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EXPLORATION & PRODUCTION
WORLDWIDE COVERAGE
APRIL 2017
VOLUME 90 ISSUE 4
A HART ENERGY PUBLICATION
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Where A&D *Begins*

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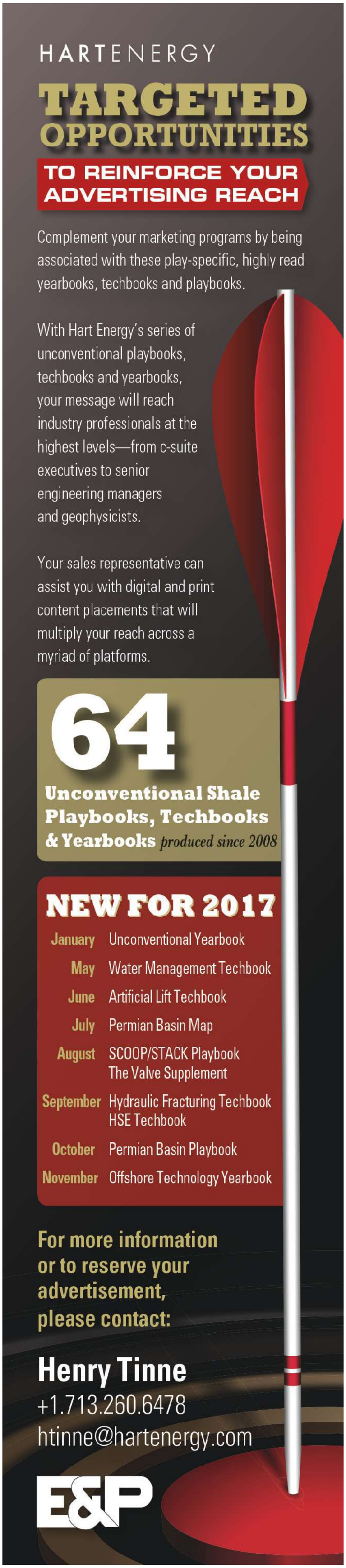
Regina Mayor
Principal, Global Sector Head and U.S. National Sector Leader of Energy and Natural Resources, ***KPMG***

Garry Tanner
Partner, ***Quantum Energy Partners***



DEPARTMENTS AND COMMENTARY

COMING NEXT MONTH The May issue of ***E&P*** will focus on offshore. Other features will include marine seismic, drillpipe and casing advances, emissions management, and subsea trees. The regional report will focus on the U.S. Gulf of Mexico. 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 subsea pump is installed in the pump station during the system integration test at the OneSubsea facility in Horsøy, Norway. Left, Mexico's offshore industry is blossoming under its energy reforms. *(Cover image courtesy of Schlumberger; left image courtesy of* Lukasz Z, Shutterstock.com; *cover design by Felicia Hammons)*

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ACTIVITY HIGHLIGHTS

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Offshore Peru unrisked prospective resource estimate: 885 MMbbl
Baron Oil Plc has reported its latest estimates of unrisked prospective resources for blocks Z34 and XXI in Peru.

Total announces oil discovery in Bulgaria sector of Black Sea
Total announced an oil discovery in the deepwater sector of the Bulgarian Black Sea in the Khan Asparuh Block 1-21.

Sea of Japan gas field reported by Inpex
According to Inpex, the company discovered an offshore gas field in the Sea of Japan. The field is about 135 km (84 miles) west of Japan's Shimane and Yamaguchi prefectures.

AVAILABLE ONLY ONLINE

CERAWeek: EPA director envisions pro-growth, pro-environment policies

By Darren Barbee, Senior Editor, Digital News Group

Scott Pruitt said regulators should not pick energy winners or wage war on any particular energy source.

CERAWeek: Gas production growth threatened by infrastructure delays

By Joseph Markman, Senior Editor, Digital News Group

A CERAWeek panel expressed concern over the ability to serve regions if projects cannot move forward.

Environmental concerns slow development of Brazil's Equatorial Margin

By Brunno Braga, Contributing Editor

Despite the Equatorial Margin's high oil reserves potential, environmental licensing issues are causing operational delays.

Mexico's private operator deals mark a new day

By Ricardo Martinez, Contributing Editor

Mexico makes history with its first deepwater contracts with private operators, including BHP Billiton, Chevron and Inpex. What does it mean for exploration on the Mexican side of the Gulf of Mexico?

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What's cooking?

As part of a laboratory experiment, oil was produced from samples of Alaskan coal, leading some to wonder 'what if?' in the coal-rich state.

I know, I know. Running a story about coal in an upstream oil and gas magazine is skirting close to sacrilegious. But as I see it, skirting the edge and considering all possibilities are what helped carry petroleum out of the dark ages and into the light where it could grow into the modern industry behemoth it is today. This particular story is one that demonstrates how, with a little collaboration, a possibility is considered and successfully tested.

In January 2017 the Alaska Department of Natural Resources (ADNR) released its initial findings of an investigation into assessing the liquid hydrocarbon potential of the state's coal deposits. "While coal has long been considered an excellent source of natural gas," the report stated, "…there has been much discussion as to whether, and to what extent, coal functions as source rocks for oil."

The investigators acknowledged that there have been commercial discoveries of conventional oil having been correlated to coal source rocks; the Cooper and Eromanga basins in Australia and the Danish North Sea are just two of the many examples cited.

With this in mind, the Alaska Division of Geological & Geophysical Surveys and the U.S. Geological Survey (USGS) initiated a collaborative project to conduct experiments on selected samples of Alaskan coal to investigate the oil potential of the state's vast coal resources. The coal samples were collected in 2015 from outcroppings at the Usibelli Group operation near Healy—near the Nenana Basin—and near Wishbone Hill in the Matanuska Valley near Sutton, according to a March 1 article on the investigation appearing in the *Anchorage Daily News.*

The samples were provided to the USGS by the state geologists, the article reported. The coal was mixed with water in a reactor vessel and superheated for three days in a process known as hydrous pyrolysis. Each submitted sample did produce oil. USGS scientists at the Denver laboratory produced 38 mg to 64 mg of oil from 1 g of coal, depending on the sample, the article stated.

It's not much as the investigation was just the first in what could be many more steps. According to the ADNR report, possible future research will focus on conducting hydrous pyrolysis experiments on more coal samples from Alaska, including older coals from the North Slope, and on the conditions required for effective oil expulsion from coal.

Considering all possibilities is second nature in the petroleum-rich—but still very much a frontier—state, where being creative means survival. E&P

Jennifer

Accounting of drill cuttings is a game changer

Companies that embrace their waste and properly manage the corresponding liabilities will come out on top.

Victoria Caylor, Scott Environmental Services Inc.

Society is always pushing for more consideration and accountability from corporations and the impact their activities have on the environment and local communities. Many companies, especially oil and gas companies, are realizing it is more profitable to be proactive on possible liabilities rather than ignoring what could be a very real and financially devastating event. It also provides companies a way to account for assets that otherwise might not have been considered and by doing so entice new investors and higher stock prices.

Whelan and Fink explained that "…executives are often reluctant to place sustainability core to their company's business strategy in the mistaken belief that the costs outweigh the benefits. On the contrary, academic research and business experience point to quite the opposite." People are more interested than ever in sustainability and corporate governance. An investor's decision-making process involves not only the profitability of the company but also its potential; longevity; and attainment of environmental, social and governance (ESG) goals. In the current exceedingly competitive market for new investors and financial backing, the days of ignoring sustainability are limited.

The Firmus process helps turn liabilities into assets. (Source: Scott Environmental Services Inc.)

Sustainability accounting overview

The Brundtland Report (Our Common Future) defined sustainability as "…development that meets the needs of the present without compromising the ability of future generations to meet their own needs." The purpose of sustainability accounting is to evaluate the ESG performance of companies through an account of their management of various forms of nonfinancial capital associated with sustainability—environmental, human and social—and corporate governance issues that they rely upon for sustained long-term value creation. The Sustainability Accounting Standards Board (SASB) has developed standards that allow companies to account for material issues that do not have an exact numeric value. In effect, materiality is the "ante" for companies to publish credible nonfinancial reports and related extra-financial information. Sustainability accounting adds detail in a narrative format to accompany the federally required financial reporting for publicly traded companies. This detailed reporting can include nonfinancial assets, potential liabilities, ESG achievements, expected upcoming trends and their overall plans for the current and future handling of the above mentioned.

The SASB addresses issues that are classified into five categories: environmental, social capital, human capital, business model and innovation, and leadership and governance. The purpose of establishing these standards was to assist investors and the public so that they can better compare companies in the same industry.

Understanding how companies plan to mitigate their risks and what assets they value as critical to their business model will ultimately

help investors better diversify their portfolios. The SASB provides guidance in certain areas that can help investors decide this. These areas include attention to the management of critical capitals, vulnerability to depletion or misuse of these capitals, scenario planning regarding alternative resources, risks associated with mismanagement of certain environmental or social issues and opportunities related to global or industry sustainability challenges. There are many areas in the oil and gas industry that are direct material sustainability issues, but for the sake of this discussion we will only focus on solid drilling waste.

Liability of solid drilling waste

Waste is a leading concern in the industry and includes oil-based and water-based drill cuttings. It is common practice in the industry to dispose of cuttings in a landfill, by soil farming or land spreading or even placing them on top of or underneath roads. If these companies use the standards set forth by the SASB, it would not be a very flattering picture of the liability they created for themselves using these methods. The sheer volume of drilling waste makes it clear the liability of not disposing of the waste responsibly could be devastatingly exponential. This is the type of information that is not currently captured using standard financial statements, directly leading to the development of the SASB.

Changing regulations

Society in general is taking a stronger stance on sustainability and corporate governance. This trend is only going to increase. Public pressure is causing regulatory agencies to take a much closer look at drilling waste and its disposal practices. Regulators will continue to crack down on the oil and gas industry and the way it manages its waste. Companies can be proactive and initiate a conversion to improve waste practices on their terms. Transitions and changes to business models are always more fluid and economical when willingly initiated and well planned by the company. Being forced to change by laws, regulations and public pressure is a much more painful and traumatic experience.

Turning liabilities into assets

In addition to the financial benefits that accrue from increased competitive advantage and innovation, companies are realizing significant cost savings through environmental sustainability-related operational efficiencies. Moreover, investors are now able to track the high performance on ESG goals and are correlating better financial performance with better ESG performance. Some oil and gas companies already use sustainability accounting to report nonfinancial assets and liabilities in regard to drill cuttings and waste management. These companies have taken an in-depth look at their waste and are no longer fearful of what it might contain or of future liabilities that might arise from it.

The common mentality of whisking the drilling waste offsite in the cover of night because no one wants to acknowledge it, let alone answer questions about it, is no longer an issue. Companies have evolved, taken ownership of their waste rather than avoiding the issue and have acknowledged that drill cuttings are an unavoidable part of the oil and gas industry, and they are handling them responsibly.

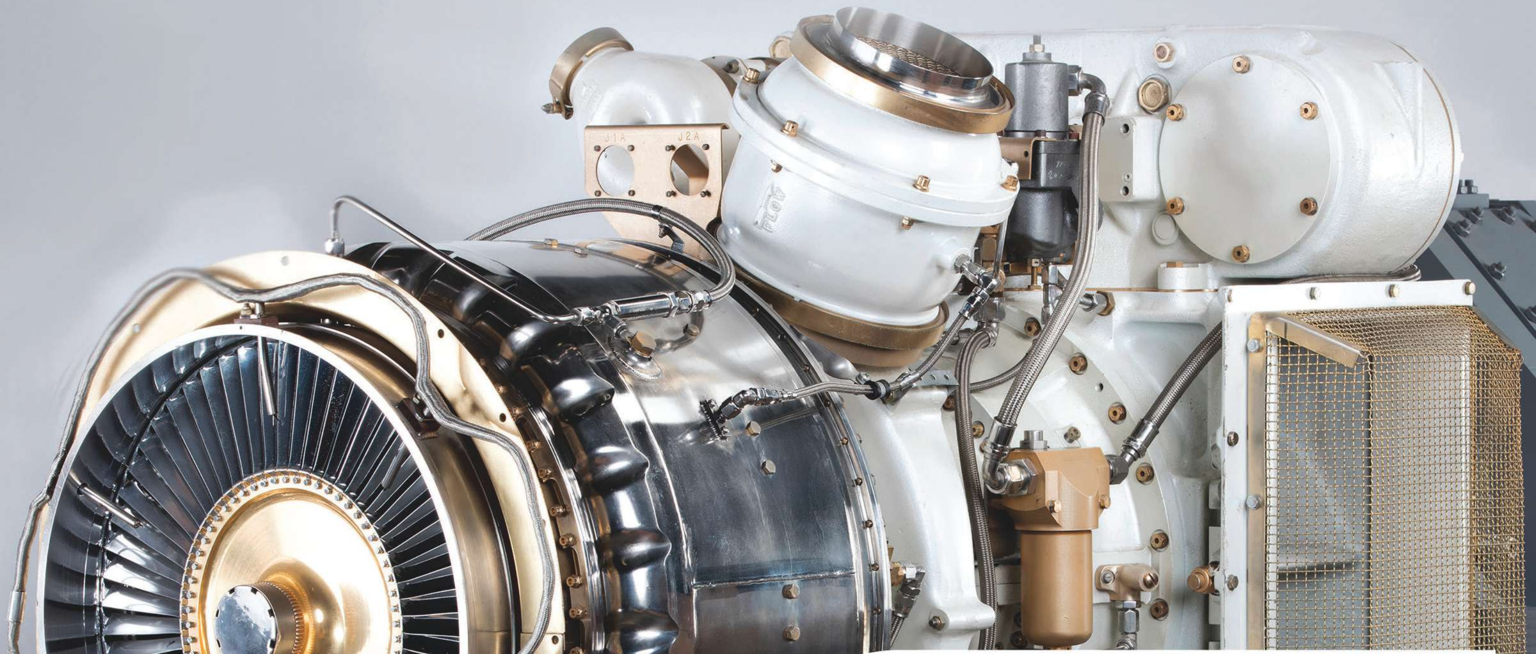
These companies have scientific test results showing exactly what is in their waste. They treat the cuttings and use processes to encapsulate the waste followed by additional scientific testing to confirm that the waste is fully contained. They are confident that it is never comingled with anyone else's waste; they know its exact location, and their footprint is exceptionally small. By addressing proper waste management of their drill cuttings, they have been able to significantly reduce a future liability that has the potential to be a fatal blow to the business.

Investors are getting a full snapshot of their current business activities, not just profit and loss. In addition, there is the impressive sustainability reporting of the company's ESG performance that speaks more to investors interested in long-term returns. Investors are paying attention. According to the 2015 EY Global Institutional Investor Survey, investors are increasingly using companies' nonfinancial disclosures to inform their investment decisions. In its survey of more than 200 institutional investors, 59.1% of respondents view nonfinancial disclosures as "essential" or "important" to investment decisions, up from 34.8% in 2014.

The oil and gas industry is being forced to become more competitive to survive the cyclical peaks and valleys that are a natural part of capitalism. Very soon the most fiscally strong companies will be ones that embrace their waste and properly manage the corresponding liabilities. The use of sustainability accounting and providing transparency to investors is the new game changer in the industry and the key for future success. E&P

References available.

Have a story idea for the Industry Pulse? This feature looks at big-picture trends that are likely to affect the upstream oil and gas industry. Submit your story ideas to Group Managing Editor Jo Ann Davy at *jdavy@hartenergy.com*.



Tomorrow's energy company

Being average is no longer good enough.

Reid Morrison, PwC

As E&P, oilfield services and drilling companies report more optimism for the industry in 2017 and beyond, the model for tomorrow's energy company also has shifted to reward specialization and excellence in core offerings.

Examples of this shift can be found in the uptick in mergers and acquisitions, asset sales and divestitures, especially in the Permian Basin. As noted in PwC's latest deals report, fourth-quarter 2016 deals volumes were 30% higher than in third-quarter 2016 and 45% higher year-over-year. Additionally, the rate of bankruptcies and restructuring filings is decreasing, especially for E&P companies, according to PwC's business recovery services practice.

These deals show that energy companies are winding down on prioritizing cost-savings initiatives and ramping up on strategically repositioning their portfolios for growth to better compete in a stabilizing commodity environment.

What's driving the change?

Prior to the nosedive of oil prices in second-half 2014 cost efficiencies and cash flow typically came second to making fast production gains and delivering strong returns on investment. At more than $100/bbl, companies dealt with inefficient supply chains and logistics, high costs for labor and materials, and need for innovation or effective use of technology because profits were much easier to come by at that price level. The rising commodity price also covered up that some parts of these companies were average and was further exacerbated by the conventional industry wisdom of the time to maintain the status quo because that's what the industry has always done.

Energy companies are strategically repositioning their portfolios for growth to better compete in a stabilizing commodity environment. (Source: Matthew Michael Ferris, *Shutterstock.com*)

After the crash, however, energy companies had to take a hard look at their stressed balance sheets and make the courageous decisions to prioritize cost cutting as well as lean into the areas of their businesses where they saw the best opportunities for stability and growth through portfolio rationalization and strategic transactions. Essentially, energy companies had to develop a mindset that fosters a strategic nimbleness to focus on where they are exceptional and have the honesty to acknowledge where they are average.

Portfolio repositioning

As is currently being witnessed through the recent flurry of deal activity in the industry, today's smart energy companies are divesting business segments or assets that no longer add value to their model for a leaner, more specialized company and are buying up assets that complement or beef up their current exceptional capabilities.

They're determining where they have the capabilities to win when the market is favorable as well as when it isn't and have realized that an up market can potentially skew performance measures while a down market can reveal unpleasant truths. They're looking beyond their own industry and drawing inspiration from automotive, biomedical and aerospace to improve both technical and financial performance, including more investment in R&D to shorten development cycles or go-to-market technology launches, reduce capital spending and decrease labor costs.

In one example of this phenomena, on recent year-end earnings calls a specialty chemistry company announced the divestment of two of its four operating segments in drilling and production technologies to focus more on its energy chemistry and consumer chemistry technologies segments, where it has seen the greatest success and where it generates the most value for its unique expertise in prescriptive oilfield chemistry. The market rewarded this company with a 15% stock jump post-earnings and praised the leadership's forward-thinking vision.

Another well-known E&P with assets in the Permian Basin has seen success by allowing its geoscientists and engineers to have greater flexibility and independence in pursuing research and identifying opportunities for asset development. This notion of allowing the company to be led by science and ideas to come from those closest to the asset rather than by industry norms has positioned them as one of the most innovative E&P companies in one of the hottest shale plays. This company also included profit targets in its bonus plan rather than just production growth.

Even the major oilfield services companies have realized one of their greatest strengths lies in their historical database, where they've worked with multiple E&P companies across the globe to optimize their wells and can more easily bring their regional and global experience to bear, having already solved similar problems elsewhere among thousands of wells. Smaller independent operators are then able to take advantage of these oilfield services' deep banks of experience in well optimization and instead focus their efforts on where they bring the most value. This also allows smaller E&P companies to do a lot more with just a couple dozen people who specialize in specific areas of excellence such as geology or reservoir management.

Rise in partnerships and cross-collaboration

As each of these examples demonstrate, specialization is key to creating a differentiated and more competitive business, but it also requires more collaboration and partnership with other peers, academics or government entities. No one company, university or government has all the expertise required, and collaboration is proving increasingly essential to innovation.

Leveraging one another's strengths not only differentiates individual competitive edges, but it also strengthens the industry as a whole to operate more efficiently. Economists call this the law of comparative advantage, where mutually beneficial results occur as a result of partnering with others who have exceptional capabilities that are complementary to one's own unique capabilities.

Along with more cross-collaboration and specialization, tomorrow's energy company will also be more geographically streamlined, having consolidated inventory, labor and logistical distribution to key targeted growth markets instead of managing a wider spread with pockets of either understocked or overstocked inventories and overutilized or underutilized employees. This swap from breadth to depth effectively lowers costs related to inventory, labor and logistics and relies on suppliers to complete the ecosystem. However, it takes a conscious decision and strategic vision to begin to integrate technologies, workflows, services, disciplines and organizations that have long been segregated or merely bundled.

Production/gain-sharing contracts

Historically, production sharing agreements or contracts (PSAs or PSCs) have been used by predominately developing regions that lack the necessary capital or experience to develop their own natural resources, such as in the Middle East, South America and Central Asia, and they agree to PSCs with foreign players to fill this void. The foreign oil company usually agrees to bear the mineral and financial risks of exploring, developing and producing the field while the country's government takes a share of the profits.

In today's landscape PSAs between E&P companies and oilfield services companies are becoming more commonplace as a way to share profits and reduce costs, with some agreements having cost reductions built into contracts.

For example, an independent oil and gas company headquartered in the U.K. recently agreed to a 50% net revenue PSA with an oil and gas consulting firm based in St. John's, Newfoundland, to produce onshore assets in western Newfoundland, Canada, with the consulting firm covering 100% of the funding and ongoing operations.

Overall, to improve operator margins, the industry must rethink the fundamental ways in which it does business. The days of being average, of being all things to all people, of being a jack-of-all-trades but a master of none, are all but written in the history books. By forming strength-based strategic relationships with best-in-class oilfield services and drilling companies, E&P players can remove costs, get access to partners' deep knowledge and experience in areas in which they might have only been average and boost returns on invested capital. Market conditions and the industry are now ripe for embracing this new model of tomorrow's energy company. E&P

Have a story idea for the Industry Pulse? This feature looks at big-picture trends that are likely to affect the upstream oil and gas industry. Submit your story ideas to Group Managing Editor Jo Ann Davy at *jdavy@hartenergy.com.*

The power of cloud storage

Storage in the cloud offers up potentially disruptive technology.

Andres Rodriguez, Nasuni Corp.

The development of new technology for improving E&P has been one of the recent bright spots in the oil and gas industry. High-resolution aerial surveys, 3-D seismic exploration, subsea light detection and ranging, and other tools have proven incredibly valuable. The recent Nalcor success story is one such example. The combination of a satellite survey, a 2-D seismic scan and a 3-D follow-up eventually yielded $758 million in commitments for the company.

Unfortunately, the tremendous volume of data generated comes with unanticipated costs. The switch to 3-D scans alone has increased the size of files at least sevenfold, leading to multiterabyte datasets. These files need to be securely stored. They have to be protected so employees don't lose access if a disaster strikes an office or a data center. Files created in one location often need to be accessed in another part of the world for analysis or collaboration.

Until recently, each of these functions would require a different solution, and as a company's data grew exponentially, the associated costs and capex would rise just as fast. The traditional way to expand storage capacity, for example, has been to buy more storage hardware from a vendor. Yet this puts the buyer in a difficult position. IT has to predict how much storage the organization will consume over the next three to five years and then incur a major capital expense. But what if IT can't predict capacity? What if an unexpected exploration project generates massive new data volumes? Companies that underestimate end up blowing their budgets to buy additional storage before the typical three-year cycle is done.

In the old world of file storage and protection, the kind of data growth that oil and gas firms are seeing today would have been an intractable problem—especially in an unstable market. The cloud has changed all that. Cloud storage has given rise to a new breed of companies that allow oil and gas enterprises to store, protect, manage and

Large enterprises need a solution that works between cloud storage and all of the enterprise's offices and data centers. (Source: Nasuni Corp.)

extend access to unlimited datasets at lower and predictable price points. These companies have transformed file storage from a capital-intensive expense to a cost-effective service. In doing so, they ensure that enterprise files function purely as an asset, not a budget-straining liability.

What is cloud storage?

Despite its ethereal name, cloud storage is a very real and reliable construct. The cloud is essentially a series of large connected data centers. Once data are moved to one of these facilities, they are copied within that data center and then replicated again to additional geographically distant data centers. This way, if an individual piece of hardware within the facility or even an entire data center were to fail, copies of the data remain accessible.

In the public cloud storage model these data centers are designed, built and run by the behemoths of the technology world—the likes of Amazon, Microsoft, Google and IBM. They are secure, efficient and incredibly scalable, allowing companies to store unlimited volumes of data. By copying data within and across multiple facilities, cloud storage effectively does the work of protecting and distributing data automatically.

Boom or bust—data still grow

Consider a new exploration project that turns into a major productive well. Demand for data about the site will increase dramatically, both in terms of requests and number of users. If a company's storage infrastructure is entirely built around on-premises hardware, this new demand and data could strain capacity and force the enterprise to buy additional expensive arrays. Storage costs will rise, and the cost of protecting those data will grow as well. Efficiently moving those files around the company will drive demands for network enhancements, wide area network optimization solutions and more.

The real dilemma is there is only a one-in-10 chance that a new exploration will yield success. Nevertheless, enterprises need to store, protect and share the data from each new exploration site. So for each site that yields economic benefits, there are nine more that simply generate a lot of data. This is where cloud storage has proven to be so disruptive.

Efficiency, agility and savings

Cloud storage can deliver far more capacity for the same dollar invested than traditional storage along with the potential for increased efficiency, agility and savings. However, enterprises cannot simply send their files to cloud storage and retrieve them at will. The cloud stores chunks of data as objects, not files. Large enterprises need a solution that works between cloud storage and all of the enterprise's offices and data centers. Nasuni connects enterprise file systems with cloud storage in a way that frees companies from the limitations of local hardware while also expanding what they can do with their files.

Once a company embraces this new model of data storage, the pre-existing hardware in a given office or data center remains in place as the local workhorse. From the end-user perspective the system still has the look and feel of a traditional on-premises storage solution. But these previously finite arrays now become linked to unlimited, distributed pools of secure, cost-effective storage. In this model the files from a new exploration project—indeed, all business files across the entire organization—are encrypted and pushed to a secure cloud storage volume. Frequently accessed files are still cached and stored on local hardware, enabling companies to continue to get the most of their expensive pre-existing infrastructure. But older, infrequently accessed data move off these expensive arrays to the cost-effective cloud.

This service-based model allows enterprises to save money and avoid capex, but it also creates entirely new business advantages. For example, all changes made to files are transferred to the cloud within minutes. As a result, users across the company can securely and easily access the most recent versions of files. End users on different continents can collaborate on the same projects without delay, even with the most recent version of very large files. Legacy technologies like VPN and replication break down when serving more than a handful of sites. For large global organizations, cloud is the "killer app" that makes true collaboration possible.

Undervalued strength of the cloud

When properly implemented, the cloud-based service model also is incredibly stable. Because of the way the cloud works, copying data within and across data centers, company files remain accessible even in the event of a major regional disaster. This stability is really one of the undervalued strengths of cloud storage. Many large companies are starting to catch on as the stability and disaster-proof availability are driving more organizations to take a completely cloud-based approach.

Nasuni has helped global enterprises in multiple industries address file growth through a service that saves them money and enhances efficiency across the company. In each case the story is the same. An essential new technology is creating a massively expensive file growth problem. The solution wouldn't be possible without cloud storage, a fundamentally disruptive entity that every large global enterprise should be looking to embrace. E&P

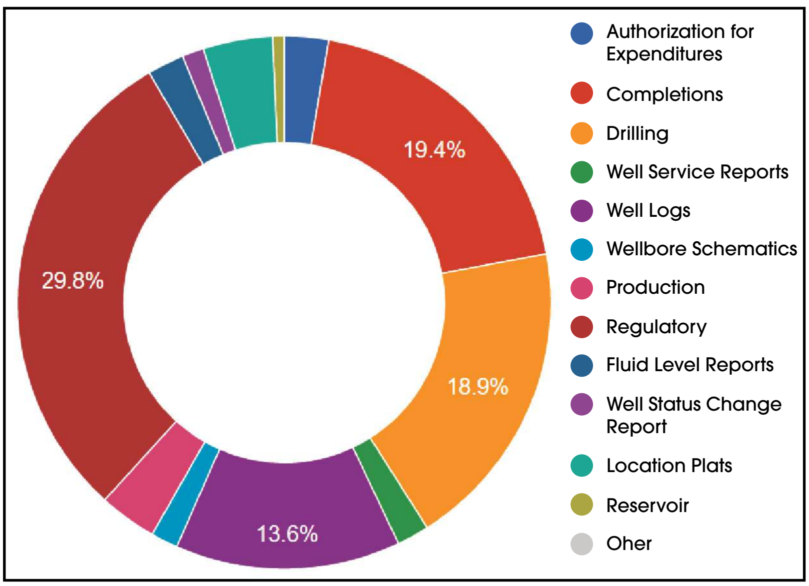
Managing well files and the unstructured data dilemma

Well information management technologies reduce costs, boost efficiency, enable informed decisions and sharpen competitive edge.

Chetan Chouhan, Archeio Technologies, and
Chase Woerndle, Parsley Energy

Think of the proverbial flood of data produced by today's digital oil field not as ones and zeros but as PDF files and JPEG images. The industry has focused so much on managing structured data—the bits and bytes that fit so nicely into databases—almost to the exclusion of the larger unstructured data problem. With drilling, acquisitions and operational momentum on the rise, the looming wave of documents is poised to create an even larger barrier to timely, data-driven E&P decisions.

According to leading IT researcher Gartner, the worldwide data volume is expected to grow by 59% year-over-year with a compound annual growth rate of more than 800% over the next five years. What's more, 80% of that growth will be from unstructured data like spreadsheets, presentations, photos and email. Consider how that trend is manifesting itself in the data-centric oil and gas business, and Gartner's forecast might look like an underestimate. Recognizing the well file challenge as a barrier to its growth, Permian operator Parsley Energy is navigating unstructured data complexity supported by new ideas and technology.



Top E&P document types are being managed by Parsley's well file solution. (Source: Archeio)

Digital documents

Today's digital document challenge began decades ago in physical storerooms and personal filing cabinets. From land and development to operations and compliance, wells have always generated a wealth of data that have traditionally been compiled into a well file. Thanks to modern digitization technology, physical well files have moved to virtual storerooms. Adding to this volume is the ceaseless digital stream of well-related documents generated every day from staff, vendors and applications across field and corporate offices such as plat records, drilling reports, logs, authorizations for expenditures, invoices, schematics, prognoses and economic forecasts.

Parsley has maintained an aggressive growth profile through sustained development of its premier acreage position in the Midland and southern Delaware basins. Due to its rapid growth, Parsley accumulated more than 50,000 well-related documents, equivalent to 150,000 pages of information, for a growing portfolio of more than 700 wells. Tapping into the full value of this large volume of information became a significant challenge for the operator.

Many E&P companies manage well-related documents on an S-drive, short for shared network drive. However, such file systems are inherently prone to information sprawl, haphazardly organized file folders and inconsistent naming conventions. Well histories spanning years, multiple document versions and incomplete datasets present significant challenges. The result is that a staff often spends hours searching for the right document to support crucial E&P workflows and decisions. In addition, poorly organized digital well information poses a risk to regulatory compliance and can delay time-sensitive mergers and acquisitions.

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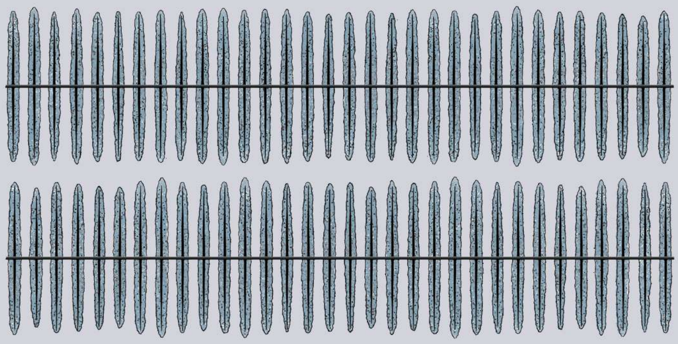

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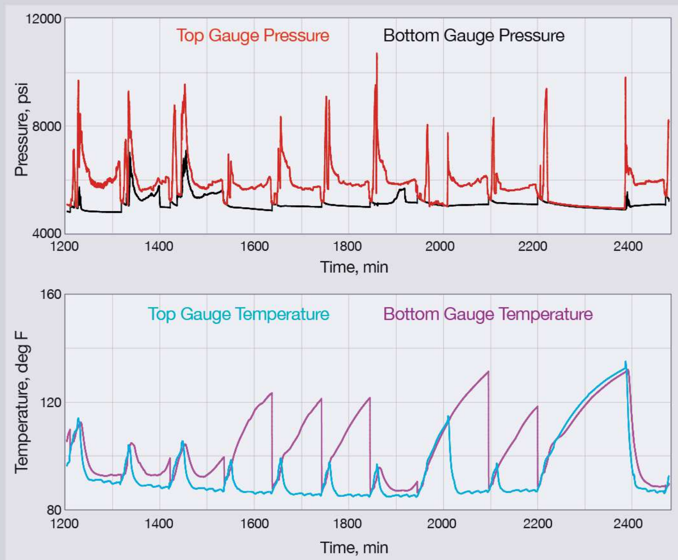

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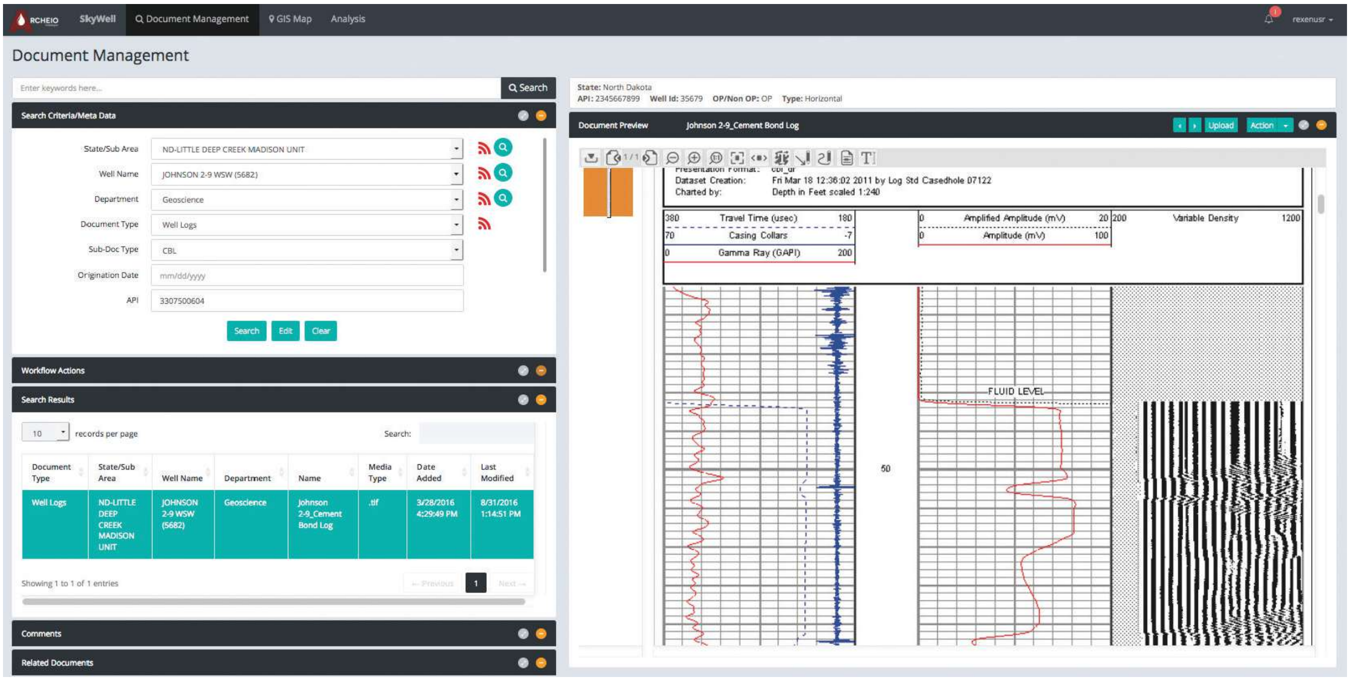

The metadata-driven well file search and document preview helps workers keep track of unstructured data. (Source: Archeio)

For the industry in general and Parsley in particular, solving the well file management challenge is less about how to store unstructured data and more about managing data complexity. Despite the large volume of unstructured well data, storage capacity and cost-efficiency continue to outpace data volume growth, which sharpens the focus on smarter ways to discover, sift and search E&P information.

In the cloud

Cloud computing is ideally suited to address the industry's unstructured data challenge. With its economy of scale and low storage costs, the cloud is meeting the demands of today's record high unstructured data volume. The cloud also drives data consumption through centralized content management and the ability to access well files and other business data from any connected device.

Several innovations are converging in the cloud to enable a new generation of well file management. Software-as-a-service (SaaS) takes advantage of the cloud's on-demand storage and computing power, creating new opportunities for resource-intensive applications, including high-speed document processing. Through its on-demand service model, SaaS eliminates the capital expenses associated with traditional servers and software. The SaaS model also accommodates multiple users, avoids the restrictions and cost of traditional end-user licenses and opens up the value of E&P applications to a larger pool of stakeholders.

Archeio Technologies provides oil and gas companies with enhanced capabilities to manage data growth and extract more value from well information through intelligent search and analytics. SkyWell, Archeio's cloud-based software, also helps operators reduce compliance risks and expedite data onboarding during an acquisition.

Archeio's approach uses high-speed document processing, machine learning and document classification technologies to add essential context to documents. Because such basic details like well name or American Petroleum Institute number are inconsistently located within a page—a problem magnified by high data volume and complexity—the SaaS developer employs smart algorithms to identify essential data to classify well documents, also known as metadata. By tagging documents with metadata, Archeio enables E&P companies to finally stitch all of their unstructured data together into a common document taxonomy that makes searching for information as easy as using traditional search engines.

Parsley selected Archeio's cloud-based well file management solution to give more than 130 employees on-demand access to its extensive volume of unstructured well information. The objectives of Parsley's well file solution include centralizing document management securely in the cloud, providing adequate classification and context for documents and enabling staff to quickly search for relevant and reliable data for all parts of a well or land file.

To achieve these goals, Parsley uses SkyWell's machine learning technology to convert, tag, classify, load and manage legacy well and land files. Importantly, SkyWell provides a flexible oil and gas industry-specific document taxonomy that lets Parsley enforce minimum metadata standards including county, well name and department.

Leveraging document metadata and smart search options accessible from a PC smart phone or tablet, Parsley's staff spends less time looking for data and more time on analysis. The well file technology is used to manage 48 high-value data types across Parsley's drilling, geology, operations, land and regulatory departments. SkyWell also enables users to find well information using an interactive map and features data analytics to provide insight into the data being managed. Most importantly, the operator estimates that E&P decisions are as much as 60% faster due to the enhanced management of well information.

Given the growing unstructured data challenge, SaaS solutions like SkyWell are proving to be increasingly critical to success in the information age for Parsley and its peers in the industry. Solving the unstructured data challenge also translates to lower risk and faster decision cycle time across business functions. Acquisition of oil and gas assets, for example, poses a massive data onboarding and file management challenge to buyers that often delays the process as staff hunt for data to understand asset integrity. The ability to quickly sort, high-grade and intelligently search through large volumes of well data accelerates the acquisitions and divestitures process, enabling smoother transitions and minimizing well downtime.

Powered by the cloud and smart search technologies, intelligent well file management is shaping up in the industry. Even as unstructured data volume and complexity soar, new well information management technologies are well positioned to reduce costs, boost operational efficiency, fuel more informed decisions and sharpen competitive edge. E&P

Industry leaders talk markets, projects

Meeting the challenge of supply and demand and climate change were just two of the many topics under discussion at the annual CERAWeek by IHS Markit conference.

Joseph Markman, Senior Editor, and **Velda Addison**, Senior Editor, Digital News Group, Hart Energy

A "second wave" of U.S. shale oil growth that will bump U.S. light oil production by 1.4 MMbbl/d won't be enough to meet rising global demand without significant investment, the International Energy Agency (IEA) said in its "Oil 2017" report. That could lead to another round of price volatility, the agency said.

U.S. production growth will depend on price, Fatih Birol, executive director of the IEA, said on March 6 at the conference where the organization released the report, formerly known as the "Medium-term Oil Market Report."

"Between now and 2022 we may see an expansion of three million barrels per day coming from the U.S.," Birol said, referring to the report's high estimate if the price of Brent crude reaches \$80/bbl. A price of \$60/bbl would result in a U.S. production increase of 1.4 MMbbl/d.

In addition to the U.S., Canada and Brazil also will lead supply growth of 5.6 MMbbl/d by 2022. Demand growth, led by China and India, will grow by 7.3 MMbbl/d by that time and eclipse 100 MMbbl/d by 2019 on its way to 104 MMbbl/d by 2022.

Fatih Birol, executive director of the IEA, discusses the agency's forecast at CERAWeek in Houston. (Source: Hart Energy)

The IEA's concern, Birol said, is that production won't keep up as upstream investment continues to decline. And unlike some in the industry, the IEA does not foresee peak oil demand over the short and medium terms. "The first signals we get from the oil companies are not very encouraging in terms of seeing a strong rebound in investments," he said. "This comes after two years of substantial declines in upstream investments."

The decline in investment means more reliance on spare oil production capacity, but that capacity is on track to reach a 14-year low by 2022 based on current trends. Cutbacks in upstream capital investment fell in 2016 for the second year in a row.

Birol compared the forecast for 2022 to the high prices experienced in 2008, when spare production capacity was 4%. The IEA's projections are that spare capacity will be only 2% in 2022.

The IEA estimated that global upstream investments will be about \$450 billion in 2017, or about 25% less than what the agency has projected will meet demand growth and counter declines in existing fields. Birol said the IEA would be more comfortable with a 20% increase in investment.

He also said he supported increased investment in all oil-producing countries, "but the difference between the United States and many others is the U.S. can respond to the higher prices much faster than the others. In other countries, if you were to make an investment today for a field, it would take a lot of time to see the products coming to the markets."

Increased fuel efficiencies in automobiles and the growing fleet of electric cars will not head off a tightening of the market, he said. "The growth in oil demand globally mainly comes from trucks, jets and petrochemicals," Birol said. "There it is difficult to find substitutes for oil for now. Today, one-third of oil demand growth comes from Asian trucks."

Challenges

Recognizing the oil and gas industry's need to respond to climate change and emissions, Statoil CEO Eldar Sætre said the company plans to allocate about 15% to 20% of its capex to renewables by 2030 if the projects are attractive.

The company is among the world's leaders in offshore wind energy and carbon capture and storage. Speaking to a


Schlumberger

IHS' Daniel Yergin moderates a leadership discussion with Petrobras CEO Pedro Parente and Statoil CEO Eldar Sætre. (Source: CERAWeek)

crowd gathered on opening day at CERAWeek, Sætre said renewable energy costs are falling amid rapid technology innovation. The company believes renewables, which is the fastest growing source of new power generation capacity, will become cost-competitive without subsidies, Sætre said.

"We all know that oil and gas will continue to be a significant mix of the energy mix for decades to come; however, we have to respond more forcibly to the challenges of climate change, reducing CO_2 and methane emissions," he said, noting this will come with a cost but added that companies who address such challenges will have a competitive advantage.

Sætre was joined on stage by Petrobras CEO Pedro Parente. The two took part in a discussion moderated by IHS Markit Vice Chairman Daniel Yergin on leadership. Each has served in their CEO roles for less than three years and, like many executives, both have faced challenges.

Yergin pointed out how Parente, who was appointed CEO of Petrobras in May 2016, was charged with the "urgent task of restoring confidence in the company and repairing its finances after being forced to write off billions of dollars," the result of a fallout from a corruption scandal uncovered by an investigation called Operation Car Wash.

Parente stressed that the company and most of its employees were "victims of this corruption scheme, not an agent, no benefit whatsoever," only huge financial losses. Since the beginning of 2015 the situation has changed for Petrobras, which has worked to reduce its debt by carrying out a more than $15 billion divestment program.

"The fact that our company moved in the newspapers from the scandal page to the business page is very good, but it's important to stress that this is just the beginning of long work," he said. "We appreciate the recognition but also are humbled by the responsibility and the challenges that are ahead of us. We will recover credibility as we deliver the results that we promise. That is pretty much what we are doing now."

These challenges for Petrobras came along with the added obstacles of coping with a recession as well as fiscal imbalances and reforms, including freeing itself from requirements to serve as operator of all of the country's presalt acreage. And then there was the downturn.

In this regard Sætre and Parente faced similar challenges as major oil and gas players with global assets both onshore and offshore.

Sætre became head of Statoil in mid-October 2014, just before the oil price crash changed life for the oil industry. At the time Sætre remembered the price for a barrel of oil being $90, and then the price collapsed, serving as another reminder that the industry is cyclical, he said. Although the last few years have been challenging, he recalled the saying: "You should never ever waste a good crisis."

Statoil has reset the cost base, reworking solutions and increasing efficiency from reservoirs to the market, he said. Breakeven costs for Statoil's so-called next-generation portfolio—which includes projects such as the North Sea's Johan Sverdrup and Oseberg Vestflanken, Johan Castberg in the Barents Sea, Peregrino II offshore Brazil and Trestakk in the Norwegian Sea with anticipated startups by 2022—went from more than $70/bbl to less than $30/bbl.

"Turns out we are capable of both thinking and acting low-cost when we have to; however, to meet the ultimate test of our ability to learn lies not in the crisis itself but in the recovery. Now is not the time to relax and repeat our mistakes from the past. Now is the time to fundamentally change how we run this industry." E&P


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Permian permanence?

A surge in drilling permits to start 2017 suggests the most active oil services market in the U.S. still has some gas in the tank.

Richard Mason, Chief Technical Director

The brightest star in the Lone Star State is the Permian Basin, which remains the hottest oil service market in the U.S. The Permian Basin has captured 60% of horizontal rig additions off the bottom in second-quarter 2016. In fact, the Permian added more rigs in tight formation plays than all other tight formation plays nationwide combined. And the trend is not finished yet. Horizontal rig count moved up 55 units in the first eight weeks of 2017.

Meanwhile, permits for horizontal wells are accelerating. The Permian recorded 731 horizontal permits in the first two months of 2017, more than the 625 filed in the last four months of 2016.

Those filings illustrate a mature Midland Basin, where operators have advanced on full-field development; rapid maturation in the Delaware Basin, where programs are moving from delineation to optimization in many cases; and full-field development in a few cases.

Among service lines well stimulation is leading the charge. Multiple metrics illustrate how the narrative is unfolding. Regional effective stimulation capacity grew 16% sequentially to start the year and was back above 1.1 million hydraulic horsepower in first-quarter 2017. Crowd-sourced data from Hart Energy's *Heard in the Field* surveys indicate crew count exceeds 42, up 10% in 90 days and still growing as fracturing spreads rotate into the region or are reactivated "off the fence" to meet expanding E&P demand.

The inventory of drilled but uncompleted wells (DUCs) is a major target for rising completion activity. Permian DUC inventory declined 8% in the first eight weeks of 2017. At the same time E&P companies are completing new wells as drilled, a pad at a time. The convergence of DUCs and new completions is reflected in the jump to 80% in batch completions as a share of total well completions. Batch completions bottomed at 35% in first-quarter 2016 and only rose above 50% in fourth-quarter 2016.

Those crews are spending more time at the well site, which has tightened the market for well stimulation services. Fracturing crews are scheduled well into second-quarter 2017, leading to waiting lists for operators. The reasons are evident in the region's well metrics. Proppant volume grew 4% to 19.7 million pounds in first-quarter 2017. Although stage count and lateral length were relatively unchanged, spacing between stages continued to decline and is down to 61 m (201 ft) on average vs. 77 m (253 ft) one year ago.

Meanwhile, hybrid gels are making a comeback in the region, mainly on a greater percentage of longer laterals with higher proppant loads. Operators are sending the gel in at the tail end of the stage.

- **The Permian oil services market is tightening.**
- **A surge in horizontal drilling permits suggests activity will remain strong in first-half 2017.**
- **Well stimulation is leading the industry forward.**

But it's not just well stimulation. Pricing rose 16% sequentially as the market tightened for higher specification drilling rigs. That price increase came on a more modest 5% rise in rig demand, which further illustrates a tightening market for specific rig classes. On a dollar basis rig rates for 1,500 hp AC-VFD Tier I units increased more than $2,000 per day to $17,400 vs. $15,000 per day at year-end 2016.

There is some discussion that the rate of change for rig additions might slow as the industry approaches mid-year 2017. E&P companies scrambled to add the best crews and equipment beginning in late 2016 as confidence grew in the sustainability of commodity prices.

The story line is that operators have accelerated spending on 2017 budgets. That might lead to a pause in the rate of change for service activity growth as the industry rounds the corner on first-half 2017, especially if commodity prices fail to advance farther. In the meantime, the stars at night remain big and bright in West Texas. E&P

Voyage to the bottom of the sea

Ocean-bottom exploration is still in its infancy.

A few years ago I attended a technology forum at Shell's then-new research facility on the west side of Houston, and Peter Diamandis gave a presentation about Xprize, a competition that puts out a significant technological challenge and asks teams to help solve the problem for a monetary prize. I honestly don't know what the challenge was that year, but one of the winners figured out a solution on a cocktail napkin at a bar in Las Vegas. Never underestimate the ingenuity of the human brain.

Now Shell has formed its own Xprize challenge, embarking on a three-year study to explore the deep sea. The challenge consists of 21 teams that comprise almost 350 people from 25 countries, according to the Xprize website.

The competition was launched in 2015 to explore the depths of the Earth's oceans. In an invitation to join the competition, Dr. Jyotika Virmani, Xprize's senior director for energy and environment and prize lead for the Shell Ocean Discovery Xprize, explained the lack of knowledge around our oceans. "We have better maps of Mars, hundreds of millions of miles away, than we do of our own seafloor," she explained. "We don't know how many volcanoes or mountains are hidden in the ocean, let alone what strange life forms exist down there. Less than 5% of the ocean has been explored because it is opaque and a physically challenging environment." It can cost $40,000 a day to run a vessel and up to $1 million to run an underwater vehicle, she added.

"We need new breakthrough technologies that can help us overcome the costs and can operate quickly and easily under great pressure in these cold and corrosive watery environments," she said.

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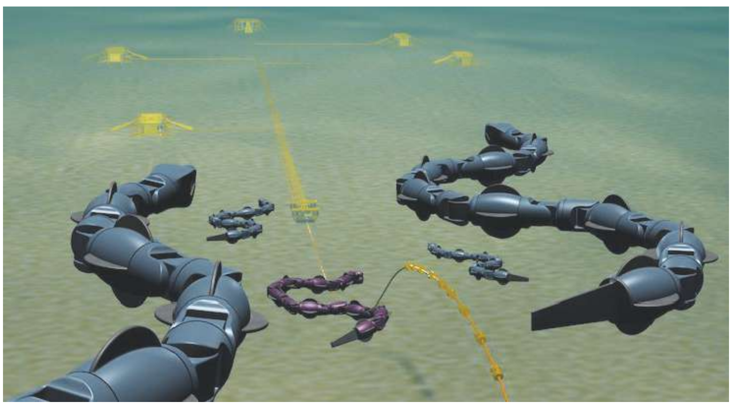
Read more commentary at
EPmag.com

The competition will award $7 million to the team that can build underwater robots that will provide safe access to enable high-resolution ocean exploration to map the ocean floor. The National Oceanic and Atmospheric Administration is adding a $1 million bonus prize to incentivize the teams to develop smart technologies to detect underwater chemical or biological signals and trace them to their source.



The Eelume snake robot provides IMR services for subsea installations. (Source: Eelume)

Already a company called Eelume has developed underwater "sea snakes" that can live permanently under water. Used for subsea inspection, maintenance and repair (IMR), they act like self-propelled robotic arms that can travel long distances and carry out IMR activities in spaces that are too tight for ROVs or AUVs. According to the company's website, they are modular combinations of joints, thrusters and payload modules that can hover and maneuver even in strong currents.

Eelume was formed in 2015 as a spin-off from the Norwegian University of Science and Technology after spending 10 years perfecting the snake robots in conjunction with SINTEF. It formed a strategic partnership with Statoil and Kongsberg in 2016 to explore the utility of the robots.

Sounds like a slither in the right direction. E&P

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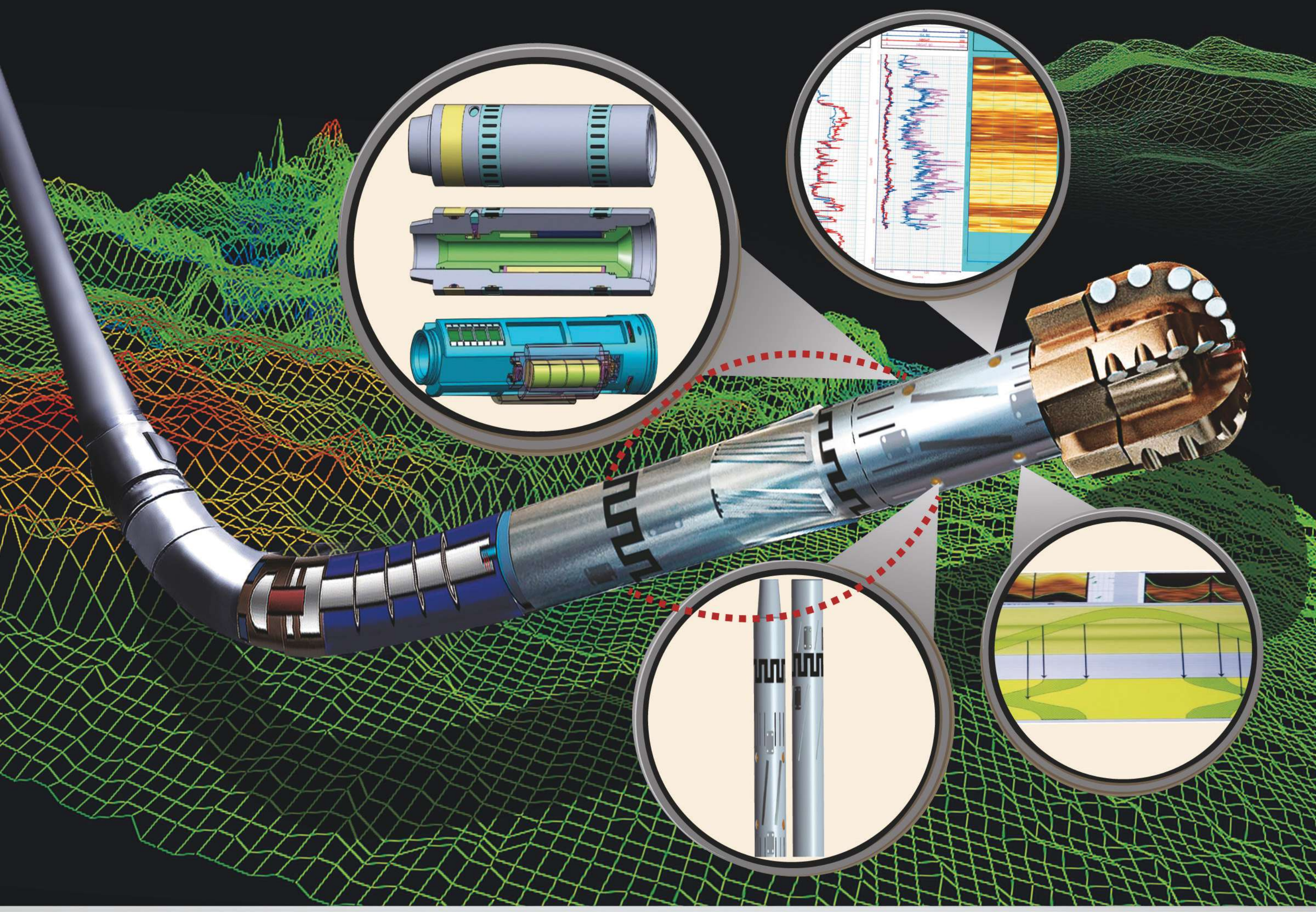

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Clock is ticking on health of offshore drilling industry

While onshore rig contractors seem to have reached the bottom of the trough, the offshore contractors are bracing for more challenges.

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Read more commentary at
EPmag.com

ExxonMobil is switching to U.S. shale drilling from long-term projects like offshore development. The company plans to spend $5.5 billion for drilling in the Permian Basin in 2017, a hefty boost for onshore contractors.

Shell Offshore Inc. and MOEX North America LLC have made the final investment decision on the Kaikias Field in the Gulf of Mexico. "Kaikias is an attractive near-field opportunity with a competitive go-forward breakeven price below $40 per barrel," the companies reported. That would make it competitive with several onshore shale plays.

There's just not that much spending going on for drilling in deep water. The Baker Hughes rig count for the week ending Feb. 24 showed 17 offshore units working, down from 27 for the same week in 2016. The January international rig from Baker Hughes on Jan. 14 tallied 206 rigs at work compared to 302 rigs in January 2014.

Offshore remains a tough environment. Seadrill with $14 billion in debt is in the process of negotiating a restructuring agreement with its lenders. The company faces bankruptcy if it fails to reach an agreement.

Paragon Offshore Plc CEO and president Dean Taylor said, "After confirmation that our previous plan of reorganization was denied, the company regrouped, developing a revised business plan that focuses our future activity on Paragon's core regions in the North Sea, Middle East and India."

Offshore drilling contractors still face rough seas in 2017. (Source: Chaikovskiy Igor, *Shutterstock.com*)

Using this business plan as its basis, the company reached agreement on this term sheet with its secured lenders, which virtually eliminates all of the previous debt from the company's balance sheet (about $2.4 billion) while providing sufficient liquidity to position the company for a longer term recovery in the offshore drilling industry, Taylor explained in the company's fourth-quarter 2016 and full-year 2016 results reported on Jan. 18.

But not all offshore contractors are in dire straits. Transocean "produced impressive operational and financial results in the fourth quarter," said CEO and president Jeremy Thigpen Feb. 23 in the company's fourth-quarter and full-year 2016 results. "As a direct result of our strong performance in 2016, we generated cash flows from operations of $1.9 billion, which, when combined with the multiple financing transactions consummated throughout the year, further strengthened our liquidity.

"Looking forward, improving market fundamentals along with a steady flow of customer inquiries are increasing our confidence that the offshore drilling market trough is near."

"Our industry continues to experience weakness. But it is not too early to turn an eye toward industry recovery," David W. Williams, chairman, president and CEO of Noble Corp. Plc, said while reporting fourth-quarter and full-year 2016 results on a company call Feb. 9.

With steady prices perhaps the offshore drilling industry can be riding the crest of the wave in 2018 instead of wallowing in the trough. E&P

Scott

Cruising altitude musings

The world is a big place, but the people in petroleum help make it a far friendlier one.

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EPmag.com

Several weeks ago I had the opportunity to travel to Italy. The world is a much changed place since I last left Houston for some far off exotic land more than two years ago. I wasn't nervous about leaving here for there or there for here. It was the 11-hour plane ride and layover to get there that I wasn't crazy about, but is anybody?

In the end the trip was a success, the Italians are wonderful hosts and the gelato was pretty spectacular, too. My reason for the trip was to attend the GE Oil & Gas Annual Meeting being held in Florence, Italy, which you can read more about in this month's cover story interview with Neil Saunders, president and CEO of subsea systems and drilling for GE Oil & Gas.

There I participated in a demonstration of GE Digital's 4-D Smart Helmet, in which I stepped through a virtual repair procedure for a turbine. With helmet securely fastened and trigger-activated wands in my hands, I found myself standing in a virtual workshop. My tools were to my left, and detailed repair instructions with hydraulic schematics were to my right. I had everything needed to remove a bearing gone bad and replace it with a good one using the wands. This virtual workshop could be the classroom setting to train the next generation of technicians, or it could be the drawing board for engineers to work through the ins and outs of a particular design without ever turning a real-world wrench. The possibilities for its use are endless.

The impressive technologies and an interesting seat mate left me with much to ponder on the long flight home.

The technologies that were on display or being presented were impressive. But it was the long trip home that left me with much to ponder after the plane touched down.

It is an experience that many of you can relate to, wherein the passenger in the seat next to yours pipes up with the question "What kind of work do you do?" How do you answer the question? Do you go with something generic like "I'm in sales," or "I'm an engineer" and then redirect attention from you back to them? Or do you roll the dice and proudly say, "I'm in oil and gas," only hoping that the next few hours in the flying pressurized tube will not be spent dodging the "oil is evil" debate?

I found myself on the flight from Paris to Houston seated next to a kindred spirit, a completions engineer for a major service company on his way home from a six-week stint in North Africa. We talked about the state of the industry, the "Great Crew Change," the tremendous opportunities and lessons learned from international travel and more. In the course of that conversation he noted that innovation and collaboration are critical. Technology is a great and important thing to keep current on. But for him it's the people he has met and worked alongside in his many years in the business that have meant the most to him. "Why do you not write about these people in your magazine?" he asked. "They are the heartbeat of the industry." I had no good answer for him because he was right.

So, with his request in mind, I want to write about you, your coworkers, your mentors and your friends. Email me at *jpresley@hartenergy.com* or call me at 713-260-6470, and let's talk. With your permission, I'll share your story here. I look forward to hearing from you. E&P

Jennifer

SUBSEA RESET

A subsea pump is installed in the pump station during the system integration test at the OneSubsea facility in Horsøy, Norway. (Source: Schlumberger)

Market recovery brings a brighter outlook for the global subsea industry.

Jennifer Presley, Senior Editor, Production Technologies

Delivering excellence in the deepwater dark is the modus operandi for the subsea industry. It is back on the beach where deliveries get challenging, where questions of cost and efficiency gains demand answers and where innovation does battle with standardization. The lower-for-longer market of the past two years has been brutal for the offshore sector and for the subsea industry.

But a new day is dawning, and the subsea industry finds itself to be a little bit busier.

By continuing to advance the technologies that make subsea possible, marginal fields shine brighter on the list of possible development candidates. With Big Data and the analytic acrobatic algorithms to decipher bringing greater insight into the remote operating environment, the global subsea market finds itself on the cusp of a full recovery.

It's always darkest before the dawn. But working in the dark is where subsea excels. E&P

Can technology save the UK sector?

Marginal fields and 'small pools' will play a role in the sector's future.

Steve Sasanow, Contributing Editor

Subsea production might have been born in the Gulf of Mexico (GoM) and used offshore Brazil before the 1980s, but it was in the U.K. sector of the North Sea that it grew from infancy to maturity.

Beginning with the Shell/Esso Underwater Manifold Centre and carrying on with shallow-water projects by Amerada Hess (now just Hess), then by BP west of the Shetlands beyond 400 m (1,312 ft) and even Chevron's recent Alder HP/HT 28-km (17-mile) subsea tieback, the British sector has not been short of ambition, adventure, enthusiasm and risk-taking. Combined with what was happening across the median line in Norwegian waters—TOGI, Snorre, Statfjord Satellites, Troll West, et al., in the 1990s; and Ormen Lange, Tordis, et al., in the 21st century—the North Sea was where it was at as far as subsea technology went, at least until the expansion into West Africa since 2000.

Scroll forward to the present, and what is found today is a British offshore sector in a major funk. The oil price crash of late 2014 had much to do with it, but there are other significant factors as well. Years of underinvestment in exploration, much of it the result of ennui by the majors who have been elephant hunting elsewhere in the world, has left the sector with a portfolio of mostly minifields, 350 at last count, that will require clever thinking to develop.

An HP/HT composite jumper is being supplied for the Alder Field developments. (Source: Airborne Oil & Gas and Chevron North Sea Ltd.)

In addition, the sector has long been known as a high-cost location, both for capex and opex. Finally, the sector hardly ever really received any support from various governments, which only ever saw it as a cash cow and never as the vibrant industrial sector that employed a workforce of more than 400,000 at its peak, more than the automotive industry, which has always been flagged as a British success story.

Finally taking notice

The price crash finally focused everyone's attention on what was needed, although an important part of the process actually began more than a year before. A sector-wide analysis undertaken by Sir Ian Wood in 2013 and presented in February 2014 added a new phrase to the offshore lexicon—"maximum economic recovery"—and sent the U.K. down a path it had never been before, trying to save the offshore sector.

In parallel with this localized approach, there had been the industry drive to reduce costs, and it was urgent. This as well had actually begun before the crash. One can go back to the early part of 2013 to find operators who were already applying the brakes to big deepwater projects. For example, BP's original scheme for the expansion of the Mad Dog Field (Mad Dog 2) in the GoM put forward in 2013 had a price tag of $20 billion. No way, said management—go back and look again. So it did, and the development scheme, described as more standardized, was sanctioned at the beginning of December last year with a price tag of $9 billion.

BP would like to take most of the credit for this major capex reduction, which it said is due to a less expensive semisubmersible floating production system, and it certainly deserves some plaudits. It also, though, had the opportunity to re-tender the whole project at a time when there was a dearth of big projects going ahead and could have benefited from general cost reduction in equipment and services across the industry.

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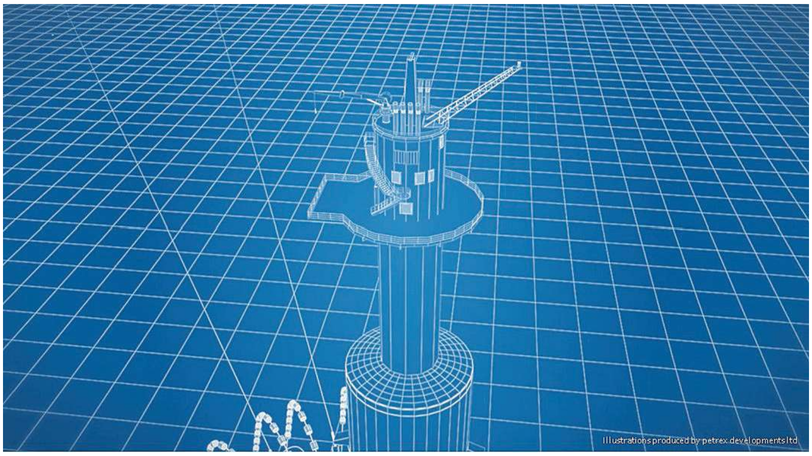
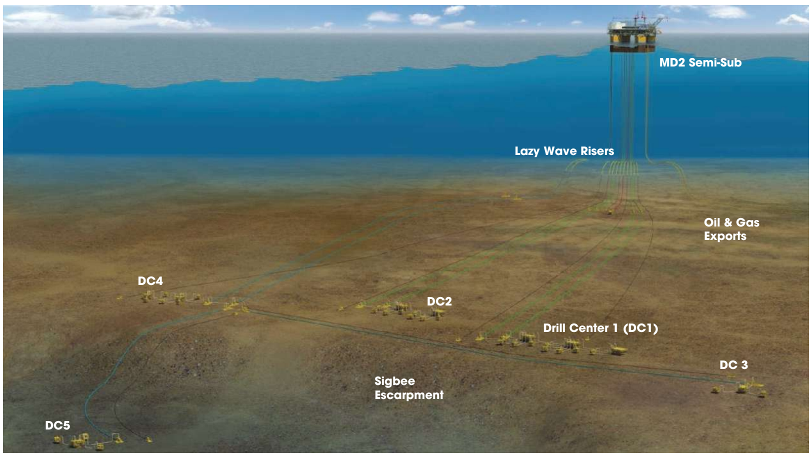


This blueprint shows a buoy concept for the North Sea. (Source: OPB)



Subsea layout for Mad Dog Phase 2 development was sanctioned at the beginning of December for $9 billion. (Source: BP)

Recommendations and studies

The Wood report made a number of recommendations, one of which was the creation of a new industry regulator. More than a few observers expressed wonderment at how a new regulatory body could make a difference to the future of the sector. If what has been learned only recently of the work the Oil & Gas Authority (OGA) has undertaken, the naysayers have been proven wrong already.

If the future of the U.K. sector is to be based on the portfolio of marginal fields (fields with less than 50 MMboe in reserves), a significant majority—about 200—will be developed as tiebacks to existing infrastructure, and many, and possibly most, will be developed using subsea wells.

The OGA already has taken on board the need to ensure that the right technology is available to all operators. In what must have been an unprecedented action by a U.K. regulator, it commissioned four studies to determine the economic viability of fields that might make use of specific technology and what the impact might be. There seems to have been some collaboration—a current favorite buzzword—between OGA and Oil & Gas UK's Efficiency Task Force. The latter body is an association of operators and main contractors.

Two of the studies involved looking at conventional subsea tiebacks and making use of already proven but less expensive pipeline tie-in technology, which produced savings of 18% to 28% on project capex. Some of the technologies identified as applicable in such cases are mechanical rather than welded hot taps, mechanical connectors as an alternative to welded pipe and spooled pipelines and composite pipe such as is being offered by Airborne Oil & Gas and Magma Global.

The other studies looked at riser systems for FPSO units and a different configuration of pipeline bundles with integral manifolds. Again, savings of 15% to 25% were suggested.

OGA also has looked at and identified technologies that might be applicable for low-cost standalone developments, which represent nearly one-third (120) of the marginal fields. Some of the options include unmanned production buoys; a mini-FPSO unit; subsea storage, which might eliminate the need for a long pipeline tieback; and the much used "subsea factory" term, which would involve some form of seabed processing prior to export.

Cluster development

What makes OGA's actions seem unfathomable compared with its predecessors is that it also has analyzed the marginal field portfolio and developed a strategy, or "cluster collaboration" for want of a better term, based on field location, proximity to infrastructure and proximity to other finds. It also has looked at some specific clusters to see how they might be developed.

Already analyzed is the West Sole Catchment Area in the U.K.'s Southern North Sea Gas Basin, with combined proven reserves of at least 14 Bcm (500 Bcf). This cluster includes Centrica's Olympus discovery, Dana Petroleum's Platypus find, two small Premier fields and one held by Hansa Petroleum plus one relinquished find (Glein West) and at least six other prospects.

One challenge that often has reared its head in the sector is alignment of development priorities. This cluster, for example, has four operators and 11 licensees, some of them small. Trying to get this group to agree to a development scenario, timetable and program is not an easy task. One advantage that OGA has is control of licenses. To make this cluster more economic, it could throw the relinquished find into the mix to benefit the entire development.

OGTC

Bolstering OGA's enterprise was the formal launch in February of the Oil & Gas Technology Centre (OGTC) in the U.K. One of its first tasks is its "small pools" initiative, which is running parallel to the work on marginal fields. Even before the launch OGTC's team had thrown down the gauntlet by declaring that it is aiming to eliminate stranded assets by 2025, a rather bold declaration.

Two of the technologies that are at the top of its wish list involve gas handling and umbilical-less subsea systems.

Disposal of associated gas that comes with small oil finds has often in the past been a major roadblock to development as the options—flaring in the case of an FPSO unit or small platform or drilling a gas disposal well as part of a subsea development—are either environmentally or economically unpalatable.

As for eliminating the umbilical from the subsea system, this has been a desire for decades, but through-water communications has a number of limitations that to date have not been overcome.

It has been suggested that technology developed for the military, such as that used with permanently deployed sensors on the seabed to track submarines, could be made available.

This is a challenge that will test the mettle of both engineers and regulators. E&P

Editor's note: *Steve Sasanow is the former editor of* Subsea Engineering News.

Subsea gets analytical

Digitization is the way forward for subsea.

Jennifer Presley, Senior Editor, Production Technologies

Neil Saunders

Data are critical for drilling and subsea operations. Without them, you're blindly navigating extreme environments. As far as extreme environments go, working thousands of feet in the air or thousands of feet below water takes the cake. For clients partnering with a company that has experience working in both extremes, the door of new opportunities opens wide. GE Oil & Gas houses those possibilities in its "GE Store." Working together, an environment of open innovation and sharing is encouraged, where with a little tweaking of a technology, a solution that works in flight can be fully realized for an under-the-sea application. From the multitude of sensors transmitting the operating data to the algorithms doing the deciphering, the future of drilling and subsea is digitization.

This transition into digitization brings with it disruption, something that Lorenzo Simonelli, president and CEO of GE Oil & Gas, said encourages "a new mindset that challenges tradition and bureaucracy." Speaking at the 2017 GE Oil & Gas Annual Meeting held in Florence, Italy, earlier this year, Simonelli said the company "heads into 2017 with the ambition of disrupting the status quo by harnessing disruption in many ways."

E&P spoke with Neil Saunders, president and CEO of subsea systems and drilling for GE Oil & Gas, on the growing importance of digitization and Big Data in subsea and drilling applications, disrupting the status quo and how technology transfer is changing the subsea landscape.

***E&P*: What advantages have digitization, Big Data and condition-based monitoring created to enhance drilling and subsea technologies?**

Saunders: Our starting point is to bring digital to life, and bringing Big Data to life is really around condition-based monitoring of our equipment. We can look to the GE Store. If you think about that from a subsea standpoint, we always have had to a point a significant amount of telemetry that's available to tell us the conditions of what's happening subsea. We know how the tree is being operated. We understand how the valves are cycling. We understand how the control system is functioning. We have sufficient telemetry down there to do some pretty impressive diagnostics already, and we can follow that all the way from the wellhead all the way back to the host.

In drilling we have our SeaLytics package, which we can add to a drilling stack. We can do much the same. We understand how the BOP is being used. We understand how the RAMs are operating. We have some clever instruments as well that we leverage from inspection technologies where we also can listen to the BOP from a vibration standpoint and almost create a digital twin of the stack in operation. Once you have that information, you're able to look for themes and get a far better understanding of how the equipment is performing. Over a period of time, when you triangulate with additional data that you get from other systems, you get to a point where you can start to predict failure. If you can predict failure, then you can optimize any intervention.

***E&P*: How does this disrupt or change the supplier/client relationship?**

Saunders: By doing this, it moves us from a break/fix scenario to a preventative scenario, where we can be pretty cost-effective. We can do that on an advisory basis. However, if you took it to the full effect, then you have GE managing that work in something that would be an equivalent to a contractual service agreement [CSA]. That is something I think in time you're going to see a company be prepared to provide—that kind of outcome. That takes you into the drilling space where we already do have a drilling CSA, where we are on the rig and we are managing the condition of the blowout preventers—eight of them across four drillships.

We have a contract with Diamond Offshore that said, 'Hey, when the rig, the stack specifically, is operational, we're getting compensated. When the stack is not operational due to equipment performance, we are not being compensated.' We have our commercial incentive. To help us really deliver and live up to that commercial

The SeaLytics platform enables actual component performance data to be used to create predictive rules that can be applied fleetwide. (Source: GE Oil & Gas)

incentive, clearly understanding how the stack is performing, gathering data and triangulating it with data we have on other stack performance allows us to really do the second thing, which is to reinvest that information into the product to get it to perform even better, so that we start to move the needle on the availability curve.

I think in time we're going to see us reinvesting that knowledge not only in the drilling equipment but also in the subsea production equipment to ultimately improve the reliability and the availability of that equipment. The less intervention we have to make, the less commercial pain, and the more commercial gain we make. Therefore, that becomes us improving the performance of the equipment. In theory, we get some commercial gain and obviously the client gets more equipment uptime.

***E&P*: What are the needs your clients are bringing to you? What are you hearing at the moment?**

Saunders: We've always heard from customers that they understand the need for standardization, and they're very aware of how they drive cost by being custom, unique and having their own specification. Now we're hearing companies talking about supplier-led solutions. A cost-effective solution is a must-have. They need their projects to work commercially.

I think with the digital discussion we get some traction. Customers understand the long-term value of GE Oil & Gas being able to optimize equipment performance, but it is not a must-have. We're typically going to the customer and having to articulate that value as opposed to the customer coming to us saying, 'Hey, we want some of that digital value.' We have to explain it, and we're really making a bet on it by moving into different commercial models, like the Diamond Offshore one. The incentive for getting the analytics out of the equipment is actually ours, before it's Diamond's. It's an enabler for us to have the equipment perform better. E&P

Global subsea market: entering an age of recovery

The industry is incorporating lessons learned to evolve into a more compact and efficient market.

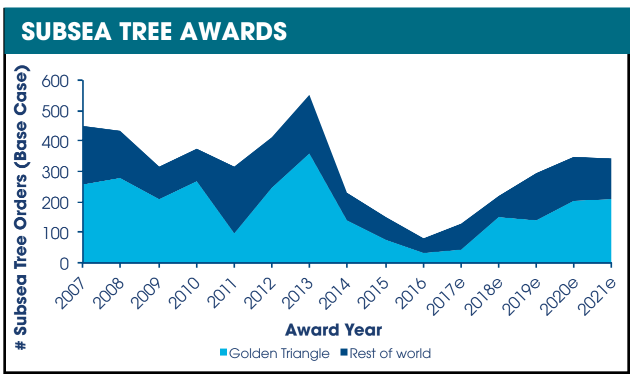
Caitlin Shaw, Wood Mackenzie

The global subsea market has undergone one of, if not the, most brutal downturn in recent history. The Upstream Supply Chain research group at Wood Mackenzie has observed that lengthy project delays caused by long-term concerns about subsea cost stemming back from the previous decade coupled with the oil price crash of 2014 have created a perfect storm of challenges for the overall offshore market.

Adapting to new conditions

The oil and gas industry has always been one of innovations driven by the challenges of maximizing recovery safely and efficiently. This downturn required the industry to closely examine how it executes subsea projects and understand how it can further increase efficiency, return and recovery.

Industry collaboration has been an ongoing theme in the industry as the supply chain comes together with unique solutions to the high cost issues in deep water. The operators are doing their part by reassessing their developments, prioritizing the highest potential and optimizing development concepts given an outlook of a lower-for-longer oil price. The operators and supply chain have come together to work on these projects earlier in the life cycle than had historically taken place in the hopes that the earlier the two parties work together on a project, the better the chances are at maximizing potential efficiencies and "red flagging" potential costly pitfalls.



Global subsea tree awards reached a record low in 2016. (Source: Wood Mackenzie)

Near-term demand outlook

According to Wood Mackenzie, the near-term outlook for subsea demand is one of growth compared to 2016, which saw fewer than 100 subsea trees ordered for the year. In the base-case forecast for 2017 Wood Mackenzie is forecasting about 120 subsea tree orders. While this still pales in comparison to previous years' activity, it remains an upward move from 2016.

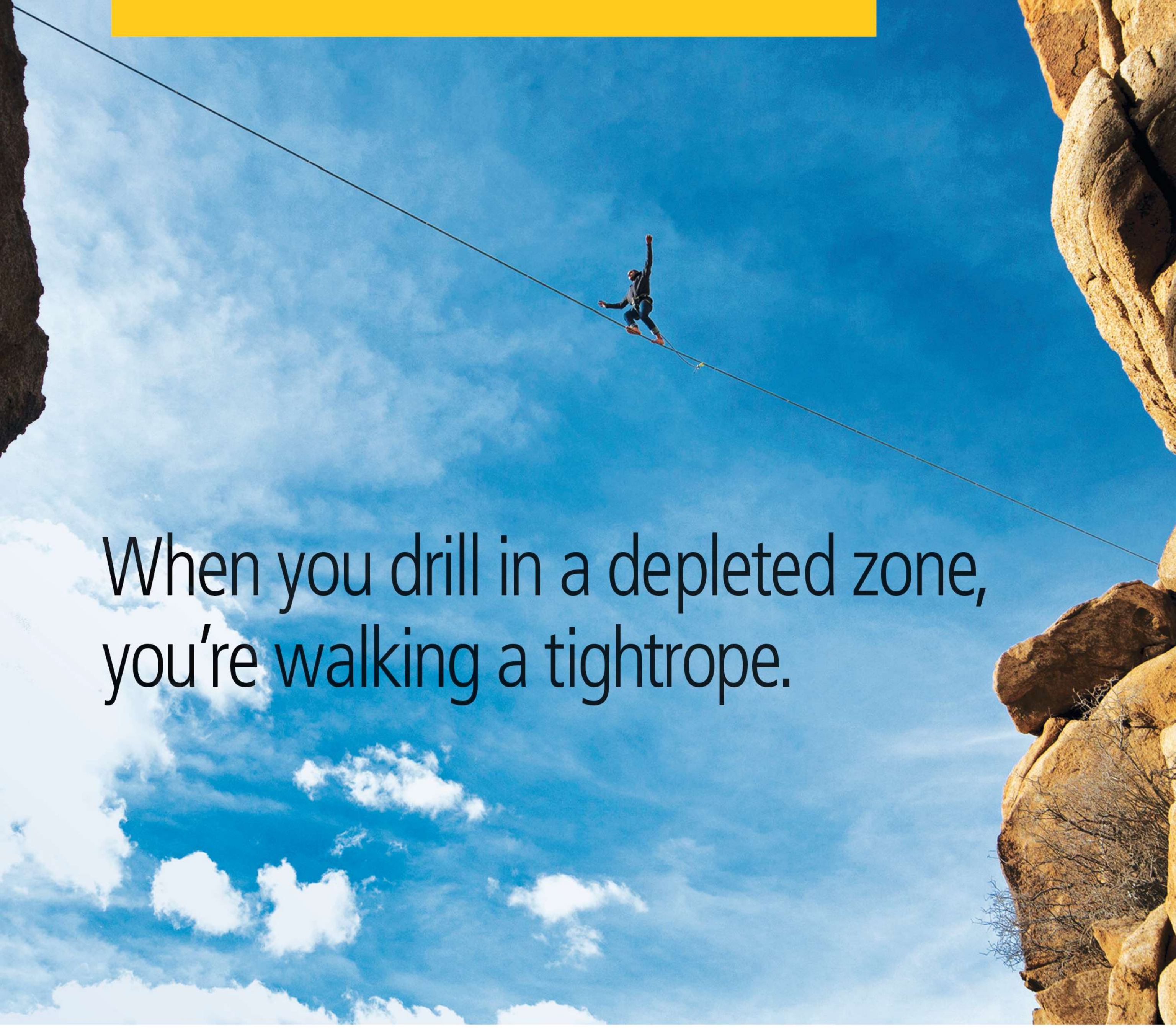
Brazil will remain weak in 2017, with limited demand potential for 2018. There remains a large inventory of subsea trees for Petrobras that will likely satisfy project startups until 2020 (containing subsea tree startups for years in the future).

Africa's outlook for the next 24 months is flat to slightly down compared to the previous two years. The natural gas projects of Northern Africa have helped buoy local subsea demand in the recent past. While Wood Mackenzie does not expect significant improvement in this market over the near term, it is important to remember the region will continue to play a critical part in overall global demand.

The North Sea actually stands to realize the highest recovery in the near term. Coming off a record year in 2013, the past three years have seen very muted subsea activity from the North Sea. Wood Mackenzie expects the region to outpace the past three years' worth of subsea demand within the next 24 months. Projects like Johan Castberg, Njord Future, Cheviot and Snorre Future projects underwrite the region's near-term potential.

Golden Triangle will remain long-term driver

With a slight adjustment to the definition, the Golden Triangle will remain dominant in future subsea demand. The Brazil portion of the region will need to be expanded to South America in general, and West



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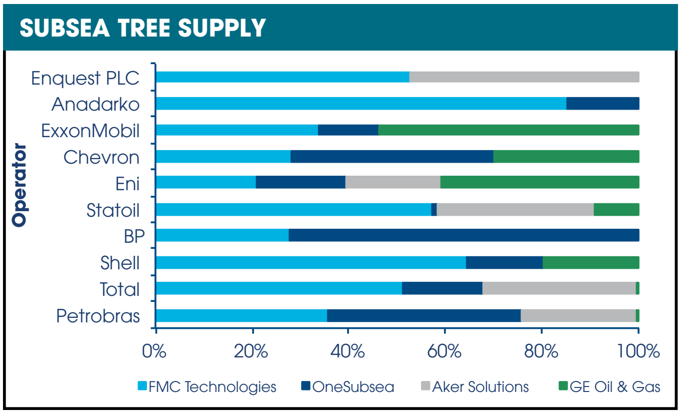


TechnipFMC and OneSubsea remain the long-term supply leaders for subsea tree manufacturing. (Source: Wood Mackenzie)

Africa will need to be extended up to North Africa and around to East Africa. These areas are expected to represent about 60% of future subsea demand through the end of the decade.

Brazil can only grow from the current lack of subsea demand experienced since its record-setting year in 2013. Recent legislature working to enable international oil companies (IOCs) to come in and operate presalt fields will help accelerate this recovery. Adjustments to local content requirements also will open up opportunity for Brazil by enabling active operators to more widely use the global supply chain. That said, exploration success and subsequent project executions in frontier areas around the continent (Falkland Islands, Guyana, etc.) will help support the continent's anticipated growth.

Due to the historical high cost of developments off Nigeria and Angola, the current downcycle has severely impacted their subsea demand. Instead of new megaproject executions, smaller scale subsea tiebacks and infill subsea orders are underlying award potential for the countries. African demand through the end of the decade will be underwritten by natural gas finds in North and East Africa. The Transform Margin also has an interesting backlog of smaller oil developments operated by a handful of different operators.

The U.S. Gulf of Mexico (GoM) will remain the main source of subsea demand in North America through the forecast period. The region has struggled considerably through this downcycle, seeing IOCs and independents alike stalling, selling and reengineering projects. This activity is leading to an anticipated uptick in 2017-2018 subsea demand, when more efficient versions of these projects are executed.

A key driver to recovery and ongoing activity is diversity—in projects, in operators and regionally. While South America and Africa are growing their diversity, U.S. GoM operators have a long history of using this diversity to their benefit. Typically, the majors will push the frontier boundary of developments in terms of water depth, and a strong mix of independent operators will come in behind that wave and develop more marginal fields as subsea tiebacks.

Suppliers competing for less

Global equipment suppliers have been grappling with quickly diminishing backlogs during this downturn as recovery remained just out of reach. Members of the supply chain have collaborated and consolidated through this challenging period and have emerged a more efficient and stronger group of companies. They're focusing on various aspects of the subsea project—well efficiencies, subsea plumbing and installation, among others—to provide cost-effective avenues to project execution.

Through year-end 2016 it appears that relationships still weigh heavily on market share results. For major subsea production equipment TechnipFMC and OneSubsea remain the long-term supply leaders. They hold strategic frame agreements with some of the most active operators in deep water, and where they do not hold frame agreements, they have longstanding relationships with them.

That said, the next few years could see some interruption in typical market share trends. Operators are considering the cost-reducing strategy of opening up the bid process to nonframe-agreement holders. The highly competitive nature of the subsea market at the moment could prove this approach successful and provide an extra amount of cost savings for the operator. How permanent, if at all, those interruptions might be long-term are hard to understand since many deepwater operators are creatures of habit and tend to stay true to suppliers and contractors with whom they have a long track record.

Cautious optimism ahead

Subsea and the greater deepwater market have undergone a tremendously difficult period wherein operators have had to reevaluate how they do business. The industry will have to redefine what a "good" year means to their business since a return to historic norms is all but impossible before the turn of the decade. That said, the industry continues to adapt and incorporate lessons learned to evolve into a more compact and efficient market better poised to withstand the lower oil price outlook. E&P

Subsea boosting offers field development solutions

The GoM stands to benefit from new wave of subsea boosting.

Phillip Luce, OneSubsea, a Schlumberger company

When subsea boosting was implemented in 1994, it opened a new frontier for offshore developments. In today's tough environment the technology has become more impactful than it was back then. The industry of late has been looking to innovative technologies in an unprecedented manner to overcome low oil-price woes. Introducing innovative methodology associated with subsea boosting technology aligned with project specifics is becoming even more relevant during the recent industry downturn. The value of subsea boosting technology is now being closely associated with a fixed development concept that takes into account various boosting methodologies including tiebacks, well deferral and brownfield revitalization.

Production economics

Subsea boosting will improve field economics by reducing backpressure on the reservoir, which will increase production rates. By allowing the pump to reduce the backpressure on the reservoir, an increase in well flow rates and total recoverable reserves results and flow assurance improvements such as increasing velocity in pipelines, temperature increases and production stability also are achieved. Deepwater and ultradeepwater Gulf of Mexico (GoM) operators who are embracing this technology (which has been used in other regions for some time) stand to gain much from both the production and economic perspectives.

At higher oil prices more wells were being drilled, flowlines were being added and more subsea hardware was the norm. Today the industry downturn has helped to highlight different approaches to field developments such as tiebacks, well deferral and brownfield revitalization.

The tieback option and use of a subsea pump is attractive in terms of reducing overall field development capital costs and improved recovery rates. In the instance of day-one boosting, net present value can be significantly increased by implementing a phased drilling approach, allowing the operator to see the benefits of the pump to maintain or increase the target production on top of saving drilling costs. In the case of brownfield revitalization, oil production from a mature field can be renewed by using a pump to supplement the amount of energy to drive the reservoir production.

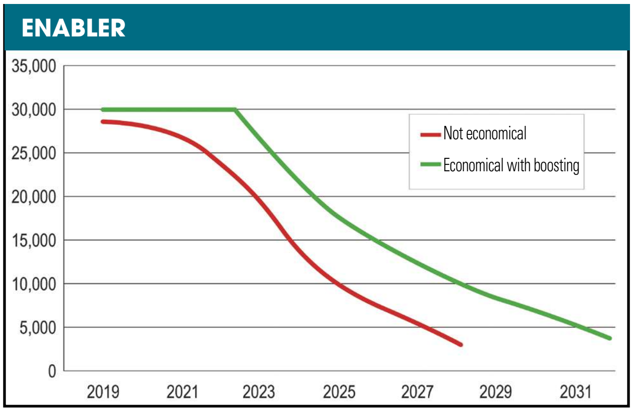


FIGURE 1. In a field where a target production was desired, use of a subsea pump resulted in accelerated production and extended plateau during the field's early years, offering an immediate return on investment and a greater return on capex. (Source: Schlumberger)

Business case to accelerate production

This better understanding of economically viable alternatives has led to customizing the methodology associated with each application of subsea boosting. For example, one GoM operator has seen enhanced production and field life extension. Based on the natural production curves, the required targets could not be reached to make the project economical. However, by implementing a subsea pump, this operator was able to increase production to the target levels and extend the production plateau, thus making the project viable. Cumulative effects of increased recovery also were witnessed in the later stages of well life (Figure 1).

In another field, an operator could reach production targets; however, enhanced production was desired. By including a subsea pump in the field architecture, the early years provided an accelerated production wedge that offered an immediate return on investment and a greater return on capex, allowing the project to become economically viable.

DIFFERENCE BETWEEN NATURAL AND BOOSTED PRODUCTION

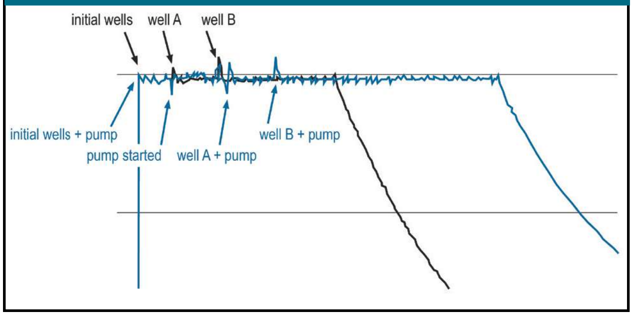


FIGURE 2. By incorporating subsea boosting, a well deferral scenario was implemented that allowed the operator to increase production while maintaining a better return on investment. (Source: Schlumberger)

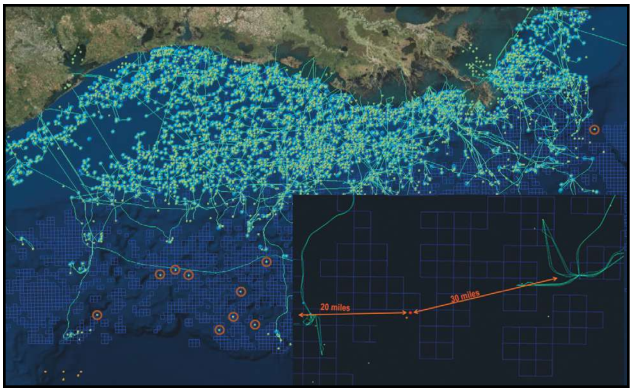


FIGURE 3. Rather than create a local host for a GoM field development, a 32-km boosted tieback provided the most economical solution. (Source: Schlumberger)

Well deferral: sensible economics

Another GoM operator was able to get over the FEED hurdle by applying a well deferral scenario that allowed the company to increase production while maintaining a better return on investment. The operator had originally planned to drill multiple wells. However, the operator was struggling to pass the FEED stage. By deferring two wells and only drilling three initial wells, the operator was able to use a subsea pump to boost these three wells, increasing production and in turn paying back costs incurred at project startup (Figure 2).

Tieback vs. host facility

One operator, also in the GoM, found that taking a tieback-to-existing facility approach had significant savings rather than taking the traditional approach to create a local host for the development. While a local host was considered in the early stage of the project, economics were just not strong enough to support that concept. A review was conducted of surrounding infrastructure that identified multiple tieback opportunities. First under consideration was a 32-km (20-mile) tieback. The effects of adding subsea pumps allowed this concept to support increased production over natural production while adding higher arrival temperatures and optimizing flowline sizing. Second under consideration was to examine the effects of extending the tieback to 48 km (30 miles), which still showed promising economics through boosted production. Considering the overall production of the field, the 32-km boosted concept provided the most economical solution, allowing the operator to progress the concept where a local host was no longer needed (Figure 3).

Brownfield revitalized

When a GoM operator's reservoir was maturing and reaching the end of its natural production, the operator decided to evaluate subsea boosting technology as a concept to remove the overburden and constant pressures being placed on the reservoir. Through the implementation of subsea boosting, the operator was able to revitalize the field and extend field life by many years. This allowed further reduction in overall life-of-field costs. Subsea pumps were able to reduce wellhead pressure while increasing total recoverables. The subsea pump also was used to alleviate flow assurance instabilities. Terrain slugging was present due to the maturing natural production. By the pump increasing velocities in the flowline, slugging concerns were eliminated. An additional enhancement of pump operations was the ability to restart flowing conditions from the weak wells. Taking advantage of these multiple subsea pump operational benefits, an additional 30 MMbbl were recovered.

Continuing a legacy of innovation

Subsea boosting technology, when combined with a well-planned and well-executed development design, yields economically viable projects and delivers the optimal solution for various well conditions and development drivers. With a multitude of GoM wells possible to be tied back and many brownfields on the decline, options abound for operators in the GoM to leverage subsea boosting as a technology and economic enabler. Under the current economic conditions subsea boosting promises to become a concept that will continue to challenge the industry to reevaluate project development scenarios. E&P

A shale completions JIP

It is time to do more.

Michael Shook, **John Jameson** and **Doug Scott**, Endeavor Management

Now that oil prices seem to be in stable recovery and the number of rigs in North America has been steadily rising month over month, shale oil seems to be on solid footing again in terms of its recovery. Since the early 2000s the industry has been working very diligently to reduce drilling costs and improve efficiency to make shale oil projects more economic. This effort was focused beginning in 2014 as a response to the stark reduction in hydrocarbon pricing. However, one area, while clearly being a driver for the economics of shale, has not been optimized to the level that perhaps reservoir development and drilling have been. That still-to-be-studied area is optimizing efficiency around completions.

There are several reasons for this lack of any major study around efficiency in shale completions. What likely focused the industry's energy was the high intensity of operations in the shale prior to 2014 and the economic nature of many of the operators (independent producers focused on time to first production). With hydrocarbon pricing just beginning to stabilize in recovery, many operators still lack the independent resources and scope of operations to fully study completion practices and options and implement best practices into their operations.

One solution for the shale industry is to initiate combined efforts to address the optimization of completion operations. A shale joint industry project (JIP) focused on creating benchmarks for shale completion operations can create better industry economics for completion operations as well as providing many operators with real data, sufficient resources and scope to implement optimized benchmarks in their operations. In addition, for service companies the need to build and maintain the right equipment and create high utilization for that equipment is driven by providing operators cost-efficient and effective completion services.

Apache's Alpine High play in the southern Delaware Basin was one of the most talked about finds in 2016. A new JIP intends to drive efficiencies in completions. (Source: Apache Corp.)

Historical perspective

Since the shale play began its strong market share push, oil and gas operators have looked to promote efficiency in their shale drilling and completion projects. Given the nature of the shale reservoir, the industry adopted a "manufacturing drilling and completion processes" mindset, with a majority of the focus put on establishing metrics and process improvements for drilling. Completion services (site preparation, pressure pumping, wireline, plugs, sleeves, coiled tubing, well flowback) were typically provided on a discrete basis by multiple service providers with the risk of downtime assumed by the oil and gas producers.

Changes over the years

With the drop in hydrocarbon prices, oil and gas operators have had to focus on driving service company pricing down, which has created the need for more efficient drilling and completion processes. Since 2014 completions services pricing has fallen anywhere from 20% to 40%. Oil and gas operators have transferred the risk of downtime during the completion process to service providers by requiring service companies to change their business model to reflect:

- "Per stage" turnkey pricing for each service;
- One service company providing multiple bundled services;
- A procedure-driven workforce;

- An efficient factory-based operations model with high safety standards; and
- Service companies sharing operational responsibility and some economic risks.

2017 outlook

While oil price has certainly begun its recovery and service companies are realizing higher demand for their existing completion services, the economic environment has demanded that both oil and gas operators and service companies change their business models to be more efficient when it comes to delivering completion services in the shale. Lower pricing, more responsibility for variable costs (like downtime) and greater liability have all "squeezed" the service companies' economic model beyond the breaking point.

In 2017 hydrocarbon pricing is at the point of making large portions of the shale an attractive investment again, especially since the overall cost of completions has dropped significantly over the last two years due to reductions in service company pricing. With a clear focus on shale drilling, pad drilling times are now less than pad completion times, with completions making up about 58% of drilling and completions authorizations for expenditure. Completion techniques (i.e., lateral length, isolation techniques, stimulation techniques) continue to increase in both complexity and size. While much of the equipment the industry stacked in 2014/2015 remains at hand, some percentage of that equipment is not usable today given the size and complexity of the completions operations being requested by operators. The latest minimum operating parameters (e.g., pressure, flow rates, operating times) now exceed the specifications on a large percentage of the equipment stacked and waiting for higher hydrocarbon pricing.

Shale completions JIP

Given the current state of completion operations in the industry, the efficiency of drilling and completions processes will differentiate the successful shale oil and gas operators in terms of profitability. In terms of service companies, the successful service companies will demonstrate an ability to provide the most efficient completion operations with the highest uptime for their equipment and well-trained personnel. Safety will, as always, continue to be paramount, and those service companies that can provide the safest and most efficient completion operations will flourish in 2017.

Currently completions operations vary dramatically by operator and geographic basin. To create more industry efficiency and better economics for all investors (operators and service companies), the industry must work cooperatively to maximize completion efficiency.

The Endeavor JIP will focus on driving efficiencies to the completions process by using data and expertise from a minimum of 90 operators and/or service companies. Specifically, the JIP will look at what can be done to shorten the completions cycle time while not compromising QHSE. In general, and for the purposes of this study, Endeavor has broken shale completions operations into six distinct study areas: site preparation; zone isolation; pressure pumping/stimulation; plug drillout; well flowback; and economic analysis and benchmarking.

The Endeavor JIP process will include:

- Formation of charter to identify the purpose and metrics for the study;
- Nomination (by the participants) of shale basins to be included in the JIP;
- Combining of participants' experts and data into a shale completion operations database;
- Observation of the JIP participants' operations by completion study area and basin;
- Conglomeration and analysis of data through collected data as well as a search of public data associated with completion operations;
- Creation of completion benchmarks by study area and basin for participating companies; and
- Publishing of a final report, which will include detailed economic modeling of the completion process by study area and basin, cost savings and recommendation of best practices.

The industry faces challenges that will always be underpinned with the cyclical nature of hydrocarbon pricing. However, one constant is that efficient economics, producible reserves and best practice service offerings will drive the value created in the hydrocarbon marketplace. North America has been once again blessed with a large resource that can supply a significant portion of the world's need for hydrocarbons far into the future. Is the industry going to operate in a way that creates historical economic value, or are the economics of the shale going to remind us of the negative economics of many exploitations of resources around the world, where more money was spent than value generated? E&P

Have a story idea for Shale Solutions? This feature highlights technologies and techniques that are helping shale players overcome their operating challenges. Submit your story ideas to Group Managing Editor Jo Ann Davy at *jdavy@hartenergy.com*.

Flange separation technique provides rigless alternative

Customer savings can be upward of tens of millions of dollars.

Guy Bromby, ThinJack Ltd.

ThinJackGAP is a recently released technology for supplying real-time (flange) gap data, whatever the method of flange separation, to minimize the likelihood of jamming the bolts on a bolt hole.

The company completed a platform christmas tree separation offshore West Africa where the previous method was taking in excess of three days while 14 adjacent wells were shut in. The process took less than 24 hours of critical path production time, bringing forward millions of dollars of production from high-producing wells.

Previously, conventional cylinder jacks were placed underneath the ends of a crucifix shape of "I" beams. However, the cylinder jacks started to bend the platform's structural beams, so the method was abandoned after 70 tonnes of force.

The common element of most of the seized flanges that ThinJack separates is rust in the bolt hole annuli. This needs significant force to overcome, sometimes up to 500 tonnes, with the capability for more force than this depending on the area between the outside of the bolt holes and the flange circumference.

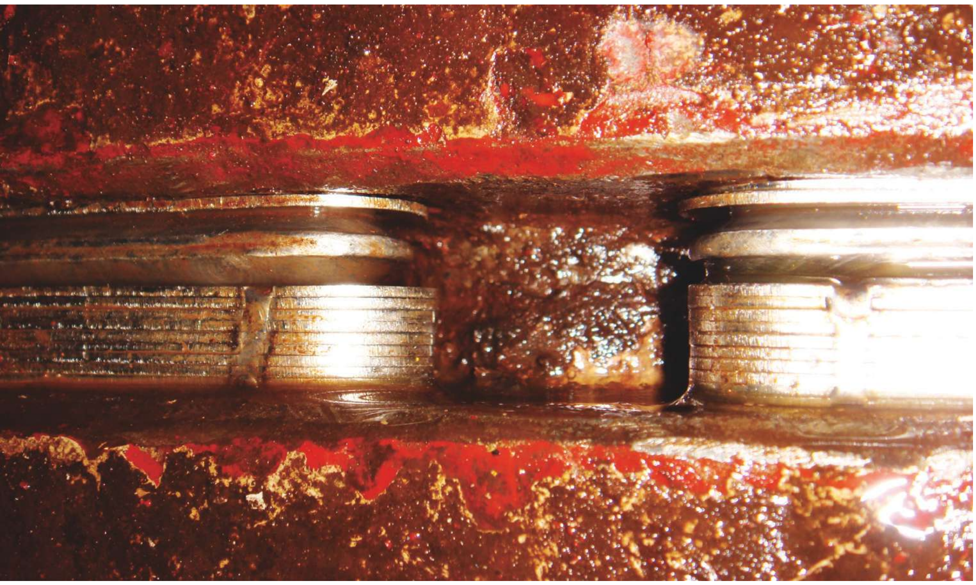
Technical challenges

In the U.S. Gulf of Mexico ThinJack separated well flanges to allow bolt replacement over a 27-month period. Bolts were internally corroded due to the combination of salt atmosphere and high wellbore temperatures from a deep gas reservoir. The platform decks were not strong enough to take bespoke manufactured jacking systems or conventional casing jacks, and alternative methods meant high engineering and installation costs for structural strengthening of the platforms' main support beams.

While the company works with drillstring and drawworks to add a powerful push to the rig's pulling power, ThinJack also separates seized well flanges when there is no platform or jackup rig. The ThinJack technology is standalone and immediately available. This is the context of the company's recent frame agreement in Egypt that followed the successful completion of emergency work to assist with restoring water injection.

ThinJack also works in combination with platform-based rigs and cranes, which typically have a lifting capability of between 5 tonnes and 30 tonnes. However, they are used for loading and unloading supply ships and moving personnel baskets and unavailable for well flange separations.

In West Africa ThinJack was contracted to assist with a backlog of christmas tree valve replacements before a jackup rig moored up alongside a production platform. There are limited methods for safe and effective sideways or angular pulls to remove valve covers or bonnets. Servicing these internal christmas tree valves or well annuli is possible once these bonnets are removed with ThinJack services.



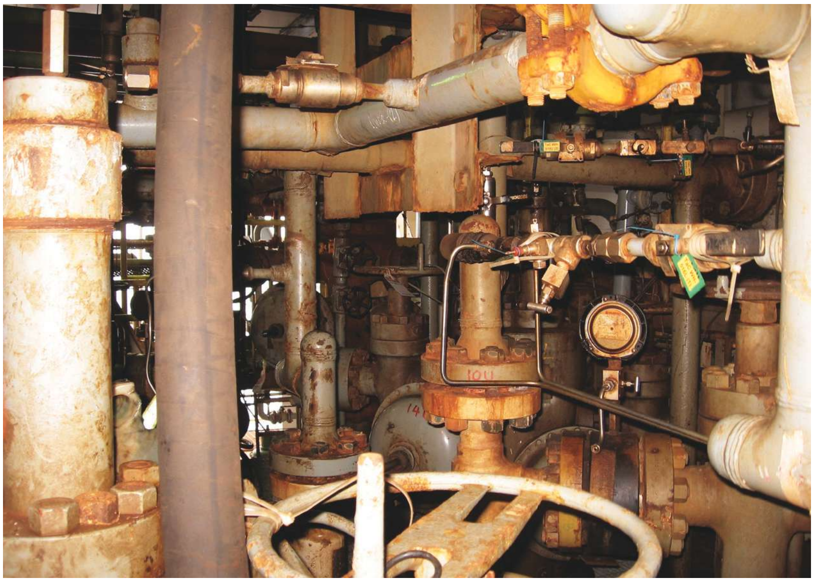
ThinJacks sandwiched within matching ThinShims are placed exactly where the force is needed, exerting 328 tonnes of force. (Source: ThinJack Ltd.)

Comparison with alternative methods

ThinJacks are both an order of magnitude thinner and more powerful than other flange spreading methods. They can be made to fit in gaps as small as 1 mm and deliver hundreds of tonnes of force safely and precisely to the right place. The most effective of the conventional flange spreaders needs a minimum 6-mm gap and delivers tens of tonnes of force.

Some traditional well flange separation uses platform or rig crews wielding hammers and crowbars and delivering several tonnes of force. Conversely, the ThinJack method minimizes the likelihood of injury to people and damage to well jewelry such as small-bore piping and pressure gauges from these various ad hoc methods.

Where there is sufficient flange gap, many operators cut flange bolts during well abandonment. Where the gap is a few millimeters, ThinJack increases the gap first. Removing cut bolts from the block before a new flange is installed might take several long shifts in addition to the bolt-cutting time. Once the bolts or studs are cut, they cannot be tightened up partway through the flange separation process. Also, bolts and studs might need to be refastened quickly when well barriers are less effective than anticipated.



On this well deck pipes, shut-off valves, flanges, gauges and support beams obstruct personnel movement and line of site to the well flange. This is the ideal site for ThinJackGAP, with flange gaps displayed at the system operator, and avoids a long work shift to unstick an unnecessarily tilted and jammed flange. Even on less crowded well decks repeatedly climbing just one access ladder adds significantly to the flange separation time. (Source: ThinJack Ltd.)

Per well flange ThinJacks generally take between 2 hours and 15 hours online critical path time depending on the extent to which a flange is stuck together. While this might not seem especially fast, it is time-effective when the ThinJack method is used before other often futile techniques. In general terms the order of cost-resultant savings to the customer can vary between $100,000 per day up to tens of millions of dollars depending on the number of wells, the oil and gas production value, and the cost of an attendant drill crew and rig.

New technology

In October 2016 ThinJack delivered ThinJackGAP, giving real-time gap data for all flange separation methods including ThinJack services, conventional spreaders, cranes, drillstrings and drawworks.

Flange gaps are measured when pulling rusty bolts through rusty bolt holes, and this minimizes the likelihood of jamming the bolts or studs inside the bolt holes. Once the flange tilts and jams, the powerful flange separation technique from a drillstring and drawworks becomes an effective flange jamming system. Note that EOR well operations might replace an old christmas tree, tubing or casing spool on a 30-year-old well conductor that is no longer vertical, but the upward pull is vertical and the small difference in angle increases the likelihood of a flange jam.

Other gap measuring systems such as a handheld vernier mean the measurer needs to clamber around pipework and obstructions on a crowded well deck to measure the gap. There is limited, if any, line of sight to see conventional gap measuring tools from a distance.

This slows down the flange separation and, because of the near inevitable jam, increases uncertainty and frustration just at the point when a drill crew thinks that the flange is about to come free.

ThinJackGAP displays the gap at several points on the flange circumference next to the separation system operator, who might be several meters away from the flange. Where the difference in gap is more than several millimeters, the flange separation should stop and a remedial plan agreed upon so that no one is blindly jamming the flange and unsticking it during the long shifts that follow. E&P

Have a story idea for Offshore Solutions? This feature highlights technologies and techniques that are helping offshore players overcome their operating challenges. Submit your story ideas to Group Managing Editor Jo Ann Davy at *jdavy@hartenergy.com.*

The *Pioneering Spirit* straddles its twin bows around the Yme platform before securing the structure, cutting the jackup facility's steel legs and lifting the 13,500-tonne topsides. (Source: Allseas)

Heavy-lift flag bearer

Mark Thomas, Contributing Editor

The decommissioning of Shell's Brent Delta platform in the U.K. North Sea will take place within the next few months, with Allseas' giant *Pioneering Spirit* heavy-lift and pipelay vessel to be the high-profile center of attention.

The vessel will carry out a world-record single lift in removing the 24,000-tonne topsides from Shell's Brent Delta platform in early summer 2017, with pre-lift preparation work including the design of underdeck lift points and strengthening of the module support frame. The work scope also will involve the cutting of the platform legs as well as the design and fabrication of lifting yokes, support stools and grillage.

Once carried out, the topsides will be transferred to the *Iron Lady* vessel for transportation to the dismantling yard in Hartlepool, U.K.

Shell's other three Brent platforms—Alpha, Bravo and Charlie—also will have their topsides removed by the *Pioneering Spirit* in a later phase under a contract awarded to Allseas in 2013. The heaviest of those will feature one topsides lift of about 30,000 tonnes.

Black Sea job

Following the work on Brent D this summer, the *Pioneering Spirit* is due to move to the Black Sea to work on the TurkStream project in what will be its maiden pipelay job. The workscope includes engineering and installation of 900 km (550 miles) of 32-in. pipeline in the Black Sea in water depths of up to 2,200 m (7,218 ft). The line will link Anapa in Russia with Kiyikoy in Turkey.

Allseas also has work lined up for the vessel with Statoil for the transportation and installation of topsides for three platforms that are part of its Johan Sverdrup Field offshore Norway, currently under development. The topsides lift weights for those will range from about 19,500 tonnes up to 26,000 tonnes, with the first installation work expected to get underway in 2018.

The *Pioneering Spirit* has a topsides lift capacity of 48,000 tonnes and a jacket lift capacity of 25,000 tonnes and is expected to be increasingly used for decommissioning work, mostly in the North Sea, as operators wind down their larger mature field operation centers over the next few years. ■

Improved directional drilling through automation

New technology improves performance and consistency of drilling horizontal wells.

Bill Chmela, Motive Drilling Technologies

One of the most significant problems identified by oil and gas operators in unconventional plays is the inability to follow a prescribed well path consistently and to hit and stay within the targets identified collectively by the company's geologists, geophysicists and engineers. One reason is that directional drilling technology lags behind other technical advances that drove the tremendous growth in horizontal drilling.

FIGURE 1. The Motive Drilling Technologies intuitive 2-D and 3-D displays deliver data, information and complete directional drilling transparency to the entire team. The computational power of the system improves the performance of the driller or directional driller. (Source: Motive Drilling Technologies)

To address this problem, Motive Drilling Technologies developed a directional drilling bit guidance system automating decision-making at the rig. Automated decision-making has been used for making medical decisions; for playing games (such as Jeopardy, chess, poker or the ancient game of Go); for automatically piloting cars and planes; for manufacturing, shipping and missile guidance; and for much more. Over the past five years Motive has applied automated decision-making to its bit guidance system's development and subsequently to the drilling of more than 610,000 m (2 million feet) of horizontal and extended-reach wells for more than a dozen oil and gas companies across North America. Use of the system has resulted in wells drilled with more consistency in less time, with more accuracy and more production potential and, in some cases, with less personnel (Figure 1).

Drilling rates are so fast that even the best directional drillers simply do not have the time to perform all the necessary calculations required to make the absolute best directional drilling decisions. The performance of directional drillers often is quite variable, costing the industry billions of dollars each year due to slower drilling speed, increased tortuosity and lost production potential.

Need for speed

While drilling horizontal wells, directional drilling experts must make quick decisions determining when to rotate the entire drillstring and when to adjust the direction of the drillstring by sliding. These decisions are based upon numerous inputs, including bit walk tendencies, motor yields, anti-collision guidelines, dogleg severity and future production consequences related to deviation from the target path. In real time the directional driller continuously analyzes data including gamma ray logs, hook load, surface torque, pump pressures, flow rates, trajectory measurements, distance to nearby wells and much more.

Good directional drillers rely upon their expertise developed over many years as apprentices to more experienced drillers. This results in an environment where most directional drilling decisions are made quickly based on the individual's experience and an acquired intuition. However, the best directional drillers also know when they must move beyond intuition and shift to performing more effortful geometrical computations to make good decisions. Nobel Prize-winning author Daniel Kahneman wrote in his book *Thinking Fast and Slow* that in many situations humans tend to rely upon intuitive thinking too much. They are not willing or do not have the time or energy to switch to more effortful thinking, even when it is required for better decision-making. This unwillingness to adapt behavior contributes to the large variation in performance often seen while drilling horizontal wells.

Automated process

The bit guidance system developed by Motive uses a high-performance computer to provide a more data-driven automated decision-making process, delivering the necessary improvement in directional drilling performance. As a foundation for better decisions, the system automatically performs standard directional drilling calculations previously done by the directional driller but calculates them continuously and faster than humans are able. In addition, the system provides a tremendous amount of additional analysis and automatically provides the driller with step-by-step slide/rotate guidance based on the dynamic analysis together with parameters set by the operator. The machine can run calculations on millions of possibilities/permutations that a human cannot do, thereby making the best decision to maximize value. The automated decision considers such variables as drilling time, lost-time risk and future production potential. Additionally, tortuosity of the wellbore is factored into each directional decision to reduce torque and drag on the wellbore, enable higher drilling rates, extend the maximum reach of laterals and reduce sumps in the lateral that impact production efficiency. This degree of analysis is rarely even considered by human directional drillers.

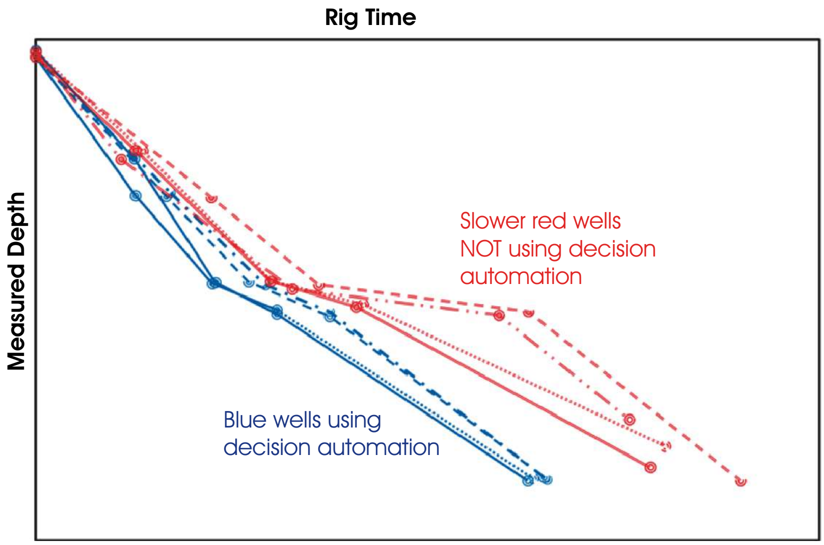


FIGURE 2. Blue lines are the time-depth curves for the four wells using drilling automation. The red lines are the time-depth curves for the four wells not using the system. The wells using the system were drilled in 25% less time and were twice as accurate. (Source: Motive Drilling Technologies)

The system continuously adjusts the guidance based on driller's actions and provides real-time feedback to enhance his or her performance. This level of automation consistently improves the driller's ability to maximize value to the operator independent of experience.

Eagle Ford case study

Figure 2 shows the results of a case study designed to test the system for a client drilling in the Eagle Ford Basin. Two identical rigs were mobilized in the same area and drilled four wells each. One rig used Motive's decision automation tool, and the other rig drilled the wells without decision automation. All other parameters were the same, including bit, bottomhole assembly and well paths. The rig using automation drilled 25% faster and with twice the accuracy.

The system does not completely automate every single task of the directional driller. But the computational power of the system combined with the experience and intuition of the directional driller provides oil and gas operators with the best opportunity for consistent performance at higher levels while mitigating risk. With the introduction of decision automation, new roles might need to be defined, and an emphasis on change management and new technology acceptance is critical.

However, the rewards are great. In addition to the gains in performance on an individual well basis, the expertise of the best directional drillers can be scaled. With the system performing all the heavy computational lifting, a single expert directional driller can guide multiple wells from a single location.

With this distributed system, the entire decision-making team (on the rig and in the office) is continuously informed about past, current and dynamically planned future directional drilling activities using automated dynamic reporting, email and text notifications, freeing the directional driller to perform other tasks. The system provides this transparency through 2-D and 3-D visualization interfaces that are available both through a browser and iPad app.

By providing complete directional drilling transparency to the entire team regardless of location, the system returns operational control back to the operator and provides better utilization of the best directional drillers.

Just as decision automation is helping doctors provide better treatments and cars to be safer, this technology has proven to improve the performance and consistency of drilling horizontal wells in today's tough environment. E&P

Have a story idea for Operator Solutions? This feature highlights technologies and techniques that are helping upstream operators overcome their challenges. Submit your story ideas to Group Managing Editor Jo Ann Davy at *jdavy@hartenergy.com*.

Reactive vs. proactive equipment maintenance programs

A mobile classroom is transforming preventive maintenance programs one field trip at a time.

Jeremy Holberg, Gardner Denver Pumps

As the industry shakes off the downturn, many U.S. operators are planning major drilling boosts in their 2017 programs. More specifically, drilling in the U.S. is expected to jump about 25% and in Canada 21%, respectively, according to industry surveys.

The economic downturn of the last few years has been challenging for the oil and gas industry. Faced with low-priced oil, operators, upstream equipment contractors and everyone in between had to determine how to make more or do more with less. As E&P companies took measures to reduce costs and delay capex to remain competitive in the market throughout 2015 and 2016, tightened budgets have had a significant impact on the equipment in the industry. Many companies were forced to shift from preventative to reactive or run-to-failure programs to survive.

As reactive maintenance programs were adopted across the industry, managers and field personnel also began to mix and match components to make quick repairs and push equipment further. These strategies only complicated the industry's aging equipment issue, which led to more serious problems down the road in most instances.

Gardner Denver's Pump University class trains pumpers to assist with fluid ends. (Source: Gardner Denver)

Now, as companies look to rejuvenate aging equipment—a move that is long overdue—they are also taking steps to implement more effective maintenance programs. This is especially important in the case of pumps and power ends, which are vital components to well servicing.

Defining maintenance strategies

There are two conventional approaches to maintaining oil and gas equipment, and both carry significant advantages and disadvantages. Companies apply different strategies to producing energy, and the same goes for developing and executing maintenance programs. The most common approaches to equipment maintenance are a reactive (run-to-failure) or a preventative (scheduled) program. Ultimately, energy producers will make maintenance decisions that best align with their operational tempo and budget. However, those organizations that have maintained a preventative maintenance program these last few years have the good fortune of "reaping what they sowed." Just like a car that's taken in for routine oil changes and tune-ups runs longer, so does the life of well servicing equipment that's been properly maintained.

Unfortunately, over the past few years limited budgets required many operators to adopt a reactive approach to maintenance. Operators have been under pressure to produce energy and increase cash flow with fewer resources.

Run-to-failure programs have allowed companies to continue operations at the lowest possible cost. This meant neglecting, or at least delaying, the maintenance requirements of equipment in need, which is very risky and often can lead to equipment failure on the job and ultimately unplanned downtime. Service interruptions can negatively affect a company's reputation and impair their ability to maintain contracts with clients. When operators consider the potential collateral damage presented by run-to-failure maintenance programs, the disadvantages outweigh the cost savings.

On the opposite end of the spectrum is the preventative or schedule-based maintenance approach. Each asset is placed on a routine maintenance schedule so that operators know precisely when it will be taken out of rotation and serviced. Scheduled maintenance has many advantages. Namely, it allows operators to schedule downtime and avoid unexpected service disruptions. Regularly servicing equipment allows operators to run equipment longer and more efficiently, greatly reducing the cost of powering each unit and enhancing the value of a company's assets.

Mobilizing instruction

Due to the cyclical nature of upstream oil and gas, labor must be expanded and contracted to levels appropriate for market demand. This presents major challenges in both the downcycles and the upcycles. In downcycles companies often lose highly skilled and experienced labor. Unfortunately, those folks often find work in other industry sectors. When the market begins to recover, skilled labor can be scarce, and many companies are competing for these limited resources. As a result, operators must hire less experienced labor. The need for these "greenhorns" to receive proper training is very high, and time is short. Operators will struggle to deploy an effective maintenance program without providing their new workforce with the education required to do the job right, thus further exacerbating the equipment reliability issue.

Gardner Denver's approach to assisting with this effort is a mobile classroom that travels to a customer's facilities and trains employees how to properly maintain pumping equipment.

Graduates of the program have found that their newly improved maintenance skills have extended the life of the fluid ends on their site, improved equipment reliability and lowered nonproductive time on the job. Beyond increasing the lifespan of their fluid ends, customers have also seen benefits in the form of lower repair costs, decreased production costs and a reduction in workplace hazards.

Pump University's instructors teach customers valuable maintenance tips through workbooks, visual presentations and hands-on training. The classes are designed for frack hands, but engineers and other employees have found value in the courses. Many participants find that these courses teach them about expendables as well as fluid ends.

Since 2013 Gardner Denver's Pump University has trained more than 3,000 students throughout the U.S. and has seen tremendous results.

Looking ahead

With market demand increasing, the time for equipment inspection is now, and the first step is an initial assessment

To date, more than 3,000 participants have attended Pump University. (Source: Gardner Denver)

of equipment. This seems easy, but the task is quite difficult. Many operators lack the resources required to inspect the condition of their large fleets and build an effective rejuvenation plan in short order. Field inspections are conducted by both factory-trained service technicians and field engineers often free of charge.

Gardner Denver also has rebuild facilities in Fort Worth, Texas; Altoona, Pa.; Odessa, Texas; Edmonton, Alberta, Canada; and San Antonio that are designed for rapid response and are strategically located close to its customers in the shale basins. If there is simply not enough time for a complete rebuild (which can take about 21 days), certified remanufactured equipment is in stock and available.

Ultimately, maintenance strategy decisions are market-driven. With an expected rise in drilling and completion activity this year, operators are busy trying to win new business and, in many cases, are spreading people and horsepower thin across locations to pump more with fewer resources.

With a proactive approach to maintenance and proper training, operators can ensure long, economical and trouble-free pumping operations. Perhaps the most important benefit to well-maintained equipment is safer operations. There is no cost-saving measure that is more important than protecting the safety of the men and women who work to unlock vital energy resources. E&P

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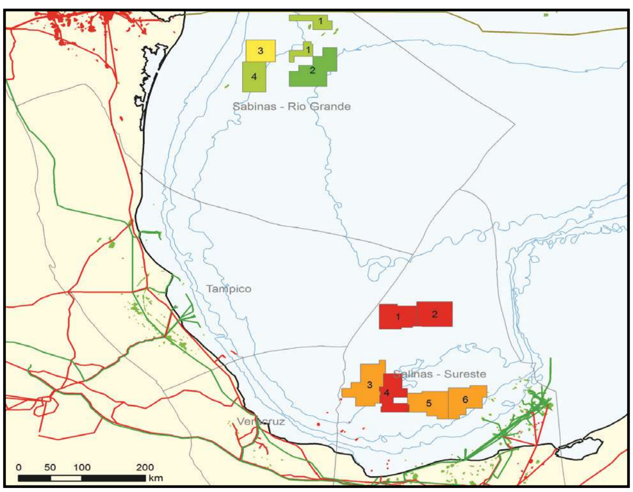
Exploration tool enables customized evaluations

Dynamic reserves modeling tool with global coverage enables exploration teams to do more with less.

Dr. Andon Blake, Petroleum Edge

Oil and gas exploration has always had a strong element of risk, not only in terms of making a discovery but also due to fluctuating product prices and ever-changing geopolitics. Many variables influence the potential value of a hydrocarbon discovery, and the evaluation of exploration acreage for investment decisions is always complicated by the limited amount of data available. The value of a prospect is not necessarily related to its volume, especially in today's volatile economic and political environments. So the need to understand and quantify the geologic risks and carefully model the complexities of petroleum economics is imperative.

EV^2 is an exploration valuation platform that has been designed to assist in this decision-making process. It has been jointly developed by CGG and Wood Mackenzie to provide an independent, transparent and consistent analysis of undrilled acreage. EV^2 uses the latest economic data and commercial insight from Wood Mackenzie combined with Robertson's geologic knowledge and expertise within CGG's GeoConsulting group to provide a user-friendly economic modeling tool.



This heat map shows the volume potential of the Perdido and Salinas area blocks. (Source: Petroleum Edge, EV^2; CNH)

Currently it contains block-level geologic risk, volume and value data for more than 100 prospective basins and 700 geologic plays, and this will increase to more than 180 basins and 1,000 geologic plays to provide a global assessment tool for exploration.

EV^2 allows geologic assumptions to be changed to accommodate different views of play risk or lead density. Scenarios can be tested to provide a range of possible outcomes so that budgets and resources can be planned. Play and basin metrics can be compared in a transparent and objective manner to evaluate corporate portfolios for petroleum economists and financial institutions.

Where additional proprietary information is available, this can be used to edit the underlying geologic assumptions in EV^2 to refine the baseline volumetric assessments. This enables users to create their own customized scenarios quickly in a confidential in-house environment and to maximize their competitive advantage. The platform provides the means for new ventures and exploration teams to compare prospects in a consistent manner to guide license round screening and farm-in evaluation.

Evaluation of the exploration acreage that was recently on offer in Mexico's Licensing Round One provides a good example of how using EV^2 for the fast assessment of potential volume and value can give valuable insights to participants and interested parties.

The EV^2 data for the Sabinas-Rio Grande Basin identify eight geologic plays based on the interpretation of a number of data sources by CGG Robertson's regional experts. Most of the yet-to-find reserves (more than 80%) are expected to be found in the Upper Oligocene, Lower Oligocene and Upper Paleocene to Lower Eocene plays. The platform identifies the most exciting play to be the Upper Paleocene to Lower Eocene, with potential volumes of between 6 Bboe and 10 Bboe estimated.

Considering the blocks on offer in the Mexican deepwater licensing round, the Perdido area blocks within the Sabinas Rio Grande Basin have been assessed as having the greater volume potential vis-à-vis the Salinas Area blocks.

Perdido and Salinas area blocks

The greater prospectivity in the Perdido area is reflected in the bidding within the licensing round, with successful bidders in these blocks due to drill five out of the eight wells committed to in the round. All the blocks on offer in the Perdido area were licensed, while there were no bids on Block 2 and Block 6 of the Salinas Area.

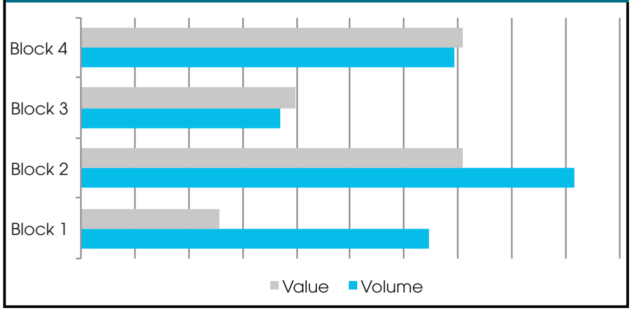
However, value depends on more than just volume, and EV² enables pretax and post-tax expected monetary values to be assessed at various price scenarios so that economic attractiveness can be quickly evaluated. An assessment of the Sabinas-Rio Grande Basin reveals that the Upper Oligocene play has greater value creation potential than the Upper Paleocene to Lower Eocene play as a result of lower expected development costs.

EV² provides an understanding of how all the plays intersect with the license blocks on offer, and the mapping can guide further efforts in analyzing opportunities. Comparing pretax expected monetary values vs. volumes of the Perdido area blocks for the two most interesting plays highlights that volumes and values do not have a linear relationship. Pretax valuations are somewhat lower in blocks 1 and 2 due to likely higher costs resulting from their deeper water locations compared to blocks 3 and 4.

Focusing on post-tax valuations and assuming a 10% additional royalty in all blocks for a clear comparison, the EV² results show the Upper Paleocene to Lower Eocene will, in the mean statistical case, be sub-commercial in these deepwater blocks under the base case assumptions. The Middle Eocene also has been determined to be sub-commercial. Of the remaining six commercial plays, the Upper Oligocene will likely be the standout play from a valuation perspective.

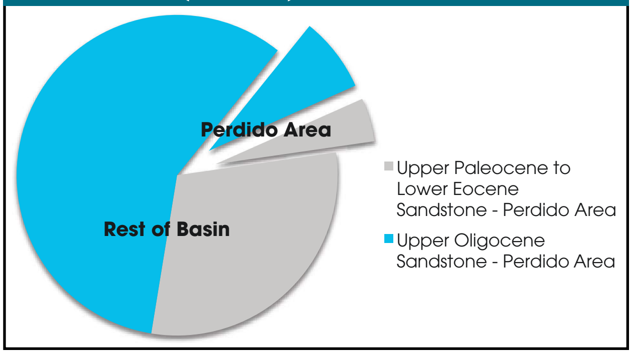
Following on from this *a priori* analysis, it is useful to provide a contrast to the actual results of bidding in the Perdido area as individual company strategic considerations are an important driver. Generally, companies in a strong financial position will be looking to take on countercyclical investments in exploration acreage motivated by their existing portfolios and exploration strategy. Apparent from the round is the aggressive bidding of Asian national oil companies, reflecting an eagerness to secure a foothold as they face a long-term growth challenge. Blocks 1 and 2 in the Perdido area received additional royalty bids of 15% and 17%, respectively, from CNOOC, with work unit commitments of two wells in Block 1 and one well in Block 2. The majors also have been active, bidding in consortia but less aggressively, perhaps as a result of already large portfolios and muted price expectations.

VOLUME AND VALUE FOR KEY PLAYS



Relative pretax valuations are lower in blocks 1 and 2 because of their water depths. (Source: Petroleum Edge, EV²)

SABINAS RIO GRANDE KEY PLAYS PRETAX EMV (US $MM)



More than 80% of the Sabinas Rio Grande Basin volumes and value are in open acreage. (Source: Petroleum Edge, EV²)

None of the consortia involving Chevron, ExxonMobil and Total in the Perdido area exceeded an 8% royalty bid. This mixture of strategic considerations, combined with EV² value and volumetric outputs, makes for valuable insight into the risks and likely rewards from the first Mexican deepwater bid round.

Looking to future bid rounds, the potential of Mexican exploration acreage is not in doubt. Under the base case assumptions EV² results show that more than 80% of the Sabinas Rio Grande Basin volumes and values are in open acreage. As more work is done on the blocks and more data are acquired, extra information can be incorporated into the platform to give additional insight to those owning the new data.

This fast but rigorous evaluation demonstrates that EV² can be used to analyze exploration acreage and provide information to new ventures teams as well as all interested analysts in government and financial services. The flexibility of the platform, enabling assumptions to be changed and different scenarios to be tested, provides answers quickly for informed decision-making. E&P

De-risking the frontier

A new study provides a clearer image of the Namibe salt basin.

Matthew Tyrrell and **Will Reid**, PGS; and
Domingos Cunha, Sonangol

Dual-sensor broadband data have been used to identify significant presalt and post-salt potential in the Namibe Basin offshore southern Angola. The superior imaging offered by dual-sensor seismic data combined with geoscience evaluation work presents an understanding of the structural setting, reservoir facies and hydrocarbon charge of this frontier basin. Studies also seek to address some of the presalt exploration challenges in this basin that also have been encountered in the neighboring Kwanza Basin.

The Namibe Basin represents a significant unexplored hydrocarbon province located onshore and offshore southern Angola. During the Late Jurassic to Early Cretaceous the eastern Atlantic margin of this part of West Africa developed as the conjugate to the prolific hydrocarbon-bearing Santos and Campos basins offshore Brazil. Although recent research describes the conjugate basins of Brazil and Angola as asymmetrical, with each basin containing slightly different petroleum elements, discoveries of supergiant oil fields in the Santos and Campos basins have resulted in a wave of presalt exploration optimism in Angola, with some notable successes.

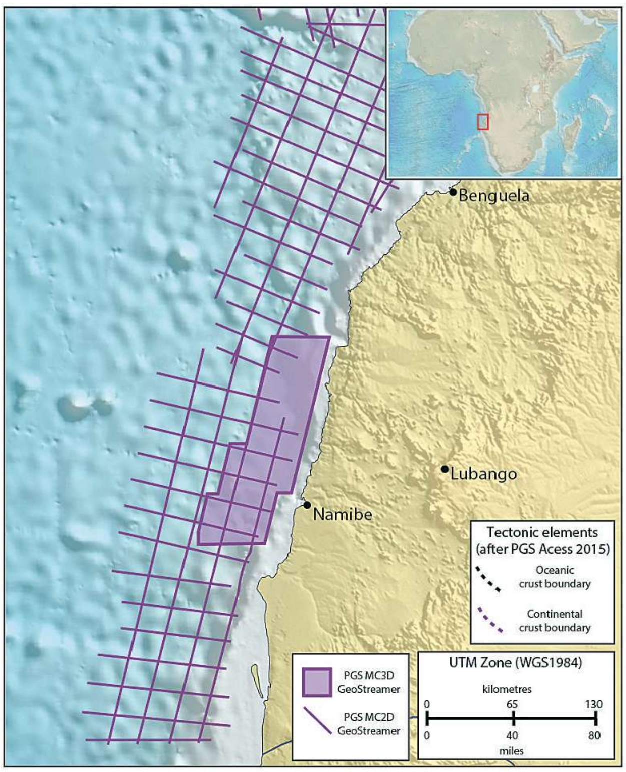


FIGURE 1. PGS acquired a regional 2-D dual-sensor broadband survey that was processed and migrated to a depth of 15 km (9 miles), allowing the basin architecture and presalt plays of the Angolan basins to be de-risked. (Source: PGS)

The recent exploration of the presalt plays in the Angolan Basin has been rapid, with significant discoveries made away from the present-day shelf in the Kwanza Basin such as Lontra, Orca and Bicuar, demonstrating the success of this play.

A large regional 2-D dual-sensor broadband survey was acquired by PGS in 2011 and was processed and migrated to a depth of 15 km (9 miles), allowing the basin architecture and presalt plays of the Angolan basins to be de-risked (Figure 1). Analysis and interpretation of this 2-D dataset, constrained by the PGS Access West Africa depositional sequence framework, highlighted the prospectivity potential of the Namibe Basin, and subsequently a multiclient 3-D dual-sensor survey was acquired to better illuminate it. This 3-D survey offers unrivaled imaging of the presalt section and allows more confident delineation of presalt reservoir facies.

Petroleum systems

Since the Namibe Basin is undrilled, the geological and hydrocarbon property information required to understand and de-risk the petroleum systems has been extrapolated from neighboring basins in Angola and Brazil, constrained by a sequence stratigraphic framework. In addition, geological knowledge has been collated from the onshore portion of the Namibe Basin, where the Cretaceous presalt stratigraphy outcrops and is exposed.

Source rock story

From a regional understanding of the source rocks of the Angolan and Brazilian margins, those for the Namibe Basin are expected to occur predominantly in the presalt syn-rift (Lower Cuvo equivalent) and sag-phase (Bucomazi equivalent) lacustrine sections, with

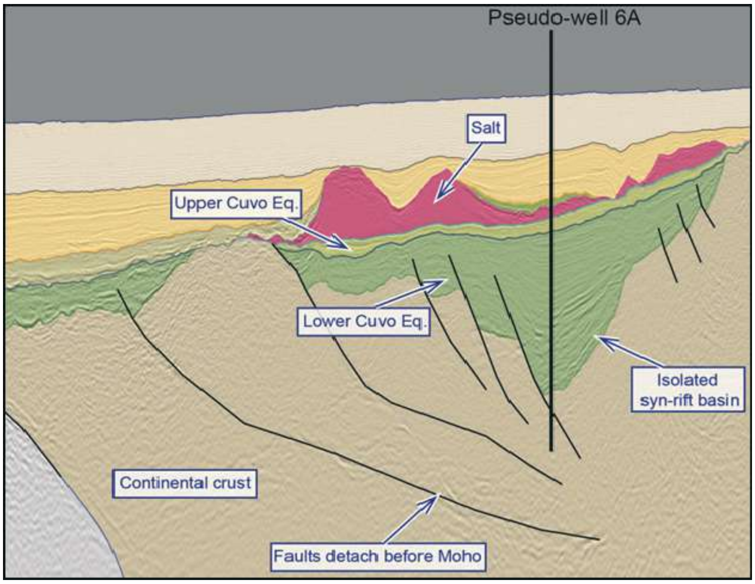


FIGURE 2. Basin modeling work conducted on pseudo well locations in the Namibe Basin exhibits encouraging maturation profiles. (Source: PGS)

potential for a secondary early post-rift source rock (Iabe equivalent) in the deeper water.

Regional temperature and geochemical information has been taken from well data in Angola and Namibia, and appropriate ranges were selected as input for the modeling of source rocks. The results of this basin modeling work, conducted on pseudo well locations in the Namibe Basin, exhibit encouraging maturation profiles, with the Lower Cuvo Formation equivalent reaching early oil generation in the Eocene and Bucomazi Formation equivalent in the Miocene (Figure 2).

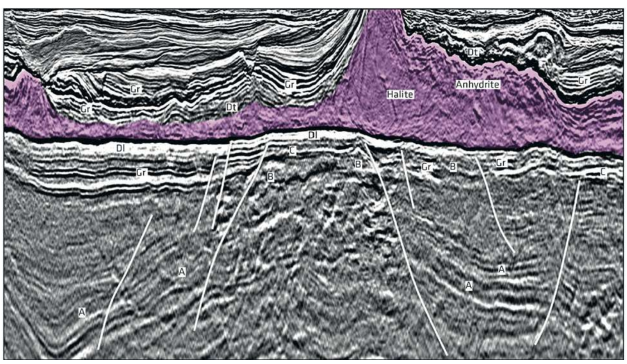


FIGURE 3. The resolution of the dual-sensor broadband survey has allowed seismic facies to be characterized and delineated with greater confidence in the presalt section. (Source: PGS)

Reservoir facies analysis

An understanding of the likely reservoirs of the Namibe Basin and their stratigraphic and spatial distribution can be established by comparing equivalent depositional packages between the conjugate basins of Angola and Brazil.

In the Namibe Basin, syn-rift reservoirs are expected to exist as formation equivalents to the Lower Cuvo Formation continental sandstones and the Upper Cuvo Formation fluvial to lagoonal. Post-rift reservoirs are expected to comprise shallow marine sandstones of the Iabe Formation, Pinda Formation (Binga Member) carbonates and deep marine sandstones of the Landana Formation.

The resolution of this 3-D dual-sensor broadband survey has allowed seismic facies to be characterized and delineated with greater confidence in the presalt section. These facies could then be compared to drilled analogs seen in equivalent dual-sensor broadband data in the Kwanza, Santos, Campos and Espirito Santo basins (Figure 3).

In the early syn-rift section equivalents of the Lower Cuvo Formation continental sandstones from Kwanza and the Lower Guaratiba sandstones of Santos can be interpreted, characterized by higher amplitude seismic facies with possible fan-like geometries. Above these, equivalents of the shallow marine sandstones of the Upper Cuvo Formation (Kwanza) and Upper Guaratiba (Santos) also can be delineated.

In the sag-phase section, seismic resolution allows the description of multiple facies characters and their spatial distribution to be mapped in relation to the rift structures. Here, depositional facies such as grainstone shoals, microbial buildups, coquinas and tidal dolomites can be inferred based on matching their seismic reflector amplitude, frequency and continuity characters to equivalent facies in the Kwanza and offshore Brazilian basins.

In the post-rift section, facies distribution is noticeably influenced by salt movement. Here, grainstone shoals and sand-dominated mass flow deposits can be interpreted with numerous plays provided by salt withdrawal collapse features and ponding of sands in palaeo-lows.

Sealed by salt

Aptian salt deposits are well known in the Kwanza, Santos and Campos basins, where they act as the main seal for multiple fields and discoveries. Interpretation and mapping on the new 3-D dataset has shown that the salt deposits are far more extensive in the Namibe Basin than previously identified in conjugate margin reconstructions or in 2-D data. Within the salt itself different seismic reflector characteristics are recorded, suggesting the presence of massive halite as well as bedded anhydrite layers.

Large presalt structures

The 3-D seismic dataset over the basin was acquired towing 12 dual-sensor streamers with a streamer length of 8,100 m (26,575 ft). These acquisition parameters allowed the deep structures and faults to be successfully imaged and the architecture of the basin to be confidently interpreted.

Numerous syn-rift structures are seen within the presalt section associated with tilted fault blocks and subsequent inversion events. Overlying the syn-rift, the sag phase similarly displays complex structural geometries with multiple subsalt closures in which hydrocarbons can be trapped.

Because of the resolution of the data in the sag-phase section, the relationship of the reservoir facies to these syn-rift structures can be understood. On the flanks of the structures, facies interpreted as grainstone shoals can be seen to be onlapping or pinching out against the highs, with the timing of rift activity clearly influencing the deposition of these facies. Toward the crests of the structures, facies interpreted as coquinas can be seen to be accruing along with possible microbial buildups, onlapped by grainstone shoals. Overlying these, in the late sag phase, facies interpreted as shallow marine dolomites are interpreted in the central part of the basin immediately underneath the salt and likely associated with the onset of restricted basin circulation.

Challenges of CO_2 contamination

A number of recent exploration wells in the southern Kwanza Basin have encountered CO_2 contamination in presalt reservoirs, interpreted to have displaced an earlier oil charge. This CO_2 has been geochemically typed to mantle, either sourced via deep-seated faults penetrating the Moho or resulting from shallow exhumed mantle degasing.

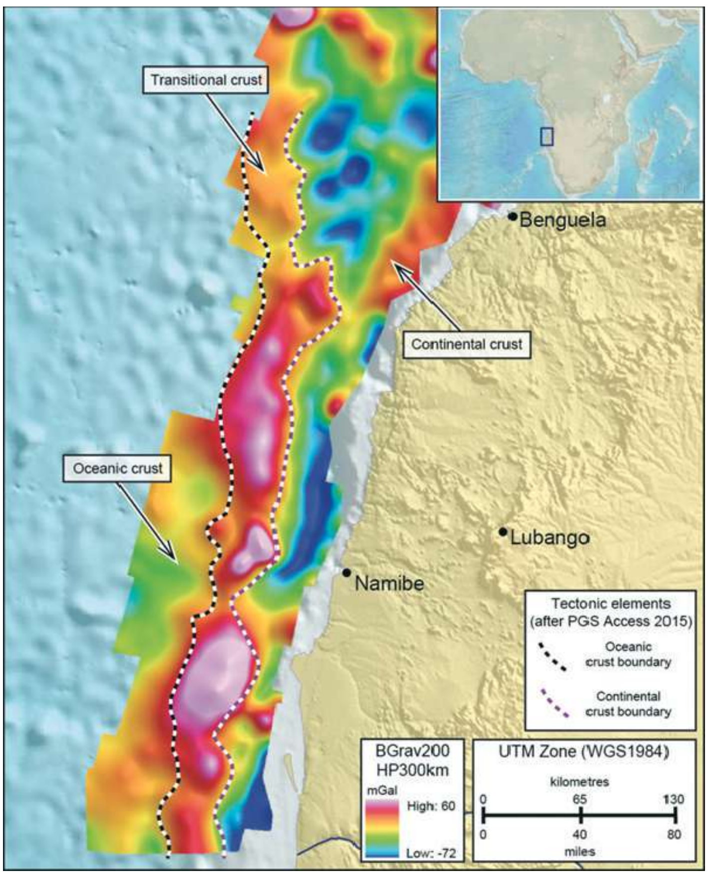


FIGURE 4. Shipborne gravity and magnetic data combined with GeoStreamer data have identified that CO_2 contamination can be de-risked through the interpretation of crustal types, mapping of volcanic hot spots and the interpretation of fault propagation depths. (Source: PGS)

A basin structure and architecture study of the Namibe Basin was undertaken as part of the PGS Access project using shipborne gravity and magnetic data combined with 2-D GeoStreamer data (Figure 4). This work has identified that CO_2 contamination can be de-risked through the interpretation of crustal types, mapping of volcanic hot spots and the interpretation of fault propagation depths. Similarly, areas of gravity highs can be assigned to areas of ridged lithosphere, reducing the likelihood of the presence of exhumed mantle.

The Namibe Basin is an underexplored and undrilled province with considerable hydrocarbon potential. PGS dual-sensor broadband data combined with targeted geoscience work has identified the key elements of a working petroleum system while reducing the known exploration risks. Basin modeling results suggest the likely generation and expulsion of hydrocarbons from syn-rift source rocks, while gravity modeling work has predicted a reduced risk of CO_2 contamination.

The resolution and imaging of the seismic data permits the identification of numerous presalt reservoir facies analogous to those of conjugate and neighboring presalt basins and demonstrate the relationship and distribution of these facies to the syn-rift structures.

Open acreage, an anticipated license round and modern multiclient data make the Namibe Basin a highly attractive focus for frontier exploration. E&P

References available.

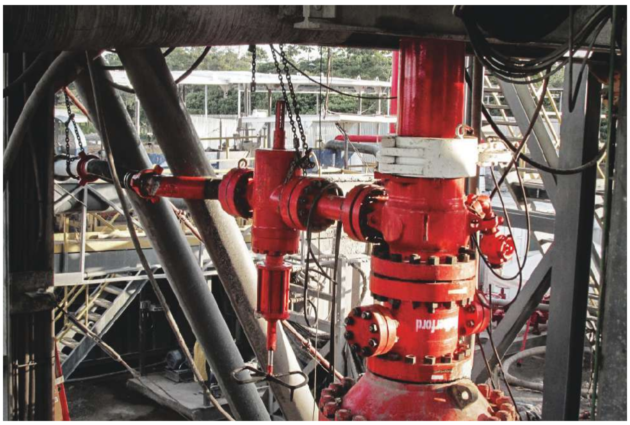
MPD for onshore operations

Automatic system reduces response times to influxes or losses, minimizes influx size, optimizes circulation rates and increases drilling speed.

Brian Grayson, Weatherford

Managed-pressure drilling (MPD) systems have proven effective in every type of well worldwide, including vertical, horizontal and unconventional designs. These technologies offer dramatic and immediate safety and efficiency benefits when drilling in HP/HT or depleted zones in offshore and onshore environments.

In contrast to offshore programs, onshore operations typically involve drilling multiple wells at significantly lower spread rates and thus require purpose-built and cost-effective land-based technologies. Scalable to the task, MPD technologies offer broad capabilities that range from basic pressure management to fully automated pressure response. Choosing the right MPD technology can deliver safer, faster operations in each land well drilled, and the cumulative impact on speed and costs can create opportunities for additional drilling to increase overall production.



The SafeShield RCD enables MPD techniques in a wide range of applications, including high-pressure wells. (Source: Weatherford)

Closing the loop

A closed-loop system enhances safety and efficiency compared to traditional open-to-air mud return systems by enabling wellbore pressure management. Every closed-loop system must incorporate a rotating control device (RCD). Additional standard components include flowmetering technologies, drilling choke manifolds, downhole isolation valves, and sophisticated software and controls that integrate all components into one automated system.

RCDs enable basic to advanced pressure-control capabilities. In basic applications the RCD contains and safely diverts fluid returns from the rig floor. For advanced applications, it creates a cap on the wellhead to enable immediate detection of minute influxes or losses and precise management of wellbore pressures.

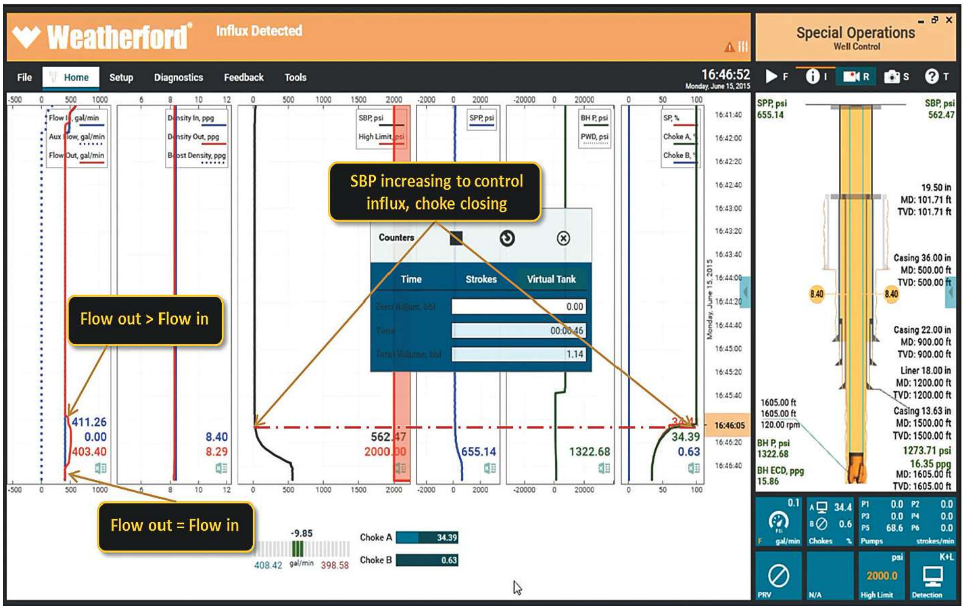
While the RCD alone provides passive pressure control and enables closed-loop drilling, additional components prepare the system for full MPD operations. The move to either manual or automatic MPD operations entails the use of surface backpressure (SBP) to actively manage wellbore pressure.

In an MPD system the driller gains control by applying SBP using a choke manifold and possibly an auxiliary pump to better maintain annular backpressure during connections. This action causes almost immediate changes to the annular pressure profile and manages very small influxes and losses before they develop into well-control events.

Benefits of active pressure management

In an onshore oil and gas field in Colombia an operator used an RCD and a choke manifold to drill a sidetrack from the parent wellbore to a higher pressure production zone. Drilling began with an open choke and no SBP to check contact with the formation pay zone. After drilling 119 m (392 ft), the drilling team applied 600 psi of SBP to the choke and monitored well behavior. Based on the information gained, the team adjusted the brine from 13.2 lb/gal to 13.5 lb/gal and maintained the bottomhole equivalent circulating density (ECD) during drilling between 15.3 lb/gal and 16 lb/gal using an SBP between 600 psi and 900 psi.

Together, the RCD and choke enabled drilling in the optimal operating window at near-balanced conditions to the planned total depth (TD) of 2,523 m (8,276 ft) in just 46.5 hours. The operation was completed without nonproductive time (NPT) or safety incidents, and the well steadily produced at a rate of 210 bbl/d—a 210% increase over the expected reservoir production of 100 bbl/d.



Weatherford's Microflux control system provides early detection and proactive management of influxes, kicks and losses with minimal NPT. (Source: Weatherford)

MPD options for onshore operations

Onshore MPD systems can be configured in various ways to provide advantages proportional to the challenges. Individual MPD components aid drilling and completion operations while enhancing overall safety, and paired or combined components greatly escalate these benefits. Adopting new technologies can further enhance MPD capabilities.

A better RCD. As mentioned previously, the RCD is a critical well-control component that enables closed-loop drilling and, with the addition of other equipment, MPD operations. After nearly 50 years of using RCDs in onshore drilling applications, Weatherford developed the new SafeShield 5M RCD. This single-platform RCD streamlines equipment management since it supports a wide range of applications and pressures. Compared to previous models, the RCD offers a shorter stack height, a larger through-bore diameter of 8¼ in. and higher pressures ratings up to 5,000 psi.

Enhancements include a remote latching system that enables installing and removing the bearing assembly without manual handling below the rig floor. The RCD also features a self-lubricated bearing assembly that eliminates the requirement for an external hydraulic lubrication unit and the need to connect lubrication lines.

RCD plus choke. Pairing an RCD with an electric set-point choke creates a system for basic MPD in production or development wells with predictable pressures and limited exposure to kicks. This pairing can reduce NPT, mud costs and the risk of well-control incidents.

The newly developed PressurePro control system, which includes the SafeShield 5M RCD and an electric set-point choke, reduces the manpower typically required for choke operation by providing semiautomatic pressure control. The integrated system enables basic MPD, flow drilling and underbalanced drilling.

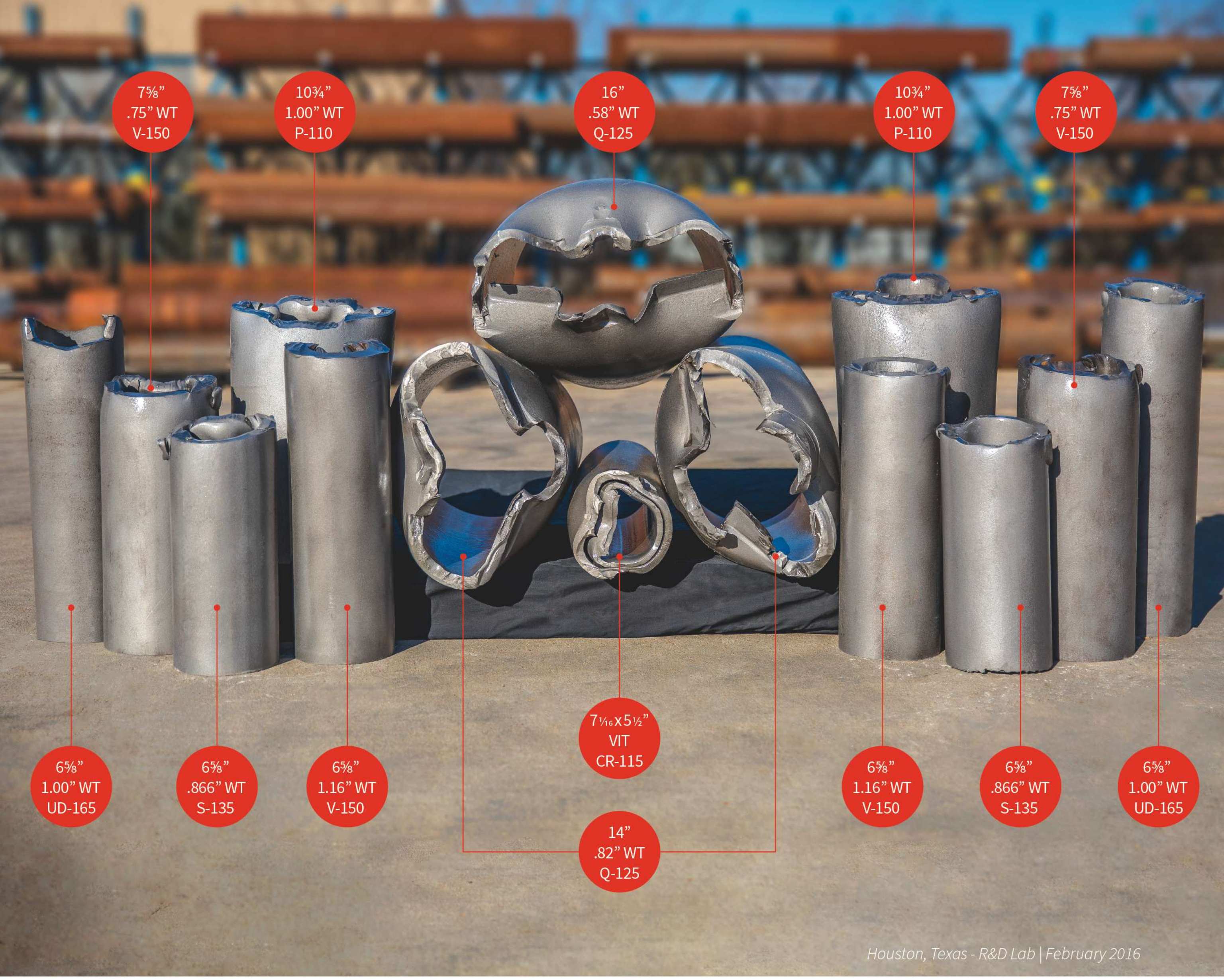
The user inputs the pressure set point, and the system automatically maintains pressures by applying constant bottomhole pressure (BHP) during drilling operations or connections. Compared to conventional manual and hydraulic chokes, the system provides more accurate and precise pressure control—within ±5 psi of the pressure point set.

RCD plus choke and detection manifold. Adding a detection manifold to an RCD and choke system delivers further benefits, especially in exploratory or development wells that have a greater likelihood of unexpected kicks. These wells require early kick and loss detection to safely reach TD.

Combining an RCD with an advanced flow detection system helps to identify influxes and losses early. This early detection capability can minimize response times and, in turn, reduce the risk of well-control incidents. The system also can distinguish kicks and losses from less hazardous events, which enables better decision-making on the rig floor and more economical drilling.

Automated control system. An automated control system suits drilling or exploratory wells that have extremely tight drilling windows, a likelihood of high-volume and high-intensity kicks, or both. The system also can apply constant BHP for continuous drilling.

An automated system for MPD, the Microflux control system integrates sophisticated software; controls; and closed-loop components that monitor, analyze and automatically manage wellbore pressure. Compared to manual systems, the automatic system reduces response times to influxes or losses, minimizes the size of influxes from barrels to gallons, optimizes circulation rates out of the wellbore and increases the speed of the total drilling program. E&P



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Service helps operator drill 'undrillable' deepwater wells

MPD system enables operator to save time and money.

Derrick Lewis, **Randy Lovorn** and
Andrew McLennan, Halliburton

Ultradeepwater presalt developments are considered among the most challenging projects for the oil and gas industry. With the increasing cost of presalt well delivery, various technologies can be used to optimize rig time, reduce nonproductive time (NPT) and decrease risks to safety and the environment.

Managed-pressure drilling (MPD) has the proven ability to help eliminate or mitigate NPT related to pressure incidents throughout the drilling process. MPD uses a closed-loop system that adds an increased level of environmental protection and allows the use of an automated early kick detection system for increased safety. The Halliburton GeoBalance automated MPD system was incorporated onto two MPD-ready sixth-generation ultradeepwater drillships to provide the control, flexibility and safety required to drill and mitigate these risks. This implementation enabled Halliburton to drill 3,785 m (12,418 ft) in an extremely challenging zone in stable and safe conditions.

Collaboration, training essential

The pore pressure and fracture gradient boundaries in the well presented two marked challenges. First, the bottomhole pressure (BHP) needed to be maintained within a 50-psi window. Second, either a pressurized or floating mud cap had to be suitable for drilling. These challenges associated with ultradeepwater presalt developments led the operator to choose the GeoBalance automated MPD service in conjunction with hydraulic modeling software for optimal adaptability and real-time pressure control.

Additionally, this project would be the world's first implementation of an MPD surface control system on an MPD-ready drillship. The safe and successful implementation of the MPD system required an engineered approach and close collaboration with the operator from the planning phase through training exercises and during the job execution.

Along with the installation of this equipment and hydraulic software, Halliburton developed a two-tiered comprehensive training program for all parties involved in these operations. The first exercise was designed as an MPD overview with the goal of exposing all operational personnel to the theory of MPD and to the equipment that would be used on this project. The second exercise was designed to expose critical personnel to the procedures and to help them develop a strong understanding of the contingency procedures in the event of kicks or losses.

MPD equipment (in red) is installed throughout the decks of the drillship. (Source: Halliburton)

Losses, kicks handled with technology

As this was the first-ever implementation of an MPD control system on an MPD-ready drillship, the operator decided to use MPD on the 16-in. hole salt section, which allowed all rig crews to become familiar with MPD operations on a live well in a nonhydrocarbon zone. This training in the salt section provided the competencies to react with proper responses once in the reservoir.

The uncertainty of the reservoir pressure created an extremely narrow drilling window that progressively got narrower due to a hydrocarbon gradient. To keep the well within the available hydraulic window, the MPD system was designed to maintain pressure slightly above the highest pore pressure in the reservoir using a statically underbalanced drilling fluid. Running speeds were adjusted to control surge and swab pressures on trips, and the automation with the GeoBalance MPD system mitigated their effects in real time.

Properly managing downhole pressure and staying within a safe "pressure window" required advanced event detection and the capability of the MPD system to react to these events. On the operator's wells Halliburton used the DetectEv application, part of the hydraulic modeling software that uses well signature patterns for event identification and applies an appropriate response within the MPD system. On these wells the two events of possible concern were incurring losses and experiencing kicks.

Salt drilled in record time

All the preparation and planning resulted in flawless execution of four drilling sections—a total of 3,785 m drilled—using the GeoBalance MPD system at a water depth of 2,000 m (6,562 ft). Manipulating the equivalent mud weight at different target depths with the MPD system made it possible to drill the salt in record time and with no NPT. Precise, accurate pressure control eliminated the need for remedial work commonly seen in salt sections. For additional safety both production sections were designed to use a static mud weight at or above pore pressure while in a hydrocarbon zone.

In both production sections severe losses were encountered, and with the precise control of the MPD system these losses were mitigated rapidly, resulting in massive savings—an estimated $30 million per well. Multiple loss zones were encountered and, with each one, the DetectEv application quickly identified the event, and the drilling team adjusted the BHP accordingly.

Due to mud weight, surface pressure losses and the lower fracture pressure, the MPD system got to a point where it no longer had the ability to reduce equivalent mud weight since chokes were fully open while circulating. At this point, because of the operator's confidence, the mud weight was reduced to a statically underbalanced fluid. With the reduced mud weight the MPD system was able to eliminate losses and avoid influxes within a 50-psi window. Losses throughout both production sections were as high as 300 bbl/hr, but by implementing proper BHP management and reducing the mud weight the team was able to finish drilling and leave the wells in stable condition, eliminating any further losses.

Without the GeoBalance MPD system these wells would have been undrillable. Each loss event would have required immense amounts of rig time to solve; in the past, these events required the use of remedial cement plugs, which cost days of rig time in addition to the cost of large losses. The GeoBalance automated MPD system enabled the operator to avoid these issues, saving a considerable amount of time and money. E&P

The Coriolis meter (in gray) monitors fluid flow of the MPD system, enabling accurate hydraulic modeling for real-time pressure control. (Source: Halliburton)

Integrated approach to production management

Reducing production cost per barrel requires efficiency and visibility at every step.

Daniel Renteria, Weatherford

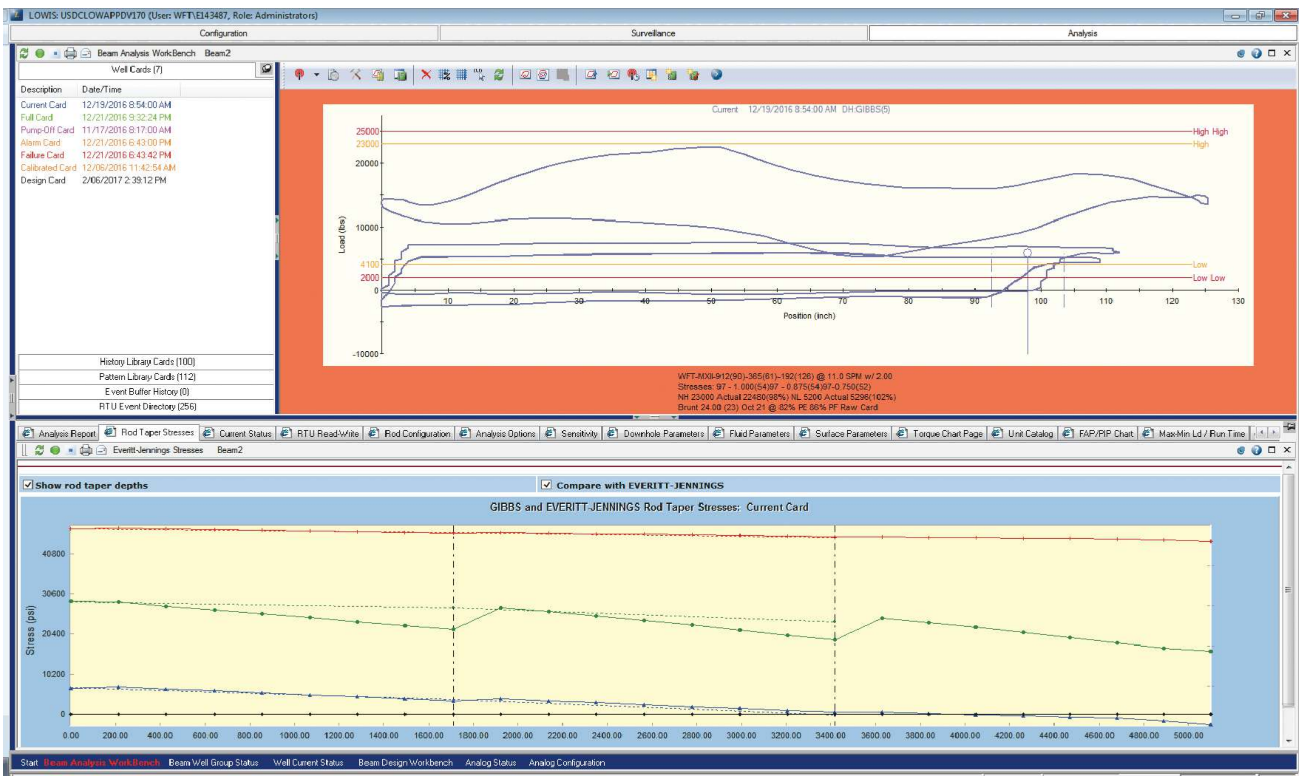
An integrated approach to production management requires real-time monitoring information, efficient workover management and robust analysis. Producing more at less cost is of utmost importance in today's market and requires systemwide efficiencies at all levels of a production operation.

To overcome operational inefficiencies, Weatherford provides production optimization software designed to achieve optimal well performance. LOWIS life-of-well information software ensures that every member of the asset management team from operational staff to the production manager can access the right information in the right format to support critical production decisions.

The software includes fully configurable and user-friendly alarms and real-time monitoring capabilities that help operators manage assets by exception and increase their efficiency. Best-practice workflows can be configured to support typical operational activities such as downtime management, well status management and well test validation.

For an integrated approach to artificial lift the software natively supports analysis workbench (AWB) modules for reciprocating rod lift, electric submersible pump (ESP), progressing cavity pumping and gas lift. The modules perform optimization analysis using real-time data and detailed mathematical models of each lift type and generate intelligent alarms to warn operators of nonoptimal use of the lift equipment.

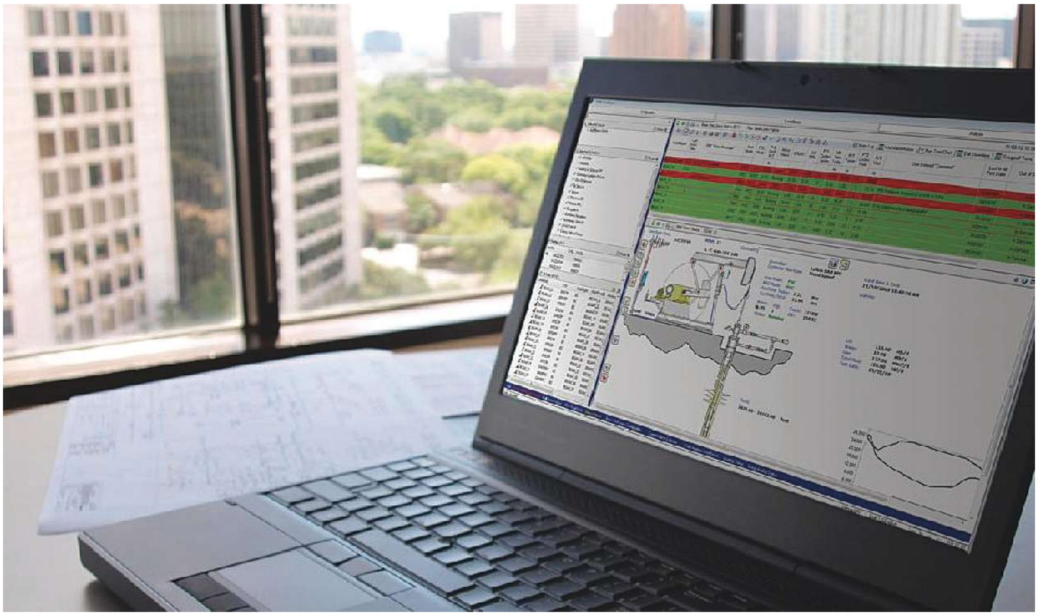
Use of the AWB modules and customizable workflows allows operators to quickly identify, prioritize,



Rod stress is measured and visualized through the LOWIS software. (Source: Weatherford)

plan and service underperforming wells, thereby reducing downtime and associated production losses. Scorecarding tools and complete well histories enable producers to develop and implement best practices of failure management.

The benefits of production optimization software can be seen in conventional and unconventional applications and in onshore and offshore assets.



Weatherford production optimization software enhances decision-making by enabling real-time remote monitoring and analysis of well data. (Source: Weatherford)

Integrated optimization system

In 2016 LOWIS was applied in Kazakhstan to optimize ESP production in 11 oil wells. The operator's objective was to establish a reliable system to remotely monitor ESP output and performance in each well. Software compatibility problems between the ESP surveillance system and the different brands and vintages of pumps in use had hindered effective monitoring of these assets.

The operator hired Weatherford to address the compatibility challenges and to effectively manage the performance of each well with the goal of maximizing field production. Together, the operator and service company executed a comprehensive review of the field layout, ESP performance and monitoring processes and jointly developed a full-field optimization plan.

As part of the plan the team deployed the software coupled with a digital mobile telephony system to optimize ESP performance. The real-time well optimization and operation software enables comprehensive well monitoring, control and analysis across all forms of production. The digital mobile telephony system provides a stable and economically effective method to connect to offsite controllers.

Engineers and technicians installed the production optimization system at the operations office and installed transmission devices at each wellhead. The team also coordinated with the field global system for mobile communications providers to overcome data transmission problems caused by unstable satellite connections.

The production optimization software enabled the client to closely monitor and analyze ESP performance despite differences in the type of remote terminal unit installed at each well and without the problems and expense the operator had faced previously related to satellite communications. With ESP data available on demand the operator was able to automate the production optimization workflow and track a wide range of ESP parameters to quickly detect problems. The combination of monitoring and detailed nodal analysis identified the full range of options available to increase operational efficiency, extend ESP life and maximize production.

The integrated system of surveillance and analysis tools enabled the client to save almost $450,000 in the first year of use.

Optimized rod lift in the Permian

In the Permian Basin the integrated software successfully optimized hundreds of reciprocating-rod lift wells that were experiencing high failure rates. Soon after acquiring the wells from another company, the operator realized the failure rate in the field was very high, resulting in significantly higher production costs.

The operator asked Weatherford to review the failures and provide solutions to optimize field operations and minimize production cost. Weatherford experts quickly identified the reciprocating-rod lift system had stopped pumping due to frequent fluid pound, a phenomenon that causes rods to buckle on each stroke that leads to premature tubing and sucker rod failures.

Based on these findings the operator decided to deploy the LOWIS software and authorized Weatherford to implement remote changes to the wellsite controllers. The client's primary request for the field was to reduce the number of failures. Additionally, Weatherford sought to extend the equipment life with the remote changes.

The integration of real-time surveillance with predictive model data provides a means for faster diagnosis and remediation. Real-time data are converted into intelligent alarms to inform stakeholders of what's happening, why it is happening and what actions might need to be taken to maintain maximum production efficiency. In this case the software identified inflow performance constraints that led to fluid pound and gas interference issues. The sucker rod fatigue that results from fluid pound often goes undetected without a proper surveillance system. Using information from the software, the team identified corrective action to achieve optimal pump fillage and minimize gas interference.

The service provider performed a detailed study on the five wells that were of the greatest concern to the operator and had each failed five or more times in a year. Prior to deploying the optimization software, the operator had experienced mean run times between failures of 32 days to 171 days.

With the ability to detect and resolve operational issues that cause pump failures, the production optimization software improved the bottom line for current and future assets. Based on the previous failure rate, a conservative estimate cost of $20,000 per well workover and an oil-per-barrel price of $50, the software delivered a net savings of about $350,000. One year after installing the new monitoring software on these wells, the operator had zero well failures.

Future of production optimization software

The reduction of total cost of ownership and integration risk through an integrated suite of applications can be applied to all types of assets. The use of production optimization software maximizes business opportunities with timely, accurate data that invoke high confidence in the decision-making process.

In addition to the capabilities and benefits illustrated by the above case studies, Weatherford is preparing to release new production optimization software with capabilities including daily monitoring and collaboration, intelligent alarms and advanced data analytics to provide effective production management and optimization for the life of the well and field. E&P

Cold-stacking for accelerated profitability and flexibility

A cold-stacked rig requires adequate preservation to protect critical components of the asset.

David Dickert, Aggreko

Last year saw the world's listed oil companies slash production by 2.4% as a result of the falling price per barrel, with key players continuing to redirect investment in an effort to stay profitable. A similar picture was seen in the gas industry. As more of the major operators make a move to differentiate their assets, the need to improve production efficiencies and cut expenditures is growing rapidly.

Of course, many operators are cutting their losses and turning to decommissioning in an attempt to reduce expenditures, improve cash flow and protect profit margins. In the North Sea alone decommissioning expenditure has risen by $62 million since 2014, with more than 100 platforms expected to be removed by 2025, according to Oil and Gas UK. It's an issue that impacts the industry. Global offshore driller Seadrill scrapped 44 floating drilling rigs last year alone due to reduced activity and persistently low prices.

Decommissioning older rigs that require significant investment to upgrade and maintain is economically sensible. It can save enormous open-ended costs and improve operational efficiencies. However, dismantling a three-year-old rig, for example, which on average costs $650 million and involves lengthy planning and commissioning phases, isn't a viable option. Decommissioning a considerable number of rigs also limits a company's fluidity and ability to react quickly to market needs and, more importantly, capitalize on opportunities (i.e., a rising oil price).

Both the cold- and warm-stacking of unused offshore drilling rigs is a sustainable alternative, particularly for advanced and latest generation rigs in key markets. However, for those who experienced the last significant downturn in the 1980s, the prospect of cold-stacking might not be seen as an attractive option either. Rigs were welded shut and inadvertently left to rust, which then cost millions of dollars to remobilize or, in some cases, eventually abandon. Despite hesitations, few operators will want a repeat of that scenario and will make efforts to safeguard their $500 million to $600 million investment by protecting the integrity of the asset.

Corrosion, condensation and freezing are major issues on a cold-stacked rig. (Source: Aggreko)

A cold-stacked rig, which can reduce operating costs by $3 million to $9 million per year compared to warm-stacked rigs' approximate operating costs of $30 million to $90 million per year, requires adequate preservation to protect critical components of the asset. While rigs are moved to safer hurricane-free waters closer to shore, failure to protect their operating systems and structures such as high and low voltage switch gears, critical parts storage, thrusters, engine rooms, power level controller instrumentation and accommodations, can jeopardize their integrity and lengthen the reactivation process. Not only would this cost more and take longer, but it will impact the company's ability to be flexible and meet demand quickly, and in some cases it also could result in decommissioning.

Most of the drillers and operators have been hesitant to cold-stack rigs in view of these potential risks and expenses as well as limited industry experience in successfully long-term cold-stacking advanced latest generation deepwater floaters. As a result, warm-stacking tends to be the major mode of operation by the operators for unused rigs despite costing about 10 times more. However, recently some top drillers have successfully implemented a cold-stacking mode, which has enabled tremendous reduction in their operating costs, improved profitability and bottom-line performance.

Modular power and heating, ventilation and air conditioning (HVAC) technology play a vital role in protecting infrastructure and operating systems. Addressing this need properly and implementing preservation strategies effectively could create a savings of nearly 90% (e.g., $5 million preservation costs compared to $40 million to repair damaged assets) during reactivation. It also could reduce reactivation time by about three months and create potential revenue of about $36 million (assuming a $400,000 day rate).

Planning process

Scoping studies and surveys are critical to evaluating the needs of a project, including HVAC, temperature control and power strategies, thereby determining where conditioning is needed and outlining the most effective temperature control and dehumidification system designs. Cold-stacked rigs are typically put away for an extended period of time—two to five years compared to six months for warm-stacked rigs—so identifying and mitigating long-term risks is a fundamental part of the planning process. Both temperature and humidity control have been identified as key parameters for the sustainability of long-term corrosion protection and asset preservation during cold-stacking.

Corrosion, condensation and freezing are major issues on a cold-stacked rig caused by the high level of salt and humidity in the air, which impact a range of different components and in turn jeopardize full operability. By using a variety of heating, cooling and dehumidification equipment, it is possible to control conditions within internal spaces. This not only ensures air spaces between machinery and pipelines remain dry but also prevents corrosion damage and moisture absorption into electrical cables and fittings.

Temperature control equipment will perform to varying levels of effectiveness depending on the geographical or seasonal climate in which the rig is located, including the consequential ambient temperature and relative humidity. For example, the optimal cold-stacking solution in the North Sea might not be viable for the Gulf of Mexico or tropical climate conditions. A key example of why scoping studies are vital to assessing the effectiveness of an operation and justifying the need for these bespoke systems can be seen with the deployment of desiccant dehumidifiers and heaters in colder climates and mechanical refrigeration equipment in warmer regions, which temper the space rather than add heat. This, in turn, creates a 35% to 40% reduction in required power capacity and a subsequent fuel cost saving.

Scalable and efficient onsite energy and HVAC equipment is crucial, particularly if the climate changes or when capacity needs increase as the rig is reactivated. Bringing the rig back online within three months rather than six creates a great opportunity to not only start producing sooner but also reduce costs. Adopting modular systems allows greater flexibility. Capacity can be increased or reduced quickly to meet changing demand and improve cost efficiency. Modular generators also allow main engines to be shut down, again creating a significant fuel and cost saving. However, perhaps more importantly, using a number of small engines rather than one big one helps to avoid economical redundancy and improves reliability and efficiency.

Reliability is a key priority, particularly as cold-stacked rigs are typically unmanned. If a disruption were to occur and potentially jeopardize the capabilities of HVAC equipment in the process, it could take weeks to resolve the issue. Contingency planning, identifying potential issues and taking steps to mitigate the risk of this occurring is crucial. Adopting a modular power strategy reduces this risk—if one generator breaks down, others can continue to provide capacity demand. However, backup generators should be in place.

Remote monitoring plays a key role in identifying inefficiencies or signs of equipment malfunctioning while also diagnosing maintenance needs before an actual disruption occurs. Engineers in Aggreko's Remote Monitoring Center can access performance data from power and HVAC equipment operating on offshore rigs to ensure maintenance needs are quickly met. This approach also reduces the number of engineers required on the rig, which has obvious health and safety benefits.

Another critical factor on cold-stacked offshore rigs is prevention, ranging from controlling the environment to preserve equipment and protect against corrosion to planning ahead for disruptions and putting contingency strategies in place. Protecting investment and the integrity of the asset through adequate power and HVAC systems is an operational priority. It provides a key advantage in ensuring the business can react quickly to market demand and opportunities but also avoids decommissioning and potentially scrapping a $600 million rig. E&P

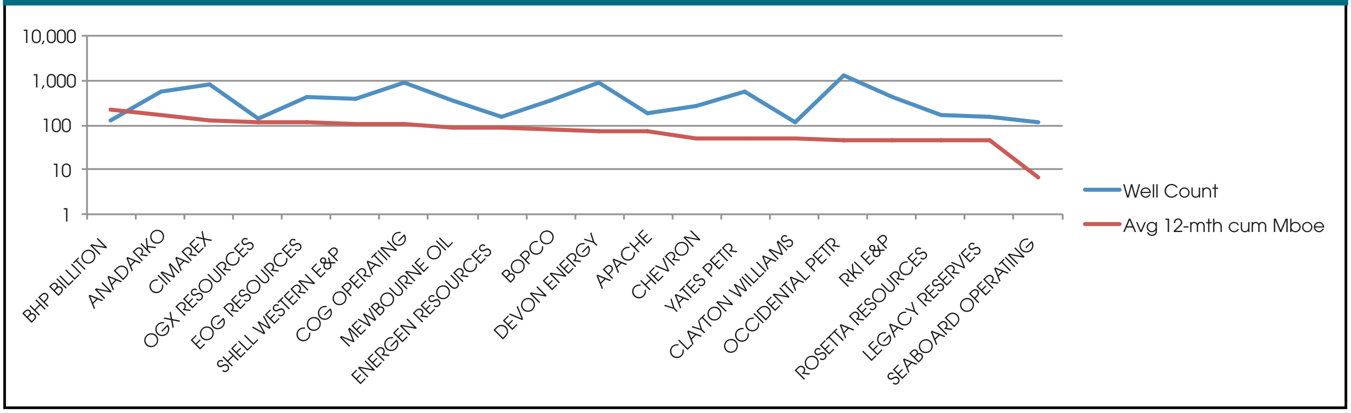
References available.

Delaware Basin

The Permian's Delaware Basin continues to lead the shale gale.

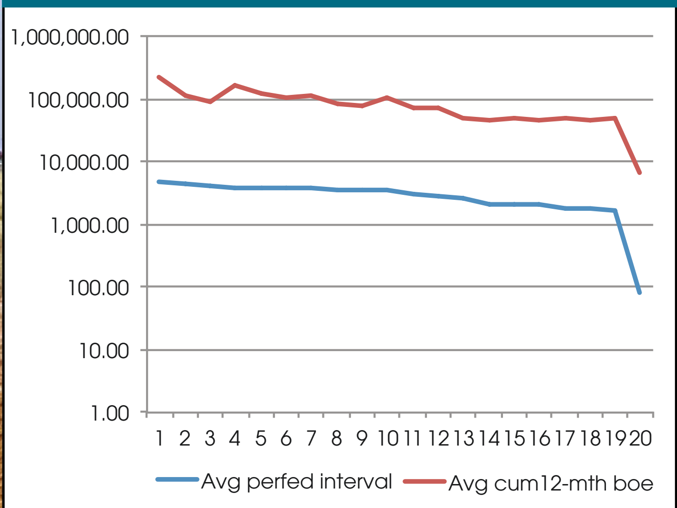
Contributed by **Drillinginfo**

WELL COUNTS vs. PRODUCTION



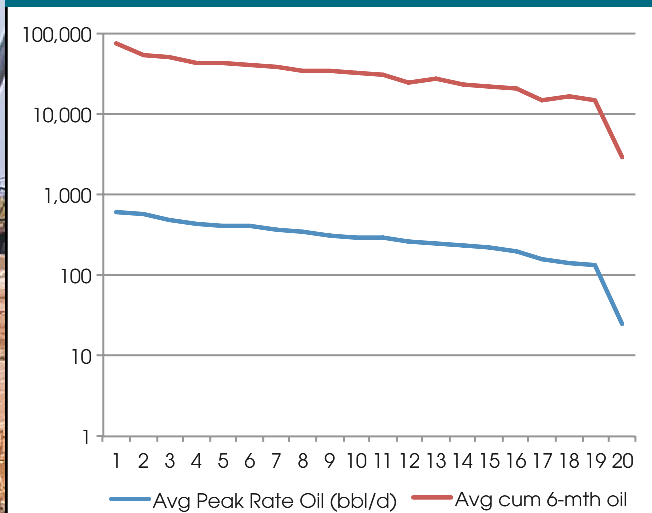
Drillinginfo often looks at well counts to give a snapshot view of operator dominance in a basin. But average well performance might be a better indicator of which operators are worth watching. In the Delaware Basin this graph demonstrates that high well counts don't necessarily predict better produced 12-month cumulative barrels of oil equivalent. This implies that operator efficiency should be factored into basin dominance perspectives. (Source: Drillinginfo, DI Web app)

PERFED INTERVALS vs. PRODUCTION



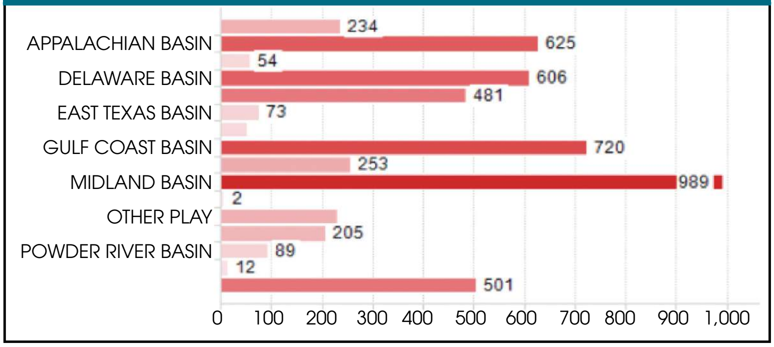
At least in the Delaware Basin it looks like there is a direct relationship between amount of perfed interval and 12-month cumulative barrels of oil equivalent. Investigating anomalies by operator can yield useful intel on best-in-class completion practices. (Source: Drillinginfo, DI Web app)

IP RESULTS



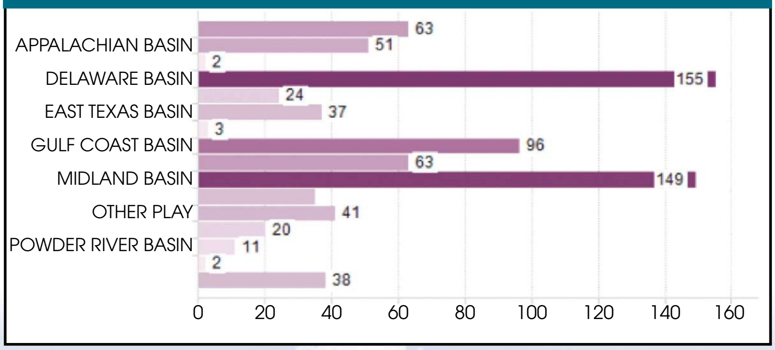
Press releases often focus on IP results as an indicator of the deliverability of well products to sales. Drillinginfo reports a better predictor is the peak rate (month with greatest production volume/number days in month adjusted for days on when possible). (Source: Drillinginfo, DI Web app)

DUC COUNT BY PLAY



Given the explosive activity in the Delaware Basin that has been driven by both Apache's Alpine High and U.S. Geological Survey Permian Basin Wolfcamp reserves statements, it's worth noting the Delaware Basin has a relatively low percentage of drilled but uncompleted wells (DUCs) compared to other basins. More analysis is required to determine whether this is due to better margins from higher oil deliverables, higher EURs or from authorization for expenditure reductions. The different shades of red indicate the number of datapoints in the sample. More datapoints mean a darker red. (Source: Drillinginfo, DI Analytics/Rig Analytics)

RIG COUNT BY PLAY



The level of activity measured by rig count shows that nearly 20% of U.S. rig placements/activity is occurring in the Delaware Basin, more than any other basin in the country. The different shades of purple indicate the number of datapoints in the sample. More datapoints mean a darker purple. (Source: Drillinginfo, DI Analytics/Rig Analytics)

US onshore regulatory overview

Jack Belcher and **Beth Everage**,
HBW Resources LLC

Federal actions

EPA withdraws information collection request (ICR). On March 2 the U.S. Environmental Protection Agency (EPA) withdrew its final ICR to gather extensive data on existing sources of methane emissions from owners and operators of the oil and gas industry, effective immediately.

Consolidated federal oil and gas and federal and Indian coal valuation reform rule facing repeal. A Senate resolution (S.J. Res. 29) was introduced to undo changes to fossil fuel royalty calculations. A House companion (H.J. Res. 71) was introduced in February.

U.S. Geological Survey report forecasts lower incidence of human-induced earthquakes for 2017. Officials said the risk of manmade earthquakes attributed to oil and gas activity in Texas and Oklahoma is reduced as companies have slowed production and disposal of wastewater. However, these regions as well as areas along the Colorado-New Mexico border remain at an elevated risk for seismic activity.

State/local actions

Colorado

- The Department of Public Health and Environment released a report in early March determining there is "little evidence that living near oil and gas sites poses health dangers."
- Broomfield City Council voted to postpone a vote on a proposed hydraulic fracturing moratorium indefinitely. The city will begin work on a plan to determine siting of oil and gas wells.

Texas

- Railroad Commission Chair Christi Craddick has requested funding from the Texas Legislature to build an online database to track compliance as well as add 55 new inspectors for energy production sites and pipelines. This request comes at a time when the agency faces increased calls for online reporting. ■

Permian Basin prevails

Continued innovation and leading-edge data drive continued growth.

Jessica Pair, TGS

The Permian Basin has prevailed throughout the industry downturn over the past several years to continue to prove its strong resilience and persistence for growth. The shale industry has drastically altered its prior operations in light of recent market fluctuations to focus more fully on identifying the optimal target locations for expansion or creating new campaigns to enhance EURs and economic returns. With the Permian Basin in the lead for onshore shale, new operators have flocked into this region to compete with existing operators to leverage the opportunities present with massive capital investments and large drilling strategies, which are likely to propel the shale industry back to prior production highs seen in 2014.

Overall, industry sentiment has been becoming much more positive, with many more acquisitions being made, rig counts increasing and West Texas Intermediate trading near recent highs of $54/bbl. The average rig count in the U.S. has been on the rise already in 2017, with an average of 700 rigs running. Of this average count the Permian holds about 42% of currently running rigs.

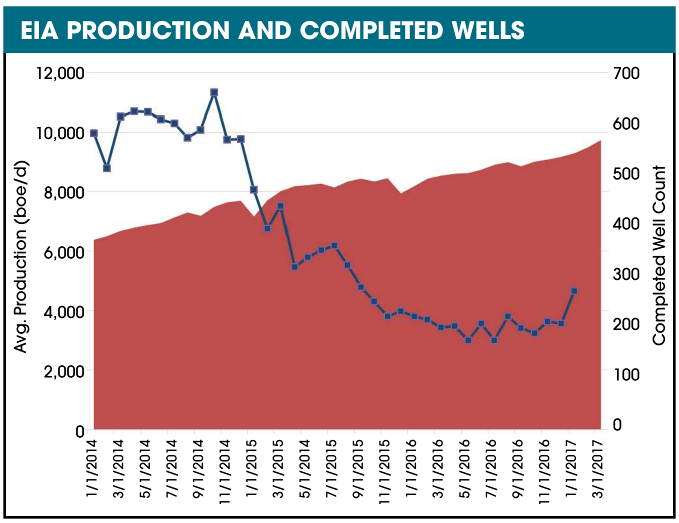


FIGURE 1. According to the EIA, the Permian Basin continues to increase production (boe/d), while the average completed well counts (blue line) recently have begun to increase. (Source: EIA DUC analysis, TGS Basin Analytics)

Well database

TGS, a provider of global geoscientific data products and services, announced in February 2017 the immediate availability of a comprehensive well database in the Permian Basin. TGS has created a database of products in the Permian Basin available commercially. With more than 430,000 wells in the Permian Basin, TGS has validated well header data for 357,000 wellbores, faster logs for all wells, digital log-assisted ASCII standard format for more than 280,000 wellbores and production volumes for all producing wells in the basin. The company also offers forecasted EURs for each producing well in the basin as well as interpreted formation tops and basin temperature models covering the entire basin.

Through this comprehensive operational process TGS has found thousands of previously unidentified wellbores. After researching millions of pages of well files, completion reports and regulatory files, and a large library of well log data, TGS has been able to complete the Permian datasets to a new level. Due to this thorough work along with generous operator donations over the past two years, much of these data are available to clients through TGS' R360 and LOG-LINE Plus! web portals.

This dataset is available through basinwide data packages covering the Midland, Delaware or Central Platform regions or over the entire Permian Basin. All data products come with 100% coverage of the wellbore system from surface to total depth; have been quality-controlled for completeness; and ensure all attributes such as depth, direction, height and elevation meet the most stringent guidelines for accuracy.

The Permian Basin well data and interpretive products complement new and planned TGS 3-D seismic surveys in the basin.

Starting with the Permian Basin, TGS' newest product, Basin Analytics, leverages the vast well production and forecast datasets, geographic information system information and detailed economics to deliver a detailed evaluation analysis. Basin Analytics is designed to be a strategic partner for clients and provides detailed research across the upstream unconventional project life cycle to aid in informed decision-making on the value of a particular area for acquisitions, divestitures or drilling campaign strategies.

PERMIAN COMPLETED WELLS vs. DUCs: ACTUAL AND FORECAST

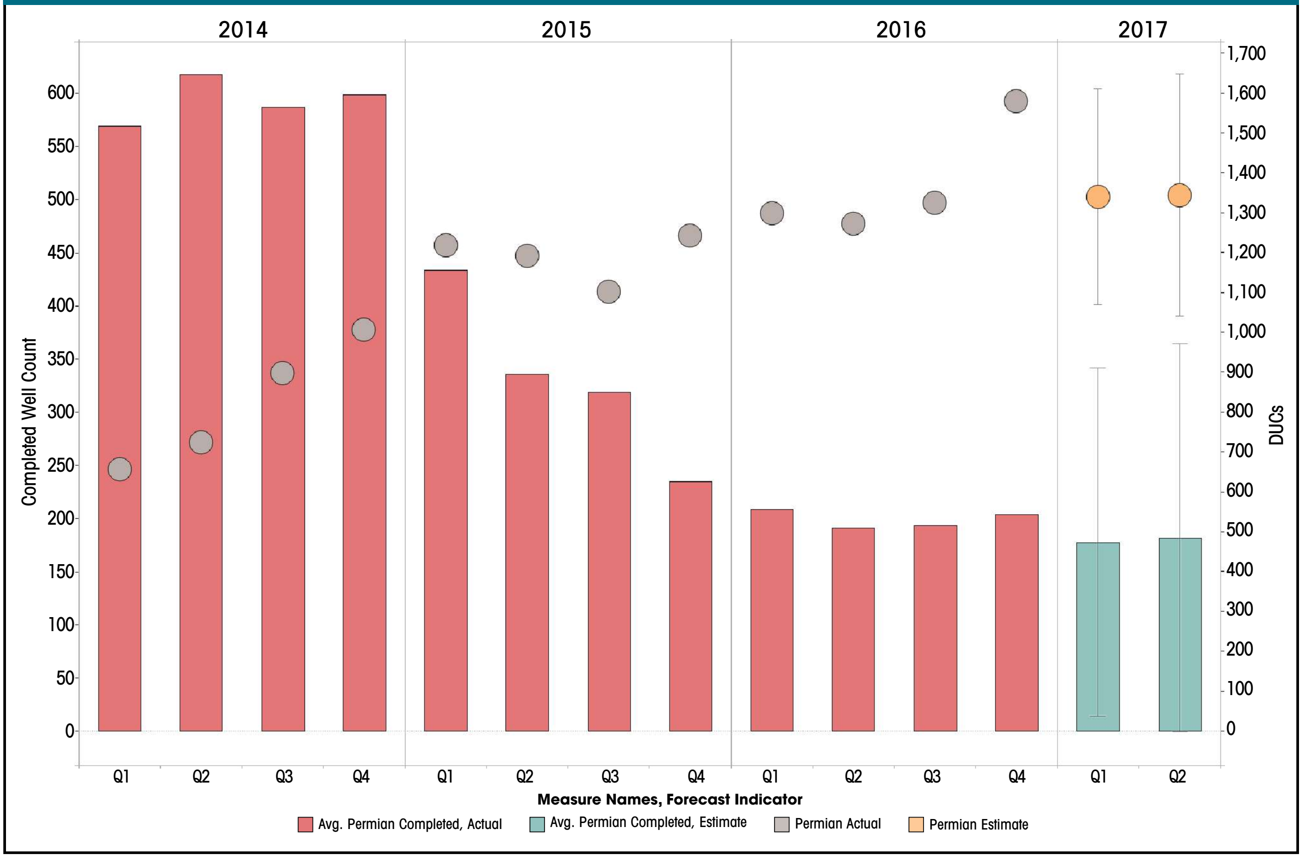


FIGURE 2. Using the EIA's DUC analysis, the Permian's average completed well count has been decreasing since 2014. However, a rebound in activity has begun, signaling an increase in 2017. This increase in completed wells will draw down the DUC inventory in 2017. (Source: EIA DUC analysis, TGS Basin Analytics)

DUC inventory

Across the U.S. the average drilled but uncompleted well (DUC) inventory had been holding relatively flat in 2015 before marginally increasing throughout 2016 as fewer wells were completed due to economic constraints. The Eagle Ford has continuously shown the largest DUC inventories year-over-year, followed closely by the Permian. However, in 2016 the Eagle Ford (total year average of 1,398 DUCs in inventory) has begun to reduce its overall DUC inventory to fall more closely in line with the Permian (total year average of 1,461 DUCs in inventory).

According to the U.S. Energy Information Administration (EIA), the Permian Basin has been increasing overall production by about 9%, up from an average of 8.7 Mboe/d in 2016 to 9.5 Mboe/d in early 2017 (Figure 1). The basin's average oil production also has increased from a 2016 average of 2 Mbbl/d to 2.18 Mbbl/d in 2017. Despite the increase in production, the overall completed well counts for the basin have been largely decreasing from its historical highs experienced in 2014 at an average of 593 wells completed per quarter to a low of about 200 wells completed per quarter as seen in 2016 (Figure 2). The overall DUC inventory will be drawn down into 2017 as Permian operators begin to complete more wells.

Basin Analytics analyzed about 6,400 horizontal/directional wells drilled within the Delaware Basin from 2006 to 2016 and has identified the top 10 performing operators. When focusing on well production performance, the top operator was identified as Cimarex Energy, which shows an average 30-day IP rate of about 881 boe/d in Culberson County and an average EUR of 1,457 Mboe. EOG Resources follows Cimarex with an average 30-day IP rate of 226 boe/d in Eddy County and an average EUR of 331 Mboe.

The Permian Basin will continue to prove to be a hotbed for drilling activity. With the continued push for technology innovation, the basin will likely carry the market share for many years to come. E&P

Chinese design house offers offshore expertise

Institute continues to expand its offshore R&D capabilities.

Li Xiaoping, MARIC, and **Jing-Dong Sheng**, ABS

China has established a name for itself as the world's manufacturing powerhouse, but the country cannot be defined solely by its ability to produce finished goods for international consumption. China is transitioning from a manufacturing superpower to an advanced economy that competes globally in offshore construction, advanced technology, R&D and engineering. Integral to China's competitive position is the Marine Design & Research Institute of China (MARIC) in Shanghai.

While R&D might not be the first thing that leaps to mind when thinking about China's offshore industry, it is an established capability at MARIC, which has been carrying out research since its founding in 1950. Expanding into offshore R&D, MARIC officially added offshore specialization to its capabilities in 1970. During the last 50 years MARIC has grown to become the largest offshore R&D institute in China, supporting domestic oil majors CNOOC, CNPC and SINOPEC in addition to some of the nation's leading shipyards: Waigaoqiao and Hudong-Zhonghua in Shanghai and Guangzhou Shipyard International and New Yangzi in Jiangsu. Today 30% of the work done by the institute is for the offshore sector.

***Hai Yang Shi You 981*, China's first deepwater drilling semisubmersible unit, began drilling operations May 9, 2012, in the South China Sea. (Source: MARIC)**

Keeping pace with offshore evolution

During the last five decades MARIC has invested to expand its capabilities, leveraging both internal and external instruction for its staff and looking to organizations like ABS for specifically selected training. Working with MARIC since the introduction of the first offshore design, ABS has provided technical support, classification, certification, training and statutory guidance and participates in joint development efforts for advanced offshore projects.

Since 2010, when offshore projects took off in China, there has been an increased emphasis on local R&D. That is reflected in the size of MARIC's staff, which grew from 80 engineers at that time to 180 by 2014. A staff of 1,000 engineers, more than 40% of whom have advanced engineering degrees, plays an important role in China's technical shipbuilding and offshore communities and hold memberships in international communities, including the International Towing Tank Conference and the International Ship and Offshore Structures Congress.

MARIC's R&D capacity, which includes extensive test facilities and a track record of testing, R&D, and design and engineering projects, places it in the top tier of research centers. Projects cover the full spectrum of offshore oil and gas activities, from seismic vessels to production units, with a sizable increase over the last five years on jackups, semisubmersible units, drillships, FPSO vessels, and more recently floating LNG (FLNG) units. Other efforts have targeted offshore support, including platform supply vessels, diving support vessels and vessels used for pipelaying and heavy-lift operations.

Landmark achievements

Among the historically significant offshore projects delivered by the organization are *Sheng Li 3*, the first shallow-water drilling unit designed in China, and *Hai Yang Shi You 981*, China's first deepwater drilling semisubmersible unit.

Sheng Li 3 was a milestone project when it was built in 1989. This jackup, which measures 80 m by 40 m (262 ft by 131 ft), was designed to work in shallow water at a depth of 9 m (30 ft) with the capability of drilling to 6,000 m (19,690 ft).

MARIC stepped out into deepwater design with the *Hai Yang Shi You 981*, built at the Waigaoqiao yard in Shanghai for CNOOC's operations in the South China Sea.

The South China Sea is known for its particularly harsh seas and extreme weather environments. The demanding operating conditions along with the relative short history of offshore exploration activity in the South China Sea posed challenges to the design team. As the lead designer, MARIC assembled an international team and carried out a range of innovative designs. The scope included general performance, key structures, the dynamic positioning (DP) system, drilling system integration and weight control. Drawing on the combined expertise of the international team, MARIC was able to adopt knowledge and integrate experience from outside China to expand its capabilities.

Safety was a top priority, so the team partnered with ABS throughout the project. This allowed the classification society to contribute by bringing extensive experience to bear as well as access to senior engineering staff of Houston, Singapore, London and Shanghai, who were active participants to the MARIC-led design team.

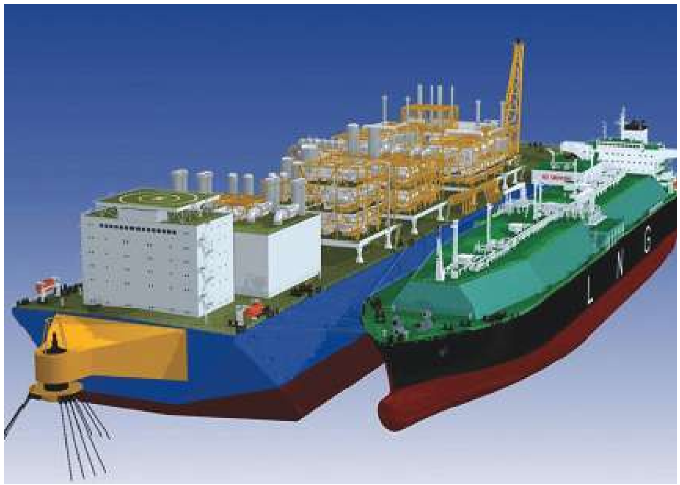
The combined effort led to the design and construction of the *Hai Yang Shi You 981* semisubmersible unit, which began drilling operations on May 9, 2012, in the South China Sea, about 320 km (100 miles) southeast of Hong Kong, at a depth of 1,500 m (4,921 ft).

Capable of drilling in 3,050 m (10,000 ft) water depth to a depth of 10,000 m (32,800 ft), this high-specification drilling unit is equipped with a sophisticated DP-3 system and is outfitted with accommodation capacity of 160. The semisubmersible unit was designed in compliance with ABS *Rules for Building and Classing Floating Production Installations*.

Additional development

Continued emphasis in the ensuing five years has been on preparing for further development of the South China Sea and expanding into more international markets. Toward that end MARIC is focusing on R&D for production units that include not only semisubmersible units but FLNG units and deepwater FPSO units.

State-funded efforts underway include a truss spar and a drillship with a water depth rating of 3,000 m (9,842.5 ft). MARIC also is evaluating concepts for FLNG units with the goal of enabling deepwater gas development in the South China Sea. MARIC has carried out a feasibility study of an FLNG concept design that included hydrodynamic and motion analysis, mooring and structural assessments, and cargo handling and offloading system optimization as well as how the topside module will be integrated. Additional work evaluated risk in typhoon conditions. The two resulting designs are for a 138-Mcm (4.8-MMcf) vessel and one for a 300-Mcm (10.5-MMcf) vessel with water depth capability of 1,500 m (5,000 ft). ABS reviewed the designs, awarding both of them Approval in Principal, a process through which ABS issues a statement affirming that a proposed novel concept design complies with the intent of ABS rules and appropriate codes.



MARIC is evaluating concepts for FLNG units with the goal of enabling deepwater gas development in the South China Sea. (Source: MARIC)

Ongoing efforts

In 2016 MARIC signed a strategic cooperation agreement with ABS to expand collaboration, focusing on operational efficiency and environmental performance in both the marine and offshore sectors. This agreement provides a framework for the organizations to work together to provide solutions that will help the industry effect improvements and to form joint industry development projects. Through this agreement ABS and MARIC will collaborate on technical support, classification, certification, training and statutory guidance for marine and offshore units.

China has invested substantially to expand its ability to produce offshore designs and is partnering with other organizations that will help it remain at the forefront of design innovation. Government commitment to research funding coupled with the ambition of the MARIC team creates a strong foundation for growth. While depressed oil prices since late 2014 have impacted investment in R&D elsewhere, market conditions have not distracted China from advancing its offshore R&D capabilities. E&P

Petrolithium: extracting minerals from petroleum brine

New lithium extraction technology offers improvements over current methods.

Jared Lazerson, MGX Minerals

Lithium is the foundation of the world's technological future, powering everything from laptops to mobile phones to the electric vehicles that promise to flood streets in the years to come. Yet as the world insists on cleaner cars, more energy storage options to further the renewable energy revolution and more consumer electronics, lithium's ability to supply enough of the precious metal to meet demand is being questioned.

Goldman Sachs Group projects demand for lithium to triple by 2025 to 570,000 tons, driven principally by smartphone and electric car applications. As the earth's lightest solid element and with double the energy density of the next closest alternative, lithium is ideal for such portable energy storage applications. In fact, Goldman Sachs calls lithium "the new gasoline" for its integral role in the lithium-ion batteries used in today's electric vehicles.

Recognizing the tension between the world's supply and demand of lithium, Tesla CEO Elon Musk stated, "To produce half a million cars a year … we would basically need to absorb the entire world's lithium-ion production." In fact, Tesla's new Gigafactory in Nevada is projected to use up as much as 17% of the world's existing lithium supply. What's more, Credit Suisse forecasts that demand for lithium "will actually outstrip supply as we approach the latter part of the decade, with demand potentially as high as 125% of total capacity."

Lithium-ion batteries power everything from cellphones to electric cars, which is leading to lithium shortages. (Source: Kiri 11, *Shutterstock.com*)

Procuring lithium

So if lithium is one of the earth's most abundant elements, how are we running low on supply? To date, there are only two conventional ways of procuring lithium—solar evaporation and hard-rock mining—and neither is particularly effective.

Solar evaporation is an inefficient and time-intensive process that requires at least 18 months to produce viable lithium carbonate. Despite this long timeline, solar evaporation averages low mineral recovery rates of less than 50%. Additionally, the technology requires hundreds of acres of land for evaporation ponds, resulting in a significant negative environmental footprint.

Hard-rock mining is also a time-intensive process that disturbs the land surface and detrimentally impacts groundwater, surface water, aquatic and terrestrial vegetation, wildlife, soils, air, and cultural resources.

Given these two lackluster approaches, it's evident that traditional means of supply need to be diversified to invent unconventional ways of procuring lithium.

MGX Minerals is pioneering a new concept called "petrolithium." The idea is to separate the most valuable minerals and salts from the brine water that accompanies petroleum as it's being pulled up to the surface. Among those valuable minerals in the brine water is lithium carbonate.

Long known to contain valuable minerals, petroleum brine is plentiful yet is currently treated as a byproduct that is either reinjected into the ground or stored in giant tanks after the oil is separated at the wellhead. These traditional disposal methods can cause major environmental issues such as the contamination of drinking water and earthquakes.

Extracting lithium from petroleum brine is exponentially faster and more environmentally friendly than solar evaporation. It's also a less expensive way of harvesting lithium than conventional hard-rock mining.

This recovery process was specifically designed for the highly mineralized brine associated with oilfield lithium brine and promises to reduce lithium brine evaporation times to less than one day. This represents a decrease of more than 99% over traditional solar evaporation techniques, which traditionally take up to 18 months.

The process is designed to operate in oil and gas fields by integration with existing environmental and disposal systems, whether they are standalone or centralized environmental facilities. What's more, the technology leaves room for the development of a scalable modular solution to lithium and other mineral extraction equipment.

MGX Minerals is working with PurLucid Treatment Solutions, an advanced water purification company, to integrate their respective technologies and purify the wastewater that results from the surfacing of petroleum brine. Together, the technologies will pretreat the brine to remove oil, colloid and metals through nano-flotation and filtration technologies. The patented technology separates oil to a high degree of purity from lithium-bearing brine, removing one of the major hurdles of oilfield lithium brine production.

Heavy oil evaporator blowdown wastewater is one of the byproducts of steam-assisted gravity drainage during production of heavy oil. Evaporator blowdown wastewater was specifically targeted because the wastewater contains mid-level concentrations of lithium and has the potential to generate high-environmental revenue based on current disposal costs. MGX and PurLucid Treatment Solutions are developing a pilot plant suitable for commercial use that will treat evaporator blowdown wastewater to provide oil sand producers with additional environmentally friendly disposal options as well as recover valuable minerals such as lithium.

Up until now the presence of hydrocarbons in lithium brine presented a potentially significant long-term hurdle to efficient large-scale production of lithium from oilfield brine. PurLucid's technology was designed for the environmental services industry to separate impurities from oil industry waste streams, producing clean water as a final product.

The company partnered with David Bromley Engineering by licensing and applying patented nano-flotation technology to wastewater treatment. The novel approach uses a removable membrane coating to capture particles. The technology provides the ability to operate at one-third less cost on a continuous basis with little to no downtime and is projected to require half the capex and reduce the carbon emissions of water treatment by 90% when compared to conventional environmental technology in thermal facilities.

Hand-shoveled salt piles dry on Bolivia's Salar de Uyuni, thought to be one of the richest sources of lithium in the world. Solar evaporation takes up to 18 months. (Source: Matyas Rehak, *Shutterstock.com*)

All of this results in a clean, consistent flow of feedstock for processing with wastewater that can be safely recycled or returned to the environment in a controlled manner.

This process will remove heavy metals and hydrocarbons, providing a continuous stream of partially concentrated lithium brine that's very low in impurities and has a higher overall grade of lithium for processing with MGX's rapid lithium production process. PurLucid, working with MGX and its proprietary process design for lithium extraction, will engineer, fabricate and deploy combined treatment and lithium recovery plants.

The world has gone electric and has dramatically increased its reliance on lithium. Continuing to rely solely on conventional extraction methods will see demand outpace supply. Not only will the concept of petrolithium provide oil providers with an environmentally responsible way to dispose of their produced oilfield water, it will create a new supply source for large-scale lithium consumers like electric vehicle manufacturers and makers of consumer electronics. E&P

Have a story idea for Tech Watch? This feature highlights leading-edge technology that has the potential to eventually address real-life upstream challenges. Submit your story ideas to Group Managing Editor Jo Ann Davy at *jdavy@hartenergy.com*.

Putting the driller back in control

NOV's integrated managed-pressure drilling (MPD) control system, part of the MPowerD product family, is now commercially available. This centralized control system aims to achieve true rig integration by holistically synchronizing MPD functionality with top drive, drawworks and mud pump control. Doing this enables consistent and optimized performance for the overall drilling operation while simultaneously accounting for both pressure control accuracy and drilling key performance indicators. When the MPowerD system is integrated into the rig, mud pump ramping and surge and swab effects of running or pulling pipe are automatically controlled to stay within the target control objectives required for the MPD operation. Without integrated automation these time-consuming manual tasks require careful planning and fingerprinting to ensure that the nonintegrated control system will actually follow the driller's commands. By adding MPD controls to the normal driller's interface NOV aims to put the driller back in control of the process, directly providing him or her with all relevant measurements and control parameters. Complex connection sequences, mud pumps ramp-up and tripping operations optimization can be activated by a click on a keypad. *nov.com*

Integrating MPD controls into the driller's interface enables reductions in NPT by putting the driller in control of the MPD process. (Source: NOV)

Monitor and control multiple zones

Conventional intelligent completions typically require multiple control lines, which complicates installation and adds a risk of failure for long horizontal completions. Schlumberger's Manara production and reservoir management system, developed in conjunction with Saudi Aramco, connects all downhole monitoring and control stations to the surface with a single electric control line, thereby simplifying deployment and reducing wellhead penetrations to one, according to the company. For the first time ever, this system makes in-lateral zonal monitoring and control possible. *slb.com/manara*

System saves 1.5 hours of operational time

Packers Plus Energy Services Inc. has released its PrimeSET liner hanger system. Anti-preset features ensure reliability and performance, resulting in time and cost savings for operators, a press release stated. Between July and December 2016 Packers Plus successfully installed and completed more than 15 wells across North America using the PrimeSET liner hanger system. Using premium sealing technology to pack off the annulus and secure the liner in intermediate casing, the hanger can be used in both cemented and openhole applications. The tool includes a balanced piston that prevents presetting while running in hole, thereby enabling the system to reach planned depths. This system saves 1.5 hours of operational time per well over traditional systems. *packersplus.com/solution/plh*

Mobile filtration system removes solids, oil

Fountain Quail has released SCOUT, a mobile automated filtration system. The backbone of the SCOUT system is a well-proven completely automated back-washable media filtration system that removes 95% to 98% solids greater than 2 microns while simultaneously removing 90% to 95% of hydrocarbons, a press release stated. This performance is achieved in a small footprint. In fact, a system with a capacity more than 10,000 bbl/d of water can be pulled by a pickup truck and set up by a single operator, thereby allowing costs and footprint to be driven down. The system operates without manpower, chemical or the need for disposal of filter media. There is a far higher flux rate than traditional filters, which means less size, weight and cost. The SCOUT platform allows quick setup time, and the product is synergistic with Fountain Quail's MAVREX and ROVER platforms. The product will be used for oilfield applications, including infield produced water treatment, pit remediation and saltwater disposal pretreatment. *fountainquail.com*

Sensors for unmanned and autonomous vehicles

LORD Sensing MicroStrain has expanded its portfolio of sensors for unmanned and autonomous vehicles for air, land and sea with the release of the 3DMGX5 family of inertial sensors, a press release stated. The latest generation of this inertial sensor is designed to measure attitude (pitch, roll and yaw), position (latitude and longitude) and velocity in a variety of applications, including antenna pointing, platform stabilization, flight tracking, navigation and regime monitoring. The GX5-45 GNSS/INS allows a greater degree of precision by moving through terrain in 3-D with a GNSS-aided navigation system when a GPS signal alone is not accurate enough. Key upgrades from the GX4 line include improved performance through *in situ* heading calibration. Automatic magnetometer calibration and anomaly rejection eliminate the need for field calibration. *lord.com*

New subsea inspection service for offshore

Lloyd's Register (LR) has released its Subsea Inspection Services to support underwater inspections of subsea pipelines, assets and facilities for energy companies operating offshore, a press release stated. Services include project management, consultancy, personnel, quality control, data processing and data management applicable to ROV, AUV and diver projects. Headed by LR's Subsea Inspection Manager Andrew Inglis and delivered by the company's in-house experts in subsea inspection, survey and asset integrity, services will be provided to operators and contractors in the offshore oil and gas, wind farm, and submarine cable sectors. As operators begin to prepare for their annual subsea inspection programs, the company's expertise will help operators achieve their subsea asset integrity requirements by optimizing project planning, execution and delivery and facilitating the potential for multiclient multiproject operations. *lr.org*

Collaboration lights the way for improved diver safety

A new on-demand wireless ribbon lighting system designed to improve diver safety and efficiency in remote subsea locations has been released following a collaboration between WFS Technologies Ltd. and PhotoSynergy Ltd. (PSL), a press release stated. Seatooth LIGHTPATH is a combination of two advanced technologies—WFS's Seatooth, a subsea wireless communication system that can download and log information gathered on subsea installations remotely, and PhotoSynergy Ltd.'s LIGHTPATH, a side-emitting flexible fiber that projects a continuous line of light that carries no electrical power. The new product works for both diver and ROV operators working either near surface or at depths of up to 3,000 m (9,842.5 ft). The light is engaged automatically when the diver or the ROV comes within 5 m (16 ft) of a structure and provides instant illumination of subsea architecture and delineating features such as control valves, docking bays and even the outline of the structure itself against the natural darkness of the underwater environment. It switches off automatically when the diver or the ROV departs the scene and has the ability to act as a proximity warning system when approaching installations, other divers, ROVs or danger areas. The unit has been successfully tested in a laboratory and was scheduled to be trialed in subsea conditions in early 2017. *photosynergy.co.uk*

Plugs deliver safer wells, more efficient operations

Archer Oiltools has released the SPARTAN plug suite to help operators deliver safer wells, boost operational efficiency and reduce costs, a press release stated. The SPARTAN plugs were developed to ensure well integrity during operations, secure well suspension and provide safe plug and abandonment for all wells. The SPARTAN plug delivers protection for short-, medium- or long-term suspensions and rapid deployment and retrieval, which ensures safer wells and reduces operational time and costs. *archerwell.com*

Drill fluid two-in-one conditioner creates super muds

ProOne has technologically surpassed its XPL+ drilling mud additive with a new industry standard two-in-one drill fluid conditioner, the company said. Effectively turning ordinary muds into super muds, Diamond Dust powder with asphalt attributes combines with XPL+ lubrication to deliver benefits for laterals, verticals and curves. The conditioner is easily dispersed in any mud (water- or oil-based). A field-proven next-generation product, the Extreme Pressure lubricant provides the best coefficient of friction reduction against competitors at a three-times lower concentration—increased power using less additive, according to the company. Developed by a longtime R&D head at a major company, Diamond Dust with its friction reducer also stabilizes shale formations, reduces drag with its lubricity, enables a better filter cake, provides high-temperature fluid loss control and is excellent for seepage and lost circulation material control. Additionally, it maintains the biodegradability of XPL+, including being ecofriendly offshore. *pro1energy.com*

On this rig site Diamond Dust drilling fluid was used with muds. (Source: ProOne)

Air-mobile capping stack for global subsea market

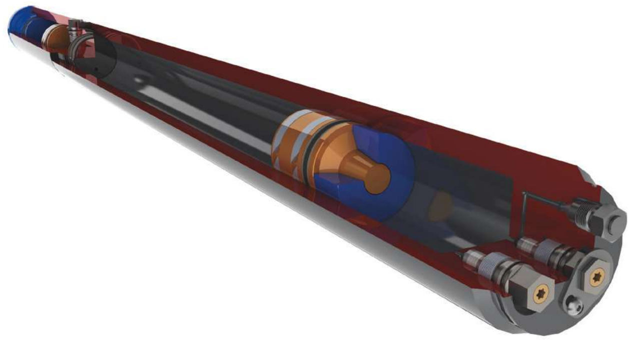
Boots & Coots Services, a Halliburton business, has developed the Global Rapid Intervention Package (GRIP), a suite of services designed to help reduce costs and deployment time in the event of subsea well control events, a press release stated. GRIP provides well planning and well kill capabilities facilitated by the company's global logistics infrastructure and existing product service lines. This includes an inventory of well test packages, coiled tubing units and relief well ranging tools. In addition, GRIP features the new high-temperature 15,000-psi RapidCap air-mobile capping stack. Sourced from Trendsetter Engineering Inc., RapidCap incorporates a specially designed gate valve-based system, making it significantly lighter, less expensive and more mobile than options currently on the market, according to the company. *halliburton.com*

Reimaging program improves data quality

TGS-NOPEC Geophysical Co. (TGS) and Schlumberger announced a new multi- and wide-azimuth (M-WAZ) multiclient reimaging program in the highly prospective Central U.S. Gulf of Mexico, a press release stated. Final results are expected in early 2018, ahead of a period when substantial block turnover in the area is anticipated. The new Fusion M-WAZ reimaging program comprises data covering more than 1,000 Outer Continental Shelf blocks (about 23,000 sq km or 8,880 sq miles) from 3-D WAZ programs previously acquired by TGS and Schlumberger with the WesternGeco Q-Marine point-receiver marine seismic system between 2008 and 2012. This large reimaging program will process data from the Mississippi Canyon, Atwater Valley and Ewing Bank areas using the latest imaging technology to provide a significant uplift in data quality for upcoming licensing rounds. The area is expected to remain a high priority for E&P companies in the foreseeable future and will benefit from two licensing rounds every year for the next five years under the new Bureau of Ocean Energy Management 2017-2022 five-year program. *tgs.com, slb.com*

New subsea sampling cylinder reduces risks

Proserv has released a new subsea sampling cylinder that is designed to improve the quality of results and reduce risks normally associated with sample transfer, a press release stated. Based on existing technology, the Proserv Subsea Sampling Cylinder (SSC) is the world's first fully qualified and certified "for shipping" sample cylinder to be deployed in a subsea environment. The system accurately captures well properties throughout the lifetime of a field. Subsea cylinders allow operators to take representative production samples from a subsea system for direct transfer to a laboratory. Proserv's SSC eliminates the risks associated with handling and transferring samples on the surface, reducing the risk of containment loss and exposure to H_2S/CO_2. *proserv.com*



Proserv's SSC eliminates risks associated with handling and transferring samples to the surface. (Source: Proserv)

Understand the growth, size and scope of subsea opportunities

Douglas-Westwood has released its Subsea Cable Tracker, which identifies the vessel installation day demand and a breakdown of component type by region as well as considering global drivers and outlook, a press release stated. Over the next five years Douglas-Westwood expects to see a significant increase in subsea cable demand, primarily driven by the strong growth in the offshore wind market. Douglas-Westwood has released the Subsea Cable Tracker to assist businesses in understanding this growth and the size and scope of opportunities that exist. The tracker details the subsea cable demand growth totaling 24,103 km (14,978 miles) over the 2017-2021 forecast period. *douglas-westwood.com* E&P

Please submit your company's updates related to new technology products and services to Ariana Benavidez at abenavidez@hartenergy.com.

Mexico's Round One: building an energy industry

Round One represented the first stone in the construction of Mexico's upstream industry.

Alfredo Alvarez and **Eduardo Lopez**, EY

On Dec. 6, 2016, Mexico conducted the fourth and final call of Round One, the first upstream bidding process opened to private companies in almost eight decades. This was made possible by the country's historical liberalization of its energy industry in 2013, which effectively abolished the monopolies of state-owned companies Pemex (oil and gas) and CFE (electricity). On the oil front, the most powerful incentive for reform was the urgent need to address Mexico's shrinking crude and liquids production. Production and proven reserves fell by 31% and 38%, respectively, over the past decade (2005-2015). Crude exports, the bulk of which is directed to the U.S., fell by 40% between 2005 and 2015. Meanwhile, refining capacity has remained largely stagnant and unable to match demand, leading to a surge in refined product imports, notably gasoline and primarily from the U.S.

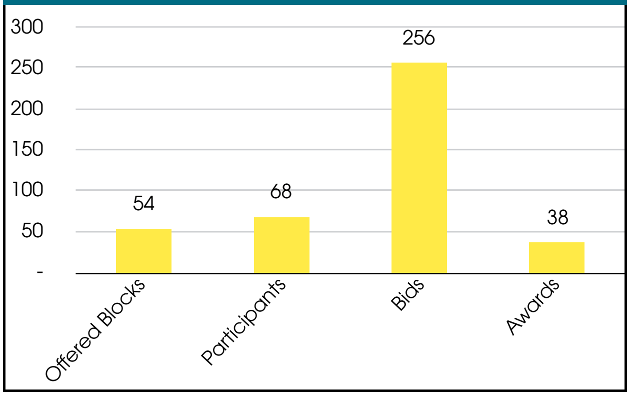
Upstream themes

The upstream market opening revolves around three broad themes:

1. Five licensing rounds are to be held up to 2020: one to award Pemex exclusive acreage or "entitlements," and four opened to private companies;
2. Pemex is to seek partners for selected promising areas; and
3. Twenty-two legacy "enhanced" service contracts between Pemex and private companies are to migrate to one of the new types of contracts specified in the new contractual framework (production and profit-sharing contracts, licenses and service agreements). Eventually, all of these elements are expected to gradually expand the country's resource base, moderate its production decline and, ultimately, result in higher production—the groundwork for a vibrant domestic industry.

Round One began in 2015, with the first call offering 14 shallow-water blocks for exploration taking place in July; followed by five shallow-water blocks for development in September; 25 onshore blocks for development in December; and 10 deepwater blocks for exploration, plus the first Pemex farm-out a year thereafter. Retrospectively, Round One can be considered a success: 38 out of 54 blocks were auctioned, an award rate of 70%, with 68 companies (of which 21 are single and the rest are grouped in 18 consortia) making an astounding total of 256 offers. Overall, upstream investment might surpass $50 billion over the next decade, although flows are likely to vary greatly in specific years given the distinct nature of the blocks awarded.

ROUND ONE: RESULTS



Round One can be considered a success, with 38 out of 54 blocks auctioned. (Source: EY)

Beating the odds

Yet when Round One began, the odds were not good, despite the fact that Mexico is arguably unique in that it offers all types of assets to would-be upstream players. Indeed, when Round One was announced in late 2014, oil prices already had plummeted, and they would hit record lows over the following two years. There was much concern over whether Mexican fiscal terms would be attractive enough to overcome both low oil prices and competition from other countries. In addition, the government itself was undergoing its own learning process with regard to best practices since the energy industry had been closed for so long.

This lack of experience was evident in the first call (shallow-water exploration). Since the government had insisted on keeping secret the minimum values for acceptable offers, the call attracted only six bids, with two blocks awarded (a paltry 15% success rate), thus casting a shadow on the rest of Round One. Moreover, the fields on offer were considered relatively small, and some were geared to less appealing natural gas. Despite the disappointing result, the first process was historic in many ways. For the first time in more than 75 years blocks were awarded to private companies, including one Mexican company, thus symbolizing the emergence of a new industry. The whole procedure was transparent, and the bids for the winning blocks were highly lucrative for the state.

Subsequent Round One processes, however, proved much more successful in terms of awards after the government amended its strategy. In particular, it began publishing minimum values ahead of each bidding process and showed greater eagerness to listen to industry concerns, modifying fiscal terms several times and addressing other pressing issues such as corporate guarantees and arbitration. As a result, the second call (shallow-water development) achieved a success rate of 60%. Collectively, there were 15 bids, and three blocks were awarded. More strikingly, the third call (onshore development) awarded 100% of the blocks on offer.

Local industry

Admittedly, it was intended to attract mostly independent Mexican companies and set the stage for the emergence of a domestic E&P industry. As such, the blocks were relatively easier to operate, with abundant seismic data and some degree of infrastructure in place. Moreover, the financial and operating requirements were more relaxed than in the first two processes.

Finally, the fourth auction (deepwater exploration) was geared toward international majors endowed with the technical, financial and managerial resources necessary to develop such complex tasks. The potential resource base in the Gulf of Mexico, one of the world's most prolific basins, would conceivably justify long-term deepwater projects despite a short-term fall in oil prices. That proved to be the case.

The four blocks on offer in the northern Perdido Fold Belt were awarded (the Belt is close enough to the U.S. maritime border to be conceivably connected to existing U.S. subsea infrastructure, which would lower development costs). More surprising, perhaps, four out of six in the southern part of the Gulf (the so-called presalt basin, where infrastructure is virtually nonexistent) also found suitors and achieved a success rate of 80%. During the same bidding process, Pemex's first-ever farm-out—the Trion Block in the Perdido Fold Belt—was awarded. Unsurprisingly, the world's heavyweights in deepwater exploration were all present, typically in consortia, although all did not bid or win. The two interesting developments were the aggressive participation of the Chinese, marking their first important foray in North American deepwater acreage, and the bid by several independents, albeit backed by a large national oil company. The results were clearly a vote of confidence for Mexico's opening.

New bid rounds

Round One was just the beginning in a series of regular auctions to be carried out in the future. In October 2015 the Energy Ministry released details for three new bidding rounds due to take place over the following five years. Including Round One, 338 blocks are to be auctioned, with total reserves of 107 Bboe spread over 236,000 sq km (91,120 sq miles). In broad terms the blocks to be auctioned in the next three rounds will be much larger and hold higher reserves on average than in Round One.

About 78% of the blocks on offer in the four rounds are located in development areas, which suggests greater urgency to reverse the current production decline. Round One concentrated on most of the proved, probable and possible (3P) reserves (61 out of 67 Bboe for the four rounds), which by definition are much more uncertain. By contrast, rounds 2 through 4 hold the bulk of "prospective" resources (29 out of 40 Bboe), which includes proved and probable (2P) reserves as well as yet-to-find resources that the government believes are abundant. Development blocks will still be mostly located in onshore areas (70% of all blocks) since mature fields could be turned around and start/increase production much more quickly than deep water. Rounds 2 through 4 will account for 144 out of the 169 onshore blocks on offer. Exploration blocks are spread across more evenly, notably over rounds 2 through 4.

Round One ultimately represented the first stone in the construction of Mexico's upstream industry over the long term, with domestic players focusing on less risky, more mature resources and international companies delving into more complex and challenging endeavors. In this sense, the country's first five-year plan, which is likely to evolve, indicates a clear direction: an effort to improve the overall attractiveness of future rounds and a focus on known albeit underdeveloped resources. E&P

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Mexico's emergent E&P sector will continue to grow

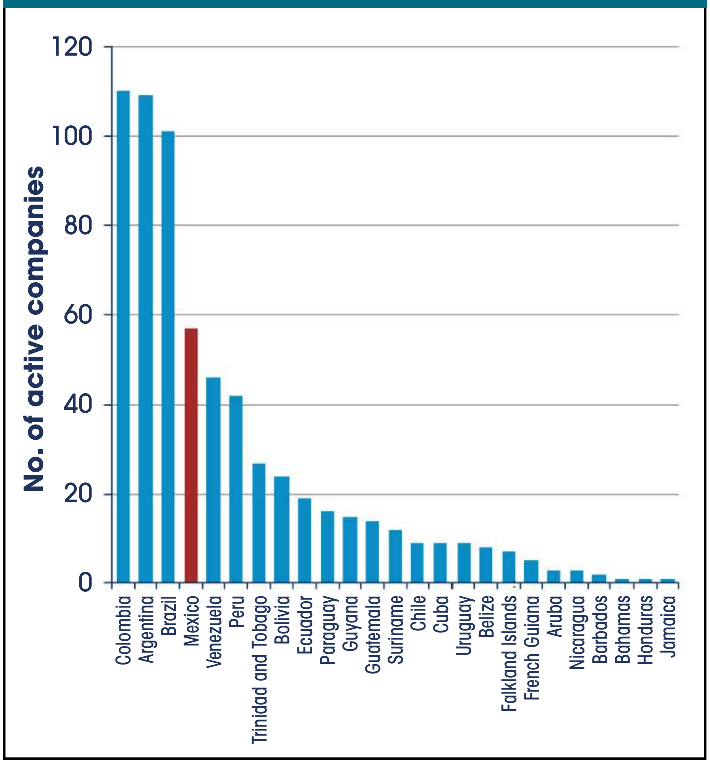
Producing assets in shallow water and onshore will spur the most interest from the industry and bring the most immediate benefits to Mexico.

Ruaraidh Montgomery, Wood Mackenzie

One measure of the success of Mexico's energy reform to date is the number and quality of companies active in the country's upstream space. There are almost 60 E&P companies with positions, including most of the majors, which have long coveted the opportunity to operate in the country. This success is the result of the country's prospective geology combined with the government's willingness to listen to the industry and adapt the terms on offer to the low-price environment. With Pemex's financial troubles constraining its capacity to invest and the easy-to-develop oil largely gone, tapping into external capital and technical expertise is essential if Mexico is to fully realize its hydrocarbon potential.

With the oil price seemingly stabilizing, the industry is slowly emerging from a downcycle in which survival was the buzz word, and stronger companies are starting to contemplate growth. Interest in Mexico is expected to stay robust. At the same time the global environment in which the country competes for upstream capital is by no means straightforward, and it's essential the government remains vigilant to the value proposition on offer to attract investment. Factors that must be accounted for include 1) the strict capital discipline that remains a strategic priority for many companies, 2) perceptions under a Trump presidency, 3) the political backlash caused by the recent domestic gasoline price increases and 4) competition for investment from the likes of Iran and Brazil.

ACTIVE COMPANIES IN LATIN AMERICA BY COUNTRY



Colombia has the highest number of active companies in Latin America, followed closely by Argentina. (Source: Wood Mackenzie)

Pemex constrained, but a diverse corporate landscape emerges

The success of *Ronda Uno* (Round One) has brought 44 new companies to Mexico's upstream sector. The breadth of opportunity—from world-class deepwater exploration acreage to small onshore discovered resource opportunities—has drawn a diverse range of companies. Underpinning this is an attractive regulatory framework with an independent regulator, competitive fiscal terms, non-onerous work commitment obligations and local content rules that reflect the capacity of the domestic service sector to deliver. This has been facilitated by a government that has worked with the industry to adjust the terms on offer to reflect a "lower for longer" price outlook.

Size of opportunity

No other group besides the majors has spent more time over the years building a relationship with Pemex in anticipation of the sector opening up. Every major placed bids and, with the exception of Shell, now hold offshore acreage. This underlines the prospectivity and scale of resource on offer. Given the majors' recent exploration portfolio rebuild efforts, the primary focus was December's deepwater round, and Wood Mackenzie's Exploration Service estimates that 7 Bboe will be discovered by 2035 in the two basins where acreage was offered. Eni and Statoil also were active bidders for the shallow-water discovered resource opportunities offered in 2015, with Eni now holding a 100% stake in the Amoca-Mizton-Tecoalli project. The participation of the majors, with their strong balance sheets, technological expertise and project management skills, is vital if Mexico is to unlock its technically challenging deepwater resources.

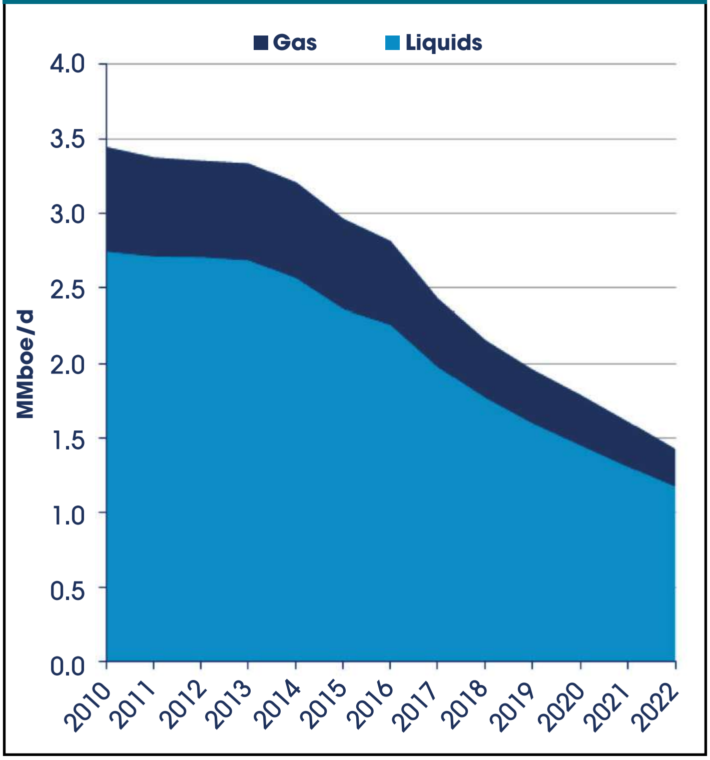
Portfolio replenishment key for Asian NOCs

Most Asian national oil companies (NOCs) face a long-term growth challenge. Maturing domestic asset bases leaves them with little choice but to look to international business development and, like the majors, find that Mexico has the scale to attract their interest. Although it was somewhat surprising that none took part in bidding for the Trion discovered resource opportunity, CNOOC and PETRONAS successfully picked up deepwater exploration acreage through aggressive bids in the Perdido and Salinas Sureste areas, respectively. The same two companies had previously made unsuccessful bids in the shallow-water discovered resource opportunity round. ONGC unsuccessfully bid in the shallow-water exploration round.

International independents making a mark

The Energy Reform has drawn a group of credible mid- and large-cap companies. Full realization of the country's hydrocarbon potential requires the active participation of many different types of companies. Leading the pack is BHP Billiton, which beat BP to win the deepwater Trion discovered resource opportunity, helping bolster its longer term growth outlook and bringing more balance to a portfolio that was increasingly weighted toward U.S. unconventionals. Murphy Oil marked a tentative return to frontier exploration, picking up a deepwater block after having sat largely on the exploration sidelines since the oil price collapse. Buenos Aires-based Pan American Energy, a tie-up between BP, CNOCC and Bridas, made its first meaningful move outside Argentina since the joint venture's (JVs) formation back in 1997, taking the shallow-water Hokchi discovered resource opportunity. Private equity also was active, with Fieldwood Energy taking the shallow-water Ichalkil-Pokoch discovered resource opportunity and Sierra Oil & Gas picking up a pair of deepwater exploration blocks. Other notable winners include INPEX, Premier Oil and Ophir.

MEXICO'S PRODUCTION OUTLOOK

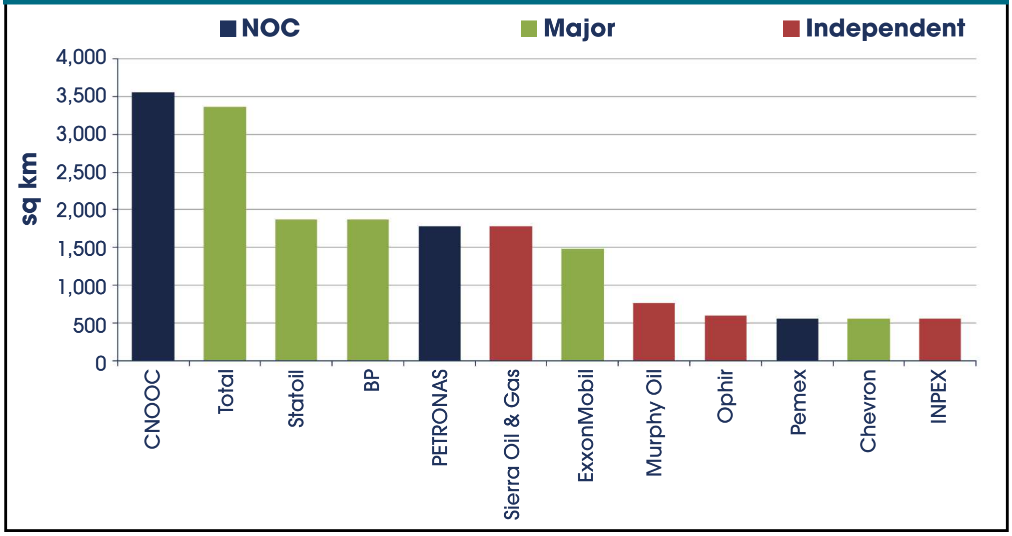


Without capital input from foreign companies, Mexico's production will continue to decline. (Source: Wood Mackenzie)

Emergence of a domestic E&P sector

The onshore bid round was the most competitive, with 40 predominantly local companies placing bids. The high level of interest was positive, and a vibrant small-cap sector can fully exploit remaining onshore opportunities, which are smaller in scale compared to the offshore. However, the high additional royalty that many companies offered to secure wins possibly reflects the immaturity of this emergent group of companies, and it's likely that some bids will prove to be uneconomic in the absence of a significant rise in oil price. Nevertheless, there is clearly appetite within Mexico for these opportunity types and, if nurtured correctly by the government, a thriving onshore sector can be developed.

DEEPWATER ACREAGE AWARDED IN *RONDA UNO*



CNOOC was the big winner in the first deepwater licensing round. (Source: Wood Mackenzie)

Pemex's participation reflects the challenge of its reality

The Mexican NOC is struggling to mitigate production declines while shoring up its finances. As of third-quarter 2016, its net debt stood at $87 billion, second only to Petrobras, which is the world's most indebted E&P company. Consequently, Pemex mostly played an observer role in *Ronda Uno*, participating in just a single deepwater block award. This also might reflect growing discretion on the part of the company as it tries to reform itself into a more effective E&P company, particularly as developing, technically challenging new resource themes like deep water and unconventionals forces it out of its onshore/shallow-water comfort zone.

Expectations for 2017 and beyond

As the Energy Reform continues, at least three rounds are planned for 2017 as part of a longer term program of licensing. The regular offering of new acreage is important since it provides new companies with entry opportunities and enables incumbent players the chance to grow their businesses. The current schedule calls for two onshore licensing rounds and a shallow-water round. Pemex also is expected to offer JV opportunities, and there might be a second deepwater round toward year-end 2017—indeed, several are planned before the end of the current presidential cycle in late 2018.

The Pemex JV opportunities continue to attract greatest interest. The company's 36% year-on-year budget cut (in U.S. dollar terms) brings a greater urgency to strike JV deals to bring in fresh capital. This should speed up the long-delayed farm-out program and incentivize Pemex to improve the quantity and quality of assets offered. The company also should be encouraged by the success of the Trion offering, in which the Mexican NOC will benefit from a $1.1 billion cost carry. Larger producing assets in shallow water and onshore will spur the most interest from the industry and bring the most immediate benefits to Mexico as new investment will result in a quick production response.

There is already strong interest in shallow-water Round 2.1, with 13 companies prequalified, including familiar names from Round One like Chevron, BP, Eni, Statoil and Premier Oil as well as potential new entrants like ConocoPhillips and Noble Energy. The round was originally scheduled to close in March but has been pushed back to June following a formal request from several companies. A mix of exploration and discovered resource opportunities will be offered. Initial analysis suggests that the subsalt exploration potential in the Salinas-Sureste Basin will be the main attraction, with discovered resource opportunities only offering marginal economics on a standalone basis. Furthermore, 40% of the 15 blocks on offer are contiguous to acreage already awarded, allowing companies to build critical mass.

Finally, there are two onshore rounds planned. The first (2.2) is scheduled for April and will offer 12 exploration blocks, some holding small existing resource. However, with much of the gas-prone acreage located in the north of the country in the Burgos Basin, interest is likely to be constrained by security concerns and low gas prices caused by increasing U.S. imports—competitive full-cycle returns will be tough to achieve. More success is expected with Round 2.3, which offers 14 large blocks with proven reserves and the prospect of exploration upside, mostly located in the south of the country where security concerns are less of an issue. Interest in these rounds is likely to largely come from domestic companies. E&P

Unlocking a Mexican prize

Rhonda Duey, Executive Editor

Talos Energy is an example of a classic independent that has a niche, understands its niche and exploits it well. With 85,470 sq km (33,000 sq miles) of seismic in the U.S. Gulf of Mexico and Gulf Coast regions, the company specializes in revitalizing older assets by coupling new technology and additional drilling investment. *E&P* recently spoke to Talos CEO and president Tim Duncan about the prospect.

***E&P*: What do you find appealing about these blocks?**

Duncan: The variables are the same once you identify the prospect: resource potential, cost, risk and then each company's return expectations relative to their cost of capital. We might have a higher cost of capital than our global peers but hope to be more efficient. We like the setup of the Miocene-aged traps and how they respond to the geophysics. It is similar to how we have built companies in the U.S. Gulf of Mexico side.

***E&P*: Since our last article on Talos, has better seismic become available? If so, what are you seeing? What types of reprocessing have you been doing on the older data?**

Duncan: We have spent the last year reprocessing the seismic data provided by CNH [Comísion Nacional de Hidrocarburous] as part of the contract, including a reverse time migration effort and a Kirchoff prestack depth and time reprocessing effort, which has provided a significant imaging uplift on our acreage. Due to this uplift we are working with WesternGeco and Ion Geophysical to reprocess additional datasets in shallow water to help tie in more well control to our acreage and look for new opportunities that could become available in future bid rounds or farm-outs.

***E&P*: Can you provide updates on your progress?**

Duncan: Progress has been made on several fronts. Due to the reprocessing efforts we have been able to tighten up our top prospects, and our first well, Zama-1 (which will be the first non-Pemex offshore exploration well in more than 80 years), will spud in the middle of the second quarter, so we are looking forward to that operation. Additionally, we have been able to put an entire portfolio of ideas across the acreage set we have under primary term, which is more than 160,000 acres. It's a robust portfolio, and by understanding the petrophysical and corresponding geophysical relationships established by the first well, we will be able to high-grade additional opportunities, which could really allow us to build a strong asset base in Mexico and hopefully be an example of what the energy reforms intended. We are also very active in the growing oil and gas community in Mexico, which includes being on the front lines of filing permits and HSE plans, being involved in providing policy feedback, etc. We take the responsibility of being the first operator awarded a license in the reforms very seriously.

***E&P*: Did you participate in the deepwater bidding? Do you have plans to participate in future rounds?**

Duncan: We did not bid in the deepwater rounds since we focused on staying on schedule with our acreage. But it was important to our model, both commercially and geologically, that the sale was active and the block north of us was competitive, and it was. In our view the amount of interest in the bid round and the competitiveness on a block that is geologically on trend with our Block 7 validates our hope that there is tremendous potential offshore Mexico. We will certainly continue to look at opportunities to bid in future rounds.

***E&P*: What else can you tell us about your future plans for Mexico?**

Duncan: The Mexican government has been committed to these reforms by being transparent and trying to encourage participation. Our success starts with a willing government partner. Beyond pushing forward on our acreage and future bid rounds, we hope Pemex, Sener and CNH continue to focus on how to pull more stranded assets to the market. We have noticed there are very attractive assets discovered but maybe not material to Pemex. These assets are waiting on investment and are not creating value without activity, but if they can make it to market in future bid or farm-out rounds, then I think it will cause an already growing industry to accelerate, creating more local jobs and using more of a willing local supply chain. The hope of a growing industry is robust participation, which is what the Mexican reforms need and I think can achieve, and our hope is to be a visible part of the story. ■

1 Alaska

ConocoPhillips, according to IHS Markit, has completed testing and initial technical assessments at its Alaska National Petroleum Reserve prospect in Umiat Meridian, Alaska. The recoverable reserves are about 300 MMbbl of oil. Two Willow discovery wells in the Greater Mooses Tooth Unit (GMT1), #6-Tinmiaq and #2- Tinmiaq, respectively, penetrated 22 m and 13 m (72 ft and 42 ft) of net pay in Brookian Nanushuk. The #2-Tinjiaq was tested flowing 3.2 Mbbl/d of 44°API oil. First oil production is planned for late 2018. In addition, permits have been filed for GMT2, located about 13 km (8 miles) west of GMT1 with peak production estimated at 25 Mbbl/d to 30 Mbbl/d gross.

2 Cuba

An assessment by Melbana Energy Ltd. of onshore Cuba's Block 9 estimates that the oil and gas exploration potential of the 2,380-sq-km (919-sq-mile) area holds about 12 Bbbl of in-place oil. The block is on trend with the multibillion-barrel Varadero oil field, which has a prospective recoverable resource of 612 MMbbl that is about 50% more than the previous assessment. The assessment was on the Lower Sheet Play, which is a conventional fractured carbonate reservoir similar to existing producing fields in Cuba and is located at depths typically 2,000 m to 3,500 m (6,562 ft to 11,483 ft). Block 9 is in a proven hydrocarbon system with multiple producing fields, including the nearby Majaguillar and San Anton fields and the Varadero and Motembo fields.

3 Colombia

In offshore Colombia's Purple Angel Block Anadarko Petroleum Corp. is underway at exploration well #1-Purple Angel. The venture is in the Fuerte Norte license area. It is designed to test objectives similar to those at the play-opening Kronos discovery to the south. Upon completion the rig will be moved to drill on the Gorgon prospect at #1-Gorgon, which will test an analogous structure along the same trend to the Kronos discovery. The #1-Kronos discovery well was drilled to 3,720 m (12,205 ft), and area water depth is 1,584 m (5,197 ft). It encountered 40 m to 70 m (131 ft to 230 ft) of gas-bearing sandstones.

4 Peru

A permit has been approved for a Peru exploration well in offshore Block Z-34. Baron Oil Plc's #1X Cuy-Z34-13 will be drilled in 1,757 m (5,764 ft) of water, and the planned depth is 3,826 m (12,553 ft). Block Z-34 is in an undrilled deepwater basin covering about 3,713 sq km (1,433.5 sq miles). The prospect is located about 15 km (9 miles) from an existing producing field in the Talara Basin, an area that already has produced 1.7 Bbbl of oil. Most of the remaining potential in this area is believed to be located in this deepwater basin. The company's internal estimates of gross unrisked best estimate (P50) prospective resources for the Cuy Prospect is 413 MMbbl of recoverable oil.

5 Brazil

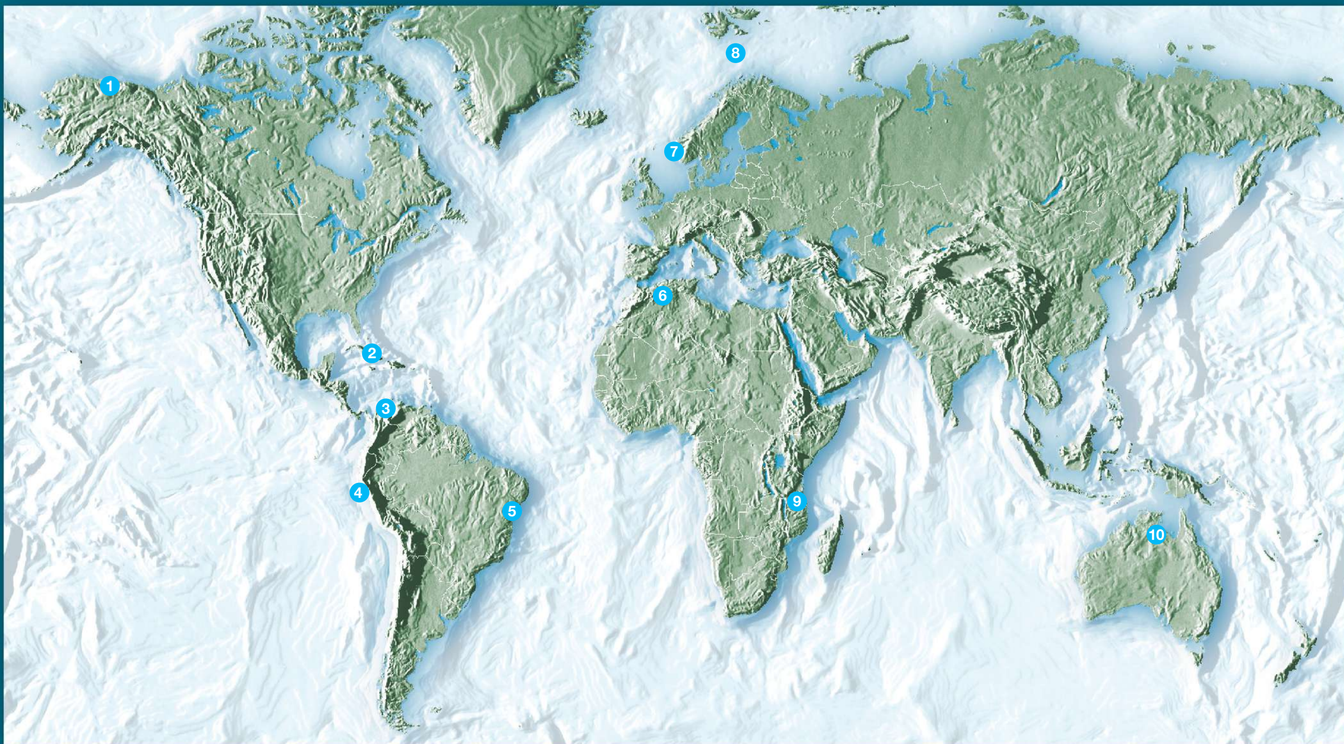
Alvopetro Energy has announced results from its #198(A1) well, which is in Block 198 in the Reconcavo Basin in Bahia, Brazil. The 1,480-m (4,856-ft) well was drilled as both a step-out well to the #197(2) gas discovery in the Caruacu Member and to target uphole exploration potential. Openhole logs indicated 31 m (102 ft) of potential net gas pay in the Main Caruacu Member. The well also hit 26 m (85 ft) of potential net hydrocarbon pay in a series of thinner up-hole Pojuca sands. The 2015 discovery at #197(2) well was completed and tested with 78 m (256 ft) of potential net gas pay with an average 33% water saturation and an average porosity of 12% in the Caruacu member of Maracangalha.

6 Morocco

Sound Energy Plc completed an extended well test at #7-TE in the Tendara license in Morocco. The 3,459-m (11,348-ft) well flowed about 793 Mcm/d (28 MMcf/d) during testing on a 44⁄64-in. choke from the TAGI reservoir. No formation water was produced. Extended well test results will be analyzed for field development planning. Another appraisal well is planned at a step-out, #8-TE, about 12 km (7 miles) to the northeast of #7-TE.

7 Norway

Lundin Petroleum AB announced an oil and gas discovery at #7219/12-1 at its Filicudi Prospect in PL533 in the Barents Sea. A sidetrack well, #7219/12-1A, is underway. The wells are between the Johan Castberg and the Alta and Gohta discoveries on the Loppa High. The well encountered a gross 129-m (423-ft) hydrocarbon column of high-quality Jurassic and Triassic sandstone reservoir characteristics, with 63 m (207 ft) of oil and 66 m (216.5 ft) of gas in the Jurassic and Triassic targets. The sidetrack well has reached total depth and has confirmed the reservoir and hydrocarbon column. The gross resource estimate for the Filicudi discovery is 35 MMboe to 100 MMboe, with significant upside potential that requires further appraisal drilling. According to the company, multiple additional prospects have been identified on the Filicudi trend within



PL533, with total gross unrisked prospective resource potential for the trend of up to 700 MMboe.

8 Norway

Statoil completed drilling at appraisal well #16/2-22S on the Johan Sverdrup Field in the Norwegian sector of the North Sea. The well is in production license PL265, Block 16/2, and was drilled to 1,963 m (6,440 ft) and terminated in the granitic basement. It has been permanently plugged and abandoned. Water depth at the site is 115 m (377 ft). The objective of the well was to prove petroleum in Upper Jurassic reservoir rocks (Draupne) and to investigate pressure communication to the northern part of the field. The well encountered a total oil column of 16 m (52 ft), most likely in Draupne, with alternating sandstone, siltstone and clay stone.

9 Tanzania

Aminex Plc has reported that appraisal well #2-Ntorya encountered a gross gas-bearing reservoir unit of about 51 m (167 ft) at a depth of 2,596 m (8,517 ft). The venture is in Tanzania's Ruvuma Block Mtwara license area. Preliminary petrophysical analysis of the LWD results indicates a porous and hydrocarbon-bearing reservoir with a potential net pay of 25 m to 30 m (82 ft to 98 ft). Aminex plans to drill deeper to 2,780 m (9,121 ft) to insert a 7-in. liner below the reservoir interval. A well testing program is planned, including flow-test and petrophysical analysis. The venture also encountered traces of oil in the gross reservoir interval, which the company is evaluating.

10 Australia

Falcon Oil & Gas Ltd. has announced results from an extended production test at its #1H Amungee NW exploration well in Northern Australia's Beetaloo Basin. The test is in permit area EP98. During the first 30 days it flowed an average of 31 Mcm/d (1.11 MMcf/d). According to the operator, B Shale member testing of Velkerri showed that drilling and seismic results across more than 10,000 sq km (3,861 sq miles) show continuity of Velkerri. The B Shale member is the most continuous of the three individual targets within the shale gas play. The #1H Amungee NW was tested with 11 stages of fracturing across about 600 m (1,968.5 ft) of the lateral section and confirms the ability of Velkerri B Shale to flow gas following fracturing. E&P

PEOPLE

Weatherford appointed **Mark A. McCollum** president and CEO.

EQT Corp. named **Steven Schlotterbeck** CEO, taking over for **David Porges** who retired from the position, staying on as executive chairman of EQT's board of directors for one year.

Ikon Science appointed **Mark Bashforth** CEO and member of the board of directors. Former CEO and company founder **Martyn Millwood Hargrave** became executive chairman following the retirement of **Peter Dolan**, previously nonexecutive chairman.

Petroplan Group selected **Rory Ferguson** as CEO.

Borets named **Obren Lekic** CEO of Borets U.S.

US Well Services LLC appointed **Joel Broussard** CEO and **Nathan Houston** COO.

Aberdeen Harbour Board has announced the planned retirement of CEO **Colin Parker**, who will step down at year-end 2017.

M² Subsea named **Stuart Bannerman** CFO.

Marathon Oil Corp. selected **Dane Whitehead** as executive vice president and CFO.

TAM International Inc. moved **L. Bentley Sanford** (top) into the position of chairman of the board and appointed **Michael Machowski** (bottom) company president.

Hoover Ferguson Group named **Troy L. Carson** CFO.

Frank's International N.V.'s **Jeffrey Bird**, executive vice president and CFO, left the company on March 1 for a position with another company.

Foothills Exploration Inc. selected **Christopher Jarvis** as executive vice president of finance for the company and vice president of risk management for Foothills Petroleum Inc., a wholly owned subsidiary. **Kevin Sylla** has been appointed director and CEO of Foothills Petroleum Inc., which oversees the company's regional operations.

LocusView named **Joseph Kaczmarski** vice president of operations.

ENODO Global selected **Luis Soto** as its vice president of operations, Latin America and the Caribbean.

The board of directors of Targa Resources Corp. appointed **Robert Muraro** executive vice president—commercial.

Flotek Industries Inc. named **Matt Marietta** senior vice president of corporate development and investor relations.

Alliant has added **Jan Nowak** to its team as first vice president.

Dr. Toshiyuki Shigemi was appointed executive vice president and executive director of ClassNK. **Yasushi Nakamura** stepped down as senior executive vice president and was appointed an adviser to the society.

CORTEC selected **Scott Gooding** as director of international business development.

David Mair joined Ashtead Technology as business development director.

OEM Group has welcomed **Mike Macleod** as its new finance director.

The KROHNE Group appointed **Dr. Attila Bilgic** managing director of Ludwig KROHNE GmbH & Co KG.

Cairn named **Eric Hathon** director of exploration.

Global Maritime Consultancy & Engineering appointed **Espen Thomassen** regional manager for the Americas.

EM&I named **Mario Paris** regional general manager for South America.

HB Rentals appointed two senior managers to its Aberdeenshire office. **Dave Mair** (top) joined as sales and business development manager and **Thomas Smith** (bottom) joined as operations manager.

ABN AMRO named **Richard de Keijzer** managing director for ABN AMRO Commercial Finance in the U.K.

Polarcus Ltd. appointed **Nicholas Smith** a new director.

CMS Energy's **Jean-Francois (JF) Brossoit**, vice president of transformation and shared services, was named senior vice president of transformation and shared services.

Richard A. Jackson has been appoin-ted vice president, investor relations, for Occidental Petroleum Corp.

E&P

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The board of directors of Sembcorp Marine Ltd. appointed **Chay Suet Yee** a joint company secretary.

Jarle Tautra has been appointed chairman of the board of Optime Subsea AS.

EXCO Resources Inc. announced the resignation of **Wilbur L. Ross** from the company's board of directors and the appointment of **Anthony R. Horton** and **Stephen J. Toy** to the board.

COMPANIES

Occidental Petroleum Corp. will relocate its investor relations office from New York to its Houston headquarters.

Global Tubing LLC opened a new service center in Grand Prairie, Alberta, Canada. The new center is located near the Montney, Duvernay and Cardium shale basins.

Saudi KAD changed its brand name to **ARKAD**.

Borets purchased a new operations facility in Midland, Texas. The 11.2-acre site provides more than 5,388 sq m (58,000 sq ft) of manufacturing and service capabilities, along with about 929 sq m (10,000 sq ft) of office space.

Well Control School announced an alliance with **Drilbert Engineering** to provide advanced technical drilling operational training for the oil and gas industry. Drilling supervision and trouble-free drilling courses are the main stay for the courses delivered through this alliance.

VAM USA opened a new VAM Field Service office in Odessa, Texas, bringing the number of service locations in Texas to three.

Frac Shack International acquired the Mobile Elevating Platform division of **Rigless Rentals Inc**. These units will be rebranded "The Wellevator."

DESMI has established a new 3,000-sq-m (32,292-sq-ft) production facility in Hyderabad, India.

Catapult Environmental Inc. has signed a partnership agreement with **Crew Energy Inc.** to design and build a water management facility in northeast British Columbia. E&P

ADVERTISER INDEX

Benefits of technology sharing

Economic challenges provide the catalyst for innovation and technology sharing.

David Sutton, Global Maritime

Rightly or wrongly, the offshore oil and gas sector has rarely been known as a center of innovation, often being compared unfavorably to its counterparts in medicine, IT and manufacturing. However, at times of greatest challenges technology innovation, sharing and value-added activities come to the fore.

No one needs reminding of the economic challenges the offshore oil and gas sector has faced over the past two years. Yet it is the twin needs for suppliers to look for new revenue streams and meet customer's capital constraints while at the same time increasing efficiencies that have driven innovation and value-added services out of, into and within the oil and gas sector. For example, offshore aquaculture offers enormous potential for food production and human nutrition but has been considered too expensive and difficult to develop. And yet many of the design, stability and structural engineering requirements for an offshore fish farm can be found in today's oil and gas semisubmersible units.

From the need to withstand the harshest offshore environments to stability and structural strength analyses, risk-based structural assessments or secure anchoring and mooring, oil and gas semisubmersible units and offshore fish farms have many commonalities. To this end Global Maritime is using its offshore oil and gas expertise to help design the world's largest fish farm offshore Norway. The facility has been developed as economical and sustainable as possible with limited maintenance requirements, highly durable structural components, the latest in automation and an estimated lifetime of up to 25 years—criteria that would fit comfortably with the latest oil and gas semisubmersible units.

Technology transfer also can be seen in the growing area of marine renewables and wave energy, where effective mooring solutions adopted from the oil and gas sector can be vital, especially as mooring typically can make up to 5% to 10% of total wave energy deployment costs and often higher.

Again, Global Maritime is using its oil and gas expertise in this area, providing mooring and risk management support to the EU's OPERA (Open Sea Operating Experience to Reduce Wave Energy) project with the project goal to reduce wave energy costs by as much as 50%.

Secondly, Global Maritime also is seeing technology transfer into the oil and gas sector. Dynamic positioning (DP) is one example. While jackups and moored drilling units were previously in its areas of operation, new DP technologies have enabled operators to drill and produce at greater depths and in most conditions as well as ensuring quick turnarounds. This has led to an increase in floating rigs and supporting DP vessels, all increasing efficiencies and having a direct impact on the bottom line.

Offshore aquaculture offers enormous potential for food production and human nutrition.

Examples of oil and gas DP operations that Global Maritime recently has undertaken include a multiple analysis of DP mandatory documentation for Woodside Petroleum and a DP failure mode and effect analysis for a Helix Q7000 drilling rig in Singapore.

From the supplier's vantage point many of these developments are driven by the need to find new revenue streams. This is manifesting itself not only in new technology innovations but also in new value-added services from within the sector.

In January, for example, Global Maritime relaunched Eagle Lyon Pope, a specialist marine casualty investigation and loss adjusting division. This new business stream will provide an important service and help mitigate risk in many offshore oil and gas sector companies. And there are many other examples from additional suppliers of new business streams being developed.

For all the difficulties over the last two years, value-added services and new technologies are emerging that can only benefit oil and gas operators. The challenge is to ensure that this momentum continues—whatever the external economic environment. E&P