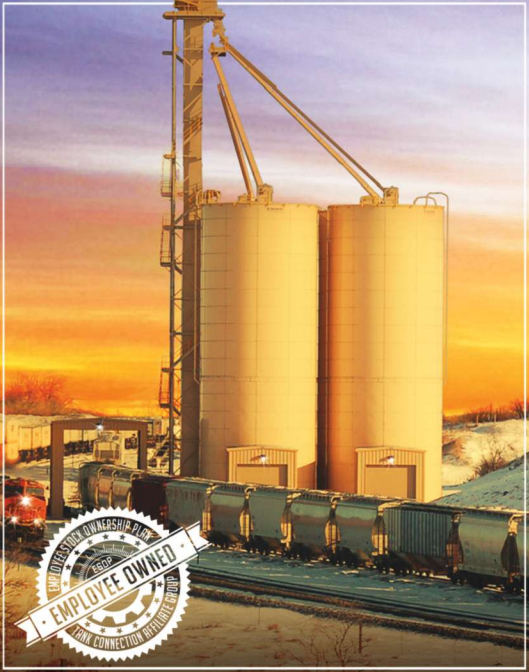
Complementing the proven installation processes that were developed, product reliability was greatly improved, he said. A well in Malaysia was suspended for 4.4 years. The isolation valve was opened remotely the first time as per plan, and the well began producing with no issues, he added.

The first isolation valves were only activated with a nitrogen (N) trigger. The modularity and flexibility in the new generation FORTRESS valve comes from the new triggers (S, N and HP) to meet different well conditions:

- S-trigger is pressure-driven, uses no nitrogen and has a reduced risk from debris locking;
- N-trigger is nitrogen-activated and can be customized for any depth of well or completion fluid; and
- HP-trigger is designed for HT/HP wells up to 177 C [350 F] and 25,000-psi reservoir pressure. **ESP**

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# The refracture debate

Some insist it's over-hyped. Others say, 'Give it time.'

**Rhonda Duey, Executive Editor**

**M**erriam-Webster's dictionary defines "trivial" as meaning "of little worth or importance." Apparently the analysts at Bernstein see the role of refracturing in shale plays to be virtually useless. Service companies are not happy with this declaration.

After defining what refracks are, the report, titled "Bernstein E&Ps: the role of refracks in the shale oil revolution – trivial," noted that the literature on the topic is "success-based." "Much of the literature is from service providers or E&P operators that achieved some success," it noted. "In addition, much of the market talk around refracks is similarly skewed positive."

Secondly, it targeted a Baker Hughes presentation, noting that this economic analysis "shows refracking economics are mediocre." The analysts determined that even with 100% adoption, refracking would account for only about 2% of U.S. supply and that refracks will dilute capex spend broadly rather than harming a specific subsegment.

The Bernstein analysts are not the only ones who are bearish about the technology. In a May 4 conference call, EOG Resources Chairman and CEO Bill Thomas said he considers the procedure to be "really technical"

and that his company prefers to drill new wells. But other companies are beginning to embrace the technology. SM Energy Co., for example, is said in a Simmons & Co. report to be "very optimistic about the potential for refracks" and is participating in an industry consortium that is refracking wells in the Eagle Ford.

In a May 5 earnings call, Jason Pigott, Chesapeake Energy Corp.'s executive vice president of the southern division, said, "Within our retained portfolio, Chesapeake has drilled 6,750 horizontal wells since 2004. Of these wells, nearly 4,600 were drilled prior to 2012, and we consider these wells under-stimulated compared to our current designs and based on their vintage."

## Is it rejuvenation or damage?

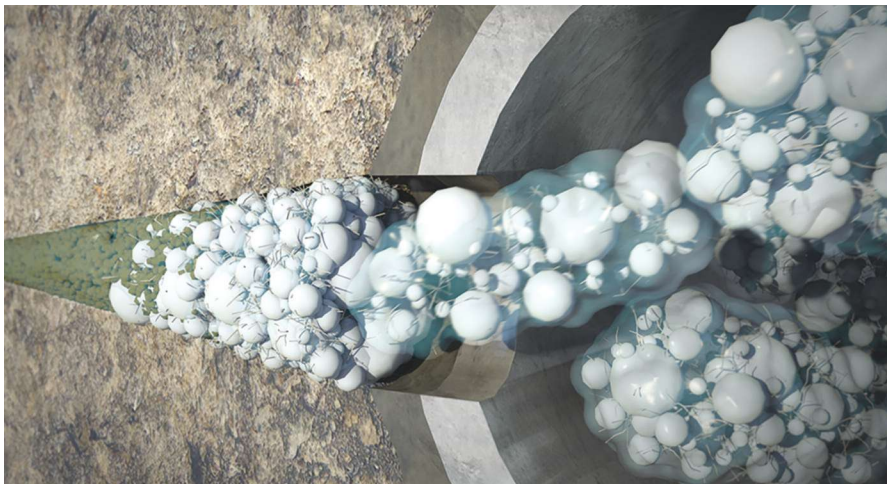
One of the primary concerns expressed about refracking is the potential to cause damage to the refrack candidate or even nearby wells. The Bernstein report lists the potential for reservoir and wellbore issues. And even proponents of the technology note that it must be carried out carefully.

In a paper presented at the recent Hydraulic Fracturing Technology Conference, authors from Pioneer Natural Resources and Barree & Associates discussed the complexity of performing the procedure. "Refracturing an old horizontal well with 5,000-ft [1,524-m] lateral length and more than 800 existing perforation holes in the casing is very challenging and requires

a careful integration of reservoir knowledge, completions skills and experience," the authors noted.

Due to this, Pioneer has developed a workflow that includes identifying the lower pressure areas along the lateral, identifying which wells within the drilling schedule are offsetting wells with high cumulative production and designing a single fracturing job with substages separated by diverting agents.

It's this integrated approach that service companies are extolling. All of the major pressure pumping companies have developed sophisticated workflows that take multiple



**A disappearing blend of four particulate sizes and fiber cohesion provides maximum efficiency in plugging hydraulic fractures at the wellbore for effective diversion during refracturing treatments. (Source: Schlumberger)**

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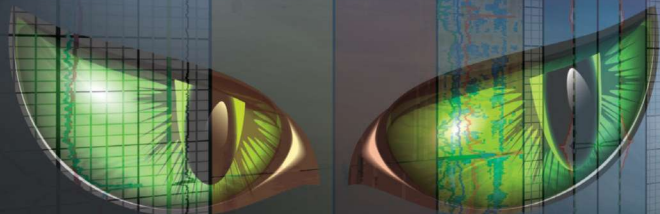
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criteria into consideration to select the candidates that will be the most likely to benefit from refracking.

Refracturing is a remedial production operation often done either because the original fracturing failed to contribute any significant amount of flow, the initial completion's performance degraded over time below economically acceptable limits or significant unfractured pay exists in the well.

Weatherford's approach to refracturing puts emphasis on evaluating current well performance, candidate well selection and the refracture design. For instance, it is critical to evaluate if the well's low performance is associated with "completion inefficiency" or with poor "reservoir quality" because completion inefficiency can be improved.

In a paper by BP America Production Co. presented at the hydraulic fracturing conference, the authors noted that the popularity of the plug-and-perf completion technique, while allowing rapid operations, might not always result in the best completion job.

"As many of these shale plays now mature, it is becoming increasingly apparent that the majority of the wells have not been effectively stimulated," the authors noted. "Fracture interference and cluster efficiency [are] among the key concerns with the completion approach, with high efficiency rarely being achieved, resulting in only partial coverage. In fulfilling the desire to complete these wells in a timely manner, it is now apparent that there likely remains a significant portion of unstimulated pay in a typical well post-completion."

Added David Sobernheim, North American stimulation domain manager for Schlumberger, "One of the key reasons for refracturing is simply that current plug-and-perf methods typically only yield about two-thirds of the perforation clusters producing. We are working to address this going forward on new wells, but the backlog of wells drilled in past years has potential candidates."

By focusing on accurate stimulation modeling and real-time control during execution based upon reservoir response, Sobernheim expects the success rate from refracturing to become more reliable and routine.

### Choosing wisely

In a rebuttal to the Bernstein report, Sergey Kotov, manager of integrated technology for Baker Hughes' NextWave solution, said that the analysts only told part of the story when quoting the Baker Hughes paper. "The 51% of the story that was not told by those statistics was what Baker Hughes learned from the industry's studies on refracturing and from the company's study of previously refractured Eagle Ford and Bakken wells:

- that far more analysis and new and more strategic ways of thinking are necessary to avoid disappointment from refracturing efforts;
- that the first step to successfully improving production, reserves recovery and economics from rejuvenation efforts is to efficiently screen and select the best candidates to invest only in those wells with the greatest potential and the least risk;
- that not all hydraulically fractured wells are candidates for rejuvenation;
- that it is important to understand what type of rejuvenation is required to meet operators' recovery and business objectives. Rejuvenation options, alone or in combination, may include wellbore cleanout, chemical treatment, recompletion, refracturing and artificial lift;
- that a thorough economic analysis of the technological solution is required to maximize the value from the existing underperforming wells;
- that the new approach must view unconventional wells as renewable assets and requires a fact- and science-based workflow focused on both the well and the reservoir; and
- that when using a holistic, data-driven approach, rejuvenation could be a viable alternative to drilling new wells."

These learnings, he added, led to the development of the NextWave solution, which he said is already improving well performance, even in current market conditions. "At the same time, we are also working to address another key issue mentioned in the SPE paper—that if refracturing is to be implemented in a larger scale, wells must be completed in a way that makes subsequent rejuvenation much easier."

For Thomas Roesner, Cameron global business development manager, CAMSHALE Completions, there are a few reasons why refracturing is still a very small part of the market. "This is like what happened in conventional wells in the late '90s and early 2000s with the development of directional drilling," he said. "People went into vertical wells, sidetracked them with the casing-exit whipstock technology, and started drilling horizontals. "It's a well intervention technology."

He's also convinced that if the major service companies throw their R&D money at a new technology, it's worth a look. "I'm a firm believer that people within the service companies have the talent and the data to engage the operators," he said. "I think the value of refracturing a well at \$1 million to \$2 million makes sense, and I'm hoping it's something that will pick up in 2016.

"There is an opportunity for the industry to innovate and change the quality of these wells." **ESP**

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# Production technology purpose-built for Lower Tertiary

New system designed for ultradeepwater, deeper wells, higher pressures and temperatures.

**Eldon Ball**, Executive Editor, Offshore

The Gulf of Mexico's Lower Tertiary plays represent one of the largest prizes of any offshore development in the world. "We believe this is the next frontier for the Gulf of Mexico," said Robbie Pateder, senior director for Lower Tertiary integrated product team (IPT) at Baker Hughes. "Operators are moving from the shelf to prospect these larger fields. They are attracted to larger reservoirs with billions of barrels of untapped oil. According to industry data, the Lower Tertiary fields are estimated to have between 14 billion and 40 billion barrels of oil. These reservoirs offer greater opportunity for reserves and returns than that of shelf fields, but the challenges are just as great.

"Some of these challenges include extremes of water depths, well depths, pressures and temperatures; oil that does not flow naturally to the surface like it does in other reservoirs; and low average recovery factors."

Responding to the industry's need for ultradeepwater completion and production capabilities, Baker Hughes recently introduced its Hammerhead Ultradeepwater Integrated Completion and Production System.

Baker Hughes researchers started thinking about what it would take to produce these reserves. What is the current state of the technology to develop and produce these wells? How can the industry increase the recovery rate to make these fields more economically viable? It has been estimated that every 1% increase in reserves from these ultradeepwater plays will equate to additional revenues of \$2 billion at \$50/bbl oil.

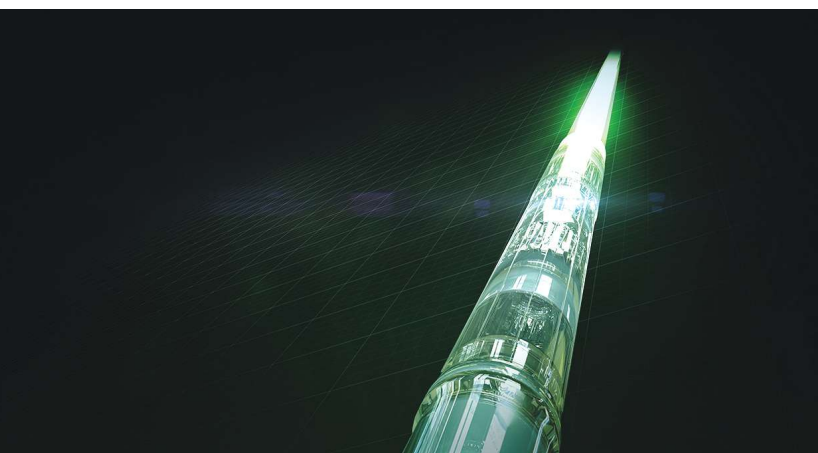
"Based on customer feedback, the requirements for this new ultradeepwater system included withstanding temperatures up to 300 degrees Fahrenheit [149 C], pressures up to 25,000 psi, water depths up to 10,000 feet [3,048 m], and total well depths of 33,000 feet [10,058 m] while enabling long-term, high-volume production," Pateder said.

## Step-change in technology

It became clear to Baker Hughes that there was a significant disparity between the current state of technology and what is needed to develop ultradeepwater reserves, Pateder explained. Safe, economic development would require a step-change in technology—and a new approach centered on collaboration and integration. It would require a fully integrated wellhead-to-reservoir completion and production system built specifically for the Lower Tertiary geology, well conditions and production demands—a system that would help mitigate the risks of ultradeepwater wells, deliver the capability to complete and produce them and maximize the recovery rate.

"That is the challenge that we were facing," he said.

Pateder's group began conceptualizing the idea of this new system with customers about three years ago, he said. "We created a cross-functional IPT composed of as many as 95 dedicated members," Pateder said. "Their first mission was to design and deliver the system, the Hammerhead system, in about three years, or about half of the time it would typically take for a project of its scope and complexity. The IPT—which is composed of members from design engineering,



Once connected to the reservoir, surveillance and control capabilities including distributed sensing fiber-optic cables and electronic pressure and temperature gauges help operators continually optimize performance and avoid unplanned downtime. (Source: Baker Hughes)

completion engineering, artificial lift, operations, customer service, reliability, quality and supply chain—operated outside the typical business cycle to ensure rapid design and development as well as accelerated manufacturing lead times.

“Our focus was to develop the next generation of completion technology driven by customer requirements and industry regulations. The design team looked at the requirements from an operator’s point of view and took an entirely new approach to development,” Pateder said.

“Typically the operators buy the individual components and/or systems from multiple suppliers, similar to a box of parts, and they take on the responsibility of integrating all of the components. We believe that our system-based approach will reduce or eliminate risk associated with multivendor integration and provide the increased reliability that customers require for these high-cost developments.

“Meeting this goal required intense teamwork, innovative thinking and extreme engineering,” Pateder said. “Many of our existing technologies offered a field-proven starting point from which we could work to develop the enhanced components required for the new ultradeepwater system.”

### System design

Fully assembled, the Hammerhead system includes intelligent production capabilities, an upper completion, an isolation assembly and a lower completion system, and it is fully compatible with subsea boosting for increased recovery.

“The system has been designed and tested for HP/HT conditions; extreme stimulation capabilities; and high-rate, high-volume production for well cycles of 20+ years,” he said.

“The lower completion is run in the hole in a single trip and features a high-performance frack-pack system that can support extreme rates, pressures and temperatures,” Pateder explained. The frack-pack system is engineered to increase reliability and simplify operations in deepwater applications. Selective shifting profiles allow the lower portion of the isolation assembly to be run in the lower completion before any sleeves are opened, minimizing fluid loss into the formation. A mechanical barrier is included to maintain reliable well control during the upper completion installation.

“The lower completion is a unique new development where operationally we upgraded the performance,” Pateder said. “While our traditional systems were 10,000 psi to 12,000 psi differential pressure-rated, the lower completion in the Hammerhead system is 15,000 psi-rated. This gives operators additional ability to draw

down the reservoirs to fully extract the hydrocarbons safely and reliably. For example, if you have 25,000-psi reservoir pressure, you can draw down to 10,000 psi if the well yields it naturally or through implementing artificial lift.

“We also needed to maximize the stimulation capability. The permeability in the Lower Tertiary formations is very low, so they require high treatment rates to make them productive. With traditional completion systems you could get 2 million to 3 million pounds of proppant to stimulate the well, but the new system has the capability of delivering 5 million pounds of proppant, or a million pounds per zone, at up to 50 barrels per minute. No other system on the market can support these rates and volumes, which are critical for maximizing reservoir connectivity and conductivity for optimal hydrocarbon flow.”

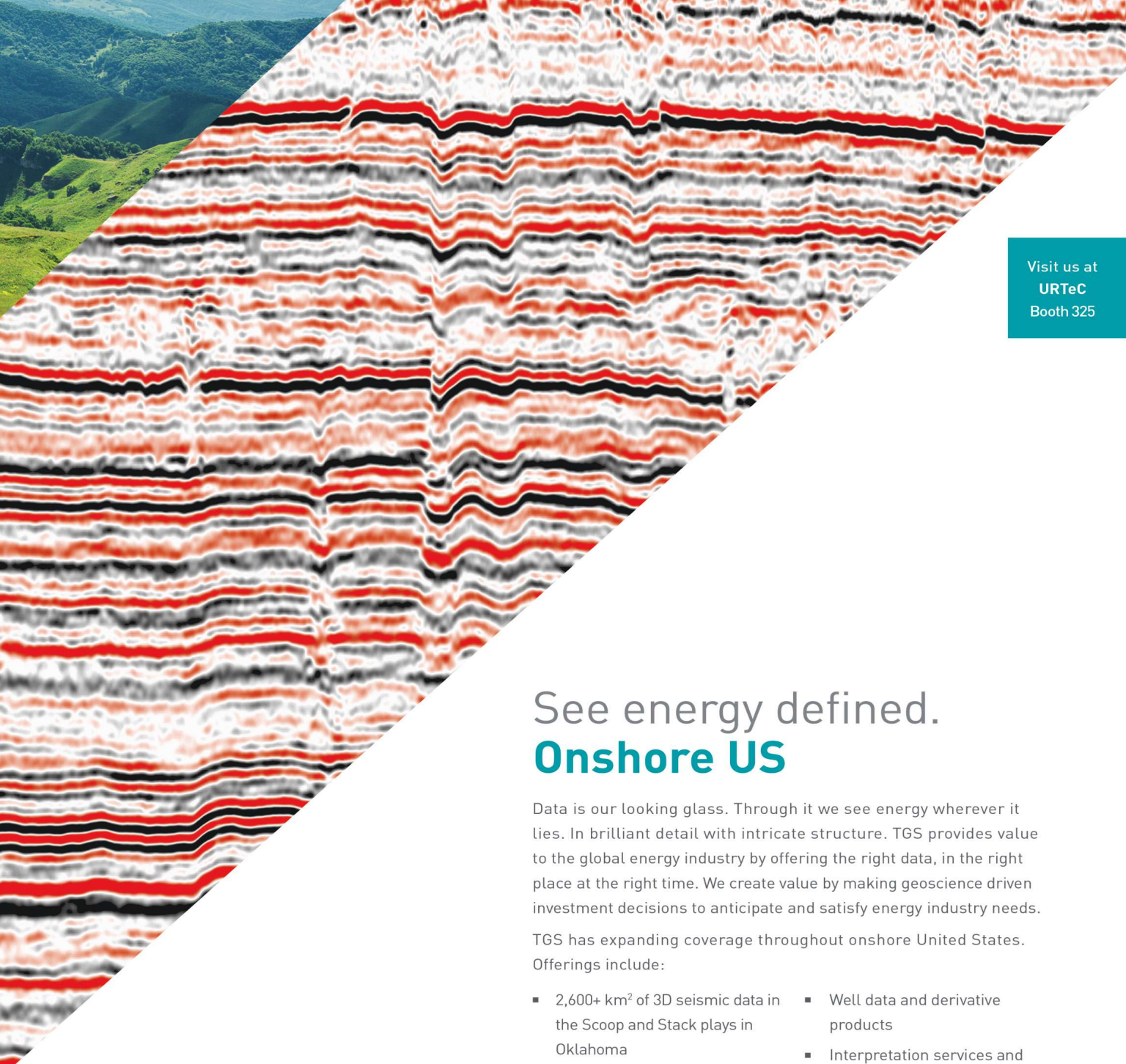
The lower completion also features a 5¼-in. minimum production inside diameter—the industry’s largest for a high-pressure 8½-in. drift completion, Pateder said. The system is capable of producing at rates up to 30,000 bbl/d for decades.

“For well control, we built an isolation assembly into the system,” Pateder said. “As we are going into the well, the assembly creates a barrier, allowing us to safely deploy the upper completion. The system’s intelligent production capabilities enable remote surveillance and control. We can deploy fiber-optic-based distributed temperature sensing into the lower completion to monitor pressure and temperature.

“The lower completion enables selective flow control using intelligent well system valves. We have flow control capabilities for two commingled zones,” Pateder said. “If



**The Hammerhead system can help operators improve recovery factors from ultradeepwater plays by as much as 2%—or \$4 billion-plus based on oil prices of \$50/bbl—through enhanced reservoir stimulation, higher drawdown capability and long-term optimized production, according to Baker Hughes estimates. (Source: Baker Hughes)**



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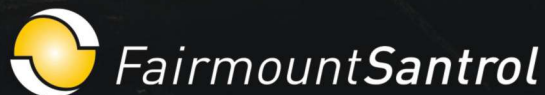
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## Energized fracturing comes to the Bakken

A major IOC is set to use CO<sub>2</sub> and proppant in a first of its kind test well in the Bakken Shale.

By **Jennifer Presley**, Senior Editor, Production

**T**he use of CO<sub>2</sub> as an energized fracturing fluid is an accepted industry practice in Canada but not so much south of its border. This may soon change if the CO<sub>2</sub> stimulation test that Statoil is set to conduct later this year in its Bakken Shale acreage delivers the success that its modeling promises.

Long recognized for its willingness to embrace new and innovative approaches to solve the big challenges facing the industry, Statoil will conduct a CO<sub>2</sub> stimulation test at a well site located about 24 km (15 miles) outside Williston, N.D. The test will evaluate the potential production uplift and partially replace water in a large multistage hydraulic fracturing operation, according to a Statoil-issued release.

Increasing the efficiency and sustainability of its unconventional operations in the Bakken, Eagle Ford and Marcellus is a major goal for the company. In the Bakken, the company holds approximately 275,000 net acres with an approximate production of 55,000 Mboe/d, according to a presentation delivered by Torstein Hole, senior vice president at Statoil, during the Jefferies Global Energy Conference in November 2014.

Accomplishing the dual goal of efficiency and sustainability is why the company sought out a partner. The well stimulation test is one of several projects under Powering Collaboration—the joint technology program between Statoil and GE aimed at accelerating the development of sustainable energy solutions.

Using CO<sub>2</sub> in well stimulation is common in the Western Canadian Sedimentary Basin, but this will be the first major application of liquid CO<sub>2</sub> to dis-

place slickwater during the hydraulic fracturing process in the Bakken, the press release stated.

The stimulation test will be the first hurdle for the company's method. Although unable to provide all the details of the method, Dr. Bruce Tocher, head of shale oil and gas research at Statoil, did provide a high-level explanation of how this approach is different from others.

"We will use liquid CO<sub>2</sub> as the initial fracturing medium because we believe that it will create a more complex fracture network, giving increased surface area, which should increase the ultimate oil recovery," he said. "Our modeling and laboratory experiments suggest that we could increase recovery by 20% to 25%. We will then complete the stimulation using a more standard water and proppant pack. By using CO<sub>2</sub> for the initial stimulation, we project that we will use 20% to 40% less water than normal in the test phase. Ultimately, as the technology matures, we hope to be able to further reduce water usage in the stimulation process. Providing the test shows positive results, the next phase will be to develop a cost-effective system to capture the CO<sub>2</sub> as it flows back and reuse it for stimulating new wells. This is where the collaboration with GE comes in. Its main part of the project is to use its world-leading engineering and technical expertise to develop this capture and reuse system. We are very excited about this upcoming test phase and subsequent progress of this project, which is one of several exciting new technologies we are developing with GE as part of our Powering Collaboration Initiative," Tocher said. ■

you detect that the well is starting to produce water from a zone, for example, you can restrict flow from these zones and still continue to produce from the remaining zones, which helps increase ultimate recovery.

"The system also includes chemical injection capabilities to mitigate flow assurance problems that could occur, such as asphaltenes or scale production. All components are rated to 15,000-psi pressure differential to ensure reliable operation for the life of the well."

Baker Hughes expects the Hammerhead system to improve recovery factors in the Lower Tertiary by 2%, which will translate to between \$4 billion and \$5 billion in additional revenues at current prices of \$50/bbl to \$60/bbl over the life of the well.

"Our next ultra-deepwater system will offer even higher differential pressures and will incorporate Baker Hughes' advanced in-well electrical submersible pump technologies to further improve reserves recovery," Pateder said. ■ **ESP**

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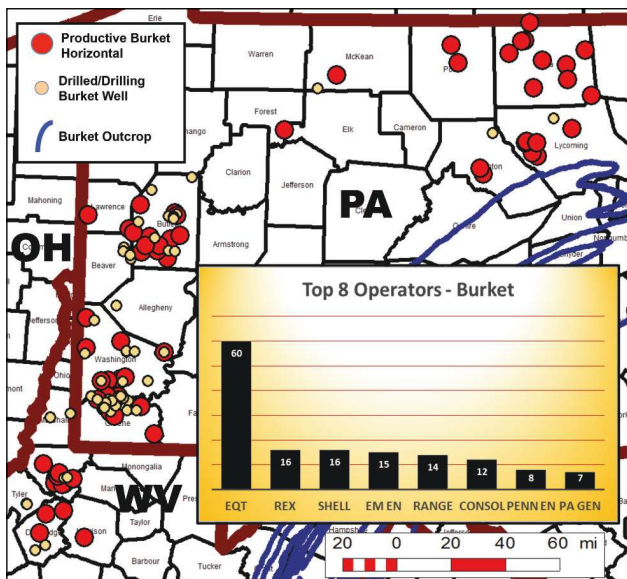
# Little brother to the Utica and Marcellus

The Upper Devonian Burket/Geneseo Shale holds yet more Appalachian riches.

**Gregory Wrightstone, Wrightstone Energy Consulting**

Energy news from the Appalachian Basin has been dominated for the last decade by the natural gas behemoth that is the Marcellus Shale. Singlehandedly, this super-giant natural gas reservoir has transformed the North American energy markets with its vast reserve potential and production rates. Recently, the deeper Utica Shale has been getting a lot of notice with its consistent high production rates in the wet gas window of Ohio and some attention-grabbing high IP rates in the dry gas windows in eastern Ohio, extending into Pennsylvania and West Virginia.

A third resource shale play, the Burket/Geneseo Shale, is being developed in much of the same geographic areas as the current Marcellus Shale development in Pennsylvania and West Virginia. This reservoir has not produced the same eye-popping production numbers as the other “Big 2” shales to date, but the play is still in its early field development stage, and it is certainly likely that operators will improve and fine-



**FIGURE 1. Active Burket/Geneseo wells are located in the same areas as the Utica and Marcellus shales. (Source: Wrightstone Energy Consulting)**

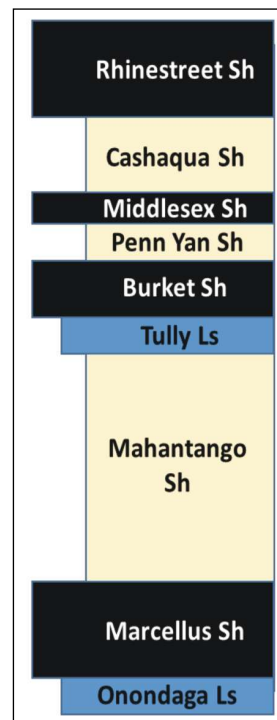
tune their completion and drilling techniques as the play moves into the full development stage. This reservoir will never challenge the Marcellus or Utica in its productivity or size of resource potential, although total reserves may be significant.

It is likely that the play will benefit from several advantages, including its stacked pay potential, liquids-rich production in some areas and possible flat decline rates.

As of mid-April 2015, a total of 85 Burket/Geneseo horizontal wells have been completed as productive, with an additional 99 wells either in the drilling phase or awaiting completion. Nineteen companies have drilled Burket tests in the two identified core areas; however, most are concentrated in the southwest part of the play (Figure 1). EQT Production has been the leader in development of this resource with more than 60 wells either completed or in the process of drilling/completion, with an additional 40 Burket wells planned for 2015.

## Geology

The Upper Devonian Burket/Geneseo Shale is the organic-rich mudstone that lies immediately above the Tully Limestone (Figure 2) and 6.1 m to more than 245 m (20 ft to more than 800 ft) above the Marcellus. The correct scientific name for this shale is Burket across most of West Virginia and Pennsylvania, while Geneseo is accepted terminology in northwest Pennsylvania and New York.

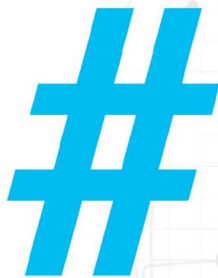


**FIGURE 2. The stratigraphy of the Burket/Geneseo in Pennsylvania and West Virginia overlies the Marcellus Shale. (Source: Wrightstone Energy Consulting)**

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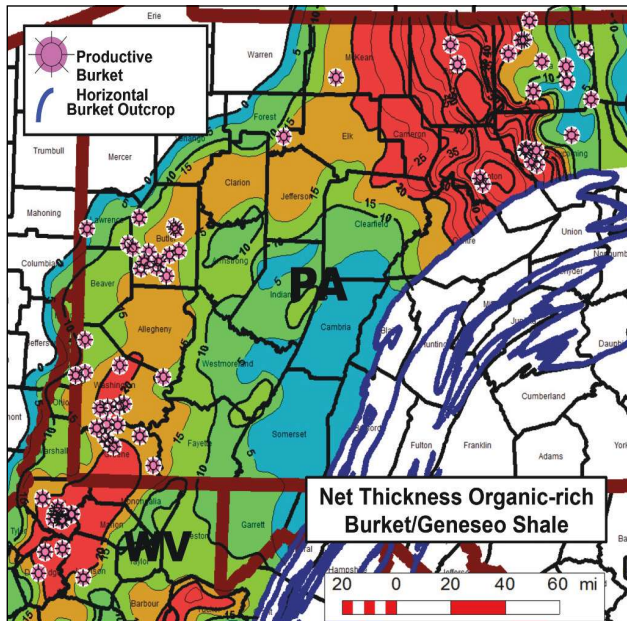
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**FIGURE 3.** This map shows the net thickness of the Burket/Geneseo Shale, which is up to 46 m at its depocenter. (Source: Wrightstone Energy Consulting)

The thickness of the shale expands from only a few feet in western West Virginia to more than 46 m (150 ft) in its depocenter in central Pennsylvania. Drilling depths increase from less than 1,392 m (4,500 ft) in northwest Pennsylvania to more than 2,286 m (7,500 ft) in the center of the basin. Net thickness of the organic-rich portion of the Burket is shown in Figure 3. Two sweet spots of better-quality reservoir are mapped, with most of the current productive wells located within these southwest and northern pods of increased reservoir quality.

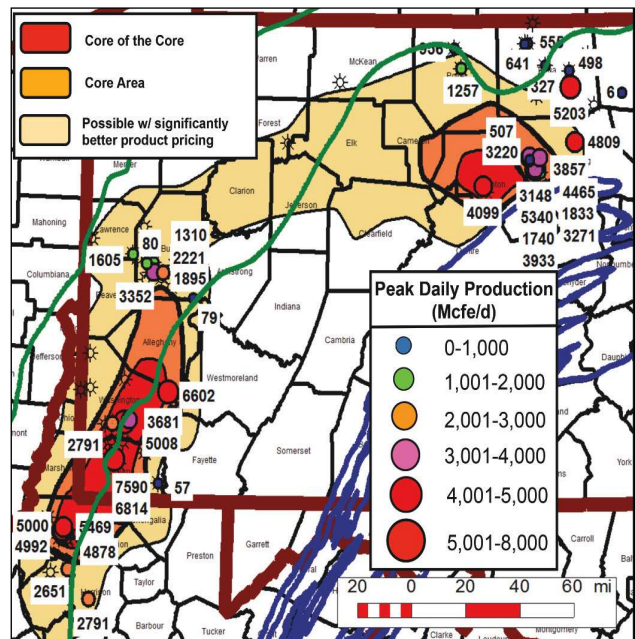
The key geologic controls on production are projected to be similar to those that control the Marcellus Shale, with rock quality (porosity and permeability) directly related to total organic carbon (TOC) percent. There are no reliable hard data available publicly on pressure gradients at this time, but early indications and personal communication indicate that the unit is significantly overpressured, enhancing production capabilities. As with the Marcellus, structural complexity is a key negative to production performance and complicates geosteering. Additionally, since the Burket/Geneseo is significantly thinner than the Marcellus, additional geosteering challenges are presented to the operator to stay in the sweet zone of high TOC, and rotary steerable drilling may be the optimal solution.

## Production

Long-term production data are available for a relatively small database via state reporting agencies but provide enough information that some early projections can be advanced. Analysis of the available production combined with geologic mapping allows operators to identify the northern and southwestern core areas within which the highest performing Burket/Geneseo wells are located. Figure 4 outlines these proposed core areas and provides peak daily production rates for many of the wells. Only 27 wells have at least one full year of production available, and prediction of good decline curves from this limited public dataset is not possible at this time.

The southwest core area encompasses an area of 1.4 million acres and is the better of the two areas based on limited data. Five wells have at least one year of production data and averaged 42.5 MMcme (1.5 Bcfe) in their first 12 months online. Additional analysis of peak daily production confirms the general outline of this area. Wells surrounding the southwest core area have significantly reduced production volumes and average 13.3 MMcme (470 MMcfe) in 12 months.

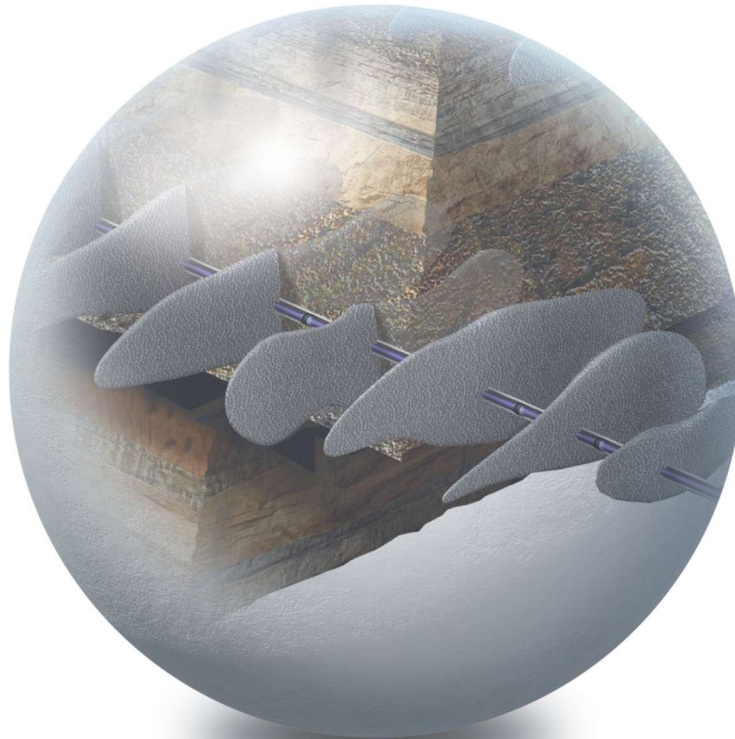
The northern core area covers about 800,000 acres but is less proven and may not reach the production potential of the southwest area. Six wells on production had average first-year production of about 19.8 MMcm (700 MMcf). Wells surrounding this area pro-



**FIGURE 4.** Already some wells are producing up to 226,500 cme/d (8 MMcfe/d). (Source: Wrightstone Energy Consulting)

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duced less than 7.1 MMcm (250 MMcf) during the time period. Only two Burket wells have been permitted in this northern area since 2010, which may be a good indication that companies are not enamored of the production potential of the Burket in this area.

### Economics and resource potential

Production rates from the Burket/Geneseo, while strong, lag significantly when compared to the Marcellus and Utica results. Economic analysis using a well cost of \$5.5 million (1,460-m or 4,800-ft lateral), Marcellus-type decline and gas price of \$3/28 cu. m (1,000 cf, dry gas) indicate that only the “core of the core” is economic in today’s depressed market conditions.

Potential considerations exist that may significantly affect economic viability for the reservoir:

- **Flat decline.** Analysis of the early Burket/Geneseo wells in the southwest core area show production declines may be flatter than published Marcellus decline rates. In a recent presentation, Consol reported that its first Burket/Geneseo well, located in Washington County, Pa., had an EUR of 255 MMcme (9 Bcfe)—51 MMcme (1.8 Bcfe) per 305 m (1,000 ft)—based on actual production, compared to predicted type decline curve estimates of 164 MMcme (5.8 Bcfe)—34 MMcme (1.2 Bcfe) per 305 m;
- **Lower AFE costs.** Drilling and completion costs can likely be reduced via utilization of existing drilling pads and infrastructure;
- **Liquids/wet gas.** Much of the southwest core area has wet to very rich wet gas, and the economics of these wells can be significantly enhanced through liquids production and increased Btu;
- **Fracture growth upward.** Upward fracture growth into the overlying Middlesex and Rhinestreet shales may add to the available productive capacity;
- **Maturation of the play.** Production from early wells in other resource shale plays pales in comparison to the later wells that were developed using practices that were fine-tuned to the specific reservoir. It is likely that similar increases will be realized in this play; and
- **Fracture mechanics negatively affected.** Significant downside may exist in delayed development of the Burket in the southwest core area. Development and production of the underlying Marcellus would likely create a negative pressure sink, leading to downward fracture growth into the drawdown Marcellus reservoir from the later completions in the Burket/Geneseo.

Technically recoverable reserves in the core of the core are projected to be 934 Bcme (33 Tcfe), with another possible 1.64 Tcme (58 Tcfe) if the remaining core areas prove viable. These numbers are likely to expand with increases in EURs through advances in completions and if the flatter decline is confirmed.

It is likely that most companies will continue to focus the bulk of their capex on the more lucrative Marcellus and Utica reservoirs to get their best “bang for the buck” in the short term, but the Burket/Geneseo holds good potential for substantial additions to the Appalachian resource base.

The Marcellus and Utica have changed industry’s perceptions and market-driven economics. The Burket is another possible super-giant natural gas field (more than 850 Bcm [30 Tcf]) in an area with well-developed pipeline infrastructure and near to the largest markets in North America. Yet few companies are rushing to develop it. The industry apparently is cursed by its own success. **E&P**

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# CFD for VIM estimation of semisubmersibles

A new approach uses CFD to overcome the drawbacks of the current VIM design practice based on model testing.

**Arun Antony**, Houston Offshore Engineering, an Atkins company; and **Bill Head**, RPSEA

**S**emisubmersible platforms are very good candidates for hydrocarbon E&P in the Gulf of Mexico (GoM) and elsewhere. These platforms are a preferred choice for deepwater applications involving higher design throughput, as shown in the application chart of existing floating production facilities.

Spars and tension-leg platforms (TLPs) are currently used for wet tree and dry tree applications but have limitations in terms of water depth and/or payload. TLP application is limited by water depth, mainly due to cost

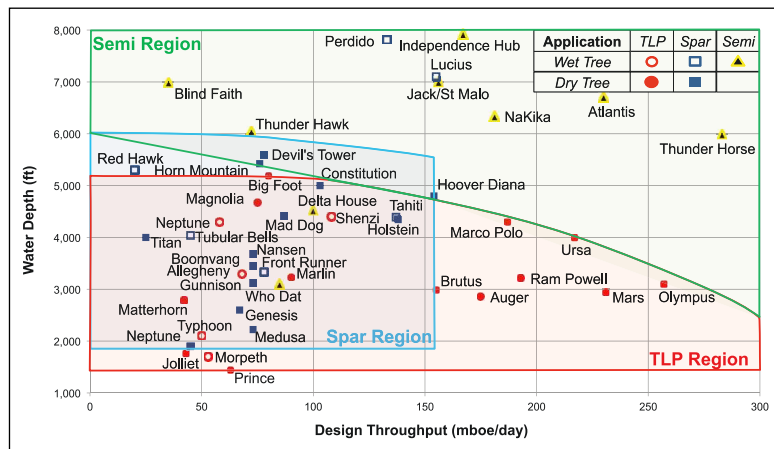
of the tendon system, whereas spars have challenges like larger payload and high top-tensioned riser counts. The existing semisubmersibles in the GoM are all wet tree applications. A dry tree application of a semisubmersible provides the benefits of improved well control, direct vertical well access, easy access to production equipment, reduced capex and other dry tree benefits in addition to the benefits a semisubmersible platform has over spars and TLPs. There is an industrywide interest in mature dry tree semisubmersible designs that are cost-effective and safe like spars and TLPs. The Research Partnership to Secure Energy for America (RPSEA) has taken a lead role on these initiatives and has been funding multiple research projects directed toward this goal.

## RPSEA studies

RPSEA started supporting dry tree development work with the RPSEA 1402 project executed during 2009 to 2011, which supported the paired-column semisubmersible development by Houston Offshore Engineering (HOE). Wave basin and wind tunnel tests were conducted during this study phase. DeepStar also funded a similar project in 2010 to 2012. It was concluded in the RPSEA and DeepStar studies that, for the same design throughput, the semisubmersible is a superior dry tree alternative to a spar.

Some of the design items not addressed in RPSEA 1402 were included in the RPSEA 4405 project conducted during 2012 to 2014. A main topic focused on in the RPSEA 4405 project was vortex-induced motions (VIM) of the

semisubmersible hull forms. Model testing was conducted to address the concern from the industry on VIM performance, especially because the semisubmersible configurations used for the dry tree application are deep draft and are more susceptible to VIM due to the high slenderness ratios of columns. Tow tank model testing was conducted for two semisubmersible hull forms:



**Application chart of existing floating production facilities shows the importance of semisubmersibles for deepwater and higher design throughput regions. (Source: Houston Offshore Engineering)**

a conventional semisubmersible and a paired-column semisubmersible hull form. The model test results of both hull forms are within the predicted design curves, but an interest remains to understand the VIM behavior of the semisubmersibles. The latest and ongoing project, RPSEA 5404, has focused on the VIM sensitivity of semisubmersible hull forms and the differences between design prediction of VIM and field-observed VIM.

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### Current practice

The current VIM design practice relies heavily on model testing. Typically, a geometrically scaled (1:50 to 1:200) model is towed in a model test basin, and the transverse oscillation amplitudes are measured. To help with the experimental setup, mooring lines and risers are either simplified or not modeled at all. In addition, the external damping also is neglected. Tow runs are conducted for different headings, current speeds corresponding to different reduced velocities and multiple repeated runs to achieve statistically meaningful amplitude values. The test results (amplitude values) are directly used for mooring and riser design.

Recently some operators have conducted studies that compared field-measured data with design predictions. These studies show that VIM does exist and will impact the mooring line and riser fatigue. However, it is important to note that the field-measured VIM responses are significantly lower than the design predictions. Clearly the design predictions were overly conservative and costly due to the reliance on the simplified geometrically scaled model testing approach.

Some of the factors identified as causing the difference between measured data and design predictions are:

- *Scale effect.* In tow testing, models are tested in the lower Reynolds number ( $R_e = 1 \times 10^5$ ) region, whereas the  $R_e$  of the actual semisubmersible is in the range of  $1 \times 10^7$ ;
- *External damping effect.* Typical model testing ignores the external damping due to mooring lines and risers. The external damping can be significant, especially in deeper water depths and higher throughput applications;
- *Current profile effect.* A uniform current profile is typically simulated in model testing, even though the actual current profile decays with water depth; and
- *Nonlinear stiffness effect.* The nonlinear behavior of the mooring system of a semisubmersible platform is neglected, and a single stiffness is modeled in a tow basin. The VIM prediction methods based on traditional tow

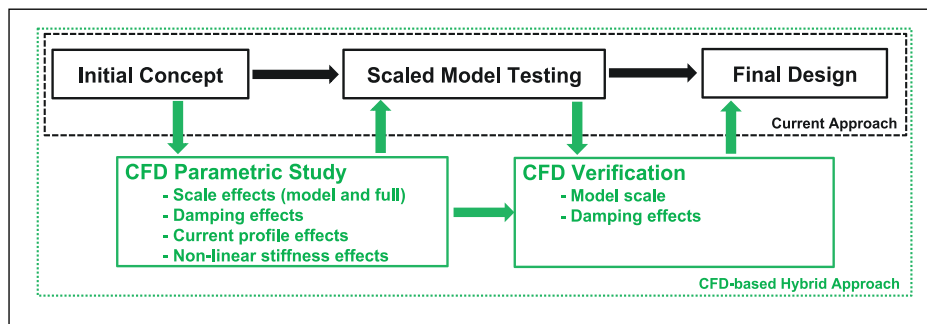
tank model tests neglect these factors. Among these factors, the scale effects and external damping effects are found to significantly impact the VIM performance prediction and need to be considered.

### RPSEA 5404 study

The aim of the ongoing RPSEA 5404 study is to improve the overall mooring system safety and riser system integrity by identifying and providing guidance on the design parameters of the semisubmersibles that have the most impact on their VIM response. The study uses both computational fluid dynamics (CFD) and model-testing to determine the sensitivity of the semisubmersible response to parametric changes in its geometry. In addition, the study also investigates the effects associated with Reynolds number scaling and the external damping due to the mooring and riser system. The study encompasses both four-column and multicolumn semisubmersibles (paired-column semisubmersible developed by

HOE).

As part of the CFD analysis, three commercially available CFD software packages were validated with the model test data avail-



**A CFD-based hybrid approach is beneficial for VIM design of semisubmersibles.**

(Source: Houston Offshore Engineering)

able from the prior project (RPSEA 4405). The validation analysis compared drag test results, free decay results and VIM results, all of which were very comparable with experimental data. This validation analysis helped to establish the meshing strategy, time-step selection, choice of appropriate turbulence models and other numerical aspects of the CFD simulation that are critical for producing efficient and accurate results.

The validated CFD software is used to study the hull form sensitivity on VIM performance, the scale effects and the damping effects. The flow separation points are different in model scale and full scale, which can cause a significant difference in the VIM behavior. The scale effects are different for circular and blunt bodies (square columns) and need to be addressed in full-scale CFD analysis to capture the correct physical phenomenon. The damping due to mooring lines and risers is found to be significant and cannot be neglected. It

A large industrial drilling rig is the central focus of the image, positioned at a well site. The rig is a complex structure of metal scaffolding and pipes, with a prominent vertical column. The scene is set against a dramatic sky at sunset or sunrise, with soft orange and yellow light breaking through blue and grey clouds. In the background, there are some industrial buildings and utility poles. The overall atmosphere is one of industrial activity in a natural setting.

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tends to reduce the VIM significantly and was captured in CFD analysis. In the next phase of the RPSEA 5404 project, the semisubmersible hull forms will be model-tested with and without external damping.

### CFD-based hybrid approach

A CFD-based hybrid approach is more appropriate for VIM design of semisubmersibles rather than one based on simplified scaled model testing. The importance of CFD as a tool lies in its ability to be seamlessly integrated into the overall concept design. It has been proven that high-fidelity CFD can be used for accurate VIM predictions and can also account for the effects (scale, damping, etc.) that are typically ignored in tow tank testing.

CFD analysis can provide a detailed picture of the overall flow around the platform that is otherwise difficult to measure in a model scale experimental setup. In the proposed hybrid approach, a CFD parametric study based on the initial hull configuration will be conducted to predict the VIM behavior. The parametric study will include a series of CFD analyses addressing the effects due to scale, damping, current profile and nonlinear stiffness. Tow tank testing will be used to verify the model scale and damping results. VIM design curves from the verified CFD analyses can be used for final design.

The hybrid approach will help to overcome the drawbacks of the current design practice and to predict the semisubmersible VIM responses that are closer to reality. The guidelines prepared as part of the RPSEA 5404 project will serve as a good tool for this approach. **E&P**

#### Acknowledgment

Majority funding for the RPSEA 5404 (Project No. 11121-5404-03) is provided through the "Ultra-Deepwater and Unconventional Natural Gas and Other Petroleum

Resources Research and Development Program" authorized by the Energy Policy Act of 2005. RPSEA is under contract with the U.S. Department of Energy's National Energy Technology Laboratory and has contracted Houston Offshore Engineering, an Atkins company, to manage the project.

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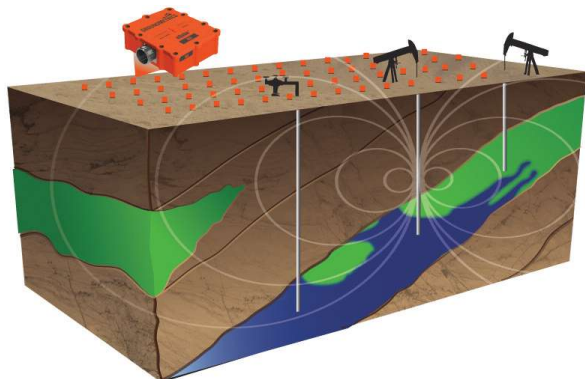
Far-field resistivity mapping yields answers for optimal field development.

J. Mark Wilkinson, GroundMetrics

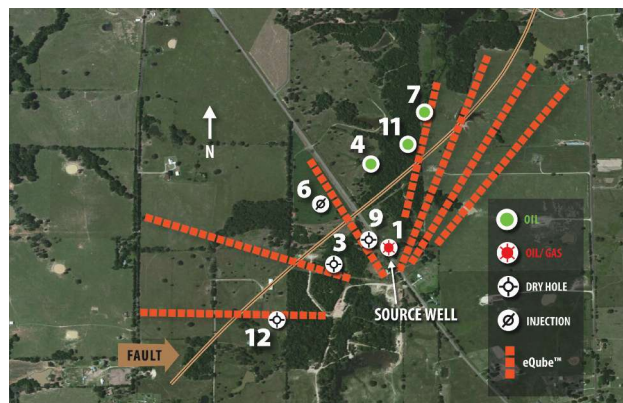
Whether it's conventional EOR or hydraulic fracturing, one of the key questions operators ask is where is the injected fluid going in the subsurface? Far-field resistivity mapping answers those questions. Resistivity, long a standard in wireline logging for detecting hydrocarbons, can also be used to detect tertiary recovery flood fronts—CO<sub>2</sub>, water, steam, etc. Hydraulic fracture fluids also can be mapped to define the extent of fluid invasion. This information, combined with an operator's knowledge of the field or formation, yields direct answers to optimize field development.

## Methodology

GroundMetrics' method depends upon two key field components. First is the eQube capacitive sensor. This technology was first deployed by the U.S. Department of Defense. It has been repackaged with new workflows specifically designed to answer oilfield questions. Unlike porous pot-type galvanic sensors, the eQube needs simply to be in contact with the ground surface. It does not need to be buried, nor does it require constant wetting with an agent to assure electrical coupling. Moreover, as capacitive sensors do not rely upon chemical/ion exchange for coupling, reliability and repeatability are



**FIGURE 1.** eQubes are sensors deployed over a field. The well (center) with the pumpjack is the transmission antenna. The green represents hydrocarbon and the blue water injection. GroundMetrics' method can detect bypassed pay, water intrusion and accumulations not originally detected. (Source: GroundMetrics)



**FIGURE 2.** This map shows wells and eQube deployment. (Source: GroundMetrics)

greatly increased. Ease of use speeds deployment and minimizes maintenance requirements during a project.

The construction and specialized feedback circuits contained in the sensor assure a broadband response from 0.01 Hz to greater than 500 Hz. Tests have demonstrated that the sensor is more sensitive than traditional porous pot sensors without the requirement of burial or specialized muds.

Second, surface resistivity measurements on land are well known to have rather shallow depth of penetration. To assure signal returning to the surface array, GroundMetrics uses a local wellbore as an antenna. The transmitter can be connected to the wellhead, or an electrode can be lowered into a wellbore via wireline. This technique greatly improves transmission signal at the formation of interest (Figure 1).

The data are collected over a few days continuously. They are processed to produce an anomaly map to yield a plan view of change in resistivity. Optionally, an inversion can be applied to produce a volumetric representation of the resistive anomaly.

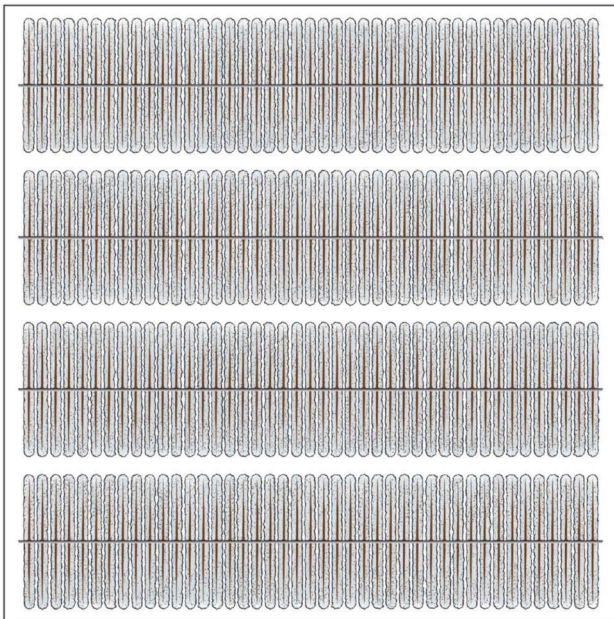
## Waterflood application

The client in this case had encountered a series of dry holes (Figure 2). The questions posed were:

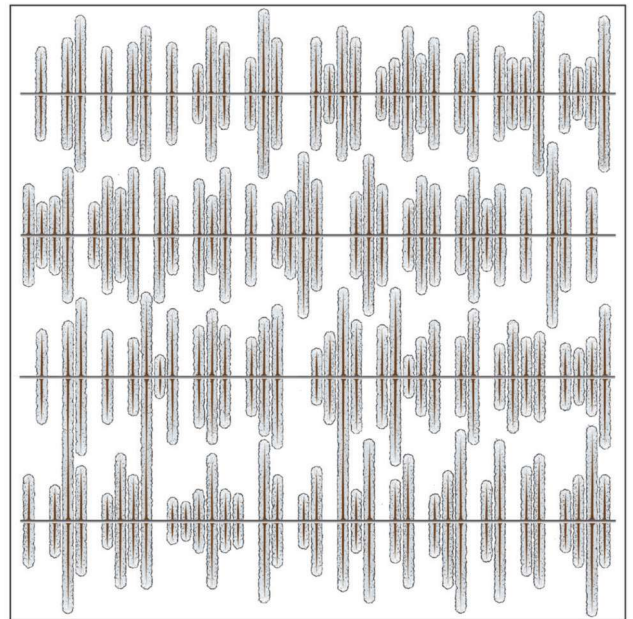
1. Where is the water relative to the well(s) and fault?
2. Is there room for another well in the up-thrown reservoir?
3. Can we determine the fault location?
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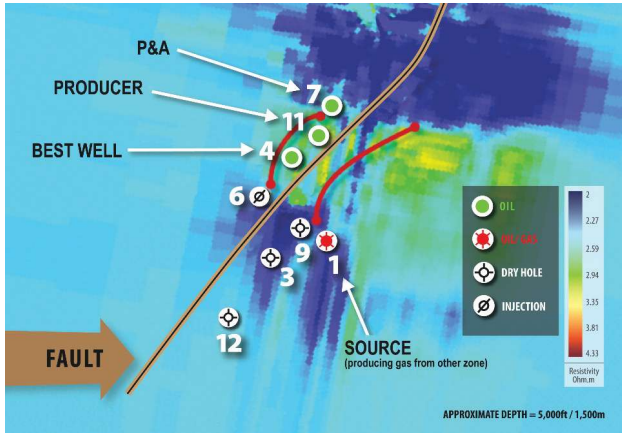
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**FIGURE 3. An inversion of surface resistivity data shows areas with higher hydrocarbon concentration. (Source: GroundMetrics)**

GroundMetrics performed a survey and processed the data through inversion. The result is shown in Figure 3. In Figure 2, the producers are Wells 4, 11 and 7 on the up-thrown side of a fault. Wells 3, 9 and 12, drilled on the down-thrown side of the fault, were dry. Well 2 produced some oil and gas. Well 6 is the water injector for this field. The lines of orange squares indicate where the sensors were deployed. Well 1 was used as the transmission antenna. Figure 3 displays the resultant resistivity contrasts after inversion. The warmer colors are higher resistivity contrast, and the cooler colors are lower. With the resistivity data, the client's questions can be answered. First, the producing accumulation is a stratigraphic trap on the up-thrown side. Well 7 was drilled very near the oil/water contact in the northeast. Wells 3, 9 and 12 are clearly off of the anomaly and in the water. 4 and 11 are centered on the resistive anomaly. Well 1 is also very close to the oil/water contact on the south side. On the up-thrown side there is no room for additional wells. For completeness, the large anomaly east of the fault is on a competitor's acreage. Had the surface resistivity data been available, several dry holes could have been avoided.

### Hydraulic fracturing

In this case the question posed was whether the sensor technology could detect the injection of fluid during hydraulic fracturing operations. Compared to a water or CO<sub>2</sub> flood, the volumes used in hydraulic fracturing are much smaller. It is here the sensitivity of the sensor really becomes advantageous.

The project was in the Denver-Julesburg Basin in Colorado. Seven stages were monitored over several days. Four of the stages were pumped using a control fluid,

commonly used in fracking. Three were pumped using a contrast fluid, a slightly different fluid commonly used in fracking, to produce an electromagnetic contrast. Figure 4 shows the setup for the experiment. An electrode on a wireline was pumped to a point in Well 8 adjacent to the treatment Well 7. Monitoring stations were placed over the area of interest. In addition to the GroundMetrics technology, surface microseismic, borehole microseismic and tracers were used in this test.

Figure 5 is the final resistivity difference map over the area of interest after all pumping on the seven stages was complete. The treatment Well 7 is the second well from the right on the map. The solid lines indicate the stages that were pumped with control fluid, and the dashed lines are the stages with contrast fluid. Note first that the two contrast fluid stages to the south in Well 7 show significantly higher resistivity contrast as indicated by the more intense red color of the resistivity data compared to adjacent control fluid stages. However, the final contrast fluid stage (Stage 5) does not indicate the same higher resistivity contrast. In fact, it appears that the resistivity contrast has been displaced to the west and



south, suggesting that the fluid rapidly migrated during the stage. The included microseismic data support this interpretation. The blue circles are microseismic data detected during the pumping of the control fluid stages, and the red events correspond to microseismic data detected during the contrast fluid stages. Note in

**FIGURE 4. In this setup for hydraulic fracture monitoring, eQube systems are marked in orange. (Source: GroundMetrics)**

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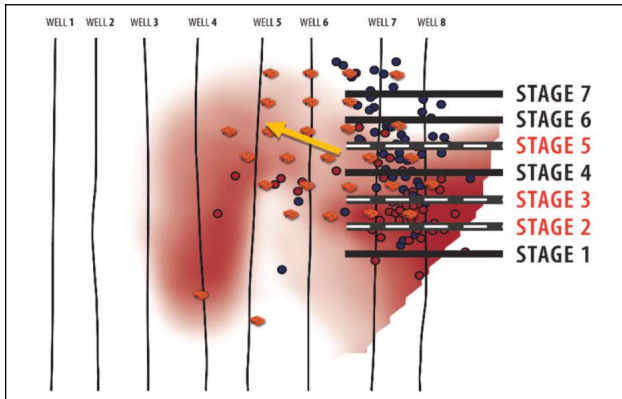
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**FIGURE 5.** In the resulting resistivity anomaly map, the microseismic data support the theory that fluid from Well 7 traversed across the pad and intersected Well 5. (Source: GroundMetrics)

particular that the red microseismic data seem to indicate fluid movement to the west as well. The tracer injected in the final contrast fluid stage was detected in

Well 5, two wells west of the treatment Well 7. This confirms the resistivity data. Fluid from Well 7 did traverse across the pad to the west and intersect Well 5. GroundMetrics also delivers a movie volume for projects that benefit from time-lapse display such as in this frack monitoring case. This volume can be formatted for most interpretive or visualization platforms.

Both for conventional EOR and hydraulic fracturing applications, this technology adds additional useful information to understand how the formation of interest is responding to injected fluid. **E&P**

**Acknowledgment**

*The author wishes to acknowledge Encana and Dr. H. Frank Morrison of Berkeley Geophysics Associates for their participation in and support of this project.*

*Some of this material is based upon work supported by the Department of Energy.*

*References available.*

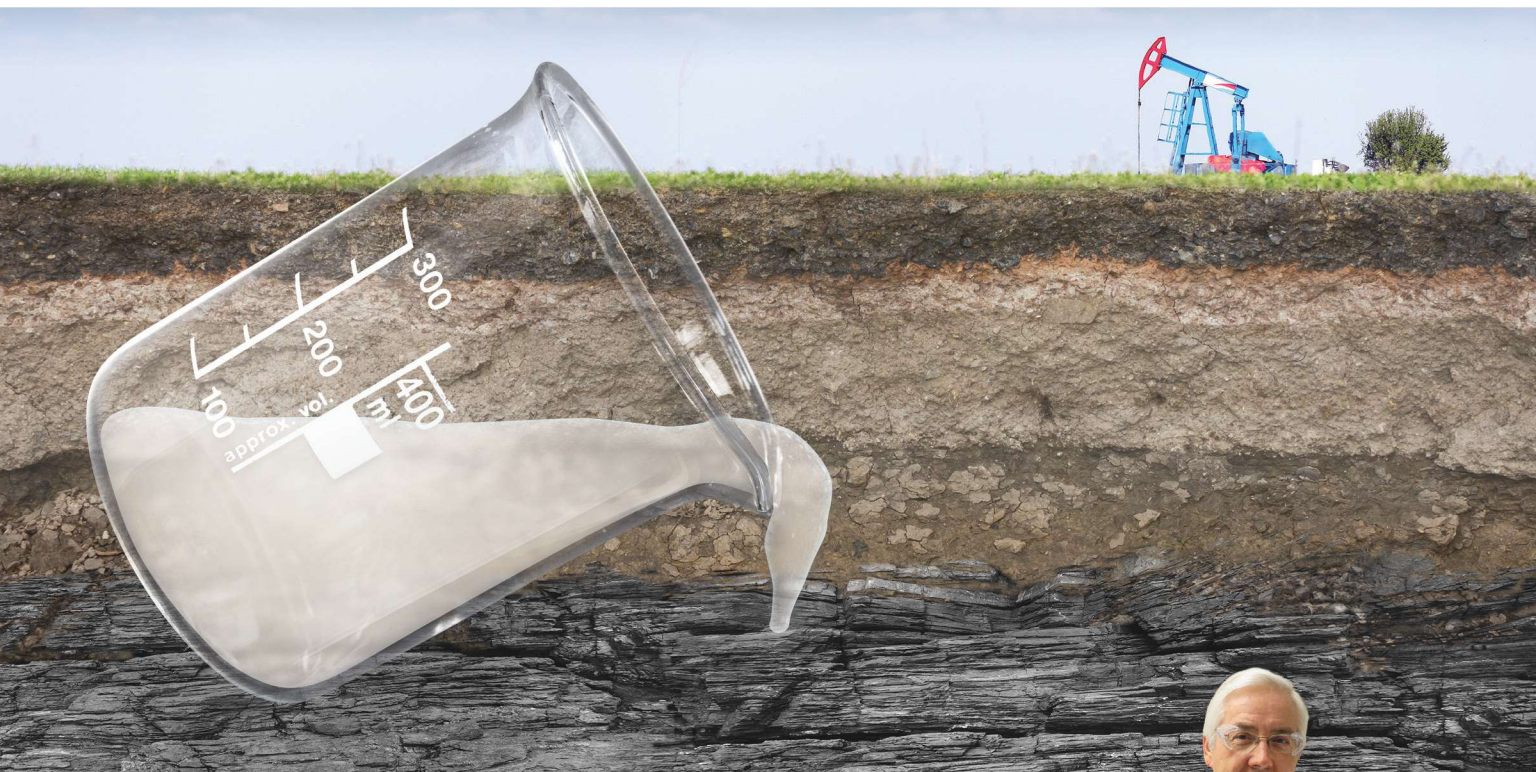
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# Wettability: critical input for reservoir characterization

Displacement processes can be visualized with digital rock technology and solutions.

**Andrew Fogden, Anna Carnerup  
and Mark Knackstedt, FEI**

**U**nderstanding formation wettability is vital to accurate characterization of oil reserves and optimization of recovery. Wettability significantly affects resistivity, capillary pressure, relative permeability and residual saturation. In a water-wet reservoir, the formation brine remains in contact with the rock. In an oil-wet state, oil contacts and adheres to much of the surface, which can disconnect the formation brine and lead to poor estimation of hydrocarbon saturation from resistivity measurements.

Waterflooding of a water-wet rock tends to lead to snap-off and bypassing of oil in the larger pores. The opposite is true of oil-wet rocks, in which oil remains connected by its stronger adhesion to rock surfaces. This may limit its displacement to the larger pore pathways. The majority of reservoirs are thought to be in a mixed-wet state, in which oil contacts some of the rock, dictated by the prevailing capillary pressure and oil affinity for mineral surfaces. This favors retention of oil and brine connectivity during waterflooding, which can result in greater oil production.

## Standard core testing

The two standard laboratory methods are the Amott-Harvey and USBM tests, based on measurements of changes in saturation and capillary pressure from drainage and imbibition. The plug undergoes primary drainage and aging at irreducible water saturation followed by spontaneous and forced imbibition (usually by centrifugation). The process is then repeated for spontaneous and forced secondary drainage. The USBM and Amott methods characterize the wettability state responsible for these displacement responses in terms of one and two indexes, respectively.

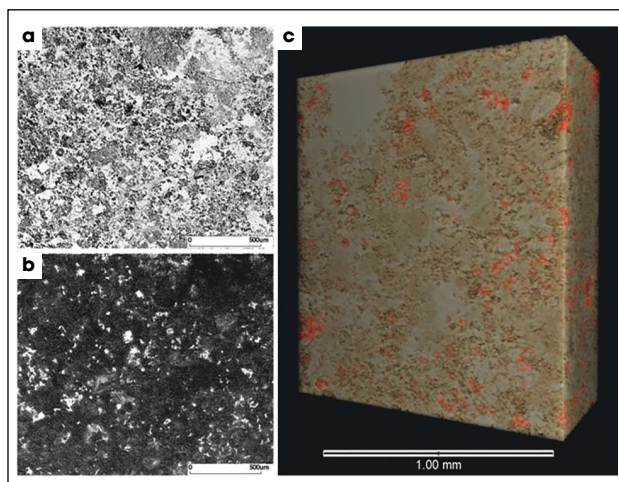
This simplification results in a lack of sensitivity, especially to the most common and most subtle state of mixed wettability, and gives no information of the pore-scale wettability variation and its plug-scale heterogeneity, which contribute to the overall averaged index. Wettabil-

ity remains one of the major uncertainties in reserves estimation, reservoir scenario planning, and pore-scale modeling and simulation. This lack of knowledge especially hinders the design of EOR strategies such as low-salinity waterflooding to alter wettability during recovery.

## Microscopy techniques

Advanced 3-D microscopy techniques such as the services offered by FEI enable engineers to supplement these classical indices and cartoons of pore-scale displacements with direct observations of the oil-brine occupancy of pores in their rocks. Through unique imaging and registration technology coupled with proprietary workflows, pore-scale imaging of oil in place has been demonstrated in preserved or restored reservoir plugs and its changes on further drainage or imbibition.

After cleaning, 2-D scanning electron microscope (SEM) and quantum electron microscope techniques enable higher resolution mosaics and mineral maps of polished sections to be registered into the corresponding tomogram slice. The detailed structure of micro-



**FIGURE 1.** The sub-area of a tomogram slice through a reservoir carbonate is shown in its preserved state (a) and contrast-enhanced state (b), in which local oil saturation increases with grayscale brightness; (c) shows a 3-D visualization of the oil in place (red) in the rock (brown shades). (Source: FEI)

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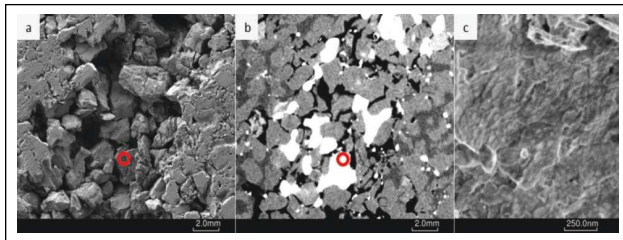


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**FIGURE 2.** In (a), a low-resolution SEM mosaic of a raw cut face of a restored reservoir sandstone is shown; (b) shows a registered projection of the same topography within the plug after forced imbibition (and prior to cutting), with brine in white, oil in black and rock in grayscales; and (c) is a high-resolution FESEM close-up within the red circle, showing the nodular texture of the asphaltene film on grain-lining clays. (Source: FEI)

pores and the mineralogy of pore surfaces aid in understanding the mechanisms responsible for the observed residual oil distribution. Further, high-resolution field-emission SEM (FESEM) images of raw cut sections provide visualization of the local distribution of asphaltene on pore surfaces due to the pore surfaces' wettability alteration by the oil.

### Case studies

A recent study (IPTC 17696, 2014) commissioned by Maersk Oil Qatar and conducted jointly by Lithicon (purchased by FEI in 2014) and the Australian National University performed 3-D imaging and wettability analysis on preserved-state carbonate core from a waterflooded zone of the Al-Shaheen Field. Micro-computer tomography (microCT) was used in combination with novel X-ray contrast techniques and image registration to visualize the 3-D pore-scale distribution of oil in place (Figure 1).

Segmentation of the residual oil gave a total saturation that was in good agreement with laboratory measurements on sister plugs and showed that a disproportionally high fraction resided in macro-pores. This was consistent with the observation from high-resolution FESEM imaging of raw cut sections that macro-pores were more water-wet than micro-pores.

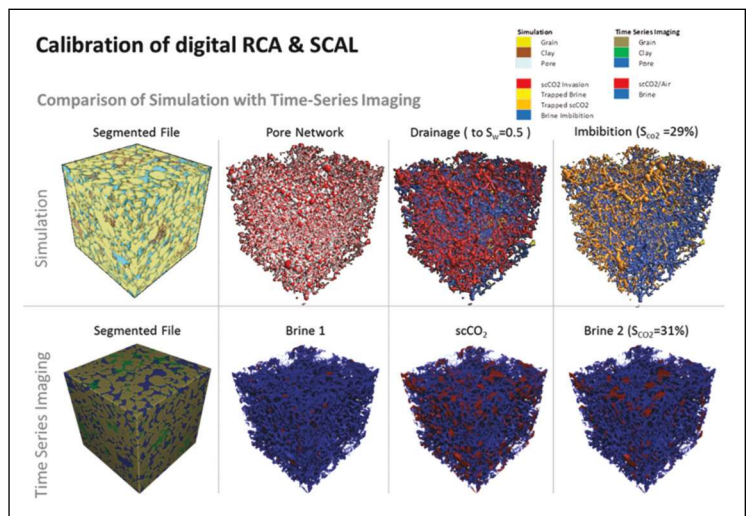
A more recent study dealt with restoration of a reservoir sandstone, which was microCT scanned after aging and after spontaneous and forced imbibition by centrifugation. Spontaneous imbibition was virtually nil, while the residual oil after forced imbibition was closely associated with rock surfaces and in tighter pores.

The 2-D SEM mosaic of the raw cut section of the

cleaned plug (Figure 2a) was registered into the tomogram of the uncut plug after forced imbibition (Figure 2b). This allowed the higher resolution FESEM imaging to focus on walls of pores in which the oil saturation exhibited interesting changes.

For example, within the red circle in Figure 2b, forced imbibition removed oil from a clay-lined grain that was seen by FESEM in Figure 2c to be completely covered by asphaltene film, which is in line with the oil-wettability inferred from microCT. The simulated oil/water displacement results from pore network modeling of the reservoir sandstone using this educated assignment of wettability parameters showed good agreement with available SCAL data.

Figure 3 shows as a final example a flow experiment in which a cleaned reservoir sandstone plug was first drained by injection of supercritical CO<sub>2</sub> and then subjected to brine imbibition to determine the extent of capillary trapping and suitability for sequestration. This time series imaging in the lower row of Figure 3 was well matched by the two-phase flow simulation in the pore network in the upper row of Figure 3. These examples illustrate how physical measurements and direct imaging of pore-scale processes and wettability in



**FIGURE 3.** Simulation is compared to time-series microCT imaging of drainage of a brine-saturated rock by injection of super-critical CO<sub>2</sub> followed by imbibition. (Source: FEI)

drainage/imbibition cycles can be used to anchor digital models of special core analysis.

From this point, an operator can more reliably and predictively use digital models to consider multiple recovery scenarios and to plan improved production strategies on the same core material. **E&P**

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# Drilling systems improve economics in fewer trips, precise geosteering

The RSS has a suite of application-specific drilling technologies that deliver high build rates and maintain stability at any inclination.

**Eric Climer** and **Liam Lines**, Weatherford

The decline in oil prices has been particularly difficult for shale plays because of the challenging economics. Although unconventional formations are the latest frontier in oil and gas development, shale plays are associated with long and complex laterals; high-angle well sections; dense, low-permeability rock; and harsh down-hole conditions, all of which increase operational costs and shrink profit margins.

Now more than ever operators are seeking strategies to spend less money by reducing rig time, eliminating non-productive time (NPT) and mitigating equipment damage.

When drilling in shale plays, conventional mud motors often fail to deliver the high accuracy and reliability required to navigate sweet spots efficiently and maximize reservoir contact. To improve economics, drilling tools must go faster and farther, in fewer trips and with more precise and nimble geosteering. As a result of new technologies, the drilling process is rife with opportunities for lowering costs while helping to enhance ultimate recovery.

## Economic challenges in Eagle Ford

Located in South Texas, the Eagle Ford shale play is the largest oil and gas development in the world based on capital investment. It is also home to the largest oil field in the U.S., the Eagleville, which produced nearly 240 MMbbl in 2013. The breakeven thresholds for shale projects in the Eagle Ford are among the lowest in the U.S., but at \$50/bbl, even these margins are thin.

## Deeper, faster, single-trip drilling

Although rotary steerable systems (RSS) typically cost twice as much per day as conventional mud motors, the savings in rig time and the improved borehole quality offset this investment many times over. The Weatherford Revolution RSS (Figure 1) decreases drilling costs by maximizing efficiency and ROP.

Using point-the-bit technology for improved geosteering along the planned well path, the RSS enables



**FIGURE 1.** The Weatherford Revolution RSS incorporates point-the-bit technology for improved geosteering along the planned well path and enables deeper, faster drilling with precision well placement—often in a single run. (Source: Weatherford)

drilling to greater depths, at faster rates, in fewer trips and with precise wellbore placement—all while leaving a smooth, clean borehole for completion.

The Revolution RSS encompasses a suite of application-specific drilling technologies that deliver high build rates—a maximum of 16°/30 m (16°/100 ft)—and maintain stability at any inclination, which makes it well suited for drilling vertical, deviated, horizontal and extended-reach sections in one run. This RSS can also withstand bottomhole temperatures up to 175 C (347 F) and bottomhole pressures up to 25,000 psi.

At the Weatherford Technology Center in Tewkesbury, England, technicians tested the Revolution RSS under various simulated environmental conditions—ranging from backward whirl and severe torsional vibration to high temperatures and pressures—to assure reliable performance in the most extreme conditions.

## Hostile-environment logging

When combined with the hostile-environment-logging (HEL) MWD system, the Revolution RSS offers an integrated approach to drilling. The HEL MWD system incorporates sensors that monitor the wellbore environment and capture a full range of data in real time.

Armed with this information, operators can make adjustments while drilling, which reduce the risks of damaging equipment, incurring NPT and prolonging the drilling process.

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## Maximize Sweet-Spot Exposure

Introducing the AccuSteer™ MWD Measurement Suite from Ryan Directional Services, a Nabors company. AccuSteer was designed specifically for the challenges inherent to unconventional plays. It provides fast, accurate downhole data between the BHA and the surface to help mitigate potential drilling problems.

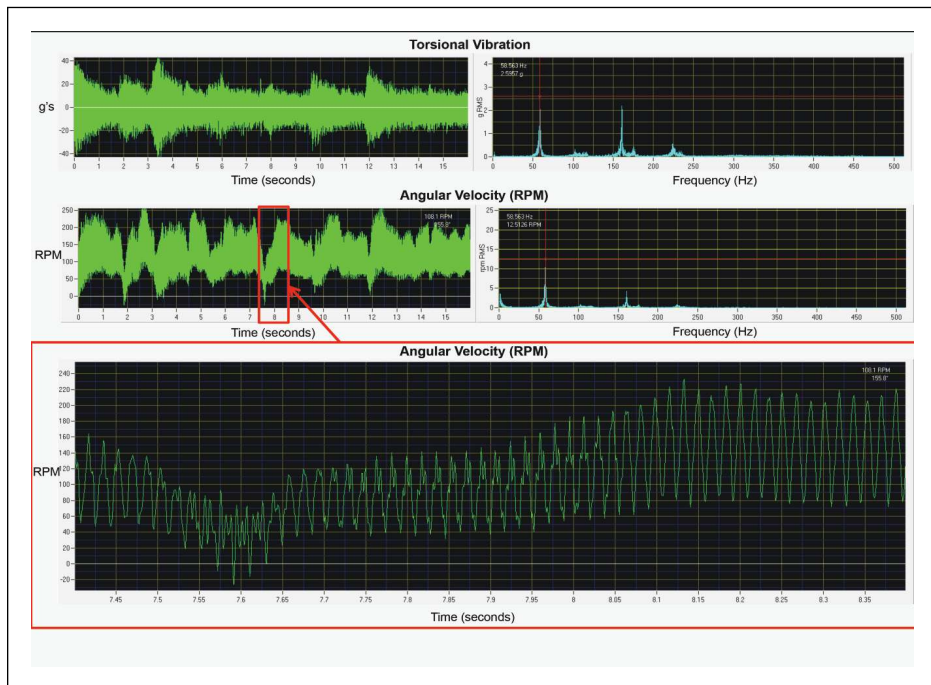
Critical to success is maximum sweet spot exposure. The available suite of measurements in the AccuSteer system are resistivity, drilling dynamics, azi-gamma, shock and vibration, ECD and continuous inclination. The integrated collar-based design optimizes sensor to bit spacing for accurate characterization of the reservoir, providing a clearer picture of the downhole environment.

The AccuSteer suite enables confident drilling optimization and geosteering decisions to maximize sweet-spot exposure. Stop guessing—contact Ryan Directional Services today!

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**FIGURE 2.** The graph shows HFTO with bit speeds fluctuating at 150 rpm, 60 times per second. Severe torsional vibration in excess of 40g causes rapid fluctuations in bit speed and can cause the bit to instantaneously travel backward against the rock face. (Source: Weatherford)

### Advanced vibration detection

The hard carbonate rock overlying the Eagle Ford Shale causes excessive vibration that accelerates wear on the drillbit and damages drilling tools. This type of vibration cannot be detected from surface-based measurements and occurs at frequencies outside the measurement range for conventional drilling sensors.

Placing advanced vibration sensors downhole is critical in preventing bit wear and tool damage. By incorporating technologies such as the Weatherford Total Vibration Monitor (TVM) on drilling tools, operators have identified high-frequency torsional oscillation (HFTO) in the bottomhole assembly (BHA) as the culprit for vibration and bit wear (Figure 2).

HFTO is the result of BHA torsional resonances, which are prompted by distinct rock-cutting processes that occur when drilling hard formations. In addition to fatigue damage to drilling tools, HFTO also causes rapid fluctuations in the bit speed, which can lead to the instantaneous backward rotation of the bit against the formation. This dulls drillbits very quickly.

Detecting and mitigating HFTO and other adverse drilling dynamics in hard carbonate rocks is the key to drilling longer laterals through shale. The TVM can be integrated into the Revolution RSS and any other

Weatherford MWD/LWD tool for enhanced control over shock and vibration.

### Real-time optimization

Bit wear and drilling tool damage are avoided by combining vibration sensors such as the TVM with real-time monitoring. Incorporating Weatherford software and technical support at regional real-time operations centers (RTOCs) helps to ensure that downhole data are constantly monitored and any issues are addressed immediately.

Additionally, subject-matter experts at RTOCs recommend and implement best drilling practices in close collaboration with operators. As a result, drilling systems remain in optimal condition longer, and operators can drill long laterals through challenging

geology to total depth.

### Case studies

The Revolution RSS routinely drills more than 4,572 m (15,000 ft) measured depth (MD) in a single run. Recently in the Eagle Ford it set a global company record for run length by drilling 4,774 m (15,662 ft) in a single run.

In one Eagle Ford project, the RSS drilled wells in half the time the operator expected based on the average time it took previously to drill the fastest 10% of wells. The client was able to drill all planned 49 wells to an average MD of 5,791 m (19,000 ft) using only half the number of rotary rigs originally anticipated.

Especially when combined with advanced vibration sensors, real-time data-gathering capabilities, and monitoring software and support, the Revolution RSS is enabling more complex unconventional wells to be drilled worldwide. Compared to conventional motors, the Revolution RSS improves field economics by drilling more efficiently, extending well reach, improving bit life, reducing rig count and creating a smooth borehole.

The technology has the added benefit of precise navigation—and real-time adjusting of operational parameters—for avoiding problem zones, mitigating equipment damage and maximizing reservoir contact. **ESP**

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# Multipole sonic service helps lower well construction risks

SWD service offers robust real-time measurements for a range of drilling and completion operations.

**Eduardo Saenz, Schlumberger**

**R**isk reduction and drilling performance are the overarching goals of any drilling campaign. To minimize risks and ensure that a well reaches target depth safely and cost-effectively, drillers increasingly turn to sonic-while-drilling (SWD) technologies. The while-drilling measurement of the acoustic properties of the formation, such as the velocity, delivers information needed to reduce drilling risk, improve well placement and optimize completions design.

The Schlumberger SonicScope multipole SWD service has advanced real-time acoustic measurements for complex reservoirs. Combining high-quality monopole and quadrupole measurements, the service delivers real-time compressional and shear slowness in any downhole environment along with the quality assurance to enable confident drilling.

## Multiple measurements provided

Equipped with wideband transmitters, an attenuator section optimized for cleaner acoustics and an array of 48 sensors, the service conducts sonic measurements in three modes. For compressional data in all formations and shear data in fast formations such as consolidated rock, the measurements are obtained from the high-frequency monopole firing mode.

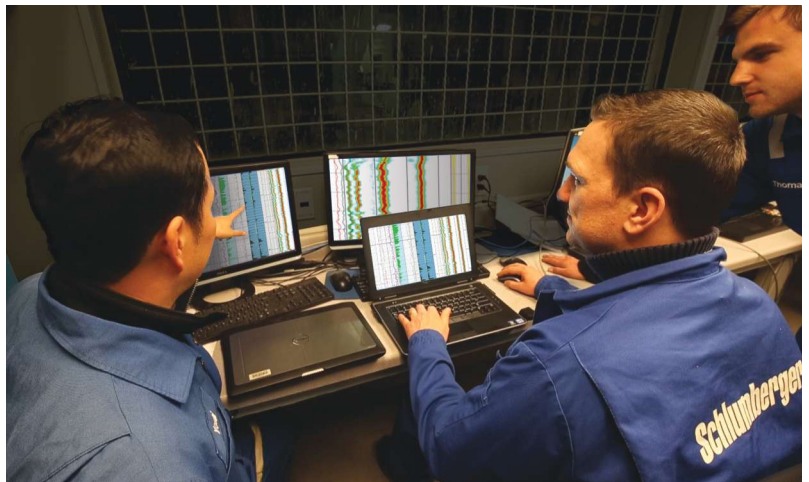
In slower formations such as the soft sediments common in shallow deepwater drilling, the formation shear is obtained from the quadrupole firing mode. Additionally, the low-frequency monopole mode is used for compressional data in extremely slow formations as well as for the measurement of Stoneley mode data.

Taken together, these compressional and shear measurements open the door for many applications. Real-time compressional and shear slownesses are vital to

more accurately monitor pore pressure, fracture gradients and wellbore stresses while drilling.

Unlike resistivity measurements, acoustic measurements are unaffected by changes in salinity and temperature. This means that acoustic is a more robust measurement for the geomechanical evaluations required to calculate the mud weight window and to adjust mud weight to mitigate against wellbore instability and kicks.

Because the monopole and quadrupole measurements provide real-time compressional and shear velocities, the operator can more accurately calibrate seismic-time-to-depth processing and interpretation



Schlumberger engineers use the SonicScope multipole SWD service for advanced real-time acoustic measurements in complex reservoirs. (Source: Schlumberger)

techniques, including amplitude vs. offset (AVO) modeling and identification of fluid in place. When limited to monopole measurements only, the operator is forced to compute a synthetic shear based on historical data and empirical formulas and models, which potentially introduces inaccuracies into the data analysis.

An important completion application for the service is ensuring deepwater well integrity and zonal isolation. The multipole SWD service can locate the top of cement in real time while running in hole to drill out a new hole section



or pulling out of the hole as well as estimate the location of free pipe and cemented zones. The data can be recorded in memory mode and also transmitted in real time.

Low-frequency monopole for Stoneley acquisition represents the final firing mode. By evaluating the reflected Stoneley waves, one can identify open permeable fractures that intersect the wellbore, an important parameter for estimating the potential productivity of the well and in completions design. By incorporating any available high-resolution imaging it is possible to characterize these fractures, including the orientation and aperture.

### Controlling quality with each measurement

Schlumberger conducts its own quality control (QC) analysis during data processing, which is made available to the operator in the form of QC logs. These logs graphically display a comprehensive set of plots that represent the data processing workflow.

Common logs include slowness-time coherence; quadrupole energy spectra, semblance projections and slowness frequency analysis; inversion quality controls; semblance spectra; waveform variable density logs; and slowness/frequency dispersion plots.

All logs are generated in a transparent manner, and operators can use them to validate the quality of the quadrupole data for themselves. This process engenders greater trust in the data and the answers provided.

While the multipole service has been available since 2011, it is steadily expanding its application base. The original 4¾-in. multipole sonic tool was joined in 2013 by a tool with an 8¼-in. outside diameter (OD) and in 2015 with a mid-size 6¾-in. OD tool.

### Data acquisition in dual-reamer BHA

The service was recently deployed for an operator in the Gulf of Mexico challenged with drilling, evaluating and completing a well characterized by unconsolidated formations, narrow mud weight windows, shallow geohazards and seismic velocity uncertainties that hindered pore pressure modeling.

Schlumberger collaborated with the operator to develop a compact bottomhole assembly (BHA) containing the 8¼-in. multipole service in combination with two reamers. The sonic tool was placed closer to the bit, which allowed drilling hazards to be detected sooner and helped place the casing at the necessary depth.

The high-quality real-time sonic data helped the client decide where to stop drilling to deliver a hole size suitable for running the casing string to its desired depth. The ability to simultaneously log and run two reamers saved the company two days of rig time, while past

drilling operations required an extra data acquisition trip to avoid the noise of the dual reamers.

### Applicability in soft formations

The 8¼-in. service also acquired high-quality compressional and shear data in a soft formation offshore Malaysia. The operator needed these datasets as part of a four-well drilling campaign, where accurate time-depth information was essential to reduce uncertainty in the surface seismic.

The BHA was configured with the multipole SWD service in combination with the Schlumberger TeleScope high-speed telemetry-while-drilling service. This technology combination was run in the shallow 12¼-in. section of each well to acquire data that would complement velocity measurements planned in deeper sections of the wells.

Despite the soft formations, the operator successfully acquired compressional and shear data using the multipole service in all four wells. Compressional slowness was extracted using a unique real-time Leaky-P processing technique, and the quadrupole acquisition provided shear slowness data of up to 960 µs/ft, which marked the slowest shear measured by the tool at the time. The operator used this information to correct the time-depth conversion and therefore update the projected depths of important geological layers and potential hazards.

### Reduced drilling risks in HP/HT environment

The SonicScope service also has supported geomechanical analysis aimed at reducing risk in an HP/HT region of the South China Sea. The operator required high-quality SWD measurements to navigate a narrow mud weight window in a high-pressure formation prone to high shock and vibration during drilling.

The service obtained reliable sonic data for both real time and memory. An excellent match was acquired between the real-time and memory compressional and shear slowness in the high stick/slip environment of the HP/HT reservoir.

Schlumberger geomechanics experts in its PetroTechnical Services provided additional insight where time-lapsed logging helped quantify the impact of mud invasion in the high-porosity formations as a reduced slowness was acquired in the gas zone.

These datasets were compared with surface seismic data collected before drilling, and a good match between the two reduced uncertainty and boosted the operator's confidence in being able to reach total depth with reduced risk. Having proven success after this first-time use of the service, the operator decided to run the sonic service in 14¾-in. and 12½-in. hole sections in future HP/HT deepwater wells. **E&P**

# New sensors improve data gathering in extreme drilling environments

Advances in HP/HT and sonic sensors have made it possible to optimize reservoir production and decrease drilling risks.

**Tim Parker and Taher Kortam,**  
Sperry Drilling, a Halliburton company

**M**WD/LWD services have been used since the 1970s to provide petrophysical measurements for evaluation of the reservoir and to monitor depletion of reservoirs as they mature. Initially, wireline services provided the same measurements as those of LWD services but with higher quality and accuracy.

However, after more than 30 years of intensive development, LWD services can now provide the same quality logs as wireline in real time to aid geosteering and early reservoir evaluation. These services are deployed along with MWD data to help mitigate drilling risks and reach farther into previously inaccessible reservoirs. Additionally, the trajectories of some wells prohibit wireline conveyance, increasing the need for MWD/LWD services, especially in high-cost operations such as deepwater drilling.

One of the main challenges that operators face is risk mitigation while optimizing returns on the reservoir. Considering the difficult market conditions, this article will particularly focus on MWD/LWD technologies that offer potential significant cost savings and risk mitigation when drilling in harsh HP/HT environments and when wellbore stability is more challenging in formations such as shale.

## HP/HT technology advancements

As hydrocarbon reserves become scarcer, technology development efforts are focused on the capability of drilling in hostile downhole environments, particularly

in extreme temperatures. HT wireline logging tools have existed for many years and have mostly used heat flask technology to insulate the tool's electronics from the high reservoir temperatures. The short duration of most wireline runs makes this a practical solution, but MWD/LWD tools operate downhole for longer periods of time, negating the effectiveness of this technology.

Without an HT tool, current drilling practice for these HT wells has been to drill until standard MWD/LWD tools "temped out," and then to pick up a dumb iron assembly to drill to total depth (TD). This method of drilling results in real-time logging data loss and borehole positioning uncertainty, forcing the operator to drill the well blind.

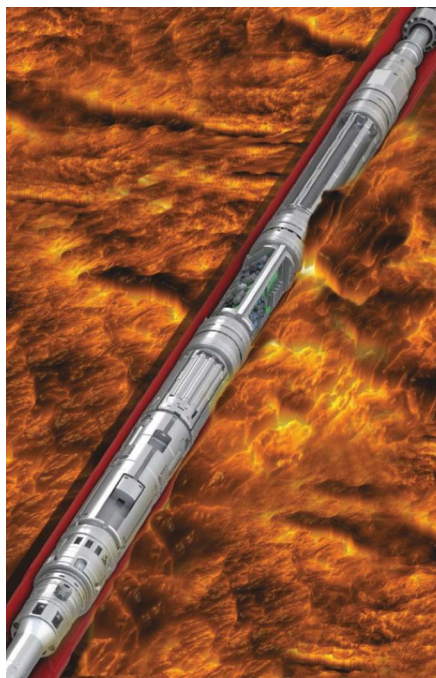
Another common practice is to extend tool runs as long as possible by employing temperature mitigation practices such as reducing rpm, staging to cool the tools and using mud chillers, but these practices increase the amount of rig time and add significant costs to drill the reservoir section.

In 2013 and 2014 Sperry Drilling launched its HT MWD/LWD drilling service, the 4¾-in. and 6¾-in. Quasar Pulse systems, which offer real-time gamma, vibration, directional and pressure measurements in environments up to 200 C (392 F) and 25,000 psi. The system contains hermetically sealed electronics designed

to operate in extreme temperatures, helping the operator reach final TD with potentially just one run.

## Quasar Pulse service case study

In a recent well offshore Southeast Asia, where bottom-hole temperatures are among the highest in the world,



**Quasar Pulse systems offer real-time gamma, vibration, directional and pressure measurements in environments up to 200 C and 25,000 psi. (Source: Sperry Drilling)**

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an operator wanted to reduce costs and achieve logging objectives in HT wells drilled from a jackup rig in 74 m (243 ft) of water.

To help the operator prevent the costly measures associated with HT conditions, Sperry Drilling recommended using the Quasar Pulse MWD/LWD service to operate in the anticipated bottomhole static temperature of 195 C (383 F). Sperry Drilling ran the Quasar Pulse MWD/LWD service with the adjustable gauge stabilizer in five wells and successfully drilled and logged in each section.

In one single-run performance where circulating temperature reached 187 C (369 F), the service drilled and logged 2,284 m (7,493 ft) to TD for an average ROP of 31 m/hr (101.4 ft/hr).

The operator calculated that using the service from Sperry Drilling saved it about \$1 million and more than 100 hours of rig time by reducing the number of wireline runs, eliminating trips for temped-out tools and avoiding temperature mitigation practices to achieve TD.

### Sonic technology advancements

There are many challenges when drilling a well, but optimizing reservoir production and decreasing drilling risks are among operators' top priorities. Advances in sonic sensors have made it possible to provide solutions to these challenges. Sonic sensors can use multipole sources to measure compressional and shear velocity data to calculate mechanical rock properties and to help optimize the hydraulic fracturing process and completion design.

In addition, sonic measurements can help determine lithology, porosity and pore pressure to calibrate the geomechanical model and optimize or define a safe mud weight operating window.

Without this information there is a risk that the formation could fracture if the mud weight is too high, or the wellbore could collapse or suffer pressure kicks if the

mud weight is too low. Both could result in increased costs, potentially up to two days of rig time and safety risks for the rig personnel.

Since 2013 Sperry Drilling has released the XBAT sonic service with a full suite of tool sizes, covering 4¾ in., 6¾ in., 8 in. and 9½ in. The XBAT LWD service, the third generation of Sperry Drilling sonic services, delivers accurate acoustic measurements in a wide range of formations via sensors and electronics that are much less sensitive to drilling noise and have a wider frequency response than earlier designs. The result is a greater signal-to-noise ratio that enables better measurements even in noisy drilling environments and poor hole conditions.

The XBAT tool combines multi-array azimuthal sonic velocity measurements with multi-axis ultrasonic standoff measurements to improve the operator's ability to determine rock properties that have a direct impact on the geomechanical model.

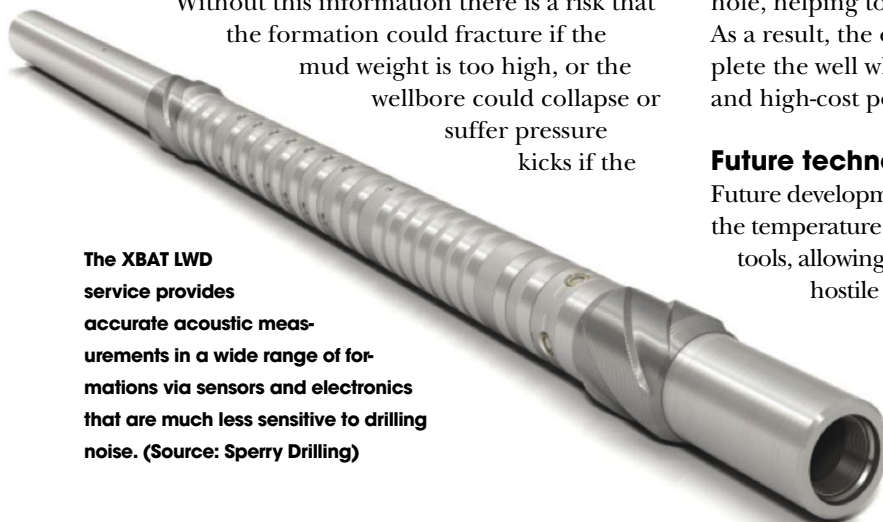
### Sonic service case study

An operator in Nigeria drilling in a shale formation in 1,666 m (3,827 ft) of water encountered issues in determining the optimum mud weight needed to maintain wellbore stability. In a previous well in the same field the operator had various challenges associated with wellbore stability. The operator had to make a clean-out run because the 9%-in. casing could not be run to setting depth and had to be pulled out of the hole. The clean-out bottomhole assembly got stuck at the same depth at which the casing was held up, requiring a sidetrack.

To avoid repeating these problems, Sperry Drilling recommended the XBAT service to provide real-time shear and compressional data while drilling the 12¼-in. hole, helping to determine the appropriate mud weight. As a result, the operator was able to successfully complete the well while avoiding any wellbore stability issues and high-cost potential sidetracks.

### Future technologies

Future developments will likely include further increases in the temperature and pressure specifications of MWD/LWD tools, allowing operators to exploit reserves in even more hostile conditions. Further enhancement of downhole rock mechanics measurements will improve operators' understanding of the drilling environment. These technology advancements will help reduce nonproductive time, minimize overall costs and maximize return on investment. **E&P**



**The XBAT LWD service provides accurate acoustic measurements in a wide range of formations via sensors and electronics that are much less sensitive to drilling noise. (Source: Sperry Drilling)**

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# New service increases fracture area, boosts production

A new horizontal hydraulic fracturing service taps the conductive fracture area above the lateral to improve production while reducing stage size and cost.

**Scott Nelson**, Baker Hughes

Shale's low permeability means oil and gas molecules move very slowly, often as little as 0.3 m to 0.6 m (1 ft to 2 ft) per year. As a result, for horizontal wells in these reservoirs to produce economically and achieve acceptable recovery rates, the well stimulation treatment must achieve three goals:

- A fracture network must be created through hydraulic fracturing to connect more hydrocarbons to the horizontal wellbore;
- The fracture network should be as large and complex as possible; and
- The conductive fracture area—the overall area of the total created fracture network that does not seal upon fracture closure—must be maximized.

## Enlarging the fracture network

The industry has begun to recognize the link between conductive fracture area and the effectiveness of the fracturing treatment to contact the reservoir. Today many unconventional shale stimulations are performed, in part or in whole, with low-viscosity fluids. These fluids have a lower associated breakdown pressure than their higher-viscosity counterparts and so do not limit far-field fracture complexity.

The drawback to the low-viscosity fluids is that they cannot provide perfect proppant transport characteristics. Conventional proppants (most often sand) have a specific gravity that is significantly higher than the fluid in which these are pumped, making it extremely difficult to place proppant above the horizontal lateral (i.e., the high side of the created fracture network). Instead, the proppant settles and creates a bank, or dune, in the bottom of the fracture at or below the depth of the horizontal lateral wellbore. Any proppant that might reach above the lateral wellbore typically settles before the fracture closes. As a result, the fracture above the lateral is either choked or shut off—sacrificing much of the total generated fracture area when the unpropped section seals.

A common approach to improving production from stimulated wells is simply to increase the overall size of the stimulation by pumping larger fluid and sand volumes. While the larger volumes of water and sand can develop a larger fracture area, this process often fails to produce an equivalent production response—again, because the majority of the proppant is placed in the bottom portion of the fracture without the ability to prop open the upper fracture area above the lateral wellbore. Although larger, the unpropped fracture area still seals, and any additional production that may occur is often a benefit of the increased fracture length.

Another approach is to pump a hybrid fluid design wherein the last portion of the treatment is composed of crosslinked fluid and proppant. The proppant becomes entrained within the fluid's crosslinked long-chain polymers. It is then transported down the well and to its final position within the formation. This approach allows placement of some proppant above the depth of the lateral wellbore. However, the overall coverage area is limited proportionally to the entire treatment volume. Additionally, the crosslinked tail-in sand stages that are placed above the lateral tend to settle in the fracture due to gravity effects. As crosslinked fluid stages begin to break and thin, they lose the ability to fully support the sand. When combined with the extended fracture closure times associated with very tight reservoirs, there is no confining force to completely inhibit the suspended sand from settling prior to closure.

## Reaching above the lateral

To achieve the goal of maximizing the stimulated fracture network using low-viscosity water-based fracturing fluids, Baker Hughes developed its Ascent fracturing service. The service applies advanced modeling and specialized pumping techniques to deliver and effectively place strong, ultralightweight proppants in water-based fracturing fluids above the depth of the lateral. The extremely strong “buoyant” proppants replace a portion of the sand during the stimulation treatment

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to ensure that a significant portion of the fracture's high side remains open following fracture closure. Because they are nearly the same density as the fluid, the ultralightweight proppants will not fall to the bottom of the fracture, even during extended fracture closure periods, greatly expanding the conductive fracture area and significantly increasing the effectiveness of the stimulation. The size of each stage treatment may even be reduced while still accessing more total fracture area.

An additional benefit of this approach is that it reduces fluid and proppant requirements and with them multistage stimulation times, operational costs and HSE risk. One pound of ultralightweight proppant can replace on the order of 10 lb of sand, thus reducing the volume of sand required by 30%, 40% or 50%, depending on reservoir characteristics. The lower sand and chemical requirements reduce associated rail and truck transportation cost, traffic and risk. The resulting improvements in well economics and the improved production benefit both sides of the cost-per-barrel equation.

### Determining treatment program, pricing

To determine the best treatment design and pricing for the stimulation, treatments of current and previous wells are modeled. The model is then optimized to predict the increase in conductive fracture area that can be expected by treating with the optimized service. Consultation between the operator and the service company determine which treatment size best fits the stimulation goals for a particular reservoir and well configuration. The treatment is executed.

Production monitoring from long-term studies shows that the most significant improvements from using the new treatments are not always visibly apparent during the initial production period. The greatest improvement becomes apparent with cumulative production over time—months and even years into production. Wells stimulated using this approach produce longer with steeper cumulative production climb because of more contributing fracture area within the reservoir.

The additional increased conductive fracture area can also contribute to a reduction in the production decline rate over the long term. It can improve the boe cost of production from either any realized increase in production or associated savings from a more effectively placed stimulation design, or both.

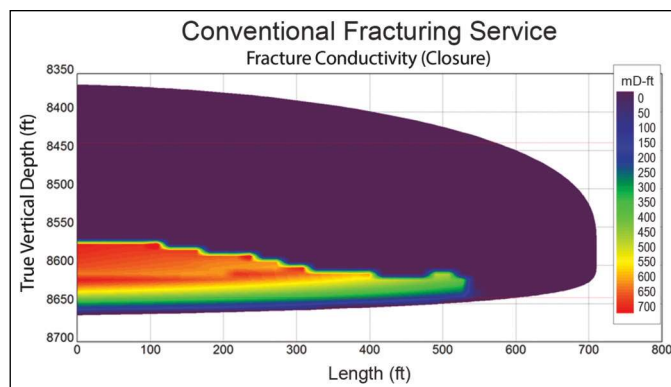
### Case histories

In a 19-well, 36-month study in the Barnett Shale in

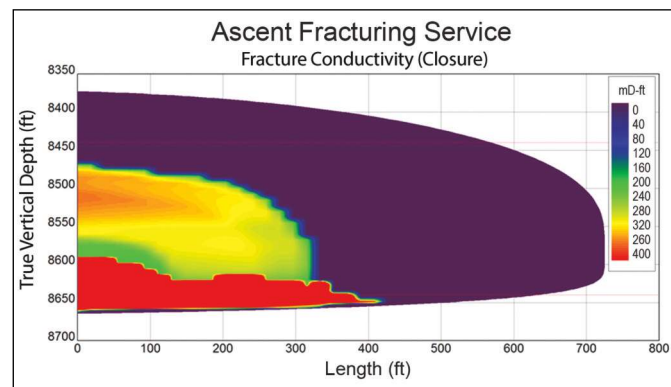
Texas, using the company's fracturing service enabled operators to increase hydrocarbon recovery by an average of 117% over conventionally treated wells of similar depth and length within a 3.2-km (2-mile) radius. Proppant volumes were lowered, and water usage decreased 20%, from 19,163 l/m (1,543 gal/ft) to 15,189 l/m (1,223 gal/ft).

Similar results were reported from a 16-well, 72-month production study in Hughes County, Okla. In Coal County, Okla., hydrocarbon recovery increased by an average of 28.2%, while proppant volumes dropped a dramatic 48%, from 1,220 kg/m (820 lb/ft) to less than 624 kg/m (419 lb/ft), and water usage also decreased.

In current market conditions, both operators and service companies are focused as never before on improving efficiencies in all aspects of well construction and production. The fracturing treatment described in

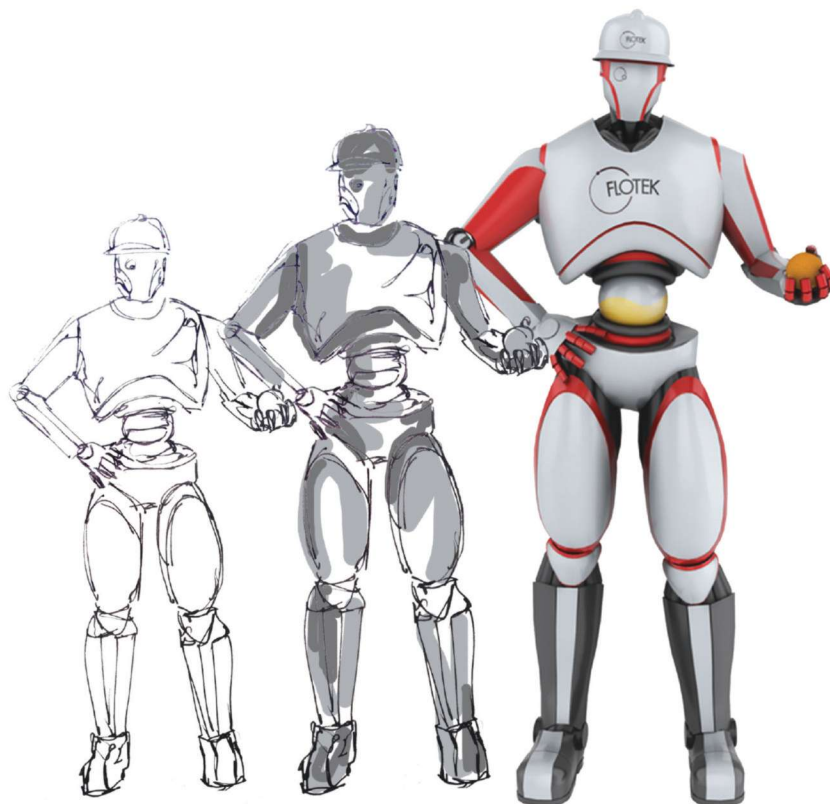


**In conventional fracturing operations, the majority of the proppant settles in the fracture below the plane of the horizontal well. As a result, little if any hydrocarbon flow is generated by the high side of the fracture. (Source: Baker Hughes)**



**With the Ascent fracturing service, strong, ultralightweight proppant is placed above the horizontal lateral for increased hydrocarbon flow. (Source: Baker Hughes)**

# The CREATION of a TECHNOLOGY

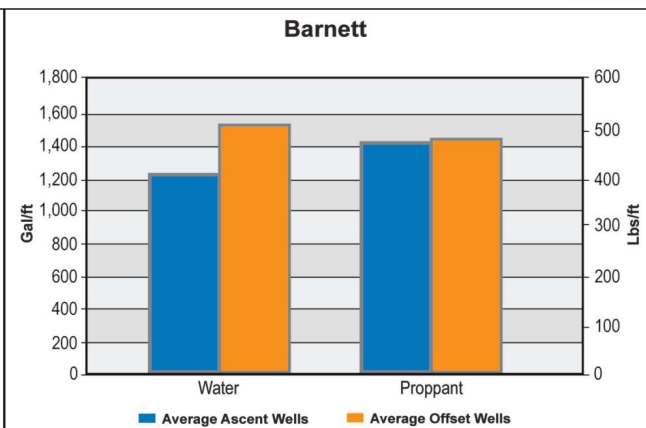
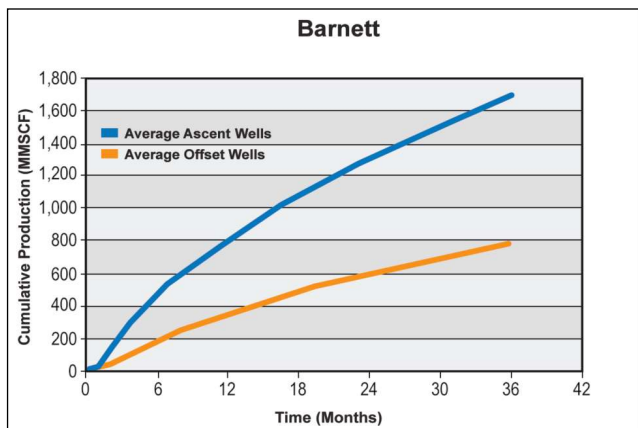


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The cumulative production over time and the water/proppant comparison of wells treated with Ascent vs. the average offset well are shown. (Source: Baker Hughes)

this article is one option in a fracturing service that exemplifies how the industry is developing smarter, better engineered solutions to deliver stimulation treatments that are more efficient in the short term, more

effective in the long term and more economic throughout the life of the well. Additional options based on new proppant and fluid technologies are expected to be introduced later this year. **E&P**

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# Sequenced refracturing boosts production, EUR without drilling

Operator improves recovery in previously completed laterals through use of sequenced refracturing technique.

**Dmitry Usoltsev, Andrew Acock and Alejandro Peña,**  
Schlumberger

**W**ith constrained oil prices, unfavorable market conditions and reduced budgets, many shale operators today are actively investigating viable alternatives to the mass drilling and completion campaigns of recent years.

Costs associated with drilling, casing, cementing, perforating, setting and milling out bridge plugs, and fracture stimulating dozens of stages along a 1.2-km to 3-km (4,000-ft to 10,000-ft) lateral typically range from \$6 million to \$20 million, depending on the play and place-

ment of the well. On the other hand, refracturing an existing horizontal wellbore—reopening established fracture networks and/or accessing previously unstimulated zones—typically costs from \$1 million to \$2 million. Refracturing, therefore, represents an economically attractive option for improving well performance and return on investment.

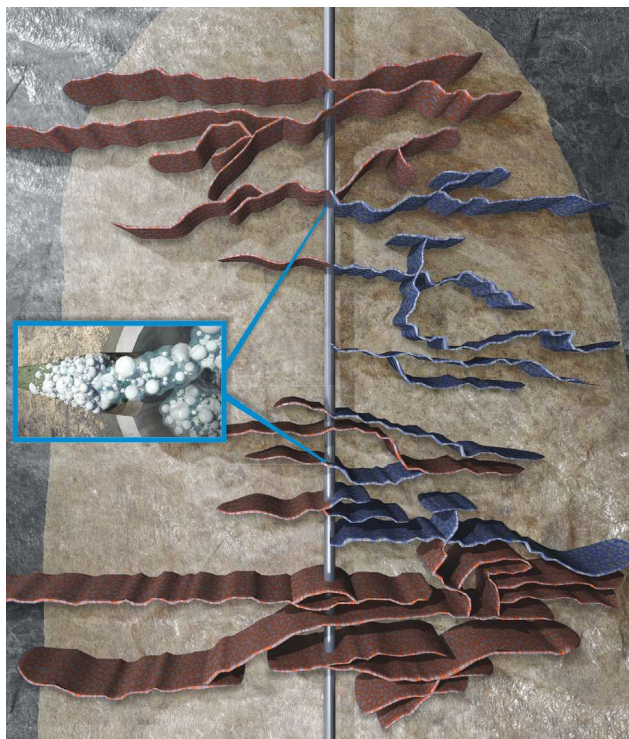
The rationale for refracturing lies primarily in the well-known fact that optimization of the completion process in every unconventional play has been gradual. Literally thousands of existing wellbores in good reservoir rock were originally fractured with substandard practices, especially those completed early in development. In addition, many initial completions suffered damage of various kinds that caused production to decline more rapidly than usual. Thus, numerous opportunities exist for operators to reenter declining or depleted shale wells and apply more effective techniques.

One emerging approach for boosting recovery in a previously completed lateral combines rigorous candidate selection and completion modeling with an innovative sequenced refracturing technique using a proprietary new diversion material.

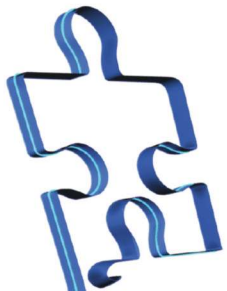
## Candidate selection, refracturing strategies

Economically successful refracturing operations require a systematic candidate selection workflow. Key factors in evaluating the post-refracturing production potential of a well or group of wells include reservoir quality and heterogeneity, original completion characteristics, initial well performance, changes in rock and reservoir properties, proximity to offset wells, decline rates, current production, and stress and depletion profiles along the lateral at the time of proposed restimulation.

Some wells are simply not good candidates for refracturing. Even when selected wells appear viable, specific goals and completion strategies can vary in significant ways. Candidate wells with sufficient remaining volumetric potential tend to fall into one of three categories.



**FIGURE 1.** The BroadBand Sequence service uses a proprietary composite pill of degradable particles and fibers to isolate depleted zones and ensure effective refracturing. (Source: Schlumberger)

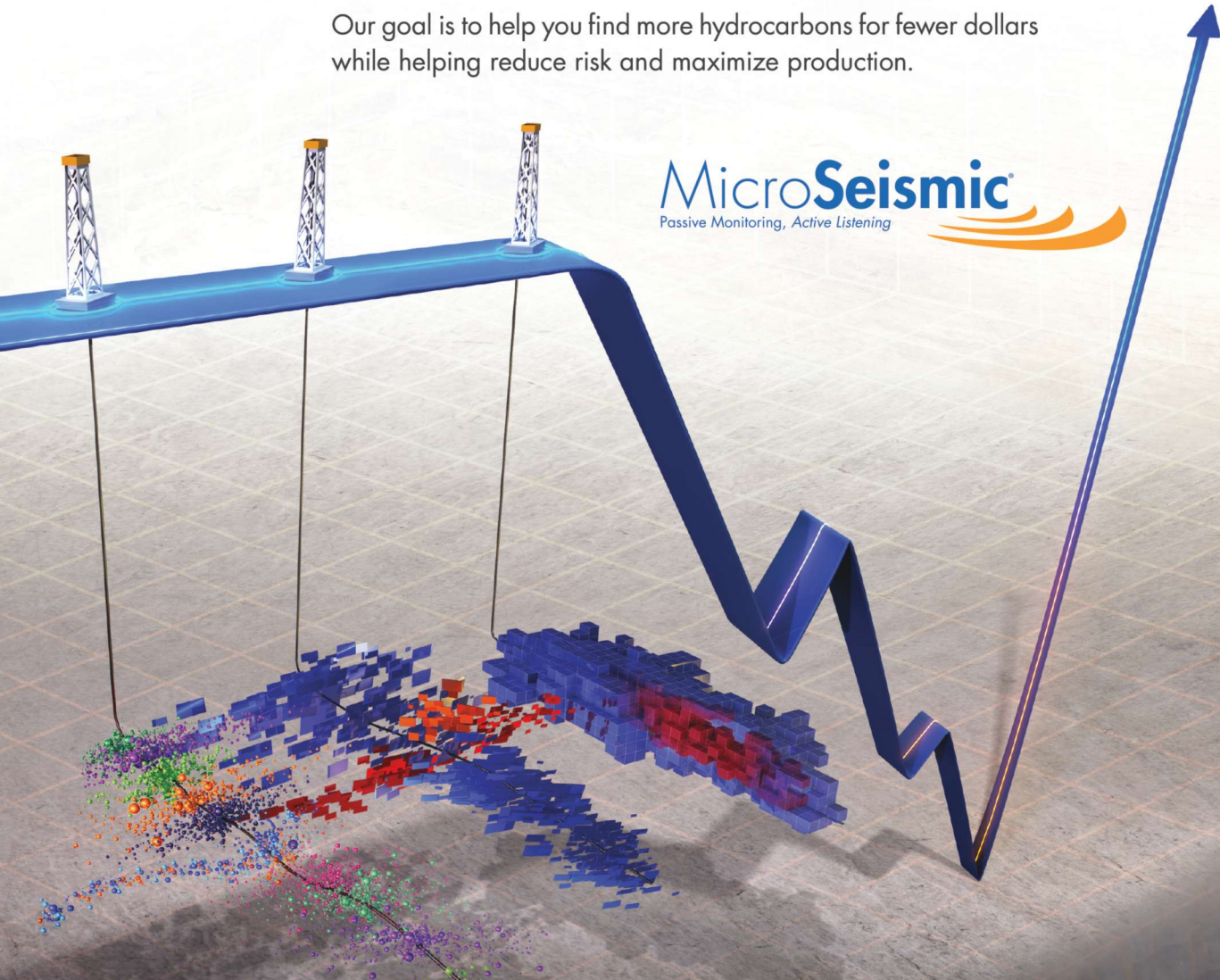


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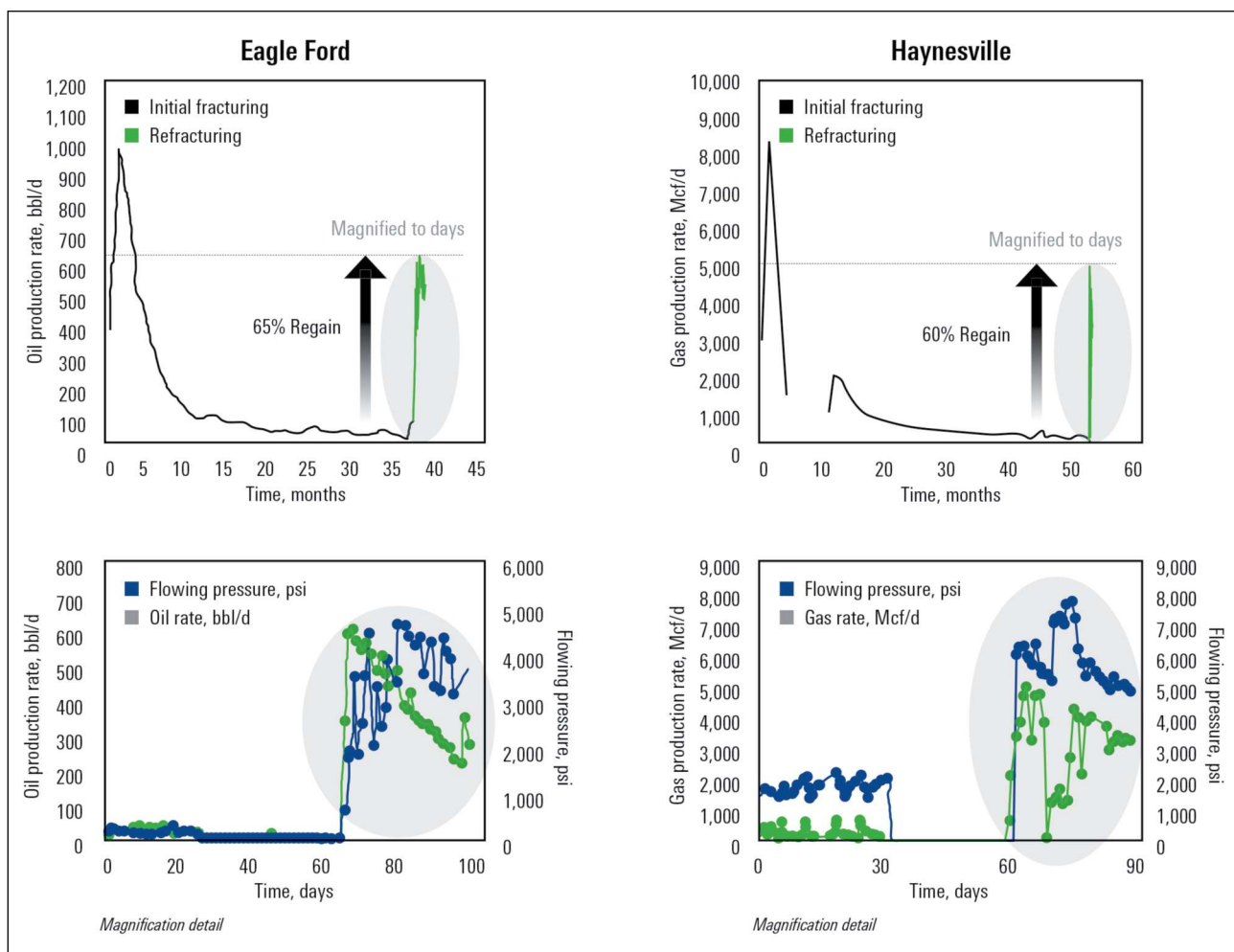
First, wells with damaged completions usually exhibit high IP rates followed by rapid declines. Damage may be due to aggressive drawdown, settling of proppant at the bottom of fractures, or overflushing of proppant away from the wellbore, all of which inhibit fracture conductivity. Second, wells with sub-optimal completions tend to show good IP followed by slower declines. Substandard completions may be the results of inadequate proppant volumes or excessive spacing between perforation clusters. A third type of refracturing candidate is the parent or first well produced in a pad, where interference with subsequent in-fill wells—due either to pressure communication or asymmetric fracture growth—may have a negative impact on production.

For each candidate type, a different refracturing strategy may be necessary. For example, a “reconnect” strat-

egy seeks to reopen existing fracture networks and restore fracture connectivity with the wellbore. A “re-stimulate” strategy strives to increase stimulated reservoir volume (SRV) by adding new perforations and fracturing new zones of high-quality rock. A “recover” strategy combines these two approaches to refracture a depleted parent well before stimulating offset wells by modeling the group as a system and taking into account potential interference.

Finally, advanced completion modeling software enables operators to simulate various refracturing scenarios, engineer appropriate completion designs for each strategy and optimize treatment parameters.

For any refracturing strategy, success depends largely on finding a reliable, cost-effective method of isolating existing fracture networks and reopened zones from new, previously unfractured areas.



**FIGURE 2.** Encana used BroadBand Sequence refracturing to increase oil and gas recovery from wells in the Eagle Ford and Haynesville plays. (Source: Schlumberger)

### Sequenced refracturing with diversion

To maximize the productivity of initial completions in unconventional reservoirs, Schlumberger developed the BroadBand Sequence fracturing service (Figure 1). To date, more than 4,500 sequenced fracturing treatments have been performed in the U.S., Canada, Argentina, Mexico, Saudi Arabia, Oman and China. Within the past year, a handful of early adopters also have begun applying this innovative technique to refracture declining shale wells at a fraction of the original cost.

To establish connectivity between the wellbore and undrained reservoir volumes, sequenced refracturing alternates the pumping of fracturing stages of different sizes with the concentrated pills or slugs of a proprietary new blend of degradable particles and fibers.

The first fracturing stage initiates fractures in zones of lower formation stress. Next, a composite pill is pumped downhole, temporarily isolating initial fractures and diverting the subsequent treatment—pumped under higher pressure—to zones of higher stress. Additional sequences of fracturing fluid and pills initiate even more fractures. Thus, sequenced fracturing stimulates a larger number of perforation clusters, boosting total SRV and associated production.

Blending degradable particles of multiple sizes with degradable fibers, this unique composite fluid overcomes the limitations of traditional chemical diversion methods and fluids containing particles alone. Fibers prevent dispersion or settling of particles in the wellbore, ensuring the material remains highly concentrated downhole. The size and amount of components are optimized to create a temporary low-permeable plug using minimal material. Larger particles pass through the perforations but not the existing fracture entrance. Incrementally smaller particles accumulate to further reduce permeability.

Field tests show these temporary plugs can withstand temperatures from 38 C to 204 C (100 F to 400 F) and a pressure differential of up to 3,700 psi for a period long enough to complete a typical stimulation treatment. Afterward, all particles and fibers completely degrade within a few days without additional intervention, opening the zone for production.

To stimulate a longer section of wellbore, the number and size of alternating fracture treatments and compos-

ite pills can be increased, along with pump rates, as needed. This, then, is how the new sequenced fracturing technique applies to refracturing operations, in which the entire lateral is open for treatment.

### Refracturing increases production, recovery

To accelerate production and increase EUR in declining wells, Encana decided to evaluate the sequenced fracturing technique to refracture candidate wells in both the Eagle Ford and Haynesville shales. Candidates were selected based on quality of the reservoir, completion and production history, and location relative to nearby wells.

Since perforations were still open along thousands of feet of lateral, use of mechanical bridge plugs or inflatable packers was not appropriate in either case. Both wells were completed in continuous pumping operations, alternating fracturing stages with composite pills to promote diversion along the lateral.

Sequenced refracturing led in both cases to significant increases in production (Figure 2). In the Eagle Ford well, oil production increased from about 50 bbl/d to 650 bbl/d, while flowing pressure increased from 250 psi to 5,000 psi. In the Haynesville well, gas production increased from 2,832 cu. m/d to 142,000 cu. m/d (100,000 scf/d to 5 MMscf/d), while flowing pressure increased from 1,500 psi to 6,000 psi.

Refracturing represents an economically attractive option for improving well performance and return on investment.

### Early days

The application of sequenced fracturing with diversion to refracture existing horizontal shale wells is growing. Initial results—like the two wells above—are very promising. Since few operators have significant experience with refracturing of any kind, many are proceeding with caution, learning as they go. Every refracturing operation is different. Success depends on holistically integrating workflows for reservoir evaluation, candidate selection, completion design with effective technology enablers, treatment execution and production management. Done properly, refracturing a good candidate well or group of wells can substantially boost production, increase EUR and ensure solid return on investment at a fraction of the capital expense required to drill and hydraulically fracture a whole new lateral. **E&P**



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# Compact processing solutions for topsides

Efficient and cost-saving design is not just about saving space and weight.

**Marcus D. Sprenkel, Cameron Process Systems**

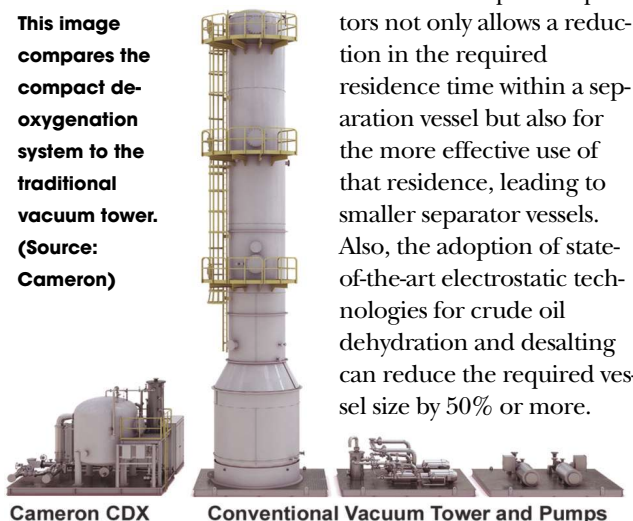
**W**hen it comes to the design of the process topsides for an oil and gas facility, real estate is expensive. It is expensive not just from a square footage perspective but also from a cubic footage perspective.

The larger the volume of a piece of process equipment is, the higher the operating and flooded weights of that equipment item are. These weights have a significant impact on the design of the support structure for the equipment via the resultant stresses, resulting in a bulkier structure that in itself weighs more. Adding more structure results in increased costs to the facility. So it will come as no surprise to find that engineers are always looking for ways to reduce space and weight.

However, reducing space and weight doesn't help if the smaller equipment brings with it additional problems with regard to operations and the associated costs. If operators solely focus on the capex and do not take into consideration the opex, they are only looking at a portion of the overall picture. Truly effective compact solutions bring benefits in both capex and opex—and even revenue improvement—impacting the life-of-field economics.

For example, the current crop of high-tech internals for two- and three-phase separators not only allows a reduction in the required residence time within a separation vessel but also for the more effective use of that residence, leading to smaller separator vessels. Also, the adoption of state-of-the-art electrostatic technologies for crude oil dehydration and desalting can reduce the required vessel size by 50% or more.

**This image compares the compact de-oxygenation system to the traditional vacuum tower. (Source: Cameron)**



## Economic trade-offs

However, compact processing technologies often come with a higher price tag when compared to their conventional counterparts. And, while the smaller and lighter equipment will have some associated savings in the structural requirement, this may not always be sufficient to justify the adoption of that solution unless it brings something else of value along with it.

Natural gas with a significant quantity of CO<sub>2</sub> present can be treated using conventional amine technologies or through the use of membrane separators. While membranes are smaller and lighter compared to amine systems, this might not always be sufficient to tip the balance in their favor. Once other factors such as the cost of operating an amine system compared to membranes, the maintenance required and operational flexibility are taken into account, other valuable arguments enter the conversation, and the economic balance shifts.

While being able to identify the capital benefits a certain technology may bring is relatively straightforward (e.g., saving space and weight, reducing ancillary equipment, etc.), trying to place an economic value on some aspects that a technology brings from an operational perspective can be problematic, even though that feature does have economic benefits.

Some operational benefits can be easily quantified, such as a reduction in chemical usage, utilities or consumables. Other benefits such as reliability, operability and maintenance costs are not so easy to put a figure on.

In produced water treatment, the current state-of-the-art compact flotation units (CFUs) can be up to 75% the size and weight of a conventional induced gas flotation unit (IGF), which is a straightforward capex benefit. Adoption of CFU technology also can reduce power requirements and achieve the needed performance with a reduction in chemical injection amounts, both being clear opex benefits. However, the fact that some designs of CFU operate flooded and therefore are motion-insensitive gives improved operability compared to designs of IGF, which operate with controlled liquid levels. Trying to put a price on this improved operability is not going to be easy, even though it would be of value to nearly all operators.



## Downstream benefits

It is not just the capex and opex benefits associated with the equipment items that have to be considered, but also the downstream benefits that the adoption of certain technologies can bring.

Seawater treatment for reinjection has been undertaken for many years using multimedia filtration that can achieve filtration down to the 2-micron to 5-micron level. While this is a very low level of particulate removal, it should not be forgotten that seawater does have a significant level of particulates below that level. And these particulates will get passed on to any downstream equipment (such as sulfate removal membranes), causing fouling or, injected into the formation, causing problems there.

Microfiltration (MF) and ultrafiltration (UF) both employ membranes, with MF removing particulates 0.1 microns and greater and UF removing 0.01 microns and greater. Both technologies deliver demonstrable savings in operating weight, which can be quantified for the capex evaluation. Additionally, filtration at this level essentially prevents any downstream fouling, extending equipment life and the time between membrane cleaning and significantly reducing the requirement for expensive downhole treatments, which have a noticeable beneficial impact on the opex and life-of-field economics. Another benefit that some compact technologies can provide—often not taken into consideration—is the associated logistical costs that come with the use of conventional processing solutions.


The removal of oxygen from seawater helps prevent corrosion of downhole equipment, and compact seawater de-oxygenation technologies, such as the newly introduced Cameron CDX compact de-oxygenation system, can provide a dramatic reduction in operating and flooded weights when compared to conventional vacuum towers and vacuum stripping. Compact de-oxygenation can also remove the requirement for chemical treatment for foaming as well as oxygen and chlorine scavenging. Not requiring these chemicals removes not only the requirement for the chemical injection equipment but also the requirement for purchasing the chemicals, storing them onshore, shipping them to the offshore



**A typical FPSO topsides structure shows the finite amount of expensive real estate available. (Source: Cameron)**

facility, lifting them onto the facility, storing them prior to use, transferring them into the injection equipment and removing used chemical tanks from the offshore facility onshore. All of these items cost operators significant time and money and unnecessarily occupy valuable real estate.

In summary, for any compact technology to be fully evaluated from an economic perspective, it is necessary that all of the value-added features be considered at an early stage from a capex, opex and revenue improvement perspective and not just the space and weight benefits. **E&P**



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# ‘One-For-Two’ design demonstrates benefits of consistency for production facilities

Adopting a single basic topsides design for two multibillion-dollar deepwater facilities in the U.S. GoM is helping the operator save both time and dollars.

**Christopher M. Barton, Wood Group Mustang**

**W**e are accustomed to daily opportunities that promote “two for one.” Usually they involve discounts on consumer products or offers of special rates to attract customers to hotels or restaurants. These promotions are often worthwhile but don’t necessarily demonstrate a high degree of ingenuity, risk reduction or long-term savings.

Contrast them with Anadarko Petroleum’s approach of building two multibillion-dollar deepwater production facilities for separate U.S. Gulf of Mexico (GoM) development projects using a single basic topsides design. That is the intended outcome for the operator’s twin spar facilities, Lucius and Heidelberg.

Anadarko is a recognized player in the deepwater sector. The company operates six spar facilities in the GoM and until recently operated Neptune, the industry’s first

classic spar (installed in 1998). It was the first company to design and install a truss spar and the only one to design and install a cell spar (Red Hawk in 2004), which has since been successfully decommissioned and now serves as an artificial reef in the GoM.

Its newest and largest deepwater facility, the Lucius truss spar, began producing in January 2015.

It also operates the Marco Polo tension-leg platform (TLP) and Independence Hub, its deepest operating semisubmersible floating production unit (FPU) in the GoM at a water depth of almost 2,438 m (8,000 ft).

With its notable position and experience in the deepwater GoM, Anadarko decided to duplicate its previously successful “Design One, Build Two” approach used for its Boomvang and Nansen twin spars for the design and construction of the large spar floating production platforms destined for Lucius and Heidelberg.

The idea germinated during the development of Lucius

in the Keathley Canyon area offshore Louisiana. During the early construction phase it became apparent that the nearby Heidelberg Field in the Green Canyon region had sufficient potential to warrant the operation of another stand-alone facility. The projected 80,000 bbl/d of oil throughput design of the Lucius facility lent itself well to the intended output at Heidelberg.

The Lucius truss spar is moored in 2,164 m (7,100 ft) of water, while Heidelberg will reside in 1,615 m (5,300 ft) of water when it reaches its expected initial production date during 2016.



Anadarko Petroleum’s Lucius truss spar facility began production in January this year in the Keathley Canyon area of the GoM. (Source: Anadarko)



**The Heidelberg spar facility, expected to achieve first production in 2016, is a replica of Lucius as part of Anadarko's Design One, Build Two approach. (Source: Wood Group Mustang)**

### Replication to generate savings

Among the main objectives in the Design One, Build Two approach is the opportunity to generate significant cost savings in engineering and construction of facilities replicated from a proven design.

The main ingredients for accomplishing this objective include a cost-efficient topsides production facilities design and a reduced cycle time from project sanction to first production. For Lucius, first production came just three years after the project was sanctioned, and Heidelberg is expected to reach first production within about the same time frame.

For its program, Anadarko relies on companies that have positive track records in the design, engineering, construction and follow-on of their previous deepwater facilities. This approach minimizes the learning curve and applies knowledge of the project participants from prior projects. The decision also reduces risks, and partner continuity provides a compatibility and communication that helps to ensure reliability and predictability for delivery.

For the hull, Anadarko selected Technip Offshore,

which designed and constructed the company's previous spars at its fabrication yard in Pori, Finland. Technip's responsibility on Lucius extended to transporting the hull across the Atlantic to the GoM. Similarly, Kiewit Corp. was selected to fabricate the multilevel deck structures at its Ingleside, Texas, construction facility.

Wood Group Mustang, meanwhile, was chosen to design and engineer the topsides production facilities. The company's credentials are well recognized in the industry, having had responsibility for more than 60% of the topsides facilities installed on deepwater floating production units of all types in the GoM as well as a significant number of international facilities.

For Anadarko, Wood Group Mustang had previously provided the FEED and detailed design services on four of the operator's existing spar facilities—Boomvang, Nansen, Gunnison and Constitution. The company also provided expansion and brownfield modifications for the Neptune and Constitution spars.

Its earlier spar designs, incorporating lessons learned and innovative technologies, provided Anadarko with



**TABLE 1:**

Project	Concept selection to cutting first steel	Reduction in fabrication man hours	Reduction in engineering man hours	Major topsides equipment procurement cycle
Lucius hull	18 months	-	-	-
Lucius topsides	22 months	-	-	22 months
Heidelberg hull	5 months	18%	15%	-
Heidelberg topsides	12 months	22%	33%	11 months

cost savings and schedule reductions in reaching first production. Additionally, Wood Group Mustang provided topsides design for Anadarko’s Marco Polo TLP and Independence Hub FPU.

For Lucius and Heidelberg, Wood Group Mustang’s goal was to again assist Anadarko in optimizing project economics through cost and schedule efficiencies. The approach was to provide a flexible solution that would allow further expansion of both facilities as they integrated production from future subsea tiebacks in adjacent blocks. As with many of its projects, design elements were standardized based on prior successes and lessons learned.

Changes were limited to only those that would be technically required to operate the facility. As the design for Lucius progressed, revisions were incorporated into early documents for Heidelberg, accelerating the FEED for that project.

The design package created by Wood Group Mustang was an essential part of achieving the financial investment decision (FID) for the two developments. For Heidelberg, the “copy” method enabled a reduction in pre-engineering, procurement and construction phases. The common package elements of Lucius enabled swift production of a complete set of engineering deliverables including process and instrument diagrams for Heidelberg.

Coupled with equipment standardization, Wood Group Mustang relied heavily on close communication with the Anadarko project teams and other participants chosen for their experience and continuity. Using Lucius equipment information, engineering and established processes, the company was able to fine-tune its procurement and contracting strategies for Heidelberg, dramatically shortening cycle times.

The approach allowed the cutting of first steel for the topsides to be done with confidence within one month after sanction. Modularization of several production components facilitated the required onshore and offshore lifts for the 14,000-ton operating topsides.

Personnel safety and environmental protection are high priorities for Anadarko and its project participants. During Lucius’ engineering phase Wood Group Mustang assisted Anadarko in developing additional procedures, analyses and documentation as is now required in the post-Safety and Environmental Management Systems regulatory environment. The company was part of reviewing and/or developing additional or modified safe work procedures, documentation, implementation and reporting that was valuable to the Lucius project and that will largely carry over to Heidelberg.

The safety culture embedded within the project participants enabled the Lucius project to be completed with more than 10 million hours and a total recordable incident rate of 0.38. This achievement, along with the experience gained during the development of Lucius, will be used when building and, if necessary, modifying methods and procedures for the Heidelberg facility.

**Reduction in man hours**

The Lucius-Heidelberg platform duo has already produced tangible results in efficiency and financial savings.

The Heidelberg facility is on schedule to achieve first production in mid-2016, improving slightly on the cycle time for Lucius. Its pre-FEED and FEED phases have already reduced man hours by more than 60% with benefits extending throughout detailed design and fabrication.

As Table 1 shows, the schedule compression has, additionally, led to significant fabrication man-hour reductions on both the hull and topsides. Heidelberg’s procurement efforts have resulted in a 50% cycle reduction for topsides equipment modules, further reducing costs.

The combination of participant, design and procedural continuity, world-class experience and close communication among project teams should deliver the results Anadarko, Wood Group Mustang and the other partners expect. The expectation is that this will likely result in total facilities project cost savings running into hundreds of millions of dollars on these large-scale, world-class megaprojects. **E&P**

# Making deals in the Delaware Basin

Operators see value in Permian acreage with stacked pay and good economics.

## Staff Report

The Permian's Delaware Basin has switched its spotlight back on as recent deals have attracted money and talent to the play.

On May 12, Carrizo Oil & Gas Inc. said it has entered a farm-out agreement in the basin and plans to begin an operated drilling program later this year. The participant was not disclosed.

Emerald Oil Inc. said May 11 that it also has entered into an agreement with undisclosed sellers to acquire core Delaware Basin acreage in Lea and Eddy counties, N.M., for \$75.2 million cash.

Jonathan D. Wolff, analyst at Jefferies, said Carrizo continues to grow its assets and generate value without straining the balance sheet.

To fund the Delaware Basin activity, Carrizo has allocated \$30 million to its 2015 drilling and completion capex plan, increasing it toward \$470 million to \$490 million. The company's 2015 land and seismic capex plan remains unchanged at \$35 million.

Wolff said the deal was largely anticipated and should be well received by the market.

Carrizo plans to drill three horizontal wells during 2015 but, due to the timing of completion and hookup for the wells, it doesn't expect material production from the play in 2015.

Carrizo said it will be the operator of the wells and expects to have an average working interest of at least 80% in them. As part of the acreage acquisition cost, Carrizo will carry its partner on the wells.

Carrizo's agreement with a larger operator gives it the right to earn about 2,800 net acres in eastern Culberson County, Texas. The deal brings the company's acreage position in the play to more than 20,000 net acres and offsets Carrizo's existing posi-

tion there. That gives the company the ability to build a contiguous nine-section unit where it has the potential to drill about 30 long-lateral wells on 305-m (1,000-ft) spacing in the Upper Wolfcamp zone.

Wolff said that Carrizo's deal "superficially" amounts to 2,800 net acres but has the potential to add meaningful value in a number of ways.

He estimates the company could efficiently drill up to 48 Wolfcamp A wells at 2,286-m (7,500-ft) laterals and 200-m (660-ft) interlateral spacing on a contiguous position.

In addition, the acreage could be prospective for the Wolfcamp B, which would represent upside to inventory.

"We also note that, while the wells are gassier, other operators have had some success drilling higher-rate Wolfcamp D wells in the area," he said.

It's also likely Carrizo can continue to do more farm-outs with the same partner going forward—building its northern Delaware Basin position well beyond its current acreage.

S.P. "Chip" Johnson IV, Carrizo's president and CEO, said the company has watched the Delaware Basin for a few years and will drill its first operated well later this year.

In New Mexico, Emerald picked up 10,746 net acres with 80% working interest, 100% operated in Lea and Eddy counties. Emerald said it will have access to multi-stacked oil-weighted pay zones prospective for the Avalon Shale;

first, second and third Bone Spring sand; and Wolfcamp Shale.

Emerald plans to drill five net Delaware wells for the remainder of 2015 at up to \$38 million.

The company paid about \$7,000 per acre.

## Delaware debut

Ring Energy Inc. is making its debut in the Delaware Basin with the addition of acreage that will nearly double its production in West Texas.



**Emerald Oil picked up 10,746 net acres in New Mexico's Eddy and Lea counties with 80% working interest. The dark green shaded area on the map represents target assets. (Source: Emerald Oil)**

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## Generator technology improves rig engine response times

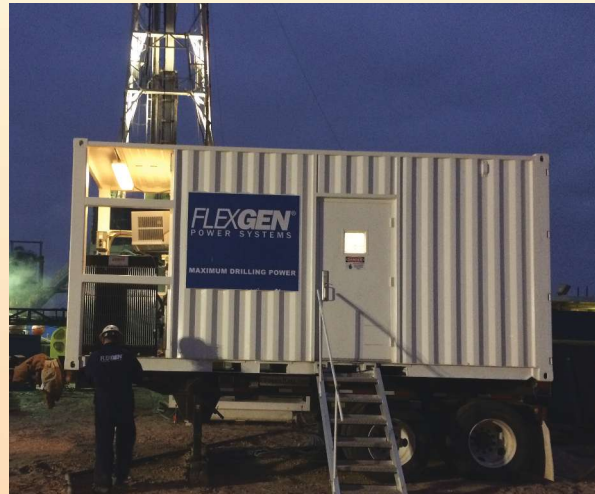
Josh Prueher, FlexGen Power Systems

**T**hink of pulling up to a stoplight and seeing a school bus or 18-wheeler in the right lane. The natural instinct is to move to the other lane because that bus will start slowly and take a while to get up to speed.

Drilling rigs have a similar power problem. When they begin drilling into the ground or are tripping in or out of the hole, drilling operations require a large amount of power during a short amount of time. Current generator sets can't ramp up that fast, resulting in either a slow response time or the need for additional generators. As a result, operators have to have more engines or drastically oversize the engines they have to handle those large transient loads. This increases fuel and maintenance costs while at the same time increasing emissions.

The technology behind the FlexGen Power Systems' Solid State Generator eliminates those problems by plugging directly into the drive house of a diesel, dual-fuel or gas rig to smartly monitor the voltage and frequency on the rig and works to dynamically manage power loads, allowing drastic improvements in engine response times.

Using solid-state generator technology reduces overall capex for power generation and power distribution by reducing the number of generators operators need to meet their existing power demands. Moreover, by operating generator sets at their higher average loads and turning generators off while using energy storage to power the loads, companies can see significant fuel savings. By elim-



**A worker reads real-time rig data showing the performance of the FlexGen Solid State Generator. (Source: FlexGen Power Solutions)**

inating load transients and running generators only at their optimal settings, users can reduce hazardous emissions and maintenance requirements. Finally, by eliminating voltage and frequency variability along with power factor correction, customers can realize improved power quality and performance.

FlexGen Solid State Generator technology has been operating on drilling rigs since September 2014, and the company reported that the technology has cut fuel costs by 15% to 25% and maintenance costs by 35% to 45% while also reducing rig blackouts and drilling time.

Ring said May 26 it signed an agreement with Finley Resources Inc. to acquire 14,000 net acres in Culberson and Reeves counties, Texas, for \$75 million.

Ring will be the operator of the properties and have an approximate 98% working interest and average net revenue interest in excess of 78%.

Current net daily production from the properties is about 1,300 boe/d, about 80% oil. The initial proved developed producing reserve is an estimated 4.7 million net boe with a PV-10 value of about \$128.5 million, according to Cawley, Gillespie and Associates.

The acquisition will nearly double Ring's daily produc-

tion and should drive nice additional revenues and cash flow, said Jason Wangler, analyst at Wunderlich Securities Inc., in a report.

Pro forma for the acquisition, Ring will have more than 2,750 boe/d of current net daily production from its Permian Basin assets and more than 45,000 gross (32,000 net) acres in the region. The company currently has acreage in the Permian's Central Basin Platform, primarily in Gaines and Andrews counties.

Management is currently evaluating drilling locations on the acquired acreage and plans to announce its findings after closing the transaction.



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Jeff Grampp, senior research analyst, Northland Capital Markets, said in a report that drilling locations will be vertical, targeting stacked pay intervals at 915 m to more than 1,830 m (3,000 ft to more than 6,000 ft). This should result in “relatively inexpensive well costs, fairly similar to development of its existing Andrews County acreage.”

Management also sees potential to expand around this new position and create another core growth area, he said.

“While the lack of near-term horizontal potential may make the acquisition appear less exciting, we still view the move as a strong positive given favorable terms and strategic fit with Ring’s core competency of vertical development,” he said.

### Permian stacks up

RKI Exploration & Production LLC is not immune to the effects of the commodity price downturn, but the E&P has positioned itself to ride it out.

Specifically, that position is a contiguous one, concentrated on 90,000 acres of the Permian Basin, mostly in Eddy County, N.M., and Loving and Reeves counties, Texas. Privately owned RKI likes liquids, and this acreage offers liquids-rich stacked pay opportunities, Ronnie K. Irani, the company’s founder, president and CEO, told attendees at Hart Energy’s DUG Permian Basin Conference & Exhibition in May.

“We’ve stayed intentionally under the radar and just gone about our business, which is about drilling and finding oil and gas reserves,” Irani said.

Irani reminded the audience that not all drilling is horizontal.

“We’ve drilled 118 vertical Delaware [Basin] wells,” Irani said. “I’ll submit to you that the vertical Delaware economics are as good as anything you’ll hear today [at the conference].”

RKI is active in four plays in the Permian, including its current favorite, Wolfcamp. The company has also drilled in the Bone Spring, Avalon Shale and Delaware Basin.

“In the Delaware, you drill vertical wells,” he said. “It’s a very thick section, it’s multilayered, and vertical wells work best at this point. We drill them on 40-acre spacing. It’s oily and great economics, so we’ll continue to do that.”

RKI’s operations are focused on the Powder River Basin in Wyoming and the Permian. Before prices crashed, the company operated 11 rigs—five in the Powder and six in the Permian. Now it is down to four, including three in the Permian.

“Part of the reason for slowing down was not knowing what was ahead of us as we headed into the dip in oil prices,” Irani said. “We’re currently at four, looking at adding one in each of the basins in the next month or so and by year-end. We plan to get up to six in the Delaware and at least three in the Powder. We feel like it’s picking back up again.”

RKI relies on oil and liquids for between 70% and 75% of its production in both basins. To keep the wells flourishing, the company has relied on technology.

While allowing that costs have come down in the oil patch, Irani pointed to the combination of innovations like pad drilling efficiencies, drilling optimization and zipper fracks that has reduced the price of drilling a well from \$9.7 million to \$6.8 million in the Wolfcamp. **E&P**

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**MERITORIOUS AWARDS  
FOR ENGINEERING INNOVATION**



From left, Matea Ropoama, Dustin Childers and Matt Morey of Archer receive their award from Russell Laas. The company topped the floating rigs and systems category with the Archer Emerald.



Peter Lawson accepts the award for Baker Hughes' CENesis technology, winner of the IOR/EOR category, from Jennifer Presley.



CNPC won the intelligent systems and components category for its Smart Driller Indicator technology. From left are Wu Qi, Wang Tiejun, Cui Meng, Wang Haige, Russ Laas, Zhang Hanliang and Zhao Yerong.



Halliburton's AccessFrac IntraCycle Stimulation Service won the hydraulic fracturing/completions category. From left are Matthew Lahman, Richard Gonzalez, Rhonda Duey and Nick Gardiner.



Hank Rogers and Ari Kar accept the award for Halliburton's Buoyancy Assisted Casing Equipment assembly, winner of the onshore rigs category, from Rhonda Duey.



Halliburton's CoreVault system won the formation evaluation category. From left are Matthew Lee, Shankar Narayan, Rhonda Duey, Soraya Brombacher, Tony van Zuilekom and David Topping.



Halliburton took home top honors in the HSE category with its Environmentally Distinctive Burner. From left are EJ Newell, Abdalla Awara, Rhonda Duey, Hossam El Assal and Edgar Almanza.



The winner of the drilling fluids/stimulation category was Halliburton's SaltShield. From left are Rahul Patil, Kris Ravi, Ari Kar and Rhonda Duey.



Nick Cronin, Andrew Coit, Steve Berkman, Tony Pink, Henry Mata, Steve Barton and Luke Jordan from NOV receive their award for their Drilling Automation System and Optimization Service from Scott Weeden. The technology won the intelligent systems and components category.



Dan Themig from Packers Plus receives an award for the company's Inferno System, which won the hydraulic fracturing/completions category, from Russ Laas.



Razali Ibrahim of Petronas receives the award for his company's Smart Centralized Fiscal Metering Supervisory System from Russ Laas. The system won the intelligent systems and components category.



Schlumberger's EPCON Dual Compact Flotation Unit won the water management category. From left are Martha Dutton, Emmanuel Delvaux, Bengt Arne Nilssen, Amir Nessim, Rhonda Duey, Karsten Rabe, Lars Hardli and Oktay Sancar.



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**The Schlumberger GeoSphere system won the drilling systems category. From left are Bruce Miller, Jean Seydoux, Uchechukwu Ezioba, Rhonda Duey, Paul Mitchell and Betty Silva.**



**Chad Harkness, Scott McDonough, Jiaqing Yu, Sandeep Tammineni, Kesh Keshavan, Mike Azar, Allen White, Jason Gregg, Charles Douglas and Chuck Muren receive their award from Rhonda Duey for Schlumberger's StingBlade, winner of the drillbits category.**



**Floyd Broussard (left) and Aaron Scollard receive their award from Rhonda Duey for Schlumberger's Petrel 2014 User Experience, winner of the exploration category.**



**John Livois, right, receives his award from Mark Thomas for Weatherford's RedEye technology, winner of the subsea systems category.**



**Weatherford's Rigless Light Duty Unit won the marine construction category. From left are Delaney Olstad, Mark Thomas, Bert Blanchard and Keith Wicker.**

# Moving CO<sub>2</sub> EOR offshore requires higher prices

Technically it's possible. Economically it needs to make sense.

**Bill Pike, National Energy Technology Laboratory**

The Gulf of Mexico (GoM) Outer Continental Shelf (OCS), an important domestic petroleum province, accounts for about 20% of total domestic crude oil production. Since reaching a peak of 1.54 MMbbl/d in 2003, OCS oil production has declined to 1.23 MMbbl/d as of mid-2013. While there is optimism that new discoveries in the deep and ultradeep waters of the OCS will reverse this decline, another option seems to offer even more promise—the application of CO<sub>2</sub> EOR. Under the Outer Continental Shelf Lands Act, the U.S. Department of Interior's (DOI's) Bureau of Ocean Energy Management (BOEM) has statutory authority to permit the use of CO<sub>2</sub> EOR on existing oil and gas leases on the OCS.

## Significant benefits

The use of CO<sub>2</sub> EOR in the OCS would provide numerous benefits, including:

- Increasing the volumes of economically viable domestic oil reserves and production, including adding significant federal royalty and tax revenues;
- Providing a market for CO<sub>2</sub> emissions from Gulf Coast electric power and industrial plants, helping “buy down” the costs of CO<sub>2</sub> capture; and

- Providing secure locations for storing CO<sub>2</sub>. In addition to the benefits above, the U.S. Department of Energy (DOE) recognizes that offshore storage of CO<sub>2</sub> provides several key advantages over storage on land:
  - Locating sequestration sites away from heavily populated onshore areas avoids storing material beneath a populated area and reduces the difficulty of establishing surface and mineral rights for storage sites;
  - Offshore storage reduces risks to underground sources of drinking water; and
  - Offshore CO<sub>2</sub> pipelines could use already existing corridors and oil and gas infrastructure, thus reducing upfront capital costs.

## The OCS prize

Three distinct resource targets exist in the GoM OCS for CO<sub>2</sub> EOR: (1) mature shallow-water oil fields; (2) more recently discovered deepwater oil fields; and (3) undiscovered oil fields, primarily in deep and ultradeep waters. While current CO<sub>2</sub>-EOR technology applied to the OCS would yield significant improvements in production and recovery factors, with “next-generation” CO<sub>2</sub>-EOR technology, the offshore GoM offers a substantial prize—nearly 15 Bbbl of additional oil recovery (Table 1) and storage for 3.9 gigatonnes of CO<sub>2</sub> (equal to 40 years of CO<sub>2</sub> capture from 20 GW-size coal-fired power plants),

The estimates of oil recovery and CO<sub>2</sub> demand from applying CO<sub>2</sub> EOR to discovered shallow- and deepwater GoM oil fields are based on detailed reservoir-by-reservoir analyses. The estimates of oil recovery and CO<sub>2</sub> demand from applying CO<sub>2</sub> EOR to undiscovered GoM oil fields are based on extrapolation of results from existing deepwater oil fields to the BOEM's assessment of undiscovered GoM OCS oil resources.

## Economic viability

The CO<sub>2</sub>-EOR potential in the Gulf of Mexico is governed by three key factors:

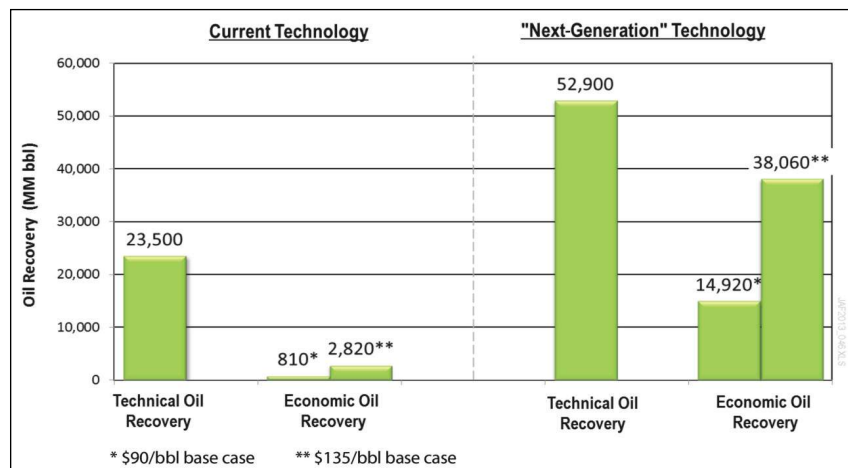


Figure 1. Economical CO<sub>2</sub> EOR will rise considerably with newer technology. (Source: NETL)

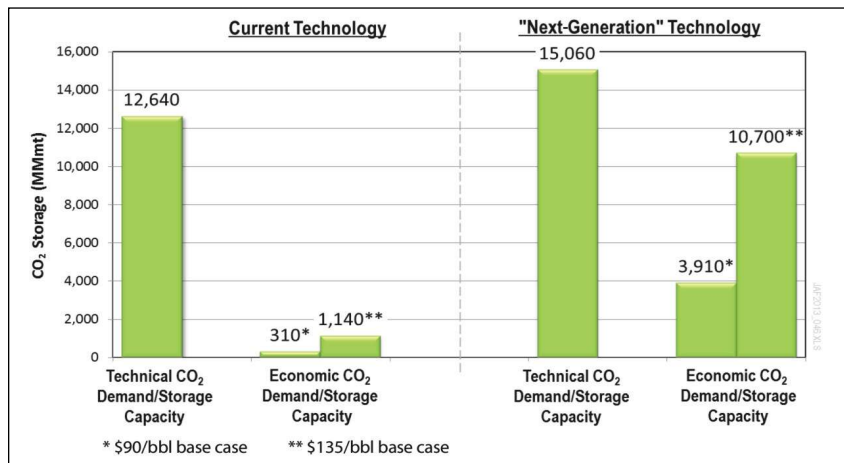


Figure 2. Better technology also will enable the storage of CO<sub>2</sub>. (Source: NETL)

- The performance level of CO<sub>2</sub>-EOR technologies, current and next-generation;
- The cost of CO<sub>2</sub> delivered to the offshore oil field. The most recent study by DOE’s National Energy Technology Laboratory (NETL) uses \$50/mt (consisting of a CO<sub>2</sub> purchase price of \$30/mt plus \$20/mt for offshore CO<sub>2</sub> transportation); and
- The world oil price. NETL examined the CO<sub>2</sub> EOR and CO<sub>2</sub> storage potential using an oil price of \$90/bbl and a future, higher oil price of \$135/bbl.

### Technology, other factors

NETL’s in-depth reservoir-by-reservoir analysis shows that the volumes of economically viable oil recovery and CO<sub>2</sub> demand vary by nearly an order of magnitude, depending on the efficiency and sophistication of available offshore CO<sub>2</sub>-EOR technology.

- Current CO<sub>2</sub>-EOR technology. With today’s moderate-performance CO<sub>2</sub>-EOR technology (current technology), an oil price of \$90/bbl and a CO<sub>2</sub> cost of \$50/mt, economically viable oil recovery and CO<sub>2</sub> demand from the GoM OCS are modest:
  - 810 MMbbl of incremental oil, and
  - 310 million mt of CO<sub>2</sub> demand.
- Next-generation CO<sub>2</sub>-EOR technology. Substituting higher performing next-generation CO<sub>2</sub>-EOR technology (oil price of \$90/bbl and CO<sub>2</sub> cost of \$50/mt), the economically viable oil recovery and CO<sub>2</sub> demand from the GoM OCS increase by more than tenfold:
  - 14,920 MMbbl of incremental oil, and
  - 3,910 million mt of CO<sub>2</sub> demand.

While next-generation technology improves oil recovery efficiency by about half, the great bulk of the impact is from the much greater number of offshore oil fields that become economically viable. The combination of more efficient use of CO<sub>2</sub> and higher recovery per well are the main reasons for the sharp increase in the number of economically viable oil fields under next-generation technology.

In reviewing these results, it is useful to recognize that a major portion of the oil fields holding substantial original oil in place (OOIP) were screened out as being too small or too lean for

CO<sub>2</sub> EOR. Specifically, for the shallower water areas, 80% of the oil fields holding nearly half of the OOIP were screened out; for the deepwater, half of the oil fields holding about a third of the resource were screened out.

Higher oil prices of \$135/bbl would materially improve the oil recovery and CO<sub>2</sub> demand potential that would result from applying CO<sub>2</sub> EOR to OCS oil fields. Figures 1 and 2 illustrate the oil recovery and CO<sub>2</sub> storage potential from the use of current vs. next-generation CO<sub>2</sub>-EOR technologies at both \$90/bbl(\*) and at \$135/bbl(\*\*).

Table 1. CO<sub>2</sub> EOR Offshore Resource Assessment

	Current CO <sub>2</sub> -EOR Technology	"Next Generation" CO <sub>2</sub> -EOR Technology
Oil Recovery	(MMbbl)	(MMbbl)
Shallow Water	390	3,260
Deepwater	80	2,100
Undiscovered	340	9,560
<b>Total</b>	<b>810</b>	<b>14,920</b>
CO <sub>2</sub> Demand	(MMmt)	(MMmt)
Shallow Water	150	720
Deepwater	30	580
Undiscovered	130	2,610
<b>Total</b>	<b>310</b>	<b>3,910</b>

(Source: NETL)



The U.S. Energy Information Agency's Annual Energy Outlook 2013 projections indicate an oil price of \$135/bbl would be reached by the year 2030. In addition, conversion of empty offshore natural gas pipelines to CO<sub>2</sub> transportation could lower CO<sub>2</sub> costs by \$10/mt or more. Most importantly, incentives for capturing and storing CO<sub>2</sub> with EOR could make large volumes of affordable, market-competitive Gulf Coast CO<sub>2</sub> supplies available for the GoM offshore EOR industry.

### Need for prompt action

There is considerable urgency for implementing CO<sub>2</sub> EOR in the offshore oil fields of the OCS.

- Shallow-water oil fields are nearing abandonment. The great bulk of the shallow-water (less than 305 m [1,000 ft] of water depth) GoM oil fields are mature and near abandonment, having produced 95% or more of their original proved reserves. Once these fields are abandoned and

their platforms removed, the costs of conducting CO<sub>2</sub> EOR or storing CO<sub>2</sub> in these oil fields increases significantly.

- Deepwater oil fields would benefit from early CO<sub>2</sub>-EOR implementation. Much of the oil resource in the deep waters of the GOM is in newly discovered (or still undiscovered) oil fields. As illustrated by the case study of the super-giant Lula oil field in the ultradeep waters of offshore Brazil, early implementation of CO<sub>2</sub> EOR at newly discovered oil fields appears to offer significant economic benefits, including higher volumes of economically viable oil recovery and accelerated opportunities for storing CO<sub>2</sub>.

While the move to offshore CO<sub>2</sub> EOR in the GoM will await increased oil prices, it is imperative that industry and government prepare the way. Recent studies by DOE and DOI are doing that. To access the most recent DOE report, go to: <http://netl.doe.gov/research/energy-analysis/publications/details?pub=e185884c-2423-47bb-a295-23614b4df5d3> **ESP**

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# The overhead of inertia

The costs of centralized business system decisions often outweigh the benefits.

**Damien Moriarty, Retriever Communications**

Centralization of information systems is a common strategy to reduce overheads by allowing shared services to be reused across disparate business units and projects. But this presents a challenge in these services in terms of meeting the diverse needs of all projects in a large organization. While there may be efficiencies in centralization, what is the true cost? Asset inspection activities can highlight some of the issues of information system centralization and how they can be managed.

The nature of standardization on central systems is that blanket policies are defined based on the minimum inspection requirements of all systems, the example being the inspection points and activities for an asset to manage its performance. In effect, these “minimum requirements” are the most stringent requirements of all projects applied across all projects. This creates overhead as staff on these projects either comply with these additional requirements or invent ways to work around them. Project staff will use IT systems according to their requirements rather than the intended use of other projects. Shoehorning systems into processes that don’t fit has a significant impact on auditability as data entry fields are not used for consistent purposes. This removes the ability to compare performance metrics across projects and systems.

While some may say disparate systems have the same restrictions, it is at least accepted that data migration is required for analysis as opposed to the false sense of security a single system used for different purposes provides.

This is the source of the true cost of centralization—

systems designed to improve onsite efficiency and compliance see their expected returns eroded through a poor match to the site requirements. Rather than facilitating the work being completed, the system requires additional effort from site staff in its daily use. These costs are experienced throughout the project life cycle.

## Requirements analysis

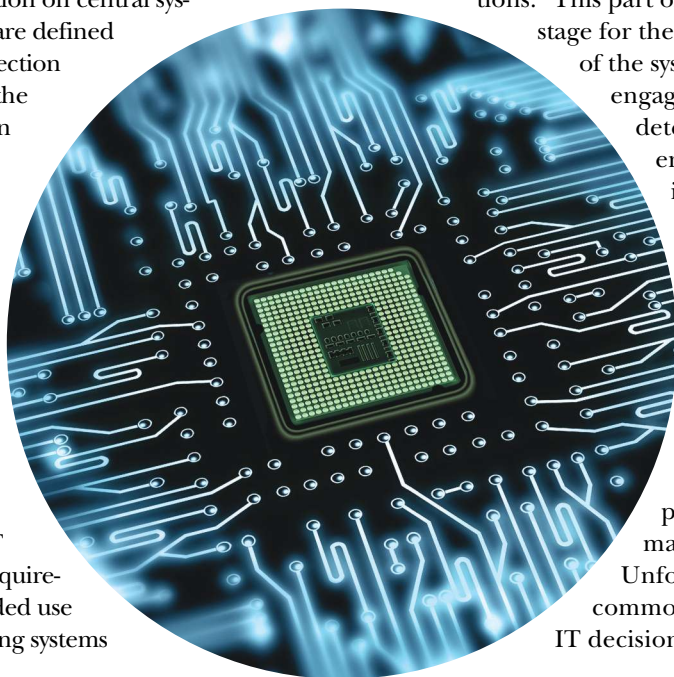
Initial requirements analysis can be challenging as gaps emerge between the system and the realities of the site. Process standardization is one thing, but people do not respond constructively to the need to change the way they work because “that’s how the new system func-

tions.” This part of the project often sets the stage for the implementation and rollout of the system. The level of user engagement or resistance will be determined by stakeholder engagement and buy-in at the initial requirements stage.

On completion of the requirements analysis there are often gaps that require further work. These are closed individually, either through customization or through change management; the system is made to match the process and the process is made to match the system.

Unfortunately, the latter is more common when adhering to central IT decisions. This also tends to include substantial compromises in system capability and technology.

Centralized strategies are slow-moving since there is a great deal of inertia in larger systems. System needs are reviewed and defined, often as part of a six-month project. A set of vendors is engaged and one selected, taking another three months. An initial implementation is completed for a single project, including detailed requirements review and site rollout. This often takes up to two years. The results are



**Localized IT decision-making can increase process efficiencies.**



then reviewed to determine the return on investment of the project and the implementation success, completed up to one year after go-live. If they are favorable, the solution becomes the corporate standard and is either retro-fitted to existing projects or put on the shelf as corporate standard methodology. At this point, the technology is three years old, and the requirements match is nearing four. With that level of investment, reviews may not come for 10 years. The net of this is that as the implementation commences on a new project, the technology is obsolete before go-live for systems with an expected life of up to 10 years.

### Cost of overhead

Training and change management require a greater effort as it isn't simply the extension and improvement of the existing site process. It can also be a vast change implementing constraints of the central system not relevant to the project or, in some instances, the organization itself. Initial rollout of the system often takes longer as the change management requirements increase. This erodes the initial returns of the system as only a portion of the users are rolled out during the initial phases. There is also an increase in the upfront costs as project staff need to be retained for the duration of the implementation cycle and, in many cases, all licenses, software and infrastructure for the system have been paid for up front.

While the impact of compromises and technology mismatches are seen to diminish at full deployment, the cost overheads remain. As with any system used outside its original design, there is often additional technology and process overhead in its use. This creates additional maintenance requirements and impedes process efficiency, eroding the returns expected from the business case.

### Local decisions

Localized IT decision-making allows for a far more agile approach to technology and system selection. Assessments can be made comparing current technology to current requirements and ensuring a greater functional match and reduced limitations. Since the local project team makes the decisions, there is a far greater sense of ownership of the

new system, driving a higher level of user acceptance.

Centralized decisions are made due to the need for adherence to standards around security and manageability. These goals can also be achieved through localized decisions and don't require centralization of all systems. Adequate guidance on standards can ensure consistency and policy adherence; however, this needs to be pragmatic and not impact the ability to implement the required business functions. Collaboration with local decision-makers on IT standards can ensure that these standards are met rather than subverted. This is not distinct to distributed IT decision-making but rather a requirement for all IT endeavors. In addition to this, security requirements can be facilitated by the separation of responsibilities of business applications from IT infrastructure. All infrastructure architectures and projects can be managed as a central service, with business applications implemented on standardized infrastructure. This can include private networking, local and remote, fixed and wireless, and standardized hosting options meeting all availability and disaster recovery requirements.

Returning to the asset inspection example, we can see how this can be implemented. Local project requirements can be reviewed and vendors engaged. Systems can then be designed according to requirements of the project, including accounting for a high level of process variability across a range of sites. An example of this is the large number of wells common in unconventional energy projects. Hardware technology can be chosen based on current capabilities, and corporate standards can guide the

choice of these technologies based on security and manageability requirements. The project is then implemented on standardized infrastructure.

While core infrastructure and security standards are (and should be) defined centrally, the nature of business systems dictates a higher level of end-user engagement. This is not always possible with central IT decisions, and as the complexity of the business process increases, so does the need for decisions on these systems to be left in the hands of those responsible for the processes themselves. Centralization may seem to reduce costs, but this is achieved at the expense of process efficiencies justifying the implementation of these systems. **E&P**

People do not respond constructively to the need to change the way they work.

### System allows use of mud pulse and EM telemetry concurrently

Enteq Upstream PLC has introduced the Twin Electro-Magnetic Telemetry System into its product portfolio. The system is used for high-speed electromagnetic (EM) MWD telemetry as an alternative or supplement to mud pulse telemetry to transmit drilling data. The system enables the use of mud pulse and EM telemetry concurrently, giving quicker EM data transmission while offering full redundancy, a press release said. The Twin Electro-Magnetic Telemetry System is based on EM wave technology used for transmitting drilling data uphole. The EM telemetry system encodes downhole MWD data into low-frequency EM waves, and the signal is transmitted from the tool through the formation and detected on the surface. The Twin system works deeper and faster and is much more power-efficient than previous EM systems, according to the release. The Twin Electro-Magnetic Telemetry System has been developed and commercialized in cooperation with Leading Magnetic Design and Drill-Tek. Enteq has agreements with the two companies to further develop and market the technology, which is based on Enteq's XXT downhole electronics platform. *enteq.com*



**The FTeX advanced formation pressure testing service provides critical formation data accurately and efficiently. (Source: Baker Hughes)**

### Wireline service delivers precise pressure data, identifies well production potential efficiently

Baker Hughes has released its FTeX advanced formation pressure testing service, which uses downhole automation and real-time control of an intelligent packer and pump configuration to deliver critical formation data—including pressure profiles, fluid contact and mobility information—reliably, accurately and efficiently, according to a company press release. The data offer an earlier and better understanding of the reserves in place so operators can quickly identify the production potential

of a well. Leveraging adaptive software, the FTeX service automates the operation sequence downhole to optimize tool controls and test parameters with minimal input from surface personnel—reducing data inconsistencies and inaccuracies that often result from manual testing, the release said. The service adapts to the formation response encountered during the initial drawdown to define the optimal parameters for subsequent drawdowns in real time, leading to increased data accuracy and efficiency. Running the FTeX service with other wireline technologies reduces the number of logging runs, saving rig time and cost. *bakerhughes.com*



**GE's new SWSR nanofiltration membrane eliminates almost all sulfate from injection water in offshore oil production. (Source: GE)**

### Membrane removes seawater sulfate from injection water for offshore production

GE launched a new water treatment technology for the upstream oil and gas market. GE's seawater sulfate removal (SWSR) nanofiltration membrane eliminates almost all sulfate from injection water in offshore oil production. The membrane removes sulfate to drastically reduce scale and corrosion in the injection well, which can reduce oil recovery and plug the well, a press release said. It also has excellent fouling resistance due to its three-layer membrane design and smooth surface. The new SWSR series is an advancement of GE's DK series nanofiltration membrane and provides a high transmission of sodium chloride into the permeate water to minimize operating pressures. It offers a physical barrier for any suspended particles, including bacteria, pyrogens and colloids. Additionally, the new membrane will help prevent strontium and barium sulfate scale in injection wells and will better mitigate well souring by reducing sulfate, according to the release. *ge.com*

### Expandable liner hanger system increases reliability in deepwater environments

Halliburton's Completion Tools business line introduced the VersaFlex XtremeGrip expandable liner hanger system, a high-performance expandable liner hanger that provides a compliant metal-to-metal seal with a fully bonded resilient elastomeric seal, a product announcement said. With a distinct design that offers enhanced bidirectional anchoring capabilities, it is designed to hang liner and seal off in temperatures up to 204 C (400 F) for oil and gas wells. The system has been tested to ISO 14310 V0 requirement on multiple sizes. The VersaFlex XtremeGrip system is ideal for use in deepwater and offshore applications where long liners must be deployed in high-temperature wells. The system is designed to minimize risks and maintain hang-weight capabilities in extreme environments. The ability of the system to rotate and reciprocate during cementing helps improve cementing results and reduce the need for costly remediation, the announcement said. The system has been run and set successfully in deepwater projects in Norway, Angola, Malaysia and the Gulf of Mexico. [halliburton.com](http://halliburton.com)

### Subsea wet gas meter reduces risk, strengthens production optimization strategies

Emerson Process Management has released its next-generation Roxar subsea Wetgas Meter for accurate production measurement, reduced risk and improved flow assurance in gas and gas condensate fields. Hydrates, corrosion, scaling and water coning in the reservoir represent the biggest challenges to offshore gas producers and are all caused by formation water breakthrough into the well. The new meter allows the earliest possible detection of water from gas wells. The new meter comes with water sensitivity, accuracy and rapid response together with the industry's first built-in salinity measurement system. The meter's microwave-based measurements and multivariate analysis functionality are operational in all field conditions and fluid compositions. The meter detects changes in water content of the flowing well at as little as 0.2 ppm. The next-generation Roxar subsea Wetgas Meter generates an uncertainty specification of  $\pm 0.02\%$  abs Water Volume Fraction at Gas Void Fraction 99% to 100%. [emersonprocess.com](http://emersonprocess.com)

### Network monitors seismicity in real time through life of asset

MicroSeismic Inc. released AlertArray, a real-time seismicity network that offers operators a single solution alternative to monitor seismicity during hydraulic fracturing and fluid injection operations. The AlertArray is capable of providing high-resolution event locations for various event types and magnitudes to establish a baseline for nat-

urally occurring seismicity prior to injection activities, according to a product announcement. The network for seismicity monitoring allows operators to improve field operations and mitigate risk cost-effectively. Additionally, AlertArray can be augmented with additional recording stations to allow operators to evaluate the performance of hydraulic fracturing completions while maintaining the ability to effectively pinpoint the safety of subsurface treatment activities in real time and through the life of the asset, the announcement said. The system is offered globally and is compliant with specific regional mandates. MicroSeismic's AlertArray is a hybrid network using the BuriedArray system combined with seismometers and is capable of spanning more than 25,900 sq km (10,000 sq miles). [microseismic.com](http://microseismic.com)



Trelleborg's MPU can be mobilized in a short time frame and sent straight to site to apply coatings. (Source: Trelleborg)

### Mobile unit enables onsite coating, increases project flexibility

Trelleborg's offshore operation has launched its new mobile production unit (MPU), a portable coating facility that will enable onsite coating of thermal insulation, passive fire and corrosion protection. The unit can be mobilized in a short time frame and sent straight to site to apply coatings such as Trelleborg's thermal insulation Vikotherm R2 and Firestop, a jetfire-resistant material. This increases project flexibility and reduces the costs and lead times associated with transporting parts to a specialist coating facility, a product announcement said. The MPU contains an extruder and a rotating spindle with the possibility for side extrusion of Vikotherm R2 directly to straight pipes of up to 12 m (39 ft). The extruder also is used to produce 25 mm thick Vikotherm R2 profiles for coating of complex geometries such as bends, valves and flanges. In addition, there are a number of vulcanization containers for up to 20-m (66-ft) pipes or structures. The MPU concept includes a conventional coating machine for coating of straight pipes for passive fire and corrosion protection. [trelleborg.com/offshore](http://trelleborg.com/offshore) **E&P**



# Egypt warms up Mediterranean market

Egypt has emerged from the turmoil of the Arab Spring to reestablish itself as the Mediterranean's most attractive offshore province.

**Mark Thomas**, Editor-in-Chief

**T**hink of the European offshore sector, and most people's thoughts turn to the cold waters of the North Sea and its relative lack of new projects. But activity in the far more welcoming waters of the Mediterranean Sea is warming up fast, with Egypt's offshore sector leading the way.

The Mediterranean is of course a well-established producing province in its own right, with more than

200 active offshore platforms on mature fields in its northern and southern waters. But while countries such as Spain, Italy and Greece have continued to struggle to find much to cheer them in their domestic waters in recent years, the well-publicized discoveries in the eastern Mediterranean offshore Israel have shown that its potential—especially for gas—remains more than achievable.

But to the south lies Egypt, a country that began producing offshore in the 1960s in the Gulf of Suez and which, after the 2011 revolution that caused a hiatus of

Egypt's offshore has produced a succession of substantial gas discoveries, the latest being BP's Atoll find in the East Nile Delta's North Damietta Offshore Concession, drilled by the *Maersk Discoverer* semisubmersible earlier this year. (Source: Maersk Drilling)





several years while the industry sat back and waited for the cards to fall, is now full speed ahead with its plans to secure its energy future.

## Energy security

In the vanguard of those efforts offshore in the Mediterranean is BP. Bob Dudley, the group chief executive, commented at the recent World Gas Conference in Paris, “The next challenge is that of energy security—connecting the energy with the people who need it—and doing that affordably. Gas has an increasing part to play here as countries are able to access more diverse sources of supply and develop more of their own.

“But energy security is not only about imports. It’s also about accessing domestic resources that have not yet been developed. We are now seeing examples around the world where such resources are being unlocked when you have the right conditions above the ground as well as the right resources below the ground. In our own business we have seen this at work in places such as Egypt, where we have just been able to sanction a \$12 billion investment package,” he continued.

Dudley was referring to the company’s long-established gas resources in the West Nile Delta. BP has done business in Egypt for 50 years and invested more than \$25 billion there as one of its largest foreign direct investors.

Through its joint venture (JV) interest in the Gulf of Suez Petroleum Co. (GUPCO), BP collaborates in producing 10% of Egypt’s current oil/condensate output, while its Pharaonic Petroleum Co. (PhPC) and Petrobel JVs produce 30% of the country’s total gas production.

The GUPCO JV operates nine offshore complexes and other satellites totaling more than 110 platforms.

## Investment of \$12 billion

But just four years after the revolution, BP has decided to really put its money where its mouth is and commit to its largest investment yet in the country.

The West Nile Delta (WND) agreement, signed in March, enables BP and its 17.25% partner DEA to develop 142 Bcm (5 Tcf) of recoverable gas reserves and 55 MMbbl of condensate from the North Alexandria and West Mediterranean Deep Water areas. With first

gas planned for 2017 and peak production penciled in to hit 36 MMcm/d (1.2 Bcf/d), equating to a quarter of the country’s current gas production, the impact of the first phase of this project on Egypt and its impetus on future activity levels in the wider Mediterranean market cannot be overestimated.

WND is BP’s first operated project in Egypt outside of a JV and will see it develop five fields initially in the two concessions. The 21-well development will tie in to existing, upgraded and new infrastructure and target gas and condensate in the Giza, Fayoum, Raven, Taurus and Libra fields, all lying between 65 km and 85 km (40 miles and 53 miles) offshore in water depths of up to 750 m (2,461 ft).

The Taurus and Libra fields in the North Alexandria concession will be a subsea development tied back about 35 km (22 miles) to the existing BG Group-operated Burullus West Delta Deep facilities. A recent project milestone saw the development drilling campaign get underway on the two fields.

## Large-bore trees

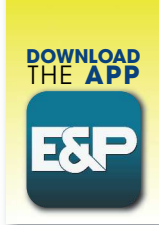
OneSubsea, the Cameron-Schlumberger JV company, was also awarded the contract to supply subsea systems for the Taurus Libra fields earlier this year. The scope of supply includes 10 large-bore gas trees and related subsea equipment. First deliveries are expected in first-quarter 2016.

The Giza, Fayoum and Raven fields in the West Med Deep area, meanwhile, will be two subsea-to-shore tiebacks over a distance of about 70 km (43 miles) to the onshore Rosetta plant. This will be modified for Giza/Fayoum and integrated with a newbuild adjacent plant for Raven. Field infrastructure will include new 24-in. gas lines, 6-in. mono-ethylene glycol lines and umbilicals.

BP said that the concessions hold the potential through future exploration to add an additional 142 Bcm to 198 Bcm (5 Tcf to 7 Tcf) of recoverable reserves that would significantly boost or extend the life of the WND project’s production plateau with additional multi-billion-dollar investments.

It has already confirmed a recent 100%-owned discovery in the North Damietta Offshore Concession in the East Nile Delta, where the deepwater Atoll-1 well, drilled by the *Maersk Discoverer*, hit about 50 m (164 ft)

BP said that the concessions hold the potential through future exploration to add an additional 142 Bcm to 198 Bcm of recoverable reserves.



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of gas pay in high-quality Oligocene sandstones. In 2013 it also discovered the Salamat Field, 15 km (9 miles) to the south.

### BP-BG collaboration

Development of the fields has only been economically viable because of the collaborative relationship between BP and its fellow U.K. operator BG Group after the latter's subsidiary BG Egypt signed a tie-in agreement with BP, which was the enabler for the whole WND project to get underway.

The Libra and Taurus fields are largely located within BP's North Alexandria concession but are being connected to BG Egypt's neighboring West Delta Deep Marine (WDDM) concession infrastructure. Gas from BP's fields will be processed at the BG Egypt-operated WDDM onshore facilities.

A portion of the Libra Field (the P80 channel) also straddles the boundary between the North Alexandria and the WDDM concessions, and production from this area will be regulated under a unitization agreement.

A separate agreement was also signed by BG Egypt with BP Egypt and DEA, whereby the right of use of the Rosetta onshore facilities will effectively be transferred from BG to BP/DEA as of mid-2016. BP plans to build new production facilities, integrating the existing Rosetta treatment plant with new HP/HT installations to process gas from the Giza, Fayoum and Raven fields from 2018. BG will continue to hold rights to the Rosetta concession and may process future gas through the WDDM facilities.

### HP/HT aspect

The HP/HT aspect is an important technology area for BP and is directly linked to its ongoing Project 20K initiative. The WND development is designated by BP as having "major project" status, with the operator planning to use some of its learnings from Project 20K on the development.

For Egypt, its most pressing need after emerging from the Arab Spring remains to fix its short- and long-term strategic gas supplies and continue its massive rebuilding process. This includes sealing deals to receive gas from projects offshore Israel in the Mediterranean such as Noble Energy's Tamar Field.

It has proved itself particularly innovative in this area, with a group of private customers in Egypt agreeing to buy at least \$1.2 billion of gas from Tamar and forming a simple but smart plan to use an old existing pipeline built originally to send gas the other way to Israel. The Tamar partners signed a seven-year deal with Dolphinus Holdings, which represents non-governmental, industrial and commercial consumers in Egypt. The deal sets out the supply of a minimum 5 Bcm (177 Bcf) of gas to be sold in the first three years.

The gas will flow via the pipeline constructed nearly a decade ago by East Mediterranean Gas, a company that once oversaw a long-since defunct Egyptian-Israeli gas deal. Egypt had been selling gas to Israel in a 20-year agreement, but that deal collapsed in 2012.

A new bid round also was confirmed earlier this year for Egypt, with eight offshore blocks in the Mediterranean up for grabs. Those offered are Block 1 (West Arish Marine), Block 2 (East Port Said Marine), Block 3 (North Rumana), Block 4 (North Raas Al-Ish Marine), Block 5 (West Timsah Marine), Block 6 (South Tinin Marine), Block 7 (North Hammad Marine) and Block 8 (East of Alexandria Marine). **E&P**

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# Legendary ‘Third Coast’

The GoM continues to astound.

Jennifer Presley, Senior Editor, Production

The Gulf of Mexico (GoM) is one of the world’s great petroleum basins, boasting a hydrocarbon-producing history that spans more than 100 years. While some could say the GoM is getting a little long in the tooth, the explorers and producers of this legendary petroleum province would argue that it is just getting its third—possibly fourth—wind and that a renaissance is underway. Driven by advancements in technologies that range from helping to decipher the resources lying under miles-thick layers of salt to safely tapping and recovering those resources in a variety of ways, the GoM continues to astound all that choose to work in it.

## Continental washbasin

The petroleum riches of the GoM are due to its unique geology and the richness of the many streams and rivers that flow into it, the greatest of which is the Mississippi River. It is a river known by many names: Old Man, Big Muddy or Great. From its start at Minnesota’s Lake Itasca, the Mississippi River flows through 10 states before emptying into the GoM. Forming the largest drainage system on the North American continent, the Big Muddy and its many tributaries drain all or parts of 31 U.S. states and two Canadian provinces between the Appalachian and Rocky Mountains, according to the U.S. National Parks Service.



**The GoM is the basin that the largest drainage system on the North American continent drains into, with the Mississippi River carrying sand and silt from all or parts of 31 U.S. states and two Canadian provinces between the Appalachian and Rocky Mountains. (Source: U.S. National Parks Service)**

It is a fertile system that has fed the GoM with sand, silt and more over the millennia, contributing to a hydrocarbon generation process that traces its beginnings back to the time of Pangea.

The GoM is a Mediterranean-type sea that measures about 1,600 km (994 miles) from east to west and 900 km (559 miles) from north to south and has a surface area of 1.5 million sq km (579,153 sq miles), according to the Gulfbase.org website.

The GoM basin resembles a large pit with a broad shallow rim. About 38% of the Gulf is comprised of shallow and intertidal areas (less than 20 m [66 ft] deep), the website said. The area of the continental shelf (less than 180 m [590 ft]) and continental slope (180 m to 3,000 m [9,843 ft]) represent 22% and 20%, respectively, and abyssal areas deeper than 3,000 m comprise the final 20%, according to the website.

The present GoM basin is believed to have had its origin in Late Triassic time as the result of rifting within the North American Plate at the time it began to crack and drift away from the African

and South American plates, the website said.

Intermittent advance of the sea into the continental area from the west during late Middle Jurassic time resulted in the formation of the extensive salt deposits known today in the GoM basin. It appears that the main drifting episode, during which the Yucatan block moved southward and separated from the North American Plate and true oceanic crust formed in the



central part of the basin, took place during the early Late Jurassic, after the formation of the salt deposits, according to the website. The basin has since been a stable geologic province characterized by the persistent subsidence of its central part, probably due at first to thermal cooling and later to sediment loading as the basin filled.

### Auspicious beginnings

Even legends have to start somewhere, and for the GoM's offshore oil and gas industry, that start would be at the Creole Field. Located 1.9 km (1.2 miles) from the shores of Cameron Parish and 21 km (13 miles) from the nearest coastal community of Cameron, La., the field was operated by Pure Oil Co. and Superior Oil Co. The 2,787-sq-m (30,000-sq-ft) platform was built on timber pilings in water depths of 3 m to 4.5 m (10 ft to 15 ft).

Years later, Kerr-McGee became the first operator in the world to drill "out of sight of land" at Ship Shoal Block 28. The Kermac No. 16 well stood in almost 6 m (20 ft) of water, 16 km (10 miles) at sea, according to the American Oil and Gas History Society website. The well was spudded Sept. 10, 1947, and on Nov. 14 the well came in at 40 bbl/hr. By 1984, the well would produce 1.4 MMbbl of oil and 8.7 MMcm (307 MMcf) of natural gas, according to the website. By the end of 1949, 11 oil and natural gas fields were found in the GoM with 44 exploratory wells, according to the National Ocean Industries Association.

The GoM has grown considerably in the years since Creole. Federal offshore oil production in the GoM accounts for 17% of total U.S. crude oil production, and federal offshore natural gas production in the Gulf accounts for 5% of total U.S. dry gas production, according to a U.S. Energy Information Agency fact sheet.

### Recent discoveries

Surrounded by the U.S. to the north and Mexico to the south, discoveries have been made on both sides of the maritime border.

On the U.S. side, major discoveries announced in 2015 include Chevron's Anchor prospect in the deepwa-

ter GoM. It is the company's second discovery in the deepwater Gulf in less than a year, according to a company-issued press release.

"The Anchor discovery, along with the previously announced Guadalupe discovery, are significant finds for us in the deepwater Gulf of Mexico. We had one of our best years with the drillbit in 2014, reporting more than 30 discoveries worldwide and adding an estimated 1 billion barrels of new resources to our holdings," said Jay Johnson, senior vice president for upstream, Chevron Corp., in the release.

The Green Canyon Block 807 Well No. 2 encountered oil pay in multiple Lower Tertiary Wilcox Sands. The well, which was spudded in August 2014, is located about 225 km (140 miles) off the coast of Louisiana in 1,580 m (5,183 ft) of water and was drilled to a depth of 10,287 m (33,749 ft). Appraisal drilling will begin in 2015.

At a June conference in Guadalajara, Mexico, Pemex CEO Emilio Lozoya announced the discovery of four new shallow-water fields in the GoM, according to a Bloomberg article.

The fields hold the potential for daily production of at least 200,000 bbl of oil and 4.8 MMcm (170 MMcf) of gas, Lozoya said following the Oil Workers' Conference. The wells, forecast to begin production within 16 months, are located close to the Cantarell Field, one of the world's largest when it was discovered in the 1970s.

The discoveries come after Mexico approved final legislation last year to allow foreign producers to explore and help

develop oil in the country for the first time in more than seven decades, Bloomberg reported.

"This is the first tangible result of the energy reform," Lozoya told reporters following the inauguration of the conference. "Pemex, thanks to the energy reform, is accelerating plans to incorporate private capital in exploration and production of our wells."

The discoveries were made in areas of the GoM that Pemex maintained last year as part of the noncompetitive bid round, known as round zero. They are close to 14 shallow-water blocks that private companies will bid on next month, the report said. **E&P**

Federal offshore oil production in the GoM accounts for 17% of total U.S. crude oil production, and federal offshore natural gas production in the Gulf accounts for 5% of total U.S. dry gas production.

# New RLWI vessel ready for duty in the Gulf of Mexico

As offshore operators seek to increase hydrocarbon recovery from existing reservoirs, the need also increases for systems capable of performing well intervention services on subsea wells to increase or maintain production in a safe and cost-efficient manner. One method of accomplishing these goals is through the use of riserless light well intervention (RLWI). When deployed on monohull vessels, RLWI systems offer an alternative to conducting operations on more costly drillships.

In fourth-quarter 2014 FTO Services, a joint venture between FMC Technologies and Edison Chouest Offshore, began a five-year lease of the *Island Performer*, its newest deep-water RLWI vessel.

The vessel's Ulstein X-bow and Ulstein diesel-electric propulsion system ensures exceptional performance with regards to fuel consumption, seaworthiness, speed, station keeping, stability and cargo capacity, according to Island Offshore's technical specifications.

*Island Performer* is capable of carrying out well interventions at depths of up to 2,000 m and pressures of 10,000 psi.

The DP3 vessel is 130 m (427 ft) long and is equipped with a 250-tonne active heave-compensated crane. The vessel's Operations+ feature allows uninterrupted operations should a substantial single failure occur such as the loss of generators or thrusters, according to the technical specifications.

The deck area features a horizontal skidding system to provide safe and efficient movement of subsea equipment modules to and from the moonpool. The skidding system features rails that are welded to the ship's main deck. System capacity is 60 t aft of moonpool and 100 t forward of the moonpool.

Equipped with FMC Technologies' RLWI stack, *Island Performer* is capable of carrying out well interventions at depths of up to 2,000 m (6,500 ft) and pressures of 10,000 psi. In addition, the highly specialized subsea support vessel features two ultraheavy-duty deepsea

ROVs provided by C-Innovation and a user-friendly control room. Designed to the Norwegian comfort class vessel specifications, the vessel can accommodate 130 persons in 40 single cabins and 45 double cabins. **ESP**

Vessel Facts	
Sector:	LWI/offshore construction/ subsea umbilicals, risers and flowlines/ROV
Owner:	Island Offshore
Vessel Design:	Ulstein SX121
Size (length):	130 m (427 ft)
Deadweight:	8,400 tonnes
Top Speed:	15.3 knots
Deck Area:	800 sq m (8,611 sq ft)
Operating Arena:	Worldwide
Classification:	DNV: +1A1
Accommodation:	130 persons



The *Island Performer* is the newest RLWI vessel in the FTO Services fleet. (Source: FTO Services)



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### SOUTH AMERICA

#### Esso's well hits oil offshore Guyana

A well drilled by Esso Exploration and Production Guyana Ltd. hit a significant oil discovery in the Stabroek Block offshore Guyana, Exxon Mobil Corp. said. The well found more than 90 m (295 ft) of high-quality oil-bearing sandstone reservoirs. It was drilled to 5,433 m (17,825 ft) in 1,743 m (5,719 ft) of water. Stabroek Block is 6.6 million acres and is about 193 km (120 miles) offshore Guyana. The well data will be analyzed in the coming months to better determine the full resource potential.

#### Brazil licensing round to launch in October

Brazil's 13th licensing round will kick off in October this year, Eduardo Braga, minister of Energy & Mining, said. Braga said the round under the concession model will launch with 269 onshore and offshore blocks going under the hammer. The blocks are in a mixture of mature plays, new frontiers and high-potential basins. In the offshore areas, 10 blocks will be offered in the Sergipe-Alagoas Basin, four in Jacuipe and nine in the Camamu-Almada Basin. There will also be seven blocks offered in the Espírito Santo Basin, three in the Campos Basin and 51 in the new frontier Pelotas Basin. The remainder will be onshore.

### AFRICA

#### Tortue-1 well finds more hydrocarbons offshore Mauritania

Kosmos Energy said that the Tortue-1 exploration well in Block C8 offshore Mauritania encountered additional hydrocarbons while drilling to total depth. Tortue-1 intersected about 10 m (32 ft) of net hydrocarbon pay in the lower Albian section, which is currently interpreted to be gas. This is in addition to 107 m (351 ft) of net pay encountered in the primary target, Cenomanian. The well was evaluating the Albian, having been drilled past the Cenomanian, the company said. Subsequent wells will test the seismic calibration of the Albian. No water was encountered in Tortue-1, Kosmos added. Tortue-1 is about 285 km (177 miles) southwest of Nouakchott in 2,700 m (8,858 ft) of water.

### NORTH AMERICA

#### Canada pledges new oil, gas emissions regulations

Canada has pledged to cut greenhouse gas emissions by about a third by 2030, partly by introducing new regulations on its oil and gas sector. Environment Minister Leona Aglukkaq announced the new pledge ahead of a UN climate summit in December. Canada will cut its emissions to 515 metric megatons by 2030, Aglukkaq said. The country isn't on pace to meet its previous goal and projects emissions to grow—not shrink—over the next five years. Emissions were 726 megatons in 2013, the most recent year for which data are available, and government figures show emissions are set to grow leading up to 2020.

#### Mexico's Round One offers onshore conventional fields

The next phase of Mexico's Round One includes an offering of 26 onshore conventional fields in the Burgos, Tampico-Misantla and Salinas-Sureste basins, Wood Mackenzie said. The key opportunities for companies looking for sizeable onshore fields will be the migrated service contracts and the Pemex joint ventures. New Mexican E&Ps can participate in this round, which has different qualification criteria from the shallow-water development round. Wood Mackenzie research analyst Pablo Medina said this round's licensing contract will have bidding variables that include additional royalty and work commitment. "Small players" could find the round beneficial, he added.

### MIDDLE EAST

#### GS Energy receives Abu Dhabi onshore oil fields stake

GS Energy Corp. secured a 3% stake in Abu Dhabi's largest onshore oilfield concession, joining Total SA and Inpex Corp. in a \$22 billion venture. The energy unit of GS Holdings Corp. will gain access to about 50,000 bbl/d for its share in the 40-year concession, the company said. GS Energy will pay state-owned Abu Dhabi National Oil Co. a signing bonus of \$670 million, it said in a regulatory filing in Seoul. Korea National Oil Corp. said it's joining GS Energy in the venture. By selecting GS Energy from South Korea and Inpex from Japan, Abu Dhabi is for the first time awarding stakes in its biggest onshore producing fields to companies from Asia, where the United Arab Emirates sells most of its crude.

### EUROPE

#### CGG extends seismic program in North Sea

CGG said that there is now a western extension of the Horda BroadSeis-BroadSource 3-D multiclient program



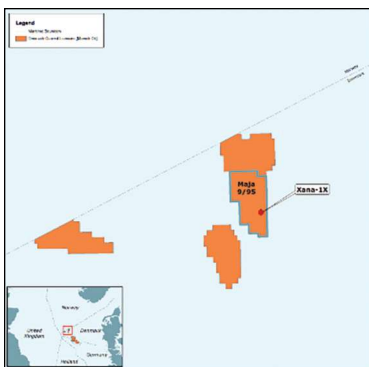
in the Northern Viking Graben area in the Northern North Sea offshore Norway and the U.K. The Tampen extension will add 17,000 sq km (6,564 sq miles) of data to the Horda survey program begun in 2014. The Tampen survey will cover a mature, high-potential area encompassing Statfjord, Gullfaks, Snorre and Osberg fields in Norway and several fields in the U.K. The survey extension is expected to be completed in 2016. CGG will have 35,000 sq km (13,514 sq miles) of contiguous, uniform broadband seismic data in the area at the end of the season, the company added.

**Tullow receives drilling permit near Heidrun, Njord fields**

Tullow Oil Norge AS received a drilling permit for wild-cat well 6507/11-11 near the Heidrun and Njord fields in the Norwegian North Sea, the Norwegian Petroleum Directorate said.

The directorate granted the permit for the well, which will be in production license 591. Well 6507/11-11 is in an area containing part of Block 6507/8, part of Block 6507/9 and part of Block 6507/11. It will be drilled about 14 km (9 miles) southeast of Heidrun and about 220 km (137 miles) west of Njord. This is the first well to be drilled on Production License 591.

**Maersk discovers hydrocarbons in Danish North Sea**



**Well Xana-1X in the Danish North Sea hit hydrocarbons. (Source: Maersk Oil)**

Maersk Oil said the exploration well Xana-1X in the Danish North Sea has discovered hydrocarbons. The Xana-1X well was drilled in license 9/95 in the northern part of the Danish sector with Maersk as operator.

The HP/HT exploration well was drilled at a water depth of 68 m (223 ft) and a total drilling depth of 5,071 m (16,637 ft) in the Jurassic Formation. The well was spudded Dec. 8, 2014, by the jackup rig Noble Sam Turner and is currently being plugged and abandoned. The license partners are currently assessing the technical and commercial implications of the discovery and looking at potential for a follow-up, said Martin Rune Pedersen, managing director of Maersk's Danish business unit, in a statement.

**RUSSIA CIS**

**Lundin receives Morskaya Field production license**

Russian licensing authority Rosnedra issued a production license for Morskaya Field in the Lagansky Block in the Russian part of the Caspian Sea to Lundin Petroleum AB. The production license is valid until 2035 and covers about 50 sq km (19 sq miles). Morskaya Field might hold 157 MMboe in gross contingent resources. LLC Petroresurs owns the field. Lundin Petroleum holds a 70% shareholding in LLC Petroresurs. Gunvor Group holds the remaining 30%. Lundin Petroleum has 187.5 MMboe of proven and probable reserves.

**AUSTRALIA**

**BHP lowers priority of Australian LNG project**

BHP Billiton Ltd. is lowering the priority of its Scarborough LNG project with Exxon Mobil Corp. in Australia amid a fall in prices and increasing competition from the U.S. "LNG prices are down quite a bit from last year," Tim Cutt, BHP's petroleum president, told reporters. The project "falls a bit lower" on the list of opportunities, he said. In September, Cutt said that he backed plans to develop what could become the world's largest floating LNG project and that BHP was aligned with partner Exxon. Exxon said at the time that while significant progress had been made, it needs to find ways to make the proposed venture more profitable and overcome challenges, including the location and water depths. "We're probably not moving quite as quickly as we were last year, but it's still a very important asset" that will be developed at the right time, Cutt said.

**Queensland open for business with acreage release**

The Queensland Government has put 11,000 sq km (4,247 sq miles) of exploration acreage up for grabs, with most of the available land concentrated in the prospective Cooper and Eromanga basins. State Development Natural Resources and Mines Minister Dr. Anthony Lynham said the state was seeking interest from around the globe in exploring for potentially rich petroleum and gas resources off Queensland's far southwestern corner. While most of the land being made available is in the Cooper and Eromanga basins, there is one small area of highly prospective land in the Surat Basin. "This is the first of a four-year land release plan for the Cooper and Eromanga basins and is designed to attract junior and major explorers," Lynham said. **E&P**

PEOPLE

**Jerre Stead** has become CEO of IHS Inc. The company elected **Deborah Doyle McWhinney** to its board of directors.

**Alastair Marsh** will replace **Richard Sadler** as CEO of Lloyd's Register.

Cartasite added **Bill Sinclair** to its team as CTO.

The Australian Petroleum Production & Exploration Association selected **Malcolm Roberts** as chief executive.

**Remi Eriksen** has been tapped as group president and CEO of DNV GL Group to succeed **Henrik O. Madsen**, who is retiring on Aug. 1.



Yokogawa Corp. made **Daniel L. Duncan** (left) president and CEO of Yokogawa's North American operations.

Flotek Industries appointed **Robert M. Schmitz** executive vice president and CFO.

TGS appointed **Sven Børre Larsen** as its CFO.

Polyflow tapped **Jim Moore** as CEO.



**Frank Jacobs** (left) has been appointed to the post of COO for TAG Oil Ltd. The company also selected **Toby Pierce** as CEO and a director.

Seatronics Ltd., an Acteon company, has promoted **Phil Middleton** (right) to group managing director.



Apache Corp. appointed **Timothy J. Sullivan** as senior vice president of operations support, **Thomas E. Voy-**

**tovich** as executive vice president of international and offshore region and E&P technology, **James L. House** as senior region vice president of the Houston region, **Grady L. Ables** as region vice president of the Canada region and president of Apache Canada, **Steven J. Keenan** as senior region vice president for the Delaware Basin, and **Cory L. Loegering** as region vice president for the U.K. region and managing director for Apache North Sea. Apache also appointed **Daniel W. Rabun** to its board of directors.



**Dorsey Morrow** (left) has been selected as the executive director for the Society of Exploration Geophysicists.

Statoil tapped **Torgrim Reitan** (right) to be executive vice president for develop-



ment and production in the U.S. **Hans Jakob Hegge** (left) was appointed executive vice president and CFO. **Irene Rummelhoff**

(right) became executive vice president for new energy solutions, and **Jens Økland** (left)



became executive vice president for marketing, mid-stream and processing.

Inspection Oilfield Services hired **John Anderson** as Gulf Coast regional manager and **Shane Falder** as West Texas drill tools manager.

**Brandon Hofmeister** was chosen as executive director of policy, research and public affairs for Consumers Energy.

Steptoe & Johnson PLLC added **Roger L. Nicholson** to its energy transactional team.

**Tore Gulbrandsøy** will head the new

Stavanger, Norway, office of Rystad Energy.

**Vince Stewart** has accepted the position of director of operations for the Channelview, Texas, facility of Patterson Tubular Services, an RPC Inc. company.



**Martin Brown** (left) will head up Aqualis Offshore's Aberdeen office as general manager.

SM Energy Co. added **Jennifer Martin Samuels** to its team as senior director of investor relations.

Penspen appointed **Carl Mook** (right) as executive vice president of asset management and asset integrity and regional director of the Americas.



The board of BP plc has named **Paula Rosput Reynolds** and **Sir John Sawers** as nonexecutive directors.

**Stephen L. Norris** joined NEAH GES advisory board.

**Yang Hua** has been appointed chairman of the board of CNOOC Ltd. and chairman of the nomination committee.

**Klaus Besier** joined the board of directors of Seven Lake Technologies.

**Jack N. Aydin** became part of the board of directors for Rex Energy Corp.

Exxon Mobil Corp. shareholders have elected **Doug Oberhelman** to the company's board of directors.

COMPANIES

**iSURVEY Group** has launched a new office in Aberdeenshire, Scotland. The new facilities include an onsite workshop, storage yard and offices.



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The **Stier Group** unveiled the first offshore training center in Spain at the Taliarte Marina in the Canary Islands. The facility has 3,000 sq m (32,290 sq ft) of training grounds and the capacity to instruct 3,000 people per year in offshore courses and 1,000 students in professional maritime education.

**Mokveld Valves BV** has opened a new 3,000-sq-m head office (below) in Gouda, Netherlands.



**Scott Environmental Services Inc.** has expanded its capabilities by creating

a custom geophysical testing laboratory designed to perform bench-scale testing on its solid drilling waste management processes. The in-house laboratory was developed for performing streamlined treatability studies that can now be completed within a matter of weeks vs. months. Engineers have access to real-time data, allowing them to make adjustments to the treatability technique used for specific situations during processing.

**Applus RTD** is opening an office in Corpus Christi, Texas, to provide nondestructive testing services for the region. This is the company's 22<sup>nd</sup> office in the U.S. **E&P**

*Clarification: In the June issue of E&P, the article "Multiple casing, cement evaluation tools enhance well integrity" was written by Dimas C. Azuaje at Weatherford.*

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# Striving for F's

F doesn't have to be a failing grade in the current commodity price environment.

**Frank Lloyd, SMU Cox Executive Education**

In schools, F is a negative letter. All students and instructors know that it stands for failure. However, in business the letter F is a positive. It stands for two things that are essential to success in today's volatile, uncertain, complex and ambiguous energy industry environment: fundamentals and flexibility.

Business fundamentals include these basics that support operational efficiency and effectiveness:

- Accounting and finance: scorekeeping that enables a company to understand its costs, know it is providing value, keep track of its cash and serve its stakeholders;
- Customer service: operational excellence to deliver what customers want when and how they want it;
- Brand: knowledge of the brand and its promises to guide decisions about what to do and what not to do;
- Leadership: interpersonal and organizational communication skills to motivate, coach and empower others; form effective teams; create alignment throughout the organization; and lead change;
- Human capital: the strategic selection, development, retention and exit of employees to achieve business results;
- Strategic thinking: understanding how day-to-day decisions and operating results advance or retard the firm's strategic intent; and
- External focus: recognizing the interests of multiple stakeholders, representing the organization and its values in the community, scanning the external environment for relevant trends and operating with a global perspective.

When times are challenging, as in today's declining oil price marketplace, it's essential to stick to the fundamentals. Companies need to manage costs but not starve appropriate revenue-generating opportunities, provide outstanding service to retain existing customers, stay connected to their brand promises, handle staff reductions strategically and with sensitivity, and over-communicate. You can't shrink your way to greatness.

Flexibility is simpler to describe but harder to achieve. It is the organization's capability to behave

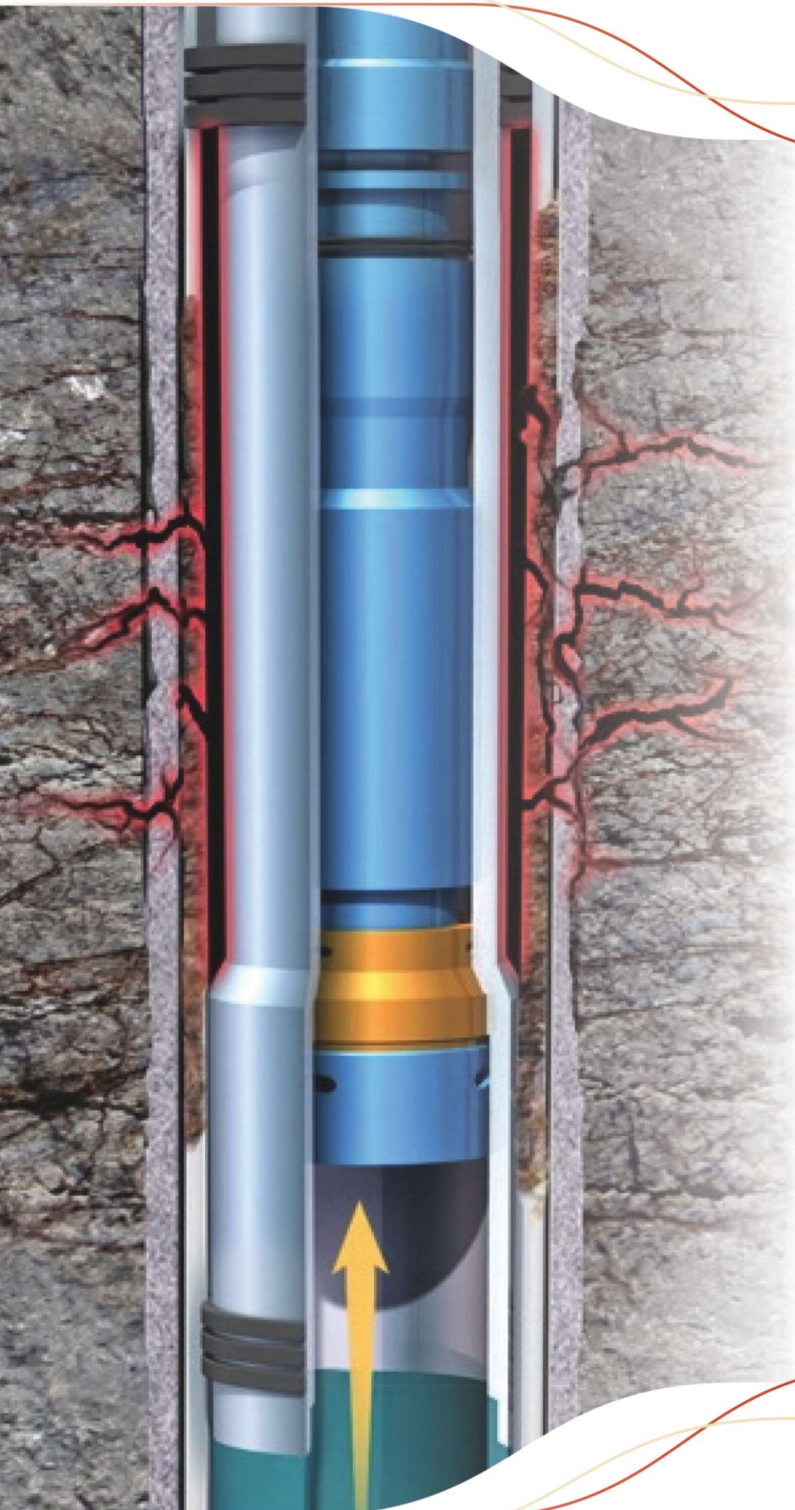
like a ballet dancer and move in response to a flow of music, emotion and narrative. It is also the organization's capability to be like a basketball player and pivot and shift with agility from point to point according to the demands of the game. Firms that achieve these capabilities demonstrate:

- Financial agility: Some energy firms have accumulated cash and avoided debt so they are able to scoop up bargains;
- Asset leanness: Some energy firms are able to drill but wait to frack. Others can produce but send production to storage rather than to market;
- Engaged customers and suppliers: Some energy firms have engaged suppliers in managing operations, thereby spreading risk; and
- Continued investment: Some energy firms have cut investment from planned levels but are able to maintain it at year-over-year increases.

Those oil and gas firms that have achieved flexibility have stockpiled a range of organizational capabilities that can meet various contingent scenarios. They have cultivated a diverse mindset within leadership and among employees. They encourage participation in the large and growing array of information exchanges, both online and face-to-face, inside and outside the organization. They create an environment that promotes learning from failure, and they support employees in pursuit of a lifetime of learning.

Sustained success will belong to energy organizations that embed business fundamentals needed to make money, engage and motivate their people, and grow strategically—and the organizational capability to act like ballet dancers and basketball players. They will be able to move flexibly and with agility, rebound quickly from failures and pivot in different directions as the market demands. Such firms will expand and maintain their commitments to education. They will upgrade their internal learning and development functions. They will maintain their education and development programs rather than cut them because they see their value in securing a steady flow of talent grounded in business fundamentals and empowered to behave flexibly. Their investments in education will stand for fundamentals and flexibility rather than failure. **ESP**

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