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PRODUCTION TECHNOLOGY

Effectiveness drives maximum recovery

EXPLORATION & PRODUCTION
WORLDWIDE COVERAGE
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COVER STORY: PRODUCTION TECHNOLOGY REPORT

PRESALT/SUBSALT

EXTENDED REACH/COILED TUBING

MATURE/STRANDED ASSETS

FLOATING PRODUCTION SYSTEMS & MOORINGS

Unconventionals: Utica

The Gulf of Mexico Renaissance: Short-Term Recovery to Long-Term Trend

It's no secret … the once quiet **Gulf of Mexico is now booming with activity.** Through the application of new technologies, mid-sized E&Ps are finding substantial resources left behind in legacy shelf fields. Meanwhile, major E&Ps are actively exploring and ramping up production in deepwater and ultra-deepwaters blocks. And according to the U.S. EIA, **Gulf of Mexico crude oil reserves** will provide steady U.S. production from 2015 to 2040. This resurgent activity creates a wave of project spending that will grow in the coming years.

Hart Energy, supported by its *E&P* and *Oil and Gas Investor* magazines and its *Subsea Engineering News* and *Deepwater International* newsletters, developed the **Offshore Executive Conference: *Gulf of Mexico*** to give senior-level industry executives a **strategic in-depth look** at oil and gas industry activity in the Gulf of Mexico. Hundreds of attendees are coming together to discuss emerging plays in both deep and shallow waters, and the key technologies that will drive growth.

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Jason Nye
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U.S. Offshore
Statoil

DEPARTMENTS AND COMMENTARY

COMING NEXT MONTH The October issue of ***E&P*** will examine the rapidly evolving arena of exploration technology. Other features will include unconventional exploration tools, drilling automation, artificial lift, and subsea processing and monitoring, and regional features will focus on Russia and unconventionals in Australia. As always, while you're waiting for the next copy of ***E&P***, remember to visit ***EPmag.com*** for news, industry updates and unique industry analysis.

ABOUT THE COVER Downhole measuring devices like this fiber-optic tool are enabling operators to better predict their production. Left, Petrobras has more than 900 projects planned in Brazil as part of a five-year investment plan of about $237 billion. (Source: Baker Hughes; cover design by Laura J. Williams)

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TGS, FairfieldNodal collaborate in Gulf of Mexico

TGS and FairfieldNodal have come to a multiyear collaboration agreement to develop, plan and execute multiclient full-azimuth nodal seismic surveys across a substantial area within the U.S. Gulf of Mexico shelf region.

Noble, Woodside gain interest in Gabon block

Noble Energy Inc. and partner Woodside Petroleum Ltd. have signed a production-sharing contract with the government of Gabon covering Block F15 in the Gabon Coastal Basin. Noble Energy will be the operator with a 60% working interest; Woodside will have 40%.

Indonesia OKs BP environmental permit for Tangguh

The government of Indonesia, through the Ministry of Environment, has approved BP's Tangguh Expansion Project Integrated AMDAL environmental and social impact assessment and issued the project an environmental permit.

AVAILABLE ONLY ONLINE

Pursuit persists for more offshore opportunities

By Velda Addison, Associate Online Editor

Poll shows backing for API-led push.

Jokowi pledges to reform Indonesian oil, gas sector

By Ravi Prasad, Special to E&P

More flexible fiscal incentives and an overhauled licensing process are among the proposed changes.

Push continues for shale gas in Poland

By Velda Addison, Associate Online Editor

San Leon Energy plans to drill a horizontal well that, if successful, could lead to commercial production.

Mozambique races to become big LNG producer, exporter

By Obafemi Oredein, Special to E&P

Updated legislation focusing on LNG is still a work in progress.

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Megaprojects a mega-problem

There's an old saying in the newspaper business: If a good story is worth telling once, it's worth telling twice. But in this case, I'm taking it further and returning to the same subject for the third time this year—soaring costs.

The subject of budget-busting costs and schedule overruns was flagged up in a report by Ernst & Young (E&Y), which highlighted that megaproject budget overruns would cost the oil and gas industry $500 billion extra this year alone.

Although not telling us anything we didn't already know (see my March and May columns), when you dig into the detail, it makes uncomfortable reading.

How serious a situation must our industry be in when one of the "positives" is that the average megaproject budget overrun in North America is 51%? But that's the case when you then find out South American megaprojects are on average 102% over budget. The averages for other regions are little better.

Middle Eastern projects come out particularly badly, with a shocking 89% of the region's projects facing cost overruns and 87% also facing schedule delays.

E&Y studied 205 projects with proposed capital investment of more than $1 billion where cost data were available (out of 365 projects examined overall).

The report's authors lay the blame largely at the feet of this industry, putting it down mainly to poor portfolio management, inadequate planning, ineffective project management and aggressive estimates.

It does go on to admit that there are other external factors, of course—financial, geopolitical, regulatory and security, to name but a few. But the industry could do "significantly more" to prepare for these, it continued.

In a somewhat forlorn attempt to soften the blow a little, it added that the high number of megaproject overruns "is not particular to the industry" and has been identified in other sectors, including government, real estate construction, mining, and power and utilities.

However, it continued, these repeated failures raise serious questions as to the industry's ability to develop accurate, unbiased final investment decision (FID) budgets and schedules and stick to them.

A look in the report at the top 20 largest post-FID projects further reveals that 65% of those analyzed were facing cost overruns, with an average escalation of 23% from the approved FID budget.

Worryingly, E&Y's findings largely fall in line with the observations of another study from three years ago, when the Independent Project Analysis study found that 78% of upstream megaprojects faced either cost overruns or delays. That in itself was already a serious deterioration from 2003, when 50% of projects were over budget or late.

The E&P sector has, thankfully, started to tackle the increased cost environment through budget cuts, standardization initiatives and so on. But it will need to be at its innovative best to successfully—and realistically—deliver its next generation of megaprojects efficiently and on budget. If it does not, investors will simply take their dollars elsewhere. E&P

Mark

Go with the flow

Employees are most productive when they can work without distractions. The right technology can help.

Rhonda Duey, Executive Editor

Where is the best place for knowledge workers to do their jobs? In many cases, it's not the office—it's anywhere but.

People who need to do deep thinking to promote their company's productivity will not find it surprising to discover that constant interruptions and distractions make it nearly impossible to dedicate focus to a task or project. The average worker is distracted six times every hour, according to a report titled "A Crisis Of Attention: Technology, Productivity, and Flow – Using the Science of Knowledge Work to Restore Flow to the Workplace" by David K. Johnson, Josh Bernoff, Christopher Voce, Elizabeth Ryckewaert, Heather Belanger and Thayer Frechette of Forrester. Johnson was recently in Houston to discuss some of the findings of this 18-month study.

Johnson and his colleagues advise corporations on using technology to advance their businesses. He said the people he counsels are already up on technology but aren't necessarily aware of how their employees use it. "I found I could ask one little question and get silence every time," he said. "The question is, 'Tell me about how the people in your company do their best work—what do they need? What conditions are necessary?' They don't really know the answer to that."

The neuroscience of work

Johnson interviewed scores of people for the report, including people who have conducted studies on the science of motivation. He also relied on the work of Daniel Kahneman, a psychologist who shared the Nobel Peace Prize in economics in 2002. Kahneman identified two different systems of the brain, one automatic and one cognitive. The automatic system uses very little energy; the cognitive system is quite energy-intensive. It is this system that comes into play when workers are fully concentrating on a project.

"When people are really working in this mode, they require an enormous amount of focus and concentration," he said. "If I'm interrupting them six times an hour, they're not getting it done. This is why they go home or go someplace else where they can be unbothered for a little while."

Another researcher, David Rock, studied the amount of energy available to people at different times in the day. "It turns out we start out with a very small amount of cognitive fuel in the morning," Johnson said. "How many of you check emails first thing? Bad idea. Really bad idea."

It's also not advisable to wait until the end of a full day to start doing strategic planning, he said.

This type of treadmill enables people to get good at "partial attention," the ability to respond to interruptions and handle mindless tasks. "But we get horrible at being able to do the deep, reflecting planning and knowledge work that we need to do, which is where company value comes from," he said.

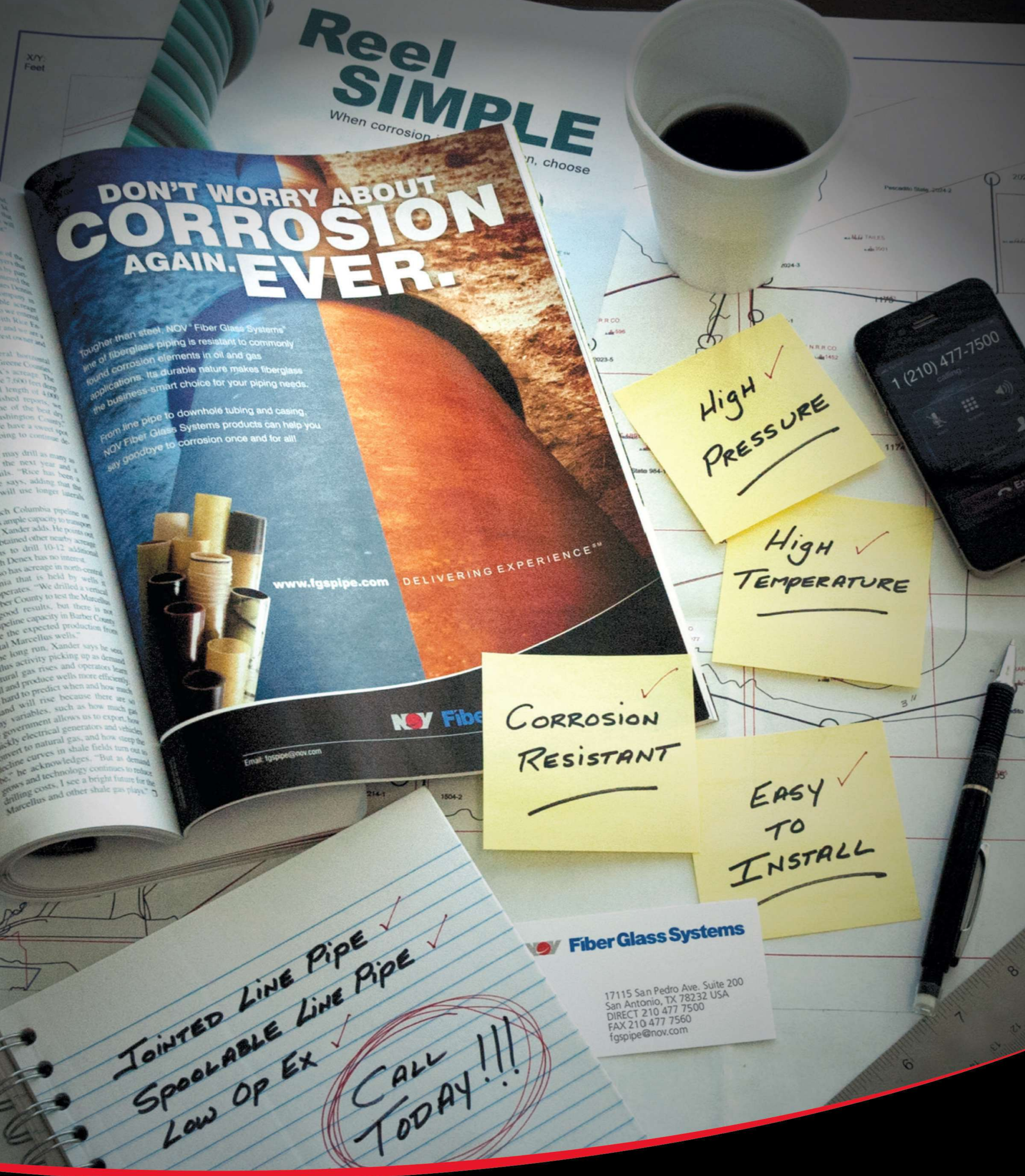
In her book *The Progress Principle*, Teresa Amabile at the Harvard Business School wrote that most corporate leaders think that financial incentives are the major motivation for their employees. But her research indicates that the ability to make progress is actually a greater motivation than money. Being able to find the uninterrupted time to make that progress enables employees to attain "cognitive flow," where they become so wrapped up in what they're doing that they can spend several hours doing it, forgetting meals and even quitting time in the process.

The researcher who coined this term is Mihaly Csikszentmihalyi, who discovered that people who can reach flow on a regular basis are 127% more productive than their average coworkers. The top 1% of people who can reach flow is 47 times more productive than the bottom 1%.

Johnson said there is a correlation between employee satisfaction and customer experience, and companies that rate high on the customer experience index are outperforming the S&P 500 by 200%. "It's no longer a touchy-feely thing," he said. "These links are significant."

Entering a virtual environment

Mastering cognitive flow is only half the battle, though. Employees also need technology to help them do their jobs. Johnson did a workshop with an electronics com-



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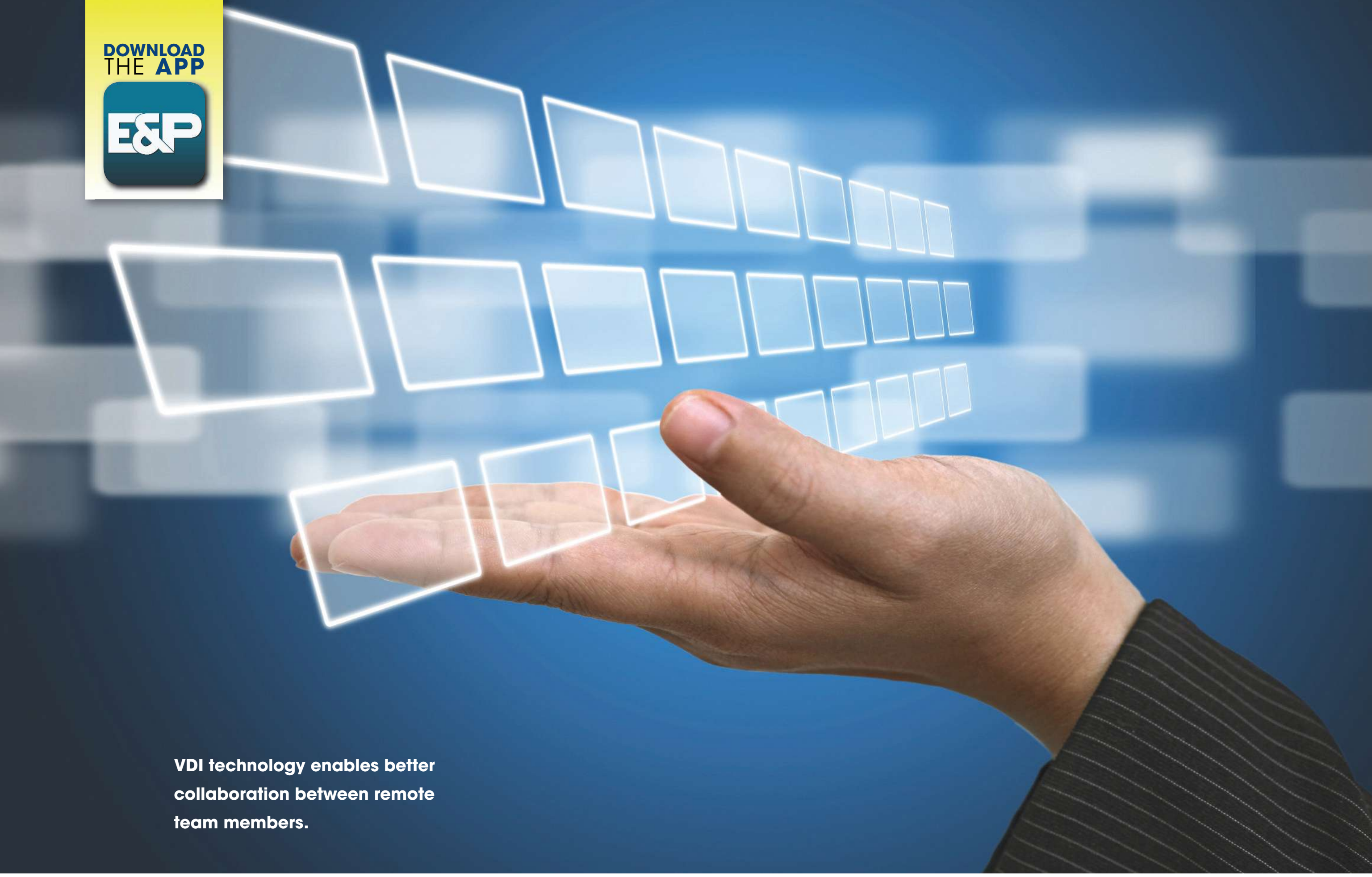


VDI technology enables better collaboration between remote team members.

pany in which members of its design group were given a simulated project to begin a product line. They had to develop the marketing, the engineering, etc.

"We watched over their shoulders as they tried desperately to get access to information to find out who in the organization knew these things," he said. "At the end of the day, they were frustrated. They had maybe 10% of what they needed, and they couldn't proceed."

A lack of resources pushes motivated employees to buy their own personal devices and applications, and many of them also will work on their own time to develop algorithms and software that aren't made available to them within the company, he said.

The concept of a virtual desktop infrastructure (VDI) is becoming a reality in the oil and gas industry. At its basic level it enables employees to access data remotely, but Johnson emphasized that picking the right technology for the use case is important, and navigating the complex landscape of available technologies is critical. For instance, a field engineer using an iPad has different technology needs than an engineer who is doing high-end design work, Johnson said.

"You may find that VDI is not great for a mobile knowledge worker except maybe as a secondary desktop device," he said. "But if they're going to do heavy engineering, they're going to need to be on a high-speed network. You have to look very carefully at the laws of physics and the characteristics of the technology before applying it."

The addition of graphics processing units to VDI systems is now enabling larger datasets to be moved and rendered without loss of latency, he said. This is critical for visualization work. New storage and network solutions are enabling companies to remove latency and improve the performance of the entire system. And increasingly, hardware companies are developing converged infrastructures for VDI in which all of the components have been matched and the latency removed, he said. This in turn is enabling cross-discipline collaboration and faster, more accurate decision-making.

For instance, NetApp and Cisco offer their FlexPod Datacenter with NVIDIA GRID and Citrix XenDesktop HDX 3D Pro technology to provide secure and remote access to dispersed cross-disciplinary teams. Important datasets can be centralized into a few locations, and visualization capabilities are available where needed. This enables near real-time decision making, removes bottlenecks and reduces nonproductive time.

Overall, Johnson said, companies will benefit from investing in the right types of technology to enable their skilled resources to do their jobs better. "They're going to start thinking a lot more about the information resources people need, that knowledge workers need to do their jobs, and investing and making those things readily available to speed up the knowledge work," he said. "Companies need to start dropping barriers." E&P

What's old is new again

One company has transformed a double-digit condensate producer into a quadruple-digit oil bonanza.

Caroline Evans, *Oil and Gas Investor*

When Treadstone Energy Partners bought East Texas' Fort Trinidad Field in 2012, it was investing in what many saw as a tired gas condensate producer that had seen its heyday in the 1960s and 1970s, peaking at 9,500 boe/d—3,000 bbl/d of condensate and 1.1 MMcm/d (38 MMcf/d). The field, discovered in the 1950s, yielded significant production from multiple Glen Rose reservoirs, with development concentrated in the Glen Rose C bench. The reservoir went into full blowdown beginning in 1975, and though it has seen continuous development since then, there have been few, if any, capital investments.

"This field has traditionally been a Glen Rose field, that's what everyone has sold it as, that's what everyone has bought it as and that's what it's been marketed as," said Frank McCorkle, Treadstone's president. "So it's changed hands quite a few times over the past 20 years, always for Glen Rose, the deeper gas condensate field."

But McCorkle and his team saw something else. "Really, we just had a view of it being an oil play in the Buda and Georgetown, primarily," he said. "And so, because of that, we had a different plan for it, a different strategy that allowed us to be able to bid high enough to acquire the field."

It sounds absurdly simple: Plug some old wells, perf and frack the shallower intervals, and watch the oil flow. And though it was sometimes as simple as that, there was nothing absurd about the numbers. In mid-2012, the field's production had dropped to 150 boe/d. By the end of 2013, Treadstone had grown production to 4,000 bbl/d of oil and 170 Mcm/d (6 MMcf/d). And production continues to grow, with May 2014 field production exceeding 9,000 boe/d (7,300 bbl of that oil) from only 36 producing wells.

"That field's been producing for 60 years," Key Sanford, Treadstone's vice president of land and business development, said. "And it's probably going to produce for another 50 to 70. Long after our kids have retired, that field will probably still be there."

For its imagination and ingenuity in finding new life in an old field Treadstone recently received *Oil and Gas Investor's* 2013 Excellence Award for Best Field Rejuvenation.

Missed connections

Treadstone, a private company based in Houston, was formed in 2011 with backing from Kayne Anderson. The founders (McCorkle, Sanford and vice president of engineering Gene Roberts) had worked together at BP, where they served in key leadership positions during the company's entry into the Eagle Ford Shale. The management team has a combined 65 years of industry experience.

After securing a $50 million equity commitment from Kayne Anderson, the company bought acreage in Alabama Ferry Field in Leon County, Texas, and began scouting in the general area. They found a trend of some old

Treadstone, led by vice president of land and business development Key Sanford (left), president Frank McCorkle (middle) and vice president of engineering Gene Roberts, viewed Fort Trinidad Field as a Buda/Georgetown oil play instead of focusing on its history as a Glen Rose gas condensate producer. (Source: Treadstone Energy Partners)

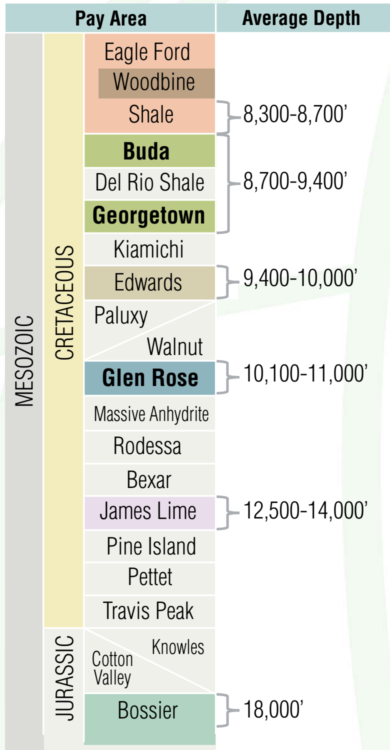
but good Buda and Georgetown wells. Using "normal, readily accessible IHS-allocated production data," according to Roberts, the company began investigating Fort Trinidad Field for the shallower trends. "It was really just spending the time. A lot of the shallow producing wells were from the late '50s and early '60s, so there was a little more detective work."

A month after the company began eyeing the field, it came on the market. Its owners were looking for a quick sale. "The field had been HBP for 50 years, and all the operators had focused on the Glen Rose, how to enhance or how to increase production out of that reservoir," Sanford said.

In mid-2012, Treadstone acquired the 18,000-acre field with the intention to rework many of the original wellbores and frack them for the Buda and Georgetown. The reservoirs are naturally fractured carbonate, but they suffer from connectivity problems.

"Previous operators in the area, using either openhole and/or perf/acid completions, would get a great well, and the one next to it would be very poor because if they weren't very close to a well-connected natural fracture, they wouldn't get a good well," McCorkle said. "So we decided to go in with some very large, propped fracks to connect up those natural fracture networks." Treadstone also saw significant upside in commingling the Buda with the Georgetown, a 122-m (400-ft) carbonate section just below the Buda that had only been tested a few times in the field, with even more mixed results.

Lower Cretaceous Stratigraphic Column



There is significant stacked-pay potential in the East Texas Basin. Treadstone is preparing to exploit Glen Rose oil reservoirs in the near future. (Source: Treadstone Energy Partners)

Bigger, stronger, better

After acquiring the field, Treadstone did five months of research, planning and strategizing. "We waited five months until we worked with every service company we could get in the door and got every idea we could before we went in and stimulated the first set of recompletion wells," Roberts said. Realizing the Buda/Georgetown trend that ran under the field differed from the segment that ran under the offset operators' field, Treadstone adopted a different frack strategy consisting of "bigger, stronger, better fluids and sand," according to Roberts. The company pays a premium for high-quality premium resin-coated sand and better chemical packages, but on a two- or three-stage frack job, it's worthwhile.

"When you're on a horizontal well and you're doing that on 30 stages, it really starts impacting the bottom line," Roberts said. "That's why a lot of the horizontal plays have been slow adopters to more sand/better fluid packages.

"When you've got a vertical well with $1.5 million to $2 million drilling costs and $500,000 to $600,000 completion costs, an extra $50,000 to $100,000 in completion costs doesn't materially impact costs, but it can materially impact the quality of the stimulation and, therefore, long-term productivity of the well."

Treadstone also uses only a small amount of acid in the rock, which is 99% calcium carbonate, and uses limited perfs to better divert the fracture stimulation. "Offset operators put as many as 300 to 350 perfs along the same interval that we do, and we have between 50 and 60 perfs," Roberts said. "That's a big step change in how much you're concentrating the force of the frack and, we believe, increasing fracture complexity and connectivity to the natural fracture system."

Four of the first five recompletions had originally been drilled for the deeper Glen Rose in the early 2000s. These wellbores left Treadstone with easy recompletion opportunities to test their concept before committing to picking up a rig to drill new wells. "It was almost as simple as pulling tubing, running cast-iron bridge plugs over the Glen Rose zones, and perforating and fracking the Buda and Georgetown," Roberts said. "Four of those early recompletions made 120,000 bbl to 200,000 bbl of oil in the first year of production—from nothing more than setting plugs, setting new facilities and upgrading pads."

Treadstone's second recompletion alone churned out 1,000 bbl/d for its first month. "At $95 oil, it produced $2.5 million to $3 million in revenues in the first month, and it cost us $1.7 million to set a bridge plug and pump a two-stage frack," Roberts said.

In just a few months, the wells were paying out enough to finance a rig for the company to drill its own wells. Though Treadstone has accessed small amounts of working capital from time to time, the field "basically spins off enough cash to fund the drilling program," Sanford said.

Rate of incline

Typically, a fractured carbonate reservoir will decline rapidly. But Fort Trinidad Field holds multiple wells that produce at or higher than their first month's production, even a year after they come online.

"We have one well that's highest month is always the last month," McCorkle said. That well is on month 13, having produced more than 165,000 bbl of oil, and is still averaging nearly 600 bbl/d of oil. The productivity is largely thanks to connecting the fracture network and reservoirs to wellbores through hydraulic fracturing.

"Because the section is so thick, if you can connect it all up, you get all the fluid expansion from the oil, the water, the solution gas drive, and you've just got a fracture system that's refilling itself," Roberts said. "By using hydraulic fracturing, we connected that entire volume, and it is providing a huge amount of pressure maintenance."

With its core area now defined, the company is prepared to downspace to 40 acres. "We've already done 80 acres and clearly do not see any impact or interference," McCorkle said. Additionally, the company is preparing to take advantage of the stacked-pay system of the East Texas Basin, beginning with, of all things, the Glen Rose.

"There are four really good benches of the Glen Rose, and really only one of them has effectively been developed, and that one we believe has tremendous upside in terms of EOR," Roberts said. "This Glen Rose horizon has still got a lot of oil in it—it still makes oil today, 50 or 60 years after it first made oil. It's just very low-pressure and needs some help." E&P

Acknowledgment
This article originally ran in the July 2014 issue of Oil and Gas Investor.

TRLs serve as metric in gauging progress

The process can be practically used to shorten the time before new technology can be commercialized in the oil and gas industry. First of a two-part series.

Peter Lovie, **James Pappas** and **Tom Williams**, RPSEA

Country music singer Kenny Chesney has a hit song that says "I went home at 2 with a 10 and woke up at 10 with a 2." Similar subjective choice variations can also be said about the technical readiness level (TRL) process used by a variety of industries to determine the maturity level of a technology and often then for gauging its commerciality. The process has been successfully used for years, although the scale, definitions and process varies, and there is now some science and logic to it. It can be practically used in the petroleum industry in gauging technological progress and commerciality of new developments.

To the technology developer, his or her baby may look like a "10," but investors worry about the nightmare of waking up with a technology that in the market is a "2." And for those investors—or company managers—there's a serious need for some science to the metric if a long-term relationship is at stake.

Continuing the country music theme, investors seriously want to "know when to hold 'em, know when to fold 'em, know when to walk away, know when to run," as Kenny Rogers sings in "The Gambler," and TRLs can be a metric to help make that call.

The American Petroleum Institute addressed the need for TRLs in a recommended practice called API RP 17N. Leading oil companies employ TRLs as a tool to track technology development on an ongoing basis and to guide toward desired outcomes; Total has been a pioneer in that. In Houston the oil company-led deepwater technology consortium DeepStar has employed TRLs in similar ways in recent years. Before that, NASA, the U.S. Department of Defense, the U.S. Department of Energy (DOE) and the U.S. nuclear industry all developed their own scales of TRLs. The practice has seen wide application by similar organizations outside the U.S.

The Research Partnership to Secure Energy for America (RPSEA) has determined the TRL process can assist it in prioritizing its R&D efforts to meet its goal to attempt to not only develop technologies that improve U.S. reserves and productivity in a safe and environmentally friendly manner but also demonstrate their effectiveness and lead to commercialization. Examples from four projects illustrate RPSEA's use of TRLs.

Relative Level of Technology Development	Technology Readiness Level	TRL Definition
System Operations	TRL 9	Actual system operated over the full range of expected mission conditions
System Commissioning	TRL 8	Actual system completed and qualified through test and demonstration
	TRL 7	Full-scale, similar (prototypical) system demonstrated in relevant environment
Technology Demonstration	TRL 6	Engineering/pilot-scale similar (prototypical) system validation in relevant environment
Technology Development	TRL 5	Laboratory scale, similar system validation in relevant environment
Technology Development	TRL 4	Component and/or system validation in laboratory environment
Research to Prove Feasibility	TRL 3	Analytical and experimental critical function and/or characteristic proof of concept
Basic Technology Research	TRL 2	Technology concept and/or application formulated
	TRL 1	Basic principles observed and reported

FIGURE 1. The nine-level TRL scale used by the DOE—more 'down to earth' than NASA—still lacks practical definition for E&P. (Reference: DOE G 413.3-4A 9/15/2011. Source: RPSEA)

Value to regulators, investors and end users

Regulators accepting a new technology/system in a high-risk permit application may use TRL values as a metric on technology maturity to help in this kind of difficult decision. Investors making risk-based decisions similarly may find TRLs to be a useful, quantifiable measure as opposed to solely relying on industry judgment by people they know.

The industry frequently conducts a hazard identification exercise called HAZID before a new project is commissioned, a subjective exercise employing subject matter experts (SMEs) in a process that has made a significant contribution to improving safety and reducing risk. The same can be said for TRLs.

Objective or subjective?

There is a distinction here between: (i) subjective choices based on a single nonexpert opinion, (ii) focus groups used in political or market research assessments, (iii) carefully weighed views from a panel of experts and (iv) absolutes such as the laws of physics. TRLs fall under category (iii). A standard, pre-agreed scale of what defines each TRL is used to calibrate and hence coordinate the judgments of a panel of experts making TRL determinations.

The TRL methodology was originated by Stan Sadin at NASA in 1974. In that era NASA was faced with developing many new systems where "failure was not an option," but there was little precedent to go on. The urgency of a search for a method to improve success for new developments from the early stages through execution along the lines of the TRL concept did not have to be space-related for the methodology to be of value; 50 years later the concept is used in many industries.

The NASA TRL scale evolved as a nine-level scale to cover technology development stages from a new idea to a reliable working embodiment of the new technology along the lines of Figure 1. The DOE has had its own typical development process, leading to an adaptation of the nine-level scale with a set of definitions that better suited DOE projects but lacked proper practical definition for the upstream oil and gas industry.

It became clear to TRL users that the language used in the definitions of each TRL was important to enable the scale to be applied practically on the ranges of technologies within RPSEA's ultradeepwater program. RPSEA adjusted its TRL scale to better suit the characteristics of projects with a somewhat different set of TRL definitions and with language somewhat similar to the API RP 17N scale but more tailored to petroleum industry systems as opposed to hardware. It is a seven-level scale adopted from DeepStar because it was felt that the language of the definitions worked well and was used by many people in the industry community, embracing everything from relatively small investments to very large investments in the ultimate embodiments of technologies examined. The RPSEA TRL scale is shown in Figure 2.

TRL Designation		
Conception	TRL 0	**Unproven Idea** (paper concept, no analysis or testing)
Proof-of-Concept	TRL 1	**Proven Concept** (functionality demonstrated by analysis or testing)
	TRL 2	**Validated System Concept** (breadboard tested in "realistic" environment)
Prototype	TRL 3	**Prototype Tested** (prototype developed and tested)
	TRL 4	**Environment Tested** (prototype tested in field realistic environment)
	TRL 5	**System Integration Tested** (prototype integrated with intended system and functionally tested)
Field Qualified	TRL 6	**Technology Deployed** (prototype deployed in field test or actual operation)
	TRL 7	**Proven Technology** (production unit successfully operational for >10% of expected life)

FIGURE 2. The seven-level TRL scale adopted by RPSEA is used for technologies being developed for the petroleum industry. (Source: RPSEA)

The broad value of TRLs may have been underestimated. Part 2 of this article will demonstrate TRL use of a fit-for-purpose process for gauging technology progress—one that is simple and consistent and that provides value, recognizing how focus on process over function can compromise the intention.

A TRL process that can be easily understood by service providers, investors, research consortia and governments will increase the likelihood of commercialization of needed technologies.

Practical guidelines

Experience with TRL votes has shown that understanding the TRL process is based on SMEs that had a background in field development activities such as drilling, well services and production facilities, all of which see a fairly broad application of a variety of technologies that were recent or even relatively untried. It is suggested that at least five and not more than about a dozen SMEs be used to perform the TRL analysis. Adding more SMEs may get cumbersome, and fewer than five may result in "groupthink." The SMEs might be individuals who would use the technology but cannot be enthusiasts for the technology or, worse still, be "sales monkeys" working for the originator of the technology. Responsible, professional independence is obviously critical.

It is recommended that a knowledgeable, professional and open-minded facilitator with no vested interest in the technology be chosen to lead the discussion and assessment. The facilitator is not essential but can often draw out the thinking of the SMEs.

Another principle that had to be addressed: The TRL needs to be an individual opinion and not that of the SME's employer. In effect, the TRL vote is part of a survey.

The value of that "survey" is dependent on the background of the people who take it. A panel of SMEs with operating companies, service providers, manufacturers, academia and consultants that might choose to use the technology in their core business is likely to be more significant than a panel of generally knowledgeable people.

There is significant research backing up the quality of judgment made by a panel of well-qualified experts—the Delphi Method developed by Rand Corp. for the U.S. Air Force Strategic Air Command in the 1950s and 1960s. The Delphi Method was used on national security matters quite separate from technology. It relies on isolated opinions from SMEs of established judgment and frame of reference to assess a situation that may not have any proven guidelines or precedents, with objectives of seeking maximum quality and validity in judgment on possible future actions. Those people can later be brought together to amass their opinions and attempt to form a consensus if indeed one might exist. E&P

Acknowledgment

The authors are pleased to have the permission of RPSEA to cite (i) the frame of reference of RPSEA in using TRLs and (ii) the experience with the specific RPSEA projects referred to in the examples.

Enhanced completions

Industry embraces closer stage spacing, increased proppant volume.

Richard Mason, Chief Technical Director

Upsized your frack or enhanced your completion lately? If so, you've joined a growing technological movement in oil and gas. Enhanced completions are showing up in a variety of metrics, enough so that the process appears to have reached critical mass in oil and gas.

Several attributes describe enhanced completions. The process can incorporate an extended lateral when acreage considerations allow. Enhanced completions involve more stages per well packed more closely together with significantly greater volumes of proppant usually delivered as part of a massive slickwater treatment. Stage counts in enhanced completions are moving from the traditional 17 or 18 per 1,372-m (4,500-ft) horizontal lateral to 30 or 40—and more than 60 in some cases for extended laterals—as operators reduce spacing between stages from 76 m to 122 m (250 ft to 400 ft) down to 61 m (200 ft). Additionally, well stimulation vendors are providing engineered perforations to increase the number of penetrations into the formation between stages.

Enhanced completions are primarily evident in the volume of proppant pumped downhole. Where operators used to pump 100,000 lb or so per stage, volumes now can rise to four or five times that level. Along with steadily rising average stage counts, Hart Energy market intelligence surveys have tracked a significant increase in average proppant per stage in recent months. In the Eagle Ford Shale, proppant use has risen from under 100,000 lb per stage among respondents in late 2013 to slightly less than 400,000 lb per stage in July 2014.

Operators use multiple varieties of sand as proppant, though upsized fracks invariably entail greater volumes of 100-mesh white sand. Volumes in fact can exceed 150 tons per stage. Adding more individual stages and multiplying those stages across four or more laterals on a single pad provides an indication of the growing intensity in downhole stimulation, which can reach upward of 11 MMlb or 12 MMlb per lateral. Furthermore, the same process is done on four or more laterals on a multiwell pad site.

Enhanced completions first came to life as a general practice in the Eagle Ford Shale in the second quarter of 2012. One operator in particular began discussing monster wells on a set of 16 horizontals with IP exhibiting a step level change to 2,500 bbl/d of oil and more than 4,500 boe/d in some of the stronger wells. State production records revealed the wells had used massive amounts of sand as proppant.

The practice has become standard in the Eagle Ford Shale and is migrating to other plays across the U.S., usually in tight oil or liquids plays, including the Bakken Shale, the Cana Woodford and the Permian Basin. In a few instances, upsized fracks—a term used interchangeably with enhanced completions—incorporate crosslinked gels instead of slickwater though still entail more sand pumped at a lower rate.

Several oil and gas operators cited rising production in second-quarter 2014 earnings calls from enhanced completions, suggesting that the practice has become widespread and confirming the significant change in downhole metrics in terms of stage count and proppant volumes that had surfaced in Hart Energy market intelligence surveys.

The theory is that finer mesh sand aggregates into pillars on flowback, keeping induced fractures open. The process not only provides larger IPs but appears to slow decline rates. As in all processes, there is some skepticism about how enhanced completions will impact ultimate recoveries. Do enhanced completions get more total recovery or simply accelerate the rate at which the same amount of hydrocarbon is extracted? Stay tuned. E&P

- **Industry moving to massive slickwater fracture stimulation in oil plays**
- **Stage spacing getting closer**
- **Lateral length increasing**
- **Proppant volume per stage rising significantly**
- **While IPs are higher, debate still open on ultimate recovery**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New methods for efficient acquisition

Combining compressive sensing with an optimal sampling loop shows promise in marine surveys.

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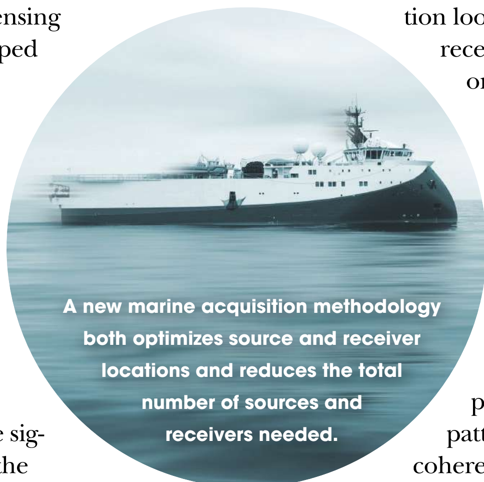
Read more commentary at
EPmag.com

It seems like the seismic acquisition side of the exploration business has been exploding at the seams over the past few years, and one of the most exciting areas has been in sampling studies. Some companies are pushing the boundaries of channel count on land, others are looking at node technology in marine environments to provide superior imaging and yet others are relying on new broadband techniques to better sample the frequency spectrum.

Attitudes toward sampling geometry are also changing, and ConocoPhillips is driving a push toward what it calls "compressive seismic imaging" (CSI) to both optimize source and receiver location and reduce the total number of sources and receivers needed. The concept is based on compressive sensing sampling theory, which was developed to reduce aliasing in sensing.

According to an article on aliasing by Bruno A. Olshausen at the University of California-Berkeley, aliasing occurs when signals are sampled at rates that can't capture the changes in the signals. To reduce or avoid aliasing, Harry Nyquist proposed a theorem stating that the sampling frequency should be at least twice the highest frequency contained in the signal. But in an article published in the April 2014 issue of *The Leading Edge*, several ConocoPhillips authors note, "The reality of limited access and funding requires us to make do with orders of magnitude fewer sampling points than Nyquist theory would dictate."



A new marine acquisition methodology both optimizes source and receiver locations and reduces the total number of sources and receivers needed.

Enter compressive sensing. The new sampling theory, according to the article, provides a mathematical basis for designing non-uniform sampling systems. This new mathematical basis can be used to determine the degree to which signal can be separated from sampling noise for a given sensor layout. The most common technique used in the industry to date is to use randomized sampling locations, which allows coherent signals to be separated from random sampling noise using well-known signal processing techniques.

ConocoPhillips has dubbed its particular brand of compressive sensing non-uniform optimal sampling (NUOS). The newer method uses an optimization loop to establish optimal source and receiver locations rather than relying on random techniques.

The system was further tweaked to allow for simultaneous sources. Two realizations of shooting patterns for dual-vessel operations, one random and one optimal, showed very similar characteristics and had comparable values of coherence. But the optimal plot also minimized both coherence within each pattern and cross-coherence between patterns. This results in 50% lower cross-coherence in the optimal realization.

The method was field-tested in the North Sea at the end of a production survey to provide a baseline for comparison. After constructing a detailed geologic model, NUOS designs for source spacing were built based on minimal cross-coherence criteria. Continuous receiver records were created by interpolating shots from the model and then blending them into continuous records, the authors noted.

After processing, it was concluded that this technique enables the design of simultaneous source surveys that maximize the fidelity of de-blended source records. E&P

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Walking the walk

The latest versions of land drilling rigs that are designed for pad drilling, automation and 360-degree movement are picking up momentum in replacing older rigs.

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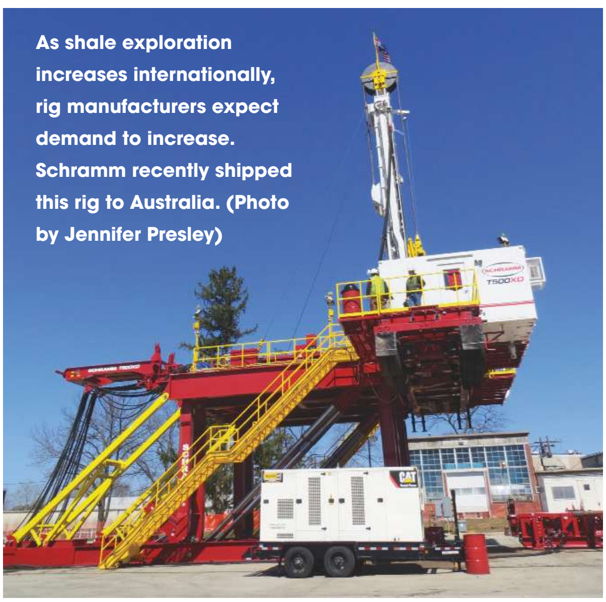
EPmag.com

Earlier this year Hart Energy market surveys reported that new higher spec rigs with walking packages were displacing older electric rigs in the Marcellus and Bakken shales. The replacement is picking up speed in shale plays where pad drilling has become the norm.

The February 2014 survey found seven of eight manufacturers reporting strong demand. At the time, the rig builders expected international demand to outpace domestic orders. All of the increased demand stems from emphasis on horizontal drilling.

In Patterson-UTI Drilling Co.'s second quarter report July 24, 2014, CEO Andy Hendricks said, "We completed six new APEX rigs during the second quarter, bringing our APEX rig fleet to 133 rigs. In response to strong customer demand, we expect to complete 25 new APEX rigs during the four quarters ending June 2015, of which 22 are currently contracted."

The company has customer contracts for three additional rigs to be completed in the second half of 2015. The strong demand for high-spec rigs is impacting rig pricing for all classes of its rigs, resulting in higher day rates. Average U.S. rig revenue rose to $23,490 per day, an increase of 2%, the company noted.



As shale exploration increases internationally, rig manufacturers expect demand to increase. Schramm recently shipped this rig to Australia. (Photo by Jennifer Presley)

Lee C. Moore has orders for 10 of its HMR SlotBox rig structures that will be delivered through 2015. The company has sold 29 of these structures to three North American drilling contractors since 2011.

"Pad drilling efficiencies are crucial in today's retooling of the land rig market. At some point, the structure needs to efficiently and safely move to another pad. This design focuses on both sides of the equation," explained Tom Wingerter, president and CEO of Lee C. Moore, in a press release April 29.

Helmerich & Payne (H&P) activated 11 of its new FlexRigs during the second quarter, it stated in a July 31, 2014, press release. That led to record levels of rig activity for the company.

President and CEO John Lindsay said, "We continue to see a strong U.S. land drilling market and expect to benefit from increasing activity, recovering spot pricing levels and additional customer commitments for new FlexRigs. Since our recent announcement last month, we have entered into agreements with six E&P companies to build and operate 13 additional FlexRigs to drill unconventional resource plays in the U.S.

"All of these rigs were ordered under multiyear term contracts. The new contracts bring the total number of newbuild commitments announced in fiscal 2014 to 74 FlexRigs," he continued.

The move internationally also has picked up this year. Schramm Inc. shipped its second T500XD walking rig to Australia where it began drilling operations in the Cooper Basin. H&P was transferring 10 FlexRigs to Argentina.

The siren call of shale plays is getting louder. E&P

Scott

Your data already know what you don't

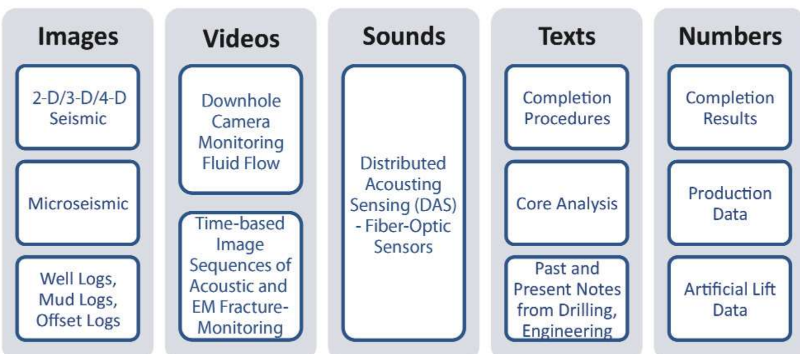
The marriage of two 'natural resources'—hydrocarbons and data—will transform unconventional oil development as we know it.

Atanu Basu, **Daniel Mohan** and **Marc Marshall**, Ayata

Known-knowns, known-unknowns and unknown-unknowns—Donald Rumsfeld's notable turn of phrase is an apt characterization of where we are with unconventional oil development today. Shale operators in the Eagle Ford, Permian, Bakken and other plays have transformed the U.S. into an energy superpower by profitably extracting oil and gas from tight rocks that weren't commercially viable even a few years ago. With that backdrop, unconventional oil development today is punctuated by significant performance variations among operators with contiguous acreage positions and meager EUR rates. Unless performance keeps improving, any fluctuation in commodity prices can send shockwaves through the oil patches around the country, as we have seen happen with natural gas. How do we gain ground on the vexing "unknowns" to tilt the inherent risks involved in shale oil development in our favor?

Standing on the shoulders of giants

Geoscience—geoscientists are the giants of the energy industry—is finally getting a shot in the arm from data science, especially from Google-like technologies that are already at work in the oil patch. Leading the charge is prescriptive analytics, which can "prescribe" optimum recipes for drilling, completing and producing wells to maximize an asset's value at every point during its operational lifetime. The premise of prescriptive analytics is to take in all data and use them to predict and prescribe how to make better wells using information from the past wells and subsurface characteristics of undrilled acreage.



Prescriptive analytics rely on all data types to help operators make the best decisions for their fields. (Source: Ayata)

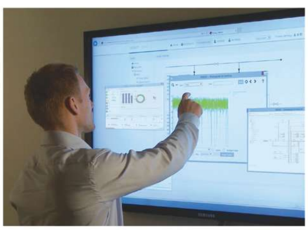
While today's sophisticated operators and energy services companies are adept at analyzing each of these datasets separately, prescriptive analytics technology is unique in that it processes these structured and unstructured datasets together and does so continually. Since reservoir conditions are anything but static, the machine learns from new streams of data and updates its "prescriptions" when the datasets signal the need for a recalibration. This adaptive environment compresses learning curves, enabling better decisions faster with less risk and much less capital.

You don't have to know as long as your data does

Operators can start using and reaping benefits from data-driven prescriptions immediately, even if the underlying causalities are not fully understood. Think about this for a minute. We use Google to find restaurants or plan a route that avoids traffic congestion without completely understanding how or why the engine's algorithms produced the suggestions they did. Does that lack of understanding make the results less useful? Of course not.

The same holds true for prescriptive analytics. The technology makes an immediate impact, while the geoscientists, in parallel, strive to understand the physics behind the predictions and prescriptions the software has derived from an operators' data—lots and lots of data of all types. E&P

OneSubsea FRIEND: optimizing equipment performance to maximize production



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Practice, practice, practice

When installation is completed in 2015, a new simulation platform will help one company train its crane operators in heavy-lift operations for the offshore.

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Read more commentary at
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Today's video games are designed to keep a player's attention while maintaining an enjoyable level of challenge. Studies have discovered patterns of behaviors or "deliberate practices" that are predictive of a skilled performance in activities like sports or music. It's how people get to Carnegie Hall: practice, practice, practice. Video games provide that full concentration and engagement necessary to refine—through repetition and problem-solving—the skills to tackle a tricky puzzle or rescue the fair princess.

The design and application of gaming systems for use in highly technical training has increased significantly over the years. From piloting a plane to performing surgery, simulations have provided specialists with a variety of real-world challenges to train for in a short span of time.

The beauty of both video games and simulations is that a quick hit on the reset button can set a digital world gone sideways back to upright before starting over. This is a luxury not available in the real world, especially when working offshore when the margin for error is slim to none.

To enhance its crane operator training program and the safe, efficient implementation of the heavy-lift operations that it is known for, Heerema Marine Contractors (HMC) recently announced that it selected Kongsberg Maritime's K-Sim Offshore simulation platform. Delivery of what will become the world's most advanced offshore heavy-lift crane simulator is planned for September 2015, according to a Kongsberg Maritime-issued release.

As a specialist in transporting, installing and removing offshore facilities, HMC required a simulation system that could "train the most competent crane operators and conduct detailed pre-mission training for heavy-lift projects," the release said. Kongsberg will develop a unique simulator based on its K-Sim Offshore platform, which is already in use at several high-profile offshore training facilities worldwide, the release said.

"In addition to the technical capabilities of the K-Sim Offshore Simulator, especially including its high-level hydrodynamics, it was important to find a simulator supplier that we could work closely with on such an extensive project," said Catina Geselschap, project manager at the HMC Academy, in the release.

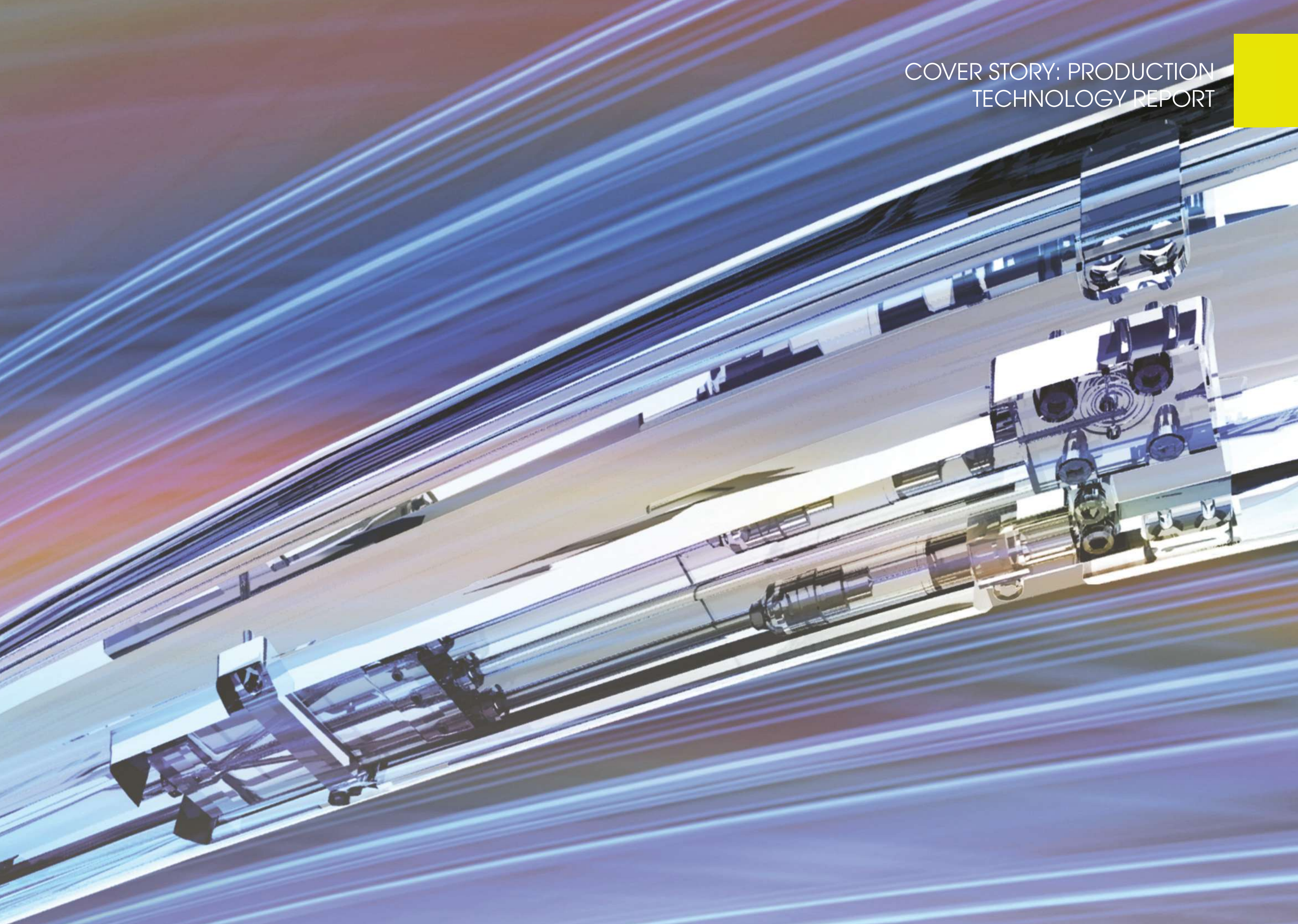
"Kongsberg Maritime demonstrates not only the technical competence to deliver such a complex and sophisticated simulator but also an open approach that encouraged dialogue and a willingness to find a solution working in close cooperation with Heerema."

The simulation platform is set to include two offshore crane operator domes and a DNV Class A bridge with K-Sim DP simulator, which is based on the same Kongsberg Maritime K-Pos DP systems used on Heerema's vessels. To achieve highly realistic training, the K-Sim Offshore simulator will feature detailed models of three HMC deepwater construction vessels, the *Thialf*, the *Balder* and the *Aegir*, in addition to several barges and a supply vessel. A library of objects and models of offshore installations and equipment used for specific heavy-lift projects also is being developed.

For those gamers that grew up to be crane operators, the skills they learned on the couch long ago will be stretched greatly to ensure a safe lift because there is no reset button in the game of life. E&P

Jennifer

IMPROVING RECOVERY



Advances in production technology are impacting the bottom line for operators.

On paper, bringing a well into production is a four-step exercise: find, drill, complete and repeat. If it were only that simple, right? But once the well is in production, keeping it online is a delicate exercise of balancing not too much with not too little.

Recent advances in production technologies have helped operators find that balance in a variety of areas.

The phenomenal growth in the number of unconventional wells drilled has resulted in a higher number of wells that are not producing from all of the stages and low ultimate recovery rates.

Operators are looking to well planning as a key first step in elevating production rates.

Advancements in high-speed computing have enabled greater insight into the modeling of reservoir behaviors during production.

Through looking at waterflood principles on an atomic scale, researchers have developed new applications that could significantly improve recovery in offshore applications.

There's no one way to solve a problem, and the next few pages offer a sampling of the technologies and techniques that are opening and keeping open the oil fields of today for the generations of tomorrow. E&P

Well planning for unconventional plays heads for mainstream

As companies move from HBP to development drilling, well planning has become more important for boosting EURs and extending well life.

Scott Weeden, Senior Editor, Drilling

In the past few years in plays like the Eagle Ford, the industry has continually pushed the envelope in terms of drilling efficiency. Even though the rig count has gone down, the number of wells drilled has gone up. The focus in the industry has been on getting wells drilled quickly and holding leases by production.

Although the drilling side of the equation has benefited, the production side has been lagging in terms of effectiveness. A high percentage of wells are not producing from all of the stages, and ultimate recovery is between 5% and 15%. Production varies greatly from well to well, and producers are beginning to be more interested in using well planning to impact variation and effectiveness.

"There is a big focus on improving production going forward. A lot of that shift is coming from operators who are switching from the exploration phase where they were proving the economics of the plays to the development phase where their focus is on improving production and efficiency," said Aaron Burton, product line manager, multistage completions systems, Baker Hughes.

"There is more and more emphasis on well planning. The industry is moving away from 'cookie cutter' versions of field development. What we're seeing now is the mentality shifting more toward long-term goals of getting good production for many years. With the shift in mentality, you do have growing emphasis on data—microseismic, production logging, production monitoring, etc.," he continued.

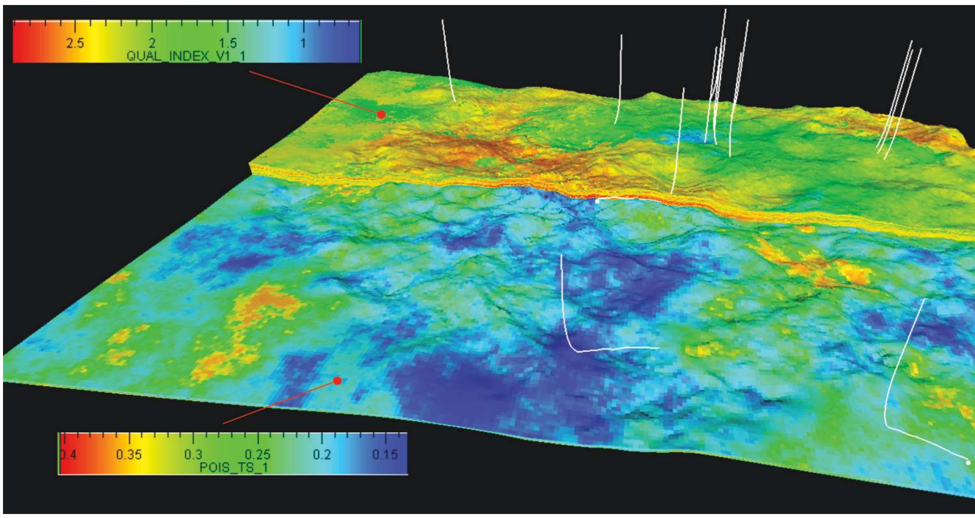
Mark Parker, technology manager, Midcontinent Area, Halliburton, emphasized, "As we've gone to more horizontal wells than vertical wells, well planning is really important. In some areas, operators are drilling 5,000-ft to 8,000-ft [1,524-m to 2,438-m] laterals. Staying in zones and understanding targets that you're trying to access are all very important.

"I think we're still trying to influence the industry in seeing how important it is to visualize and understand where we're going with drilling wells. When an operator drills a well that is 4,000 ft [1,219 m] in a lateral direction, it wants to treat all 4,000 ft. I totally understand that. If we're not accessing all 4,000 ft because we are not in good-quality rock or we're not doing the proper stimulation treatment, that has a huge influence on production," he said.

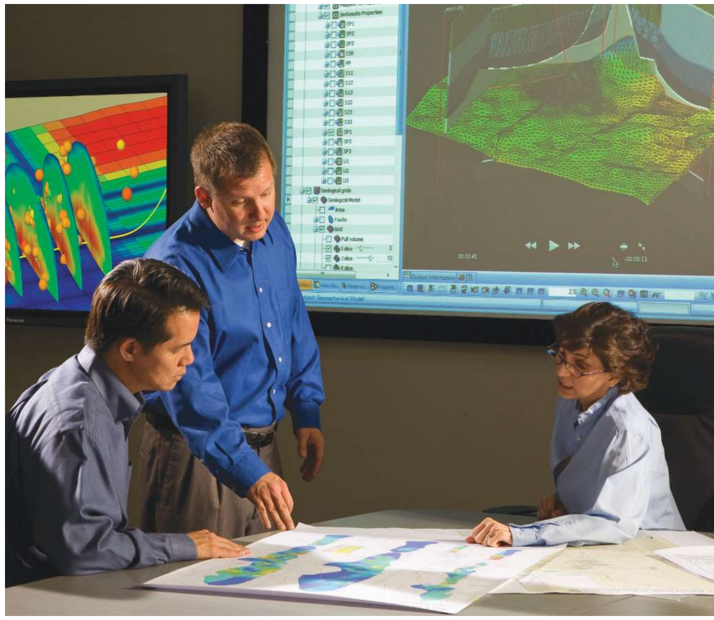
For quite some time, the industry has been reluctant to perform production logging, for example. Now, though, the industry is beginning to recognize the value of all well data, including production logging, in well planning.

Cumulative learning process

The key to well planning is incorporating and using the information that the industry currently has available. Data could include microseismic, MWD, LWD and pro-



Halliburton is developing subsurface visualization with its CYPHER process. (Source: Halliburton)



For well planning, the key is incorporating and using information the industry currently has available. (Source: Baker Hughes)

duction monitoring. For well planning, there are a lot of aspects to consider.

"First off, where is your top hole?" Burton asked. "Where are you going to actually drill the vertical portion of your well? In which zone are you going to place your lateral? There are a lot of variables there—everything from hydrocarbon content to 'frackability' to how many stages you want to put into that lateral.

"Obviously, it will take well planning to determine the optimal completion and stimulation design. In tight oil plays like the Bakken, you also have to consider post-fracture needs. If you want to run an electric submersible pump, you need to be sure it is compatible with the rest of your completion," he said.

Well planning is a cumulative learning process. Information is taken from previous wells to improve the plan for the next well. There is a variety of ways to integrate data into well planning.

"Microseismic, for example, would be done during the frack job so you can get an idea how your fractures are growing. That can lead you to know how effective your fracture is. With real-time microseismic, there are opportunities to adjust on the job," he continued. "I believe most operators are using it to evaluate one well, take the data and apply it to future wells. The same could be said for production logging and monitoring."

Identifying the production volume from each stage allows operators to determine the effectiveness of the

hydraulic stimulation. "If they discover that the frack plan was not effective for certain stages, they can apply the data gathered from the most productive stages to optimize future operations," Burton added.

Even drilling from a pad, there can be variations in wells that can be addressed by well planning. For example, if wells are close together, the wellbores align with the stress regimes and the rock properties are comparable, the well plans can be similar. In this application some operators choose to focus on the efficiency aspects and design a frack plan that contacts the entire reservoir in that lateral. As long as the wells are efficient and don't miss any hydrocarbons, they can continue to use a cookie-cutter approach, he said.

But if the wells head into different sections of the formation, different assumptions—largely based on rock properties—will need to be made. Although there are similarities between plays—multistage completions, hydraulic fracturing, etc.—that can be transferred from play to play, the formations are different enough that operators can't cut and paste their frack designs. They have to modify the frack according to the formation, he explained.

Subsurface visualization

Decades ago when the industry was drilling only vertical wells, a lot of those wells were drilled on structures that could be observed from the surface. Now, with unconventional resources and basins with shale-type reservoirs, the industry is looking at different characteristics.

"When we incorporate all the geology and geophysics along with all the engineering data, we can use that to generate targets we can incorporate in the well-planning process," Parker said. "It is not just looking at the location from the surface and saying, 'I've got surface and section outlines for the lease.' We are taking a look at it in 3-D to see how the formations and reservoir targets may vary in a lateral direction.

"That is something we can do with subsurface visualization, which is something Halliburton is developing right now. We call it our CYPHER process," he said. "The industry has all this information, but how do we incorporate and utilize it? That's part of what CYPHER does. It allows all this data to reside in one place where we can look at it, visualize it and literally see where we are going."

Operators can look for petrophysical characteristics—water saturation, total organic content (TOC), etc.—that can be used for a target. "With CYPHER, we can visualize it. It is not just numbers on a paper or values in a spreadsheet; we can actually see 3-D representations of what that looks like," he said.

For example, there are geological hazards such as faults that need to be identified. "In some areas, there is a lot of faulting. What happens if we put a wellbore across a fault? Would we have a severe lost circulation problem that would limit us from going further? Could that fault lead to a high-water area that would cause problems with production?" he asked.

"It will show structural information about the reservoir so that the well plan could be guided along the structure even if there were no geological hazards. By structure, I mean things like the dip of the formation and how that may change," Parker added.

Well planning goes hand-in-hand with maximum production. "There is a typical disconnect in the industry. On the drilling side, we want to get the well drilled in the most efficient and timely manner to save money. But that can have implications for how the well can produce. For well planning, if we could look at other characteristics or parameters in the reservoir, we could use those as targets," he continued.

Perhaps the operators want to drill high in the interval to take advantage of better porosity distribution or TOC. Or the operators could target the middle of the reservoir because they want to access as much of the reservoir as possible from top to bottom, and centering would be best. Or the operators want to land the well low in the formation to take advantage of gravity drainage for liquids production.

"There are a lot of different aspects involved in bringing together a well plan that are important in consideration of future production," he said.

Well planning requires collaboration

Both Baker Hughes and Halliburton emphasized the importance of collaboration with the operators in well planning as well as collaboration between engineers, geologists, geophysicists and petrophysicists.

"The keys are communication and seeing it from start to finish," Burton said. "You can't just focus on one aspect of the drilling, completion or production because these all must correlate. The drilling will directly affect your wellbore completion. For example, if you want to run a certain type of completion system but you have the wrong size casing or the wrong size hole was drilled for that completion, you obviously would have to change your completion plan."

Drilling a rough wellbore makes it difficult to land the completion at the intended depth. Also, the wellbore completion directly affects the frack design. The wellbore completion controls how much flow area there is in each stage and determines the pressure ratings downhole. It also helps control fluid displacement, which indirectly can control the frack growth, he continued. It is important that the completion be designed with the frack in mind to ensure that the intended frack job can be executed.

To maximize the production effectiveness, the service company has to collaborate with the operator in all aspects of the drilling, completion and production process.

"From Halliburton's point of view as a service company, we know how to do a lot of things from the engineering aspect of drilling and completing the well. But from the operator's side, that property is their asset. They understand it and know things we don't. Collaboration is really bringing the two knowledge bases together to come up with the best solution," Burton said.

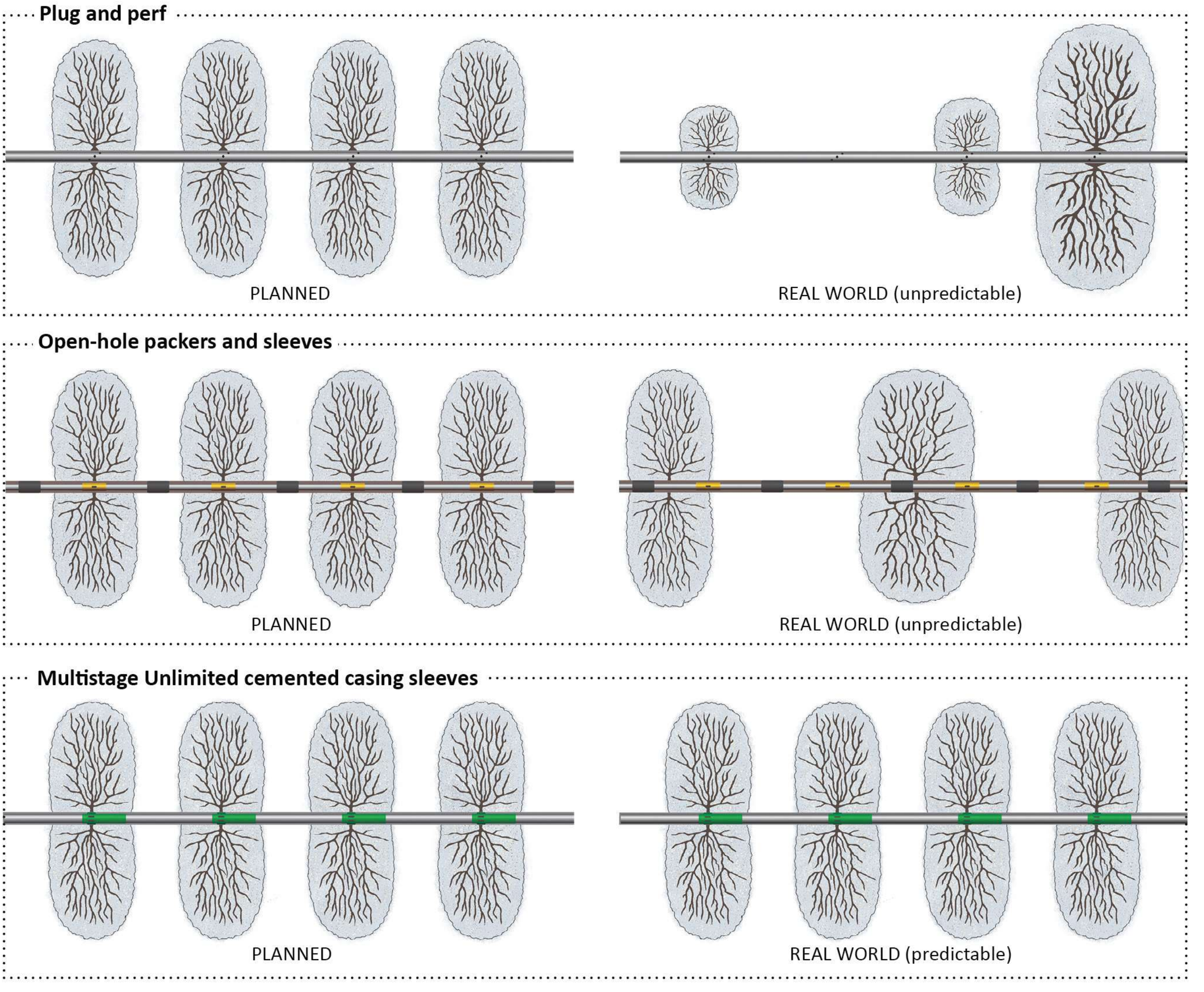
In one project Halliburton worked with Devon Energy on the latter's asset in the Barnett Shale in an area that was more liquids-rich. "They had a situation where there was a lot of variability in production from one well to the next. Continued development of this area was at risk of abandonment due to poor economics and unpredictable production results.

"We applied the CYPHER process and incorporated data to improve reservoir understanding, including wide-azimuth 3-D seismic. A collaborative team of Halliburton and Devon technical representatives was formed and made recommendations and a new well plan. The team adjusted the drilling target to a lower landing point within the reservoir compared to what was originally planned," he continued.

Several changes also were made on how the fracturing treatments are performed. The combination of changes implemented by the collaborative team resulted in reduced variability from one well to the next and a significant overall uplift in EURs. The project has been documented in various publications, Parker said. E&P

The moment of truth:

Where do your fracs (and your well investment) go?



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Simulating a hidden reality

Reservoir simulation has made great strides in predicting a reservoir's inscrutable behavior.

Rhonda Duey, Executive Editor

While seismic data processing often leaps to mind when discussing high-performance computing demands in the oil and gas industry, reservoir simulation also is a very compute-intensive process in the upstream. Based on surface and subsurface measurements and more than a little intuition, these models are expected to simulate the highly complex process of coaxing hydrocarbons out of a reservoir. It's not a simple undertaking.

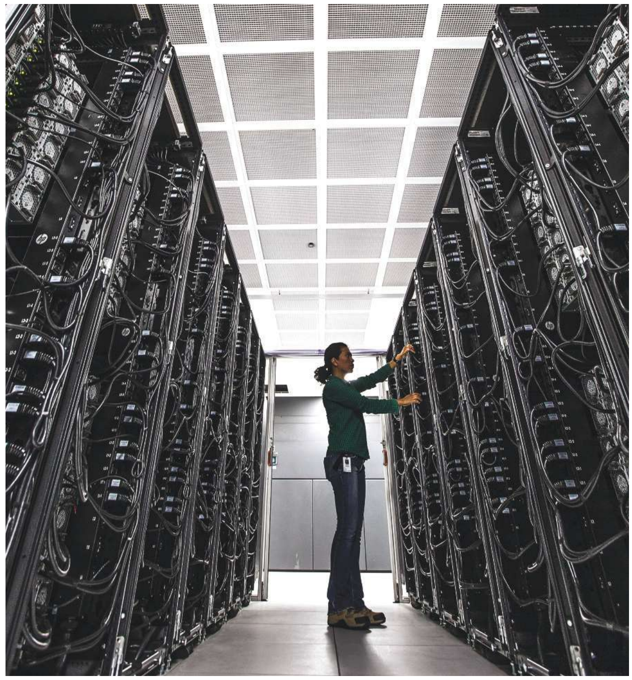
But computing advances and better mathematical approaches are speeding up this process and giving reservoir engineers a greater sense of confidence in these models.

Starting with the model

A reservoir simulation model starts with the geologic or earth model, a representation of the subsurface created by myriad measurements including seismic, well logs, core data, etc. These models are used to determine the best places to land the wells.

"A reservoir simulation model can be viewed as the assembly of data from a number of different elements," said Bob Gochnour, manager, advanced reservoir simulation and deployment/advanced reservoir performance prediction/reservoir management for BP America. Gochnour said that the shape and size of the "container" both vertically and laterally are derived from geological and geophysical measurements and interpretation, including the existence and extent of faults. Geologists also identify the formations and work with petrophysicists to identify facies.

The value of these measurements cannot be overstated. "These measurements have a direct impact on the ability of the reservoir simulation model to predict reservoir behavior," said Agha Hassan Akram, reservoir engineering adviser for geosciences and petroleum engineering at Schlumberger. Estimates such as porosity and fluid saturations are directly proportional to estimated hydrocarbons in place, he said. Permeability estimates also are important since they have the biggest impact on the optimal well type and spacing, including the ability of reservoir fluids to reach these wells. And seismic inversion helps the simulator to model the "blank" spaces between wells.



BP's Center for High-Performance Computing is an important tool for reservoir development. (Source: BP)

"Substantial inaccuracy in these measurements can result in a simulation model that cannot accurately predict future reservoir performance," he said.

Joe Lynch, director of reservoir management at Landmark, a Halliburton company, recalled a simulation problem in the North Sea in which the simulator predicted a late and steady water breakthrough, but the actual breakthrough happened much more quickly and suddenly. It turned out that the reservoir was channelized, and the water was following the oil through the channel pathways. The inability to image those pathways through seismic led to an inaccurate simulation model, he said.

But even with the best geologic models, significant tweaks are needed. First of all, the model needs to be upscaled. "The blocks in the geologic model are typically too small to be of practical use in reservoir simulation," said Steven Crockett, senior product manager for Nexus at Landmark. "Upscaling increases the gridblock size while

JIP studies separation technology

Southwest Research Institute (SwRI) has announced the launch of a multimillion-dollar joint industry project (JIP) to better understand oil and gas separation technology. The objective of the Separation Technology Research (STAR) Program is to combine industry knowledge and resources to advance research that could lead to better equipment and test protocols.

SwRI is leading the three-year program, which is open to operating companies, contractors and equipment manufacturers. International participation is welcome. The three-year membership ranges from $75,000 to $450,000, depending on the type of company.

"Separating fluid mixtures into streams of oil, natural gas and water efficiently and cost-effectively using lighter weight equipment that requires less space is very important to the industry. The STAR Program will involve this three-phase separation process as well as gas/liquid separation and liquid/liquid separation," said Chris Buckingham, a program director in SwRI's Fluids and Machinery Engineering Department and manager of the STAR Program.

The advantage of the program is its ability to pool resources and industry experts to allow a more cost-effective approach to solving problems, especially in a collaborative environment. "This approach means both company-proprietary and nonproprietary equipment can be tested, with results shared among the members," Buckingham said, adding that the research will be conducted using SwRI's existing gas/liquid flow loops.

Members of the program will guide research initiatives by developing a project scope, identifying technologies to be tested, providing input on standard test approaches, witnessing testing and commenting on results.

Goals of the program are to develop standardized testing methods, collect data to improve equipment performance and develop analytical models for various types of separation equipment. ■

retaining as much as possible the flow behavior of the finer scale blocks, reducing the number of gridblocks."

Once upscaling is complete, the permeability and porosity data from the geologic model need to be integrated with reservoir data and pressure, volume and temperature data to describe the interaction between fluid phases and the rock data, he said, either measured from cores or based on correlations. Well trajectories are converted into sets of perforations to describe the wells.

The model is then history-matched to tune it to match the permeability and well characteristics of the field.

"Once these steps are completed, you have a reservoir simulation model that can be used to predict the behavior of the field under different operating scenarios," Crockett said. "Many reservoir engineers use workflows that begin with a set of realizations of the geologic model to capture uncertainty."

Recent advances

Reservoir simulation has taken advantage of many technology advances and, as a result, has made tremendous strides over the past few years. Gochnour characterized older methods as solving "only the reservoir problem."

"The first coupled surface/subsurface models were loosely connected numerically," he said. "More recently, today's next-generation reservoir simulators solve the complete production system, reservoir through to the surface facilities, in one fully coupled system."

This means these models can solve multiple reservoir systems; account for complex well trajectories; model hydraulic fractures as well as naturally fractured shale systems; solve for fluid flow in a wide range of fluid types; and allow multiple recovery process modeling options, including polymer flooding with both conventional and recent temperature-sensitive polymers, foam injection, gas injection floods for miscible recovery, thermal recovery techniques and low-salinity waterfloods, he added.

Robert Frost, development manager at Roxar Software Solutions, a business unit of Emerson Process Management, likened the old vs. new systems to a Model T vs. a Ferrari. "They may fundamentally have the same technology behind them; the difference, however, (and there is a big one!) is the detail, resulting in huge increases in power and applicability," he said.

Many of these improvements have been enabled by the dramatic increases in compute power over the past few years. Gochnour noted that Moore's Law has slowed in recent years, but reservoir simulation is still taking advantage of multiple processors per central processing unit, continuing to drive the throughput speed of the applications. "As such, there is a greater uptake in parallel computing, even down to the notebook computer," he said.

Frost added that the availability of parallel computing technologies is triggering advances in linear solver technology, which is needed to solve the coupled equations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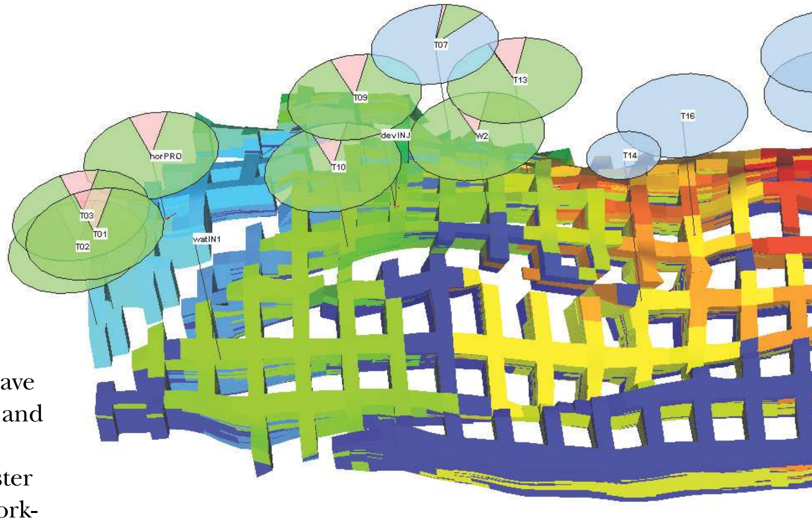
that represent the flow physics in the reservoir. "Here we have come a long way," he said, "but still have progress to make with the challenge to find solvers that can be efficiently parallelized as well as being fast and robust enough to solve many different types of problems."

Crockett said that modeling all the relevant physical behaviors of the reservoir rock and fluids in the simulation results in a large nonlinear problem with millions of unknown quantities and the same number of equations governing them. "You convert this nonlinear problem into a set of linear problems, and you have to solve each of these linear problems in the same way," he said. "Each one of these linear solutions is used to nudge the best estimate of the solution to the nonlinear problem along until it gets to be sufficiently accurate."

These advances in simulation technology allow a greater use of uncertainty analysis. "A tightly matched model is usually a poorer predictor of future reservoir performance than an ensemble of more loosely matched models," Akram said. Tools are available that use a simulator to create multiple forecasts within an acceptable error band of history-matching, generating a fully probabilistic set of outcomes. These can focus on any parameter of interest.

Reservoir simulators have long relied on gridding technology, but in recent years this technology also has dramatically improved. Cameron McBurney, reservoir engineering manager in the reservoir consulting division at Baker Hughes, said that advances in 3-D gridding mean that complex reservoir faulting can be modeled much better than before "as the limitations of gridblock shape/ordering have all but vanished."

"Now that hydraulic fracturing is so prevalent in the completion of wells, especially in the unconventional plays, reservoir gridding has made some significant advancements to enable proper modeling of flow in and around hydraulic fractures," he said. "The obstacle with hydraulic fracture modeling was inserting a very thin region of extremely high permeability into a vast region of extremely low permeability without creating solver



Modern-day reservoir simulations rely on parallel computing to provide more robust estimates of reservoir performance. (Source: Roxar)

problems due to large pressure changes between gridblocks of large size variation and not sacrificing transient flow conditions. The new gridding options have overcome this and allow us to provide better flow rate and decline rate predictions."

All of these advances have provided the ability to foster better integration among different disciplines. New workflow platforms help keep the subsurface model "live and current," said Akram.

Added McBurney, "Software packages have become start-to-finish workspaces that take you from the input of raw data to the final production forecasts predicted by a history-matched dynamic reservoir model. Everything from the raw geological data such as logs, core and seismic combined with reservoir engineering data like well production data, pressures and relative permeability are analyzed and processed under the same roof, allowing geologists, petrophysicists and engineers to work together on the same project file."

This in turn is affecting the way engineers approach their models. "One of the biggest advances isn't the technology itself," Lynch said. "It's in the thought processes behind using it. People are really beginning to understand that simulation is a tool you use to answer a question. If you don't know what question you're asking, you can make all kinds of simulation runs and get all kinds of data, but it's not of much use in making decisions." E&P

Keeping giants active

EOR/IOR technologies help one operator's giant fields mature gracefully.

Jennifer Presley, Senior Editor, Offshore

A common investment goal is to squeeze as much value as possible from the investment. For operators of the world's multimillion-dollar oil fields, the squeezing is more in the form of injection when primary recovery begins to decline. Optimizing recovery in its maturing fields, BP primarily uses water or gas flooding. According to the company, the average industry recovery factor is only 35%, leaving behind some 65% of the oil known to be in the field. From Alaska to Azerbaijan and several places in between, the company has deployed or is in the planning stages of deploying its EOR/IOR technologies to help improve recovery.

"Our philosophy around technology is that we're not going to do everything. We're going to pick out a few areas and try to be leaders in those," said Andrew Brayshaw, vice president of emerging and integrated technology, upstream sector for BP. "The three big areas we feel we're leaders—where we spend most of our investment dollars—are imaging, digital technologies and EOR."

The current rate of global oil production is around 90 MMbbl/d, of which about 3 MMbbl/d is due to EOR, according to a BP-issued release. Of that 3 MMbbl, only about 1 MMbbl are from EOR of conventional oil, with the remaining made up by thermal EOR of heavy oil. BP-operated conventional oil EOR projects produce in excess of 100 Mbbl/d, representing more than 10% of the world's conventional EOR production rate, the release stated. The company has more than 70 years of EOR experience and operates the world's largest hydrocarbon miscible gas EOR project in Prudhoe Bay Field, Alaska.

In the latest issue of its "Energy Outlook 2035," the company's economists projected that global energy consumption is set to rise by 41% by 2035, with 95% of that growth coming from rapidly growing emerging economies. As energy demands increase around the world, so do the challenges to meet the demand with adequate supplies. The discovery of new oil reserves and the application of EOR methods in the maturing giant fields first tapped decades ago are increasingly helping to meet that demand.

"We have a lot of giant fields in our portfolio," Brayshaw said. "EOR is really important to us as we see significant oil remaining in those existing fields. It is a great prize."

Water works

Artificial lift and infill drilling are among the methods used by industry to seek higher recovery. Another is to inject and flood the reservoir with water or a gas like nitrogen or CO_2 to keep the wells flowing.

"EOR is typically looked at in the industry as the last thing that can be done in a field before 'turning out the lights' on it," said Raymond Choo, EOR deployment manager for BP. "First is primary depletion, then typically a waterflood. When a high water cut is produced, the question becomes 'What can be done next?' That is when chemicals, gas or other techniques are applied in the reservoir."

For BP, "waterflooding is very important," according to Brayshaw, adding that the company is one of the largest waterflooders in the industry.

"One of the things we're doing differently from the past—where the belief was that waterflooding is just a physical process, where recovery is a function of the amount of water that could be cycled through the reservoir—is really understanding the chemistry of the process, and that's what's given us an opening," Brayshaw noted.

Being readily available, relatively inexpensive and highly effective at increasing oil recovery has made saline water a popular choice. One example of better recovery through better chemistry is Bright Water chemical and application technology, a BP invention that was codeveloped with Nalco and Chevron. Bright Water is a submicron particulate chemical that is injected downhole with flood water. It is designed to activate at a predetermined "in-depth" location within the reservoir. Upon activation, the Bright Water particles begin to expand to many times their original volume, blocking pore throats and directing injection water into untapped, oil-rich zones. This deep reservoir profile modification causes additional oil to be swept toward the producing wells.

Another example is the company's LoSal EOR technology. The company observed that "reducing the salinity of the water could have a positive impact on pore-scale displacement and ultimately recovery," according to a company release.

"Waterflooding is a commonly applied technique," Choo said. "And if you can do something to the water without needing to add a lot of expensive chemicals, then it becomes very beneficial. It's an area where we've done considerable work on developing our low-salinity technology. It's a form of waterflood where we've reduced the injection water salinity to help release more oil."

He added that LoSal EOR also helps prevent scaling and production of hydrogen sulfide or "souring" of a well. "Hydrogen sulfide creates problems when it gets to the surface production facilities, and it also causes corrosion issues. LoSal EOR takes care of that as we're cleaning up the water by removing the sulfate and other ions before it goes in the well."

After more than a decade of R&D in the company's lab and testing in its Endicott, Alaska, field, the first use of LoSal EOR in a full-scale sanctioned deployment is set to occur in the North Sea's Clair Ridge oil field.

"What we're trying to do at Clair Ridge and with future big projects is to start thinking about and recognizing the need for EOR from day one and in some cases actually starting it on day one like we're going to do at Clair Ridge," said Choo. "In other cases, we may want to allow for the space and design with EOR in mind; otherwise, it will be quite difficult to put in later on in offshore settings."

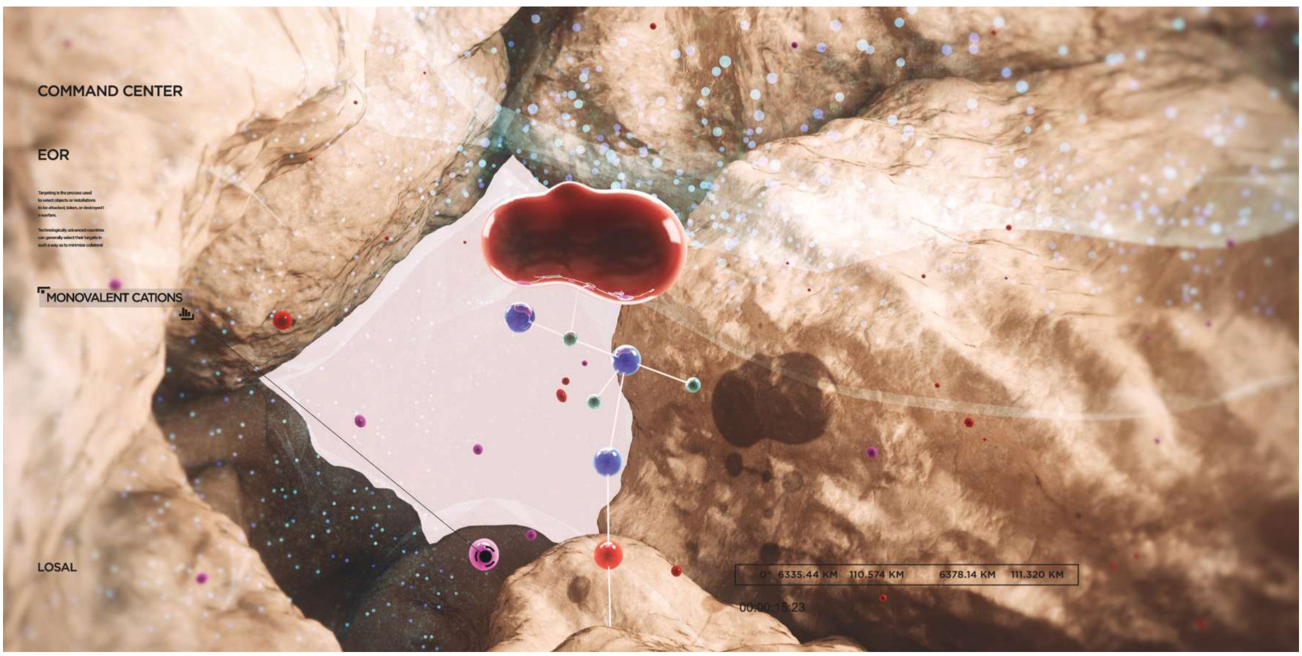
Next generation

It is the transition from onshore to offshore that can be most problematic for operators looking to deploy EOR technologies in their maturing fields. For its newer fields, EOR is now a routine part of BP's field development planning and evaluation process.

"For offshore, it is important to consider EOR in advance, whereas for onshore, there's land available where additional equipment can be installed a bit easier," Choo said. "Once your structure is in place offshore, if you haven't allotted for the space and weight of the additional equipment, it becomes very difficult to retrofit it for installation of EOR systems. That is a big challenge in the industry: understanding how you do brownfield production offshore with EOR. There are very few offshore EOR projects in the world; two of these are operated by BP, namely, hydrocarbon miscible gas EOR in Magnus and Ula fields in North Sea. Some 30% to 40% of current oil production from Magnus Field and nearly all of the oil production from Ula Field today is from gas EOR."

BP's EOR technology is underpinned by a global team, world-class laboratory facilities and digital reservoir characterization.

What is the next generation of EOR technologies that will help the current generation of giant oil fields mature gracefully? Neither would provide much detail into the company's current EOR R&D efforts, other than to say they are working on "next-generation" digital rocks, designer water, designer gas and designer voidage EOR technologies. E&P



LoSal EOR is a low-salinity waterflooding technology. (Source: BP)

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SUBSEA SYSTEMS: Christmas trees, BOPs, tiebacks, manifolds, processing (separation, compression and boosting), SSIVs, SURF (subsea umbilicals, risers and flowlines), pipelines, power supply and controls, ROVs/AUVs, IRM (inspection, repairs and maintenance), intervention, flow assurance, and metering and monitoring

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MARINE CONSTRUCTION & DECOMMISSIONING: vessels and systems, pipelay and flowlines, platforms, subsea construction, marine transportation and installation, heavy lift, hook-up and commissioning, structure removal, intervention and workovers

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EXPLORATION: potential fields, geochemistry, seismic acquisition (land and marine), processing algorithms and software, reservoir characterization, interpretation software, and hardware

FORMATION EVALUATION: wireline logging, core analysis, cuttings analysis and well testing hardware and software

HSE: hardware; software; and methodologies related to health, safety and the environment

DRILLBITS: natural diamond, impregnated, PDC, bi-center, milled tooth, hybrid, insert and hammer

DRILLING FLUIDS/STIMULATION: chemicals, drilling mud, additives, flow enhancers and green systems

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E&P

Using aluminum alloy drillpipe for tophole drilling lightens drillstring

The more flexible aluminum pipe gave the spudder rig an additional 25,000 lb of pullback capacity due to reduced side force loads, allowing the air-drilling rig to reach a deeper KOP.

Oleg Tolmachev, Eclipse Resources Corp.; and
John Hansen and **Jacob Porter**, ALTISS Technologies LLC

Technological advances in recent years have made it possible to reach natural resources previously hidden. Aluminum drillpipe (ALDP) is now contributing to this trend. When compared to steel, ALDP's higher strength-to-weight ratio and lower modulus of elasticity allows spudder rigs to extend their reach with significant cost savings per well when pad drilling.

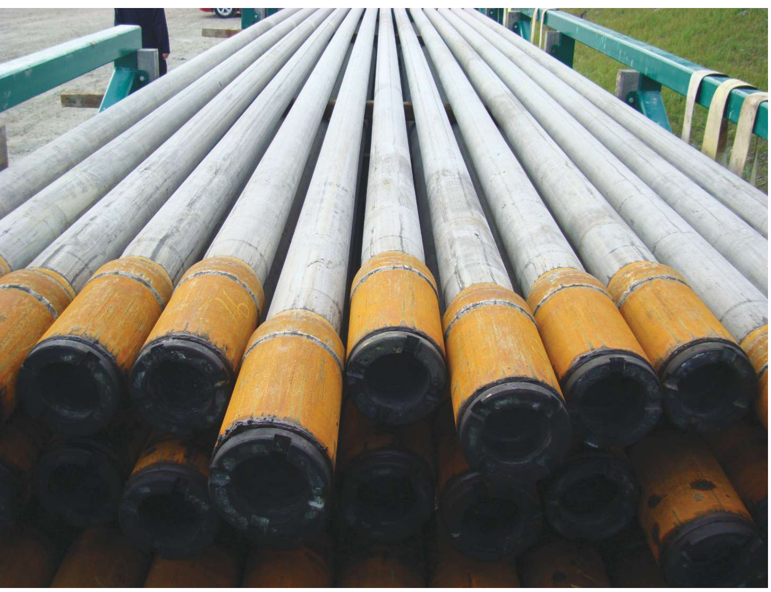
Even though ALDP has been known of for many years, its manufacturing and handling has evolved to the point that it is now feasible and cost-effective to deploy ALDP in strategic locations. This is the strategy that Eclipse Resources Corp. is using in the Utica core area partnering with ALTISS Technologies.

Situational analysis

Eclipse Resources currently uses a spudder rig for air-drilling the tophole sections of its wells in the Marcellus and Utica shales (Table 1). With the preferred bottom-hole assembly (BHA) configuration, the spudder rig often cannot reach the kickoff point (KOP) depth because of the rig's pullback limitations.

A larger rig must then reassemble the vertical string to hydraulically drill the rest of the tophole on oil-based mud as opposed to air, then trip the pipe before setting the intermediate casing and starting on the lateral section. This inefficiency is exacerbated if the spudder rig quits above the Clinton Formation, which is often the case.

After the spudder rig reaches its maximum achievable depth, the wellbore needs to be loaded with oil-based mud for borehole stability. This generally means an extra two to four days for the well for the larger rotary rig and higher costs of $150,000 to $300,000 per well. An additional complication is encountered in angled formations, which increase the overall tortuosity of the hole and the drag created by the side forces acting on the drillstring. The KOP was established at 1,981 m (6,500 ft). Using a steel drillstring configuration, the spudder rig has been limited to depths of between 1,676 m and 1,829 m (5,500 ft and 6,000 ft).



ALTISS' premium ALDP is racked at an Eclipse Resources Utica shale well site. (Source: ALTISS)

ALDP solution

ALTISS Technologies delivered a 4½-in. string of ALDP to Eclipse Resources. Using ALDP reduces string weight. With a modulus of elasticity one-third that of steel pipe, ALDP also reduces side forces acting on the string. The goal was to reduce pullback weight in a tortuous well without sacrificing the integrity of the existing BHA.

The reduction in weight from the 1,798-m (5,900-ft) all-steel string to one with 1,204 m (3,950 ft) of steel drillpipe and 594 m (1,950 ft) of ALDP was approximately 15,000 lb. The mechanical properties of ALDP are shown in Table 2. Because of the deviations in the well, the spudder rig reached its pullback/power limit at a depth of 1,944 m (6,345 ft), slightly short of the 1,981-m target vertical depth to the KOP.

"The well had way too much deviation," said Eclipse Resources' drilling consultant Shawn Burns. "It was only because of the aluminum that we got to 1,944 m."

After experiencing the potential benefits of using

Engine	Detroit Diesel, 760 bhp (567 kW) @ 1,800 rpm
Weight	95,000 lb
Hookload	200,000 lb
Top Drive	• Four two-speed disc-valve type hydraulic motors • Infinitely variable rotation speed • 3.5:1 reduction gear • 0-90 revolutions per minute @ 17,750 ft-lb. • 0-180 rpm @ 7,670 ft-lb
Feed System	• 15 m (50 ft) top head travel • 30 m (100 ft) per min. pull-up speed rapid-feed • 32,000 lb pull-down capacity • 4 m (14 ft) per min. pull-down speed slow-feed • 61 m (200 ft) per min. pull-down speed rapid-feed • 15 m (48.8 ft) working clearance floating sub to table
Drill pipe and Casing	• Range 3 pipe up to 14 m (47 ft) • Range 3 casing up to 30-in. diameter • 30.25 in. max. diameter through slip box
Winch	• 9,600 lb bare drum line pull • 46 m (151 ft) per min. speed

TABLE 1. These specifications are for a spudder rig for air-drilling the tophole sections of Eclipse Resources' wells in the Marcellus and Utica shales. (Source: ALTISS)

ALDP, Eclipse Resources optimized its steel-plus-aluminum string by drilling with only 792 m (2,600 ft) of 4½ -in. steel pipe and adding 1,006 m (3,300 ft) of ALDP. As a result, the combined steel/aluminum string weight was reduced by 17% vs. a standard steel string.

More notable, however, was the benefit provided by ALDP's lower modulus of elasticity. The more flexible aluminum pipe gave the spudder rig an additional 25,000 lb of pullback capacity due to reduced side force loads. Eclipse Resources was able to successfully drill to the KOP of 1,954 m (6,410 ft), demonstrating the potential for expanded use of ALDP in much deeper spudding operations in other regions.

Technical considerations when using ALDP

ALDP's ability to achieve a high tensile load limit is partly derived from an extruded tapered tube with a steel tool joint on each end. This somewhat unique geometry combined with aluminum's lower hardness relative to steel necessitates the use of ALTISS-modified drill slip equipment, which must be installed by the rig personnel before running ALDP. This change took less than five minutes. The rig crew reported that the lighter pipe was easier on the equipment and easier to use than their typical steel drillpipe.

ALDP's lower hardness requires that the rig crews exercise greater caution when handling the pipe to avoid gouges and other surface damage, which can reduce the life of the ALDP. In general, after the rig crews were instructed on the care and use of the ALDP, no gouging or unusual damage was observed. It must be noted that damage can occur when the rig crews grab with or wrap chains onto the ALDP body instead of the steel tool joints when handling the pipe. Surface gouges on ALDP can be crack propagation points, so it is extremely important that the custom handling equipment provided by ALTISS, which is a rental service provider of premium ALDP, be used at all times when drilling with ALDP. Additionally, it is very important that the rig's rotary slip/bowl be oriented directly over the center of the wellbore.

An additional consideration when using ALDP is its sensitivity to pitting corrosion when exposed to high-pH substances or used for drilling in high-pH well environments. As a general rule, prolonged exposure of ALDP to pH levels above 10 is to be avoided. Care must be taken to avoid getting high-pH stabilizer substances such as quick lime on the surface of the pipe. When some of these lime-based additives combine with water vapor, pH levels can rise to as high as 13.5. ALDP also should not be used in wells where there is exposure to temperatures greater than 149 C (300 F).

Overall conclusions

Eclipse Resources found that ALDP's high strength-to-weight characteristics and low modulus of elasticity, combined with relative ease of use, allowed the spudder rig to drill efficiently without any modifications to the preferred BHA configuration and reach depths that were unattainable with 100% steel strings. Additionally, the margin of overpull in the mixed steel/ALDP string was increased, significantly adding to the safety of the drilling operation.

Feedback from the rig crew suggests that the custom slips provided by ALTISS Technologies to handle and protect the ALDP are lighter than those used for the steel drillpipe, which helped reduce operator fatigue. This creates a safer working environment. E&P

Pipe Body	New	Premium
Tensile strength, lb	400,000	312,000
Torsional strength, ft-lb	36,100	27,900
Collapse pressure, psi	12,200	9,580
Internal yield pressure, psi	11,400	10,900
Adjusted weight in air, lb/ft	12	12

TABLE 2. The mechanical performance is shown for 4½-in. ALDP. (Source: ALTISS)

MPD can be used to drill carbonates in deepwater on DP drillship

Fractured carbonate formations can be safely and efficiently drilled and evaluated from a DP drillship with CBHP and PMCD techniques.

R. Ho and **D. Moore**, Marathon Oil Co.; and **J. Kozicz**, Transocean Ltd.

Carbonate formations present drilling challenges due to the high potential for lost circulation and well control situations because they often have flow paths (fractures, wormholes, vugs, caverns, etc.) that are large enough to freely pass whole mud, making pore pressure and the pressure at which returns are lost essentially the same.

If the fractures are small or limited, loss rates may be low, and it may be possible to plug them with drill cuttings or lost circulation material. However, if the fractures are large, even a very slight overbalance can result in total loss of circulation, while a very slight underbalance can result in inflow from the reservoir.

If the formation is thick, this problem is compounded since the formation pressure typically increases at a rate equal to formation fluid gradient while wellbore pressure increases by the drilling fluid gradient (Figure 1). When the top of the formation is balanced, the formation below it will be progressively overbalanced. If the density of the drilling fluid is reduced to balance formation pressure at the bottom, the top will be underbalanced. The proper application of managed-pressure drilling (MPD) can help improve safety and greatly reduce nonproductive time (NPT).

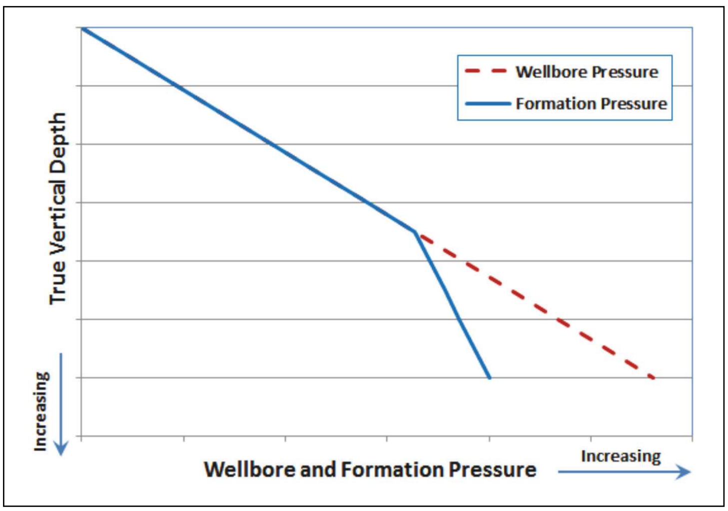


FIGURE 1. The formation pressure typically increases at a rate equal to the formation fluid gradient, while the wellbore pressure increases by the drilling fluid gradient. (Source: Marathon Oil)

Since it is not possible to balance the formation pressure throughout the interval, it may not be possible to control the losses while circulating. When drilling from a floating vessel with synthetic-based mud (SBM), formation influxes masked by losses when drilling fractured reservoirs have resulted in gas entering the riser without the driller's knowledge. Gas dissolved in the mud at bottomhole pressure expands rapidly when it reaches a depth where wellbore pressure is less than the bubble point.

In deepwater, this may be well above the BOP. In that case, the gas breaks out of solution in the riser, resulting in a rapid increase in volume associated with the phase change. As the gas approaches the surface, it continues to expand with additional breakout adding to the problem. In extreme cases, the riser can be unloaded and even collapse.

This article presents a brief discussion on the planning and execution of two deepwater carbonate exploration wells offshore Indonesia using various forms of MPD and the world's first-known application of a below tension ring rotating control device (RCD) on a dynamic positioned (DP) drillship.

MPD installation on deepwater rig

The RCD was installed below the telescopic joint to facilitate drillship rotation during station-keeping. A fit-for-purpose buffer manifold incorporating overpressure protection of the riser was incorporated into the fluid circulating system to allow:

1. Conventional drilling with returns from below the RCD to the flowmeter and shakers;
2. MPD using surface backpressure with returns to either the shakers or mud gas separator; and
3. Pressurized mud cap drilling (PMCD) with no returns and a semistatic annulus.

The RCD, 21¼-in. 2,000-psi annular and a flow spool were pre-assembled into a single joint (MPD joint) for ease of handling and installed in the riser just below the tension ring.

MPD equipment. The RCD provided an annular seal around the drillpipe during drilling and tripping under pressure. Wireline logging operations also were conducted under pressure using a pack-off and lubricator joints, which were latched into the RCD.

The MPD choke manifold contained two adjustable chokes and a Coriolis flowmeter. The Coriolis meter measured the flow rate and density of the return fluid. The riser boost pump was used to constantly circulate the riser through the choke to maintain constant wellbore pressure at a selected point by replacing the annular circulating friction pressure with surface backpressure when the downhole pumps stopped.

Two nonreturn valves and a pressure-while-drilling tool were used in all bottomhole assemblies.

Time Associated with MPD Operation	Well #1	Well #2	Improvement	
	Hrs	Hrs	Hrs	%
R/U RCD Equipment (incremental time over normal BOP & riser running)	31.00	10.00	21.00	68%
R/D RCD Equipment (incremental time over normal BOP & riser pulling)	12.00	4.75	7.25	60%
Commissioning RCD RT (excl.NPT)	18.50	0.00	18.50	100%
Install RCD Wear Sleeve	9.50	0.00	9.50	100%
Retrieve RCD Wear Sleeve	12.00	0.00	12.00	100%
Install RCD Bearing Assembly	14.00	4.50	9.50	68%
Retrieve RCD Bearing Assembly	16.00	9.50	6.50	41%
Pressure Testing RCD	7.00	5.50	1.50	21%
Jet to clean RCD housing	4.50	4.75	-0.25	-6%
P/U & R/B Bearing Assembly	4.00	5.00	-1.00	-25%
Fingerprinting (excl. NPT)	8.50	4.50	4.00	47%
Calibrate Choke Manifold	2.00	0.00	2.00	100%
R/U & R/D Wireline lubricator	14.00	17.75	-3.75	-27%
Total	153.00	66.25	86.75	57%
MPD NPT (excluded from Total)	24.0	10.0	14.0	58%
MPD activity while under NPT (excluded from Total)	13.0	19.0	-6.0	-46%

FIGURE 2. Rig critical-path time improvement during MPD operation is shown from Well #1 to Well #2. (Source: Marathon Oil)

Well control equipment. The rig's 18¾-in., 15,000-psi subsea BOP stack consisted of two 10,000-psi annular preventers, two 15,000-psi double rams and one 15,000-psi single ram-type preventer. The BOP ram preventers were fitted with one set of blind shear rams, one casing shear ram, two variable bore rams and an extra set of blind rams (BRs) in place of the lower pipe ram. This lower set of BRs was used as the working ram during MPD operations and was excluded from the emergency disconnect system. The lower kill-and-choke lines allowed pressure monitoring and fluid injection below the BOP when the BRs were closed.

Case histories

The first wildcat exploration well was drilled in 1,006 m (3,300 ft) of water, and the second well was drilled in 1,921 m (6,300 ft) of water.

Constant bottomhole pressure (CBHP) techniques were used successfully to restore wellbore stability, control losses and prevent influx when minor fracturing was encountered by maintaining overbalance pressures as low as 35 psi.

Several kicks were detected and immediately contained, with influxes as small as 2 bbl and no more than 9 bbl by comparing metered outflow to inflow rates calculated from pump strokes.

One 10-bbl influx that occurred slowly over an hour was observed by the driller from pressure-volume-temperature data and not detected by the MPD system due to the low inflow rate. When circulated to surface, the influx was distributed throughout such a large mud volume that the only indication of the influx was gas-cut mud.

When large interconnected fractures were encountered, total losses occurred while circulating. The static mud weight was below pore pressure, so when the pumps stopped, so did the losses. PMCD was used to continue drilling by pumping seawater down the drillpipe while maintaining a semistatic SBM fluid column in the annulus.

Multiple wireline logging runs were successfully conducted under pressure, and the abandonment plugs were set while holding surface pressure.

On Well #1, a total of 862 m (2,828 ft) was drilled using MPD and PMCD techniques. A total of 11,572 m (37,956 ft) of pipe was stripped through the RCD on six bearing assembly runs in 761 operating hours, including the four days of wireline logging.

Well #2 penetrated a total of 427 m (1,400 ft) of carbonate. Eight wireline runs were made, and the abandonment plugs were spotted under pressure using MPD.

Figure 2 shows the overall rig critical path time associated with MPD operations, the improvement due to the increase in operational efficiency and a decrease in the MPD equipment NPT.

Field experience confirms that fractured carbonate formations can be safely and efficiently drilled and evaluated from a DP drillship with CBHP and PMCD techniques. E&P

Leading the way in oil spill detection

A new three-pronged approach using infrared, radar and algorithms leads to earlier detection of oil spills.

Jose Vicente Solano Ferrandez, Repsol

Over recent years, oil and gas companies worldwide have invested billions in new technologies to make drilling safer for both the environment and their personnel. The latest technological innovation has included the development of new production techniques that increase the efficiency of drilling in deepwater and open up new areas for production. But perhaps most significant is the development of technology to detect oil spills, particularly as firms continue to drill deeper and farther offshore where safety can be compromised. However, until now, the technology has lacked the sensitivity and specificity to detect small-scale spills. In most cases, spillages are detected only once these reach the water surface, and at that point it is often too late to contain them.

Two companies join forces

Recognizing the increasing demand for an early detection system, Repsol and Indra have partnered to create a pioneering piece of technology known as hydrocarbon early automation detection system (HEADS).

Repsol provided HEADS with its extensive knowledge of physical phenomena related to hydrocarbons and the marine environment as well as its experience in crude oil exploration and production offshore. The firm also provided all the technology developed at the Repsol Technology Center, which includes a laboratory to reproduce weather conditions at sea.

Indra, a consultancy in Europe and Latin America, provided its expertise on image interpretation and algorithms as well as its experience in the development of real-time data processing and the construction and use of infrared and radar cameras. The company also has developed and implemented cutting-edge technology solutions for the hydrocarbons industry with projects around the globe.

HEADS is based on highly advanced infrared sensors, radars and algorithms that maximize the probability of detection and minimize the likelihood of false alarms. The system's computer has artificial intelligence and the ability to teach itself while monitoring for oil spills, which increases its effectiveness over time and achieves an unprecedented detection of oil spills.

How does it work?

HEADS consists of three main elements. The first is infrared cameras that scan the sea areas continuously for between 20 and 60 seconds. The technology is able to detect differences in temperature and emissions of different substances and is able to endure bad weather by lowering infrared activity when temperatures drop to 0.5 C (32.9 F) or lower.

The second element is the oil spill detection radar, which scans the water for anomalies in their echo, with each scan revolution only taking three seconds. The radar is used in conjunction with the infrared sensors improving HEADS' efficiency as the radar is capable of operating at full capacity even in adverse weather conditions and can reach distances of up to 5 km (3.1 miles).

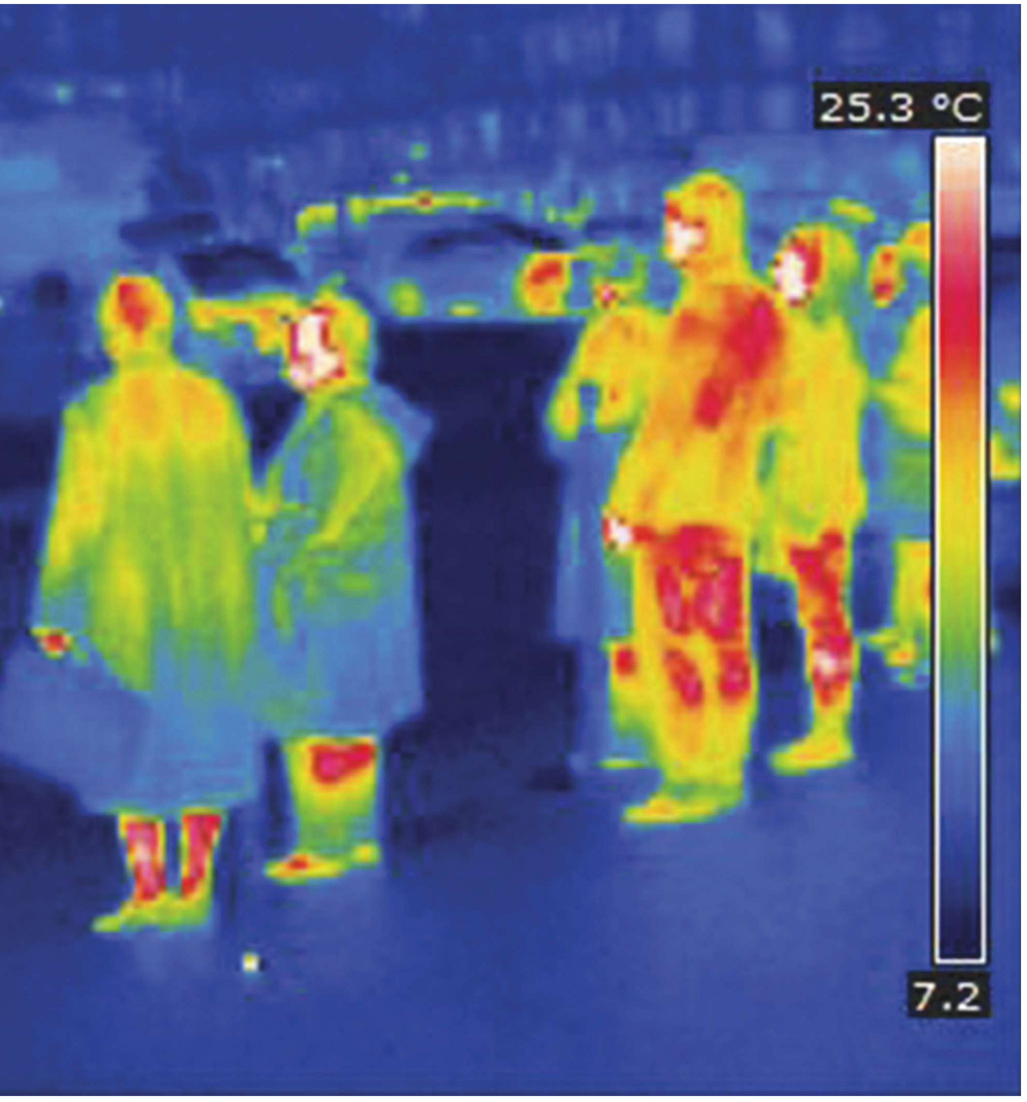
The third element of HEADS is its two control algorithms. The first one detects the oil spill and sets off an alarm through the infrared sensors. The second algorithm integrates the signals of both sensors and—based on these signals and the weather conditions—decides whether to set off the alarm to signal an oil spill.

Due to the highly advanced infrared sensors, radars and superfast algorithms, HEADS can maximize reliability, improve reaction times and allow constant monitoring without the need for an operator, thereby minimizing risk of human error. No other system exists that combines multiple sensors of different technologies with algorithms and an automated response. The application of different technologies maximizes the probability of detection, reducing the chances of a false alarm. HEADS boasts a 90% spill detection rate compared to an average of 65% for existing systems. The system can operate night and day detecting spills of as little as 10 l (2.6 gal) with a response time of less than two minutes.

In addition, HEADS is modular and scalable and can be adapted to any typology using different combinations of thermal and radar sensors. The system also is coupled

with a functionality that can automatically identify vessels in its vicinity using the automatic identification system, allowing ships to communicate their positions and other relevant information so others can track them and avoid potential collusions. Hence, if an oil spill is caused by a vessel within HEADS' detection range, it can record registration numbers and monitor the event.

HEADS is not only an upstream application but can also be used at ports, harbors and any other installations where large volumes of hydrocarbons are stored or managed. As the system aims to detect even the smallest of oil spills, it also could be a useful tool to identify accidental oil releases caused by shipping.



The first element of HEADS is an infrared camera that is used to detect differences in temperatures as shown here in this thermal scan.

Testing

The development of new technologies to tackle challenging but important issues for the oil and gas sector has always been at the forefront of Repsol's activities; therefore, the company has actively grown its team to ensure that it reached almost 100% probability of oil spill detection. So far HEADS has employed 25 people, with the new company initially taking on six people with additional labor requirements depending on the growth of the joint venture.

The project was formally initiated in 2011 and consisted of four stages of rigorous testing. During the first stage, which was carried out at Repsol's Technology Center, technical-economic viability was tested. Phases two to four were carried out through the use of two pilot studies at Repsol's Tarragona Industrial Complex and the Casablanca platform. The project included a multidisciplinary team of more than 20 highly qualified experts and researchers specialized in a variety of areas such as oil and gas, physics, chemistry, software programming, radar technology and algorithms. After 21 months, HEADS was put into commercial use in July 2013 and underwent further fine-tuning until the end of 2013.

HEADS has a positive patentability report, and both companies have registered the patent with a standard Patent Cooperation Treaty application, a single procedure that allows registration in more than 147 countries.

As firms continue to explore for oil and gas deeper and farther offshore, the associated risks will become all the more challenging. What is more, the environmental impact of oil and gas spills has never been under as close scrutiny as it has been in recent years, and oil and gas companies need to demonstrate that they are equipped to deal with these potential scenarios. It is essential that E&P companies and service providers gear up to this reality and ensure they continue to invest in the technology necessary to mitigate these risks. E&P

Reliable connectivity key to offshore communications

The offshore communications challenge is solved for one flotel operator in the North Sea.

Blake McLane, EMC

In an area historically recognized as one of the world's harshest environments for E&P operations, an oasis of calm appears far offshore in the North Sea. It is a "flotel," one that houses rig workers on and off the job. On the flotel, the crew is able to use state-of-the-art Internet connectivity in their daily work of maintaining or modifying field installations, using online applications to stream real-time subsea video back to onshore offices in Houston, Aberdeen or Brazil. Then during time off they are able to spend time communicating with their families.

While these services are not new to the offshore world, they have traditionally added unmanageable expense because of costs of unpredictable bandwidth use to an industry dependent upon positive return on investment, eating away at the daily budget while delegating the majority of precious bandwidth to corporate endeavors and leaving crew members with little to nothing to boost morale in their often monotonous "free time." Offshore crew members have come to expect a similar connectivity performance as they experience in onshore offices or at home, which makes this improved connectivity so important.

In this new environment, Emerging Markets Communications Inc. (EMC) was chosen by the flotel operator because of its ability to provide fully managed connectivity services and support to a crew of more than 400 in the North Sea using its Global Maritime Satellite network. EMC's Global Maritime network offers value-added services such as its patented HD Connect video on-demand services and its Speednet browsing service. The latter is a cloud-based browser that is finely optimized for satellite operation that increases webpage upload and download speeds; enriches the delivery of audio, video and multimedia content; and enables faster typing and scrolling. These value-added services have been proven to benefit customers by providing a faster and more enhanced web browsing and videoconferencing experience over satellite.

The SeaTel maritime antenna is used by EMC to capture minimal up-front capital costs while maximizing an optimal connectivity solution. (Source: EMC)

Operator requirements

EMC's client in the North Sea had more than just crew morale in mind. As the world's leading owner and operator of semisubmersible accommodation/service vessels, the company had several mission-critical "must haves."

The first was that 99.5% service availability be constantly maintained for both project operations and crew welfare. This reliability is important for operations because if communications go down for more than eight hours, all operations must be stopped for safety reasons. Any connectivity downtime where data cannot flow back and forth between rig and onshore operations impacts overall efficiency; health, safety and operations; and ultimately revenue.

Downtime on an offshore rig can mean tens of thousands of dollars each hour, so it was critical that the company was able to meet the client's criteria of 99.5% availability.

For the crew, this reliability is important because they lose the ability to remain in touch with their families and the outside world via the Internet.

Second, the client requested to use its existing SeaTel antenna, minimizing up-front capital costs of the solution. Signal blockage is not uncommon and can happen when vessels are moving and cranes or other equipment obstruct the satellite signal. Therefore, the company requested a solution to avoid satellite line of sight blockage, which could entail a specific dual-satellite antenna configuration to avoid signal blockage while the flotel moves.

Finally, the solution must be able to separate the bandwidth capacity in the satellite connection into two virtual networks: one to be employed for the client's mission-critical and corporate data transmission needs and the other

EMC's flagship teleport facility located in Raisting, Germany, is the largest in Europe and the third largest in the world. Owned by EMC, the facility hosts Germany's major national and international fiber backbone to serve customer sites throughout Europe and the Middle East. (Source: EMC)

dedicated to crew welfare. Providing a dedicated pool for crew welfare purposes means the site operator does not have to worry about compromising important project data with data generated by the applications that the crew uses in their leisure time.

The solution

The company customized a solution to meet all client requirements. For this particular case, a Ku-Band satellite was used for primary and backup coverage for the anticipated route. However, quite often the route changes, and EMC is able to shift connectivity to accommodate the client's needs. This customized service ensured that the bandwidth would be separated into two distinct networks with guaranteed reliability. These objectives were accomplished while keeping the existing SeaTel Maritime antenna in place.

Other equipment that enabled the exact service solution included a SatLink 2900 Mobile VSAT modem, a proprietary platform technology that is capable of delivering up to 50 packets per second (MBps) of downstream IP throughput and up to 5,000 MBps in the upstream using either bandwidth-on-demand or dedicated single-channel-per-carrier uplinks. Because the VSAT modem supports mobility, as the vessel sails through satellite coverage areas, EMC's Global Maritime network enables the flotel to have a smooth transition of connectivity between satellite and beam using the automatic beam switching feature that is built into the system. Whether for work or leisure, all members aboard the flotel enjoy optimized bandwidth solutions that allow them to use the Internet in the same way they are able to use it onshore. Cell phone calls and voice-over Internet protocol included in the solution are delivered in a model that is commercially accepted by both operations and the crew members.

In addition to the benefits of a reliable satellite communication service, EMC's Aberdeen Network Operations Center provides 24/7 field support for the entire North Sea. This center also is equipped with sufficient spare parts to significantly reduce service downtime in the event of any equipment malfunction.

Providing top-tier communications in a "one-stop-shop" solution is important to customers in this industry. Operating companies using these services are able to ensure rig communication with onshore offices at all times as well as provide suitable communication means for increasing crew morale while working offshore and helps to maximize rig employee retention, all of which affect the company's bottom line. E&P

Meeting safety standards in hazardous environments

New regulations will require more attention to detail in telematics instruments.

Gary Naden, Geoforce

E&P operators today face a complicated set of evolving standards, requirements and emerging technologies when it comes to effective operational procedures in hazardous environments. Geographically distributed field operations and joint corporate colocated operations create complex working environments. To address these challenges and optimize workflows, companies increasingly are leveraging communication technologies in the field to more efficiently manage their operations. However, along with the many benefits that new technologies deliver in the field come new regulations, most of which are being driven by international compliance standards.

More specifically, the rate of telematics adoption in modern industrial environments such as oil and gas E&P is pushing the pace for new standards intended to address safety from electronic and radio devices. The introduction of radio-frequency identification (RFID), cellular and satellite telemetry devices can help operations personnel know where and when field assets are in use or being moved.

For many field operations, dozens of companies may have assets at a single drillsite. In addition, many of these assets are leased for use in drilling operations. As a result, it becomes difficult to know exactly which asset is owned by one company but potentially operated by another company and tagged with yet another company's telemetry device.

In response to the influx of new technologies in hazardous areas, the international safety standards bodies ATEX (Europe) and IECEx (international) have revised the standards of intrinsic safety of devices. And with the U.S. and Canadian standards scheduled to conform to the more stringent international standards in 2016, E&P companies need to educate themselves on the new regulations and prepare effective communication plans, policies and procedures around inserted technologies to close any compliance gaps.

Technology insertion

Telematics solutions are proliferating globally in every market sector, and it's becoming increasingly difficult to procure equipment that doesn't contain radio components. Companies have fully adopted use of technology to improve operational efficiency, transparency and safety. What used to be managed by pad and pen is now managed by smart pads, Wi-Fi barcode scanners, RFID, satellite and cellular telemetry tags. Technology insertion is cost-justified by improved efficiency, lower labor costs (time) and faster asset transfer from site to site or company to company.

A typical land-based upstream operation will use dozens of companies providing various services. Most of the hard assets on the site are managed by a small group of companies, while those same assets are typically leased from a larger group of companies. To manage use-case billing and monitor multiple assets in motion, companies are increasingly leveraging GPS tracking and satellite-tagging their assets. While satellite tags may not provide onsite functionality, the site manager must still manage the safety and compliance aspects of having radio transmitters at the drillsite.

Evolving standards

In the U.S., intrinsic safety standards have been governed by National Electric Code as the leading certification for electrical device safety since 1997. Machine-to-machine telemetry was in its infancy then, and most of the telemetry tags developed with intrinsic safe operation requirements were certified under this fifth edition of UL913.

In 1997 intrinsic safe satellite telemetry in the oil field was nonexistent. Since then, RFID, satellite and cellular technologies have accelerated and have become common in logistics management of sparsely distributed assets in the energy sector.

Historically, the industry has been slow to adopt guidelines around these changing certification standards. And companies that operate exclusively or predominately in the continental U.S. may be unaware of the international standards that are impacting domestic certifications. They also may not realize that many of their leased assets that are provided by other companies with international deployments are already tagged with ATEX or IECEx-rated telemetry devices.

The current shift in standards is being driven in part by the proliferation of telemetry technology in the oil field. But now international acceptance of U.S. standards is a thing of the past, and new standards are driving new requirements for domestic and international operations. These new standards impose electrical and radio frequency power limitations that impact land mobile radio and radio telemetry devices currently approved in the U.S.

After July 2016, all manufactured products carrying Intrinsic Safe classifications (UL913) must adhere to the new seventh edition standard (UL60079). This new U.S. standard is harmonized to ATEX and IECEx, making it easier to achieve global acceptance for intrinsic safe telemetry devices based on a single standard for all.

The technical differences between the U.S. standards (fifth edition vs. seventh edition) are significant. The new requirements are more aligned to risk mitigation and use zone designations that correlate to hours of operation per year in hazardous conditions. The highest zone designation is Zone 0, which supports operation in excess of 1,000 hours per year in hazardous environments.

Separate from zone designation are equipment protection method and level. This is a change from the old method for marking devices. The equipment protection method describes how the device achieves a specific protection level. "Intrinsic Safety" is an approved protection method that certifies the electrical circuits are designed to limit heat and spark. "Flameproof" is a method that certifies that if the electrical circuits spark, catch fire or explode, the device enclosure will contain the event.

Both of these methods can be used to achieve the Zone 1 hazardous duty designation. However, "flameproof" is not an approved method for a Zone 0 service. Therefore, a device carrying the "flameproof" method can only operate less than 1.4 months per year in hazardous areas. Only devices certified for Zone 0 operation are certified for full-time use in hazardous environments.

Industry adoption of these new standards is mixed. International operators that previously accepted domestic fifth edition products now demand international ATEX/IECEx Zone 0 products—even for applications that do not require 100% hazardous location protections.

The complexity of the changes can be challenging to communicate to operational and field teams. In most cases it's easier to designate the highest protection rating for any product fielded to avoid training field personnel about what devices can be used where. And because many companies don't fully understand when and where their assets are moving or are being used in hazardous areas, they require all Zone 0 products to mitigate risk.

Widely distributed field operations create complex working environments. (Source: Geoforce)

With an ever-changing global work environment, it's difficult to know for sure that assets tagged for U.S. domestic operation will remain forever stateside. In addition, the complexity and expense of maintaining both domestic and internationally distributable assets is driving more companies to demand telemetry devices like the Geoforce GT1 that are compliant with the IECEx and ATEX international safety standards.

Be prepared

Safety certifications in oil and gas exploration are now being driven by international standards. The U.S. market is gradually adapting to conform to these new, more stringent regulations for intrinsically safe devices. Set to take effect in July 2016, the updated standards are impacting new procurement and processes in the oil and gas industry.

With many operators already demanding ATEX/IECEx Zone 0 certifications from their suppliers and service providers, companies should fully evaluate the impact of the evolving standards on their operations. By taking an informed approach to the new standards, companies can be strategic in how to simultaneously achieve compliance and leverage new technologies to maximize business performance. E&P

Drillpipe grades, industry standards meet increasing H_2S challenges

A new grade of drillpipe has been fully qualified to provide higher safety margins from sulfide stress cracking.

Vincent Flores, Vallourec

Hydrogen sulfide (H_2S) is hazardous to human health, living organisms and more generally to the environment. Historically, this is the reason wells found with sour gas were often carefully plugged and abandoned.

Steel tubular such as drillpipe may be exposed to H_2S during drilling operations in the event of loss of well control or if the drillpipe is used with underbalanced drilling techniques. If unfavorable combinations of different factors coincide, this contact can lead to crack initiation that can propagate and lead to catastrophic failure even with stresses largely below the yield limit of the steel.

With the increasing demand of gas worldwide, some highly sour oil and gas reservoirs have been explored in Russia, the Middle East, China and North America. The development of such fields represents significant technical challenges regarding drillpipe integrity and operations safety. The combination of tubular failures due to sulfide stress cracking (SSC) and rising HSE concerns when dealing with sour gas led industry to develop new drillpipe grades with enhanced resistance to SSC.

Selecting H_2S-resistant drillpipe

Material selection for drillpipe in a sour environment is not straightforward since there is no dedicated international standard. Both API and ISO do not include any requirements for sour service drillpipe.

The NACE Material Recommendation MR0175 was written in 1975, although it left drilling products out of the scope because those tools are generally used in a controlled environment (drilling fluids). It nevertheless clearly defines four application domains that provide a range of susceptibility to H_2S related to well conditions. NACE MR 0175 is considered a reliable selection guide for casing and tubing material. Most of the current or future highly sour field conditions fall outside of this diagram.

NACE also defines normalized test methods gathered in the NACE Testing Methods TM-0177. These were created in 1977 and reviewed in 2005. Four testing methods are specified by NACE for oil and gas tubulars: A, B, C and D. The testing methods are not equivalent, and each can play a specific role. Method A evaluates the suitability for service by testing the material's resistance to axial stresses (pure tension), which can be close to the maximum operational stresses that will actually be applied to the drillpipe.

At a regional level, however, the "Industry Recommended Practices" (IRP) Volume 1 was published in 2004 in Canada. The standard was created with people's safety in mind and provides material property specifications and guidelines for manufacturers, including quality control, testing and inspection of drilling products intended to be used in critical sour wells.

Decade of H_2S-resistant drillpipe use

Sour service drillpipe as defined in the IRP has been used for a decade in Canada as well as in other regions and continents along with a variety of other proprietary sour service grades of drillpipe and bottomhole assemblies.

For instance, the development of several gas fields in the Sichuan Basin in China has involved numerous drilling and safety challenges due to the depth of the reservoir and to the high content of sour gas (around 14% H_2S). The occurrence of several drilling incidents due to H_2S during exploration and development led the operating company to select highly engineered drilling products to avoid such problems in the future.

Based on the experience and expertise of well-known manufacturers, fit-for-purpose grades of drillpipe have been selected to resist these harsh sour conditions and encourage safe drilling conditions. Such proprietary grades largely exceed the resistance of API grades to SSC and are being manufactured using the NACE TM0177-Method A and as per specifications largely inspired by the IRP 1.8.

Starting from December 2006, several critical wells have been drilled using sour service grades instead of standard products. Since late 2006, it has been proven that the use of such sour service grades minimizes the risk of failure, even in the harshest well sections, and no incident has been reported so far.

A more recent example is the exploration of the Kurdistan region in northern Iraq, where the extraction of oil and gas reserves began in 2007. Significant amounts of H_2S gas are present, with reservoir depths easily reaching more than 6,100 m (20,000 ft). Throughout 2010, the use of standard grades of drillpipe led to several drillstring failures due to SSC as a result of well control loss.

Today most operating companies drilling in this part of the world carefully select H_2S-resistant drillpipe, and the tubular inventory in this region largely meets IRP requirements. One of the first operators to have switched its inventory to sour service grades has drilled several exploration wells with two rigs equipped with 5,000 m (16,400 ft) of IRP 1.8-compliant drillpipe. The strings have been used in severe environments containing 18% to 20% H_2S and high-pressure conditions. No SSC failure has been reported during the year of operation.

Highly sour fields: New frontier

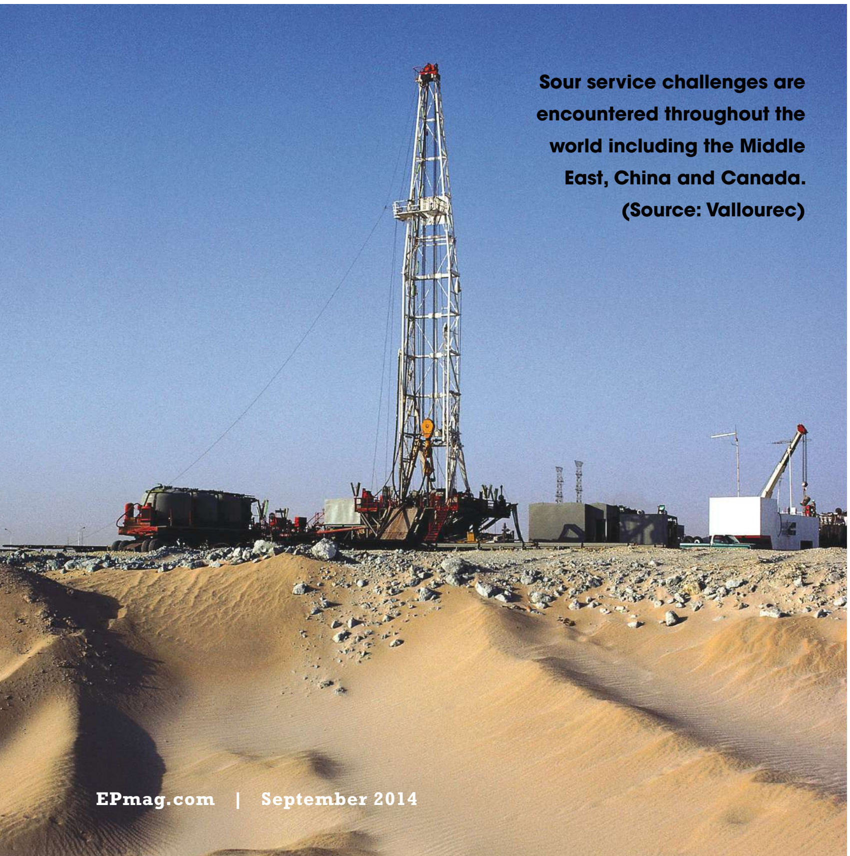
With the increasing demand of domestic gas in different parts of the world, some highly sour oil and gas reservoirs are being explored with H_2S content beyond what could have been imagined a decade ago. To explore, appraise and develop these new fields, which often combine sour gas and deep/complex well profiles, significant safety challenges need to be overcome, including maintaining drillpipe integrity.

From a normative standpoint, regional initiatives are still pretty active with the upcoming revision of IRP Volume 1 but also the emerging use of IRP Volume 6 in the industry. This volume was published in 2004 and addresses critical sour underbalanced drilling, although it has barely been used until very recently.

Also, the Chinese government has put together its own standard to specify more stringent requirements toward sour service drillpipe used in sour gas wells. The standard has been issued by the National Energy Administration of China and implemented in 2012. The specification is largely influenced by the IRP 1.8 and 6.3 sections and includes high-strength steels and SSC requirements in the assembly zone of the drillpipe.

From a product standpoint, the new challenges associated with the particularly sour fields require new highly engineered drillstring solutions to increase the safety margin related to SSC failure risks, especially in the upset and welded zones. Sour service drillpipe has long been used with tool joints and tubes fulfilling separate criteria for sour service as defined by the IRP.

Both the upset area and the friction weld present some challenges for preserving SSC resistance due to metallurgical factors such as heterogeneous microstructure, different chemical compositions between the tool joint and the pipe body and high hardness values close to the weld line.



Sour service challenges are encountered throughout the world including the Middle East, China and Canada. (Source: Vallourec)

Latest innovations

Manufacturers and end users are perpetually looking for new grades able to extend the current drilling envelope and push the frontiers of sour gas development in a safe manner. One of the latest products developed to address the highly sour field market exhibits SSC resistance in the weld and pipe body upset areas, which exceeds the requirements of IRP 1.8.

To achieve such results, several modifications of the drillpipe tool joint chemistry and the post-weld heat treatment have been implemented. As a result, the hardness gap between the pipe body and the tool joint has decreased drastically. The weld line is no longer distinguishable on micro-hardness mappings, indicating a more homogeneous microstructure. The SSC resistance of both the welds and upset areas has been assessed by the NACE TM177 Method A and Solution A. This new grade of drillpipe has been fully qualified to provide higher safety margins compared to existing grades on the market. E&P

Coming to terms with subsalt

CSEM has a role to play in subsalt characterization.

Peyman Moghaddam, EMGS

With offshore Brazil, the Gulf of Mexico (GoM)and Africa all containing subsalt discoveries, operators today are facing some of the world's most complex geologies but not always with the most effective exploration tools. While there have undoubtedly been marked developments in seismic technologies over the last few years, seismic continues to struggle in the imaging and interpretation of salt body geometries, in creating clear subsalt images, and in generating a robust earth model around salt bodies.

Seismic and reverse time migration provide a good definition of top-salt interfaces (where a large portion of the seismic energy is reflected due to the high seismic impedance contrast) but are often only able to provide a partial definition of salt flanks and the base of salt and subsalt.

All too often the seismic wavefield in base and subsalt is distorted, illumination is irregular and velocity distribution is complex. Furthermore, the highly irregular (rugose) structures and many interchanging layers of salt and other rock types generate complex wave propagation, multiple internal reflections and scattering. This leads to incomplete ray distribution, a suboptimal velocity model and limited seismic depth imaging.

A complementary exploration technology—3-D controlled-source electromagnetic (CSEM) acquisition—is providing crucial additional structural information to seismic interpretation and delivering salt bodies for improved seismic imaging and velocity models. In many cases, these techniques also can be applicable to sub-basalt imaging as well.

Growing influence

In CSEM surveys, a powerful horizontal electric dipole is towed about 30 m (98 ft) above the seafloor with the dipole source transmitting a carefully designed low-frequency electromagnetic (EM) signal into the subsurface. Grids of seabed receivers measure the energy propagated through the sea and the subsurface. Through a numerical inversion process, a 3-D resistivity volume of the subsurface is constructed. CSEM can then be used to improve seismic imaging by incorporating such resistivity information into the velocity models.

How can CSEM complement seismic as well as generate information from subsalt that seismic can't? First, since salt is very resistive in contrast to sediments, EM methods are well suited for imaging subsalt sediment structures. The EM energy is also rapidly attenuated in conductive sediments but is attenuated less and propagates faster in more resistive layers such as basement structures. An intelligent, well-constrained attribute correlation between inverted resistivity and compressional velocity in sediments can be used to refine the seismic velocity model and produce better seismic imaging for basement structures. Second, CSEM measures different rock properties to seismic and is subsequently unperturbed by the scatter and refraction that causes seismic difficulties. Through EM, the base of the salt is accurately picked out in depth by the change of resistance and applied to the velocity model to improve the quality of the migrated image. Low-frequency magnetotelluric data also have a large penetration depth and are able to delineate deep basement structures.

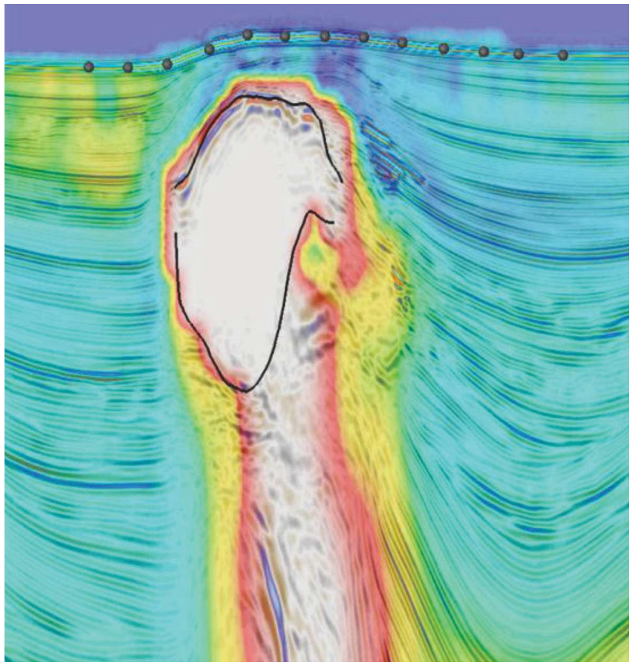


FIGURE 1. The 3-D CSEM inversion is overlain with 3-D seismic. Black lines represent the salt top and base interpreted from seismic. The 3-D CSEM inversion result showed a salt root that was not previously mapped. (Source: EMGS)

The result is that both the structural information and the resistivity distribution recovered through EM methods can be used to update and improve the velocity model for seismic depth imaging.

CSEM offshore Mexico

One example of how CSEM is complementing seismic is a 3-D CSEM inversion survey recently acquired in the deepwater GoM by EMGS for PEMEX. In this case, conducting a resistivity survey through EM and then incorporating the reinterpreted geobodies back into the seismic via migration reaped dividends.

The survey targeted a salt diapir with potential hydrocarbon reservoirs at the flanks where 3-D seismic was available and where the approximate location of the salt diapirs were known. There was a need to identify amplitude vs. offset anomalies and provide an improved structural definition of the target area.

Through the acquired CSEM data along with additional data such as well logs and previously acquired CSEM, a robust initial resistivity model for 3-D CSEM anisotropic inversion was established. The model was defined by a ver-

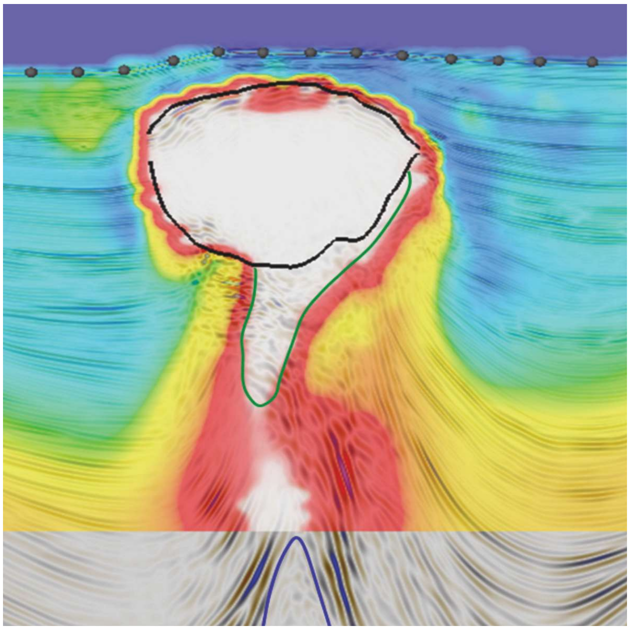


FIGURE 2. Based on CSEM data it is obvious that the salt body extends further to the side and that the base of the salt is a large 'drop' shape. (Source: EMGS)

tical and horizontal resistivity grid with salt bodies based on seismic data interpretation included in the initial model to enhance convergence in inversion.

Figure 1 shows the result of the 3-D CSEM inversion overlain with 3-D seismic with the vertical resistivity component shown and the black lines representing the salt top and base interpreted from seismic. The 3-D CSEM inversion result showed a salt root that was not previously mapped based on seismic data alone.

In addition, the geometry of the salt flank was seen to vary in places from the original interpretation, changing the prospectivity of the salt flank. In Figure 1, for example, it's clear that the overhang of the salt is larger.

A horizontal cross-section of the inversion results also indicated a connection in the northeast between the two main salt bodies in the survey area—separate bodies, according to the original seismic interpretation. The resistivity within the central salt body as well as between the different salt bodies in the survey area also varied significantly, helping the operator better understand the composition and internal structure of the salt—higher clay content in pinch-out structures and in the salt root, for example.

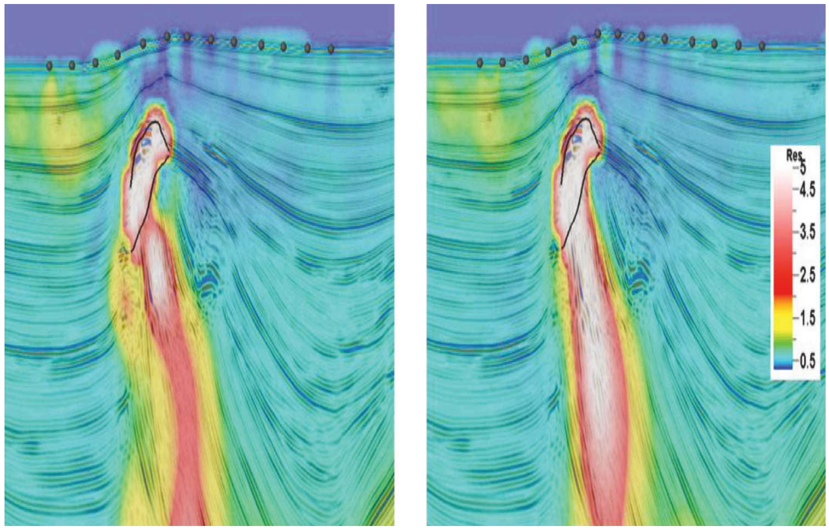


FIGURE 3. Anisotropic 3-D CSEM vertical resistivity without regularizing the anisotropy ratio (on the left) is compared to a sample using the anisotropy regularization function (on the right). Black lines show the seismic interpretation and indicate how the additional information contributed by the regularization leads to an improved structural reconstruction. (Source: EMGS)

Figure 2 illustrates how the larger resistivity associated with the salt body extends further to the side and that the base of the salt is associated with a large "drop" shape rather than the simple convex shape indicated by seismic.

Based on the combined CSEM and seismic data, a more appropriate interpretation seems to be the green line. Where the seismic data are strong (such as on the left), the resistivity information confirms the seismic interpretation. Where the seismic data are poor, EM provides an improved interpretation. It's through the cross-referencing and interconnectivity between the two datasets that a complete picture of the subsurface can be generated.

Since salt is expected to be nearly electrically isotropic on the length-scales of the measurement and to constrain the range of anisotropy, it was also necessary to introduce a new regularization function to mitigate the sensitivity difference between horizontal and vertical resistivity components. This was achieved through the inclusion of *a priori* information about anisotropy.

Figure 3 compares anisotropic 3-D CSEM vertical resistivity resulting from inversion without regularizing the anisotropy ratio (on the left) and using the anisotropy regularization function (on the right). In this case, the black lines represent the salt top and base interpreted from seismic, with the results indicating how the additional information contributed by the regularization leads to an improved structural reconstruction without sensitivity artifacts in the vertical resistivity model. It is this regularization that ensures that the salt body geometry is reconstructed realistically in both the vertical and horizontal components of resistivity, thereby improving the definition of geometrical details.

The imaging results from the GoM demonstrated that CSEM data have the potential to enhance interpretation in complex salt-affected areas, with the incorporation of the resistivity data into the seismic velocity model-building workflow enhancing the resolution of seismic subsalt imaging. In such cases, a 5% to 10% improvement in the imaging of the structure post-migration can have a huge impact on future drilling and appraisal decisions and the accompanying costs.

Power of integration

The industry is still at an early stage in the full integration of seismic and EM data. Yet even where geobodies are being reinterpreted and incorporated into the seismic migration, powerful changes in the geometries of the fault lines are already being seen.

What is clear is that by interconnecting and cross-referencing between seismic and EM and by fostering a closer integration between different measurements, a more complete picture of subsalt surfaces can be revealed. E&P

Finding the sweet spots in West Africa

A data- and technology-driven strategy enabled one independent to discover the region's presalt play.

Rhonda Duey, Executive Editor

When Petrobras made what was then called the Tupi discovery in the new presalt play offshore Brazil, it kicked off a storm of interest in this new type of play, and many companies began to look for analogs on the other side of the Atlantic.

Cobalt International Energy was already there.

The company, formed in 2005, spent its first few years of existence examining data from around the world to find promising areas. The three founders had extensive deepwater and subsalt experience and were not timid about exploring for these kinds of reserves.

"The reason we focused on deepwater in and around salt was, first of all, that's where we thought the best oil reserves were likely to be found," said James W. Farnsworth, chief exploration officer and one of Cobalt's founders. "It also happened to be our area of expertise, and we've been very disciplined about sticking to what we know."

The young company was initially focused on the Gulf of Mexico (GoM), successfully participating in the major deepwater GoM OCS lease sales in 2007 and 2008, but it also wanted an international footprint. Through a lot of regional work, the company decided to focus on West Africa. Early on, Cobalt licensed a large 2-D dataset across all of West Africa and migrated it from time into depth.

"No one had done this before, so we were instrumental in pushing that and using it to identify and rank various play types," Farnsworth said. Added Christopher Olson, a senior geologist working West Africa and new ventures, "All of the 2-D data was regional prestack time (PSTM) data of various vintages. Taking that time data and both stretching and reprocessing it to depth improved our image below the salt and allowed us to construct a regional framework for the presalt play.

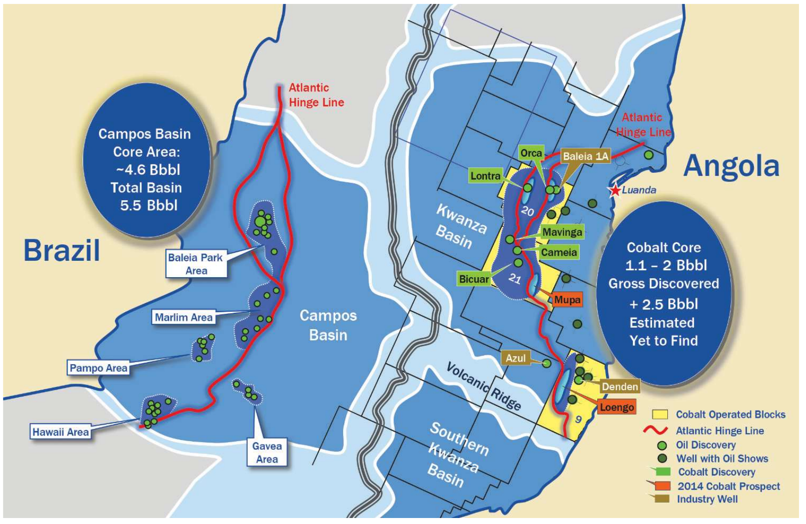
"We never would have been as successful if we hadn't taken that initial step to specifically reprocess the data to be able to see below salt," Olson said.

After considering multiple opportunities, these efforts ultimately landed Cobalt in the Kwanza Basin, an area they referred to as "a graveyard" from multiple failed drilling attempts in the 1980s and 1990s. "Most of the Kwanza Basin's exploration history has been focused on post-salt Albian objectives," Olson said. "The Albian source rocks in the basin are immature. Really, those early wells never had a chance because they'd have to be sourced from presalt source rocks, which were also largely immature in the basin's shallow-water areas."

Fortunately, a few of these early post-salt wells drilled exploration tails that penetrated the presalt section and provided critical data used by Cobalt years later.

Ultimately, with the lack of success in the Kwanza Basin, the industry moved north to the Lower Congo Basin, which turned out to be much more prospective.

But more recently geologists have realized that there are likely to be rich source rocks below the salt. "We figured that if we could combine these rich source rocks with



Cobalt's core acreage is analogous to some of the most prolific presalt plays offshore Brazil. (Source: Cobalt International Energy)

some reservoirs, we would have a fantastic play because it was sealed by salt," Farnsworth said. "That goes back to why we invest in seismic." He added that the few post-salt wells that did have oil shows in the Kwanza Basin indicated that the oil migrated from presalt source rocks.

"We had suggestions that something should be working," Olson said. "But we initially had no clue what the reservoirs would really entail."

There were other uncertainties as well. Cobalt explorationists were bullish on the play but had a few questions: Are the reservoirs present, and where are they? Do deeper seals exist? Are the source rocks present and mature? "We had some hints," Farnsworth said.

What they didn't have was the knowledge that the presalt play was about to become big news offshore Brazil. "It would be nice to say that we saw what was going on in Brazil and we put the story together," he said. "It didn't actually work that way." Cobalt acquired its acreage both in Angola and Gabon before the Tupi discovery well reached total depth, he added.

Nevertheless, Angola was happy to see them. "Nobody wanted to touch the Kwanza Basin because it had been so unsuccessful," he said. "And Angola was also intrigued by the idea of real presalt potential within the basin."

Better living through seismic

The depth-processed data enabled Cobalt's exploration staff to start identifying structures below the salt. "We could identify where real structures were at the base of salt as opposed to being artifacts from post-salt velocity overprints," Olson said. But the 2-D data still had their limitations, so they were primarily used to build a regional petroleum system model to determine which blocks to focus on. A preexisting 3-D PSTM survey was later reprocessed to depth and then studied. Finally, the company acquired its own proprietary 3-D surveys.

"Each of the surveys we acquired was incrementally better, and by the time we were acquiring data in Block 20, it was a real step-change for us," Olson said.

Sweet smell of success

Cobalt's homework has since paid off. "It's relatively rare for anyone to go from first entry into a basin to making a discovery right off the bat and following it up with four other discoveries," Farnsworth said. "It's been a lot of fun."

As of this year the company has drilled the Cameia, Orca, Lontra, Mavinga and Bicuar discovery wells offshore Angola and participated as a partner in the successful Diaman well offshore Gabon.

The Lontra #1 discovery well was named the top discovery of 2013 by Tudor, Pickering & Holt Co. as well as the American Association of Petroleum Geologists. The initial Cameia discovery is due to come onstream in 2017.

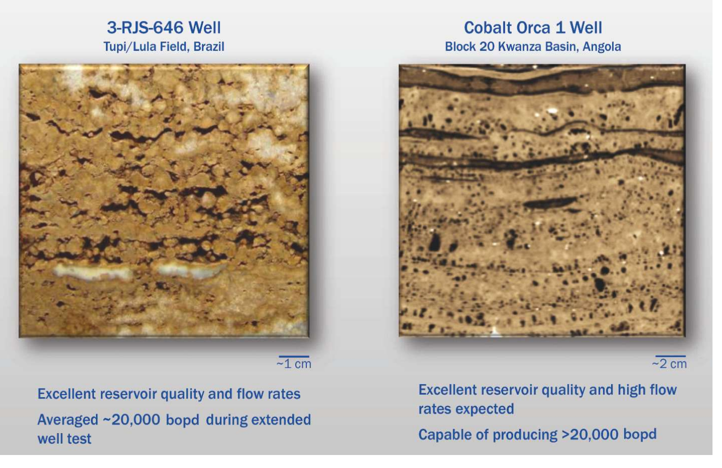
What kinds of production challenges might these wells offer? Farnsworth said that in spite of significant technical hurdles, Brazil is producing 500,000 bbl of presalt oil per day. "Despite problems, they've actually done something really remarkable to bring that much production on so quickly," he said.

The West African geology is a bit more forgiving. The salt layer is significantly thinner, and there are no HP/HT concerns. "You're never 100% certain of how reservoirs will perform until you start producing. As we've learned from Petrobras' experience, when it comes to understanding presalt reservoirs, there is no substitute for production," Farnsworth said. "Drilling more wells isn't going to get us there without seeing long-term production performance."

Cobalt finally has company in its revived graveyard. All of the blocks in the Kwanza Basin have been leased, and the land rush is over. The area has gone from a dead sea to one of the most active areas in the world. But it's taken some time.

"We were out there by ourselves for so long," Farnsworth said. "At times it felt very lonely. But a lot of companies were here before drilling dry holes. It's a really hard thing to go back to your manager and say, 'Oops, we made a mistake 10 years ago. We should have held onto our leases and drilled deeper.'"

Added Olson, "A lot of companies were unsuccessful chasing the traditional plays within the basin. But this is an entirely different play in the deepwater. It just took a different vision." E&P



The Orca core and drillstem results further support the commerciality of the Kwanza Basin discoveries. (Source: Cobalt International Energy)

Identifying, mitigating CT risk in GoM

Roderic K. Stanley, co-chair of the API Resource Group for Coiled Tubulars, speaks with Thomas Angell, director, Offshore Network.

Thomas Angell, Offshore Network

With an aging subsea well stock, shelf assets requiring frequent well work to maintain recovery and the necessity to access deepwater wells, offshore well intervention is becoming a vital element of increasing Gulf of Mexico (GoM) production—with coiled tubing (CT) often being the most desirable method of intervention.

However, key CT planning and process challenges need to be addressed to avoid equipment failures and overruns and increase CT project certainty. Due to this, Offshore Network spoke to Roderic K. Stanley, co-chair of the API Resource Group for Coiled Tubulars, to best understand how to navigate CT risk for GoM operations.

With well intervention on offshore platforms in the GoM increasing, CT reliability presents a critical commercial risk that needs to be mitigated.

Angell: The Gulf of Mexico industry is realizing the growing opportunity that adopting coiled tubing technology can bring to recovery efforts, but what do you see as the main risks coiled tubing presents?

Stanley: Coiled tubing is actually a fairly delicate piece of equipment. The tubing itself is relatively thin-walled, and there is little room for operational damage. Since the tubing is constantly bent and straightened, often at high internal pressure, even the smallest of flaws, whether caused mechanically or by corrosion, can lead to premature failure.

Although this is commonly known, the industry appears to take the risk that is inherent in the assumption that tubing remains undamaged through its theoretically calculated life. While it is difficult to get data on the cost of failures, multimillion-dollar losses were mentioned in a seminar last year, especially when the tubing is used offshore.

Apart from the obvious safety concerns, time for lost production, fishing and repair is very expensive, making coiled tubing reliability a critical commercial risk that needs to be mitigated in the Gulf.

Angell: Based on your experience, what can be done to mitigate the risk of coiled tubing failures in the Gulf of Mexico?

Stanley: At present, very few users know the true state of their coiled tubing at all points in its life but rather rely on theoretical models for accumulated fatigue and corrosion. As such, common operational damage to the tubing remains totally unknown unless the tubing is inspected. This can cause unwanted premature failure,

which has been shown by many recent coiled tubing evaluations.

Assessing the state of the tubing's wall at regular intervals and performing necessary repairs when needed appears to be essential, but this has not caught on with regulators or the industry as well as one would hope.

This approach has been adopted for drillpipe for many years and is well accepted and even mandated in some areas, but a similar approach for coiled tubing has not taken off. I suggest this would greatly mitigate the risk of coiled tubing failure in the Gulf.

Angell: What would the industry need to do to develop standardized approaches to coiled tubing inspection and manufacturing to aid tubing reliability?

Stanley: At present, we have coiled tubing manufacturers in the U.S. and China, all using the same method of manufacture. A manufacturing standard has actually been written (API Spec 5ST). API Spec 5ST documents what the industry currently does to manufacture this product. It also defines the current grades and their tensile limits, testing and inspection methods, and documentation. The API also has issued licenses to two mills to manufacture standard grades to this standard and to Q1, so that is a start toward standardization.

Other mills are now seeking API certifications and licenses, and the onus is on users to purchase these standard grades. However, this has been and continues to be a slow process, which I believe could be accelerated with more high-level attention from the well operators across the Gulf of Mexico.

Angell: What role do you believe new coiled tubing technology has to play in the Gulf of Mexico, and what risks does this new technology present?

Stanley: New higher grades using existing manufacturing technology (high-frequency welding of plate into tubing), and at least one other existing OCTG [oil country tubular goods] tube-manufacturing technology are under investigation and may prove viable for the Gulf of Mexico and other offshore environments.

New technologies and methods always come with new risk. Perhaps some newer and different tests and inspections other than the ones used today need to be developed and added to those that are documented in API 5ST to mitigate this risk.

Some discussion on these potential new tests is certainly required throughout the scientific community, in API meetings, for example. Strings are now

getting to 10,671 m (35,000 ft) in length and are used in sourer and hotter conditions as wells get deeper, so we need to see what test methods are appropriate.

Further, operational risks must be carefully thought out knowing the condition of the tubing at all times, which implies the availability of good inspection tools. From their experiences with casing, tubing and drillpipe, operators are well placed to contribute to this discussion.

Angell: You are currently working toward a new recommended practice for coiled tubing, API RP 5C8. Can you advise the benefit you believe this would bring, your current status on the project and the core goals of the integration?

Stanley: Draft 5C8 covers care, maintenance and inspection of coiled tubing—all of which are aimed at lengthening the life of a string more toward its theoretical fatigue life limit and knowing its condition as it ages. With so many new smaller companies coming into the coiled tubing business, the practices recommended in the document, if followed, should lead to fewer early failures on coiled tubing jobs and, therefore, better profit for the tubing user.

When published, it may also help in the training of coiled tubing operators to enable them to know and understand more about the product they are using. All of this is obviously designed to encourage safe and efficient coiled tubing operations—a topic which is critical in the Gulf of Mexico. E&P

Editor's Note: *The Offshore Well Intervention Conference, Gulf of Mexico, is taking place Oct. 14-15 at the Royal Sonesta Hotel in Houston, Texas. For more information, please contact the conference director Thomas Angell at* tangell@offsnet.com *or visit the website for more details at* bit.ly/OWIGOM2

A new recommended practice for CT, API RP 5C8, is being devised, which should lead to fewer early failures on CT jobs.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Upgrades to CT equipment push limits on deep, long wells

New CT packages deployed in various shale fields in the U.S. in 2013 demonstrated an average 50% reduction in rigup times.

Iain Thomson, Boots & Coots, a Halliburton company

Meeting the growing global demand for energy is requiring oil and gas operators to increasingly extract hydrocarbons from unconventional resources such as shale reservoirs. While North America has led the charge in shale resource development over the past decade, the U.S. Energy Information Administration (EIA) estimates that there are 287 Bbbl of technically recoverable crude oil and 187.9 Tcm (6,634 Tcf) of natural gas in shale plays in more than 41 other countries globally.

As they work to develop their own resources, shale developers in these countries are closely watching the lessons learned and technology developments advanced by U.S. shale operators. Considerable improvements to horizontal drilling technology and multistage stimulation have already been made in North America and will likely occur at a more measured pace. However, efficiency improvements are likely to continue at a faster pace for other technologies, including surface coiled-tubing (CT) equipment.

CT units have played a larger role in post-fracturing cleanup in recent years in U.S. shale developments, particularly in milling out frack plugs after a multistage hydraulic fracturing job (commonly known as plug and perf) in extended-reach horizontal wells (Figure 1). But as lateral lengths get longer—up to 3,050 m (10,000 ft) or greater—and the number of frack stages increases to 30 or more, service providers are challenged with developing CT technologies that increase the speed, efficiency and safety of post-frack cleanup operations such that the well can be brought onto production as quickly as possible.

Unconventional rigs for unconventional wells

Compared to conventional workover rigs, CT units have demonstrated reduced operational times, lower environmental impact and an ability to operate under live well conditions. However, performing intervention work on

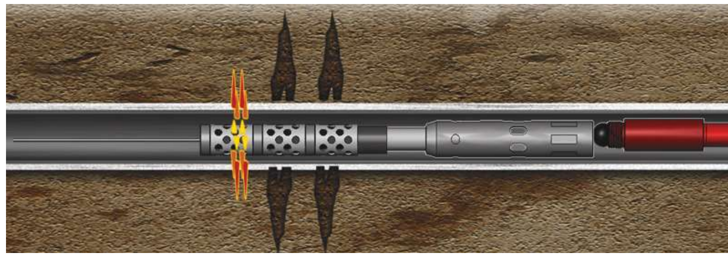

FIGURE 1. CT units have played a larger role in post-fracturing cleanup in recent years in U.S. shale developments, particularly in milling out frack plugs after plug-and-perf completions in shale formations. (Source: Boots & Coots, a Halliburton company)

deep or long wells with conventional CT units is generally limited either by the dimensions (length or outer diameter) of the CT strings or by reel capacity. This is in direct conflict with the industry requirement to use larger CT diameters to help prevent helical buckling and tubing lockup where high wall-contact forces prevent the CT string from being advanced any deeper into the wellbore.

Boots & Coots has developed a new CT system to address these challenges and improve efficiency and safety during frack plug mill-outs in shale wells. The system is designed with the well-control package preassembled on a mast, thus improving operational efficiency, reducing rigup time and creating an overall safer rigsite environment compared to conventional CT applications.

The system's design upgrades reside in three primary components. The first, an auxiliary mast unit, consolidates all well-control and power systems for the package on a single trailer, reducing wellsite footprint and emissions. The unit's trailer base comprises front and rear outriggers and also carries the CT hydraulic power pack, a 110-VAC generator, mast unit with pressure-control equipment, a fuel tank and hydraulic-hose packages. By incorporating the preassembled well-control stack and mast trolley system, the unit reduces rigup time by as much as 50% compared to conventional CT systems and reduces the need for working

FIGURE 2. The new CT package includes a 60-ton crane. (Source: Boots & Coots, a Halliburton company)

under suspended loads while also reducing potential for dropped objects.

The second component, a quad-axle reel trailer, carries the reel with tubing, the operator house and tubing guide. This trailer contains several size and equipment upgrades to meet the operational requirements for plug mill-outs in longer extended-reach laterals.

These include:

- Capacity for 6,098-m (20,000-ft), 2-in. CT, a significant increase over traditional reel capacities of about 4,573 m (15,000 ft) of 2-in. pipe;
- A maximum width of 2.6 m (8.5 ft) and height of 4.27 m (14 ft);
- A standard hydraulic start tractor (no wet kit);

- A maximum design loading of 25,000 pounds-mass (lbm) per axle;
- Sufficient accumulator capacity to operate 5⅛-in., 15,000-psi well-control equipment (WCE);
- Circuit capacity to operate up to three CT strippers;
- The ability to accommodate both current and in-design CT injectors on tilt system; and
- Enhanced display and control functions in the operator house.

New boom crane trucks

The third main component of the new CT system is a dedicated boom crane capable of meeting the greater lift requirements of larger sizes of WCE and riser sections for extended-reach lateral applications. Different cranes have been purposely sized to suit the requirements of various pressure-control equipment stacks. An 80-ton climate-controlled crane is capable of lifting 40,000 lbm 5⅛-in. well-control packages over a radius of 7.6 m (25 ft) with a boom extension of 26.7 m (87.5 ft). A smaller-capacity 60-ton crane is capable of lifting 35,000 lbm for $4\frac{1}{16}$-in. well control packages over the same radius and boom extension lengths (Figure 2).

The relatively simple design of both cranes makes them suitable for operation by trained and certified CT personnel. Standardized controls of both cranes would enable personnel to operate either of the crane options.

Because the new boom crane trucks would typically be at maximum axle loading and could not support additional equipment, the upgraded CT system also includes an auxiliary equipment trailer that would carry, at a minimum, the CT unit's power pack and all the WCE. The trailer features a base design that enables the entire well control stack to be carried preassembled on the trailer, which saves a considerable amount of rigup time.

Further rigup time savings are realized by mounting the equipment on a hydraulic mast that lifts the entire well control stack into the vertical position. The addi-

tion of a docking trolley system, which could be latched in position while making up bottomhole assemblies (BHAs), extends the mast concept further.

The use of a preassembled WCE, mast, and trolley system presents several benefits, including:

- Faster rigup/rigdown of CT equipment as the number of flange connection makeups onsite is drastically reduced. This also lowers the risks of finger injuries and dropped objects when making up the flanges;
- Reduced number of crane lifts as the preassembled well-control stack removes eight lifts from the rigup operation;
- Reduction of working under suspended loads. With the trolley docked and locked into the mast, preparing tubing end connectors and making up the BHAs can now be performed without the loads suspended below a crane; and
- Reduction of pinch and crush points, which is a natural extension of the reduced number of lifting operations.

Delivering tangible results

During 2013, more than 20 of the new CT packages were deployed in various shale fields in the U.S., where these demonstrated an average 50% reduction in rigup times while also improving safety metrics. In many cases, the units were rigged up on the wellhead with BHA ready for pressure-testing and running in hole in under three hours, with no recordable incidents to date.

Additional units, custom-designed for local requirements, are being deployed in the Middle East and Australia during 2014. As best practices continue to be shared across the world and local variations of these new equipment designs are developed to meet individual country requirements, the efficiency and safety benefits of the new CT system will be realized by the E&P community. E&P


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Lowering friction takes CT to TD in extended-reach laterals

A fluid hammer tool in CT operations creates vibrations that overcome static friction between the CT and wellbore to allow the CT to advance more easily.

Silviu Livescu, **Tom Watkins** and **Steven Craig**,
Baker Hughes

The past two decades have seen impressive advances in drilling and completion technologies, allowing E&P companies to extract oil and gas from deep, tight reservoirs that conventional wisdom considered economically off-limits. In North America, for example, the growing development of unconventional shale reservoirs has necessitated the development of longer horizontal (3,049 m [10,000 ft] and beyond) and extended-reach wells.

As the length of these lateral wells grows, so does the need for new stimulation and intervention techniques. Coiled tubing (CT) is commonly deployed as part of the plug-and-perf method of hydraulic stimulation to run tubing-conveyed perforating guns ahead of fracture stimulation and then to deploy a mill or bit to remove plugs.

The farther that CT is deployed in a well, the greater the frictional effects build up to counter the tubing's forward progress to target depth (TD). Unless these downhole frictional effects are minimized, the CT can lock up well short of TD.

The service industry has spent considerable effort to develop technologies that lower the coefficient of friction between the CT string and the wellbore. Simply increasing the CT diameter to improve lateral reach may work in theory but presents logistical challenges in the field. Solutions such as vibrating tools, conveyance tools (tractors) and lubricants are commonly used but poorly understood. Operators often experience a lack of consistency in results from well to well and poor correlations between laboratory tests and field results.

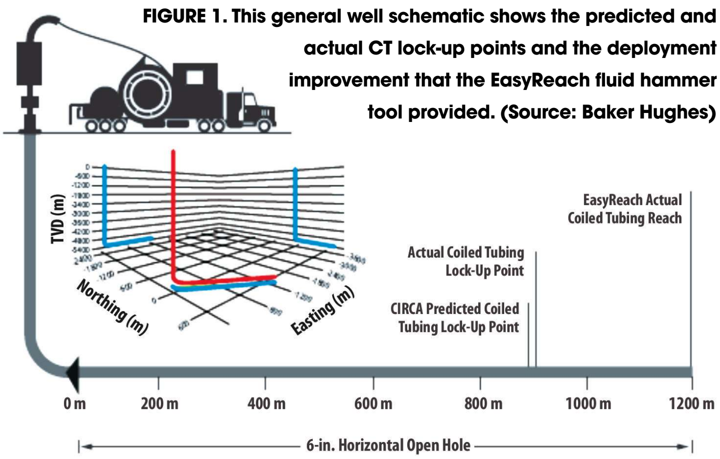

FIGURE 1. This general well schematic shows the predicted and actual CT lock-up points and the deployment improvement that the EasyReach fluid hammer tool provided. (Source: Baker Hughes)

Back to basics

Baker Hughes embarked on a research project to understand downhole frictional effects so deployment technologies could be designed to minimize friction and reach TD.

The first part of the project investigated the design and function of a fluid hammer tool in CT operations. This tool employs a fluidic switch that activates a piston in the tool. The back-and-forth movement of the piston generates regular pressure pulses, which subsequently create vibrations in the CT that overcome the static friction regime between the CT and wellbore. This allows the CT to advance more easily along the lateral.

The research focused on gaining a better understanding of the relationship between fluid hammer pulses and the axial and radial vibrations generated. A numerical model was developed to simulate the fluid hammer pulses and the subsequent axial and radial vibrations of the CT string. The model factored in the CT size and metallurgy, hammer tool parameters (size and valve frequency), pumping rate, and downhole pressure.

For operational parameters chosen in this study, the model indicated that axial vibrations were the predominant driver for pulling the CT string toward TD. However, radial vibrations helped keep the CT in a dynamic state, providing a higher dynamic coefficient of friction that lowered overall friction between the CT and wellbore.

This research helped the service company develop better deployment options for its EasyReach fluid hammer tool. This was particularly helpful for an operator in western Kazakhstan, which was looking to convert existing vertical wells to horizontal producers. Conventional CT deployment proved ineffective in covering the entire 1,200-m (3,937-ft) horizontal section as frictional forces

caused the CT to lock up before it reached TD of 6,492 m (21,300 ft).

The company's CIRCA CT modeling software predicted lock-up at 6,234 m (20,453 ft), and after the CT string was deployed, lock-up actually occurred at 6,312 m (20,709 ft). Once activated, the fluid hammer tool allowed the CT to reach TD (Figure 1). The operator was able to mill out a ball and acid-stimulate the reservoir section that could not be reached with a standard CT bottomhole assembly.

Building better lubricants

The coefficient of friction reductions achieved through the hammer tool studies would fall short of getting the CT string to TD in extremely long laterals (6,096 m [20,000 ft] or longer). This prompted a closer look at lubricants, which have historically provided a 15% to 20% reduction in the coefficient of friction from a generic 0.24 (without lubricant) to 0.19 (with lubricant).

These field results compare poorly with laboratory tests run in traditional high-pressure rotational friction instruments. Downhole coefficients of friction may be an order of magnitude higher than values obtained in the lab—a difference that might result in the CT string being 1,524 m to 1,829 m (5,000 ft to 6,000 ft) short of reaching TD.

The company believes that a lubricant's field performance depends on parameters that have never been accounted for in lab tests. These include downhole temperature and pressure, roughness of the surfaces in contact, metallurgy of the CT, weight on bit, well length and inclination, and chemistry/composition of the reservoir fluids.

These parameters were inputs to the software, which provided estimates of the length or depth that the CT string can reach at a given weight gauge reading and when lubricants will be required to prevent lock-up. The estimates obtained from a set of downhole conditions were corroborated with a laboratory linear friction-testing instrument designed to better mimic downhole conditions such as linear sliding and light contact pressure.

To date, the company has conducted more than 6,600 measurements with this system using various combinations of lubricants, base fluids (brines, freshwater, seawater and produced water), fluid friction reducers, various temperatures and pressures (up to 150 C [302 F] and 12,000 psi, respectively), and CT and casing samples of different metallurgy and roughness. This extensive testing was instrumental in the development of a new lubricant that provided a coefficient of friction of approximately 0.13, which was confirmed in West Texas field tests in late 2013. The new water-based lubricant is compatible with seawater, freshwater and produced water systems; has a low hazard profile; and is approved for use in the North Sea.

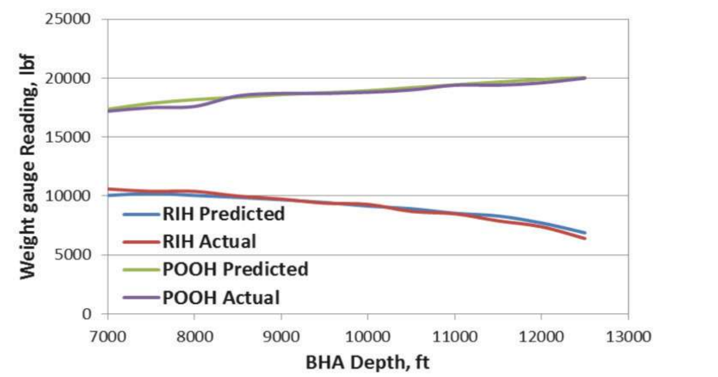

FIGURE 2. Case history for new lubricant shows predicted and actual weight gauge curves during RIH and POOH (coefficient of friction = 0.22 and 0.13, when no lubricant and the fluid hammer tool were used and then when lubricant and fluid hammer tool were used, respectively). (Source: Baker Hughes)

These parameters were particularly important for a North America operator with a well in the Permian Basin containing a 1,555-m (5,100-ft) lateral with the majority of the inclination in the 89° to 93° range. This operation was to perform an annular fracture treatment with diversion achieved by using a CT-deployed packer. First runs with the fluid hammer tool produced a coefficient of friction of 0.22 with 1,000 pounds force tensile force. This slightly lower coefficient of friction (0.22 vs. 0.24 default value) was attributed to the vibrations of the fluid hammer tool.

While running the CT for packer deployment and fracture treatment, the new lubricant was introduced at a concentration of 1% of the total fluid volume with a pump rate of 0.75 bbl/min. This assured that a thin film of lubricant was uniformly distributed in the lateral. In addition to the lubricant, friction reducer was added at 0.01% for fluid frictional pressure reduction. Both lubricant and friction reducer were circulated via constant rate chemical additive pumps to remove any human errors during mixing.

Post-job force matching in CIRCA revealed coefficients of friction in the lateral of 0.13, a friction reduction of 41% and 46% compared to the cases when no lubricant and the fluid hammer tool were used and when no lubricant and no fluid hammer tool were used, respectively. Weight matching results for running in hole (RIH) and pulling out of hole (POOH) are shown in Figure 2.

The back-to-basics research approach developed testing protocols that provide closer confirmation between field trials and lab results and allowed the service company to fine-tune its fluid hammer tool, simulation software and lubricant chemistry achieving consistent reductions in downhole coefficients of friction of between 40% and 60%—effectively doubling the deployment length. E&P

New interventionless fracturing technique rescues stranded assets

Diversion technology helps increase lengths of lateral and number of clusters effectively fracture-stimulated.

Ryan Loya and **Matthew Lahman**, Halliburton

Advancements throughout the past 10 years have made horizontal drilling more available, reliable and cost-effective. This technique along with multistage fracturing designs has played a major role in the development of many unconventional oil and gas fields globally, particularly the "shale revolution" in North America.

These horizontal well designs include long lateral sections intersecting the target formation with many closely spaced perforation clusters grouped in planned stages. Placing the laterals perpendicular to the formation's least principle stresses allows an effective fracture system and drainage architecture to be created in the reservoir. The large drainage area covered by each wellbore leads to efficient, economical drainage of large sections of reservoir but also leaves the possibility of stranding reserves either during the primary completion or later in the well's life. The development of a groundbreaking diversion technology is providing a viable solution to rescue stranded assets in an array of applications from the most complex well rescues, remedial treatments and refracturing operations.

Well rescues

A flexible new diversion technology is proving to be up to the challenge of rescuing these problem wells through an interventionless process where increased lengths of lateral and numbers of clusters can be effectively fracture-stimulated. This new diversion technique does not use conventional wellbore interventions such as isolation plugs to help ensure zonal isolation but rather uses a new generation of diverting technology. Along with improved design and delivery methods, advanced diverting agents used in Halliburton's AccessFrac service are providing higher competent diversion efficiency and offer many advantages compared to earlier materials used in oil and gas wells for temporary fluid diversion. The new engineered diversion spacers used during well rescue operations consist of the new diverting agent, which contains a multimodal particle distribution with self-assembling properties that make it useful for packing off the near-wellbore region of the formation. The new chemical diverter is environmentally benign and self-degrades in any aqueous fluid, leaving behind products that are nontoxic and that do not interfere with recycling or disposal of the recovered water.

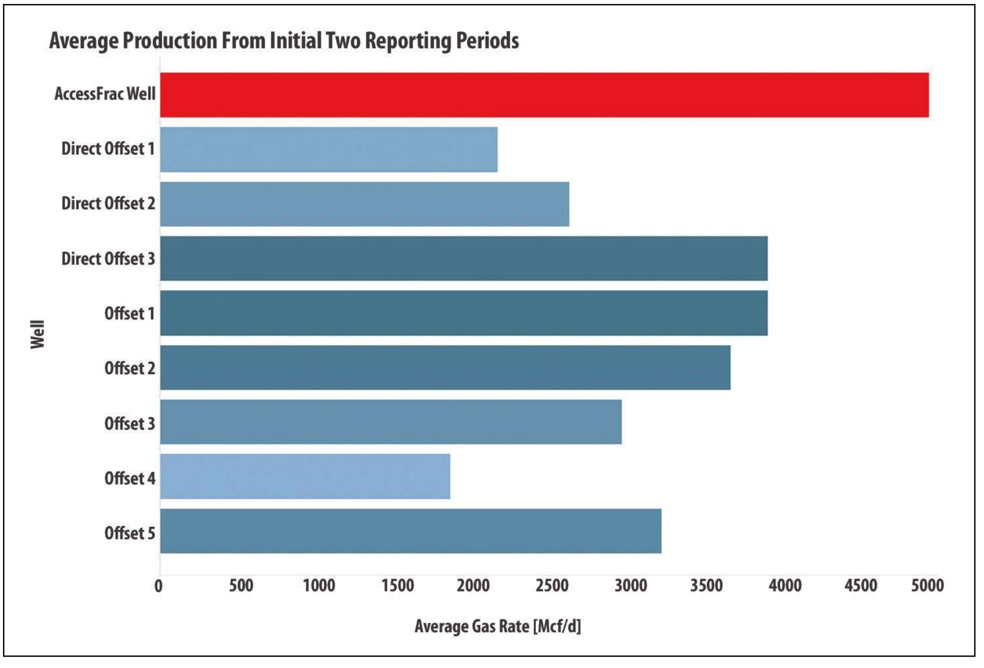

FIGURE 1. Average daily gas production rate for the rescue well that used the AccessFrac RF to execute a 'perf-n-plug' technique is compared to neighboring offsets. (Source: Halliburton)

Stimulation technique used in Marcellus

A horizontal well in Lycoming County, Pa., was drilled to access the Marcellus Formation. After completing the first stage of hydraulic fracturing in August 2012, the operator discovered a failure in the heel of the production casing and elected to run a casing patch to remedy the situation. The inside diameter of the casing patch was too small for standard isolation plugs to pass through it. Without a new approach it was unlikely that effective stimulation coverage of the lateral could be achieved, and the operator faced the possibility of an uneconomical well. The challenge was to provide effective zonal isolation along an entire lateral without the use of mechanical plugs so fluid and proppant could be distributed evenly across all of the planned perforation clusters.

'Perf-n-plug' process

Halliburton's solution was to apply a novel stimulation technique enabled by advancements in diversion technology. The technique is sometimes dubbed "perf-n-plug"—not to be confused with plug and perf (PNP), which uses a bridge plug to isolate each fracturing stage. In the perf-n-plug technique, after a fracturing stage, only the perforation guns are pumped down for the next stage and no plug is set. Instead of relying on a mechanical isolation plug to separate each stage, a newly engineered diversion process is executed on the front end of the following fracturing stage to plug the stimulated clusters from the previous stage. This provides isolation for the new zone, and the next stage is then pumped as designed through the newly shot perfs. This process is repeated for as many zones for length of lateral as desired.

The new technique was used in early 2013 to complete the remaining length of lateral in the Lycoming County well. Nine stages were successfully pumped, each placing roughly 300,000 pounds-mass (lbm) of proppant in 4,500 bbl of fluid. This technique can be employed any time a reduction or elimination of fracturing plugs is desired.

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Strong pressure responses along with effective formation breakdowns on each of the new stages were seen. After the well was successfully completed using the new service, another benefit became apparent: no plugs to drill out. The new well rescue technique saved completion and drill-out time and provided superior well performance compared to conventional PNP offsets (Figure 1).

Unconventional refracturing

In recent years, advancements have led to dramatic progression along the learning curve in designing wells and fracturing treatments for the most efficient reservoir drainage. This has left many wells that were completed early in a play's development understimulated when compared to the more recent progressive strategies. The recent aim of most operators has been to increase reservoir contact area with an optimal number of conductive transverse fractures or access points that intersect the wellbore. Trends to better accomplish this have been to reduce cluster spacing (RCS), shorten stage lengths and increase proppant pumped per foot of lateral. In addition to a desire to "catch up" to present-day progressive designs, some wells observed low cluster efficiency in primary completions; this often leaves areas of the reservoir ineffectively stimulated. Most diagnostic studies have shown that on average only 60% of the clusters are significantly contributing to production. This means that thousands of existing wellbores in most unconventional plays have vast stranded hydrocarbon reserves in existing perforation clusters that did not receive effective stimulation initially.

A successful refracturing program can have big economic and asset implications for field development and thus is economically and environmentally appealing because treatments involve reusing the existing wellbore. Additionally, permitting issues, pad construction, rig moves, pipelines and several other operational issues can be eliminated when production can be enhanced using an existing wellbore.

Due to their unique attributes, it appears that most unconventional multistage horizontal wells are going to be potential restimulation candidates at some point in their life, particularly those completed early in a play's development that are deemed to have been understimulated or are underperforming.

Refracturing also provides the ability to go back in time and apply the current optimized methods to the old wellbore. This means a well remediation opportunity to clean out the wellbore, diagnose any scaling issues and optimize drainage volume with new formation fluid mobility modifiers to alter wettability and optimize interfacial chemistry as part of the refracturing program.

Marcellus refracturing

CONSOL Energy's GH-15 is a horizontal well drilled in Greene County, Pa., with a 556-m (1,825-ft) lateral targeting the Marcellus Shale Formation. During the original completion in September 2009, the rig encountered casing-to-bottom issues, leaving a roughly 396-m (1,300-ft) openhole section past the toe of the production casing. The original completion included typical slickwater fracturing treatments through three sliding sleeve ports

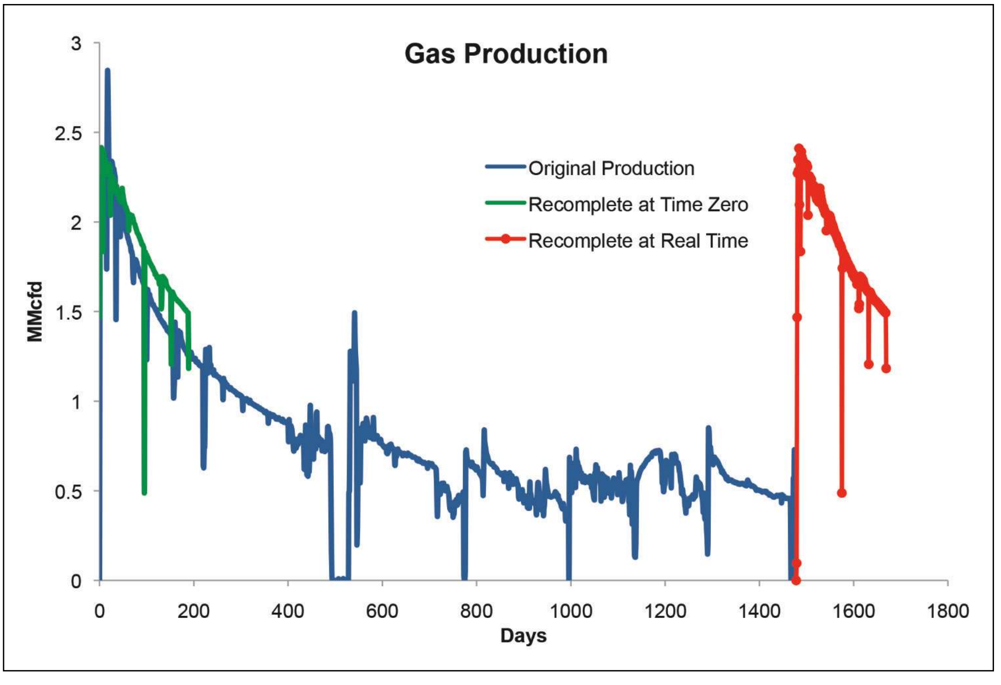

FIGURE 2. Daily production of the CONSOL Energy GH-15 well is seen. An AccessFrac RF treatment was performed after just under four years of being online. The refracturing uplifted production in line with the original completion and added 59.5 MMcm in incremental EUR. (Source: Halliburton)

spaced roughly 137 m (450 ft) apart. Due to the completion complication scenario encountered and the current fracture spacing, the well was deemed understimulated compared to current evolved stimulation designs and techniques. It was clear that refracturing potential existed. The challenge would be to effectively stimulate the openhole section as well as add newly optimized perforated zones within the cased section and initiate dominate fracture geometry at each one.

In October 2013, an AccessFrac RF treatment was performed. To start out on the refracturing, the two upper sleeves were closed, 72 perforations were added at the toe of the casing and six discrete proppant treatments separated by diversion spacers were pumped through the new perfs and the deepest sleeve out of the bottom of the casing into the openhole section. The second phase of the refracturing treatment included setting a plug with coiled tubing (CT) toward the toe of the production casing and adding new perforations with a RCS scheme between the existing ports. This phase was done in two parts that were separated by a bridge plug. The first large perforating run added 11 clusters and 88 perfs, which were stimulated using three proppant treatments. The second CT-conveyed perforating run added 10 clusters with 80 perfs and was again fracture-stimulated through three proppant treatments. A continuous pumping operation was used to stimulate the first phase in the openhole section and then in each of the two new large sets of perforations. To separate each proppant treatment, a specialized diversion spacer was pumped. A total of 12 treatments were pumped placing 1,091,881 lbm of proppant.

The post-refracturing production was in line with the original and has held a slightly shallower decline profile (Figure 2). The production potential also was increased through the refracturing, adding 59.5 MMcm (2.1 Bcf) results, CONSOL has recently applied the service technology to several subsequent wells and has identified more than 200 potential wells to recomplete. E&P

Mooring line monitoring reduces risk of line failure

New system offers FPS operators a way to monitor mooring line integrity from the comfort of the vessel's control room.

Edward Elletson and **Steven Gauthier**,
Pulse Structural Monitoring

The number of floating production systems (FPSs) in operation globally has continued to rise over recent years, reaching around 400 installed facilities in 2014. With E&P activities continuing to move into more isolated locations, this number is expected to grow by a further 50% over the next five years.

Floating installations are subject to a variety of extreme weather conditions, which can have a severe impact on the integrity of mooring systems. Since 2001 there have been almost 30 reported mooring incidents on FPSs, with eight classed as system failures.

Mooring systems on FPSO units are Category 1 safety-critical systems, meaning there are a number of potentially severe human, environmental and economic consequences of a failure. The FPSO vessel *Gryphon Alpha* in the North Sea provides a stark example of the potential financial impact, where reinstatement costs are expected to reach an estimated $1.8 billion for replacement and upgrades to the mooring system and subsea infrastructure.

For these reasons, greater attention is being placed on mooring line integrity management (IM) practices as a means to maintain system condition and operational integrity, particularly since FPSO units are increasingly expected to remain on location for longer periods. Historically, these practices have focused mainly on inspection and maintenance, with an emphasis on limiting interruption to production. However, as the demand has risen for more regular and complete information on mooring integrity, monitoring systems have become an increasingly standard feature of IM strategies on FPSs.

Mooring line monitoring

Monitoring systems provide an effective and reliable method to accurately assess mooring line fatigue. Most monitoring systems either use load cells to directly monitor tension or use inclinometers to measure line angle

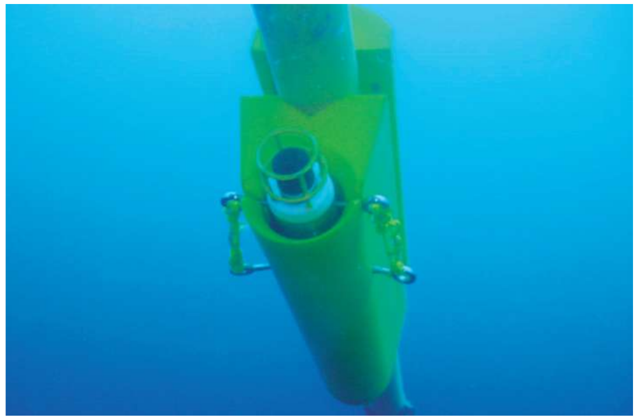

FIGURE 1. The INTEGRIpod acoustic data logger is installed on a mooring line. (Source: Pulse Structural Monitoring)

and infer tension using lookup tables that have been established using the catenary equations of the mooring line. These systems provide two main benefits:

- A record of tension history-monitoring can help derive the range of loads imposed on the mooring line together with their frequencies. Long-term averaged tensions can be compared to initial mooring line pre-tensions to indicate any system deterioration; and
- Early warning of line failure-monitoring allows any failure of mooring line components to be identified immediately without awaiting the results of planned inspection activities. This early warning reduces the risk of component breakage turning into a system failure.

One option to monitor mooring line tension is to install a system that uses inclinometers to measure mooring line angle that can be converted into tension using lookup tables. The main advantages of this method are that it requires fewer or possibly no design requirements and constraints for the FPSO mooring system and can be retrofitted to existing FPSO units on station. The monitoring system is designed so that the devices are not in the load path, allowing ease of maintenance. The system components can be replaced without requiring

anchor leg tensions to be relieved, and—if required—each mooring line can be retensioned without having to relocate the sensors.

Case study: FPSO unit in South China Sea

The South China Sea is a region where typhoons are frequent, leading to a number of mooring failures in recent years. The mooring system comprises nine mooring lines bundled in three sets of three, 120 degrees from each other around a single-point mooring buoy, making the FPSO vessel naturally weathervaning. Each mooring line is composed of chain and wire segments with clump weights on the upper chain section to reduce offsets and extreme line tension. The mooring system is designed for a 25-year service life and to withstand a 100-year typhoon condition. The FPSO unit is moored in more than 90-m (295-ft) water depth.

The monitoring system provided is a fully diver-installable mooring monitoring system using inclination measurement. The vessel had been on station for five years and required equipment retrofit. Acoustic communication is used to relay data to the control room to avoid the use of cables, which can become trapped and severed during subsea intervention.

Equipment

The main components of the system used on the FPSO unit include the INTEGRIpod motion data loggers, acoustic data acquisition units (DAU) and software. Nine acoustic INTEGRIpod data loggers were deployed—one on each mooring line—that communicated to two DAUs installed underneath the FPSO vessel hull (Figure 1). Each data logger communicated with either of the acoustic receivers. The INTEGRIpods are attached to the mooring lines using diver-installable holders. These holders have two design priorities: special coating to resist marine growth and allow simple diver-deployment and removal of logger throughout operational lifetime.

The DAUs are mounted on the underside of the FPSO vessel hull using specially designed magnetic holders (Figure 2). This ensures that communication can be achieved with the INTEGRIpods regardless of FPSO unit orientation and position. The design of the DAU magnetic holder takes into consideration both the ease of diver installation and retrieval and also system durability throughout operational lifetime. Acoustic communication means cables can be avoided along the mooring line, which minimizes risk of system failure. However, cables are used to transfer data from the acoustic receiver to the control room. Magnetic clamps are used to attach the cables along the vessel hull, creating a fully diver-installable and -retrievable system and allowing communication between the subsea equipment and a real-time mooring monitoring software installed in the control room.

Data are transferred to a standard personal computer in the control room running MoorASSURE mooring line monitoring software. Two 200-m (656-ft) cables are run from the turret to the control room: one for power supply and one for data transfer. The software carries out a number of tasks, including the conversion of angle data into tension using a software model of each of the mooring lines, and also presents historical tension and angle data, providing operators with detailed information about the mooring system performance (Figure 3).

The software also allows system configuration to specify the regularity of data communication. The data loggers are programmed to measure data for 15 minutes every six hours and communicate these data once a day. Using the software, the operator can alter this regularity to either increase or decrease the number of communications. In this case study, the operator increases the frequency of communication during typhoon events to give a more accurate indication of the condition of the mooring lines and tensions. The software also can use the measured data to generate monthly and yearly reports on the integrity of the mooring system.

System deployment

The monitoring system was installed in the first half of 2013. A diver support vessel was used for the subsea installation of the data loggers, acoustic receivers and subsea cable. Because this is a retrofit application, the vessel and subsea equipment (which had been installed for more than five years) had accumulated marine

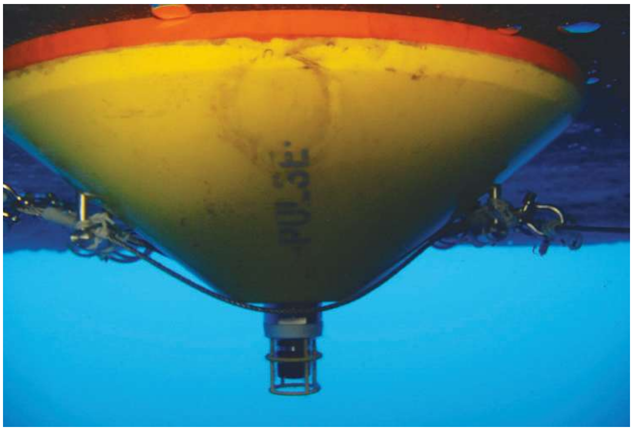

FIGURE 2. The acoustic receiver is installed to the underside of the FPSO vessel using a magnetic holder. (Source: Pulse Structural Monitoring)

growth that could have affected the efficiency of the magnetic and mechanical interfacing. This meant that before installation could begin, the mooring lines, underside of the hull and cable routes all had to be cleaned of marine growth using a high-pressure jet hose. Careful consideration was given to the design of the cable installation. A drag force calculation using location-specific current data and the coefficient of friction of the hull was done to determine the magnetic force required. Since installation, the system has witnessed several typhoons. All magnetic interfaces are still attached, and the system continues to deliver accurate data.

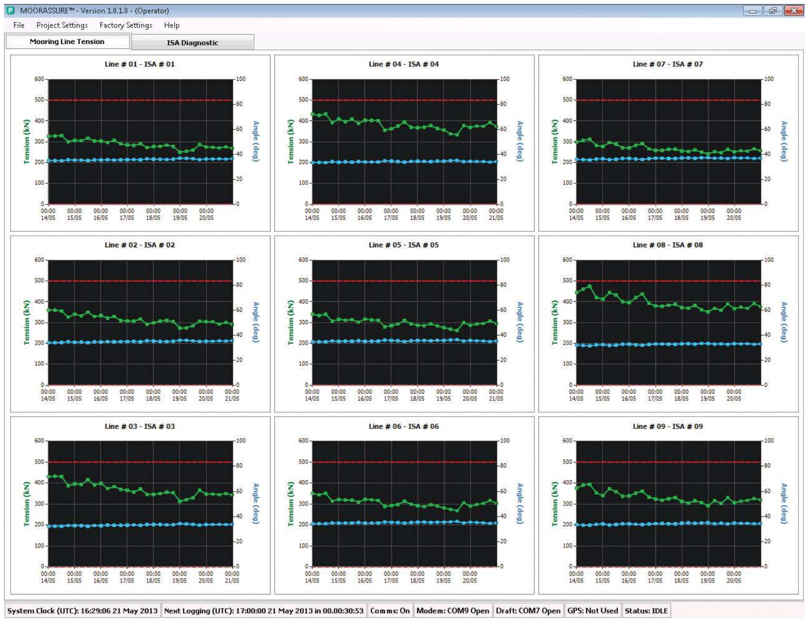

FIGURE 3. This MoorASSURE software screenshot shows an example of the angle and tension readings on each mooring line. (Source: Pulse Structural Monitoring)

Mooring line failures are a very real threat in all offshore oil and gas producing regions. The cost of failure can be substantial. However, the cost of mooring failure is not just measured in financial terms, with reputation, the environment and personnel all potentially at risk. Mooring line monitoring systems provide offshore personnel with reliable data on mooring line integrity, allowing informed decisions to be made. E&P

Advances in modeling methods support moorings and risers

New numerical and physical modeling methods help ensure reliability in design of ultradeepwater moorings and risers.

Alex Argyros, DNV GL - Oil & Gas

According to the International Energy Agency "World Energy Outlook 2013," in 1990 the contribution from deepwater (defined as in excess of 400 m [1,312 ft]) exploration was 60 Mbbl/d. In 2012, this rose to about 270 Mbbl/d (6% of all worldwide crude). The projections for Brazil are that by 2035, 11% of conventional crude will be produced from deepwater fields. This rapid demand for deepwater field development presents an opportunity for large returns on investment but at the same time high technical and economic risk as the industry ventures into new territories.

Publications at the 2014 Offshore Technology Conference on the survey of past failures, pre-emptive replacements and reported degradations for mooring systems of floating production units show a persistence of high annual rate of mooring line failure (per year, per facility) over the last 15 years, with more than a third of failure events occurring between initial installation and the third year of operation.

Mooring incidents occur due to poor mooring integrity management such as a lack of in-service inspection and/or structural monitoring. Additionally, line failures occur due to lack of design analysis and testing, especially when innovation is introduced to the design process. DNV GL, in collaboration with Cambridge and Strathclyde universities in the U.K., has developed more innovative means of modeling ultradeepwater mooring and risers.

Ultradeepwater model-scale tank-testing

Model testing is primarily needed as proof of concept. It confirms the assessment of hydrodynamic loads on the vessel and can be used to verify assumptions. It is used to validate/calibrate numerical models (loads, motions and line tensions) and can reveal unexpected and/or highly nonlinear phenomena such as wave steepness, slamming, run-up and vortex-induced vibrations. It is particularly important for assets with high strategic importance and when innovation such as new technology, vessel concept or territory is introduced. The challenges with ultradeep water are that numerical time domain models have long simulation times due to the large number of line elements. Subsequently, design optimization is limited, and tank testing of the complete system at conventional model scales is not possible due to depth limitations in wave tank basins.

This issue was addressed through the DeepStar and Verideep joint industry projects (JIPs), where line equivalence (or truncation) was developed.

The hybrid verification approach (Figure 1) uses an equivalent numerical model at reduced depth, which then uses a conventional model scale for tank testing

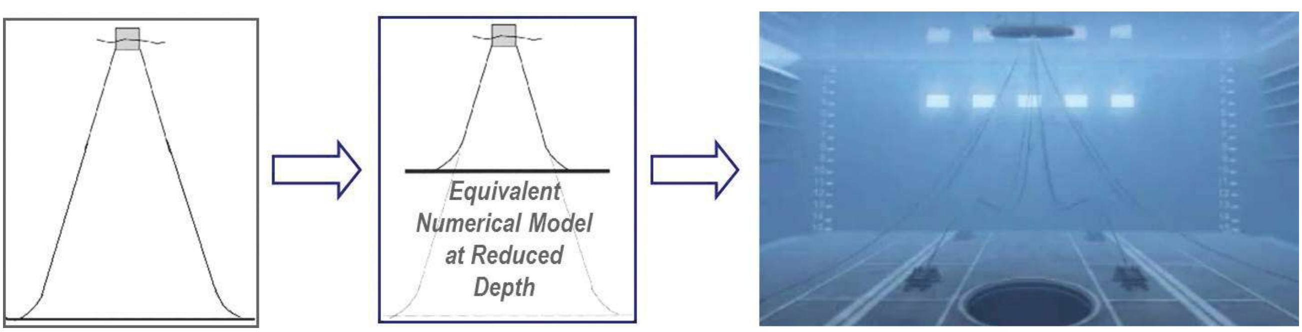

FIGURE 1. The hybrid verification approach uses an equivalent numerical model at reduced depth, which then uses a conventional model scale for tank testing followed by a model-the-model stage to calibrate the numerical model and extrapolate to full water depth. (Source: DNV GL – Oil and Gas)

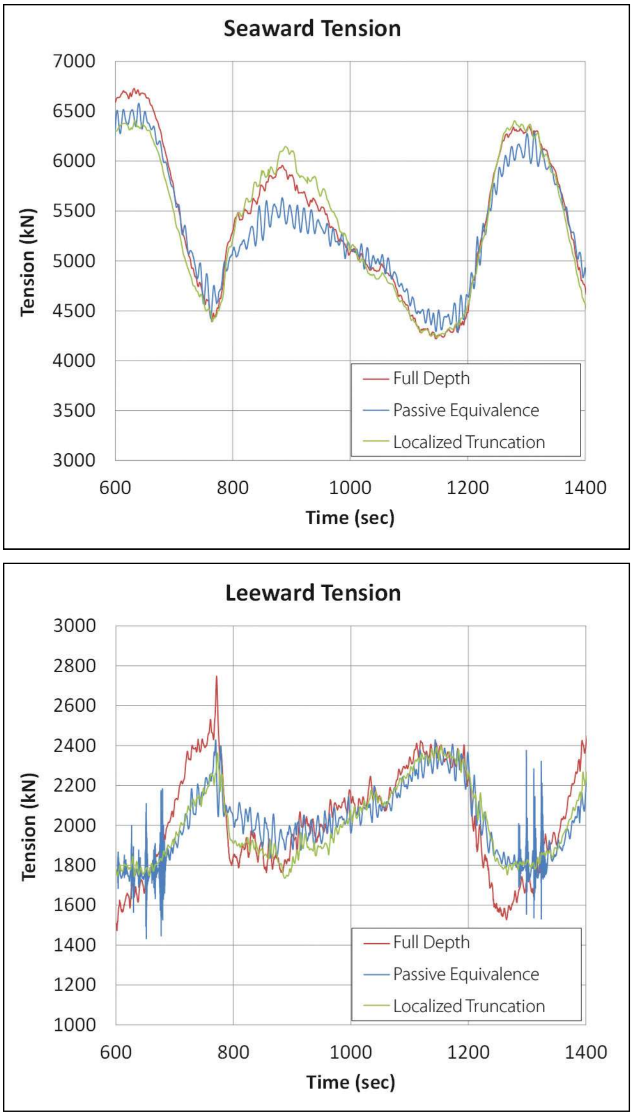

FIGURE 2. Numerical analysis of a four-line spread moored semi-submersible in violent storm conditions showed that the system response (motions and mooring static/dynamic tensions) of the localized truncation model matches the response of the system in full depth. In contrast, the truncation model based on line equivalence has a poor estimation of line dynamics. (Source: DNV GL – Oil and Gas)

followed by a model-the-model stage to calibrate the numerical model and extrapolate to full water depth. This work has proven model scale equivalence for certain systems such as taut leg moorings. The method for setting up the equivalent mooring system is primarily based on a mooring/riser system that replicates the static characteristics of the full depth system using an optimizer to preserve the line geometric properties. This is referred to as a passive-equivalence model, which generally leads to model test data that poorly reflect line dynamics (tension and damping).

With increased water depth and number of moorings and risers, coupling between vessel motions and line dynamics will increase. This renders the importance of developing truncation approaches for ultradeepwater moorings and risers that reflect not only the quasi-static performance in full scale but also the dynamic performance as closely as possible.

Work at Cambridge University has developed a methodology that drives the truncation based on the expected mooring line dynamics rather than the static response. The equivalent numerical model is set up at reduced depth by modeling the upper sections of each line in detail, and these terminate to an approximate analytical model that represents the rest of the line.

The analytical model is a simple spring-damper model that could be confidently replicated in a test basin. In such an approach, the truncation point (where to "cut" the line) is key, and this is based on a minimum truncation length criterion below which the transverse response of the line is inertia-dominated. Figure 2 shows some results of mooring line tension for an example case study with both truncation schemes applied (passive equivalence and localized truncation, Cambridge approach).

Technical innovation only covers one aspect for successful ultradeepwater model tests. As identified in DeepStar, further effort is required to provide guidance for when to test and what type of truncation is suitable, dealing with uncertainty in the two-step process and to improve model test schedule efficacy. To this end, DNV GL is looking to launch the DeepTest JIP that aims to develop a complete set of model test guidelines that the offshore oil and gas sector can work to when designing floating production systems in ultradeep water.

Mooring damping

In related work at Strathclyde University, the effect of line dynamics on mooring system damping is studied in a general way using numerical analysis. It shows that for a turret-moored FPSO unit, wave frequency motions will dramatically increase the mooring system's low-frequency damping. This is because energy dissipation, which is mainly caused by fluid drag opposing the transverse motion of the line, is greatest close to the seabed for a semi-taut or catenary mooring configuration due to the geometric coupling of axial and transverse vibrations. These dynamics are highly sensitive to the period and amplitude of the wave frequency motion at the top.

This work also emphasizes the importance of having a reliable estimation of the drag coefficient (Cd) for chain located at depth. Operationally, this means having accurate predictions of marine growth by monitoring and comparing the observed drag diameter with values assumed in the analysis to ensure there is sufficient margin to allow uncertainty in the marine growth prediction methods.

Strathclyde has studied the sensitivity of Cd using coupled analysis of a turret-moored FPSO vessel in hurricane conditions and revealed that an increase in Cd by a factor of two reduced vessel motions by about 40% but increased total tension by up to 20%. This forms the motivation for the second theme of research at Strathclyde—using computational fluid dynamics (CFD) to estimate Cd for chains.

Flow past a smooth cylinder is first considered to validate the CFD model against published experimental data. The CFD model of the chain consists of one full link and two half-links modeled using periodic boundary conditions, and the domain is defined with no slip walls, inflow/outflow boundaries and symmetry of lateral sides.

For the case of steady flow past the chain links, the analysis showed that flow direction does not impact the estimation of Cd and that DNV-RP-C205 recommended values provide a good average over a large range of Reynolds number (Re ~ 10^4 to 10^6). For the case of oscillating chain in still water, the analysis showed that Cd can vary up to 30% depending on the Kuelegan Carpenter number for flow with low Reynolds number. Such a variation in Cd will impact the calculation of extreme tension and therefore provides motivation for future work to analyze Cd values for chain in oscillating flow.

As industry engages in operations in increasing water depths, it becomes more important for operators to fully understand riser and mooring system design limitations.

Technology developments are progressing at a rapid pace to adapt to the new environments encountered in ultradeepwater locations. It is therefore important that modeling methods, both numerical and physical, keep pace to assess the reliability of the floating production system with confidence at the design phase. E&P

Utica gas production expected to grow

The Utica play kicks into second gear as operators begin expanding into other counties.

STAFF REPORT

The Utica is starting to step out of the shadow of the Marcellus as technology continues to improve EUR, wells in the play exceed gas production expectations and operators commit increased budgets to the area.

The Utica Shale is a black, calcareous, organic-rich shale of Middle Ordovician age that lies in portions of Ohio, Pennsylvania, West Virginia, New York, Quebec and other parts of eastern North America. The Utica Shale is located beneath the Marcellus Shale, and both are part of the Appalachian Basin, which is the longest-producing petroleum province in the U.S., according to a 2012 U.S. Geological Survey report. The report also said the Utica Shale contains 1.1 Tcm (38 Tcf) of undiscovered, technically recoverable natural gas and has an average of 940 MMbbl of unconventional oil resources and an average of 208 MMbbl of unconventional NGL.

Moreover, gas production for the Marcellus and Utica Shale is expected to grow to 963 MMcm/d (34 Bcf/d) by 2035, compared to 708 MMcm/d (25 Bcf/d) projected in first-quarter 2014, according to ICF International's second-quarter 2014 Detailed Production Report. "Utica wells are 'more gassy' than initially expected; therefore, gas production growth from the Utica wells is expected to be much greater," the report said.

In addition, improvements in drilling and hydraulic fracturing technology continue to increase EUR per well. "Recent well statistics reported by producers suggest that newer wells have longer horizontal laterals and more fracture stages," the report stated. Furthermore, "gas EUR in the Utica is projected to average 93 MMcm [3.3 Bcf] per well compared to 70.8 MMcm [2.5 Bcf] per well in the last quarter report," the ICF report said.

The Utica had a slower start than the Eagle Ford and Marcellus shales in gaining industry momentum, partly due to a slowing, grinding economic recovery after the Great Recession. Comparisons with the two plays are only natural: the Utica is similar to the Eagle Ford in having a condensate/wet gas window, and it is in the same neck of the woods as the Marcellus.

Gulfport Energy Corp. is using science to unravel the optimum development strategy for this play, said Stuart Maier, vice president of geosciences at the company. (Photo by Heather Heindel)

The play seems to have kicked into second gear, however, when operators started expanding into other counties in 2013 that previously had not been considered the "core," although they were in the fairway.

For example, operators increased well completions in 2013 vs. 2012 in Belmont, Guernsey, Mahoning, Trumbull and Washington counties in Ohio. These counties continue to attract operators such as PDC Energy Inc., Rex Energy Corp. and Hess Corp., which all announced an increase in 2014 capital allocation for the Utica.

Meanwhile, the majority of Ohio's core counties—Carroll, Harrison, Monroe and Noble—experienced a decrease in wells coming on production in 2013 vs. 2012. Despite the year-over-year decrease in tie-ins, most of the operators that drill in these counties also have announced increases to their 2014 Utica budgets.

Overall, the state of Ohio has reported about 1,230 horizontal permits issued since the play's inception, beginning in 2010. The state's fourth-quarter 2013 report shows 397 wells within the play, with 352 reporting

Company	1Q14 Well Count	1Q14 Total Production Mboe	1Q14 Total Production MMcme	1Q14 Production/Well Mboe	1Q14 Production/Well MMcme	% Wet Gas
Eclipse Resources	2	200.1	34.0	100.0	17.0	96%
XTO Energy	2	171.0	29.1	85.5	14.5	96%
Antero Resources	24	1,617.1	274.8	67.4	11.4	77%
HG Energy LLC (acquired by American Energy)	6	360.2	61.2	60.0	10.2	100%
Gulfport Energy Corp.	50	2,674.5	454.4	53.5	9.1	89%
Hess Corp.	13	576.1	97.9	44.3	7.5	92%
Carrizo Oil & Gas Inc.	1	44.3	7.5	44.3	7.5	0%
Hall Drilling LLC	3	131.1	22.3	43.7	7.4	100%
R E Gas	16	579.8	98.5	36.2	6.2	85%
Chesapeake Energy	247	6,159.9	1,046.6	24.9	4.2	86%
Hilcorp Energy Co.	2	46.3	7.9	23.2	3.9	100%
Chevron	2	44.3	7.5	22.2	3.8	52%
PDC Energy	13	256.9	43.6	19.8	3.4	44%
Magnum Hunter Resources Corp.	2	33.2	5.6	16.6	2.8	98%
Atlas Noble LLC	5	73.3	12.5	14.7	2.5	45%
EQT Corp.	3	29.8	5.1	9.9	1.7	64%
Halcón Resources	6	56.3	9.6	9.4	1.7	72%
CNX Gas	9	68.2	11.6	7.6	1.3	84%
Anadarko Petroleum Corp.	5	30.3	5.2	6.1	1.0	80%
Enervest	3	14.1	2.4	4.7	0.8	65%
Brammer	1	1.7	0.3	1.7	0.3	58%
BP Plc	3	4.7	0.8	1.6	0.3	77%
Total	**418**	**13,173**	**2,238**	**Avg: 31.5**	**Avg: 5.4**	**84%**

The table shows first-quarter production data in Ohio. (Source: Ohio Department of Natural Resources; Topeka Capital Markets)

associated production results, as the remaining wells are waiting on infrastructure tie-in.

Utica Shale moves south

The Utica Shale play, long concentrated in Ohio, could be most prolific in West Virginia, according to a report from Topeka Capital Markets. The report, which culled first-quarter production data from the Ohio Department of Natural Resources (ODNR), said the play in Ohio was moving south and east toward the Mountain State, where the greatest upside could be in the gas window of the play.

"Based on the data, the most prolific portions of the Utica Shale continue to be in the gassier areas closer to the West Virginia and Pennsylvania borders," according to the report. Specifically, the core of the dry gas Utica appears to be in Monroe County in Ohio and in Wetzel, Marshall and Tyler counties in West Virginia, according to Topeka. This means West Virginia wells could see IP rates of 849.5 Mcm/d (30 MMcf/d) to 1.4 MMcm/d (50 MMcf/d) and EURs of 424.8 MMcm to 708 MMcm (15 Bcf to 25 Bcf) and higher, according to Topeka.

Citing ODNR data, Topeka found that total first-quarter 2014 production volumes were up 52.7% over the previous quarter, with the bulk of production coming from the Utica and Point Pleasant zones. The best Utica well belonged to Magnum Hunter and produced 625.8 Mcm/d (22.1 MMcf/d) over an eight-day period. This was the same well that Magnum Hunter had previously said produced about 424.8 Mcm/d (15 MMcf/d) over 45 days.

Total first-quarter production in Ohio was 2.2 Bcme (79 Bcfe).

Tackling optimum development

The Utica is the oldest active major shale play in North America. Eastern Ohio was once a shallow, warm-water shelf environment with early marine life forms that generated all T-I and T-II kerogens, which are the best organic materials and make up the Utica-Point Pleasant shales, said Stuart Maier, vice president of geosciences at Gulfport Energy Corp.


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Speaking at Hart Energy's DUG East Conference June 4, Maier described the depositional environment for the shale. "It was isolated, pretty much closed in, oxygen-starved and not a lot of circulation. [Being oxygen-starved] is really key to the preservation of organic matter for subsequent burial and thermal maturity."

Gulfport and other operators are using science to unravel the optimum development strategy for this play. They are working hard to answer the biggest questions in optimizing development in the Utica-Point Pleasant shales: frack design; well spacing, lateral length and lateral orientation; and production rates.

"These are all dependent variables. I'll emphasize that you can't look at one variable without looking at the others. These are all interrelated. The result of that is this is a very complex problem. You have lots of data that go across disciplines," he explained. "All the working disciplines—engineers, geologists and petrophysicists—have to work together to answer these questions."

The key factors for the Utica-Point Pleasant shales are shallow, warm waters and multiple sediment sources that were oxygen-deprived. For the multiple sediment sources, there were clastics coming in, carbonate debris coming in and the deposition of organic matter, Maier said.

"Couple that with rising and falling sea levels, and you've got interbedded sand and shale sequences both macroscopically and microscopically," he added.

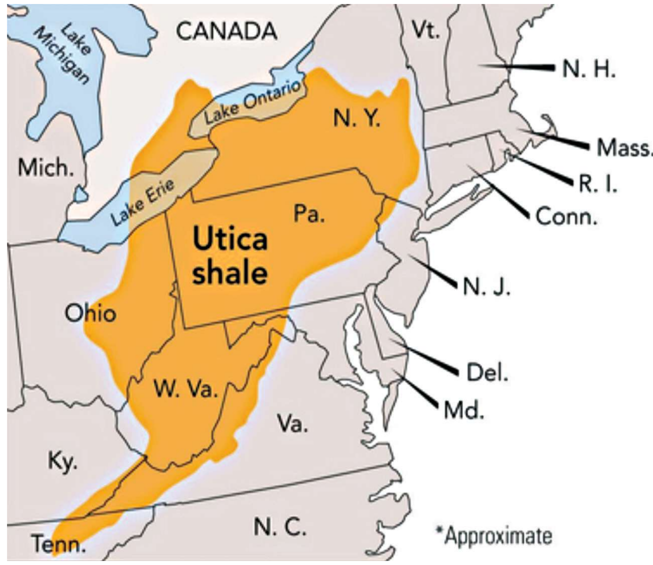
In describing a photograph of cores, he pointed out that macroscopically the cores are extremely stratified with respect to the major rocks. Even on a microscopic level the cores are stratified, with fossil debris sitting on top of detritus that is on top of carbonate fossils.

In looking at the mineralogy of one of the shales, there are carbonate grains, some fossil debris, quartz grains and dark areas that are basically organic matter with a little bit of clay. He emphasized that there is a tremendous amount of organic matter. The nature of these organic particles is important on a micron scale.

"The pore network for the Point Pleasant is primarily in the kerogen particles, which create the network," Maier said. "The spaces are about two microns across. Looking at various sizes of pore throats compared to the approximate size of the largest molecule of oil shows plenty of room in the pore spaces.

"What the organic pore network looks like is a very small, delicate selection of pore throats that form the network," he continued. "These are very well-connected. The network does have high tortuosity and very restricted flow, which are challenges.

"Gulfport entered the play in late 2010 and on a leap of faith stepped into it. So far it has paid off. Currently, we have 179,000 net acres in the play and seven active drilling rigs," Maier said.



The Utica Shale includes portions of Ohio, Pennsylvania, West Virginia, New York, Quebec and other parts of eastern North America. (Source: Baker Hughes)

Although the company has some of the highest IP rates in the play, it has a long way to go to determine the optimum frack design, lateral length and spacing.

"What we're doing to address this is on our Darla pad, where we've constructed a geomodel. We are going to do microseismic when we frack the wells and run chemical tracers. We've run optic fiber along the outside of the casing on three of the wells to monitor fluid flow. We are also going to run some production logs to see how the various zones contribute," Maier explained. "The three Darla wells are built in a fan pattern to really monitor the effect of well spacing along those laterals."

The well pad will be used to identify where each cluster is located in the Point Pleasant, monitor the frack job with fiber optics and see how many clusters per stage are effective. One of the variables the company looks at is the kind of rock where the frack is initiated.

"We will monitor the frack jobs of one of these wells to see which perf clusters take fluid. That is one of the big questions—what is your perf cluster efficiency? How many perf clusters and stages are you effectively treating?" he asked. "We should be able to find that out."

In the Utica, the company expects to drill about 80 wells in 2014, which is about a 25% increase over 2013. Gulfport is still very early in the play and has a lot of work left to do and a lot of science yet to gather. E&P

Water treatment system enables flowback reuse

Reusing produced and flowback water in hydraulic fracturing operations is transforming the industry's biggest waste product into a resource while also reducing the environmental footprint.

Morgan McCutchan, Baker Hughes

It has been more than a decade since the oil and gas industry cracked the code that launched the North American shale boom. Along the way, breakthrough technologies have helped operators overcome a multitude of barriers to produce fields more efficiently, economically and safely while reducing the environmental footprint.

One of the biggest challenges confronting producers centers on what is arguably shale production's greatest enabler: water. The tremendous amount of water needed to fracture a well and the subsequent issues and costs to transport and dispose of it have prompted companies to consider solutions for reusing, recycling and reclaiming this precious resource in ways that make both economic and environmental sense. Reusing produced and flowback water in hydraulic fracturing operations is proving to be a win-win proposition, transforming the industry's biggest waste product into a resource, with the added benefit of reducing the environmental footprint.

Baker Hughes' water management service uses environmentally preferred chemistry to effectively treat and clean produced and flowback water for reuse. The process has been essential to use in the prolific shale plays because the logistics of trucking and disposing of wastewater have become increasingly more difficult. The system has proved beneficial in helping the operators reduce their demand for freshwater and has improved field economics by significantly lowering trucking and disposal costs.

Situated in the expansive Appalachian Basin along the eastern U.S., the Utica Shale gas play spans through nine states and Canada; however, production is expected to be most prolific in Ohio, West Virginia, Pennsylvania and New York. The Utica play accounts for a significant share of the basin's oil production, which between 2012 and 2013 increased nearly 95%, according to a June 2014 Southeastern Ohio Oil & Gas Association Gas Committee Report. Extracting gas from the Utica requires large amounts of freshwater from lakes, rivers and streams that is either stored in nearby impoundments or in some cases trucked from a water source, posing safety and cost issues.

A typical Utica Shale well fracturing operation can use on average 19 MMl (5 MMgal) of water, and roughly 15% to 20% of that—between 2.8 MMl and 3.8 MMl (750,000 gal and 1 MMgal)—flows back to the surface. Managing this flowback water is challenging for a variety of reasons, including disposal and how to treat contaminants.

When it comes to the Utica Shale play, the majority of the wells being drilled and completed are in Ohio. Ohio has numerous disposal wells, but they are not always close to a disposal site, and they have limitations on the amount of fluid that can be transported to them through the lines.

Disposal, trucking concerns

Due to limitations, the wastewater often is trucked by third-party transport firms to saltwater disposal wells (SWDs) at a cost of $8 to $12 per barrel. Trucking poses increased risk of accidents, spills and road damage. In addition, SWDs often face permitting delays, which can postpone drilling new wells that would increase capacity in the area.

Onsite treatment of produced and flowback water in Ohio is stringently regulated. Under requirements of the Ohio Department of Natural Resources, onsite water treatment of produced and flowback water must be carried out in above-ground storage tanks to prevent accidental fluid release.

These challenges have prompted operators to examine various water treatment methods for poor-quality flowback and produced water that is being moved by truck to above-ground storage tanks. Similar to produced water in other shales like the Marcellus, the water often contains significant bacteria, dissolved iron, hydrogen sulfide (H_2S) and iron sulfide (FeS) and also emits an unpleasant odor. All the contaminants limit the water's reuse, and the H_2S presents safety concerns in fluid-handling and hydraulic fracturing operations as well as potential corrosion during production. High levels of iron can break down the friction reducers required in slickwater fracturing operations, and high sulfate-reducing and acid-producing bacteria can contaminate the wellbore.

Typically, several chemical applications are considered and can include liquid biocides that address only some of the contaminants and surfactants for odor control. A common solution is a comprehensive system that uses chlorine dioxide (ClO_2), which is a fast-acting oxidizer used to treat about 30% of U.S. drinking water. The treatment can be generated on site via mobile or permanently mounted generators to treat produced and flowback water in above-ground tanks.

Baker Hughes' H_2prO HD water treatment system neutralizes microorganisms, H_2S, FeS, phenols, mercaptans and polymers in the surface water, allowing the water to be reused for downhole operations with no threat of corrosion and equipment plugging. The treated water poses no reservoir damage or HSE issues, including offensive odors and dangerous fumes, which occur with the presence of H_2S.

The oxidizer system, which has been approved by the U.S. Environmental Protection Agency, uses three common liquid precursors—sodium hypochlorite, hydrochloric acid and sodium chlorite. The automated system is designed with inline monitoring and built-in safety features that ensure the ClO_2 is activated in water only while the vacuum-based generator is running, even if power is lost. By using no more than 3,000 ppm, the system keeps power costs low, further reducing the environmental footprint. A mobile unit can be assembled in about an hour and can treat up to 200,000 bbl/d of water.

Reducing freshwater demand

A key objective for operators in deploying the mobile ClO_2 oxidizer system is to treat produced and flowback water in tanks before it's blended with freshwater for use in hydraulic fracturing operations. For example, a hybrid strategy for one operator was implemented with water in the first impoundment treated on-the-fly as it was being transferred. Water from the other two impoundments received batch treatments in place, which required the impoundments to be thoroughly mixed before, during and after the treatment to reduce the chance of hot spots occurring due to excessive chemical residue. Mixing also ensures that all contaminants are effectively oxidized.

A thorough water analysis was performed on all the source water impoundments prior to treatment to determine the ionic and bacterial composition of the water and the amount of ClO_2 that would be needed for treatment. The source water also was periodically tested during the treatment process, and finished product samples were taken to measure water quality and check for any ClO_2 residue.

About 300,000 bbl of water were treated from the three impoundments. The treatment resulted in an eight-bottle log reduction in bacteria and complete oxidization of the FeS. The process significantly improved the water clarity and eliminated the odor, resulting in a greater percentage of the produced water becoming eligible for reuse. By removing the contaminants from the produced and flowback water, the operator was able to achieve the same hydraulic fracturing formulation typically required for freshwater.

The use of the mobile ClO_2 treatment service delivered multiple benefits to the operator, significantly reducing the costs and risks associated with water disposal and transportation, and it preserved millions of gallons of water already in the impoundments, thus eliminating the need for additional freshwater sourcing.

Ongoing success in the shale plays is dependent on optimizing field and wellbore economics while conducting operations in ways that reduce the environmental footprint. Development of technologies that enable prudent use and reuse of water signifies an important step-change in the industry's ability to confront and overcome extraordinary challenges to the safe and efficient production of hydrocarbons in these important frontiers. E&P

A Baker Hughes water management specialist analyzes water in the field to adjust treatments for variability in the water. (Source: Baker Hughes)

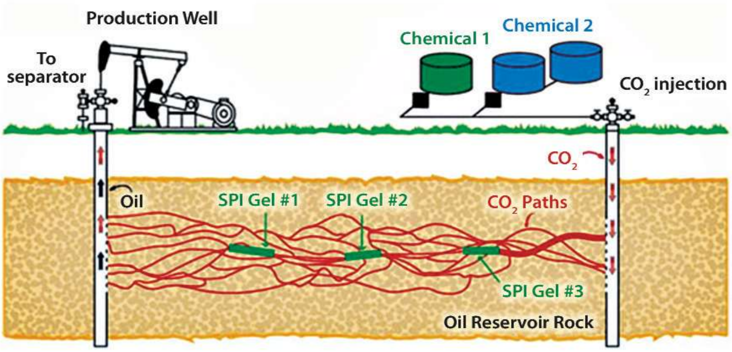
Mobility control for CO_2 EOR using SPI gels

New gels thicken when exposed to CO_2.

Ken Oglesby, Impact Technologies LLC; and **Eric Smistad**, National Energy Technology Laboratory, U.S. Department of Energy

The purpose of performing silica polymer initiator (SPI) treatments in EOR CO_2 floods is to increase oil production and ultimate oil recovery. SPI gels do this by redirecting injected CO_2 away from already swept zones in the reservoir rock with no oil left to recover and into new unswept zones. EOR operations using CO_2 are expensive. Once started, CO_2 will continue to flow through the same oil-depleted zone because of its very low viscosity and high mobility relative to the oil and water in the reservoir. As this process continues, the operation becomes more and more inefficient and eventually becomes too costly to continue. Improving that recovery efficiency by blocking the depleted zone will allow the EOR operation to continue at a profitable level and recover additional oil.

SPI gels are multicomponent silicate-based gels for improving (areal and vertical) conformance in EOR operations, including waterfloods and CO_2 floods, drilling well problems, and other applications. They were originally developed under a U.S. Department of Energy- (DOE-) funded Stripper Well Consortium project in 2006 and have been continuously improved. They are patent pending and are environmentally friendly, containing many food grade components. SPI gels are pumped as a water-like liquid into the oil-depleted zones of the formation and can then be triggered by an initiator (e.g. CO_2) to lower its pH and form light gels up to very thick paste-like gels. SPI gels can be three to 10 or more times harder (per penetrometer tests) than any crosslinked polyacrylamide (PAM) gel now available, allowing it to seal in difficult applications where PAM systems would break down. However, the hardest SPI gel is not as strong as cement or epoxy, allowing it to be chemically washed/jetted and/or otherwise removed from the wellbore without drilling.



CO_2 flows through aqueous SPI in the reservoir to form carbonic acid, which initiates the SPI gelation process. (Source: National Energy Technology Laboratory)

Field testing

This DOE-funded project field-tested a total of eight SPI treatments in six wells (five injection wells and one production well) in a relatively new central Mississippi sandstone under immiscible CO_2 flooding and in a mature west Texas San Andres dolomite under water-alternating-gas/CO_2 (WAG) miscible flooding. The SPI treatment sizes ranged from 130 bbl to 4,349 bbl. Chemical and water buffers before and after the SPI mix ensured that the pre-gelled SPI mix got placed out into the formation before contacting CO_2 and setting into a hard gel.

Clean Tech Innovations' laboratory performed static bottle/beaker tests to improve the SPI chemistry and find new chemicals for easier/lower cost field treatments. Tests also were done on core rock material, brine and crude oil samples from both fields to ensure compatibility in the field tests. Brookfield Viscometer readings showed that even high-concentration SPI gels had viscosities near water at reservoir temperatures. But once set, SPI gels are stronger than commercially available crosslinked high molecular-weight (HMW) PAM gels, allowing use in difficult applications. Additives were developed to prevent significant losses into tighter zones of the reservoir.

Dynamic flow tests in this equipment with Ottawa sand (crushed and sieved to 20-40 mesh) showed permeability reduction from 737 millidarcys to 8 millidarcys, with one low-concentration SPI treatment that was initiated with CO_2. A second SPI treatment reduced that permeability down to only 2 millidarcys. This calculates to residual resistance factors (Frr) of 92 for the first SPI treatment, four for the second treatment and 450 overall for the Ottawa sand. Dynamic testing with Field A sandstone

(at 43 C [110 F]) showed an overall Frr of 123, and with Field B San Andres dolomite (at 41 C [105 F]) the overall Frr was 2,425, both with two SPI treatments.

The overall goal of this program was to test SPI gels in as wide a variety of CO_2 flood field conditions as possible: The tests were successful. The earliest field treatments were in Field A, a central Mississippi sandstone that is about 1,524 m (5,000 ft) deep. The sandstone reservoir matrix has a Dykstra-Parson ratio of 0.97, and there are multiple natural fractures in the area of the SPI-treated wells. It is a fairly new immiscible CO_2 flood with no water injection. Most producers are forced-flow, with a few on artificial lift. These earliest SPI field treatments have lasted for more than a year.

The later West Texas treatments in Field B were in the San Andres dolomite formation, also at about 1,524 m deep. These were in a mature, miscible WAG injection cycle CO_2 flood. There are only eight months of injection and production data available under these variable WAG conditions, which are insufficient to fully evaluate the treatments. Monitoring of this field continues to finalize the evaluations. Both fields had other operational events and offset well work occurring during both the treatment and evaluation periods that complicated the treatment evaluations.

Field A injector Well #1's SPI Treatments of 950 bbl during SPI1 and 3,842 bbl during SPI3 showed:

- 58% CO_2 injectivity reduction, indicating that the injected CO_2 is now going into new, lower-permeable zones/paths. That reduction has lasted for more than one year;
- Increased oil production in five offset/area production wells, totaling about 14,250 bbl over the first year. Offset work complicated this evaluation, and the total impact of the treatment was reduced accordingly. The value of that incremental oil is estimated at $1.283 million (at $90/bbl sold); and
- A reduction in the produced gas/oil ratio (GOR) in five offset producers, indicating a direct operation cost savings and improved CO_2 utilization in the reservoir. Operator A estimated the CO_2 recycle cost to be $3.18/Mcm ($90/MMcf) in Field A "because it is a compression-limited operating environment. The primary value for reducing the GOR is the additional oil resulting from more efficient use of the compressed gas." Redirecting the injected gas should cause long-term benefits of increased oil production.

Field A marginal producer Well #2's SPI2 treatment of 691 cu. m (4,349 bbl) showed:

The image on the left shows an SPI gel with internal initiator. The image on the right shows an SPI gel with CO_2 initiator. (Source: National Energy Technology Laboratory)

- Increased oil production totaling 1,500 bbl; and
- An initial 81% GOR reduction that dropped to 44% and then trailed down to its pre-treatment level by the end of the first year.

In West Texas Field B, data collection is ongoing on 21 offset/area production wells and nine injectors to evaluate the total impact of the five SPI treatments in four wells in the field. To date, results include:

- The four treated injection wells (Wells #3, 4, 5 and 6) showed 23% to 71% reductions in CO_2 injectivity after the treatments;
- One offset production well has shown increased oil production from 28.5 bbl/d to 47.3 bbl/d of oil post-treatment, or a 66% increase, for an incremental recovery of 1,468 bbl, equal to $132,000 for the 90 days monitored;
- One offset production well showed a decrease in water production from a pre-treatment 70 water/oil ratio (WOR) to an 11 WOR; and
- Ten (12 total including the two above) offset production wells show increasing/positive trends that will be monitored for up to one year.

In addition, comparison was made between the SPI treatments and other competing treatments performed in the same fields and, in some cases, in the same wells. Competing treatments included one Marcit treatment, a few Poly-Crystals treatments and many HMW crosslinked PAM treatments. Two wells have direct comparisons to SPI treatments: Field A Well #1 had a Marcit treatment in 2010 that did not change CO_2 injectivity nor impact any offset production wells, and Field B Well #3 had a crosslinked PAM gel treatment, which did reduce water injectivity but not CO_2 injectivity, adversely increasing offset well GOR and gas/liquids ratio and resulting in no incremental oil recovery. However, SPI gel treatments in both fields, and specifically in those two direct comparison wells, showed injectivity decreases and some impact on their offset wells. E&P

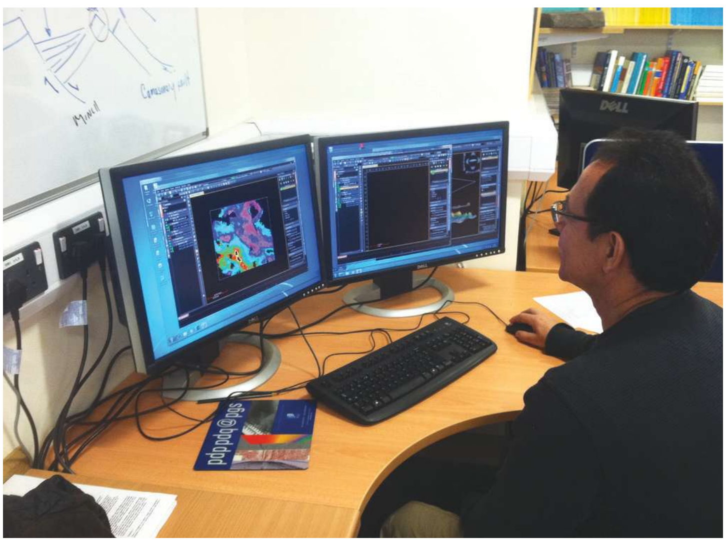
The science behind geoscience decisions

New search tools enable faster workflows.

Phoebe McMellon, Geofacets

The oil and gas industry has seen significant scientific and technological advances since the Drake oil well was drilled in Pennsylvania. In the 1800s, explorers drilled based on minimal surface geological information—i.e., observations of oil seepages. Since the 1920s, however, significant progress in geophysical methods has aided the industry in gaining greater insight into the geologic characteristics and structures that give rise to oil and gas discoveries.

From earthquakes and seafloor spreading to volcanic eruptions and mantle convection, geoscientists can now study the Earth's characteristics and processes with greater precision and depth than ever before. Advances in technologies such as seismic, satellite, magnetic imagery and modeling tools have led to a huge rise in the amount of data generated and available for analysis. At the same time, the industry itself has evolved, becoming far more competitive and budget-sensitive. New technologies that filter and present information more clearly can be the key to gaining an edge.



The Geofacets plug-in for Petrel enables geoscientists to quickly search for maps, articles and other data to aid in their exploration efforts. (Source: Elsevier)

Traditionally, geological information was in the form of physical maps and piles of scientific papers and reports. Geoscientists would sift through maps and associated articles to find important pieces of data and information they needed to fill knowledge gaps in their own proprietary research or validate their analytical interpretations. This was clearly an inefficient and laborious process. With the digital age, many of the physical maps have been transformed into electronic files that can be easily stored and retrieved.

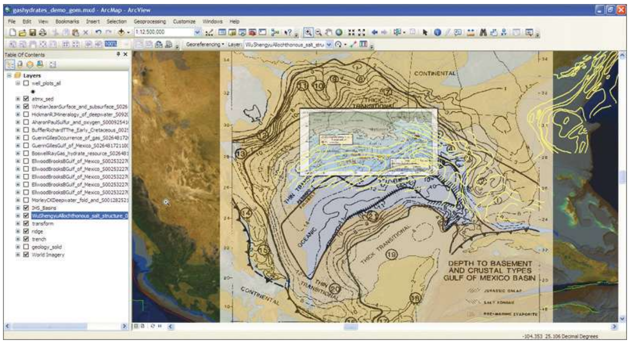
However, as geological information has become more readily available digitally, there is also much more of it to sift through. The issue then becomes one of access and interactivity; namely, how available, transferable and complementary is the information? The answers geoscientists are looking for are not typically found in one place. Putting all of the pieces together requires technological tools to ease the still impressive burden required to integrate this information.

Geoscientists need to be able to combine data from multiple respected sources, including leading journals from scientific publishers and geologic societies. Those journals and societies publish maps and research that deliver insights about the subsurface and provide analogs for comparable exploration along with well and seismic data, industry reports, and 2-D and 3-D models. Additionally, with the looming skills shortage in the oil and gas industry, solutions must be built with ease of use in mind so that even the most junior team member can obtain actionable information without a long and steep learning curve.

With diverse, fragmented exploration teams that need to keep up to date on the latest developments and discoveries, the ability to share information is also key. Finally, usable solutions must perform tasks seamlessly in a single integrated environment. This significantly reduces the burden of switching between multiple platforms and databases, both saving time and reducing the chance of missed opportunities.

Data discovery

Combined, these features would increase confidence in go or no-go decisions and thus lead to more successful



Maps must be georeferenced to allow geoscientists to filter results to only cover a particular location. (Source: Elsevier)

outcomes. Elsevier has made agreements with many of the industry's leading sources of geological data to make their information more discoverable through one tool. Those sources include bodies such as the Geological Society of London, the Geological Society of America, the Society for Sedimentary Geology, the Society of Economic Geologists, the European Association of Geoscientists and Engineers and others.

To make maps usable, these must be georeferenced to allow geoscientists to "filter" search results to only cover a particular location. A user searching potential opportunities in, for example, Central America will be able to see the most relevant geological information and the precise area it depicts. The majority of Geofacets maps are georeferenced and accessed via a simple interface. This kind of automation eliminates painful manual searches, scanning and georeferencing from the geoscientist's workflow. By automating this task, geoscientists can spend more of their time analyzing and making decisions.

In addition to research and maps analysis, the ability to compare those maps and the underlying metadata (and to analyze them alongside 2-D and 3-D models) allows geoscientists to validate and deepen their interpretations providing even greater confidence in their recommendations and decisions. Elsevier recently created the Geofacets Connector for Petrel and Studio, a modeling software. It allows geoscientist users to integrate multiple information streams into one workflow.

By adding geological maps and associated data from the scientific literature to Schlumberger's Petrel E&P software platform, the interpretation environment is unified with regard to structured and unstructured data. It is further unified across geology, geophysics, reservoir modeling and engineering domains, providing the ability to collaborate and share insights and interpretations from early-stage exploration projects to development to production. This is important since it enables geoscientists and businesses to make complex exploration decisions quickly and effectively.

From exploration to development

Geoscientists need to be able to quickly increase their geologic knowledge of a basin or region, especially when little or no proprietary data such as seismic or well data are available. For geoscientists working in new ventures and frontier exploration teams, they must be able to easily find a variety of map types (e.g., geologic, structural, isopach, facies, etc.) and associated data such as cross sections and seismic profiles. These data sources combined with scientific articles allow geoscientists to conduct a quick petroleum system evaluation, helping them identify the potential for a reservoir within a single platform—in the case of the Geofacets Connector, within the Petrel E&P platform.

Take, for example, a new ventures team considering whether to bid for acreage or partner with a company in a new basin with only one to two weeks to make a go or no-go decision. When 2-D seismic lines can cost anywhere from $8,000 to $30,000 per kilometer, Geofacets can provide a solid starting point to gather enough information and gain a significant understanding of the subsurface geology. This supports a quick assessment of the potential existence of a hydrocarbon system, identifying potential high-risk vs. low-risk areas.

Working with Schlumberger to build a petroleum system model of the Orange Basin (off the coast of South Africa and Namibia), Elsevier was able to find several regional geologic and structural maps as well as more than a dozen seismic profiles located in scientific articles.

Those maps were imported and georeferenced into Petrel to identify the existence of a regionally extensive reservoir and potential seal in the target area. In addition, loading additional maps and associated data from the literature via the Geofacets Connector, the existence of source rock and trap was confirmed without spending any money on data acquisition. Of course, the other potential value of such a screening is to target high-potential/low-risk areas where acquiring seismic and/or well data will be well worth the investment.

In many ways, there has never been a more exciting time for the intellectually curious geoscientist. The ways in which geoscientists work and continue to work in the 21st century continue to evolve. With the wealth of content available and the increased availability of analysis tools that help them make sense of that data, today's geoscientists have access to the best of both worlds. E&P

Electronically activated cutter performs without impact or explosives

The Peak eCutter from Peak Well Systems is an electronically activated power-charged nonexplosive cutter for severing slicklines and cables downhole. The eCutter is activated via an electronic timer and trigger module, which makes it suitable for deployment in highly deviated and complex geometry wells, Peak said. Unlike other cutters available, the tool does not rely on impact or explosives. This nonimpact eCutter uses the same cutting technique as Peak's alternative impact-driven Cutter launched last year and offers the same performance of being able to cut all types of industry wire up to 5⁄16-in. heavy-duty Dyform cable. The eCutter also is field redressable. The tool offers activation with a range of preset countdown times. An LED operability indicator located within the tool provides confirmation of controller functionality and timer commencement on surface. The eCutter can be retrieved quickly from the well on the recovered upper section of cable to which it is assembled, enabling the subsurface safety valve to be reinstated and making the well safe until fishing operations can be carried out to recover the lost tools. *peakwellsystems.com*

Thermal imaging cameras detect gas leaks from safe distances

The three new thermal cameras for optical gas detection from FLIR Systems Inc.—FLIR G300a, G300pt and A6604—are used for monitoring gas pipelines and installations from safe distances, FLIR Systems said in a press release. Optical gas imaging cameras are widely used in industrial settings like natural gas processing plants and offshore platforms. They improve efficiency by allowing inspectors to scan wide areas quickly without interrupting normal operations. These new infrared cameras also can play a role in minimizing environmental damage by detecting the unintended emissions of dozens of volatile organic and inorganic compounds. Each model contains a cooled Indium Antimonide detector, which enhances the sensitivity of each camera to detect even the smallest gas emissions. The G300a and G300pt cameras have a resolution of 320 pixels by 240 pixels, while the A6604 has a resolution of 640 pixels by 512 pixels. Each camera can be controlled via Ethernet or integrated into any TCP/IP network. They also are GEV/Genicam compatible. The three new FLIR cameras detect gases including benzene, ethanol, ethylbenzene, heptane, hexane, isoprene, methanol, methyl ethyl ketone, methyl isobutyl ketone, octane, pentane, 1-pentene, toluene, xylene, butane, ethane, methane, propane, ethylene and propylene. *flir.com*

FLIR Systems' three new thermal cameras improve efficiency by letting inspectors scan wide areas quickly. (Source: FLIR Systems)

Sleeves close for multistage completions, production, remediation

NCS Energy Services has introduced a closable version of its GripShift cemented casing sleeve. The sleeve can be opened and closed as needed to provide completion, production and remediation flexibility and control. During completions, the sleeves can be closed temporarily after individual stages to prevent proppant inflow or to permit out-of-sequence fracks. During production, specific sleeves can be closed to shut off thief zones or unwanted water or gas production. For remediation, selected sleeves can be closed temporarily to secure the wellbore above a target zone that is being stimulated. A virtually unlimited number of GripShift sleeves can be run as part of a casing string, giving operators completion flexibility, the company said. The sleeves are operated by the coiled-tubing-deployed Multistage Unlimited frack-isolation tool. They are full-drift at all times, are handled and made up like casing joints, and can be added to the casing string in any order. *ncsfrac.com*

Application aids rapid oil spill response, damage assessments

The CSA GeoPortal application, a secure login-based GeoPortal built and hosted by the CSA Ocean Sciences Inc. GeoSpatial Services business line, provides real-time data and enhances the efficiency of incident responders. It has been used for tasks associated with planning, science and operations for oil spill response. The GeoPortal serves as a tool for streamlining the planning, visualization and coordination efforts of multiple contractors working on a cooperative damage assessment. Specific tasks include enabling the tracking of multiple field teams on small vessels through SPOT real-time communicators; guiding operational decision-making based on observed progress of field teams; and providing an ability to assess transit times to, from and between various study areas to improve field team efficiency, safety and integration. By providing a common frame of reference, the GeoPortal allows team members to store and view project-specific spatial data, including oiling observations over time, sampling designs and sampling results. Spatial data integrated into the GeoPortal also include GPS digital still photographs collected by field teams in airplanes, helicopters, boats and on foot. The availability of these resources in one online location improves communication and understanding among team members regardless of location, according to a product announcement. The GeoPortal provides intake capacity for field data and seamless migration into an enterprise database. This efficiency allows for real-time decision-making to guide incident response decisions. *csawebmap.com*

FROG-XT range of capsules provides a more secure passenger experience during personnel transfer. (Source: Reflex Marine)

Cables comply with European hazardous substances directive

RSCC Wire & Cable's Exane Products Segment has developed a line of Exane-ROHS multiconductor cable products that comply with the European directives for Restriction of Hazardous Substances (RoHS) and Waste of Electrical and Electronic Equipment. The RoHS directive prohibits or limits usage of hazardous materials such as lead, cadmium, chromium and other chemicals. The Exane-ROHS product line has been certified by Intertek Testing Services and is environmentally friendly. The cables are manufactured with ruggedized thermoset insulations and jackets that will not cold flow or deform under pressure. These cables pass the IEEE 1202 Vertical Cable Tray Flame Test at 70,000 Btu/hr, the IEC 60332-3-22 Vertical Cable Tray Flame test, a -55 C (-67 F) Cold Bend Test and the -40 C (-40 F) Cold Impact Test. The Exane product line also released the Exane-TF torque flex cable that allows both twisting and flexing at the same time for installation in bridge rackers and pipe-handling systems on mobile offshore drilling units. The Exane-Profibus cable has been designed with flexible stranded tinned copper conductors selected to withstand the operating conditions found on drilling equipment. *r-scc.com*

Devices improve crane transfer safety for personnel

Reflex Marine's FROG-XT is a range of rigorously tested and verified personnel transfer devices available in four-, six- and 10-person capacities. The FROG-XT is an evolution of the current FROG capsule allowing low- and high-capacity transfers as well as the capacity for all devices to be quickly and easily converted to MedEvac mode to transfer casualties, according to a product announcement. The design features of the new FROG-XT provide greater comfort and a more secure passenger experience while being more compact and easier to ship and maintain. Wider operating parameters make the FROG-XT range extremely versatile, allowing flexibility in operations. The range has undergone a rigorous development, testing and verification program to verify the capsules' performance and integrity and the level of protection afforded to passengers. The range of capsules is built to ISO 9001:2000 standards and is fully CE Marked. *reflexmarine.com*

Cap protects tools during hyperbaric welding, cutting

MacArtney has developed a protection solution for its LUXUS series of compact underwater cameras and lights. The LUXUS Protection Cap is primarily used to shield the lens of diver camera and light systems during hyperbaric welding, blasting and cutting operations, but it can also be used for equipment protection on other mission types. MacArtney LUXUS units often are deployed during installation, service, repair and decommissioning of metal structures in harsh subsea environments. Divers and equipment must remain in close proximity to the sparks and liquid metal spatter discharged during hyperbaric welding and cutting, exposing camera and light systems to the negative effects of this material such as burn damage to unit lenses. The protection cap is manufactured from transparent polyurethane with a metal strap to provide sealing and is mountable on any LUXUS compact camera or light model with no significant impact on the performance of the camera or light unit. The protection cap has been extensively tested to ensure performance and efficiency in harsh underwater environments. *macartney.com* E&P

Brazil bets on presalt

Presalt production appears promising, but development remains in its infancy and challenges remain both above and below the seabed.

Velda Addison, Associate Online Editor

Brazil's Petrobras has solidified its prowess as a presalt production powerhouse, setting records that have surpassed the 520,000 bbl/d mark with 25 wells just eight years after oil was discovered in the presalt layers.

The deepwater giant is placing its bets on the geologically challenging deepwater resource in the Campos and Santos basins, hoping it will boost the company's overall production and generate massive cash flow despite having consistently missed production targets. Crucial to achieving its goals are platforms capable of tapping the vast offshore deposits.

Plans were for nine production units to lift capacity in 2013, with an annual growth target of 7.5% in 2014. However, a combination of setbacks hampered efforts. Demobilization of *FPSO Brasil*, the 103-day stoppage of Marlim P-20 due to a fire, delays in platform deliveries by the shipyards and a longer execution time were among them, Petrobras said.

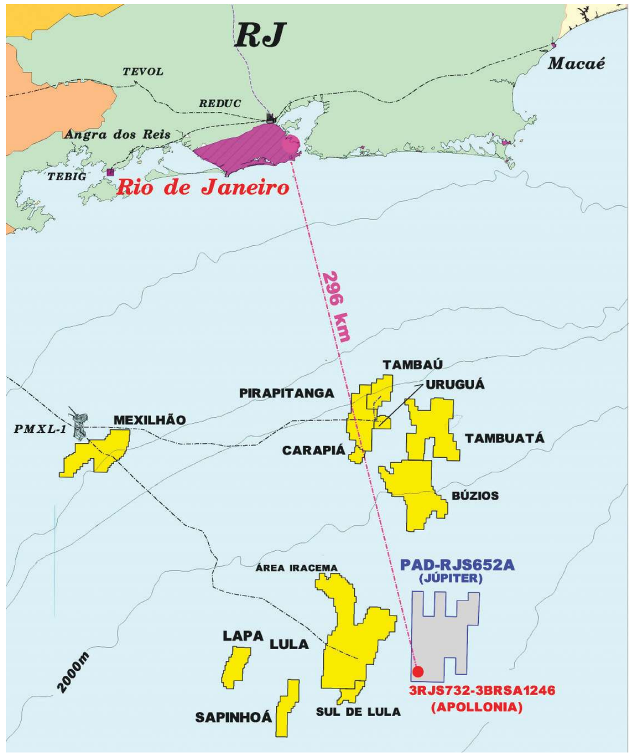
The trouble may be well worth it, considering Brazil is believed to have an estimated 13 Bbbl of proven oil reserves, according to the U.S. Energy Information Administration.

"Petrobras is the major player [in Brazil], accounting for more than 90% of operated production and holding a dominant position in exploration areas. In the last two years there has been an abundance of licensing—something that hadn't taken place since 2008. Now we're seeing a revival in the sector as a whole," said Ross Lubetkin, upstream analyst, Latin America for Wood Mackenzie. "Companies have already started the process of acquiring seismic. You should see a significant number of exploration wells that companies have already committed to drill in the next few years. Hopefully, a series of discoveries will bring a lot of new players to the board in terms of development from companies outside Petrobras."

But risks remain both above ground and below seabed.

Promising presalt

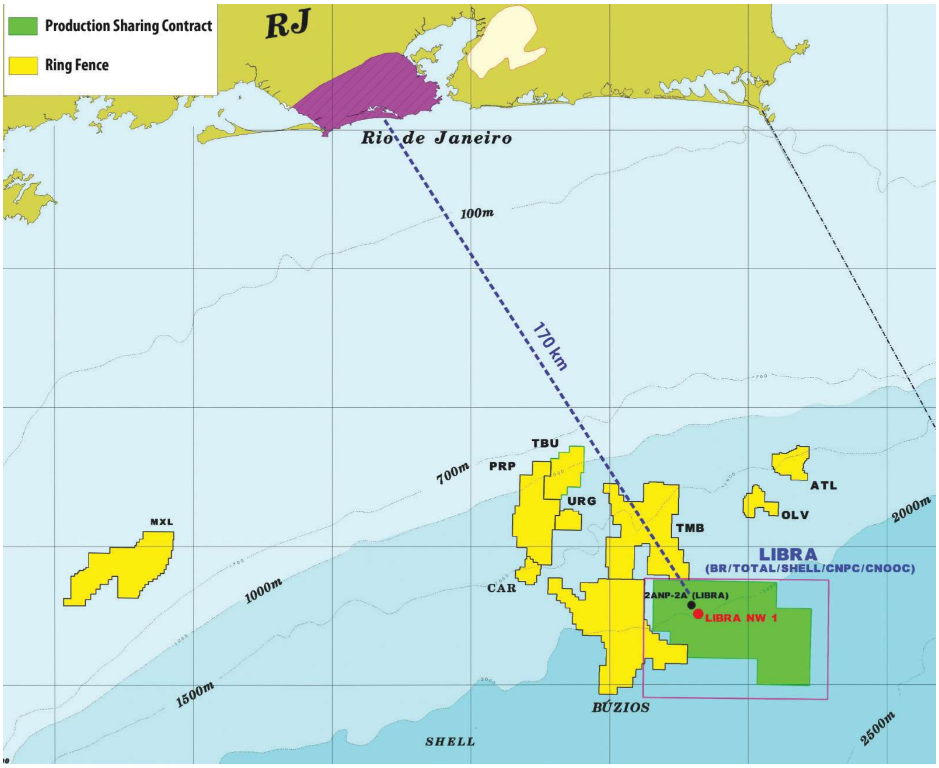
Petrobras is counting on presalt production to replace declining volumes from the Campos Basin, which has historically dominated offshore production and reserves for Brazil. Presalt fields now account for 22% of Petrobras' oil production in Brazil. However, that percentage is on course to jump to 52% of the country's total production by year-end 2018, when total output is expected to hit 3.2 MMbbl/d, aided by 19 new presalt production units operating in the Santos Basin.



Petrobras confirmed in August the extension of the Jupiter discovery in Santos Basin presalt Block BM-S-24 following drilling operations at the Apollonia well. (Source: Petrobras)

In August Petrobras confirmed the extension of the Jupiter discovery in Santos Basin presalt Block BM-S-24 following drilling operations at the Apollonia well. The well, the fourth drilled in the Jupiter area, confirmed a hydrocarbon column of about 313 m (1,027 ft), with rocks showing good porosity and permeability conditions, Petrobras said in a news release.

In addition to the gas cap and condensate, the well verified an oil column some 87 m (285 ft) thick. Based



The Libra consortium began drilling the first exploration well in the Libra Field in August. The field could hold between 8 Bbbl and 12 Bbbl of oil in the ultradeep water of the Santos Basin. (Source: Petrobras)

on samples collected, Petrobras said the fluids are similar to those found in the pioneer Jupiter well and two previously drilled extension wells.

However, "With the presalt relatively new, there is a great deal of uncertainty about how the reservoirs are going to perform in the future and how much they will deliver," said Ivan Cima, lead analyst, Latin America for Wood Mackenzie. "There are questions about gas reinjection and the impact that will have on the reservoir."

Getting to the hydrocarbons presents a myriad of challenges. Aside from the difficulties associated with drilling beneath as much as 1,981 m (6,500 ft) of salt, the reservoirs' complex heterogeneous layered carbonates pose challenges for reservoir characterization, seismic analysis, well engineering and flow assurance.

According to a statement from Halliburton, which is active in Brazil, "Drilling these wells is proving to be extremely difficult, with low penetration rates. The tendency for borehole deviation while drilling in salt elevates the importance of precise directional control. Flow assurance related to paraffin deposition, hydrate and scaling control is also a challenge. In addition, the presalt environment is very corrosive, with significant amounts of CO_2 and H_2S present. This places a high demand on special cement and metallurgy throughout the drilling and completion process."

Technology remains an area of focus in the region by Halliburton, which opened a technology center at the Federal University of Rio de Janeiro Technology Park in 2013.

"The research and development center provides technology solutions for exploration and production focusing on deepwater field development and technologies to maximize productivity from mature fields," Harold Mesa, Halliburton's country vice president for Brazil, told *E&P*. The center is addressing offshore challenges associated with drilling, well integrity, completions, reservoir characterization, flow assurance and production optimization.

But efforts are not being limited to offshore reservoirs, namely presalt carbonates, or revitalizing mature fields. Onshore solutions are being targeted as well, as Mesa said the company expects to see more projects targeting tight gas and conventional gas reservoirs.

Halliburton has some new technology that aims to boost E&P efforts in Brazil, but the service company is not sharing specifics yet due to confidentiality agreements. "We can mention that most of them will have a great impact on well construction, reservoir characterization and production, enabling our customers to optimize the final recovery of their reservoirs in a safe and economic way," Mesa said.

Production from presalt wells has exceeded expectations so far. "We have seen, especially recently, very positive news," Cima said.

At the Lula and Sapinhoá fields, flow rates have surpassed 30,000 bbl/d per well.

The appraisal wells have delivered at rates much higher than expected, Cima said, noting that as a result, the projects may require fewer wells for development. That could amount to a significant savings, considering drilling and completing a well can cost about \$120 million plus another \$60 million for subsea umbilicals, risers and flowlines.

However, presalt development is still relatively at infancy stage, Cima pointed out, with many key projects such as the Lapa, Lula and the giant Libra Field—believed to hold up to an estimated 12 Bbbl of recoverable oil—still at early stages of development. In August the Libra consortium announced it started drilling the first exploration well in the Libra area. The 3-RJS-731 well is the first of two wells planned for the first phase of the Minimum Exploration Program, Petrobras said in a news release. The plan also includes an extended well test scheduled to begin in December 2016.

"We'll have to wait and see what comes out of it," Cima said. "But so far the news has been fairly positive."

That has not been the case above the seabed.

Obstacles remain

Local content is the most pressing issue facing Brazil's offshore sector. A group of shipbuilders even met with Brazilian government officials seeking changes to local content rules, hoping to get permission to have more construction and engineering work done in Asia, according to a Bloomberg report. Orders have fallen behind schedule at local yards, causing delays.

"The issue around local content and the impact that has on the development and hindrance on current growth cannot be overlooked. The local content requirement is partially responsible for some of the delays that we've seen," Cima said. "Petrobras has consistently failed to deliver on expectations in terms of production targets, and local content delays will be an even more key factor to watch in the future."

In an emailed reply to questions from the news agency, Petrobras said that 33 new wells will be connected in the second half at P-62 and sister platform P-55, each platform with the capacity to lift 180,000 bbl/d.

"New production systems will go onstream in 2014 to ensure sustained growth, as outlined in Petrobras' 2014-18 Business and Management Plan, which has set a 7.5% rise by the end of 2014, with a margin of tolerance of one percentage point upward or downward," Bloomberg reported, citing the Rio de Janeiro-based company's May output report.

However, there have been delays, including with the P-62 platform.

"The amount of repairs needed now aren't small," Jose Maria Rangel, a union leader and former board member, said in the article. "They were having problems connecting wells on both P-62 and P-55. Obviously, if you have setbacks, this will reflect on production results."

Lubetkin also noted problems with platforms that are set to be delivered.

"We've seen quite a few instances where operational mishaps and equipment bottlenecks have slowed down the development of these projects," he said. "Longer term, local content will continue to have a large effect on meeting project deadlines. Getting the nascent Brazilian shipbuilding industry up to speed to deliver the new drilling and production facilities represents one of the biggest challenges."

However, Cima added that the comments are in no way a knock on Petrobras or Brazil because what Petrobras is trying to do is unprecedented.

In all, the company has more than 900 projects planned as part of a five-year investment plan of about $237 billion.

"It's the most aggressive and ambitious deepwater development plan that any company has ever attempted to undertake, and even delivering part of that is a very successful feat," Cima said. "Now, we can argue whether Petrobras has too much on its plate or not. But regardless, what they are doing is still very impressive in the grand scheme of things." E&P

Brazil is among the locations with a high number of floating production projects in the visible planning stage. According to International Maritime Associate's August floating production report, Brazil has 44 planned projects, while Africa has 50 and Southeast Asia has 40.

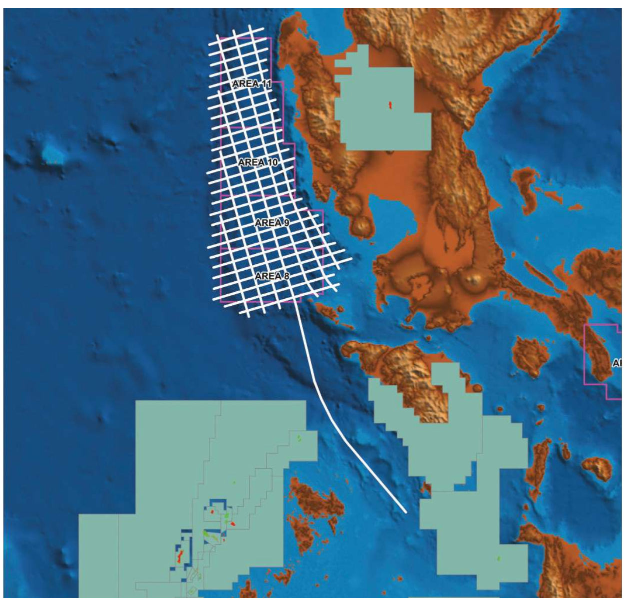
PACIFIC RIM

Tembakau well test succeeds, hits gas

A well test has been successfully completed on the Tembakau 2 appraisal well with the West Prospero jackup offshore Malaysia after the 2012 Tembakau discovery. Operator Lundin Petroleum said the shallow-water Tembakau 2 well, which was drilled 3.7 km (2.3 miles) south of the original discovery to test stacked Miocene gas reservoirs in the PM307 license area offshore Malaysia, encountered 22 m (72 ft) of gross pay sands in four intervals and produced up to 450 Mcm/d (15.9 MMcf/d) of gas during testing.

Searcher starts seismic survey in Philippines

Searcher Seismic in cooperation with the Philippines Department of Energy has commenced acquisition of the Pinatubo multiclient 2-D seismic survey in the West Luzon Basin, Philippines, a news release said. The 3,843-km (2,388-mile) survey covers a 10-km-by-20-km (6.2-mile-by-12.4-mile) grid and includes coverage over the PECR5 bid round blocks 8, 9, 10 and 11. It is expected to tie to the regional Pala-Sulu 2-D seismic survey acquired by Searcher in 2011. Acquisition is due for completion in late August.



Searcher Seismic has commenced acquisition of a 3,843-km multiclient 2-D seismic survey in the Philippines. (Source: Searcher Seismic)

SOUTH AMERICA

Petrobras starts drilling in Libra area

Petrobras and the Libra consortium started drilling the first exploration well—3-RJS-731—in the Libra area. This is the first of two wells planned for the first phase of the Minimum Exploration Program agreed with Brazil's National Oil, Natural Gas and Biofuels Agency. The well is positioned about 170 km (106 miles) off the coast of Rio de Janeiro state. Fundamental tests will be carried out to obtain information needed to develop the field.

Statoil enters Colombia with latest bid round

ExxonMobil Corp., Shell and Repsol were among top bidders for offshore blocks in Colombia's 2014 oil round as explorers stayed away from shale areas. The round marked the entry of Statoil to the South American state that's betting on offshore and shale deposits to boost reserves amid a failure to make significant onshore discoveries in recent years. Twenty-six blocks, or 27% of the 95 blocks on offer, received bids, below the 30% the government had been hoping for. Five deepwater and ultradeepwater blocks received offers out of a total 19 offshore that were offered. Anadarko Petroleum Corp. was the sole bidder for three blocks, with a joint offer between Repsol, ExxonMobil and Statoil the sole offer for another. A joint bid from Shell and Colombia's state-controlled Ecopetrol was the highest bid for a Caribbean site.

NORTH AMERICA

Mexico Lower House passes last oil bill

Mexico's Lower House passed a final package of bills to regulate an end to the nation's state oil monopoly, sending the legislation to the Senate for final approval after making minor changes on pension and retirement issues. Lawmakers modified the bill to make the age when workers at state-owned Pemex can retire rise gradually to the same as for other federal employees. They also decided the company needs to have its pension funds audited, which, like the age requirement, is contingent on the government assuming some Pemex debt.

Blackbird farms out Mantario interest

Blackbird Energy Inc. has entered into a farm-out agreement with a private oil and gas investment company to drill the first two horizontal wells at Blackbird's Mantario Oil Project in west-central Saskatchewan, Canada. The private company will pay an aggregate of about $1.6 million or 100% of the costs to drill, complete and equip two horizontal wells with a minimum of 600 m (1,969 ft) of horizontal length to earn a 50% working interest in the project.

GULF OF MEXICO

Shell makes third discovery in Norphlet

Shell made its third major discovery in the Norphlet Play in the deepwater Gulf of Mexico with the Rydberg exploration well, a press release said. The Rydberg well is located 120 km (75 miles) offshore in Mississippi Canyon Block 525 in 2,280 m (7,479 ft) of water. It was drilled to a total depth of 8,038 m (26,371 ft) and encountered more than 122 m (400 ft) of net oil pay. Shell is completing the full evaluation of the well results but expects the resource base to be about 100 MMboe.

EUROPE

OMV Petrom strikes oil in Black Sea

The Marina 1 well has hit oil in the Black Sea, OMV Petrom said in a news release. The exploration well Marina 1 was drilled 60 km (37 miles) from shore in Istria XVIII Perimeter to a depth of about 2,150 m (7,054 ft) below the seabed. First estimates from production tests show a potential production per well of 1,500 boe/d to 2,000 boe/d. After the completion of tests, the Marina 1 well will be plugged and abandoned.

Ithaca acquires interest in three UK fields

Ithaca Energy Inc. has completed the acquisition of three U.K. producing oilfield interests from Sumitomo Corp., a press release said. Ithaca has acquired Summit Petroleum Ltd., a subsidiary company of Sumitomo, which holds the Cook (20%), Pierce (7.48%) and Wytch Farm (7.43%) field interests that have been acquired. The net consideration paid at completion was $163 million taking into account working capital and net cashflows since the transaction effective date of Jan. 1, 2014.

SOUTH ASIA

PPL joint venture finds gas, condensate in Pakistan

Pakistan Petroleum Ltd. (PPL), the operator of Gambat South Block (2568-18) with a 65% working interest, and its joint venture partners Government Holdings Private Ltd. (25%) and Asia Resources Oil Ltd. (10%) have made a gas and condensate discovery over its exploration well Sharf X-1 located in the Sanghar District in Sindh, Pakistan. This is the third discovery in the block after gas and condensate discoveries from Wafiq X-1 and Shahdad X-1, a PPL press release said.

AFRICA

Eni detects gas, condensate offshore Gabon

Eni has made a gas and condensate discovery in the Nyonie Deep exploration prospect located in Block D4 about 13 km (8 miles) from the coast of Gabon, according to a press release. Preliminary estimates suggest the new gas discovery is significant, with initial potential in place estimated at 500 MMboe. The discovery was made in the presalt of Gabon through the NFW Nyonie Deep 1 well. The well encountered a thick hydrocarbon-bearing section (320 m [1,050 ft]) in the presalt clastic sequence of Aptian age. The structure, which extends more than 40 sq km (15 sq miles), covers two offshore exploration blocks, both operated by Eni with a 100% stake. The discovery will be followed by an appraisal campaign to assess its potential.

Shell produces first oil from Nigeria project

Shell's deepwater subsidiary, Shell Nigeria Exploration and Production Co. Ltd. (SNEPCo), started oil production from the first well at the Bonga North West deepwater development off the Nigerian coast, a press release said. Oil from the Bonga North West subsea facilities is transported by a new undersea pipeline to the existing *Bonga* FPSO export facility. The *Bonga* FPSO unit has been upgraded to handle the additional oil flow from Bonga North West, which is expected to contribute 40 Mboe/d at peak production. E&P

The *Bonga* FPSO unit has been upgraded to handle the additional oil flow from the Bonga North West deepwater development. (Source: Shell)

PEOPLE

Liquefied Natural Gas Ltd. expects to appoint **John Godbold** as COO and project director of Bear Head LNG Corp. when the acquisition is finalized. **Ian Salmon** is expected to be made CFO and chief commercial officer.

Schramm Inc. named **Bobby Bryan** (left) COO.

Halliburton tapped **Jeff Miller** as president and appointed him to the board of directors.

John Gerstenlauer has taken on the role of CEO for Gulf Keystone Petroleum.

The Society of Petroleum Engineers named Baker Hughes' **D. Nathan Meehan** (left) 2016 president.

Aaron Gaydosik has been tapped to be CFO of Gulfport Energy.

Jerry Beeson (left) became CEO of Circulation Solutions LLC.

BP has named **Spencer Dale** its group chief economist.

The Petroleum Exploration & Production Association of New Zealand selected **Cameron Madgwick** to become CEO.

Carolyn Kotsol became the president and CEO of Winner Water Services, a joint venture formed in early 2013 by Battelle and Winner.

Lloyd's Register selected **John Rowley** to be managing director for the Management Systems business LRQA. **Paul Graaf** was made COO for LRQA, and **Steve Allison** became the business' finance director.

Industry Technology Facilitator appointed **John Wishart** (right) as chairman.

Martin Jolley (left) has been made vice president of sales and commercial for Claxton Engineering Services, an Acteon company.

Occidental Petroleum Corp. named **Todd Stevens** CEO and **Marshall D. Smith** senior executive vice president and CFO, both for its subsidiary California Resources Corp.

Chris Lambert has been selected as regional vice president for Gulf of Mexico, **Brian Keefover** became regional vice president for North America land and **Ricky Begnaud** is now regional vice president for Middle East/North Africa/Central Asia for RigNet Inc.

Ultra Petroleum Corp. promoted **Garland R. Shaw** to senior vice president and CFO.

Azman Nasir (left) has taken on the position of head of the Asia-Pacific region for Energy Industries Council.

Sigma Cubed Inc. has chosen **Dr. Alan J. Cohen** as CTO and **Mark Bozich** as Houston engineering manager.

Julian Walker (left) assumed the role of director of communications for AMEC.

Hampco chose **Steve Hanna** (right) to become technical manager.

Royal Dutch Shell Plc selected **Harry Brekelmans** as projects and technology director.

Stochastic Simulation made **Leo Mullins** its new managing director.

Elaine Hicks (right) now serves as senior vice president and CIO for HOLT CAT.

Aquatic Engineering & Construction Ltd., an Acteon company, has appointed **Martin Charles** (left) as regional general manager for Europe, Middle East and Africa.

Scott Lamoreaux has taken on the role of director for the natural resources oil and gas group of ING Capital LLC.

Petrofac Training Services, part of Petrofac Group, hired **Pedro Vergel** as vice president of Western Hemisphere.

Matthew Hancock and **Amber Rudd** were named ministers in the U.K. Department of Energy and Climate Change.

Amir Ghaffari joined Vinson & Elkins as a partner in London representing energy, among other areas.

Amos Hochstein was tapped by the U.S. State Department to be acting head of the Bureau of Energy Resources.

Paul F. Boling has retired from his post as vice president, CFO, secretary and treasurer for Carrizo Oil & Gas Inc. **David L. Pitts**, the company's vice president and chief accounting officer, will become CFO and treasurer in addition to his current positions.

Thomas J. Moore joined Mayer Brown's Houston office as a partner in the Corporate & Securities and Oil & Gas practices.

COMPANIES

Variable Bore Rams Inc. has opened a new distribution center in Midland, Texas, to improve response time in New Mexico, Oklahoma and West

E&P

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Texas by up to seven hours and facilitate inventory rotation into and out of the company's headquarters. Available inventory will include about 100 sets of various dressed rams and 200 sets of spare elastomers.

DNV GL is expanding its existing facilities in Katy, Texas, to accommodate all Houston-area staff in one location. The maximum capacity of the expanded facility will increase to 700 people from 350. The expansion will add 4,413 sq m (47,500 sq ft) of office space to the existing 8,338 sq m (89,750 sq ft). The construction project is scheduled to be completed by June 2015.

MECO Inc. opened a new 7,432-sq-m (80,000-sq-ft) manufacturing headquarters in Mandeville, La. The facility features recycling of process water that reduces the demand for makeup water and eliminates process water disposal as well as state-of-the-art heating, ventilating and air conditioning systems in production areas to improve product quality and workforce productivity.

CGG inaugurated its subsurface imaging center in Yangon, Myanmar, to support anticipated growth in Myanmar's oil and gas exploration sector. The center is equipped with the latest hardware and CGG's seismic processing software to meet the subsurface imaging requirements of CGG's clients operating in the country. A fast dedicated network link to CGG's Singapore hub also is available for processing large data volumes. E&P

The technology bridge

Software can unify the reservoir life cycle.

Kjetil Fagervik, Emerson Process Management

There's a lot of talk these days about "integration"—in new product launches, company visions or even petroleum science degrees. Terms such as "integrated operations" (IO) refer to a new way of working that is now an integral part of the oil and gas lexicon.

Yet when we talk about "integrated petroleum technology," what do we actually mean?

For me, integration means uniting technologies to support the decision-making process across the reservoir life cycle and from exploration to production and beyond. It means putting data, knowledge and analysis in the hands of decision makers spanning exploration and prospect evaluation right through to simulation and day-to-day production operations. IT, and in particular software, is the "technology bridge" that enables this integration to happen. And the best means of delivering truly integrated operations is through the reservoir model.

Reservoir modeling today stands at the epicenter of the upstream oil and gas workflow, not only in the mapping, understanding and predicting of future oil and gas reservoir behavior over the asset life cycle but also in day-to-day production. Reservoir models form the glue that brings different elements and players in reservoir and production management together. They provide a broad ecosystem where real-time data are continually fed back into the model for analysis by geophysicists, geologists, reservoir engineers, drillers, asset managers, production and reservoir engineers, auditors, and senior managers, all of whom are responsible for crucial decisions relating to the development of the field.

Yet to ensure that this vision becomes a reality, it's equally important to appreciate the huge challenges reservoir modeling faces. First, there's the growth in complex geologies and tectonics. In frontier regions, reservoir models must accurately represent complex structures such as thrust faults and salt domes while at the same time honoring stratigraphic relationships and fault geometries. How operators and reservoir models account for these complexities in the geology and physical interactions has a huge impact on production decisions further down the line.

Second, there's the issue of scale and level of detail. We know from geological analogues that reservoir porosity and permeability can vary dramatically over a range of just a few centimeters. These small-scale heterogeneities that are beyond our ability to image can be detected in part by a careful analysis of daily production data.

Unfortunately, centimeter-scale representations of the reservoir are not currently computationally feasible within a standard field development timeframe. Therefore, successful reservoir models need to provide a realistic depiction at an appropriate scale of all the geometries and properties that impact fluid flow and volumes. It's through a realistic representation of this data that operators can understand the risks associated with their models and how these risks impact field development decisions.

Third, a tight and integrated workflow that enables all members of the asset team to share data and work together toward common objectives—namely the maximum productivity of the reservoir—is crucial. To meet this and other challenges, the development and deployment of a scalable, flexible and collaborative computing solution (whether via internal or external clusters) becomes inevitable.

Today reservoir modeling is meeting the challenges of geological complexity, detail and integration. Whether through generating a range of plausible scenarios or model realizations or testing the sensitivity of production to uncertainties in key parameters, geologists and production engineers are using reservoir models to assess the range of production outcomes and make sure facilities are in place to meet those needs.

Ultimately, through standardized risk assessment processes, operators will be able to balance risk across their full portfolio of assets and use reservoir modeling as the technology bridge that brings together all available data from the field, whether subsurface, metering or production data. Operators also need to be able to update the models in near-real time to explore and impact production scenarios and decisions.

Through this approach and a focus on connectivity, flexibility and scalability, reservoir modeling can be the technology bridge that unifies the reservoir life cycle, reduces exposure to risk and delivers increased investment returns. E&P