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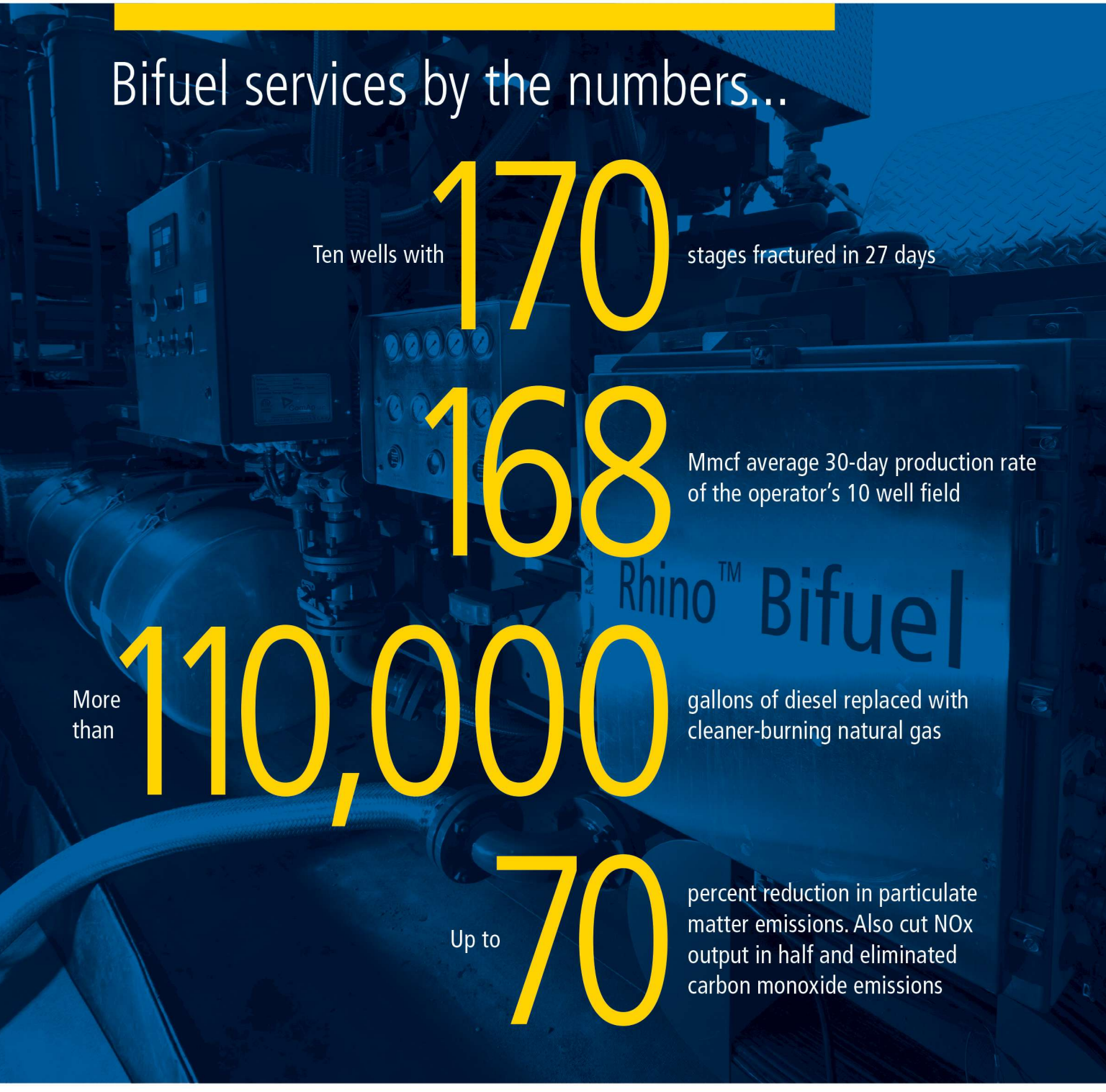

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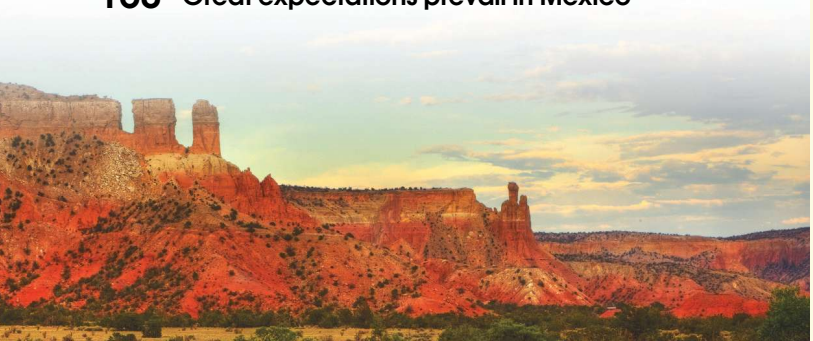

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DEPARTMENTS AND COMMENTARY

COMING NEXT MONTH The May issue of ***E&P*** will examine the booming offshore market, including an offshore technology report and features on marine seismic; deepwater rig advances; offshore projects; and marine construction, transportation, and installation. Regional features will highlight Canadian unconventionals and Venezuela. 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 The largest floating structure in the world – the Prelude floating LNG facility – has launched the era of offshore natural gas liquefaction. Left, Pemex seeks partners not only to invest in existing fields such as the Sonda de Campeche but also to target new exploration opportunities. (Photos courtesy of Shell and Pemex; cover design by Laura J. Williams)

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IOG acquired North Sea gas discovery

Independent Oil and Gas (IOG) acquired 100% equity in a North Sea gas discovery in UK block 48/22a originally drilled by Perenco in 2007. The discovery is being considered a new project by IOG.

Murphy produces first oil from SNP

First oil production has commenced from Siakap North-Petai (SNP) development offshore Malaysia, Murphy Oil Corp. said. Peak gross production from the SNP field is expected to reach 35 Mb/d of oil in mid-2014.

Salamander confirms gas in Indonesian well

Salamander Energy's West Kerendan-1 exploration well in Indonesia has reached total depth and successfully tested gas from the Upper Berai reservoir. The well will potentially be completed as a future producing well.

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Geopolitical study ponders LNG possibilities

By Velda Addison, Associate Online Editor

Above-ground issues such as geopolitics and economics create uncertainty for future LNG market.

Upstream activity picks up in China

***By Steve Hamlen, Special to* E&P**

Natural gas and gas hydrates finds are among the latest discoveries.

Arctic research targets oil spill response technology

By Velda Addison, Associate Online Editor

Areas of focus include *in situ* burning and fate of dispersed oil under ice.

South Sudan's oil industry faces setbacks due to armed conflict

***By Obafemi Oredein, Special to* E&P**

Consequences could impact future oil production and cause project delays.

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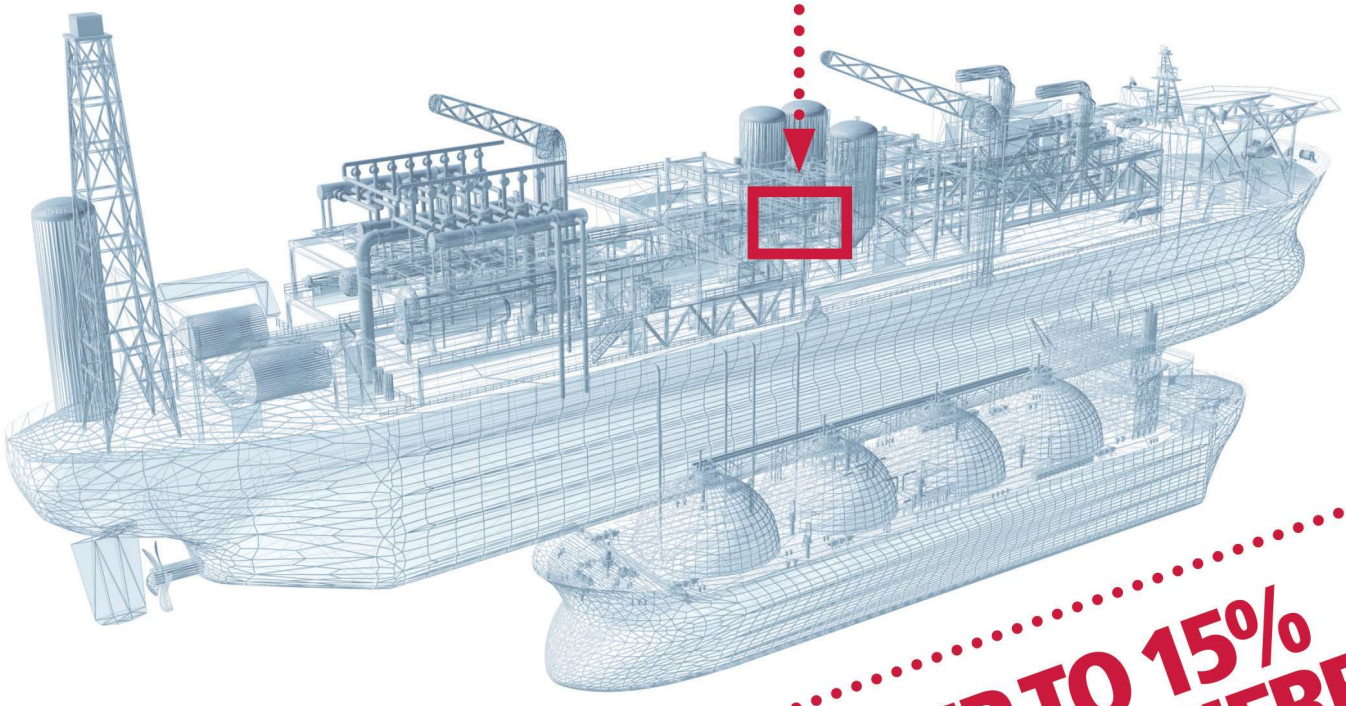

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Rebooting the GoM

Recent moves by specialist operators in the GoM highlight how much life is left in this basin. It's not so much a mini-revival but rather – potentially – a whole fresh start.

The recent US $1.5 billion deal by Energy XXI Ltd. to buy and merge with its closest rival EPL Oil & Gas created the largest public producer focused on the Gulf of Mexico (GoM) Shelf and illustrates nicely the competition taking place in what was – until just a few years ago – dubbed the "dead sea."

If you ignore the deepwater sector of the GoM, which has itself (post-Macondo) seen a strong and well-documented resurgence in activity by operators to a peak beyond that achieved before the tragedy occurred, the shallows have become very desirable property.

Energy XXI's aim in buying EPL is to better compete with private equity-backed players such as Fieldwood Energy (the largest private player on the Shelf) in squeezing out more oil and gas from both mature fields and new deeper plays. Although not huge figures compared to the majors – the acquisition would boost Energy XXI's production to roughly 65,000 boe/d – the returns are good. "EPL's assets and operations closely resemble our own ... with some of the highest margins in the industry," said CEO John Schiller in the company's release on the deal.

Interestingly, EPL's CFO, T.J. Thom, spoke with *E&P*'s Rhonda Duey in last month's issue (before the above merger was unveiled) about its strategy of bringing new life to a mature basin. It involves the use of improved technologies, in terms of seismic data in particular, with technology such as nodal acquisition and full-azimuth surveying employed to help image features that have been tough to find until now.

She stressed that the new data allowed EPL to use its technical expertise and regional understanding to "really go after these untapped reservoirs."

Another CEO who sees only growth in the GoM is Fieldwood's founder, Matt McCarroll. In a recent interview with Hart Energy's Steve Toon, he admitted that little more than a year ago the company was "three guys and an idea – and not even with a GoM focus." After the opportunist acquisition of Apache's shelf assets (more than 500 fields), it became the largest shelf player, followed by the further acquisition of SandRidge's assets.

Again, like Thom, McCarroll stressed that technology, including new seismic acquisition techniques, is key to unlocking new offshore reserves.

The image of so-called "smaller players" picking through the leftovers in a mature basin written off by the oil majors is a big misconception. The above deals clearly demonstrate that operators with strong field development strategies and a flexible approach can revitalize older fields – and whole regions. And that's an approach that can be applied in many other producing basins around the world. E&P

Managing the risk calculus in the Arab Spring

Operators need to strike a balance between protecting their people and assets, managing operational imperatives, and dealing with multifarious threats on the ground.

Louisa Barnett, Salamanca Group

The Maghreb, or North Africa, boasts Africa's most developed oil region, with the majority of the continent's proven oil reserves and refining capacity. While Algeria, Libya, and Egypt dominate the sector, significant opportunities exist in Tunisia and Morocco. Notwithstanding the enormous potential presented by the Maghreb, the operating environment remains

A Salamanca Group oil protection vehicle works onsite in Libya. (Images courtesy of Salamanca Group)

far from straightforward. A variety of risks abound – geopolitical tensions, political instability, civil unrest, and transnational militancy. Aside from these macro risks there are the operational questions of corruption, complex legal and regulatory environments, and tactical security concerns.

Political and operational risks have long been present in the region but are felt more acutely today as the revolutions that toppled dictators in Libya, Egypt, and Tunisia have unleashed complex and violent forces that dramatically weaken state structures that previously suppressed these forces. The conundrum facing international oil companies (IOCs) and investors is how to interpret and manage the risk calculus of making sure their people, assets, and reputation are not exposed while at the same time juggling the economic pressures of restarting or increasing their operations. This is further complicated if the asset is noncore or operated by an indigenous company that has a very different interpretation of threats and required responses. The enduring consequences of the In Amenas attack in Algeria in January 2013 are an example of this.

Militancy in southwest Libya

A relevant case study worth examining is the multifarious security risks facing IOCs operating in North Africa presented by militant networks in southwest Libya. There are strong suggestions that southwest Libya has become a haven for transnational militant networks exploiting the vacuum left by the ousting of the Gadhafi regime and the current uncertain political transition. In periphery areas often neglected by central government, militant networks hold a certain appeal to some local interest groups that are politically and economically marginalized by Tripoli. Various reports speak of the worrying emergence of "islamo-gangsterism," whereby jihadist militants involve themselves in the contraband networks in the border areas blending Islamist militant activity and organized crime. As militant networks build relationships with certain local groups, their ability to use southwest Libya as a rear base for attacks against oil and gas facilities in the wider Sahel region increases. The overall picture is more complex, but this is just one of many factors that influence the way these networks operate.

A proper understanding of these militant networks to project force and target oil and gas facilities requires both

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a strategic perspective and a clear view of specific threats that can only be had from close study on the ground.

Crucially, operators and investors need to understand the domestic political situation in Libya and that of its neighbors as well as the capabilities of the internal security apparatus in these countries to challenge such militant networks. In some cases, the lack of capability in this area is a key vulnerability. The In Amenas attack has shown the shortcomings of relying too heavily on internal security systems, overly bureaucratic command structures, and inadequate response capabilities – even in a country known to have the largest military budget in continental Africa. Libya, for its part, is not yet capable of providing effective security for IOCs as it is plagued by a range of security challenges including the fundamental question of how to create a new security force from a variety of competing interest groups. As for Tunisia, its security forces tend to overestimate their strength while being under-equipped and lacking an overall national security strategy.

A Salamanca Group security review of oil facilities takes place in Algeria.

As well as understanding the individual composition, capabilities, and character of each country's internal security forces and intelligence services, it is important to examine the nature of cooperation between these governments. This is a transnational threat where militants benefit from the freedom of movement afforded to them by lax border controls and relationships with local communities. The role of foreign governments, including the US, Britain, and France, in the provision of counterterrorism measures must also be properly understood. Impact assessments and scenario planning should be undertaken on situations such as overt military intervention (e.g. the French into Mali) or covert drone strikes in and around an oil and gas asset.

Last, and most challenging, is the opaque nature of the militant networks themselves – mapping such complex, nebulous, and rudimentary networks is fraught with difficulty and runs the danger of oversimplification. While certain questions about the presence, intent, and capability of these networks have to be chalked up to the unknown, this by no means makes the risk unquantifiable and therefore unmanageable. Decision-makers need to rely on a more sophisticated treatment of security risks, one that not only assesses the likelihood and impact of the risk but also an asset's vulnerability to that risk.

Shortcomings in risk assessments

The In Amenas attack and the two attacks at Arlit and Agadez in Niger in May 2013 have drawn attention to some significant shortcomings in traditional security risk assessments. As Statoil's publication about the investigation into the In Amenas attack observed, "the terrorism threat was not broken down into defined scenarios against which protective measures could be planned and designed."

Based on its experiences of operating in the post-Arab Spring environment and other challenging jurisdictions such as Yemen and Somaliland, Salamanca Group has developed an in-house security risk assessment (SRA) that aims to tackle the shortcomings of traditional methods by applying a more structured, intelligence-led approach to security solutions. The SRA is based on a collaborative approach, with

Salamanca experts working with clients to develop successful outcomes. The threat of militancy, for example, is treated as a broad threat stream against which detailed tactical scenarios of how it may manifest itself against a given asset are developed. This logic allows for the identification of vulnerabilities in a sequence as the scenario develops, thereby minimizing the possibility for vulnerabilities to be overlooked.

Addressing vulnerabilities

"Protective measures" does not just mean practical measures to physically secure an IOC facility. This is one aspect, albeit a crucial one, but it must go hand in hand with other more strategic measures. Ongoing monitoring of local political, security, and transnational dynamics is essential and can be achieved through sophisticated community relations building and ground-truth intelligence gathering. This provides the much-needed early warning threat reporting on both "over the horizon" and local issues. Stakeholder mapping and behavioral analysis of the local operators, state oil companies, and security structures are also crucial and allow IOCs to adopt an appropriate and nuanced engagement strategy with key stakeholders. As well as engaging with host governments, relationships between IOCs and national governments are vital, in particular in the resolution of certain strategic disputes that IOCs may face. Lastly, collaboration among IOCs working in the same regions should be continually encouraged so that corporations adopt a more unified approach to sharing intelligence, conducting risk assessments, delivering coordinated security responses, and agreeing on key strategic decisions that affect the region and sector as a whole.

There is no silver bullet approach for IOCs who have to deal with the challenges presented by the energy-rich yet high-risk Maghreb region, but bespoke, intelligence-led security solutions combining the measures outlined above will provide greater clarity for decision-makers to make informed judgments about their investment decisions and risk strategies. E&P

Flare gas regulation: challenges, opportunities for energy companies

With growth comes growing pains and increased scrutiny for fracing, but some companies are adjusting and profiting as a result.

Jeremy Lessaris, Power Solutions International

With the spectacular rise of hydraulic fracturing in the US, it was inevitable that concerns about the effects of the process would arise. The *Wall Street Journal* recently reported that one in 20 Americans now live within a mile of a fracing site. One of the most hotly contested issues surrounding fracing involves air emissions resulting from the flaring of natural gas at new wells.

In April 2012 the US Environmental Protection Agency (EPA) issued its first-ever federal rules for fracing wells, requiring that companies fully phase in control measures to capture targeted emissions by January 2015. These control measures are called reduced emission completions or "green completions." Green completions primarily involve using portable equipment to capture and separate the mixed gases, liquids, and other substances that flow from new wells. This takes place primarily early during the flowback period when fracing chemicals and water injected into the ground return to the surface along with newly released gas. The captured natural gas can then be reinjected, used onsite, or sold.

Thinking local

Two states, Colorado and Wyoming, already require control measures. Nonetheless, states and local communities in Colorado, Pennsylvania, New York, and Ohio have continued to push for even greater oversight and regulation through lawsuits and ballot measures. And the trend is likely to continue.

Even in a "pro-drilling" state like North Dakota, where the Bakken and Three Forks shale formations spurred record production highs this year, local residents and newspapers are calling for a harder line on natural gas flaring. Roughly 29% of all North Dakota natural gas is flared, with volumes having doubled over the past two years. In a surprising twist, some North Dakota landowners have actually filed class-action lawsuits against oil companies, seeking millions of dollars in allegedly lost royalties due to the flaring rather than capturing of natural gas during production, according to Blank Rome.

Compact engines can easily turn field gas that would otherwise have been flared into fuel to power oilfield operations. (Image courtesy of Power Solutions International)

Contested projections

Historically, industry groups such as the American Petroleum Institute (API) have resisted flare gas regulation, citing infrastructure, equipment supply, and cost issues. The infrastructure for bringing recaptured natural gas into the power grid is often lacking, particularly in remote areas. However, green completions using portable processing equipment can resolve the infrastructure problem. Nonetheless, the API raised concerns about the equipment availability should new rules be phased in too quickly. API's greatest concern focused on the cost of green completions, which it initially estimated at US $180,000 per well.

Other organizations argue that green completions are neither complex nor expensive. Both the EPA and the Natural Resources Defense Council (NRDC) point out that green completions rely on readily available,

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validated technologies that are already widely deployed and that offset the cost of compliance. NRDC's *Leaking Profits* report stated that green completions and other pollution control measures could increase industry revenues by up to $2 billion per year through recovered natural gas. Similarly, a recent Ceres report, *Flaring Up*, estimated the value of flared gas in North Dakota at $1.2 billion for 2012 – about $3.6 million per day. These groups also note that in the years after standards were implemented in Wyoming and Colorado, drilling did not slow – in fact, Colorado drilling permits more than doubled.

Companies finding silver lining

It's not just environmentally oriented groups making these claims. According to FBR Capital Markets analyst Benjamin Salisbury, the EPA rule struck a balance; "Given sufficient ramp-up time, the cost of green completions is expected to be manageable or even positive net of revenue from selling captured methane."

And when the EPA rules were announced, *Bloomberg News* found several major companies with green completion systems in place that considered them "both practical and profitable." Mark Boling, president of Southwestern Energy's V+ Development Division, told *Bloomberg*, "Reduced emissions completions in our wells don't cost us any more than just venting the gas into the atmosphere." Southwestern's initial cost was $20,000 per well, but it has now cut costs to zero. Even at $2 per MMBtu, "we're making money."

Likewise, a spokesman from Devon Energy, which has used green completions for more than seven years, told *Bloomberg*, "We're capturing value that would otherwise be lost. It makes good economic sense for us." *Energy In Depth* reports based on input from Devon found that the rental cost for the equipment was roughly $1,000 per day, with a conservative net value of gas saved per well of $50,000.

Completing the efficiency circle

Several companies are taking these efficiencies further, using field gas for localized onsite power generation to cut costs and emissions even further. Apache Corp. is exploring this option, according to company reports. Apache found that the industry used more than 2.6 Bl (700 MMgal) of diesel for hydraulic fracturing in 2012 at a cost of around $2.38 billion. By switching to field gas, the industry could cut its fuel costs by 70% or about $1.67 billion, the company estimated.

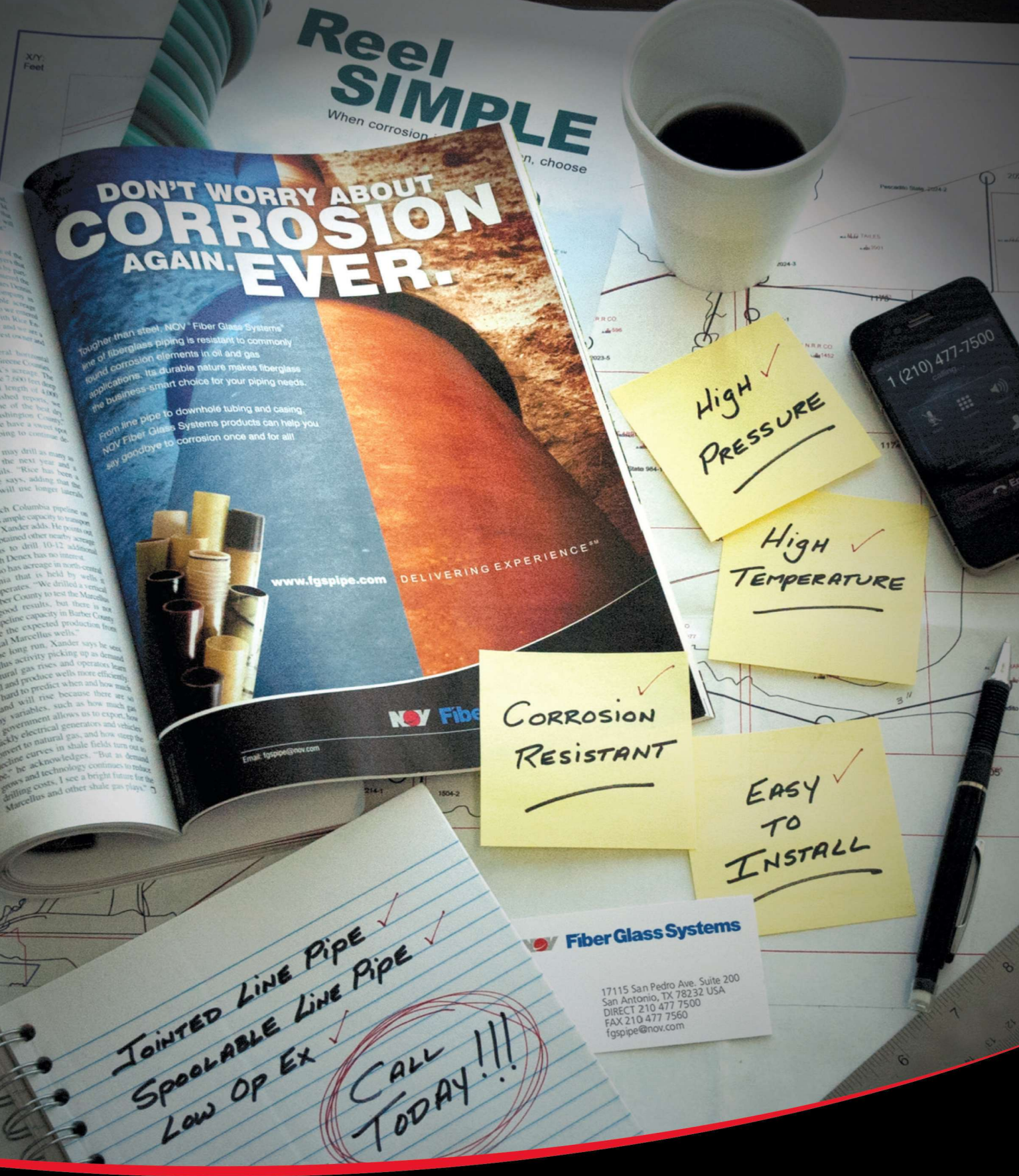
And companies are lining up to make this switch possible. Blaise Energy powers North Dakota well sites. The company originally delivered power from generators back into the power grid but found it was easier and cheaper to power well sites directly. Mark Wald, owner of Blaise, said that many of the wells are in remote off-grid areas and use diesel-powered generators to run the sites 24 hours a day. Swapping in field gas rather than hauling in diesel makes more sense. Wald told the *Bismarck Tribune* that oil companies that made the switch experience savings of up to $25,000 per month in the cost of diesel fuel alone for a single well pad.

Flaring gas is getting increasing attention from regulatory bodies.

Blaise has 25 operational sites and continues to add more units all the time. The company also is building bigger generators to keep up with the demands of multiwell drilling on well pads. Wald said it takes 100 kW to 150 kW to run a typical single well pad and 250 kW to 450 kW to run multiwell sites.

New engines meeting new demands

The trend dovetails nicely with developments in the engine industry toward increased options for alternative-fuel, heavy-duty engines designed for off-road mobile applications. Natural gas-burning engine providers have been ramping up their powerband offerings from the 250 kW to 450 kW range all the way up to the 1.2 MW range. These suppliers have found that due to the savings from trucking in diesel fuel and what is essentially "free" fuel from field gas, the payback on their systems is only a matter of a few months. E&P



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Ready, set, go: Croatia to launch first offshore licensing round

About a year following the unveiling of a new hydrocarbons law, Croatia will offer onshore and offshore blocks.

Velda Addison, Associate Online Editor

After years of stagnation with terms deemed not positive for oil and gas investors and nearly no offshore exploration since the end of the 1980s, the tide appears to be turning in Croatia.

"Before 2014 Croatia was not prepared," said Alen Leveric, the country's deputy economy minister. "In the past there were challenges to change the law, have new seismic data, to give security of investment. We've finished all of this."

Streamlined regulations are in place, a new hydrocarbons agency is open, and the country's hydrocarbons law is updated and aligned with European Union (EU) regulations and worldwide best practices. Hopes are that these accomplishments, with proven oil and gas areas in the Adriatic Sea, will lure oil and gas companies to Croatia.

"Croatia must work under the EU's terms. That means stability for companies that come to Croatia," Leveric said, pointing out that in this regard Croatia is on the same footing as countries such as Italy, Cyprus, and Greece. "What is there is also in Croatia. So this gives investors security. Also, this means that the company has to deal with the rules and directives in the areas of the environment, production, and free market."

The EU newcomer is on pace to launch its first offshore licensing round this month.

"I think we have done a lot of efforts in 1.5 years in this area. I hope investors will see this positive approach by the Croatian government and minister of economy," Leveric said. "With the new law, the new data and everything, it's something that is very interesting and positive."

Licensing round nears

Prerequisites for the upcoming licensing round were unveiled in late February after the country's hydrocarbons agency – dubbed a one-stop shop where investors can be guided through the process – opened for business.

Croatia will offer 29 offshore blocks ranging in size from approximately 1,000 sq km to 1,600 sq km (386 sq miles to 618 sq miles), according to Ivan Vrdoljak, the country's economy minister.

"Even though additional offshore areas have been previously available for exploration, we excluded near-shore and other sensitive areas," Vrdoljak said in a prepared statement. Fiscal terms have been defined, and "an extensive benchmarking exercise has been undertaken to ensure that we will be competitive with both our regional and global peers."

Companies will get a chance to venture onto Croatia's side of the Adriatic Sea and possibly hit hydrocarbon pay in the proven Pliocene gas plays of the northern Adriatic or tap oil in the pre-Tertiary farther south. Information such as block maps, fiscal terms, and a model contract was set to be available for download via the hydrocarbons agency website by the second week of March.

The offshore license round will be followed by the opening of the onshore license round by 3Q.

Leveric said the country's hydrocarbon potential is "huge." It's too early, however, to speak in absolute terms concerning resource expectation.

Assessing the possibilities

Beginning in September 2013, Spectrum acquired multiclient 2-D seismic data targeting underexplored areas of the Adriatic basin offshore Croatia covering approximately 15,000 km (9,320 miles) of long offset with a 5-km by 5-km (3-mile by 3-mile) grid. All processed data will be available by early April.

"What we can say is we are seeing with the better higher resolution data lots of structures that are possibly hydrocarbon-bearing – both within the shallow gas-prone section, which is the Miocene-Pliocene, [and] also within the deeper carbonate play, which already has oil-proven structures on the Italian side of the Adriatic," said Jevon Hilder, project manager for Spectrum.

A 2010 hydrocarbon potential assessment of the slope deposits along the southwest Dinarides carbonate platform edge showed the estimated recoverable reserves are between approximately 386 MMcm and 524 MMcm

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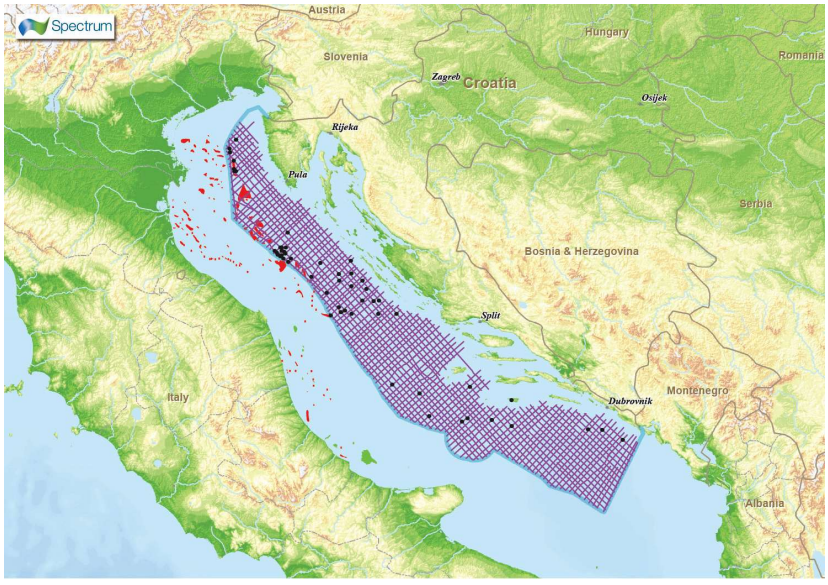
(14 Bcf and 18 Bcf). Estimated original oil in place could be between 13 Bbbl and 19 Bbbl.

The study, which was based on 12 interpreted cross sections of the north, central, and south Adriatic, also noted the oil discovery on the Rovesti structure on the Italian side of the Adriatic in 2007, where commercial oil quantities were found.

"It is very difficult to assume that along the whole edge of the carbonate platform the same sediments were almost continuously saturated with hydrocarbons, but it can be assumed that there is bigger or smaller number of possible accumulations that would contain significant quantities," the study said.



Spectrum has acquired a multiclient 2-D seismic dataset targeting underexplored areas offshore Croatia. (Image courtesy of Spectrum)

Barbara Doric, interim president for the hydrocarbons agency, spoke during the NAPE International Conference in Houston about the country's exploration opportunities and its market potential during a presentation with the deputy minister.

"We have a proven hydrocarbon province which is largely unexplored. We have a stable democracy. We have recently become a member of the European Union, and we are a member of NATO," she said. "We have a significant offshore area – 57,000 sq km [22,008 sq miles]. We have [a] skilled labor force, and we have a government that is very committed to positive reforms in Croatia, especially when it comes to investments in hydrocarbons."

Croatia currently has more than 60 exploitation fields, Doric said before comparing offshore Croatia to Italy's more developed offshore acreage. Italy has drilled more than 1,350 wells offshore the Adriatic, compared to Croatia's 116. Italy also has discovered recoverable reserves of 3.6 Bboe, compared to Croatia's 241 MMboe.

"This is proof of how underexplored the Croatian side of the Adriatic Sea is," Doric said. She later referred to vintage 2-D data spanning as far back as the 1970s and said, "We can surely say that on the northern part of the country there is a proven gas area, and on the southern part of the country there is a proven oil area."

The Croatian advantage

Now that Croatia has a new hydrocarbons law in place, updated seismic data, and the investment security that comes with being a member of the EU, the country is ready to embrace the next phase of development for its oil and gas industry.

"I think that there will be no challenges," Leveric said, adding the country has enough qualified workers to support oil and gas projects. "Lots of Croatian workers work in all of the countries known for oil and gas, from Libya to Egypt, [Saudi] Arabia, and Norway. Everybody knows the Croatian workers."

Besides having a competent workforce, Croatia has infrastructure in place, and the future could bring more improvements. The Adriatic oil pipeline system is in place to transport crude locally and abroad. There are oil refineries with pipeline, rail, and marine connections destined for central and eastern Europe. There is an existing gas transportation system and pipelines connecting offshore Croatia production to natural gas infrastructure in Croatia and Italy.

In addition, plans are for the Ionian-Adriatic pipeline to connect Croatia's gas infrastructure to the future Trans-Adriatic pipeline. The country also will add to its underground gas storage capacity at a new facility.

Currently, Croatia imports gas, but the country aspires to one day become a net exporter of oil and gas.

"Croatia is now very important for energy security and diversification of gas coming from Croatia to the European Union," Leveric said, pointing out that the country's strategic location also offers the deepest and northernmost port in the Mediterranean region.

Hilder added, "There was a large hiatus back at the end of the 1980s until now when there was little exploration. In fact, almost zero exploration was conducted offshore Croatia. It's the perfect time to resurrect those exploration efforts and reenergize the offshore." E&P

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Slow HR processes result in lost talent for majors

Recruits have too many offers pending to wait weeks for the second interview.

Dominic Morris, Twenty Recruitment

For the big firms in the oil and gas industry, skills shortages will be the hot topic of 2014. Engineers and geoscientists, particularly those working subsurface, are in high demand. For example, the Texas Independent Producers & Royalty Owners Association recently reported that the US oil and gas industry alone added 23,000 new jobs in the first half of 2013. Furthermore, the Bureau of Labor Statistics showed oil and gas industry jobs grew 40% in the US between 2007 and 2012, way above the 1% growth in US payrolls over the same period. Despite all the positive news, skills shortages still appear to be much discussed in oil and gas. But is there really a skills shortage, or do the major players simply need to adopt a different approach to recruitment?

Too often in the modern world securing talent appears to be a low priority. However, it's crucial to develop talent pipelines, especially in the oil and gas industry. It's the geoscientists who establish what's underneath the ground and how much of it there is, and it's these findings that convince organizations to make the investment and drill. Consequently, it could be argued that technical professionals in oil and gas are the people who help make huge investment decisions, and the penalties of missing out on the top-drawer talent could potentially be enormous for firms. It's for this reason that base salaries in some countries such as Canada, New Zealand, and the Netherlands rose above US $120,000 in 2012, according to *oilprice.com*, reflecting the importance of securing the right technical staff.

These lucrative opportunities aren't centered on one area. In the modern oil and gas industry, job opportunities are truly global. Professionals have the chance to work in a vast range of locations. And, because of the varied nature of the sector, it really comes down to individual choice. Often this is influenced by family or geography, but usually it's down to what employers are paying.

Currently, the same people are in demand across the globe with firms of all sizes. There is a particular thirst for subsurface engineers and geoscientists; however, there's also a need for deepwater engineers as advances in technology have meant drilling is now possible in the most challenging locations. As a result of this ever-growing demand, companies are trying harder to hold on to talent. The increased use of retention bonuses and counter-offers has shown just how important technical professionals are to many firms. If a leading engineer was to leave an organization, it not only means the company loses the individual's expertise, but the move could also perhaps be strengthening one of its rivals.

The ideal candidate

So what are firms looking for? The ideal candidate is someone who has demonstrated a stable career path across a number of locations. The major firms are constantly on the lookout for experienced professionals and engineers who can show varied drilling histories from all over the world, which will always be sought after. International experience is as important as it's ever been as organizations want a guarantee that their new hire can work in a range of locations and cultures, sometimes in hostile environments. Those with experience with and an appetite to work in East Africa are in particular demand at the moment, and this trend is expected to continue as firms manage the problems with security and infrastructure in the region. So if the opportunities are available, why are the supermajors still struggling to recruit the right professionals?

Barriers to recruiting

One of the reasons behind the perceived skills shortage could be the increasing prevalence of internal job moves. Some of the big firms are providing opportunities to move internally to a wide variety of locations. With the focus on retaining talent becoming ever more important, engineers are increasingly choosing a change of location over a change of employer, and this could, partially at least, explain the lack of available professionals in the external market.

More than anything, the number of companies in the industry has grown hugely over recent years due to new technologies and discoveries, and some believe this led to the perceived skills shortage. More firms operating

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in the industry mean a diluted talent pool, which ultimately leads to less expertise and harder-to-find specialists. This is particularly the case with subsurface professionals, where there's already a smaller pool of experts. As a natural result of the lack of available and qualified talent, much of the focus has turned to contract roles as organizations look to secure the top professionals. These aren't typical short-term contract roles; many last up to two to three years and pay on average a third more than permanent positions. The benefits and job stability may not be the same, but in an industry where career decisions are usually motivated by money, this makes a big difference.

And in this hugely competitive environment, it appears that the smaller players are winning the war for talent. So why are the big companies missing out?

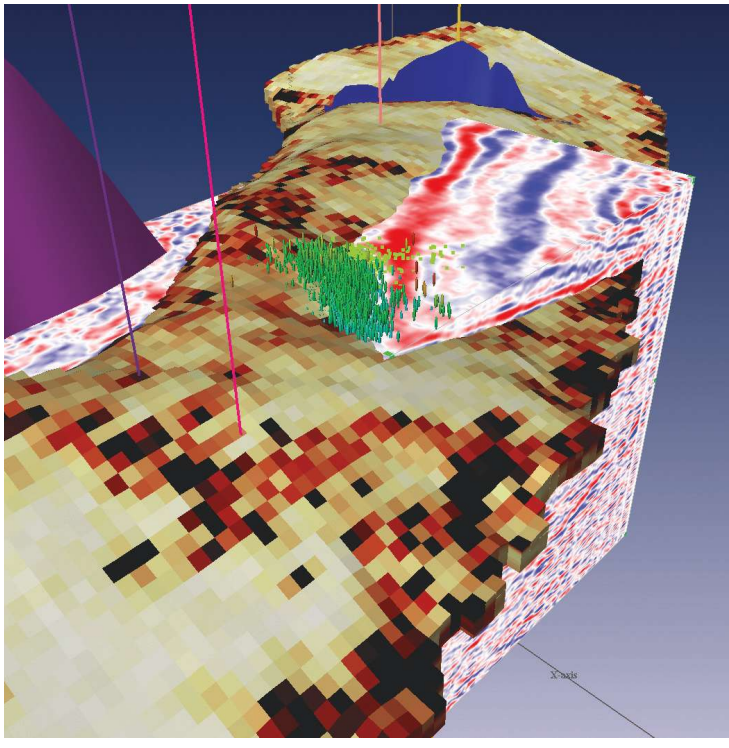
Brand isn't everything

Currently, the supermajors seem to be too reliant on the power of the employer brand. They have to realize that this doesn't carry as much weight in today's market. As a result, they need to be looking for more ways to sell themselves to candidates through fast and efficient recruitment processes. If professionals are left waiting around for too long or don't think the organization is doing enough to get them to join, they could quite easily find a more attractive job offer with a smaller, more agile company. Consequently, the big players have to make their decisions more quickly.

Too often, the problems are as basic as the mishandling of applications. Anecdotal evidence has suggested that in some companies, human resource teams without a full understanding of the technicalities of specific roles are ruling out competent candidates, and in today's market this just isn't sustainable. Technical professionals need to be involved at all levels of the recruitment process to ensure this doesn't happen and that talent isn't slipping through the cracks.

If the supermajors want to get their hands on the best professionals in the market, they also need to increase their understanding and awareness of current market rates and salaries. Proposed rates from bigger companies are sometimes below what is expected for top-level professionals. While it isn't surprising that smaller firms pay more (without this happening, they wouldn't have a place in the market), it's still a point of interest.

There also needs to be more detailed and clarified role specifications so that professionals have a clearer understanding of what's required of them when changing roles. These need to be more definite and focused not only on technical ability but also on "softer" skills. It's often underappreciated how big the cultural and social shift can be when moving between locations, and this is something that needs to be looked at in more depth. While some companies are very good at onboarding and provide superb packages for their employees, the challenges and requirements of the role need to be more clearly outlined in specifications.



Employees with subsurface experience are of particular interest to recruiting companies. (Image courtesy of Sigma³)

More than anything, the entire recruitment process has to be compressed. At the moment it's too drawn out, especially at the supermajors. Far too often weeks, sometimes even months, may lapse between interview stages, and this won't impress potential employees in any discipline, let alone one where they have ample opportunities available to them in a range of attractive locations. The period between the second and third meeting, in particular, needs to be shortened as this is where candidates are often drawn away by appealing offers from more nimble firms.

So is the skills shortage a reality or has it been created because of inefficient human resources processes? The talent is out there, but it has to be attracted and used by the big firms. Any skills shortage that may happen in the future will probably be avoidable; it's up to the big players to take note. E&P

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Newbuild rig cycle underway

Move to pad drilling generates demand for new high-spec rigs.

Richard Mason, Chief Technical Director

It's Field of Dreams for the land drilling industry. But the narrative for drillers is a reverse of the fantastical baseball movie. In this case, customers came first and now await construction of the equipment that will allow the ball game to commence.

The land sector has embarked on another newbuild cycle following a hiatus during 2012 caused by the sudden mid-year drop in commodity prices. Previously, the industry built 250 units in the 2011 to 2012 era as the move to unconventional drilling gained momentum.

The major driver in this cycle centers on the transition to pad drilling, which spread rapidly across the industry in 2013. As it did, it created demand for specialized rigs with top drives, self-mobilization systems, and automation packages integrating digital controls at the surface with advancements in downhole motors and drillbits to build better wellbores consistently and quickly.

The confluence of events and equipment is generating improvements in drilling performance, providing more wells per year for each active rig.

The trend has been transformative, with pad drilling moving from less than 20% of wells in late 2012 to more than two-thirds of wells in early 2014. But for an event to be truly transformative, it must have transformative industry impact, and that is exactly what is happening with the US land fleet.

New higher spec rigs with walking packages are now displacing older electric rigs in the Marcellus and Bakken shales, according to Hart Energy market surveys, or they are finding new demand as horizontal delineation work spreads in the Permian basin. In previous rig building cycles, new rigs were always "in addition to" existing rigs. In this cycle, new rigs are "instead of" existing drilling units.

- **Newbuild rig cycle underway**
- **116 units on order**
- **Domestic orders are mainly pad-friendly designs**
- **New rigs displacing older rigs**

Considering that only 40% of horizontal drilling occurs with the new higher spec alternating current variable frequency drive (AC-VFD) rigs – roughly 500 units – it is reasonable to expect a replacement cycle that unfolds at a cadence of about 100 rigs annually for the next half decade.

Hart Energy's market intelligence program surveyed eight rig manufacturing firms and found 116 rigs under construction, split 71% for the domestic market, or 88 rigs, and the remaining 29% for international applications, or 28 units currently.

The February 2014 survey found seven of eight manufacturers reporting strong demand, led by demand from top-tier contractors who account for more than three-fourths of new orders.

Additionally, the move to pad drilling is evident in new rig designs, with new rigs equipped with pad-friendly walking or skidding systems, top drives, and swing-up substructures for two-row pad drilling.

Rig builders anticipate demand for drilling equipment internationally will soon outpace domestic orders as interest grows overseas in horizontal drilling.

Contractors are seeking higher spec units, with most rig orders specifying drawworks of 1,500 hp, though some demand exists for units with 2,000-hp and 3,000-hp drawworks. A majority of units feature modern AC-VFD power systems, though a few are for standard diesel-electric silicon-controlled rectifier rigs.

Manufacturers report the average cost for a new 1,500-hp rig is at US $17.4 million, though the price ranges from $12 million for basic configurations up to $22 million, depending on the rig package. Larger 3,000-hp units top $30 million. Meanwhile, smaller 1,000-hp rigs cost $8 million to $12 million.

Current lead times for delivery range from 90 days to nine months, though the average is closer to six months, with little change over the last half year. In some cases manufacturers have prebuilt standard components, which shortens the time to delivery.

Manufacturers suggest the industry can build 150 rigs annually at current capacity. EP

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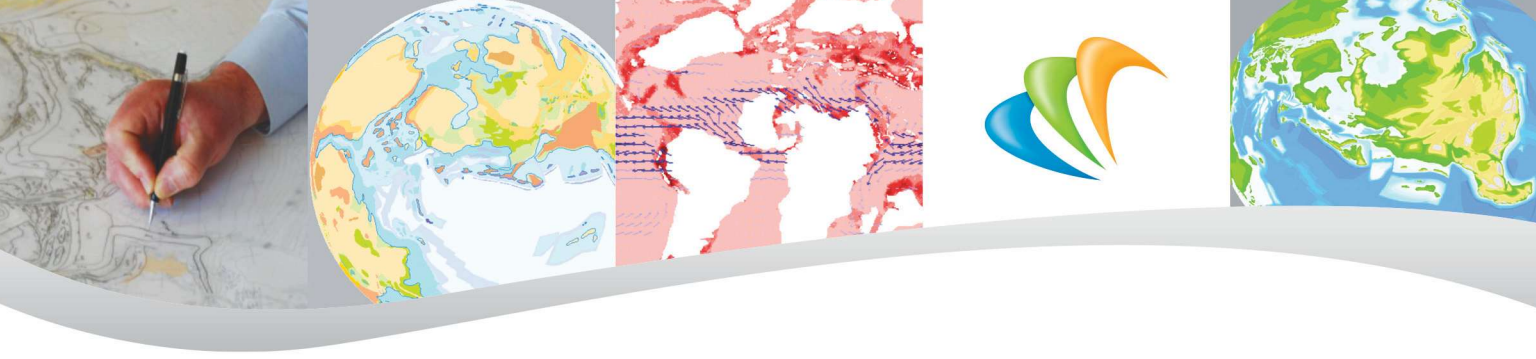

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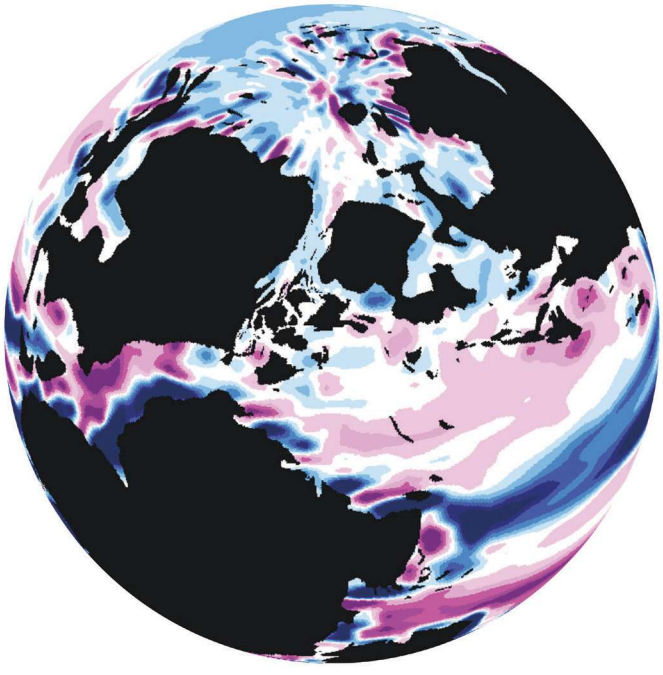

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Arctic surveys take careful planning

Chevron's success in the Beaufort Sea provides a blueprint for successful harsh-environment operations.

The famed explorer Roald Amundsen, who claims to have visited both poles, once noted, "Adventure is just bad planning." With this in mind, oil companies wishing to explore in the Arctic are taking special precautions.

At the recent Arctic Technology Conference in Houston, Kevin Williams, manager of exploration operations for Chevron Canada Resources, discussed the need for especially careful planning during a talk titled, "Sirlauq 3-D: Beaufort Sea Marine Seismic." The talk discussed Chevron's successful 3-D survey of its exploration license 481 in the Canadian Beaufort Sea during the summer of 2012.

Chevron, which has been active in Canada for 75 years, has two licenses in the Beaufort Sea. It owns 60% in Exploration License 481, the subject of the survey. The survey area is 120 km (75 miles) north of Hershel Island in water depths of 800 m to 1,800 m (2,625 ft to 5,905 ft). The area experiences only four to eight weeks of open water per year.

With this constraint in mind, the company executed a strategy to account for as many issues as possible. This started with an environmental assessment, which included consultation with local communities as well as planning for marine mammal and seabird mitigation if necessary. It also considered search and rescue issues.

"This became a significant issue if someone got injured or sick," Williams said. "We couldn't get them off." Through coordination with the Coast Guard, Canadian Search and Rescue, and Shell, Chevron was able to put together an independent search and rescue team consisting of three boats and two helicopters. All of the assets were in the rescue position for the entire survey.

Pack ice leaves a narrow operating window for seismic surveys in the Beaufort Sea.

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Read more commentary at
EPmag.com

Additionally, there are no deepwater ports and very little infrastructure in the region, so the company had to plan to shoot the entire program with no refueling.

Planning the survey itself was a bit more challenging. The team had to take the operating window into consideration. "We asked for ice forecasts and discovered that ice forecasters don't like to give ice forecasts," he said. "But we evaluated data from 2002 to 2011. Based on that, the weather window averaged 55 days per year of open water. Bad years were only 30 days. And there was one year, 2003, where the block was never free from ice."

This added complexity to the survey plan. The area is 100 km (60 miles) in the strike direction and 30 km (15 miles) in the dip direction. The dip direction is more desirable from a resolution standpoint. But it would take more time to shoot.

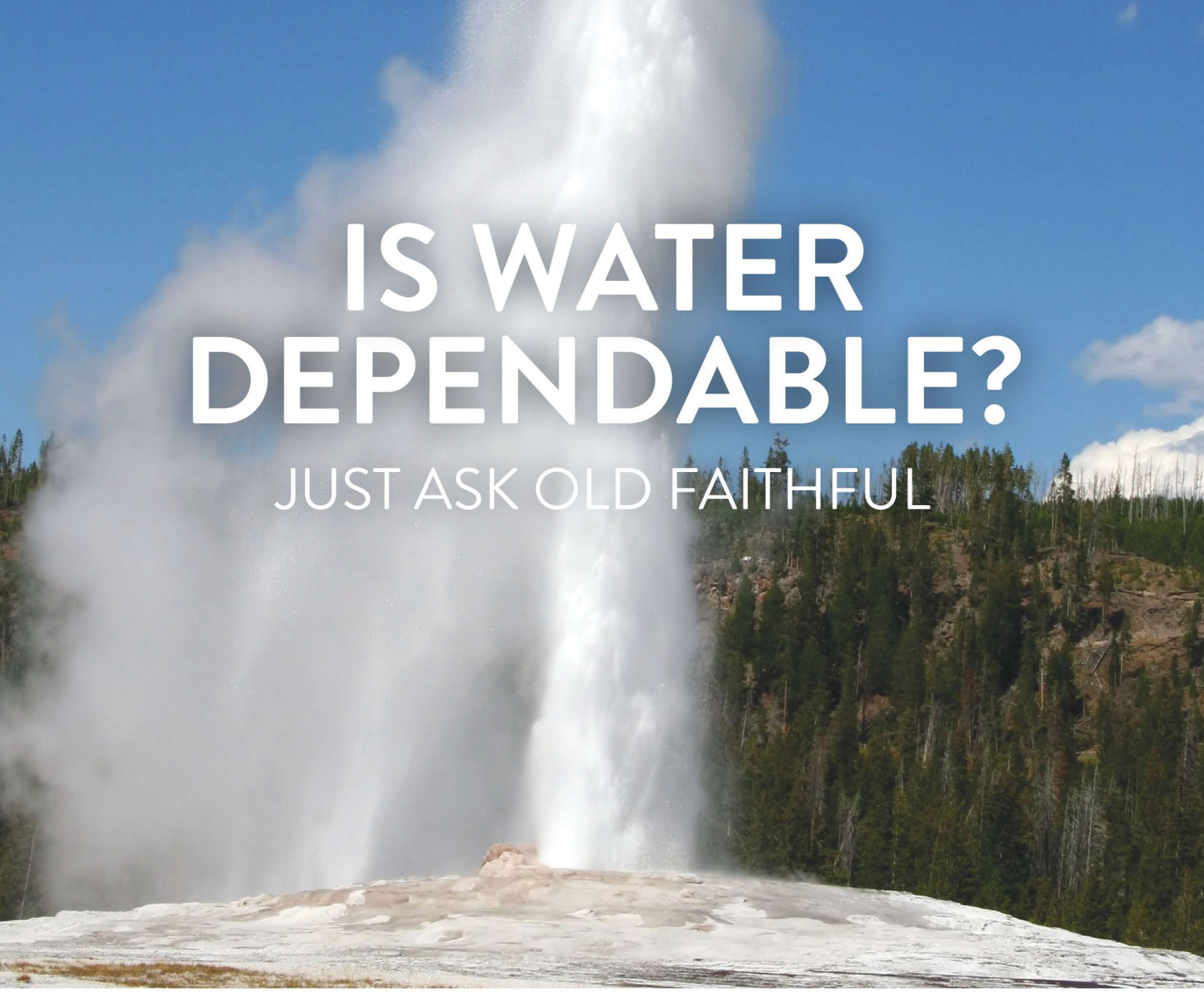
"We would have gotten better resolution in the dip direction, but production and efficiency were maximized in the strike direction," Williams said, adding that shooting in the strike direction shaved an estimated 16 days off of the overall program.

The team got lucky – 2012 had one of the longest weather windows in many years. Once the main survey was shot, it was able to reshoot some of the lines in dip direction and record data during the turns, he said.

Best practice learnings from the survey include:

- Beginning front-end loading early;
- Engaging early, regularly, and openly with stakeholders and contractors;
- Soliciting input from subject matter experts; and
- Preparing multiple designs.

"We had zero safety or environmental issues and got 3,700 sq km (1,430 sq miles) of high-quality multi-azimuth seismic data," Williams said. EP



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Oil and water do mix in design of semisubmersible fish farm

New design combines technology from the Norwegian fish farming industry and the offshore oil and gas sector.

The offshore oil and gas industry has been operating out-of-sight of land since the late 1940s. The technology has moved from shallow waters in the Gulf of Mexico (GoM) to more than 2,744 m (9,000 ft) of water. Now that same oil and gas technology is moving fish farms from shallow water to deeper waters to improve the growing and harvesting of salmon.

Ocean Farming AS, a subsidiary of the SalMar Group, began feasibility studies in 2012 for the development and implementation of new technologies for the next generation of fish farming. The company presented a conceptual solution in 2013 suitable for installation in exposed offshore areas. Ocean Farming received grants from Innovation Norway to develop the project.

Global Maritime AS performed the FEED for the semisubmersible fish farm. (Image courtesy of Ocean Farming AS)

The semisubmersible fish farm is a huge fish cage with netting. The unit is 110 m (361 ft) in diameter and has an overall height of 67 m (220 ft) with a volume of 245,000 cm (8.7 MMcf). The fish farm is designed for water depths of 100 m to 300 m (328 ft to 984 ft). The semisubmersible will be anchored in place.

There is a central column that houses the control room, living quarters, utilities, and feed silos as well as six columns around the circumference of the facility.

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Read more commentary at EPmag.com

The fish cage is above the water while being towed to location. Once onsite, the semisubmersible is ballasted down so that the cage is submerged.

Global Maritime AS performed the FEED for the fish farm, and basin model tests were performed by Marintek. Ocean Farming AS will tender an engineering, procurement, and construction contract for the pilot facility in spring 2014. The earliest that fish farming will begin is spring 2016.

All of the farming operations will be managed onboard the facility without service vessels and outside equipment. The fish can stay inside the net from smolt stocking to final harvesting. The facility also has one moveable and two fixed bulkheads that can divide the facility into three compartments for different fish operations. During normal operations, a crew of two to four people will monitor and manage the facility. The facility also is fully automated to reduce manual operations.

Operational experience from the pilot facility will be used to improve the industrial development of this kind of fish farm.

Fish farming in the open ocean may address some of the problems associated with near-shore aquaculture such as liquid waste and diseases from closely packed salmon in pens.

It is encouraging to see another offshore technology being used for raising fish, much like the platforms being used for artificial reefs in the GoM. The only difference is that the Norwegian facility will likely have a "No Fishing" sign on it. EP

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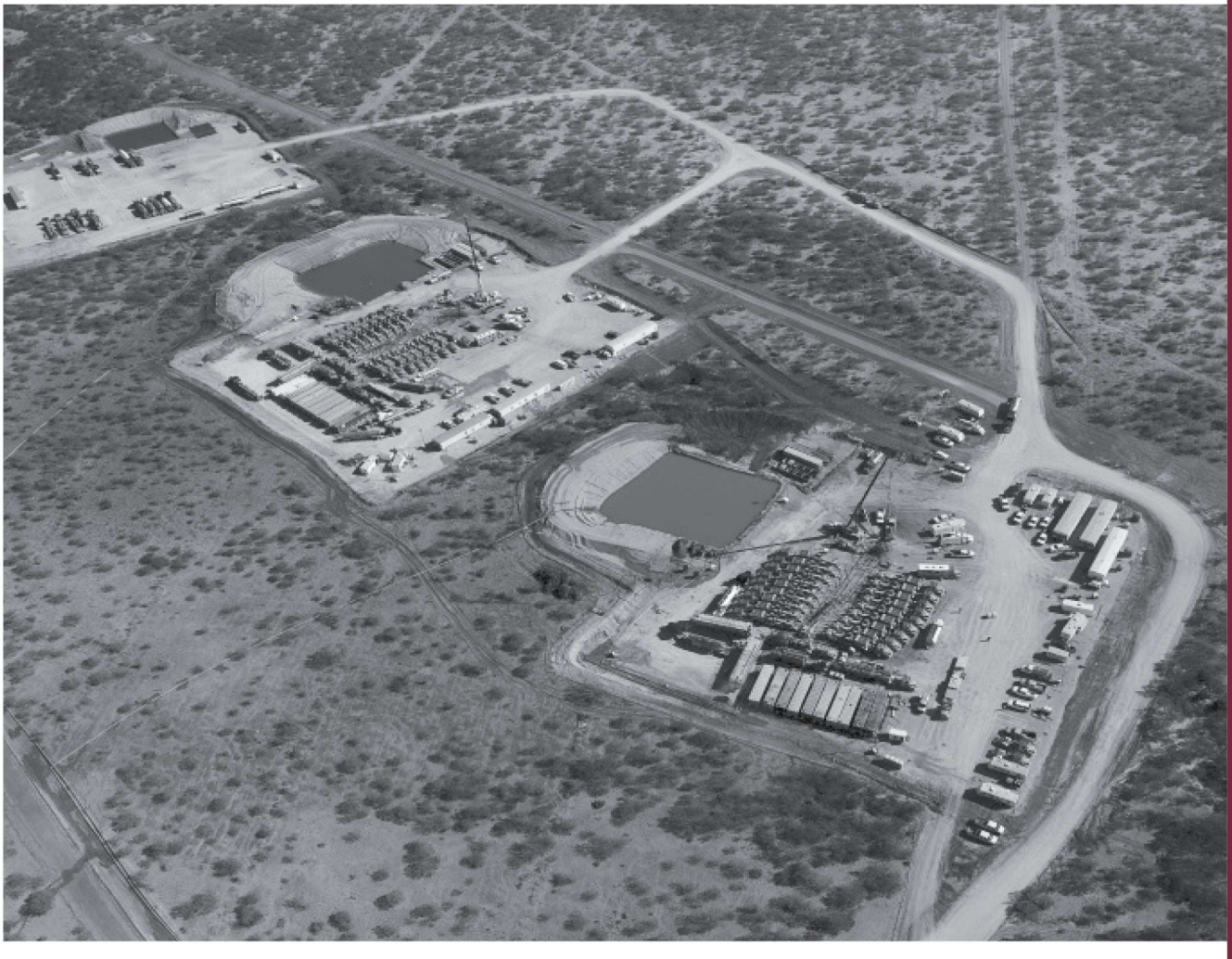

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‘Baby, it’s cold outside’

Production takes a dip in one of the coldest Bakken winters, but ‘spring will come again.’

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Read more commentary at EPmag.com

This winter as I watched the weather channel from my comfortable, relatively warm home in Houston, Texas, I was dazzled by the bright-white wonderlands being created elsewhere in the US. I was a little jealous at first. But as I watched the news unfold, I began to see how the pretty photos of snow my friends were posting from Virginia differed from the blizzards occurring in the Midwest.

Sure, every winter is frigid in some northern US cities like Williston, N.D. – the heart of the Bakken oil boom. But it got a little bit worse this year, according to the US Energy Information Administration (EIA).

The EIA reported in its March 11 *Short-Term Energy Outlook* that colder weather experienced from October 2013 to February 2014, particularly east of the Rocky Mountains, put a strain on the consumption and prices for fuels used for space heating. It also reported that it was significantly colder in states such as North Dakota. It was colder, in fact, than “both last year and the average for the past 10 years,” according to writer David Shaffer in his Feb. 14 *Minneapolis Star Tribune* article, “N.D. oil output drops due to cold weather in December.”

Oil and gas companies took a big hit on their bottom lines as they shelled out the extra cash to keep their crews warm and fed (you have to consume many extra calories to stay warm in below-freezing places like Williston in the winter). Production declined substantially while the crews were forced to wait out the worst of the winter storms in areas heated by the expensive fuel.

Soon the Williston, N.D., oil patch will thaw, allowing operators to pick up the pace of production as they strive to achieve 1 MMb/d in the Bakken shale play. (Image by Ole Jørgen Bratland, courtesy of Statoil ASA)

Shaffer reported that the “snow, high winds, and extreme cold” ultimately caused a 5.5% drop in output for North Dakota oil in December. This unfortunately slowed the state’s “march toward the symbolic benchmark of 1MMb/d,” he wrote.

As of press time, production in the Bakken reservoir had not yet achieved the million-barrel-a-day goal. But with a record-high production rate topping 900,000 b/d recorded in August 2013, it’s only a matter of time.

Spring will soon scatter the snow and ice into the annals of weather history, and the oil and gas companies working in the Bakken play will have a better shot at reaching the 1 MMb/d milestone. It will be quite an achievement for a play that wasn’t really even on the map 10 years ago. It certainly makes weathering these ice storms worth the effort. EP

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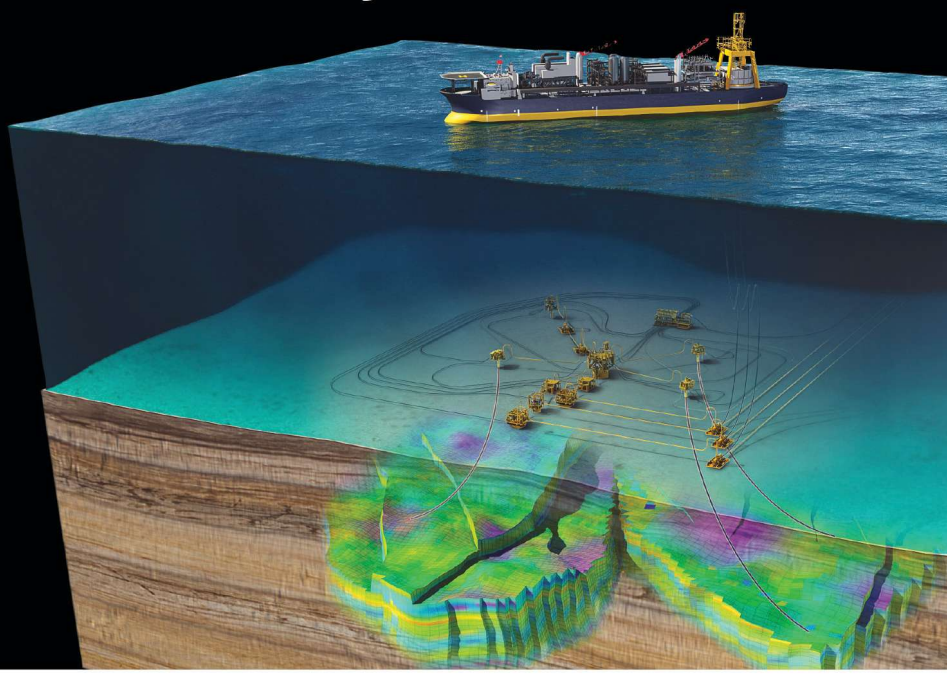

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Subsea splashes down at Sakhalin

Selection of proven subsea production technology by Russian gas giant delivers an offshore first for Sakhalin III.

For eight out of 12 months, thick sheets of ice cover the soon-to-be-operational Kirinskoye field located offshore Sakhalin Island. This leaves four relatively ice-free months for operator Gazprom Dobycha Shelf to accomplish the upgrades and preventive maintenance necessary to keep gas and condensate flowing over the next 30 years through Russia's first subsea production facility.

Discovered in water depths of approximately 90 m (300 ft), Kirinskoye is part of the Kirinski block – one of four blocks – that form part of the Sakhalin III development. Discovered in 1992, Gazprom estimates gas reserves in the field total 162.5 Bcm (5.7 Tcf), with gas production estimated to be 5.5 Bcm (194 Bcf) per year.

The produced gas mixture is set to begin flowing from the field to the onshore processing facility via a 28-km (17-mile) subsea pipeline for treatment before it is transferred to the 139-km (86-mile) gas pipeline to the main compressor station of the Sakhalin-Khabarovsk-Vladivostok gas pipeline in 2014, according to the operator.

FMC Technologies was awarded the contract for the manufacture and supply of the subsea production equipment in 2010.

"Gazprom approached us and asked, 'What kind of technology do we need for this field?'" said Arild Selvig, director of sales and marketing for FMC Technologies. "We were able to recommend standard systems in our portfolio that suited the field conditions."

A conceptual rendering shows a subsea production system in an arctic setting similar to the one deployed in the Kirinskoye field off the coast of Sakhalin Island. (Image courtesy of FMC Technologies)

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These field conditions include – in addition to being covered under ice for most of the year – a lack of infrastructure in the remote area, according to Selvig.

"We asked why they were interested in subsea," he said. "One driver for them was surface climate conditions like ice, darkness, wind, and sea currents. They would like to avoid surface facilities and put as much as possible on the seabed.

"The other is limited infrastructure like airports, roads, and ports. Subsea equipment can be manufactured elsewhere, transported directly to the site by barge, and installed in the field. We're independent of infrastructure."

The Arctic's remoteness – particularly the impact of long distances on control system operations, power generation, and flow assurance – presents a key technical challenge in unlocking the full potential of the area, Selvig said. Another unsolved issue is effective well intervention in ice-affected areas, he noted.

So how will the six subsea wells of Kirinskoye be monitored when the bitter winds blow across the Sea of Okhotsk?

"We included in our delivery our condition and performance monitoring system," Selvig said. "It is a surveillance system that monitors the equipment to ensure it is running safely, to ensure that we see a potential malfunction coming before it occurs. It's an additional safety feature since the systems are under ice eight months of the year." EP

Shell's Prelude development opens FLNG floodgate

Scott Weeden, Senior Editor, Drilling

With an eye on moving liquefaction plants offshore to reduce costs, operators in Australia, Colombia, Indonesia, Malaysia, Equatorial Guinea, Israel, and the US Gulf Coast are studying FLNG projects.

When the final investment decision (FID) was signed for the Prelude floating LNG (FLNG) facility offshore Australia, FLNG technology quickly became the leading option for developing offshore gas fields or stranded gas fields onshore.

The Caribbean LNG project being developed by Exmar and Pacific Rubiales Energy is a barge-mounted FLNG plant that will be docked in Colombia to liquefy gas from onshore fields.

Then Petronas began construction on its PFLNG 1 project in June 2013 and made its FID on the PFLNG 2 project in February 2014. Both units are for offshore fields.

FLNG provides advantages for stranded gas reserves. For example, the Bonaparte LNG project offshore Australia will include the Petrel and Tern fields that were discovered more than 40 years ago and were considered too remote and relatively small to develop. Once those reserves are depleted, the FLNG vessel can be moved to another field to continue operations.

The Prelude development opened the floodgates for FLNG projects offshore Australia. Although Shell's facility is under construction and the Scarborough LNG and Bonaparte LNG projects have been approved, Western Australia's government wants to put the brakes on further FLNG projects, citing fewer jobs and less opportunity for domestic engineering and fabrication companies. However, the juggernaut of FLNG is picking up steam.

Rising costs drive FLNG development

During 2013, the Economics and Industry Standing Committee for the Parliament of Western Australia held hearings on the economic implications of FLNG.

At the committee hearings June 26, 2013, Nicole Roocke, director, Western Australia Chamber of Minerals and Energy, testified, "Unfortunately, research has identified that the cost of doing business in Western Australia has put us at the wrong end of the cost curve with us being at the more expensive end. Unfortunately, LNG projects in Western Australia are becoming less competitive in a significant manner with the costs of building and operating LNG facilities continuing to increase over and above that of our competitors."

She quoted a report by McKinsey & Co. on "Extending the LNG boom: Improving Australian LNG productivity and competitiveness" that said LNG projects in Australia were now 20% to 30% more expen-

sive than competitors in emerging regions such as North America and East Africa.

For Shell, "FLNG allows a significant cost reduction. We expect something like 30%," explained Andrew Smith, Shell's country chair for Australia, to the committee Oct. 23. "The reality is that competition has increased for the markets that Australian LNG has traditionally supplied. Costs have increased, and we need to address those issues to remain competitive. FLNG is one of the ways that we can address those issues and remain competitive.

"FLNG will not be the best solution in all cases. But it is clear that FLNG has an important role in the development of Australia's gas resources right now. In many cases, the choice will be to develop with FLNG or not to develop at all," he added.

State government prefers onshore plants

Fran Logan, member of Parliament (MP) for Cockburn and deputy chair of the committee, was very blunt in his criticism. "What will Western Australia get out of FLNG technology? Nothing. We will get no engineering, fabrication, or construction jobs and no domestic gas. None of that will emerge from the implementation of FLNG technology.

"The only thing that comes out of FLNG technology for Australia is the wellhead taxes that are raised by the federal government because all the gas that is extracted by FLNG is in commonwealth waters. It is not surprising that the commonwealth will give approval to these FLNG operations," he continued.

In a speech before the state parliament, Logan said, "FLNG [facilities] are a job-killing technology for Australia and specifically for the Australian engineering, fabrication, and construction industries."

As many as 7,000 fabrication and construction jobs would be lost to FLNG facilities that are built in other countries, according to one trade union.

Browse LNG project strikes raw nerve

Woodside is the major equity holder and operator of the Browse Joint Venture (JV). The other partners are Shell Development (Australia) Pty. Ltd., BP Developments Australia Pty. Ltd., Japan Australia LNG (MIMI Browse) Pty. Ltd., and PetroChina International Investment (Australia) Pty. Ltd.

The development includes three gas and condensate fields – Brecknock, Calliance and Torosa, which are about 425 km (255 miles) north of Broome, Western Australia. Gross contingent resources (2C) are estimated at 450 Bcm (15.9 Tcf) of dry gas and 435.8 MMbbl of condensate.

The Prelude hull was completed and floated from the drydock in November 2013. Nine tugboats were required to move the 488-m long hull. (Image courtesy of Shell)

The original development plan called for an onshore LNG plant at James Price Point, north of Broome, at a cost of US $36.1 billion. During the inquiry, Shell estimated the cost for FLNG would be 30% lower than for onshore plants given estimates that indicated that the Browse FLNG development would cost about $25.3 billion. With the size of the liquefaction plants on FLNG vessels, up to three FLNG facilities would be needed.

On Sept. 2, 2013, the Browse JV participants selected FLNG technology to commercialize the Browse resources, using Shell's FLNG technology and Woodside's offshore development expertise.

The members of the inquiry committee took the companies to task during the hearings, especially over the claimed return on investment. Jan Norberger, MP for Joondalup, quoted a report from an unnamed major organization during a hearing with BP representatives Oct. 21, 2013, that said the Browse FLNG project would have an internal rate of return (IRR) of 12.5% to 13%, while the onshore plant would have an IRR of 11.5%.

Norberger questioned the company's definition of rate of return. "It would seem to me that if you have two projects – both of which return a positive rate of return – they both make money. I would state that I believe what really happened was that you wanted to go for the more profitable option. By going to the more profitable option, the indigenous people of the Pilbara now miss out – a massive loss to Western Australia in regard to construction and potentially with royalties and domestic gas."

Peter Metcalfe, external affairs manager, BP, responded by saying the definition of commercial viability for BP is a combination of risks, costs, and revenues,

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which is inherently a judgment. "We can only speak for BP, and the view we arrived at is that [the onshore option] was not commercially viable."

In testimony Oct. 16, 2013, Robert Cole, executive director, Woodside, told the committee that the FLNG development cost was materially lower than the James Price Point reference case. "Woodside considers FLNG as the only viable option for commercialization of the Browse resource," he said.

The Browse JV participants agreed to begin basis of design (BOD) work in relation to the FLNG facility Aug. 20, 2013. The BOD phase will determine the major design parameters for FEED of the proposed subsea and FLNG facilities and associated infrastructure.

Woodside expects the completion of the BOD in 2014, followed by awarding the FEED in 2014 with the FID in 2015.

The state opposition to FLNG is aimed at forcing companies to build LNG plants onshore to provide jobs and royalties for Western Australia.

Prelude dwarfs other offshore production vessels

The most challenging aspect of the Prelude FLNG project is the scale. Shell has a world-class facility in a world-class shipyard on a bigger scale than has ever been done before, said Neil Gilmour, Shell vice president, development for integrated gas.

"You've always got that question: If you scale things up, what happens? We've been doing the preparation for Prelude going back 15 years actually. In the last two or three years there's an enormous amount of preparation put in by the Shell team, the Technip engineering team, and the shipyards at Samsung in Korea and also in Dubai. I feel that this is really about making sure we get the technology right and do this safely," he said.

"At Prelude we're using Shell's double-mixed refrigerant (DMR) technology. It's been used on Sakhalin. In fact, the mantra in Shell for FLNG is that it's a completely unorthodox combination of technologies we've already demonstrated. We have a huge LNG technology

portfolio. We were really determined to take it offshore for FLNG. The technology that's gone onto Prelude has been proven," he explained.

"You always encounter things that you haven't anticipated, but we've adapted to that. Of course, for us on the FLNG program, we're really interested in getting No. 1 right because No. 1 is the starting point for No. 2 and so on," he added.

Prelude will become one of the first offshore fields in the world exploited using FLNG technology. The FLNG facility will produce at least 3.6 million tonnes per annum (MMtpa) of LNG, 1.3 MMtpa of condensate, and 0.4 MMtpa of LPG. The FLNG facility will stay permanently moored at the Prelude gas field for 20 to 25 years and in later development phases should produce from other fields where Shell has an interest.

The keel was completed in May 2013, and Samsung began assembling the hull. A hull section is being lowered into place. (Image courtesy of Shell)

Shell (67.5%) is the operator of Prelude FLNG in JV with INPEX (17.5%), KOGAS (10%), and OPIC (5%), working with long-term strategic partners Technip and Samsung Heavy Industries (the Technip Samsung Consortium).

The Prelude FLNG facility will be 488 m (1,600 ft) long and 74 m (243 ft) wide. When fully equipped with storage tanks full, it will weigh around 600,000 mt. The facility will be moored in about 250 m (820 ft) of water and remain on site during all weather events, having been designed to withstand a Category 5 cyclone. It will be about 475 km (285 miles) north-northeast of Broome.

Shell is well into the construction phase, with the majority of the attention focused on Samsung's Geoje shipyard. The hull was completed and floated from the drydock in November 2013. It was towed by nine tugs across the harbor and is secured quayside, where the topsides are installed and integrated. There are 14 topside modules. "The first module was completed in September, shipped back to Geoje, and installed in the hull," Gilmour said.

At the Dubai Drydocks, Shell has the world's largest turret assembled. SBM Offshore fabricated the turret for high mooring loads. It has a total weight of 11,000 tons with a height of 93 m (305 ft) for Prelude, according to SBM.

"One of these big records is the chain connectors that are going to link the FLNG to the mooring lines. These are enormous. You can almost stand inside edge to edge in the links," he said.

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The subsea infrastructure is largely being built in Malaysia. The installation testing of the christmas trees was done before Christmas, Gilmour laughed.

FMC Technologies Inc. stated in a press release that it will supply seven large-bore subsea production trees, production manifolds, riser bases, subsea control systems, and other related equipment. An aftermarket agreement was signed that will result in FMC Technologies Australia Ltd. performing installation and commissioning services for the project.

The LNG and natural gas liquids will be stored in tanks in the hull. (Image courtesy of Shell)

FMC also will supply the Technip Samsung Consortium with seven offshore footless marine loading arms – four for LNG and three for LPG from FMC's plant in Sens, France. "In Singapore we've got the control systems for the processes for the FLNG. Some have been completed, and some of them are still under manufacture," Gilmour said. "Then we're drilling the seven production wells in Australia. That started in August 2013."

Shell awarded the infield support vessel to KT Maritime Services Australia Pty. Ltd. The JV partnership between Kotug International BV and Teekay Shipping Australia Pty. Ltd. will supply three 100-mt bollard pull vessels to assist in product offloading.

The concrete and structural work is underway in Darwin on the site of the mainland shore facilities.

"Basically we're making progress across a number of locations. As ever, safety and quality are the priority to make sure all this comes together right and also works the way that we planned," Gilmour emphasized.

"I think it's an extraordinary achievement, doing an extraordinary project in an extraordinary place. We talked about a program before we even had a project. I was personally amazed when I had a look at the plans for assembling the hull. I remember talking to the Samsung yard manager who showed me the schedule. It was like the world's largest Lego set," he said. "Then you look at the assembly of the hull. The construction of the hull went very fast, extraordinarily fast. We were very, very well prepared. It's like the choreography of a complex orchestra."

Bonaparte LNG remains on track

In January 2010, GDF Suez signed the final agreement for the purchase of a 60% share in three offshore gas fields in Australia from Santos. The transaction was part of the Bonaparte LNG project announced in August 2009.

Bonaparte LNG is an integrated FLNG project with a capacity of 2 MMtpa of LNG. The project includes the development of the Petrel, Tern, and Frigate gas fields in the Bonaparte basin in the Timor Sea.

The operator for this project, which has been approved, is GDF Suez Bonaparte. "We are now in the pre-FEED phase of the project, confident but still with a lot of work to do before reaching FID," said Jean-Fran-

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cois Letellier, general manager, GDF Suez Bonaparte, to the committee Oct. 21, 2013.

"Today there is a design competition ongoing between two consortia – Technip and Daewoo Shipbuilding & Marine Engineering (DSME); and KBR and Hyundai Heavy Industries. There will be a winner in this competition, and this winner will be awarded the FEED and, subject to the FID, the execution," he explained.

ExxonMobil, BHP Billiton disagree on FLNG

The Scarborough gas field is about 220 km (132 miles) northwest of Exmouth in the Carnarvon basin. It is a mid-sized field with 226.5 Bcm to 283.2 Bcm (8 Tcf to 10 Tcf) of essentially dry gas resources in 950 m (3,116 ft) of water. The field is being developed by a 50/50 JV of ExxonMobil and BHP Billiton.

"ExxonMobil has selected FLNG as the lead development concept for Scarborough," said Luke Musgrave, vice president, LNG, ExxonMobil (Australia), during testimony to the inquiry committee Oct. 21. "We are doing concept studies, which we expect to continue through 2014. At the conclusion of those we need to make a decision whether to do FEED. At the conclusion of that we would have [to make an FID]."

The FLNG facility would have a capacity from 6 MMtpa to 7 MMtpa. He explained that the facility could increase the capacity because of the dry gas. No equipment or storage would be required for gas liquids, allowing more space for liquefaction.

In a Dec. 12, 2013, article in the *West Australian*, Tim Cutt, president, BHP Billiton Petroleum, was quoted as saying his company wanted to make sure all options were considered for Scarborough. BHP Billiton would like to look at existing infrastructure to see if it could be leveraged for the field.

Musgrave told the committee that the gas field has relatively low pressure. A pipeline to an onshore location would be at least 200 km (120 miles). Because of the low pressure, a floating compression platform would be required to move the gas that distance. The cost of

The cargo storage tank is lowered into the hull of the Caribbean FLNG barge at Wison Heavy Industry's shipyard in Nantong, China. (Image courtesy of EXMAR Marine)

building the compression platform, pipeline, and onshore liquefaction plant would be more than just building an FLNG facility for the field.

"It becomes very capitally efficient to eliminate the compression step and the transportation step by putting those facilities proximal to the reservoir itself," he added.

Barge-mounted FLNG for Colombia

The Caribbean FLNG Project is another facility under construction. In December Wison Offshore & Marine Ltd. began the installation of the topsides liquefaction equipment on what will be the world's first floating liquefaction and storage vessel in operation.

Exmar awarded an engineering, procurement, construction, installation, and commission (EPCIC) contract to Wison Offshore. The FLNG facility is being built for Pacific Rubiales Energy, Colombia. Fabrication began in late 2012 and is on schedule for first deliveries in 2Q 2015. The project consists of a nonpropelled barge that will be installed off the coast of Colombia. The FLNG barge will have a capacity of 500,000 mt/year. Black & Veatch will supply its single mixed-refrigerant PRICO liquefaction technology.

Exmar will build, operate, and maintain what it calls a floating liquefaction and storage unit. Storage capacity is 16,100 cm (568,600 cf). The barge is 144 m long, 32 m wide, and 20 m deep (472 ft long, 105 ft wide, and 66 ft deep) with a draft of 5.4 m (18 ft). The barge is designed with all power generation and utilities installed onboard and can perform offload side-by-side with an LNG carrier either with transfer hoses or loading arms.

On Nov. 5, 2013, Pacific Rubiales Energy and Gazprom Marketing & Trade Ltd. signed a heads of agreement with respect to a five-year sales and purchase agreement for about 500,000 cm/year (17.7 MMcf/year) free on board Colombia.

The FLNG barge is expected to be mechanically completed in April 2014 and be ready to be transported from the Chinese shipyard in fall 2014.

Malaysia orders two FLNG facilities

On Jan. 23, 2014, Malaysia's Petroliam Nasional Bhd. (Petronas) made the FID for its second FLNG project, which is named PFLNG 2. At the same time, the keel was being laid on the PFLNG 1 at the DSME shipyard in Okpo, South Korea. The PFLNG 1 is scheduled for completion by year-end 2015, while the PFLNG 2 is expected to begin LNG production early in 2018.

The PFLNG 1 vessel will be 300 m (984 ft) long and 60 m (197 ft) wide with a capacity of 1.2 MMmt/year and will be the first FLNG vessel to use a dual-row cargo containment system to limit sloshing within the tanks.

For PFLNG 2, the vessel will be 365 m (1,197 ft) long with a capacity of 1.5 MMmt/year.

For the PFLNG 1 project Petronas is working with Technip and DSME. The vessel will be located on Malaysia's Kanowit gas field, which is 180 km (111 miles) offshore Sarawak. The EPCIC contract for PFLNG 2 was awarded to a consortium of JGC Corp. and Samsung Heavy Industries, including their Malaysian subsidiaries. The facility will be installed on the Rotan gas field in deepwater Block H offshore Sabah, Malaysia.

These FLNG facilities are part of Petronas' strategies to tap gas reserves in Malaysia's remote and stranded fields that are currently considered to be uneconomical to develop and evacuate.

Noble Energy targets Eastern Mediterranean

There is a smorgasbord of choices for Noble Energy for developing the Leviathan field offshore Israel, which contains about 538 Bcm (19 Tcf) of gas. Between all of its fields offshore Israel and Cyprus, the company has discovered about 991 Bcm (35 Tcf) of gas. It could deliver gas by pipeline to several countries, build an onshore LNG plant, construct an FLNG facility, or pipe gas to LNG plants in Egypt.

"The government lets you export 50% of your discovered big fields. Noble's strategy is to monetize the export reserves. We want to do that in a way that is mutually beneficial to the region, us, and our shareholders. Besides just taking care of the domestic market, we're also looking at regional markets that could be fed by pipeline," said Gerry Peereboom, director of LNG development, Noble Energy. "We have a modest contract with the Palestinian Authority, and we've already signed up with Jordan. Other possibilities are Egypt and Turkey. Besides LNG there are other options to seriously consider," he added.

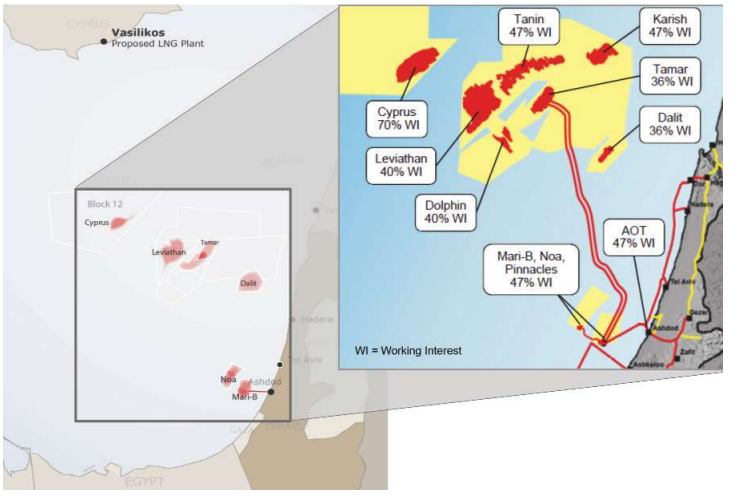
With that much gas, Noble could have a portfolio of different options that would give the company some risk mitigation. Reducing risk is one of the reasons Noble took on Woodside Petroleum as a partner in Leviathan. This will allow Noble to use its deepwater technology and gain Woodside's expertise in marketing LNG in places like Asia where that company has some excellent connections, he continued.

"Woodside is anxious to get into a producing region that is at an early stage of development. They seem pretty comfortable with Israel since they have taken a considerable period of time to do their due diligence. They are fully committed to this area, and I think Woodside is going to be a good partner," Peereboom said.

In February 2014 Woodside entered into a memorandum of understanding (MoU) with the Leviathan JV partners (Noble Energy Mediterranean Ltd., Delek Drilling LP, Avner Oil Exploration LP, and Ratio Oil Exploration 1992 LP) to acquire a 25% participating interest in the 349/Rachel and 350/Amit petroleum licenses for $1.03 billion. The parties were negotiating toward executing a fully termed agreement by March 27, 2014. After the agreement is signed, the interest shares will be Noble, 30%; Woodside, 25%; Delek, 16.94%; Avner, 16.94%; and Ratio Oil, 11.12%.

LNG is the preferred option for export since the markets are more geographically divergent. An onshore location in Israel faces the problem of limited coastline that the country would like to save for tourism. The

The artist's rendition of the Caribbean FLNG facility shows an LNG carrier docked next to the liquefaction barge. Caribbean FLNG will begin commercial production in 2Q 2015. (Image courtesy of EXMAR Marine)



Noble Energy has discovered about 991 Bcm of natural gas in its acreage position in the eastern Mediterranean Sea. (Image courtesy of Noble Energy)

areas with industrial activity are very crowded, and space is at a premium.

"It is not that onshore would be impossible, but it is enough of a challenge where we are seriously looking at FLNG," Peereboom explained.

Part of the government's export policy mandate is that a project must supply the domestic market. Noble is already producing gas from the Tamar fields using a pipeline to shore. The government wants a second independent pipeline from Leviathan for supply security. Providing gas through another pipeline as well as exporting gas will be a win-win situation, he emphasized.

The decision whether to have an onshore LNG plant or an FLNG facility has yet to be made; however, the company is interested in FLNG.

"We're going into FEED for FLNG. We've already shortlisted a few companies and consortia that are going to get an invitation to tender. We hope to be in FEED by mid-summer," Peereboom said.

"We're looking at an FLNG vessel with a capacity of about 3.25 MMmt/year. That could go up. Part of our overall planning is that we have to juggle how much we're going to supply domestically, how much might be piped to other regional countries, and how much LNG."

Noble will set the capacity going into the FEED work so that all the groups will have the same basis. The company will have two or three competing FEED contracts.

Leviathan is a very large field with a relatively flat structure, which is more challenging for development. The field is in water depths around 1,630 m (5,346 ft). Wells will be drilled to a depth of about 5,000 m (16,400 ft). The field is located 135 km (84 miles) west of Haifa, Israel. The field has very dry gas that is more than 99% methane. Wells are expected to be prolific. For example, wells in the Tamar field are producing 7.1 MMcm/d (250 MMcf/d), he said.

"Noble wants to be a real player in LNG. It is really a mix of staying involved in the upstream where we have a competitive advantage and becoming a serious player in the midstream – onshore LNG, offshore LNG, and pipelines," Peereboom said. "It is a pretty exciting time in FLNG, which will be an area of focus for Noble for several years."

Ophir taps FLNG for Equatorial Guinea

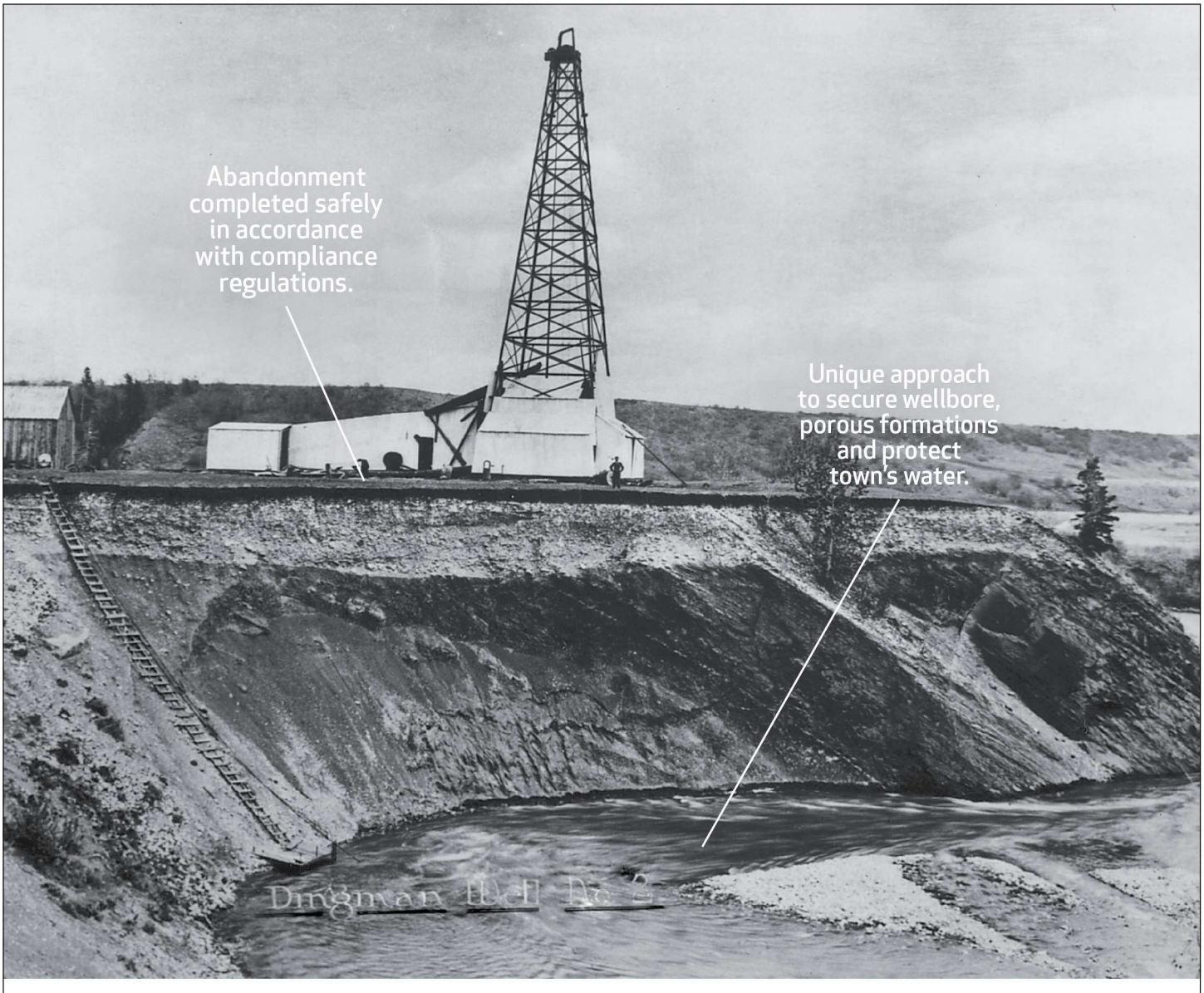
A number of companies have submitted proposals to Ophir Energy for FLNG facilities for offshore Equatorial Guinea, and several of these were shortlisted for further assessment with nonbinding letters of intent signed Feb. 20, 2014, in Singapore with the counterparties involved.

The Equatorial Guinea Ministry of Mines, Industry, and Energy and Ophir are reviewing the competing proposals and will execute an MoU with the selected FLNG vessel provider.

Ophir also signed a nonbinding letter of intent with Petrofac to provide services to the operator of the proposed gas development up to the FID. Duties likely will include preparing and issuing the field development plan for the project and coordinating the interface between the upstream and midstream elements. The project includes an FLNG vessel and a later onshore LNG train.

Currently, Ophir has an 80% interest in Block R, which covers 2,450 sq km (946 sq miles) in water depths from

The Vantage drillship *Titanium Explorer* will drill the wells offshore Equatorial Guinea for the FLNG project. (Image courtesy of Vantage and Ophir Energy)



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600 m to 1,950 m (1,968 ft to 6,396 ft) in the southeastern Niger Delta. Three fields were discovered with total 2C of 74 Bcm (2.6 Tcf), which is enough to support a 2.5-MMmt/year FLNG development.

The FLNG project will be completed in phases, allowing slow ramp-up of volumes. The phased field development will be funded out of cash flow, Ophir said in a press release. Phase 1 will require seven wells. First LNG production is expected in 2018. The project has the full support of the government. A second onshore train is viable but needs more resources to underpin the higher cost and more capital required, according to the company.

During 2014 the key objectives are to establish the value chain for the FLNG development, confirm and increase the resource base with a three-well drilling program, and test a deeper liquids play. Ophir expects to add upstream partners to enhance the LNG development.

Abadi LNG project offshore Indonesia

The Indonesian government approved a plan of development for the Abadi gas field on the Masela Block in December 2010 for an FLNG vessel with a capacity of 2.5 MMmt/year and 8,400 b/d of condensate. Inpex (65%) and Shell (35%) are in the midst of two FEED contracts that are expected to be completed by mid-2014.

In January 2013 the FLNG FEED contract was awarded to two groups: JGC Corp., Technip, Samsung Heavy Industries, and Modec Inc.; and Saipem, Chiyoda International, PT Tripatra Engineers and Constructors, PT Rekayasa Industri, Hyundai Heavy Industries, and SBM.

The groups will conduct the FLNG FEED in parallel under a design competition. The FLNG EPC contract will be awarded to the group that provides technical and commercial superiority based on its overall design solution. The FID and the start of production will be determined based on the FEED results.

The Abadi gas field is estimated to hold enough reserves for the production of 2.5 MMmt/year of LNG for more than 30 years.

North American FLNG projects

As interest in LNG exports from Canada and the US con-

Class keeps pace with FLNG development

By **Tor-Ivar Guttulsrod**, ABS

According to Clarkson Research Services Ltd.'s "Offshore Intelligence Monthly," there is a cumulative FLNG requirement of 36 FLNG projects with targeted delivery dates by 2020. While all of these projects will not materialize, it is probable that as many as 16 FLNG vessels could be in operation by that time. FLNG technology could make a significant contribution to the 4 Bcm/d (140 Bcf/d) of natural gas production expected in six years' time.

Although the FLNG process is relatively new, the basic technologies – such as gas processing and liquefaction – are proven technologies that can be modified for offshore application. The same goes for gas storage and offloading. But it is unwise to assume that these similarities make the transfer of technology from onshore to offshore simple. It is important to recognize that land-based plants and floating units are different in a number of significant ways. An FLNG unit introduces vessel motions to the process and to offloading and presents challenges for carrier operations. The separation distance between the FLNG and the carrier can introduce considerations for topsides arrangement.

Design and operational issues combine to create the biggest technical challenges in FLNG terminal design. Among these are the large size of terminal hulls and LNG containment systems, load effects in shallow water, sloshing that can occur when a hull is only partially filled, offloading operations, and critical interfaces between the hull and topsides and between the hull and the mooring system.

Mechanical stresses are another concern because they can cause fatigue that impacts the operational life of topsides processing equipment. Offshore equipment can be subject to cracking caused by vessel motions and by corrosion resulting from saltwater spray. Meanwhile, space and weight limitations make equipment installation and piping more challenging than for land applications. Modular equipment on FLNG installations changes the layout and necessitates additional safety and operational studies.

Recognizing these challenges, the industry has undertaken R&D targeting such issues as integrating subsea architecture with FLNG, process marinization, side-by-side and tandem offloading systems, and testing and qualifying the components that will be used in LNG transfer systems.

For the FLNG sector to grow safely, there have to be international standards and regulatory requirements, best industry practices, and environmental guidelines. ABS is helping to create this framework through the recently formed global gas solutions team, which is working with industry to address FLNG challenges. ■

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tinues to increase, several companies have begun work on FLNG facilities to move shale gas to overseas markets.

The Canadian project is ahead of the US developments. In August 2013 Exmar entered into a letter of intent with LNG Partners LLC and LNG BargeCo BBVA to provide a floating liquefaction and storage unit (FLSU) that will be docked on the west bank of the Douglas Channel near Kitimat, British Columbia.

Exmar will design, construct, and deliver a barge-mounted liquefaction plant, which uses the PRICO liquefaction process for a facility with a capacity of 700,000 mt/year in 1Q 2016. The FLSU will be chartered by Exmar to the BC LNG Project for a firm term period of 20 years.

The project has already received its export permit from the Canadian government and was expected to obtain all required approvals and permits by the end of 2013, according to Exmar.

Three FLNG projects were proposed for the US Gulf of Mexico near Port Lavaca and Brownsville, Texas, and Venice, La.

Excelerate Energy completed its FEED work for its 4.4 MMmt/year dockside FLNG, which will be near Port Lavaca, Texas. The study determined the Lavaca Bay LNG facility will cost $2.4 billion dollars, according to a May 2013 press release from the company. The facility is expected to be in service by 4Q 2018 pending Federal Energy Regulatory Commission (FERC) approval.

The company was granted permission to export to free-trade agreement (FTA) nations by the US Department of Energy (DOE). It filed for non-FTA approval in October 2012.

On Feb. 24, 2014, Excelerate said it filed its formal application with the FERC requesting authorization to construct, own, and operate the first US FLNG export facility. Rob Bryngelson, president and CEO of Excelerate, noted in a press release, "We continue to make strong progress on all fronts and hope to make an FID within the next 12 months."

Excelerate is fourth in order on the list of applicants the DOE is currently processing, the company continued.

The floating liquefaction, storage, and offloading (FLSO) vessel will have a storage capacity of 250,000 cm (8.8 MMcf). There will be a fully integrated onshore gas processing plant. The facility will interconnect to the region's existing pipeline system. The project will be designed and permitted to add a second FLSO facility for a total production capacity of up to 10 MMmt/year.

The Evolution-class FLSO vessel has a maximum production capacity of 3 MMmt/year using three individual 1 MMmt/year processing modules. The LNG storage consists of 10 side-by-side GTT Mark III membrane cargo tanks.

The Port of Brownsville project is being developed by Eos LNG LLC. The project will use a barge-mounted liquefaction plant. Wison will provide project management, engineering, procurement, construction, and commissioning of the facility, according to a presentation by Andrew Kunian, CEO, Eos, at the North American LNG Export conference sponsored by Zeus Intelligence Dec. 12, 2013.

An FID is expected by July 2014 with a date of delivery of Jan. 1, 2018. The facility will have a capacity of 2 MMmt/year. The site can be expanded to 4 MMmt/year. The FLNG barge is estimated to cost $750 million with another $250 million for onshore infrastructure.

The Edinburgh, Texas, pipeline connection is 96 km (60 miles) away from the terminal site.

Cambridge Energy Group Ltd. is proposing the 8.2 MMmt/year FLNG export project near Venice, La., Sherman Bryant, CEO, told the North American LNG Export conference. The project would consist of two self-propelled 4.1 MMmt/year FLNG vessels, one pipeline to six interconnections with intrastate pipelines, 12 LNG carriers, six tugs, and six LNG shuttle carriers.

The project received DOE approval for FTA countries Nov. 21, 2012. Cambridge Energy Group filed for non-FTA export approval in the same month. The company received FERC approval to begin prefiling its project April 16, 2013. FERC approval for the project and the FID are expected in 3Q 2015.

FLNG projects delayed

Since February 1999, when an environmental impact statement was completed for evaluating onshore liquefaction and FLNG for the Greater Sunrise development in the Timor Sea, Shell has been pursuing FLNG. However, in 2001, Shell and its partners, Woodside Petroleum, ConocoPhillips, and Osaka Gas, tabled the FLNG concept. Political differences between the governments of Australia and Timor-Leste continued to delay the development of the Greater Sunrise fields, which were discovered in 1974.

Then in April 2010, following the announcement of the Prelude FLNG project, the Greater Sunrise JV partners selected Shell's FLNG technology for field development – subject to, of course, government approvals and FID. The facility would produce around 4 MMmt/year of LNG.

Petrobras and BG Group also put an FLNG project on hold. In 2009 the companies signed a JV to work on FLNG projects. According to a press release, in July 2011 Petrobras postponed the use of FLNG to develop fields in the Santos basin beyond 2016. A FEED that compared

FLNG to a pipeline option was completed, and the company selected the pipeline.

Another promising FLNG project offshore Papua New Guinea (PNG) also hit rough sailing. Flex LNG executed agreements with InterOil, Pacific LNG, LNG Ltd., and Samsung Heavy Industries in April 2011 for EPCIC of an LNG project to liquefy gas from the Elk and Antelope fields in Gulf Province, PNG. The target date for commercial production to begin was 2015.

The FEED was completed in December 2011 for the Gulf LNG project, and Flex LNG was ready for the FID. However, the PNG government and other stakeholders were unable to finalize terms, according to a January 2012 press release. The company already had deployed capital for the project with Samsung. The initial order for the FLNG vessel was changed to LNG carriers instead. No decision has been made on the Gulf LNG project.

Speculative FLNG projects

SBM designed a mid-scale FLNG solution for stranded gas fields. The concept consists of converting two Moss-type LNG carriers into a catamaran-type FLNG facility. The FLNG facility would have a capacity of 1.5 MMmt/year to 2 MMmt/year and be suitable for stranded gas fields between 14.2 Bcm and 56.6 Bcm (0.5 Tcf and 2 Tcf).

Converting older LNG tankers into FLNG facilities would reduce costs and require less time since the storage tanks would already be installed. SBM has performed generic pre-FEED work together with Linde Engineering on an FLNG vessel using a pre-cooled dual nitrogen-expansion process.

Press reports speculate such an FLNG vessel could be installed first in either Indonesia or Australia.

Another FLNG project has been touted by ENI for its Area 4 license offshore Mozambique. This would be in addition to the onshore LNG plant, which is currently in FEED. Australia also has a speculative FLNG project based on the Crux field in the Browse basin. The field could be tied into Browse FLNG. E&P

FLNG market riding investment wave

With forecast total expenditure of nearly US $65 billion between now and the year 2020, the global FLNG market is set for a period of significant expansion.

Mark Thomas, Editor in Chief

The floating LNG (FLNG) market is set to grow strongly due largely to two already well-known factors. One is the explosion in global population over the next several decades accompanied by continued GDP growth in the major developing economies (mainly China and India), which is expected to see world energy demand surge by around 50%. The other is that, while oil's percentage share of the energy mix will decline (although rising in actual terms), the largest growth will be in natural gas consumption.

According to Amanda Tay of analyst Douglas-Westwood, gas is the outstanding fuel for power generation, with gas-fired power plants having the lowest capex while producing less than half of the CO_2 emissions of coal. It also is relatively cheap, and there are abundant reserves – the International Energy Agency suggests there is enough to last 230 years at today's consumption levels.

Recent years have increasingly revealed giant new offshore gas reserves from the emerging frontiers of the Eastern Mediterranean to the outstanding resources off the east coast of Africa and the western shore of Australia. But these resources also share similar constraints — they are often significant distances from potential markets and, unlike oil, are expensive to transport as most pipelines become economically unviable when longer than 1,000 km (621 miles).

FLNG's star rising

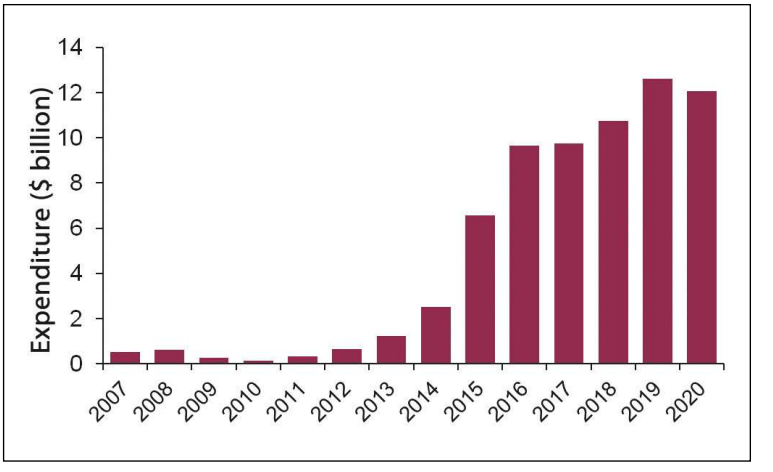
FLNG's star has been rising steadily as a result. Floating liquefaction is no new concept, of course – its development began in the 1970s. The practical logic behind it is simple, as cooling the gas to -162˚C (-260˚F) liquefies it and reduces it to one six-hundredth of its original volume, allowing it to be transported in large insulated tanks on ships.

Some 30% of global natural gas imports are already being delivered via LNG. Douglas-Westwood's *World LNG Market Forecast* for the period 2013 to 2017 forecasts that US $143 billion will be spent on liquefaction plants, $35 billion on LNG carriers, and $50 billion on import facilities. The total is double the amount for the previous five-year period.

First movers

The first FLNG vessels are well under construction with Shell's Prelude facility – destined for offshore Australia – the most well-known. The operators have succumbed to the solution's inherent advantages, which eliminate the need for costly production platforms linked by long pipelines to shore.

There are other advantages. FLNG is attractive in providing more secure operations than onshore plants in regions of potential unrest. It also offers a solution for unwanted associated gas from oil production, which traditionally has been reinjected or flared, and removes the aspect of land footprints in environmentally sensitive areas.



Global capex on FLNG facilities is expected to rise dramatically from 2014 to 2020. (Image courtesy of Douglas-Westwood, *World FLNG Market Forecast* 2014-2020)

Market of $64.4 billion

The predicted growth for the global FLNG market is astonishing. Expenditure is expected to rise from $3.7 billion (for the period 2007 to 2013) to $64.4 billion (2014 to 2020).

According to Douglas-Westwood, about two-thirds of the total spend is attributable to liquefaction infrastructure, while the remainder is from import and regasification facilities.

Year-on-year growth between now and 2020 is forecast to average 64% per year, and the analyst expects this rise to be more pronounced after the successful startup and operation of the first wave of pioneering FLNG vessels, namely Prelude and the PFLNG 1 unit offshore Malaysia.

Asia, which is a focus area for both floating liquefaction and regasification vessels, is expected to account for 29% of expenditure, contributing $18.2 billion. Australasia accounts for the largest proportion of global capex at 30%, driven by its queue of liquefaction projects with a forecast expenditure of $19 billion between 2014 and 2020.

Shell's Prelude facility will be the largest floating production unit ever made, displacing more water than six aircraft carriers. This craft will be in the vanguard of the FLNG fleet, and its performance will be scrutinized minutely by the industry for its operational and commercial performance.

Size matters

Size is a factor in FLNG thinking. Thierry Milatec, a lead process engineer at Saipem, has been working on the Abadi FLNG project destined to work offshore Indonesia for Inpex and Shell. Speaking at the Australasian Oil & Gas conference in Perth, Australia, he pointed out to delegates that an FPSO unit might normally be around 300 m (984 ft) in length, while a large-scale FLNG vessel is closer to 500 m (1,640 ft). "And a 100-m (328-ft) increase in length means you can essentially double the production levels," he said.

Inpex recently awarded parallel contracts for the FEED of the Abadi facility, with one going to a JGC Corp./PT JGC Indonesia consortium and the other to a PT Saipem Indonesia/Saipem consortium. The eventual winner will progress into a full FLNG engineering, procurement, and construction phase.

A further FLNG unit also has been chosen by Malaysia's Petronas for its second such project in its domestic waters. It has issued a design, build, and installation contract for the PFLNG 2 unit, which will be located in deep water off the coast of Sabah.

The engineering, procurement, construction, installation, and commissioning contract went to a consortium of JGC Corp., Samsung Heavy Industries Co. Ltd., JGC (Malaysia) Sdn. Bhd., and Samsung Heavy Industries (M) Sdn. Bhd.

The facility will be moored on the Rotan field in Block H and will produce 1.5 million tonnes per annum (MMtpa) of LNG. It is scheduled to be ready for startup by early 2018. The operator's PFLNG 1 unit will be moored on the Kanowit field offshore Sarawak, is slightly smaller (designed to produce 1.2 MMtpa of LNG), and is scheduled for startup by year-end 2015.

Changing LNG landscape

Petronas said that, once operational, both its PFLNG facilities are expected to "change the landscape of the LNG business." As such, it added, the facilities will play a significant role in the company's efforts to unlock Malaysia's remote and stranded gas reserves.

Elsewhere, the eastern Mediterranean has Noble Energy, Woodside, and its partners progressing toward the use of an FLNG unit for the second development phase of the producing Tamar field offshore Israel, while a further unit is expected to be employed on the giant neighboring Leviathan field, the world's largest offshore gas discovery of the last decade. A third unit also is being considered for the development of another large gas field (Cyprus-A) close to these two fields in Cypriot waters.

Off Africa's east coast, Eni and its partners are considering an FLNG solution for monetizing part of their giant gas reserves off the coast of Mozambique, while on Africa's west coast Ophir Energy has short-listed bidders to supply it with a leased FLNG unit for its deepwater gas resources in Block R off Equatorial Guinea.

Perhaps tellingly, the initial costs pre-first gas for Ophir's project had previously been estimated by the company at between $1 billion and $1.5 billion. It says it chose FLNG as the fastest route for getting its gas to market and that it also had a lower cost of production compared to a land-based LNG train (as well as enabling staged upstream capex and an expandable vessel capacity).

Douglas-Westwood's Tay supports that approach but warned, "In some situations, an FLNG vessel built in a specialist shipyard can be a lower-cost solution than a one-off 'stick-built' onshore plant. However, such offshore vessels, which are huge in size, are still a high-cost item with significant technical challenges." E&P

Well stimulation firms see rising demand in the Rockies

Oil plays driving increased development.

Richard Mason, Chief Technical Director

Contractors are looking for an increase in demand for 2014 pressure pumping services in the Rockies as activity expands in rapidly developing oil plays. Optimism on improved activity levels comes despite a sharp pullback in activity in dry gas plays such as the Piceance basin.

Some of the demand increase stems from the evolution from vertical to horizontal drilling as oil plays transition from delineation work to the optimization phase of unconventional development. Horizontal work involves more stages downhole and features greater service intensity. The transition adds to demand over and above expanding activity levels as operators delineate several up-and-coming liquids-rich plays in the region.

That said, contractors are less optimistic about pricing improvements in 2014 since there is an adequate supply of well stimulation equipment in the region. Equipment supply is considered excessive in the Piceance as activity winds down in the wake of poor natural gas economics. Well stimulation firms have laid crews off in the Piceance and moved equipment to other more promising areas in the Rockies. Consequently, there is enough capacity in the region to meet demand, even in an expanding activity environment.

Low gas prices are driving operators into oil plays in the Rockies.

Comments about market conditions in the Rockies outside the Bakken originated as part of a Hart Energy survey of oil service contractors in the region. Contractors reported an installed base of 732,600 hhp spread among six service providers who are marketing 25 fleets in the Rockies outside the Bakken shale. The installed well stimulation base is about one-third lower than the same period one year ago. Small-tier service providers have vacated areas like the Piceance, while larger firms are rotating equipment out of dry gas plays into oil areas both in the Rockies and other regional markets.

Contractors report the average cost per stage ranges from US $30,000 on vertical wells to $53,750 for horizontal work. The drilling mix in the region has repolarized from 75% natural gas-directed previously to 75% oil-directed currently, survey participants said.

A separate survey of well servicing contractors also revealed expectations for rising activity in 2014. However, optimism here came with a note of caution regarding oil prices. Oil prices at present levels would lead to an expansion in work, according to well service contractors, while a decline in commodity prices would adversely impact demand.

Well service contractors noted they had received positive comments regarding 2014 budgets and increased workflow from many of their E&P customers.

Contractors reported a sufficient supply of well servicing equipment in the region with some capacity stacked out. The main issue for contractors, according to survey participants, is labor. Crews have left the well services sector for better-paying employment in other segments of the oil services industry or have moved to the Bakken, where wages are higher for well servicing firms. A number of experienced hands have gone to work for customers as consultants.

Well service contractors noted that coiled tubing (CT) is making inroads in the Rockies outside the Bakken, though workover rigs continue to gain the greater share in an expanding market. Hurdles facing

CT include pricing since it is much more expensive than a workover rig even when considering the enhanced performance capabilities of CT units, the fact that laterals are getting longer, and CT is less effective drilling out stages at some of the extended laterals that operators are now drilling in the Rockies.

The survey found hourly rates for workover rigs at about $1 per unit of horsepower, or $300 to $500.

Regional trends

Slickwater fracs and sliding sleeves illustrate that the Rockies still present tight sands opportunities for hydrocarbons. Much of that opportunity involves going back into older fields and prospecting for different layers or turning wellbores horizontal to capture bypassed hydrocarbons.

Contractors identified several regional trends including moving from vertical to horizontal wells in the liquids-rich Dakota formation in the Greater Green River basin. Regionally, the move to horizontal drilling suggests operators are still in delineation mode in new plays, though early optimization efforts are unfolding in select markets as operators experiment with downhole practices.

Operators made significant progress on the evolution to pad drilling in 2013. Pad drilling now accounts for up to 90% of horizontal wells in a few specific plays and is spreading rapidly elsewhere in the region, with contractors anticipating a 15% increase in the number of horizontal wells drilled on pads in 2014. The average number of wells per pad remains fewer than three, however, slightly more than in the Permian but below the averages in the Eagle Ford, Bakken, and Marcellus shales.

Proppant volumes are lower here than in other plays, partly because completion practices feature fewer frac stages than other basins. Proppant rates range from 600,000 lb to 800,000 lb of sand on a 10-stage vertical well to more than 1 million lb on a representative 18-stage horizontal lateral, with coarse sand the predominant proppant. Zipper fracs are the main completion method on pad wells.

While stage clustering is beginning to dominate mature regions elsewhere, operators in the Rockies are still spacing stages at even intervals. The region has yet to see the widespread implementation of longer laterals that is characteristic of the Bakken. While contractors anticipate demand will grow for higher spec rigs on the basis of longer laterals, particularly in 2015, most customers are still comfortable with 750-hp to 1,000-hp rigs for drilling laterals. Higher spec rigs will likely be newbuild units when they arrive since it is unlikely the Rockies drilling market outside the Bakken shale will draw higher spec units currently active in North Dakota.

Drillers tell Hart that more contracts are available from customers but feature shorter terms. One- and two-year contracts have given way to six-month contracts, though operators in the Rockies signal they will be looking for rigs in June when the newer, shorter term contracts roll over. E&P

Powering up the seabed

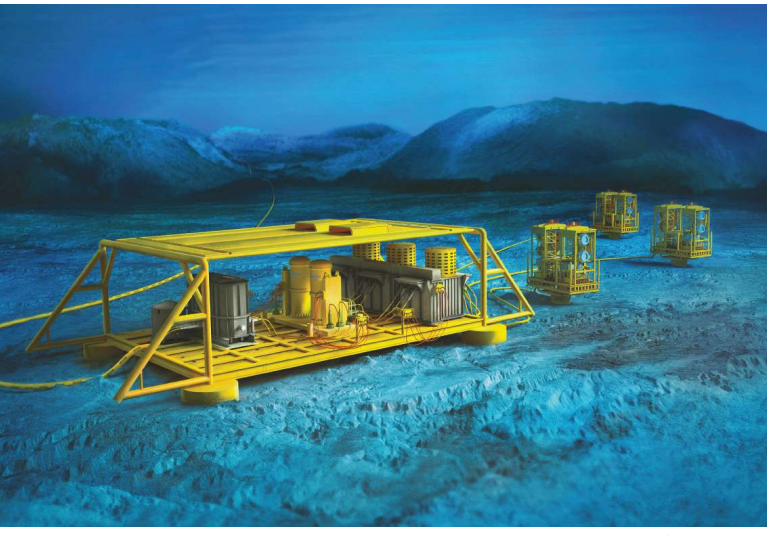
With subsea processing technologies firmly established as a viable development solution, the industry's attention is focused on how to supply the power required to drive the large and complex systems destined for the seabed.

Mark Thomas, Editor in Chief

With the success achieved to date on high-profile projects offshore Angola, Norway, and Brazil, both in terms of technological innovation and operational performance, the challenge now is to push the boundaries further.

Seabed processing solutions – Statoil's ambition to have a full "subsea factory" in the water by 2020 is one such high-profile example – will by their very nature require a step-change in the levels of power required. Subsea separation, boosting, and compression hardware is now a recognized piece of kit in an offshore operator's toolbox, especially for those targeting deepwater and harsh environment developments.

It also is seen as a key enabling technology for enhancing oil and gas recovery in both greenfield and brownfield projects as operators strive to improve average offshore recovery rates around the world from the current levels of 30% to 40% to a desired range of at least 50% to 65%.



Dependable power supply and distribution will be vital for large-scale subsea processing facilities. Siemens' subsea power grid, currently in the detail design and test phase, will include transformers, switchgear, and variable speed drives. (Images courtesy of Siemens)

Dependable power

All of this equipment, however, needs dependable power – and lots of it.

One solution under development by Siemens is the company's subsea power grid system, which is aimed at complementing the company's existing subsea portfolio that includes connectors, power systems, and permanent reservoir monitoring technologies.

A recent briefing by Siemens on the company's new power grid solution stressed the limited means currently available to transmit such power underwater over long distances to components such as pumps and compressors. Typically, single power feeders are run from land or topside facilities with cables running to the sea floor. According to Siemens, these solutions add complexity and cost to operations while simply not being viable for long stepouts or for situations that need relatively high power output or a high number of power consumers.

The power grid is designed to distribute power along the seabed to multiple consumers, minimizing the number of cables running to surface and simplifying operations. It also will enable the placement of processing equipment closer to wells, boosting production.

Phased approach

The company has adopted a phased approach to developing the system, which is currently in the detail design and test phase. The transformer was successfully tested in shallow waters in 2012, while other components such as switchgear and variable speed drives have been and continue to be tested. The aim is to bring the subsea power grid to the market next year.

One recent innovation is the 36-kv subsea connector that ultimately will be used to connect the different grid modules together. The connector's design incorporates new features to improve insulation performance, reduce the risk of leakage, and optimize pressure compensation.

Bjørn Rasch, Siemens' head of subsea power, pointed out that the subsea sector is the global offshore E&P seg-

The subsea power grid (mid-image) is seen as being a key enabling technology for seabed processing systems, including subsea distribution units, connectors, and christmas trees.

ment expected to grow the most, with a compound annual growth rate of 16.2%. Within that, getting reliable, field-proven subsea power distribution systems is seen as the "key enabler" for seabed processing, he said.

Rasch lists the key drivers as follows:

- ***Number of consumers*** – subsea power distribution can reduce the total length of cable and number of risers;
- ***Water depth*** – subsea power distribution can reduce the complexity of riser arrangements;
- ***Available space on existing platform installations*** – marginal fields can be developed with existing infrastructure;
- ***Long stepouts*** – Realization of subsea-to-beach; access of remote areas, e.g. Arctic; and
- ***Increased need for large-scale processing*** – subsea power distribution is the key enabling technology for realizing the subsea factory.

Likewise, the main benefits he sees are that:

- The complete system approach is important for success;
- The use of modular building blocks reduces cost and complexity;
- Built-in redundancy increases availability;
- These systems provide condition monitoring and intelligent operation;
- Operators can "trust in technology" by qualification and standardization; and
- Development has taken place in cooperation with leading oil companies.

System evolution

The last benefit has been a vital one in the subsea power grid's evolution. Siemens began the process with the launch of the original R&D project in June 2010 with joint industry project (JIP) contracts signed the following month with supporting operators including Statoil, Petrobras, Chevron, and ExxonMobil.

The product development was enhanced through targeted acquisitions of companies with specific subsea and power expertise, including Bennex and Poseidon (both based in Norway) in March 2011 and Tronic and Matre of the UK a year later. By September last year the JIP had completed qualification of the subsea transformer; product qualification and testing of the complete subsea grid are now underway. A shallow-water system test is currently penciled in for early in 2015, with the scalable system to eventually be rated for operation in up to 3,000 m (9,843 ft) of water and capable of handling long step-out distances of up to 200 km (124 miles).

Jan-Erik Lystad, who heads up Siemens' Subsea Technology Center in Trondheim, Norway, is in charge of the rigorous testing being undertaken on all of the company's subsea components there – what he described as "a kind of torture chamber for technical components." The tested components have to withstand pressures of up to 6,670 psi, equivalent to a water depth of 4,600 m (15,093 ft).

Current focus on AC

Lystad flagged AC transmission (36 kv to 145 kv) as the main focus of oil companies in terms of subsea power distribution technologies. "AC is the key focus area today, while DC by most is put off for the next three to five years," he said, adding that technology risks are viewed as manageable "and oil companies do not see any real showstoppers."

He also highlighted some subsea electronic power deliveries already made by the company, including converters for seabed logging – Siemens has developed and built a power converter to perform high-accuracy electromagnetic surveys offshore in extreme pressures. With a design requirement to be able to operate in water depths of up to 3,500 m (11,483 ft), endure pressure cycling, and cope with a high current of 1,500 Amps, Siemens has so far delivered 16 units and clocked up approximately 65,000 survey hours.

If the company hits its future milestones mapped out for its subsea power grid, the first system is planned to be operational circa 2016. E&P

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Pilot project in Oman reduces need for natural gas in thermal EOR.

Amy Logan, Senior Editor, Production

In sun-drenched southern Oman, vast acres of desert dotted by pumpjacks and oil rigs stretch far into the distance. But nestled in this petroleum landscape known as the Amal West oil field are 4 acres of glass and steel greenhouses, sparkling in the sun like an oasis in a mirage. As incongruous as these greenhouses may seem, they are no optical illusion. They are home to giant parabolic mirrors that produce – of all things – *steam*.

Instead of harnessing heat from the sun to drive machinery or generate electricity, these mirrors track the sun throughout the day, focusing sunlight on a tube containing water to create steam used for oil extraction. This concentrated solar power architecture, called an enclosed trough, is designed specifically for the oil field, and it represents a new form of powering thermal EOR.

This solar EOR operation in the Amal West oil field in southern Oman takes up four acres. The glass houses protect the sensitive mirrors and solar technology from the harsh elements. (Images courtesy of GlassPoint Solar)

Petroleum Development Oman (PDO) partnered with California-based GlassPoint Solar to build and test the new enclosed trough technology. GlassPoint built similar structures in February 2011 for its first commercial solar EOR project with Barry Petroleum in Kern County, Calif. The success of that project brought the young startup solar company to PDO's attention.

In January 2012 GlassPoint and PDO broke ground on the Middle East's first solar EOR project, completing the project in December 2013. By May 2013 GlassPoint was exceeding contracted performance targets by 10%. In December 2013 the system was generating an average of 50 tons of steam per day with a success rate boasting 98.6% uptime and an average steam output that is 80% steam vapor and 20% water. At the end of January, just two years after it broke ground, the project was producing enough steam to replace 1 MMcm (36 MMcf) of natural gas.

Forecast calls for sunshine

Daniel Palmer, GlassPoint's director of business development for the Middle East, said what's important to his clients is that the technology makes sense for countries such as Oman and areas such as the Middle East that are seeking solar solutions for their energy needs.

What is often referred to as the "easy oil" in the Middle East is now mostly gone. What remains is the hard-to-reach heavy oil. These assets require thermal EOR and high-pressure steam injection to produce them. Powering this steam generation with vast amounts of natural gas has been the EOR method most commonly used. But while heavy oil is abundant in Oman, natural gas is not.

Due to the shortage of natural gas in the Middle East, the price for it has skyrocketed. Palmer said that with GlassPoint's solar EOR technology, natural gas is only needed to make up for the loss of sunshine. This significantly reduces the amount of natural gas needed to recover oil and gas from Oman's rich reserves, he said.

Rod MacGregor, CEO of GlassPoint, said in a video interview that there are three economic criteria that must be met before deciding whether solar EOR is an appropriate solution:

"For [solar] EOR you need [abundant] sunshine – Oman has some of the best in the world. You need heavy oil – Oman is the leader in heavy oil production in the Middle East. And you need scarcity of an abundant fuel supply [such as natural gas]. Oman has all three of those things, making it the ideal location," he said.

If the project meets MacGregor's three criteria, Palmer

said GlassPoint will be able to offer its solution at a competitive price. "Our goal is always to be more economical than natural gas," he said.

He added that like most renewable energy technology, after operators put up the initial capital to purchase a solar EOR system, the system will pay for itself over time. "Once they're running, they're good to go," he said, referring to the solar steam generators and overall system.

Lean and clean

Part of what makes GlassPoint's solar EOR system unique is its glass and steel housing that keeps out the wind, humidity, sand, and grit that would otherwise impair the movement and sturdiness of the sun-tracking mirrors and components. There are no solar panels used. Instead, the mirrors sit upon a single-axis system that positions them to track the optimum amount of sunlight. That sunlight is then focused on stationary boiler tubes containing water waiting to be heated to the point where they can produce steam for thermal EOR.

Palmer said the GlassPoint system integrates perfectly with the existing equipment and uses the same type of feedwater needed for traditional gas-fired steam generators. It was designed this way to save money and account for the overnight hours when solar energy cannot be harvested and natural gas is required to maintain steam production. The large glass houses that protect the solar components are not only aerodynamic and made to withstand peak-wind force, but they are readily available to the market as mass-produced greenhouses. Not having to custom-design and build the glass housing from scratch also helps keep the cost down, Palmer said.

He added that mass-produced robots designed to clean greenhouse rooftops are handy in desert environments. "The dust levels are extremely high in Oman," he said. "You have to wash your car every day. We'd see a 3% drop in output if we didn't have the robots cleaning the glass overnight." The robots help ensure the sunlight has unrestricted access to the solar mechanics inside the housing to produce steam at a consistent 312°C (594°F).

Another big cost savings comes from the curved mirrors used in the solar EOR operations, Palmer said. Because the mirrors are protected from the harsh elements, they are thinner and lighter, saving on transportation and maintenance costs. Keeping all of the mirrors and solar components in a glass house that is filled with dehumidified and filtered air keeps them clean and operating at peak performance, Palmer added.

Crew safety is another advantage to the solar EOR system, Palmer said, adding that throughout the yearlong building and testing of the pilot project in Oman there were no lost-time injuries. "We can build the whole thing with no working from height," he said.

The entire solar EOR operation is fully automated. No one need enter the glass houses or try to keep the housing clean, he said.

Moving 'full steam ahead'

In a May 21, 2013, press release, Dr. Syham Bentouati, head of New Technology Implementation at PDO, said "preliminary results from this project demonstrate that solar steam generated with GlassPoint's enclosed trough architecture is equally as effective as natural gas for thermal EOR.

"This unit serves as a performance and operational baseline for future solar-steam generation projects in Oman," she added, "providing us with valuable information for planning potential future large-scale solar-steam projects."

Laura Atkins, executive director of upstream research at Hart Energy, noted in a Jan. 8, 2014, press release that heavy oil "will play a significant role in the global energy mix of the future." Since most of that oil will require steam injection for production, she said, GlassPoint's solar EOR technology and its ability to reduce natural gas use for EOR by up to 80% will be useful.

"This is a compelling proposition for many oil-producing nations," she said, "as gas saved can be redirected toward LNG export or put to use by local industry to fuel economic growth."

In the Middle East, Palmer said, "that makes perfect economic sense." E&P

A robot roams the glass rooftops, keeping them clean so the sunshine can be harnessed for solar EOR. Without regular cleanings, the rooftops would be coated in dirt and grime, reducing solar steam output by 3%.

Logging depends on conveyance, versatility

Complex wellbores are driving advances in wireline tools and techniques.

Aamir Hameed, Weatherford

A better understanding of the reservoir has resulted in the design of significantly more complex wellbores to optimize exploration and development. These advanced wellbore geometries have presented a major challenge to conventional openhole logging.

Complex well geometries

The shift from vertical wells to more deviated, S-shaped, horizontal, and multilateral wells has been achieved with a broad scope of innovative drilling technologies and techniques. Coiled tubing (CT), underbalanced drilling, and managed pressure drilling methods are increasingly common tools for improving drilling efficiency and limiting near wellbore formation damage.

However, growing wellbore complexity, tortuosity, hole instability, low-pressure zones, and a multitude of other issues have made conventional wireline conveyance problematic and often impossible. This comes at a time when a full set of logging data is often critical to optimizing the completion and long-term productivity. The need for formation data contrasts strongly with the risk of sticking or losing tools in the hole and the repercussions of limited or no openhole logs.

Poor hole conditions and convoluted trajectories result in excessive washouts that often create a zone that is impassable for tools under gravity or with conventional tool-push techniques. These tools have limited compressive strength and, being the first point of penetration, they tend to buckle in these zones, resulting in a series of incomplete operations, tool damage and fishing, and many times a failure to acquire data.

In particular, logging operations are commonly challenged on two key counts: well control and the ability to reach target depth. It becomes imperative to circulate and rotate to defy these challenges. Unfortunately, while wireline provides useful data, it also inhibits drillpipe rotation and puts constraints on circulation.

Technology advances

The solution relies on the marriage of a similarly diverse set of conveyance systems and a unique suite of logging tools. Weatherford is regularly logging complex and difficult wells in both real time and in memory using an array of Compact 2¼-in. openhole tools. The small-diameter tools acquire a full range of wireline-quality data to make basic and specialized petrophysical measurements including resistivity, porosity/lithology, formation testing, acoustic, and imaging. This year, the world's first memory-capable 4.1-in. oil-based microimager is being introduced.

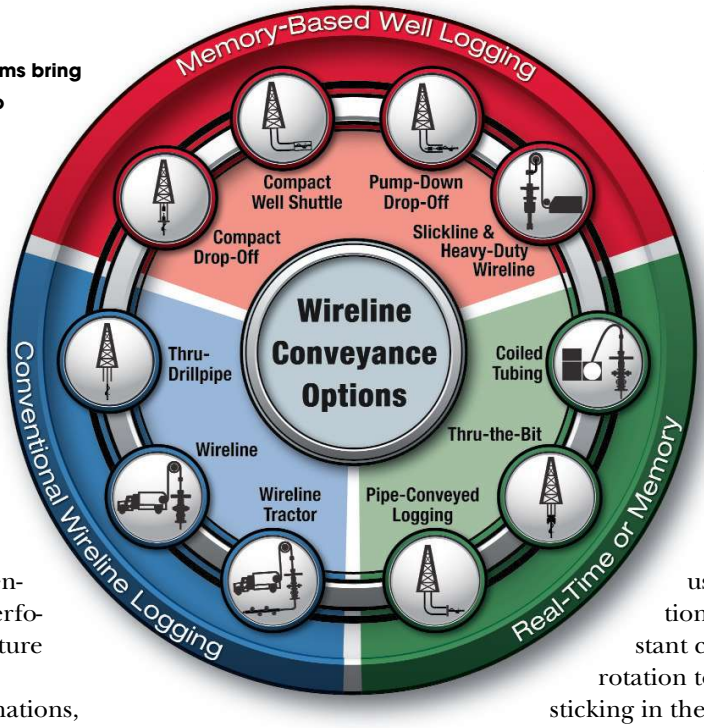
The flexibility to operate in real time or memory modes with the same set of tools provides a high degree of flexibility in planning and responding to specific wellbore challenges. It also eliminates logistical challenges posed by dedicated systems that operate in only one mode. Where wireline operations present well control issues, logging to memory provides a nonwireline alternative for acquiring data.

Options and applications

The ability to dependably log these wells has only come with the development and integration of two key components: a full suite of small-diameter tools and multiple conveyance options. The solution is twofold. It provides reliable acquisition of critical formation data in complex wellbores, and it reduces the risk of losing tools in the process. The success of this system assures future well designs are not constrained by the capabilities of the logging system.

Memory logging such as a well shuttle system protects tools inside the drillpipe until they are deployed into open hole. The technology logs in a single pass to save time in extended-reach wells, and it allows circulation and pipe rotation to deal with the hole conditions.

A memory-based drop-off method uses drillpipe with a special bottomhole assembly (BHA). The BHA is lowered to the target depth without the tools with full freedom. Once the drillpipe reaches desired depth, the tools are lowered inside the pipe on wireline and released into the BHA. The "drop off" conveyance technique enables the driller to have full control over the well, allowing mud circulation and conditioning while having logging tools deployed and providing the largest flow area.



Ten distinct conveyance systems bring reliability and predictability to openhole logging in complex wellbores. (Image courtesy of Weatherford)

Inherent to the utility of this versatile openhole logging system is the ability to log a full set of data. For example, in unconventional assets, the world's slimmest cross-dipole sonic, microimagers, and spectral gamma ray tools are being used to identify sweet spots to guide perforation placement and fracture treatment.

In thinly laminated formations, microimaging logs provide the only alternative to coring for determining net pay thickness. In developing the Grayburg formation in the Permian basin, Apache Corp.'s collaboration with Weatherford has developed a fit-for-purpose logging program incorporating the Compact microimager. Initial oil production rates increased nearly 40% in the first 180 days when the imaging tool was included in the operator's completions strategy.

Case histories

In western Russia, a drilling program converting vertical wells to highly deviated, complex-geometry horizontal wells required a formation tester log to evaluate pressure and permeability. The wireline through-pipe operations minimized cable sticking for reduced rig time. More than 40 out-of-pipe jobs were performed, including formation testing in memory, to achieve operational efficiency of 95% and a 99% sealing success rate.

The data were used to confirm formation saturation and fluid contacts as well as dynamic fluid model parameters. They also allowed more effective planning of the production well grid and saved drilling time when low pressure led to one planned horizontal candidate being reassigned as an injector well.

Wireline logging attempts in western Texas failed to reach total depth despite hole conditioning. To acquire the measurements, including rock mechanical properties, the 2¼-in. triple combo and cross-dipole sonic tools were run through the drillpipe, extending just below the well obstruction.

Highly deviated wells in a coalseam gas field in Australia challenged conventional wireline evaluation. Drilled from pad sites, the wellbore deviations reached from 60° to 85° in an 8½-in. hole. To log the wells, a nonwireline solution was selected that combined CT memory logging and shuttle conveyance. The shuttle used for openhole formation evaluation allowed constant circulation and pipe rotation to mitigate differential sticking in the tight hole. In addition to the traditional quad combo suite, an advanced microimager and a cross-dipole sonic were also run for full evaluation of the coalseams. CT memory logging was used in the cased hole to evaluate casing inner diameter and provide a cement bond.

To optimize hydraulic facture design in a complex volcanic reservoir development program in Argentina, a cross-dipole tool was deployed through the drillpipe into the open hole. The tool acquired data for rock mechanical properties, brittleness, and formation anisotropy to inform perforating and fracturing design. The same tool was later run in the cased hole to evaluate the fracturing results.

Global solutions

While this multiconveyance system brings reliability and predictability in the logging operations, it is also redefining the limits to acquiring logs. For example, in unconventional reservoirs it is being used in short-radius wells and long laterals common to multiwell pad drilling and stacked pay designs.

Recent tests have shown that certain tools can successfully navigate dogleg severities as high as 120°/30.5 m (100 ft) using pipe or CT conveyance. This system also allows logging a full suite of formation evaluation services in highly deviated or horizontal slim holes such as 3⅞-in.

Each drilled well comes with its own challenges. Conveying tools to the desired depth and mitigating well control issues requires a versatile response using flexible tools and the most suitable conveyance method to reliably acquire critical data while minimizing risk. E&P

FTG survey helps derisk Barents Sea exploration

The growth of multiclient FTG surveys aids explorers in frontier areas.

Stephen Rippington and **Anne-Marie Liszczyk**, ARKeX

Multiclient seismic surveys have represented an established tool in frontier exploration and in supporting licensing rounds for many years. Recently, multiclient full-tensor gravity gradiometry (FTG) surveys have begun to share the same status.

FTG measures the spatial rate of change of the Earth's gravitational acceleration in response to small variations in subsurface density. In frontier exploration areas such high-resolution, broad-bandwidth, and strong signal-to-noise ratio data allow operators to quickly and accurately map zones of structural complexity at a variety of scales and depths.

Operators can use FTG data to understand the regional geological setting of a prospect and to quantify the 2-D and 3-D architecture of the geological setting in which it resides. FTG data are fast becoming a key component of risk evaluation prior to making commitments on exploration licenses.

One particular application where FTG data have proved to be valuable is in areas where seismic faces illumination problems. For example, in salt basins the relatively low density of salt in comparison with the surrounding strata and the complex morphology of salt bodies are ideal targets for detection and modeling using FTG data. The result is accurate mapping of the density interface between salt and the surrounding strata in 3-D. With a greater understanding of the structure and density/velocity relationships derived from modeling FTG data, seismic data can be reprocessed and interpreted with more confidence.

FTG data complement seismic data, not only as a means of enhancing and understanding existing seismic data but in helping to shape, design, and optimize future seismic surveys. FTG data provide increased spatial awareness in frontier exploration regions and are particularly useful for interpolating between sparse 2-D seismic lines or between areas of 3-D seismic. This helps interpreters make better decisions about fault linkages and reduces uncertainty by aiding the construction of more accurate structural models.

The FTG instrumentation can be deployed on either airborne or marine platforms (Figure 1) depending on how far the target area is offshore, with the resulting data indistinguishable from each other.

Data are acquired quickly and efficiently with a single instrument, resulting in a rapid exploration of vast frontier regions. The acquisition technology is passive, has minimal adverse environmental impact, and limits the risk to personnel and equipment in the field. In addition, FTG data can be processed and delivered to clients within weeks of survey completion, making them a highly cost-effective alternative and/or complement to seismic surveys.

Multiclient FTG surveys are a win-win for all sides. For the operator, they mean high-quality data sooner and at a lower cost than exclusive proprietary ownership. This offers the operator an enhanced earth-model, leading to improved exploration success rates and better investment decisions around licensing.

For governments, increased understanding of exploration targets means more efficient and profitable development of their oil and gas resources.

Barents Sea case study

The Barents Sea region has seen strong interest from oil companies during the last few years, with 20 new licenses being awarded in the Barents region during the 22nd

FIGURE 1. FTG instrumentation can be deployed on either airborne or marine platforms, depending on how far the target area is offshore. (Images courtesy of ARKeX)

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Offshore Croatia

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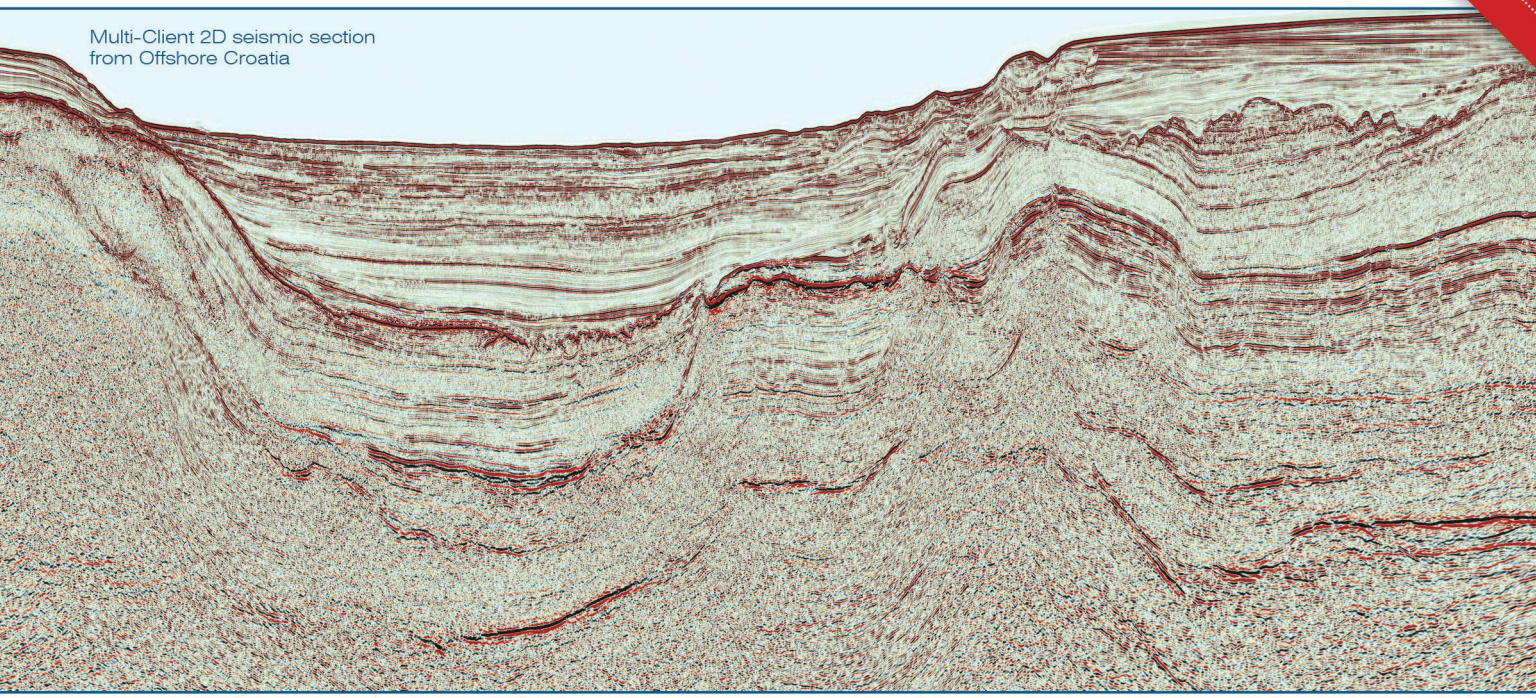
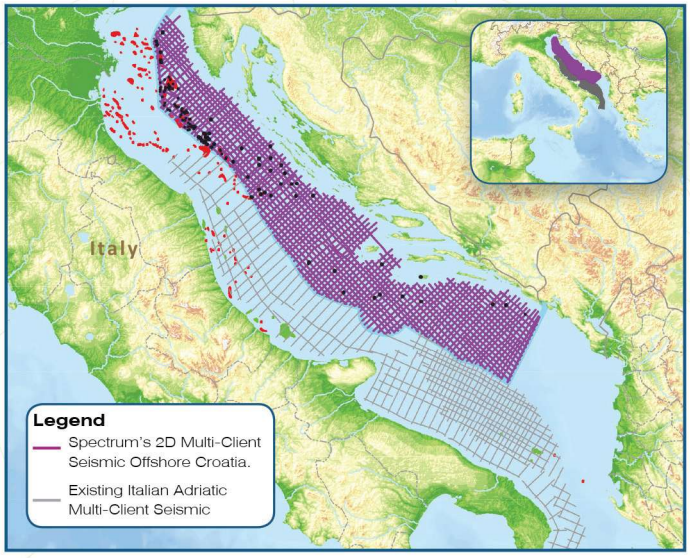


Multi-Client 2D seismic section from Offshore Croatia



Spectrum has acquired a truly unique Multi-Client seismic survey offshore Croatia. This is the only seismic data available to license in this hugely underexplored region which expects to see its first offshore licensing round this year.

The survey, acquired under contract to the Ministry of the Economy in Croatia, covers approximately 14,700 kilometres of long offset seismic data with a 5 km x 5 km grid. It extends across most of the Croatian Adriatic Sea and connects with Spectrum's reprocessed seismic data covering the Italian Adriatic Sea.

Final PSTM data has now been delivered and all processed data will be available in April. The Government of Croatia plans to hold a licensing round over the country's offshore continental shelf in 2014.

Spectrum

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licensing round. To date 40 companies have submitted nominations according to their interests in the 23rd Licensing Round, and already more than 30 companies have purchased the NPD 2-D seismic data from the southeast Barents Sea area.

The Norwegian energy ministry announced its proposal of areas to be included in the 23rd Licensing Round in February 2014. This will be followed by the formal announcement of the included blocks before the summer.

ARKeX began acquiring a multiclient FTG survey in the southeast Barents Sea in late 2013, optimal timing to coincide with the 23rd Licensing Round. Data already available from acquisition in 2013 cover parts of the Nordkapp and Tiddlybanken basins and the Fedynsky High. Acquisition was postponed in 2013 due to deteriorating weather conditions; however, the survey was to resume in mid-March 2014. Due to the exploration interest in the northern part of the southeast Barents Sea region, ARKeX has confirmed an extension of the original survey plan northward, with all fully processed deliverables available from August 2014 (Figure 2).

The Barents Shelf is a structurally complex mosaic of platform and basinal areas. Structural trends formed during the Caledonian and Uralian Orogenies dominate the basement and have exerted a strong influence on the structure and development of the overlying basins and highs.

To this end, mapping areas of structural complexity and understanding the area's regional architecture is crucial to reducing exploration risk. Furthermore, the Nordkapp and Tiddlybanken basins both contain large quantities of Carboniferous and Permian salt, which form large, subvertical diapirs, the majority of which extend upwards to the seabed. The flanks of the salt domes and inversion structures in these basins have significant potential as hydrocarbon traps.

To investigate such geologically complex areas it is necessary to create the best possible geological subsurface models. ARKeX uses XFIELD, a powerful interpretation tool, to build 2-D/2.5-D density, velocity, and susceptibility models of the subsurface. XFIELD enables the user to combine geological and geophysical data and interpretations in one 3-D visualization space.

XFIELD also allows users to test the gravity and magnetic signal response of their geological model and compare it to observed data. The interpreter can use the constraints offered by integrating gravity, gradiometry, magnetic, seismic, and well data to build more geologically sound models (Figure 3).

The ARKeX multiclient southeast Barents FTG survey will provide a high-resolution dataset for exploration geoscientists. The FTG survey has been designed to complement existing 2-D seismic and planned 3-D seismic surveys. When combined with 2-D and 3-D seismic data, FTG data provide a powerful tool for structural interpolation on a regional to prospect scale and a quantitative basis for interrogating seismic interpretations.

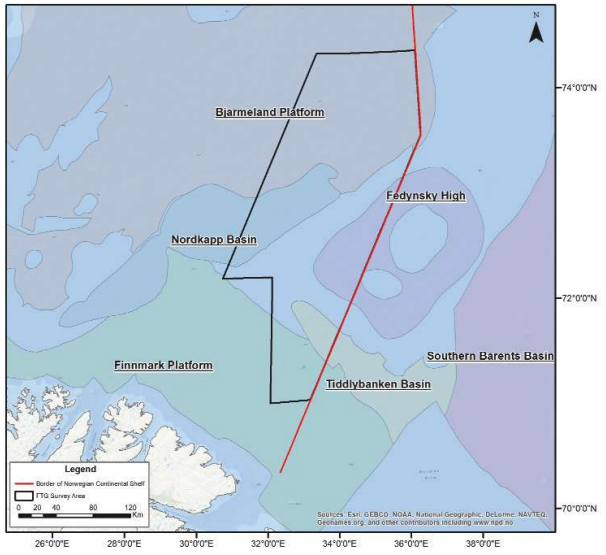


FIGURE 2. ARKeX will extend its original survey plan northward, with deliverables available in August 2014.

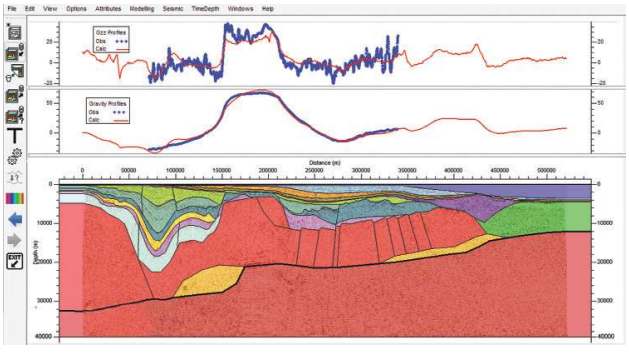


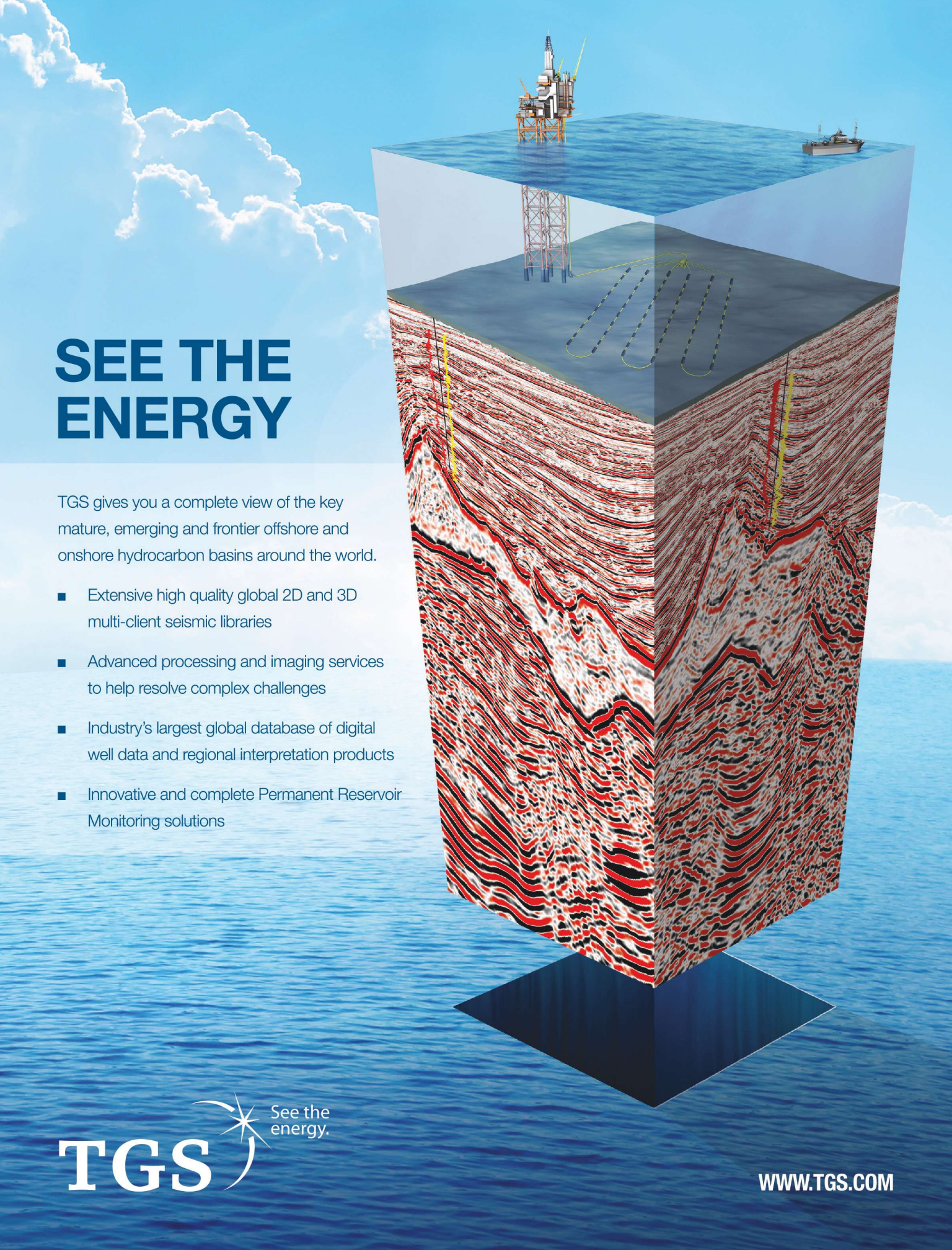
FIGURE 3. Interpreters can use the constraints offered by integrating different data types to build geologically sound models.

Preliminary results already demonstrate the value of FTG surveys as a key exploration, interpretation, and planning tool in frontier hydrocarbon-bearing regions.

Reducing exploration risk

Whether applied at a regional or prospect scale, in frontier or mature hydrocarbon-bearing regions, FTG is a powerful derisking tool.

Multiclient surveys such as the ARKeX FTG survey in the southeast Barents Sea will be an important tool when evaluating prospects in frontier areas. FTG multiclient surveys also are increasingly becoming an important element in future licensing rounds. E&P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Would you like some towed-streamer EM with your seismic?

Simultaneous acquisition of seismic and EM provides more subsurface information.

Folke Engelmark, **Johan Mattsson**, **Allan McKay**, and **Zhijun Du**, Petroleum Geo-Services

The development of the towed-streamer electromagnetic (EM) acquisition system is now seeing its 10-year anniversary. The technology has finally reached maturity, and the service is commercially available. The impetus behind the design is obvious. It facilitates efficiency similar to seismic acquisition where only one vessel is required, quality control is performed real-time on the source signal as well as the recorded data, and onboard processing provides quick-look results similar to a brute stack in the world of seismic. The EM acquisition software is conveniently based on the same modules as the seismic data. Simultaneous acquisition of seismic also is facilitated, all at a sailing speed of 4 knots to 5 knots.

The engineering of this system was considered impossible to achieve due to the EM noise generated when the receiver dipoles are towed in the water under the influence of the Earth's magnetic field, but the acquisition system now produces data of excellent quality. The residual uncertainty in the processed data is normally within 2% to 3% for most of the offsets and typically within 5% even for the longest offsets and lowest frequencies.

The layout of the towed-streamer EM acquisition system with simultaneous acquisition of 2-D seismic is shown in Figure 1. The 800-m (2,625-ft) long bipole source is towed at 10 m (33 ft), and the source current is 1,500 Amps. The streamer is 8,000 m (26,250 ft) long with configurable receiver dipoles, and it is towed at a nominal depth of 100 m (328 ft). The bipole source and the seismic streamer also are laterally separated by 100 m to prevent crosstalk from the powerful source to the low-level signals in the seismic streamer.

The typical streamer configuration consists of 72 receiving electrode pairs distributed along the streamer to facilitate densely spaced offsets from 0 m to 7,700 m (25,262 ft). At the near offsets the electrode pair is 200 m (656 ft) long. The lengths are successively increasing to 1,100 m (3,610 ft) for the most distant offset. This increases the signal-to-noise (S/N) ratio since the signal decays with increasing offset. Additional stochastic noise reduction is achieved by stacking and low-rank approximation by means of singular value decomposition. Correlated noise originating in sudden tugs of the streamer also can be reduced by an algorithm based on Wiener filtering. The maximum nominal water depth is 400 m (1,312 ft) since the water column absorbs part of the transmitted energy. Larger water depths are acceptable if the lateral extent of the resistive structure of interest is large and/or has a very high transverse resistance.

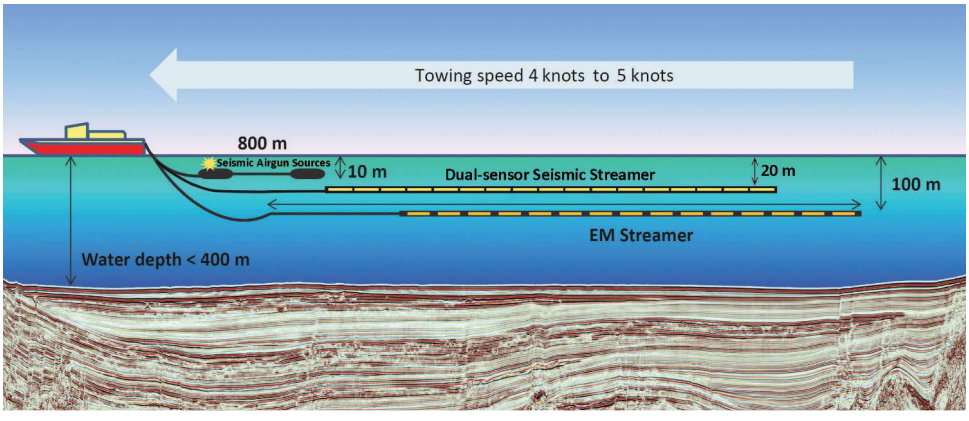

FIGURE 1. This image shows the layout of the EM and seismic acquisition systems. The EM streamer has 72 configurable receiver electrode pairs that are short (about 200 m) at the near offset and long (about 1,100 m) at the far offset. (Images courtesy of PGS)

The source signal is referred to as an optimized repeated sequence (ORS) that generates a denser set of discrete frequencies than the conventional monochromatic square wave. Typically the ORS has twice the den-

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sity of discrete frequency peaks compared to the conventional square wave. The signal is typically transmitted for 100 seconds followed by a 20-second window of no transmitted signal that is used for background noise estimation and noise reduction processing. The dense spatial sampling combined with the dense set of discrete frequencies facilitates improved resolution and a more data-driven inversion with less dependence on *a priori* information. The dual-sensor seismic streamer is towed at 20 m (66 ft), and the seismic source is a conventional airgun array. The EM acquisition is not as weather-sensitive as seismic is, and the deep tow of the dual-sensor seismic streamer lowers the wave-induced noise and extends the weather window.

Multiclient project

An extensive multiclient acquisition program was undertaken in September 2013 in the Fastnet basin in the Irish sector of the Celtic Sea (Figure 2).

The program involved simultaneous acquisition of towed-streamer EM and 2-D seismic as well as 2-D seismic only in areas where the water depth exceeds the nominal maximum of 400 m. In total, 2,800 line km (1,740 line miles) of EM and seismic data were simultaneously acquired in 35 days for an average of 80 line km (50 line miles) per day.

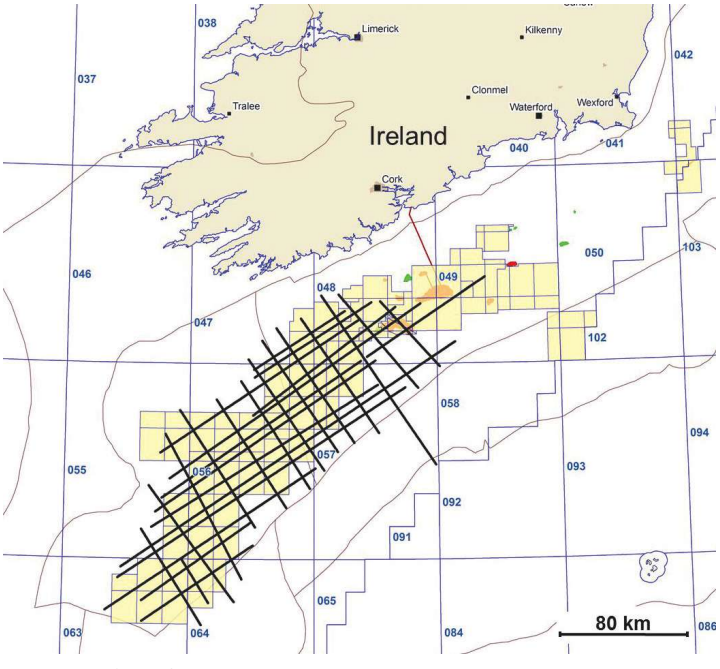

FIGURE 2. The acquisition grid covers the Fastnet basin located in the Irish sector of the Celtic Sea. Most of the program involved simultaneous acquisition of EM and seismic data.

Anisotropic inversion case study

Towed-streamer EM data facilitates anisotropic inversion in spite of the fact that only the inline electric field component is measured. The main reason this is possible originates in the shallow tow of the EM source and receiver, which increases the amount of energy that travels through the atmosphere. This so-called airwave propagates horizontally through the atmosphere, and it will couple with the horizontal conductivity in the anisotropic subsurface.

PGS considers anisotropic inversion algorithms to be mandatory since the overburden tends to be at least mildly anisotropic and the hydrocarbon-charged reservoirs tend to be strongly anisotropic, especially when the high-resistivity sands are interbedded with layers of low-resistivity shale. Assuming the subsurface is isotropic is likely to introduce artificial banding in the inversion that creates an effective anisotropy due to the poor vertical resolution. The basement always seems to be isotropic, and this fortuitous fact offers an interesting advantage because this allows surveyors to identify a charged reservoir located immediately on top of the basement simply by displaying the resistivity ratio.

Currently PGS uses two different anisotropic inversion algorithms. The first is an open source program that can be described as a regularized non-linear 2.5-D anisotropic inversion built around a parallel adaptive finite element approach that only requires a sparse horizon model from depth-converted seismic as constraint. The second algorithm is based on the 3-D contraction integral equation method using a reweighted regularized conjugate gradient technique to minimize the objective functional. The low computational cost for the 3-D inversion is unprecedented within the world of EM and requires very little *a priori* input.

Bentley and Bressay are heavy oil fields in the North Sea that were originally discovered in 1977 and 1976, respectively. So far they have not seen any production due to the low value of the oil combined with a low recovery factor. A further complication is that these are injectite sandstone reservoirs with sills and dykes extending upwards from the top of the reservoir. However, production is about to commence with a renewed interest in characterization of these reservoirs. A number of towed-streamer EM survey lines were acquired in the area, and an example of the 2.5-D anisotropic inversion is shown in Figure 3.

The EM acquisition sail line runs from north-northwest on the left to south-southeast on the right. The resistivity is shown as a color overlay on a depth-converted seismic section. Only a sparse seismic horizon

model was used to constrain the inversion. The top of basement is seen at about 1.4 km (0.9 miles) to the left and dipping gently to the right. The two oil fields are seen in yellow and red, with Bressay at about 1.2 km (0.7 miles) depth and at 7.5 km (11 miles) distance along the survey line. Bentley is located at approximately 1.2 km depth and at 17 km to 21 km (13 miles) along the survey line. The depth, lateral extent, and resistivity agree very well with what is known about the two reservoirs.

Towed-streamer EM now provides a fully mature service from acquisition to 2.5-D and 3-D inverted resistivity volumes. With simultaneous acquisition of EM and 2-D seismic at an acquisition speed of 4 knots to 5 knots, the efficiency is unprecedented. The dense subsurface sampling combined with the dense set of discrete signal frequencies results in high resolution and data characterized by excellent S/N ratio that requires very little *a priori* information for the inversion to resistivity. E&P

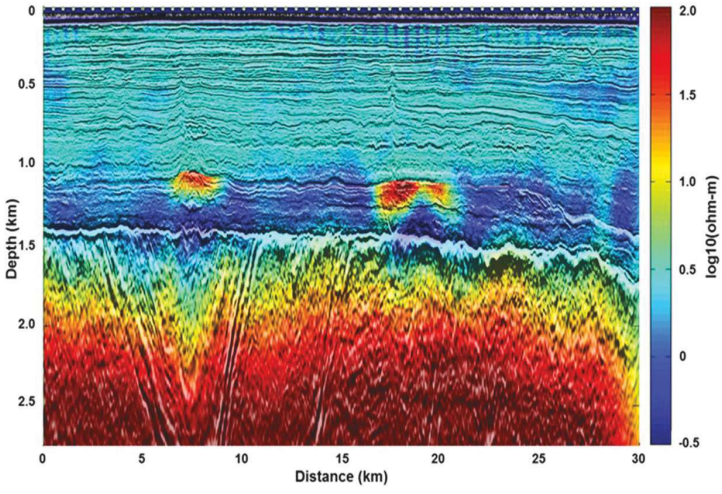

FIGURE 3. A 2.5-D inversion is shown in color as an overlay on a seismic 2-D section. The two fields are seen in yellow and red at a depth of 1.2 km, with Bressay on the left and Bentley on the right.

Improving R&D through collaboration

Companies team up to develop enhanced reservoir intelligence.

Laurent Fontanelli, Repsol CTR

Recently, the Repsol Technology Centre (CTR), located in Mostoles, Spain, and the Institut Français du Petrole Energies Nouvelles (IFPEN) signed a global framework collaboration agreement to conduct R&D in the field of E&P.

This collaboration represents an industry trend that is seeing global oil and gas firms and industry associations focus on the application of pioneering technologies to access the world's declining oil reserves and derive value from recent discoveries and acquisitions through more efficient operations.

One of the main objectives of this project is to develop common technologies for a better understanding of the reservoirs using real data from a Repsol-operated field. These data will be used to improve the software developed by IFPEN and adapt it to specific challenges faced by Repsol in analyzing its carbonate reservoirs.

The first collaborative project between Repsol CTR and IFPEN will focus on R&D to define innovative solutions for the characterization and modeling of carbonate reservoirs. This will be a game changer in the future of E&P.

It is estimated that more than 60% of the world's oil reserves are held in carbonate reservoirs. Carbonates can exhibit varying properties and can be extremely difficult to characterize due to their structure (faults and fractures), depositional environment, stratigraphy, facies types, diagenesis footprints, petrophysical properties, and dynamic behavior.

To carry out these studies, Repsol and IFPEN will form a team of more than 30 researchers, some of whom will be based at Repsol's CTR in Madrid and Houston, drawing on the expertise of each company's team in the field of geosciences.

This project is a key strategic initiative for Repsol given that a large number of its upstream assets are held in carbonate reservoirs. This includes plays in the US, Russia, Spain, and Venezuela, all of which have varying geological elements and characteristics. Moreover, Repsol plans to apply work carried out with IFPEN to its pre-salt play in Brazil – one of the most significant in Repsol's E&P portfolio and the most complex in terms of its geological structure.

To improve future field development, define the best well placement strategy, and increase hydrocarbon recovery, it is important to ensure accurate, innovative modeling of carbonate reservoirs instead of using the traditional modeling methods, analogs, and statistics.

There are three components to this. First, the carbonate reservoir needs to be better understood by identifying its type and specific diagenesis. Then, the carbonate reservoir needs to be characterized by defining the key controlling parameters and weighing the impacting heterogeneities. Finally, the carbonate reservoir needs to be modeled by distributing heterogeneities in 3-D, reproducing geological events, and quantifying its behavior.

Through Repsol's experience in building 3-D models, researchers know that geostatistics cannot be relied upon to build adequate 3-D geological models, especially when applied to carbonate reservoirs with more geologically complex compositions. This also should be taken into consideration when applied to the appraisal phase or early development phase of a project with few control wells. The Repsol-IFPEN collaboration will focus on using geostatistics in a more effective way to better understand the complexity of carbonate reservoirs rather than strictly distributing properties in 3-D.

In addition to this, carbonate characterization and modeling will continue to be developed. In particular, depositional environment modeling, diagenesis modeling, and upscaling methods using software developed by IFPEN will be continued.

This collaborative project will allow both companies to deliver new insights into some of the most challenging aspects of reservoir characterization and modeling. Repsol and IFPEN will continue to work together throughout 2014 to better understand the complexities of its reservoirs, optimize production, and manage the associated risks. E&P

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Wireless-enabled downhole tools aid deepwater well test

Measurements allow engineers to make decisions in real time.

Mark Ratchinsky, **Andy Sooklal**, and **Carl Walden**, Maersk Oil; **Marcelo Gandra Braz** and **Ifeanyi Nwagbogu**, Schlumberger

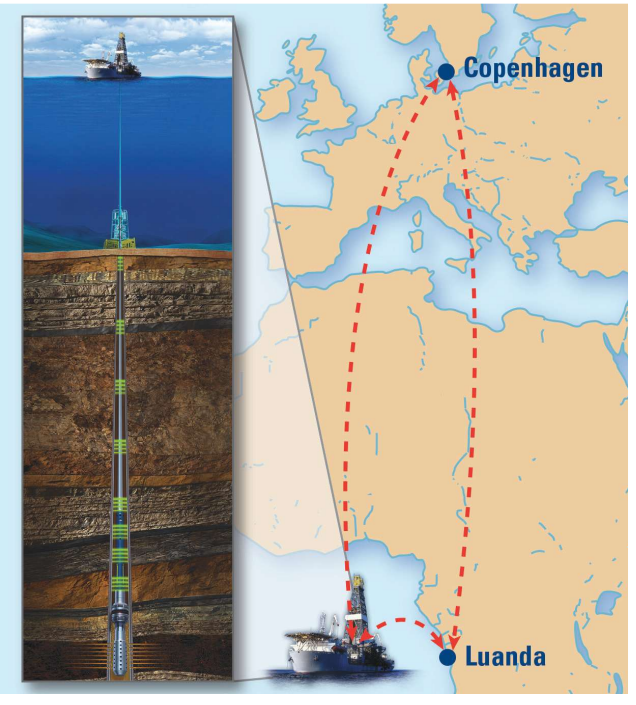
Deepwater exploration drilling costs are prohibitively high, and operators look for new technologies to minimize uncertainty about reservoir characteristics and well deliverability. Reducing operational risk and increasing the information gathered from an exploration well are critical in deepwater frontier environments. Decreasing the individual well costs as well as the number of wells before proceeding to the subsequent phases of field development also rank high on the operator's list of priorities.

Today, with wells more complex than ever, operators are putting a premium on real-time pressure and temperature readings. The objective of the well test is to analyze reservoir response during sequential flowing and buildup periods and determine reservoir characteristics such as skin factor, permeability, productivity index, and initial reservoir pressure.

Historically, reservoir information has been obtained using memory gauges without the benefit of real-time bottomhole data, requiring the extrapolation of surface data to estimate downhole conditions. This lack of real-time data encouraged engineers to design conservative estimates for the flowing and shut-in periods.

Planned well test durations often didn't suffice to meet the minimum data requirements for interpretation. The planned duration was either too long or too short, incurring excessive rig costs or leaving out valuable data. Also, without the benefit of real-time downhole data, the operator would be unaware of problems that occurred during the operation, which could not be remedied after the drillstem test (DST) string was pulled out of hole.

Previous methods of acquiring bottomhole data during the test involved running an electric line connected either directly to a downhole gauge or to a probe capable of communicating with gauges installed in the string. The main limitation of electric line intervention is the risk associated with deployment during flowing periods. The electric line may be blown upward in the flow or stuck in the well if sand or fines are produced, making operators hesitant to deploy intervention tools beyond shut-in periods.



During the well test, real-time downhole data was wirelessly transmitted to surface and streamed into the InterACT global connectivity, collaboration, and information service, allowing Maersk engineers in Luanda and Copenhagen to collaborate on decisions, manage wellbore events, and refine the test sequence in real time. (Images courtesy of Schlumberger)

For deepwater environments where the price of failure is high, operators require reservoir testing solutions that deliver real-time information to optimize decision-making and reduce risks and rig costs. A wirelessly enabled downhole reservoir testing system was developed to transmit real-time bidirectional information throughout the test. Maersk Oil recently deployed the wireless system to manage uncertainty and transmit

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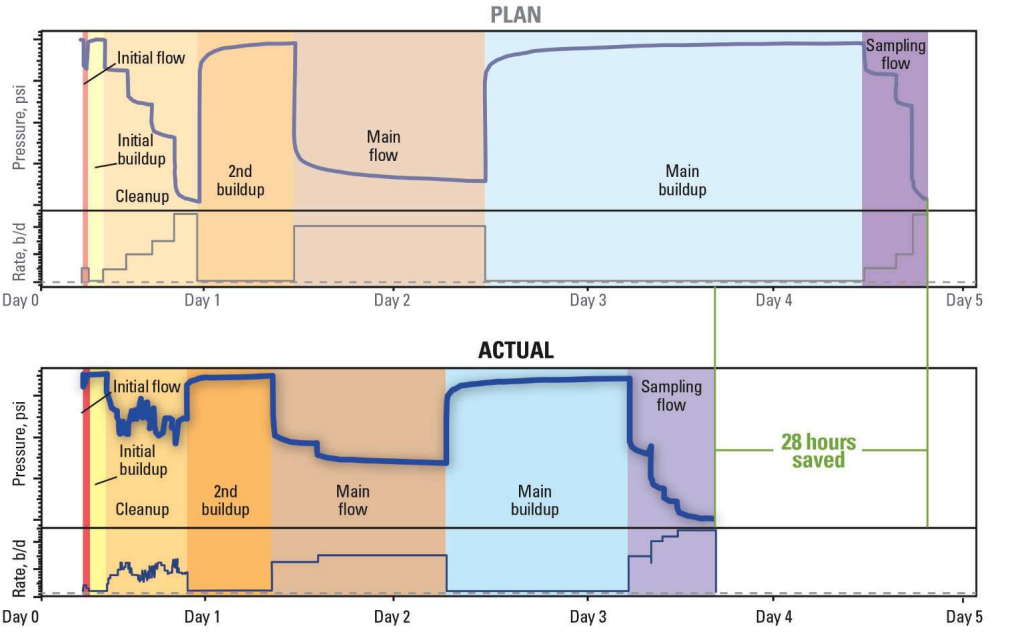
important bottomhole measurements in a challenging deepwater exploration well test in Angola, achieving significant value from optimizing the test and reducing total rig time.

Wireless-enabled testing

The Quartet downhole reservoir testing system enabled by Muzic wireless telemetry enables customers to isolate, control, measure, and sample a reservoir in a single run while providing bidirectional downhole tool communication and real-time readout of tool status and downhole pressure data. This advanced downhole reservoir testing system offers several advantages over conventional configurations, including the ability to function at a lower operating pressure, use less nitrogen, eliminate drill collars and slip joints, and use fewer seals and connections.



	Flow period	Plan, h	Actual, h
	Initial flow	0.5	0.5
	Initial buildup	02	2.4
	Cleanup flow	12	9.9
	2nd buildup	12	10.5
	Main flow	24	21.7
	Main buildup	48	22.7
	Sampling flow	8	10.8
	Total	106.5	78.5

With the new testing system, the operator monitored reservoir parameters and made decisions in real time, shortening the well test by 28 hours and saving costly rig time. The operator obtained necessary downhole data to characterize the reservoir and meet test objectives.

The modular telemetry system interfaces with the testing system and allows modifying the test sequence in line with the reservoir response and validating downhole pressure data during the test. Operators can now know exactly when sufficient information has been gathered for analysis, so test durations are optimized in line with objectives.

The platform provides reservoir testing in one package integrating four key tools, including Signature quartz gauges that deliver accurate downhole pressure and temperature measurements for the entire test duration. Enabled with wireless telemetry, the gauges provide bidirectional communication and verification of real-time pressure and temperature data. Each gauge can be independently interrogated for pressure or temperature data in either real-time or historical mode.

Other technologies in the system include the CERTIS single-trip isolation system that combines the elements of a retrievable isolation system with those of a permanent downhole packer; the intelligent remote dual valve for control; and SCAR inline independent reservoir fluid sampling, which collects representative samples. The system's modular design gives operators flexibility in choosing which features to enable with wireless telemetry. All tools are equipped with conventional redundant backup control.

The exploration well is located southwest of the Chissonga discovery block in Angola's Lower Congo and Kwanza deepwater basins, about 176 km (109 miles) off the coast of Luanda, Angola. Maersk Oil spudded the well in March 2013 and drilled into oil-bearing sandstones, with the primary target at a depth of approximately 5,000 m (16,000 ft) in water depth of 1,462 m (4,796 ft). The objectives of the well were to acquire data confirming the presence of hydrocarbons in the sand formations by testing the pressure and determining reservoir connectivity to the main wells of the Chissonga discovery block.

The operator launched the reservoir test after verifying the presence of hydrocarbons using MWD, LWD, and electric line logs. In an environment where rig costs can exceed US $1 million per day, the key challenge was

to design a well test program that would optimize operational efficiency without compromising the objectives.

Remote decision-making

Schlumberger Testing Services proposed a single-trip solution using the reservoir test string enabled by wireless telemetry with the quartz gauges to monitor and manage the well test operation in real time. The decision to use wireless readout was delayed until completion of the logging program to confirm that the technology was suitable for the well.

The integrated system facilitated bidirectional communication between the surface and downhole gauges with real-time data streamed into the InterACT global connectivity, collaboration, and information service. This allowed engineers in Luanda and Copenhagen to make decisions, manage wellbore events, and refine the test sequence in real time.

The downhole gauges enabled by the wireless telemetry transmitted data successfully throughout the test duration. The operator was able to verify the underbalance prior to perforating, establish initial reservoir pressure after perforation, verify the status of the downhole tools used during the test, optimize the clean-up period by monitoring sandface pressure, reduce duration of buildup, and confirm that samples were being taken in ideal conditions. The RT Certain real-time test collaboration service with reservoir experts provided data interpretation.

Other aspects of the suite brought benefits to the well test. Using the single-trip isolation system, the operator avoided running two additional trips in the hole. Deploying the intelligent remote dual valve enabled the operator to efficiently shut in downhole and displace fluids into the wellbore as required, and the inline independent reservoir fluid sampling system captured representative reservoir fluid samples.

The wireless downhole testing system saved 28 hours of rig time and generated data to estimate key reservoir properties. A comparison of memory data from the gauges retrieved at surface against the real-time data used for interpretation during the test validated the decisions made during the operation.

Twenty-three jobs have been conducted globally using the wirelessly enabled reservoir testing system with a 100% success rate. As the industry increasingly ventures into challenging deepwater frontiers, wireless-enabled solutions that integrate all aspects of reservoir testing into one package with single-trip conveyance are giving operators greater certainty that their reservoir test objectives are being met efficiently and cost-effectively. E&P

MPD techniques overcome formation damage

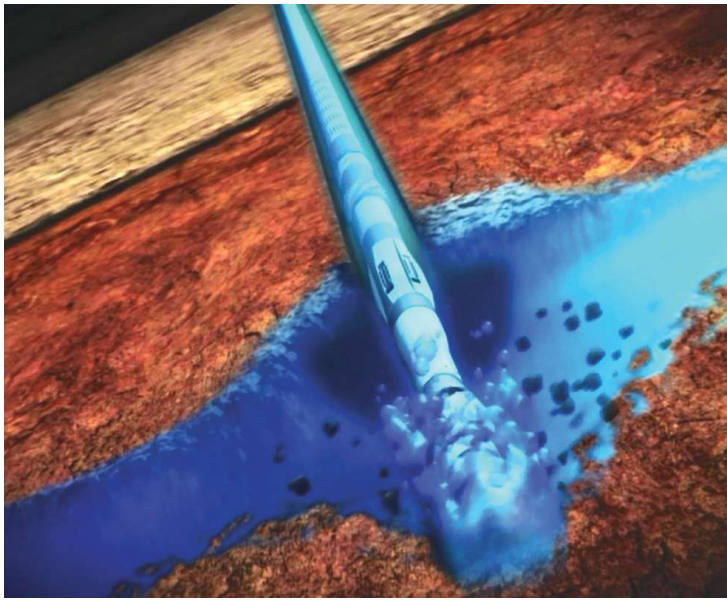
Total circulation losses are prevented in Sumatra, Indonesia.

Krisboa Agustinus, **Yoshua P. Iskandar**, **Fikri Irawan**, **Ardia Karnugroho**, and **Julmar Shaun S. Toralde**, Weatherford

The seamless combination of two managed-pressure drilling (MPD) techniques has resulted in the successful drilling of a statically underbalanced high-rate onshore gas well in southern Sumatra, Indonesia. The integrated MPD approach reduced formation damage and provided the means to continue drilling ahead despite total circulation losses.

Formation damage in the reservoir was reduced using the constant bottomhole pressure (CBHP) variant of MPD to enable drilling with a statically underbalanced freshwater fluid system. When severe circulation losses were encountered, freshwater drilling fluid was sacrificed to the formation in a simple transition to pressurized mud-cap drilling (PMCD) methods, which allowed drilling to continue without restoring circulation.

The application is the latest advancement in the use of MPD methods in South Sumatra. Total circulation losses and minimizing formation damage have long been the object of MPD innovations in the area.



During PMCD operations, all of the drilling fluid and cuttings are lost in the formation. Using statically underbalanced fresh water as drilling fluid in both the drillstring and annulus in PMCD mode minimizes formation damage. (Images courtesy of Weatherford)

MPD heritage

MPD applications in South Sumatra began more than a decade ago with PMCD methods to drill in total lost circulation conditions while monitoring and controlling wellbore influxes. While successful, the technique required killing the well prior to pulling out of the hole, which is time-consuming and can result in formation damage. Weatherford's development of a downhole isolation valve (DIV) to isolate the wellbore eliminated the need for killing the well, reduced the risk of formation damage, and greatly improved the efficiency and effectiveness of the PMCD technique.

The most recent MPD applications in Sumatra add CBHP methods to this system to further reduce potential formation damage. This plan uses CBHP to drill with statically underbalanced fresh water, unlike previous applications where overbalanced drilling fluid was required, only to be lost and to impair the productivity of the reservoir once circulation losses occurred. In the current setup, with the automated MPD manifold and the CBHP option available, when total losses were encountered, drilling would be transitioned to PMCD and fresh water would be pumped down the drillpipe and the annulus to prevent any gas migration up the wellbore. Having the same fluid in CBHP and PMCD modes greatly simplifies the MPD operation, thereby making operational efficiency an added advantage of the setup in addition to mitigating formation damage.

Methods and technology

CBHP allows the formation to be drilled with the same bottomhole pressure while circulating and with pumps off. The technique also facilitates drilling in an overbalanced state with a drilling fluid density that is less than

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A view down the bore of the DIV shows the flapper transitioning from closed to open position (left to right), facilitating tripping efficiency in both PMCD and CBHP modes.

the formation pressure. PMCD allows drilling to continue in total loss conditions with a sacrificial fluid that is lost to the formation along with cuttings. Without the need to mitigate losses, formation damage and costs from lost circulation material (LCM) and cement are eliminated with PMCD. Both MPD techniques depend on a small set of equipment that includes a rotating control device (RCD), an automated MPD choke manifold, and a DIV.

The RCD creates the prerequisite closed-loop drilling system by containing and redirecting annular flow to an automated choke manifold. The model used for the Sumatra well has dual-barrier rotating sealing elements.

Downstream of the RCD, the automated MPD choke manifold monitors flow in and out of the wellbore and is used for applying surface backpressure to manipulate the bottomhole equivalent circulating density (ECD). The manifold model used is equipped with two 3-in. chokes, a Coriolis mass flowmeter, and precision quartz pressure sensors. It is automated by a real-time monitoring, analysis, and control system.

The DIV used in the MPD operations is a surface-controlled system run as an integral part of the casing string. Its purpose is to avoid the introduction of swabbing and surging pressures when the drillstring is pulled out or run in the hole.

In operation, the drillstring is tripped out until the bottomhole assembly (BHA) is above the valve. The valve is then closed. Pressure above the valve is bled off, and the drillstring can be safely removed. The drillstring is tripped back into the well until the BHA is above the valve, at which point the valve is reopened and the operation continues.

CBHP technique

When drilling a well using CBHP, achieving an overbalanced condition requires application of backpressure. Backpressure enables a drilling fluid that is lighter than the formation pressure to function in an over-balanced state.

There are limits to how much pressure can be applied. The first limit is defined by the RCD pressure rating. The second limit is defined by the leak-off test (LOT) pressure. The total ECD at the shoe, which includes the SBP, must be lower than the LOT pressure.

Backpressure is managed through the MPD choke manifold by setting the desired SBP value. The MPD control system calculates the difference between the set value and the real value sensed by pressure sensors in the manifold and commands choke adjustments accordingly.

When a pipe connection is made and there is no circulation through the drillstring, SBP is applied using an auxiliary pump that circulates drilling fluid directly to the annulus and back to the choke manifold.

CBHP drilling was conducted successfully in the section using SBP to create pressure sufficient to balance the formation pressure.


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PMCD technique

As the drilling assembly reached deeper into the formation, natural fractures were encountered, and losses began to occur. The resulting decrease in the rate of returns initiated a choke response to compensate for the annular pressure drop.

Total loss conditions occurred and, with the choke fully closed, additional water was injected into the annulus to offset the lack of returns from the well. This shift produced a seamless transition from CBHP operations to PMCD.

In PMCD mode, three mud pumps were used to deliver the water volume needed to maintain an annulus pressure sufficient to balance the formation pressure. Two pumps provided a 1,893-l/min (500-gal/min) rate down the drillstring, and one pump delivered 757 l/min (200 gal/min) down the annulus. With data from pressure sensors on the RCD and at the standpipe manifold, it was possible to determine a likely cause of what was occurring downhole based on changes in annulus and standpipe pressures. While drilling continued, the injection rate was increased to bullhead the migrated gas out of the annulus. Success was indicated by an annular pressure drop.

The DIV made the tripping operations (in and out) more efficient, allowing tripping to continue with the certainty that any gas or fluid influx was trapped under the downhole valve.

Drilling complex wells

The successful application and integration of the two MPD techniques to drill the Sumatran well illustrates a growing ability to address complex well issues. The production impairment potential from drilling-related formation damage in the high-rate gas well, along with the likelihood of total circulation losses drilling the production interval, presented significant challenges.

These difficulties could have terminated the drilling short of total depth or limited the well's production rate. Instead, CBHP and PMCD techniques used in conjunction with a DIV provided a single MPD solution that mitigated both challenges. E&P

Old tech used in new ways boosts production, cuts costs

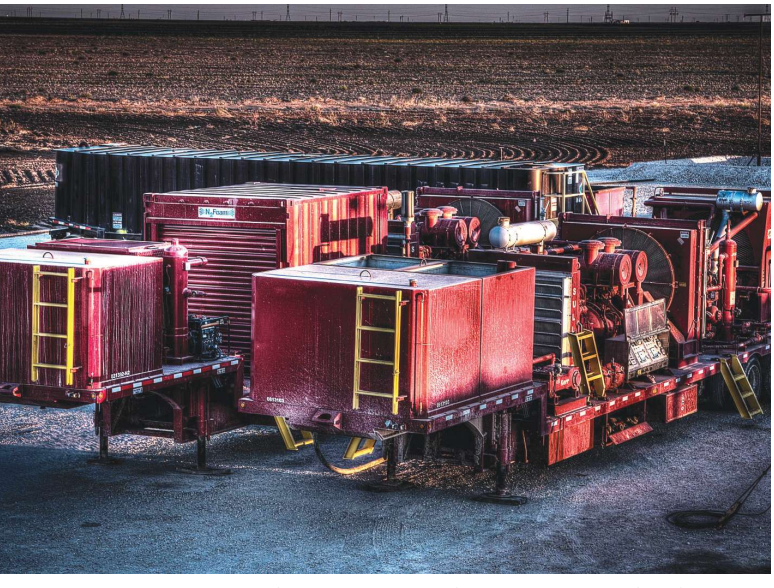
Air foam is ideal for sand cleanout, bridge plug drilling, fluid recovery, fishing, and deepening projects in lost circulation zones or pressure-depleted reservoirs.

Dee Moorhouse, Omni Air

Many companies are slow to adopt new technology. However, sometimes old technology used in new ways can boost production and cut costs. Underbalanced drilling (UBD) is not new technology. Air drilling was used in the Texas Austin Chalk region in 1978, with reports of the technique being used as early as the 1950s.

A September 1984 report by the Society of Petroleum Engineers stated that "using UBD is a sound and economical procedure with an average of [US] $500,000 being saved per well" and with "19 days being cut from the average drilling time per well."

Shell Oil Co. uses UBD drilling and servicing on more than 80% of the wells it drills and estimates that UBD has the potential to improve well production by 800%. Thanks to the improved flow of oil and gas, fewer wells are needed to drain a reservoir, and the overall environmental footprint is smaller.



This nitrogen foam unit has all of the advantages of air foam. However, nitrogen is an inert gas that eliminates the risk for a downhole fire or explosion and also eliminates corrosion issues associated with air foam.

In China complex geological formations reduce drilling speeds. Using UBD has increased penetration rates by 2.6 times and cut the average drilling cycle from 138 days to 57.4 days. The yield from UBD horizontal wells is 3 to 8 times as much as vertical wells.

There are several benefits to using UBD:

- It eliminates formation damage routinely caused by using drilling mud and overbalanced drilling (OBD) and production techniques;
- It increases ROP with less pressure at the bottom of the wellbore, so it is easier for the drillbit to cut and remove rock;
- It maximizes hydrocarbon recovery since using OBD blocks the natural flow of oil and gas from the well. UBD allows hydrocarbons to flow freely. The well is producing as soon as the reservoir is penetrated; and
- Differential sticking is eliminated. Using OBD can cause drillpipe to stick. When using UBD, the pipe is pushed away from the wellbore walls, which eliminates differential sticking.

How UBD works

What is UBD and how does it boost production and save costs? UBD is a procedure used to drill oil and gas wells where the pressure in the wellbore is kept lower than the fluid pressure in the formation being drilled. As the well is being drilled, formation fluid flows into the wellbore and up to the surface. This alone enhances production because oil and gas flow begins immediately when the well is completed.

This is the opposite of the usual situation, where the wellbore is kept at a pressure above the formation to prevent formation fluid entering the well. In a conventional OBD well the invasion of fluid is considered a kick, and if the well is not shut in it can lead to a blowout – a dangerous situation.

In UBD there is a "rotating head" at the surface, essentially a seal that diverts produced fluids to a separator while allowing the drillstring to continue rotating.

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If the formation pressure is relatively high, using a lower density mud will reduce the wellbore pressure below the pore pressure of the formation. Sometimes an inert gas is injected into the drilling mud to reduce its equivalent density and hence its hydrostatic pressure throughout the well depth.

This gas is commonly nitrogen since it is noncombustible and readily available. But air, reduced-oxygen air, processed flue gas, and natural gas have all been used in this fashion. The most common are:

- Dry air: This is also known as dusting. Air compressors combined with a booster (which takes the head from the compressors and increases the pressure of the air but does not increase the volume of air going downhole) are used, and the only fluid injected into the well is a small amount of oil to lubricate bit bearings or motor stators when downhole motors are used;
- Mist: A small amount of water and a foaming agent (soap) is added into the flow of air. Fine particles of water and foam in an atmosphere of air bring cuttings back to the surface;
- Foam: A larger amount of foaming agent is added into the flow. Bubbles and slugs of bubbles in an atmosphere of mist bring cuttings back to the surface;
- Stable foam: An even larger amount of foaming agent is added into the flow. This is the consistency of a shaving cream;
- Airlift: Slugs and bubbles of air form a matrix in water. Soap can or cannot be added into the fluid flow of air; and
- Aerated mud: Air or another gas is injected into the flow of drilling mud. Degassing units are required to remove air before it can be recirculated.

Drilling, workover services

Omni Air uses air and generated nitrogen foam-based UBD techniques to accelerate drilling and workover services while increasing production. Omni was originally created in 1978 and did air drilling. The company has since adopted the latest high-tech nitrogen UBD processes.

Nitrogen is inert, and it prevents downhole fires. It is not corrosive like mud and chemicals, and it can drive unrecovered hydrocarbons from an injector well to a producing well to boost or extend production.

In the past UBD was often more expensive, especially if nitrogen was used. Omni Air has lowered the cost by using onsite nitrogen membrane production units that provide unlimited quantities of nitrogen, eliminate transportation issues, produce nitrogen for half the cost of cryogenic units, and provide enhanced safety features.

High-tech control units also are used to select oxygen levels from 0.01% to 0.5%. These also control set points and include auto shut-down alarms that aren't fixed and can monitor temperatures, liquid levels, and flows into and out of the well. Quality is assured by using nitrogen that is 95% to 99.9% pure, with a dewpoint of -80 and flow capacities ranging up to 2.8 cm/min (100 cf/min).

Newer air foam units deliver up to 42.5 cm/min (1,500 cf/min) at 2,500 psig. Air foam is ideal for sand cleanout, bridge plug drilling, fluid recovery, fishing, and deepening projects in lost circulation zones or pressure-depleted reservoirs. Air foam and N_2 foam increase penetration rates while minimizing formation damage.

These types of drilling services are typically used in applications such as dust drilling, drilling with membrane nitrogen, mist drilling, aerated fluid drilling, foam drilling, percussion hammer drilling, directional drilling, and payzone drilling. Air drilling can increase drilling penetration rates by 5 to 7 times and eliminate lost circulation, differential sticking, and formation damage. Some customers have achieved drilling rates of up to 61 m (200 ft) per hour.

Fracing increases the need for UBD and underbalanced services. Fractured wells produced using OBD techniques naturally have sand and particles left in the well that reduce oil and gas flow and cause tubing to stick and pumps to fail. Using compressed air and nitrogen foam cleans out the well. Using UBD on existing wells has been proven to reduce maintenance issues and boost production.

UBD technology continues to evolve. Often old proven technology can be updated and improved to produce amazing results. UBD is the perfect example. E&P

ICDs with feedback control for steam conformance

Simulation shows benefits of hybrid completion system for SAGD wells.

Terry Stone, Schlumberger

Steam-assisted gravity drainage (SAGD) is the most extensively used process for development of bitumen resources in Western Canada. It involves pairs of closely spaced horizontal wells where steam is injected into the upper well while the lower well produces reservoir fluids that drain from the steam chamber.

Ideally, the steam chamber should evolve uniformly along the entire length of the well pair; however, there is often very irregular steam chamber development. Reasons for this include hydraulic gradients in the horizontal completion, geologic and fluid variations in the reservoir, and well placement issues.

Operators have implemented various strategies to improve steam conformance. Simultaneous injection/production in dual-tubing completions is commonly used to provide controllable injection and production from the heel and toe regions, but this does not guarantee uniform and efficient performance.

Inflow control devices (ICDs) incorporated in the horizontal completion can improve SAGD performance by adjusting the completion pressure differential to balance reservoir drawdown. Among other benefits, properly sized and distributed ICDs can create a more uniform flow profile along the horizontal section of the well regardless of permeability, formation damage, and wellbore location. Furthermore, ICDs on the producer can provide a self-regulating effect to prevent steam from entering the sand control screen.

Proportional integral derivative (PID) feedback to control steam injection can lead to further improvements in SAGD performance and can be practically and inexpensively implemented in the field with current technology.

Dual-tubing operations

Installation of dual-tubing strings in the injector and producer wells provides some control of the distribution of heat and production zones. In the example shown in Figure 1, a short string connects to the heel, and a long string connects to the toe of the well. An additional coiled tubing instrument string with either a fiber-optic distributed temperature sensing (DTS) system or thermocouple array may be included in the completion.

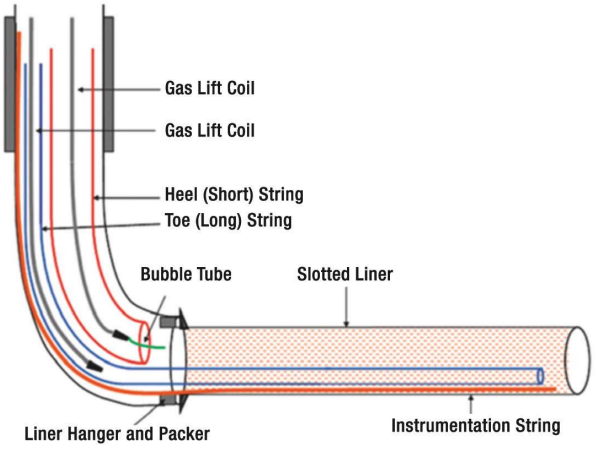

FIGURE 1. This represents an example of a dual-tubing well configuration. (Images courtesy of Energy Resources Conservation Board Alberta)

To prevent the steam chamber from touching the lower producer, which will remove hot steam instead of using it to heat the upper reaches of the chamber, injection and production rates are usually set to maintain a prescribed temperature difference between fluids exiting the upper injector and entering the lower producer. This temperature difference – also referred to as "subcool" since it is set to be several degrees below a water saturation temperature – may be controlled at both the heel and toe of the well pair. However, the ability to set injection and production rates to reflect the current state of the reservoir and current subcool is difficult using conventional reservoir engineering analysis.

ICDs

When placed in injectors, ICDs can better equalize the outflow of steam from heel to toe regardless of variations in reservoir mobility properties. In producers, ICDs can equalize the toe-to-heel influx of the emulsion and

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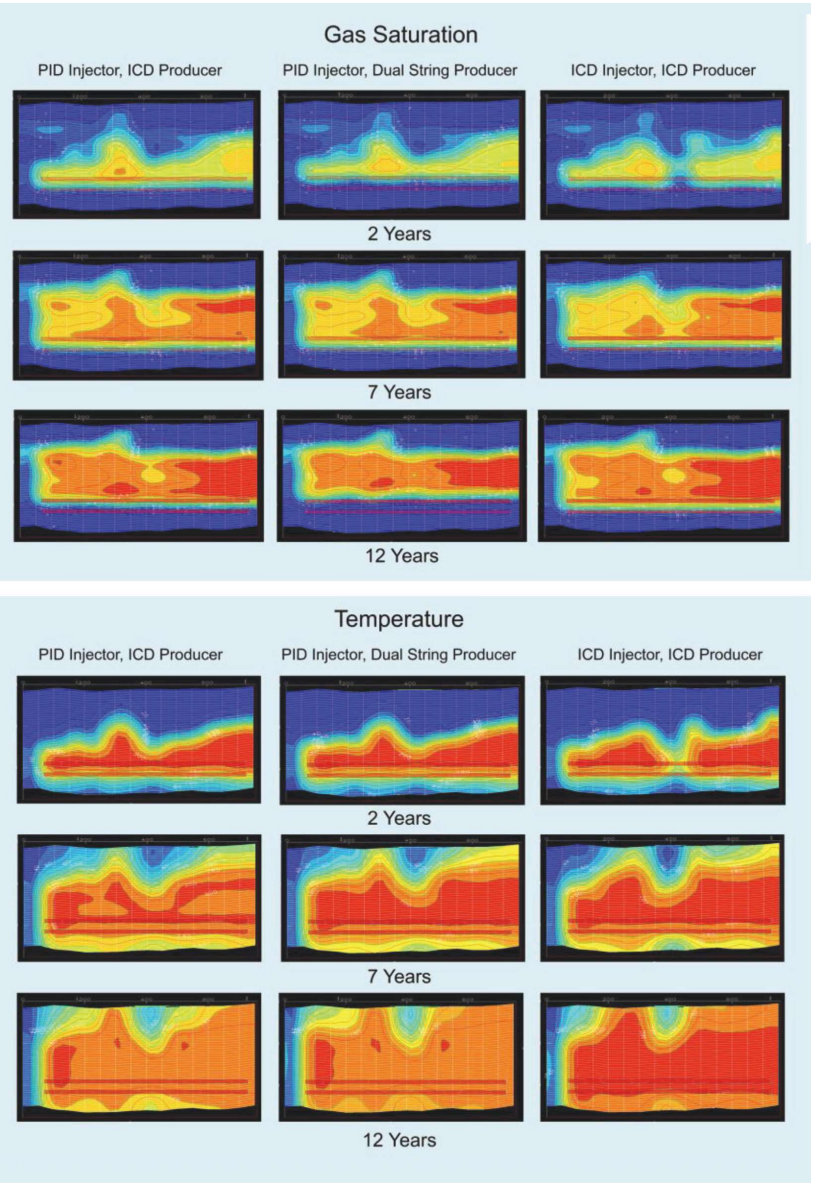

FIGURE 2. Gas saturation (blue = 0, red = 1) and temperature (blue = 15°C, red = 220°C) contours vs. time for three SAGD well-pair configurations are shown.

provide greater control of the subcool. ICDs also behave as autonomous or self-regulating valves since, if the liquid level gets close to the device, flashing of the fluids will occur in the nozzle, thereby increasing pressure drop, which in turn decreases drawdown on that section of the wellbore and consequently prevents steam from entering the screen. When a SAGD well is equipped with ICDs, there is no need for a second tubing string to be landed at the toe, saving both capital and installation costs as well as reducing the complexity of operating the well pair. This study was based on a high-temperature ICD design that combines a sand control screen with a choke designed to give a linear production or injection profile throughout the length of the horizontal wellbore. The devices are installed in 7-in. base-pipe joints, each 14 m (46 ft) long.

PID feedback control

PID feedback control of the steam injection can lead to further improvements in SAGD performance. Each steam injection point in the horizontal well pair is regulated by a PID feedback controller that monitors temperature differences between injected and produced fluids and automatically makes adjustments to both enforce a specified subcool and to achieve uniform production along the entire length of the producer. Achieving the subcool prevents steam from entering the lower producer, and both toe and heel halves are encouraged to produce uniformly since, if one half temporarily operates at a lower/higher subcool than the target, steam injection is decreased/ increased in that half to compensate.

For the dual-tubing cases examined in this study, two separate controllers were used for the heel and toe tubulars, each with their own error term. The error term in the heel region was calculated using an average pressure in the annulus of the injection well between the heel and middle of the well, the saturation temperature according to this pressure, the average temperature of fluids flowing into the lower producer between the heel and middle of the well, and a specified target subcool. Equivalent values were used for the second half of the well to calculate the error term in the toe region. Minimum and maximum allowable injection rate values and increase/decrease factors were also predefined.

Wellbore model

The accuracy of a reservoir simulator is determined by the accuracy of both the flow calculations within the reservoir and the wellbore model itself. As wells become more complex, accuracy of the wellbore model is likely to determine the final acceptability and reliability of the simulation. The multisegment well model used in this

work is part of a new scalable parallel commercial reservoir simulator that treats the well as a network of nodes and pipes. A segment consists of a "node" and a "pipe" connecting it to the neighboring segment's node toward the wellhead. Tubing strings may be added at any point within the multisegment well model.

Case studies

A synthetic heterogeneous reservoir model was created based on publicly available logs and bitumen properties from a region in the Athabasca Tar Sands, Alberta, Canada. As many of the reported parameters as possible were accounted for, including wellbore design and parameters such as absolute and relative permeabilities and injection rates. Grid and linear dimensions were 201 m by 15 m by 44 m (659 ft by 49 ft by 144 ft) and 201 m by 750 m by 55 m (659 ft by 2,461 ft by 180 ft), respectively. The model contained a single SAGD well pair 700 m (2,297 ft) long with a vertical spacing between injector and producer of 5 m (16.4 ft). Bitumen properties were 9°API gravity, 1.2 MMcP gas-free viscosity at 10°C (50°F), and an initial solution gas-oil ratio of 8.

A multisegment well model was constructed to accurately model the behavior and flow dynamics in both a dual-tubing configuration and in a well equipped with ICDs. Evolution of the steam chamber, temperatures, and pressure were examined during the production cycle to discern differences in the processes. Four cases were run with this model:

1. PID Injector, ICD Producer: An injector containing dual 3-in. inside diameter (ID) tubing strings was landed at the heel and toe, and steam injection rates to the heel/toe strings were PID-controlled with a specified subcool target. The producer was equipped with ICDs and hence contained only a single 6.3-in. ID tubular with no additional tubing string landed at the toe. The subcool target was set to 11°C (51.8°F).
2. PID Injector, Dual-String Producer: The injector and producer both contained dual-tubing strings, the injec-

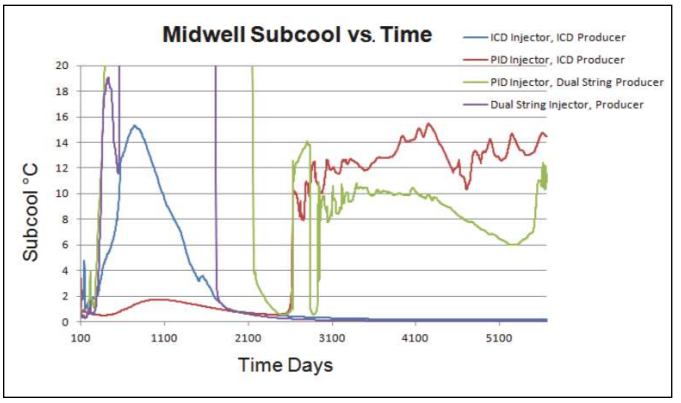

FIGURE 3. The figure shows subcool temperature vs. time at the midpoint of the well pairs.

tor PID-controlled by a heel/toe subcool target, and the producer produced equally from both heel and toe tubing strings. The subcool target was set to 11°C.

3. ICD Injector, ICD Producer: Both injector and producer were fitted with ICDs along their entire horizontal length. Again, there was no additional tubing string landed at the toe for this case.
4. Dual-String Injector, Dual-String Producer: In a base case in which the injector and producer both contained dual-tubing strings, steam injection rates were constant and equally split between the heel and toe strings, and production also was split between heel and toe.

Results

Figure 2 shows gas saturations and temperatures in a vertical plane containing the well pair after two, seven, and 12 years for the three cases with ICDs and/or PIDs. At two years, temperature and gas saturation profiles are similar between the three cases except ICD Injector, ICD Producer, which displays greater coolness in the mid-region together with lower gas saturations although with similar chamber growth near both ends.

All cases show a good degree of uniformity along the length of the well pair. By seven years, the two PID

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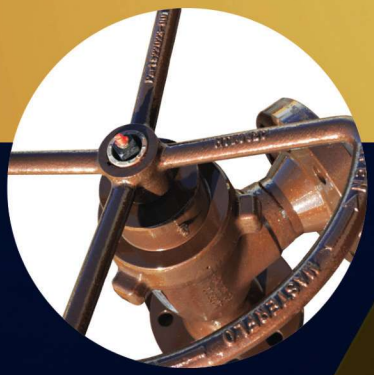

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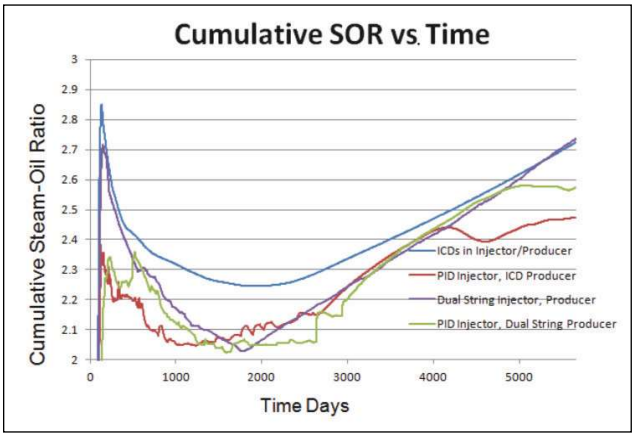

FIGURE 4. The chart compares the cumulative steam-oil ratio for three SAGD well-pair configurations and the base case.

injector cases show equivalent steam chamber growth along the entire length, while the case without PIDs shows slightly less growth near the toe.

By 12 years, both PID cases show cooler steam chambers than the other because both are achieving their subcool targets. Note also that the steam chambers in the two cases with PID injection are closer to the producer at seven years than later at 12 years, which demonstrates the benefits of enforcing a subcool that is not too small (11°C in this simulation).

In Figure 3, the two cases with dual-string producers show large, uncontrolled subcools up to approximately 5.5 years (2,008 days), while the two ICD cases show controlled subcool throughout the production cycle.

Figure 4 is a comparison of cumulative steam-oil ratio for the four well pair configurations. The base case demonstrates the least favorable economics by exceeding all cases at late times in the production cycle. The two cases with PID-controlled injection start showing economic benefits of controlled subcool later in the production cycle. The case with ICDs in both the injector and producer shows higher steam-oil ratio than expected throughout the production cycle.

Benefits

The aim of the study was to investigate some methods for accurate simulation of PID-controlled injectors and wells equipped with ICDs as well as to demonstrate the ability to simulate complex thermal processes.

While the cases presented are specific to the synthetic model used, the results suggest that a hybrid method of using PID-feedback-controlled steam injection from dual-tubing strings with a producer equipped with ICDs may have several benefits. An ICD-equipped producer provides a more even inflow, which results in better controlled subcool throughout the production cycle – particularly in the early stages after switchover when it is more difficult for PID-controlled steam injection to achieve a subcool target. Also, later in the production cycle, the ability of the PID-controlled injection to force a specified subcool target appears to keep the steam chamber close to, but not touching, the producer, improving the economics of the process. E&P

Acknowledgment

This article was prepared with the approval of the Society of Petroleum Engineers and is based on paper SPE 163594 presented at the SPE Reservoir Simulation Symposium, The Woodlands, Texas, Feb. 18 to Feb. 20, 2013.

Operator finds optimal solution for steamflooding operation

Choosing the right HP/HT steam-resistant elastomer seal was critical in EOR job.

Steve Jagels and **Mohammed Fiaz**,
Precision Polymer Engineering

There are several different methods of EOR being practiced, including steamflood and waterflood injection.

Steamflooding introduces heat to the reservoir by pumping steam into the well with a pattern similar to that of water injection. High-temperature steam heats the oil in the formation, lowering its viscosity and forcing the oil within the formation to move toward the producing well. High-temperature steam will challenge the sealing materials, which is why operators using this method of EOR can benefit from the reliability of an elastomer specifically developed for the environment.

Sealing for oil and gas applications

High-performance O-ring seals used in the oil field require specialist grades of elastomers specifically tailored to meet the challenges of the most inhospitable operating environments in the world. Sealing high-temperature steam is particularly difficult as many high-temperature elastomers are unable to maintain their sealing properties. Selection of the correct elastomer for this type of application is therefore challenging and critical.

FIGURE 1. Above is a standard EPDM after 24 hours in 316°C steam. Specimen is warped with surface cracking. (Images courtesy of Precision Polymer Engineering)

The materials used to create seals must withstand, both physically and chemically, the extreme conditions in which they are increasingly being used. There are limited options for sealing with elastomers in hot water or steam environments in temperatures up to 288°C (550°F). Most elastomers in high-temperature steam environments will become brittle and crack, resulting in leakage from a valve, pump, or other equipment. Leakage resulting from a cracked seal can cause hazardous conditions and ultimately equipment failure and lost time.

	Units	HNBR	FKM Copolymer	FKM Terpolymer	FEPM	FFKM
Original values						
Hardness	International Rubber Hardness Degrees (IRHD)	89	92	90	94	89
Ultimate tensile strength	MPa	32	16	24	25.4	28.9
Elongation @ break	%	264	120	210	123	86
Steam aging 168 hrs @ 288°C						
Hardness	IRHD				88	82
Ultimate tensile strength	MPa		Brittle		16.5	27.5
Elongation @ break	%				129	86.8
Volume change	%				-5.6	-2.6

TABLE 1. Although FEPM and FFKM may display steam-resistance properties, these materials have disadvantages such as poor low-temperature performance. Some FFKMs have very poor steam resistance, depending on the compound.

Designed to work

The seal designer has to consider many factors such as temperature range, pressure, and fluid environment in determining the optimal sealing material for an application. Temperature range of the application is an important factor that

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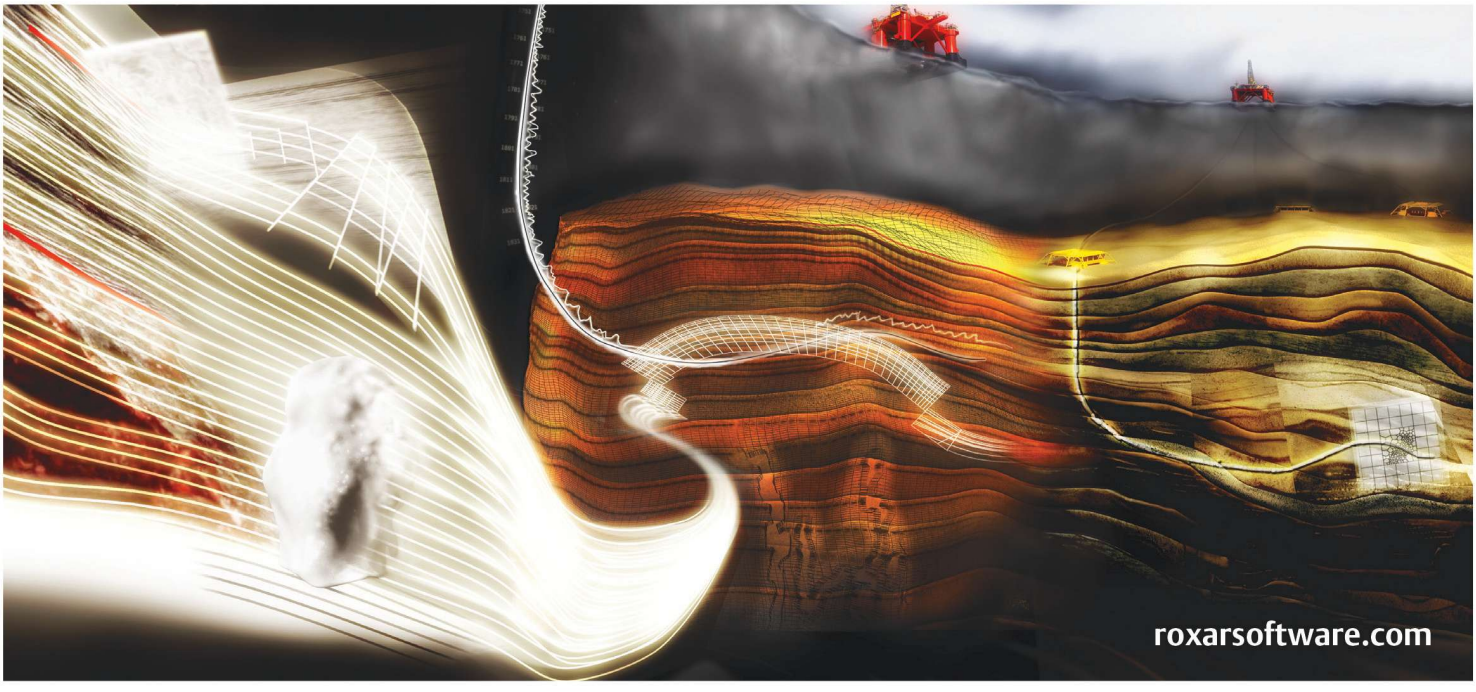

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FIGURE 2. This FKM terpolymer is shown after 24 hours in 316°C steam.

FIGURE 3. This FKM copolymer is shown after 24 hours in 316°C steam.

must be considered. Low temperature decreases the flexibility, and if the temperature is low enough, the material will lose its elastomeric properties. The low-temperature resistance is dependent upon the material's glass transition temperature, or the temperature at which the elastomer changes from a rubber-like to a glass-like material.

High temperatures can increase crosslinking, where the structure of the material tightens, causing a decrease in elasticity. The material also can become chemically altered under high temperatures, where an elastomer may lose some process oils or low molecular-weight fragments of the polymer.

Pressure of the application may cause mechanical extrusion of the seal, or if gases are present they will absorb into the elastomer, creating the potential for damage from rapid gas decompression. Permeation of a gas under high pressure may not result in any long-term effect providing the pressure is released gradually, allowing the gas to permeate out of the elastomer slowly.

The fluid environment is critically important to seal selection. Fluid incompatibility can cause high-volume swell in the seal. Though the volume increase in such instances may be reversible, the effects on the polymer may not be.

In the case of hot water and steam, all three factors need to be considered: high temperature that can affect elasticity and sealing force, water that can swell or react with the polymer, and pressure that can extrude low-strength materials or increase the risk of rapid gas decompression.

The limitations of the most common sealing materials create an opportunity for new elastomers that will seal in applications such as geothermal wells, turbines, EOR, and other situations where high-temperature steam may be encountered. In each of these applications, reliability is critical for safety as well as profitability. High-temperature steam and water-resistant seals enable downhole tools to be used to improve well drilling and completion.

Standard materials

Standard ethylene propylene diene monomer (EPDM) elastomers are well suited for water-sealing applications. They seal up to approximately 150°C (302°F) but will show property loss such as high-volume swell, durometer loss, and cracking in higher temperature steam applications (Figure 1). If this seal was used in a valve or other application, there would likely be a leak or failure requiring downtime and repair.

Fluoroelastomers (FKMs) are well known for their resistance to high, dry temperatures. They will typically

Aging in steam – 168 hours, 288°C	Units	Value
Hardness, IRHD	Micro M	82
Ultimate tensile strength	MPa	16
Elongation at break	%	280
Volume change	%	8.2
Aging in steam – 168 hours, 316°C		
Hardness, IRHD	Micro M	75
Ultimate tensile strength	MPa	4
Elongation at break	%	55
Volume change	%	12.6

TABLE 2. Steam-aging data shows how EnDura E90SR holds up at 288°C and 316°C.

FIGURE 4. This EnDura E90SR O-ring remains flexible without cracking after 24 hours in 316°C steam.

FIGURE 5. Above left: a fresh O-ring seal; Above right: A steam-aged EnDura E90SR O-ring seal left in 288°C for 168 hours.

retain properties up to 200°C (392°F). In high-temperature steam, FKMs become brittle and crack, which can result in seal failure (Figures 2 and 3). Nitrile butadiene rubber and hydrogenated nitrile (HNBR) elastomers also become brittle after high-temperature steam exposure (Table 1).

What works in HP/HT

Recently an upstream EOR application managed by a global E&P company was experiencing failure of a standard FKM elastomer in an HP/HT steam environment. Work had halted, and operating costs were rising. The operator required a solution immediately.

Precision Polymer Engineering (PPE) offered a new EPDM elastomer, EnDura E90SR, which is resistant to both hot water and saturated steam – the type of solution the operator was seeking. The material is in the 90 durometer range, making it resistant to extrusion at elevated temperatures and rapid gas decompression. Tests have shown that E90SR retains its properties in very high-temperature steam at both 288°C and 316°C (600°F) and has resistance to rapid gas decompression (Table 2, Figures 4 and 5).

PPE's rapid response reduced downtime by two weeks, minimizing the daily accruing costs. The PPE materials supported the EOR operation and survived the HP/HT environment, unlike materials used before. EnDura E90SR helps to improve the performance of products in geothermal tools, pumps, valves, turbines, and other components that require a critical seal in higher temperature-saturated steam environments. Its use also can extend equipment life, mitigate costly downtime or repairs, and enable seal designers to use elastomer seals in environments that are likely to degrade nearly all other commercially available elastomers. Engineers now have more choices in designs and the range in which they can operate their equipment. E&P

Custom EOR reduces natural, synthetic damage to wellbore

Operator chooses customized solution after it is tested and meets with success.

Tom Swanson, Clariant Oil Services

Near-wellbore damage restricts production and negatively impacts operators' revenue. It gets worse if there is a recurrence of damage caused by misdiagnosis because it could lead to an increase in capital and operating expenditures until they are above sustainable levels. As operators struggle to maximize production in the mature fields where they operate, the need for effective and complementary EOR solutions is great.

When the damage is done

Natural damage occurs over time during the decline of the well due to organic and inorganic deposits, which is common in mature oil fields as fluids and gases are drawn into the near wellbore and lead to various types of deposition. Synthetic damage is often the result of repeated stimulation and/or workover of the near wellbore to address a single challenge, e.g. inorganic scale, asphaltene, paraffin, emulsion, halite, and clay swelling.

Another factor in production impairment of the wellbore is liquid holdup. This occurs when water is drawn from the surrounding near wellbore into the tubing. Liquid holdup is the leading cause of the decline in low-pressure gas wells, when production is essentially choked off due to the hydrostatic head created by the unproduced water. Formation water can lead to corrosion issues and is often the source of seeding for organic scale when naturally occurring divalent captions such as calcium are exposed to CO_2 over time.

TABLE 1. An operator's system conditions were analyzed in Clariant's LEAD program before a customized solution was devised. (Images courtesy of Clariant Oil Services)

Permeability	2 mD to 10 mD
Porosity	12% to 17%
Geology	Turbidite deposition, stacked sand/shale sequences
Clay Content	10% to 25% (illite, smectite, kaolinite, chlorite)
Depth	2,743 m to 3,505 m
Connate Salinity	27,000 mg/l to 30,000 mg/l NaCl

Clariant Oil Services offers a universal approach to diagnosing and delivering effective and sustainable control of near wellbore damage. To address each customer's unique challenge, Clariant provides its LIBERATE Engineering Analytics and Diagnostics (LEAD) program.

Where there's a well, there's a way

The LIBERATE fit-for-purpose products and services are designed to function in complex environments and increase crude oil productivity in the near wellbore. The program draws from a custom-designed combination of inherently compatible solutions that can be applied continuously or in a multistage approach to address and prevent a combination of damage mechanisms. This approach offers an efficient process to return the near wellbore and tubing to its most productive state.

After assessing the historical performance, application options are determined. Application engineering is an important aspect of the overall near wellbore program. The company uses its LEAD process to create customized solutions for each of its customer's challenges. This is accomplished through in-depth collaboration with the customer to define well history and devise the most appropriate type of solution in the design phase.

Applications are designed in this beginning stage, which includes recognizing the minimum inhibitor concentration and finding a way to maximize contact with the blockage and surrounding areas in a way that will provide longevity to the treatment, thereby reducing the intervention frequency.

Chemical analysis and measurement are important to the sustainability of a near-wellbore treatment. In the LEAD process, key performance indicators are agreed upon following the engineered design, and they are wholly aligned to the treatment program. The analytical tools guide the program's problem definition and accurate data collection to measure and predict treatment efficacy and future damage onset frequency.

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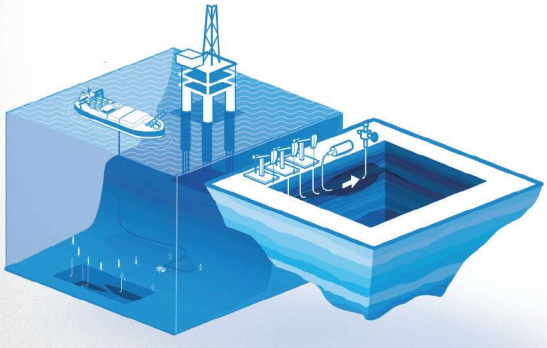

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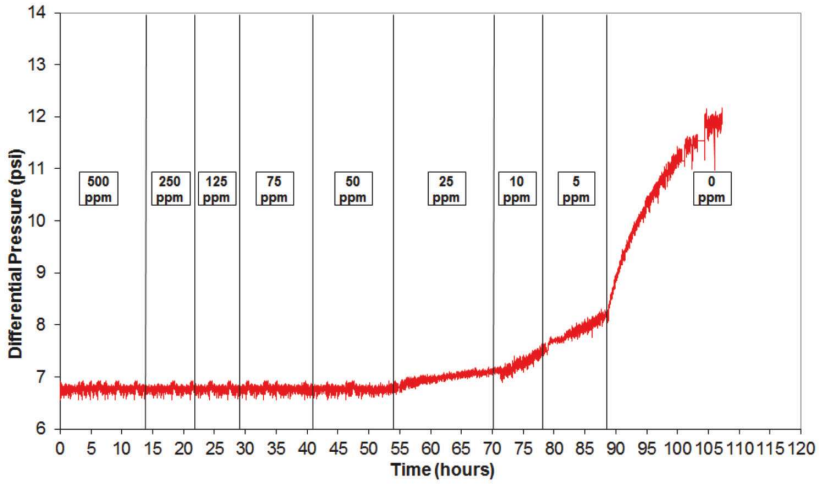

FIGURE 1. This Clariant in-house core flow study shows a client's field-specific lithology, measuring differential pressure in relation to the LIS-13212 concentration using nonpreserved core at an ambient temperature.

The final stage to ensure sustainability is diagnostics. Diagnostics allow both Clariant and the customer to provide health checks, ensuring cohesion between defined engineering and analytics steps.

The data and interpretation in the diagnostics phase provide insight to the entire program and allow for collaborative adjustments to be made in a dynamic process. Data capture, transparency, and routine discussions provide a platform for learning and adjusting to the specific near-wellbore requirements and changes. This stage is active and drives the decision-making process when re-evaluating the product, application, and analytics.

Following the LEAD

Recently, an operator using the LEAD program was able to fully customize its wellbore solution, ultimately allowing for the successful treatment of its wellbore casings. The operator came to Clariant Oil Services with a reservoir impairment issue. The operator's field in Southern California was operating a secondary recovery waterflood process. The waterflood injection in the field had experienced cycles of different water blends throughout its lifetime, with waterflood injection salinity decreasing from 28,000 mg/l NaCl to 15,000 mg/l over the last few years. This drop was impairing injectivity into the deeper intervals of the reservoir and having a negative effect on crude oil production. The system conditions are shown in Table 1.

While the clay sensitivity had been studied through core testing, the injectors needed to be protected against potential clay swelling. The incumbent treatment plan called for soaking the new wells with $CaCl_2$ for several days prior to commencing injection and then continually injecting $CaCl_2$ into the injection water at approximately 7,500 mg/l to 10,000 mg/l to prevent clay swelling and loss of injectivity.

When Clariant presented the customer with its alternative clay-swelling protection strategy, internal core flow studies were performed (Figures 1 and 2) on field-specific core and on the Clariant LIBERATE product LIS-13212.

The results showed that by using low-salinity injection water with the addition of a defined low concentration of LIS-13212, a differential pressure increase in the core could be prevented by reducing clay swelling. Third-party core flow studies verified these results, and the operator decided to inject 300 ppm of LIS-13212 into the low-salinity injection water. Field application commenced and was successfully deployed to a waterflood of 60,000 b/d of water with no losses in injectivity, which provided significant value and cost savings for the customer. E&P

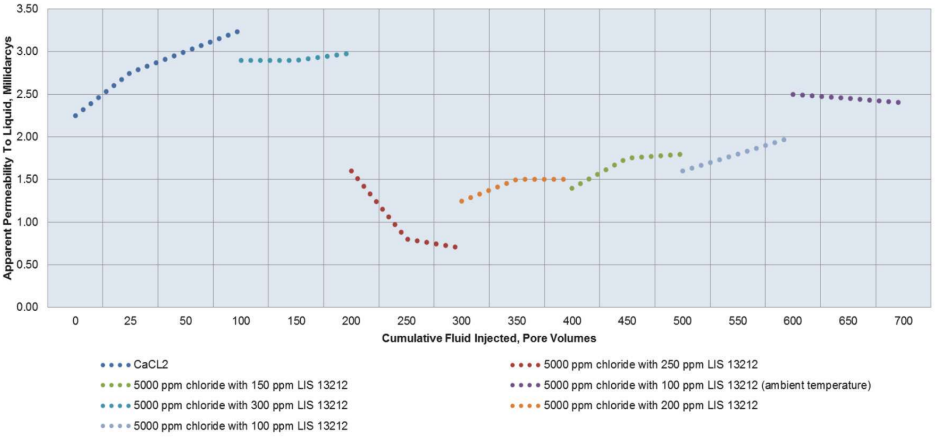

FIGURE 2. This third-party core flow study of field-specific lithology measures the core flow permeability in relation to Clariant's LIS-13212 concentration, using preserved core at field temperature. The 300 ppm LIS-13212 gave the same performance as 30,000 ppm $CaCl_2$.

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Marcellus activity continues apace

Conference presentations reflect rosy outlook.

Staff Report

The Marcellus shale in the northeast US is one of the hottest shale plays in the world. Figures from Pennsylvania's Department of Environmental Protection indicate that shale gas production increased to 87.8 Bcm (3.1 Tcf) in 2013, a 93.1% increase over 2012 and a 190.3% increase over 2011. At Hart Energy's recent DUG East event, several presentations focused on this remarkable resource.

Ramping production, dropping rig count

The North American shale revolution has stood many traditional notions about oil and gas development on their heads. The rig count as a leading indicator is one of these notions.

Allen Gilmer, CEO of DrillingInfo, gave the crowd at the event some rather startling numbers. Effectively, since his company began following activity in the Marcellus and Utica shales, production has ramped up considerably. Marcellus gas production saw the beginnings of an uptick in 2010, with daily production rising from about 14 MMcm (500 MMcf) in 1Q to 57 MMcm (2 Bcf) in 4Q. By the end of 2012, daily gas production was four times that amount.

Yet the rig count in the region is dropping. This would seem to be counterintuitive based on traditional thinking, but new changes in the development of unconventional plays paint a different picture.

One of Gilmer's slides showed a macro view of the movement of rigs in the US. By using GPS tracking, DrillingInfo was able to show where the rigs were moving from and to. "There have been some rigs coming into the Utica and the Marcellus, but a fair number are leaving and going to the Rockies and Oklahoma," Gilmer said.

A closer view of the region indicates a cluster of movement within and between the two plays, indicating that many rigs are being utilized in multiple areas across the region. "It's interesting to watch how successful these rigs are," he said.

The growth of drilling activity in the Utica has somewhat offset a drop of activity in the Marcellus, but the overall rig count has dropped substantially, with little more than 120 rigs running as of October 2013 compared to almost 160 in January 2012. Additionally, more than half of the rigs drilling in the Marcellus shale are drilling outside of Pennsylvania, the original sweet spot.

The most active operator drilling in the region is Antero, followed closely by Chesapeake and trailed by EQT Production, CNX Gas, Cabot Oil & Gas, Gulfport Energy, and Range Resources. Patterson Energy is by far the most active contractor in the region.

Gilmer noted that, unlike some plays like the Eagle Ford where operators stay with the same contractor and often the same crew to increase efficiencies, this is not the case in this region. "Very rarely do you see an operator with a single contractor," he said. "Typically an operator uses two or three contractors, and contractors work with a lot of operators. That's good for stability."

A map of drilling activity in the two shales shows that wells drilled since 2004 are definitely targeting the sweet spots. Gilmer said that the noncore areas should not be overlooked. "My prediction is that in five years, or maybe even two or three years, the areas we think of as noncore are going to have good economic returns because we're not going to be drilling wells with 6,000-ft [1,829-m] laterals and 2 million-lb fracs," he said. "We've spent a lot of time looking at what we call low-effort results, the idea of 1,000-ft [305-m] laterals and 50,000-lb fracs, looking at what people have done by accident.

"We're seeing that if you're in fantastic acreage, it makes sense to put in long laterals. But in areas that are not very good, the benefit you gain by adding more lateral is minimal."

The average lateral length in the region is around 1,676 m (5,500 ft), he noted.

Well spacing is another issue that continues to generate debate. Gilmer said that while there is not a specific spacing at which production drops to zero, there is a specific spacing level at which the operator will start to recover less gas per well.

"I think the regulatory bodies need to be familiar with this because we're going to see a steady evolution of drilling more in these noncore areas to extract smaller amounts of hydrocarbons," he said. "It's something we've seen in every area."

Of all of the technology and methodology that has caused the rig count to drop, pad drilling is the biggest culprit. Pad-drilled wells have increased from 0% of quarterly rig count total in 2008 to 80% today, Gilmer said. This is particularly prevalent in the southwestern sweet spot, where virtually all of the wells have been pad-drilled from multiwell pads.

"This has made it difficult to understand the rig count," Gilmer said. "It's not rig count anymore; it's how many wells we are drilling."

It's also skill and experience. "Given the same geological propensity to produce, the same quality of land, and looking at the difference between the best operators in the play and the average, the best ones will produce 30% to 50% more than the average," he said. "The worst will produce 30% to 50% less than the average.

"What this really means is that there will be opportunities for people who know what they're doing to pick up acreage that looks to be bad. People are going to mistakenly take good geological areas that aren't producing because of bad operating practices and commit the cardinal sin of selling off their acreage because they didn't drill economic wells."

Seneca's success

Most of the Marcellus shale drilling in Pennsylvania has been focused on opposite corners of the commonwealth – the southwest and northeast – but Seneca Resources has plenty happening elsewhere in the Keystone State.

Matthew Cabell, president of the National Fuel Gas Co. unit, told conference attendees his firm continues to complete strong wells across a sprawling acreage block stretching across northern Pennsylvania.

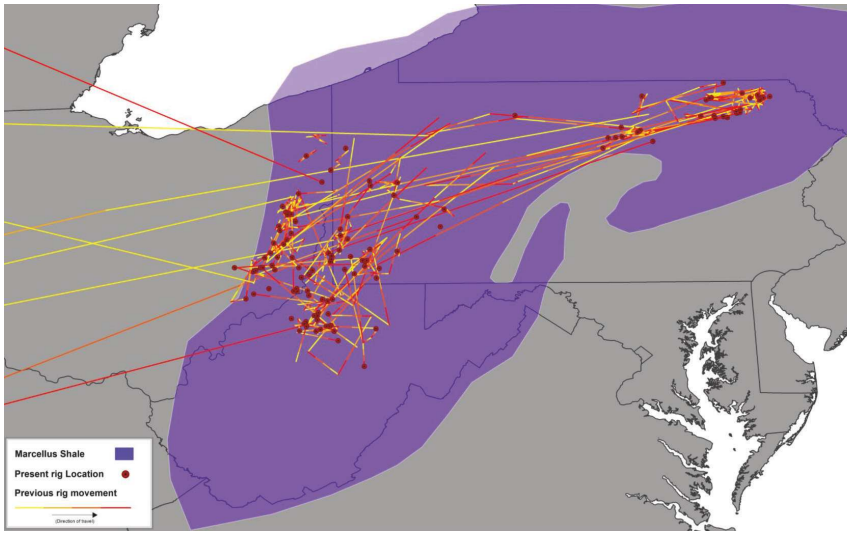
"We've taken time to identify sweet spots through the center portion of the state," Cabell told the group. "We have a significant Marcellus exposure."

Seneca has substantial acreage focused on the Marcellus totaling 775,000 net acres, "some of which are held in fee so we don't pay royalty," he added.

The firm divides its Pennsylvania acreage in two. It has an eastern development area in Tioga, Lycoming, and Potter counties that includes 60,000 net acres, mostly leased. Lycoming County wells have an average initial production rate of 456 Mcm/d (16.1 MMcf/d) and an average estimated ultimate recovery (EUR) of 326 MMcm (11.5 Bcf).

A much larger western area, centered in Cameron, Forest, and Jefferson counties, has about 720,000 net acres, most of which is held in fee. Cabell rated the area "highly prospective" with wells that have had peak seven-day production of 283 Mcm/d (10 MMcf/d) and EURs as high as 244 MMcm (8.6 Bcf).

Acreage of that size covering a prolific trend like the Marcellus means "there is literally decades of drilling for us," Cabell added, with 1,700 to 2,000 identified derisked locations at US $3 to $4 per MMBtu prices. Things look better still if and when gas prices perk up.

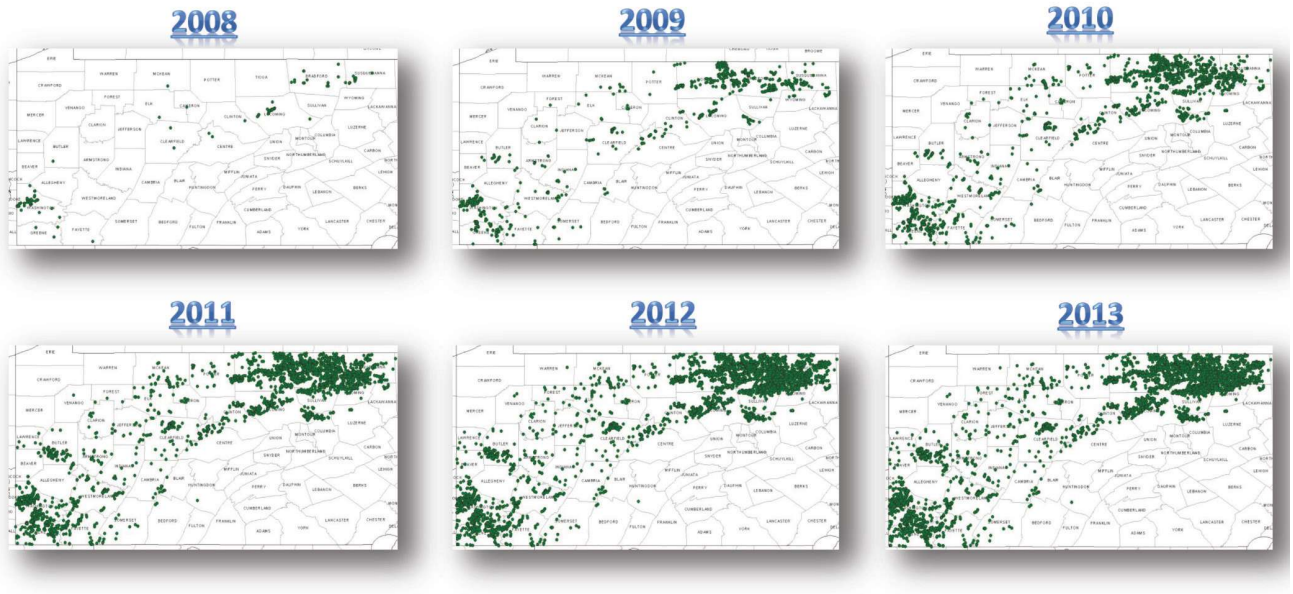


This map tracks rig movement in the Marcellus from April 2013 to October 2013. Yellow shows where the rigs are moving from, and red shows where they're moving to. Overall the map indicates efficient rig utilization within the region. (Image courtesy of DrillingInfo)

The firm's fiscal 2013 Appalachia region annual production will exceed 2.8 Bcm (100 Bcf), and Cabell projected fiscal 2014 production will be between 3.5 Bcm and 4 Bcm (125 Bcf and 143 Bcf). Its fiscal 2013 Marcellus exit rate was approximately 10 MMcm/d (360 MMcf/d), and Seneca currently projects its fiscal 2014 exit rate in the Marcellus will rise to around 14 MMcm/d (500 MMcf/d).

Much of that drilling success has come because Seneca has successfully "cracked the code" through an active drilling year, he said. That has yielded a much better understanding of the region's geology and identified more effective hydraulic fracturing techniques, including longer horizontal laterals and tighter spacing of frac stages.

Seneca projects its fiscal 2014 capital budget for its Appalachian drilling and production operations of



Permitting outlines the main Marcellus fairway. (Image courtesy of US Capital Advisors)

$460 million to $520 million, compared with $428 million for fiscal 2013.

Range banks on Pennsylvania

As Range Resources Corp. continues on a "line-of-sight" of 20% to 25% production growth per year, it also benefits from holding some 540,000 net acres in southwest Pennsylvania where three stacked pays come together, combining some of the highest gas-in-place (GIP) estimates in the Marcellus, Utica, and Upper Devonian, according to Range Resources' president and CEO, Jeff Ventura.

Range holds about 1 million acres prospective for shale in Pennsylvania, where industry's rapid development of the Marcellus field has taken production to "probably in excess of 12 Bcf/d [340 MMcm/d]," making it the largest gas field in North America, noted Ventura. In addition to 540,000 acres in southwest Pennsylvania, Range holds 315,000 net acres in the northwest, largely held by shallow production, and 145,000 net acres in the northeast, where one rig is expected to hold acreage it plans to develop. However, while Range nominally holds 1 million acres, "1 million acres is really more like 2 million net acres when you look at the prospective stacked pays," said Ventura. While the company holds 835,000 net acres prospective for the Marcellus, another 580,000 acres are prospective for the deeper Utica, and a further 565,000 acres are prospective for the Upper Devonian, which lies above the Marcellus. Collectively, this adds up to just under 2 million acres.

Ventura noted Range's proved reserves grew at a compound annual growth rate of 23%, with some 133 Bcm (4.7 Tcf) of resource potential moving into the proved category in the last three years. "That's really the equivalent of a nice company," he said.

Regarding Range's 540,000 net acres in southwest Pennsylvania, "we think our acreage position down there is largely derisked," said Ventura, citing some 2,100 wells now drilled by industry in the area and up to eight years of production history. Just in the Marcellus, he projected 6,750 potential drilling locations in the area based on 305-m (1,000-ft) spacing (approximately 80-acre spacing). Of these 6,750 locations, only about 500 horizontal wells had been drilled, accounting for a little more that 7% of potential locations and now producing some 16 MMcm/d (570 MMcf/d).

Assuming all the acreage could be drilled at once, all the wells were equal, and grossing up the 16 MMcm/d of current production by 7%, said Ventura, the implied result would be 227 MMcm/d (8 Bcf/d) net.

"We're not saying that we can get there, but it gives us great confidence that we can get to 3 Bcfe/d to [more than] 4 Bcfe/d [85 MMcm/d to 113 MMcm/d]," said Ventura.

In addition, with three ethane contracts in place, Range has cleared a path that allows the company to produce more than 85 MMcm/d net from the Marcellus alone, said Ventura.

The Marcellus phenomenon

The Marcellus is the undisputed king of North American shale gas plays, and it is expected to retain its heavyweight title for years to come. The experts say tens of

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Permanent, interventionless frac plugs speed production

By **Ryan Allen**, Baker Hughes

The economics and rapid decline curves of unconventional shale plays make it imperative for operators to start producing from newly drilled wells as soon as possible. The Marcellus shale is serving as an early staging ground for a game-changing technology that has the potential to completely eliminate the coiled-tubing (CT) drillout phase of plug and perf (PNP) completions so that production can be turned on sooner without the risks involved with intervention. Baker Hughes' SHADOW series frac plugs are permanent millable plugs that are designed to stay downhole and allow operators to produce through the inside diameter (ID) of the plug – without intervention – as soon as fracturing operations are complete.

Improving PNP

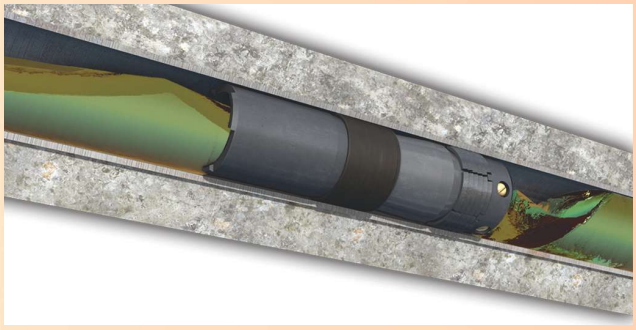
PNP technology enables operators to rapidly perforate, stimulate, and produce multistage wells, which explains its dominance as a completion method in unconventional plays. In fact, it is estimated that 70% to 80% of new unconventional oil and gas wells are completed using the PNP method.

Composite plugs, which are designed to set easily and hold the high differential pressures associated with hydraulic fracturing, are commonly used to isolate one newly fractured zone from the next. The primary limitation of the PNP method is that production following the fracturing operation cannot begin until after the isolation plugs have been removed from the wellbore. The plugs and drop balls are drilled out and debris circulated to surface during a live well intervention that usually requires two days but can require three days or longer. Production is delayed throughout the intervention operation.

Operators working in remote locations or, as in the Marcellus, drilling lateral sections that extend beyond the reach of traditional deployment methods have begun requesting alternatives to the composite plug for PNP completions. Baker Hughes responded with the industry's first interventionless frac plug.

Disintegrating frac balls are key enablers

The new plugs feature a large flow-through ID and use IN-Tallic disintegrating frac balls so production can flow with the plugs in place. The frac balls are made of controlled electrolytic metallic nanoconstructed material, pioneered by Baker Hughes. The frac balls hold pressure during fracturing, then completely disintegrate in the well when exposed to produced fluids to prevent blockages and eliminate debris. IN-Tallic balls are stronger than composite frac balls and can withstand higher pressures without deformation, enabling a larger ID through the plug.



SHADOW plugs allow flowback directly through the plug ID to eliminate intervention requirements. (Images courtesy of Baker Hughes)

IN-Tallic frac balls seal off the plug for fracturing and then disintegrate in the well to leave an unobstructed ID for production.

The interventionless plugs are run in-hole and set just like traditional composite plugs. Initial access to the reservoir is created using the company's Alpha sleeve pressure-actuated valve rather than a CT-deployed perforating gun. Zones can be independently treated after dropping a ball to seal off the plug. Multiple plugs can be run to isolate multiple zones, and more stages can be fractured at higher pressures. And commingled testing and production of zones both above and below the plug can occur once a higher pressure differential from below is established. Because the plugs can be set in horizontal sections beyond the reach of CT-conveyed milling tools, longer lateral sections can be fractured to expose more of the reservoir to the wellbore.

Field trials for the plugs began in May 2013, and uptake has been quick. The company recently deployed the plugs during a PNP application for an operator in the Northeast who was trying to cut down its completion time. The customer ran 14 units and saved approximately two days of time on location that would have otherwise been spent performing drillouts. For this operator, the plugs eliminated the need for a CT unit and accelerated the startup of production. ■

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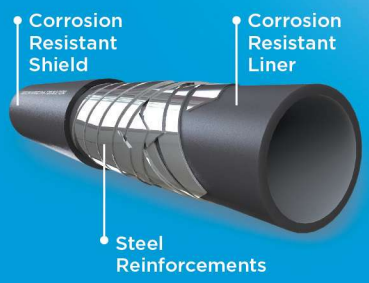

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thousands more wells are yet to be drilled, and Cabot Oil & Gas Corp. is expected to continue to be a production leader.

Dan Dinges, Cabot's chairman, president, and CEO, told oil and gas professionals that the "Marcellus is such a phenomenon that it will be hard to duplicate."

Cabot drilled its first Marcellus wells in Susquehanna County, Pa., in 2006. Since that time, the company has reported several of the best wells in the play. Make no mistake: Cabot's day in the Marcellus is not done. In fact, Dinges is confident that greater production numbers and favorable results for shareholders lie ahead.

"Right now, Cabot has 3,000-plus identified drilling locations in the sweet spot of the Marcellus. We also have peer-leading rates of return and EUR per lateral foot in the Marcellus. And the Marcellus has 25-plus years of inventory at current production levels," he said.

And Cabot aims to tap the vast supply of gas by operating around the clock. "We will implement a new rig-move process, and that includes 24-hour operations for rig-up and rig-down," Dinges said.

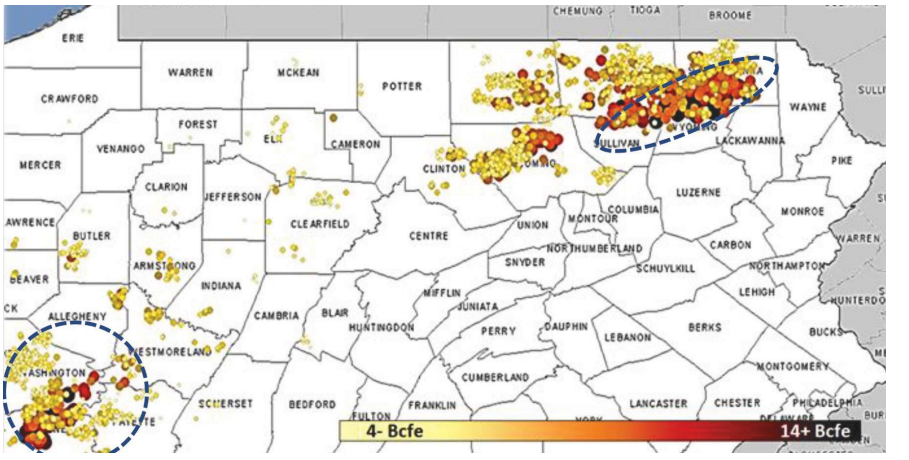
Ultimately, Cabot will bank on efficiency as it aims to drill wells in "shorter periods of time and at larger measured depths," according to Dinges. Also included in the efficiency equation are using CNG to power drilling operations and field gas as an energy source for pumping services, he added.

Dinges pointed out that Cabot has been able to increase the number of frac stages it performs daily. In 2010, the company averaged 2.5 frac stages per day. The daily average is now 5.1, Dinges said, adding that the company record is nine stages per day.

Governor fond of Marcellus

For Pennsylvania Governor Tom Corbett, the benefits of the oil and gas boom in his state can be summed up by a bumper sticker he spied on a pickup truck – "American energy, American jobs." Except he thinks it should read "Pennsylvania energy, Pennsylvania jobs."

"I want to be clear about something because there seems to be a question mark about it," he said. "More



Sweet spots in the Marcellus are primarily located in the northeastern and southwestern parts of Pennsylvania. (Image courtesy of US Capital Advisors)

than 220,000 jobs have either been created or made more prosperous or more secure by the vast wealth that is being tapped by our own Marcellus and, now, Utica shale plays," Corbett said.

Corbett spoke to DUG attendees in Pittsburgh, but he was actually addressing the oil and gas industry's opponents, those he called "economic change deniers."

"The industry has, to a vast degree, been environmentally responsible," he said, calling it one of the "inconvenient truths" opponents have had to face.

Corbett challenged drilling opponents and jobs skeptics to visit Pennsylvania for themselves and see the industry's help in creating jobs.

"Visit Williamsport, the home of the Little League World Series, and see the crowded restaurants, the full hotels, the additional hotels being built, and the stores that sell everything from equipment used on a rig to hats and boots, and then sk the people in those stores if they're doing this kind of business without the drilling industry," he said.

Citing the $400 million in impact fees assessed on unconventional wells in the Marcellus during the last two years as a result of statewide legislation called Act 13 and how the funds benefit local economies, the governor said, "If those who question the positive impact you have had from this industry on our communities just took the time to personally visit these areas, they would know what we have learned here in Pennsylvania. Pennsylvania is an energy industry," he said.

Corbett indirectly attributed some of the jobs creation to Act 13, which was enacted in early 2012. "We knew that our energy producers would compete not only with other states but with other nations. So we avoided a burdensome and job-killing system of taxation in favor of allowing the industry to flourish, to grow, and to create the jobs and the related business expansion that generates real prosperity and real revenue for all peoples," he said.

Corbett reminded the oil and gas audience that history is repeating itself in his state by recalling that the nation's first commercial oil rig, the Drake Well, was drilled in Pennsylvania a little more than 150 years ago. With hydraulic fracturing and horizontal drilling, he said, "Pennsylvania is once again a major energy-producing state, with the world's most famous natural gas reserve resting beneath us."

And this time around, he said, the industry has a duty to the environment. "Under Act 13, we passed the most comprehensive and effective system of guidelines and regulations of any drilling state in the nation," he said. "Our system protects the many streams and aquifers that we have and, when necessary, (and very rarely has it been necessary), we have imposed fines and taken action to protect the environment. The drilling industry has complied very well with these regulations."

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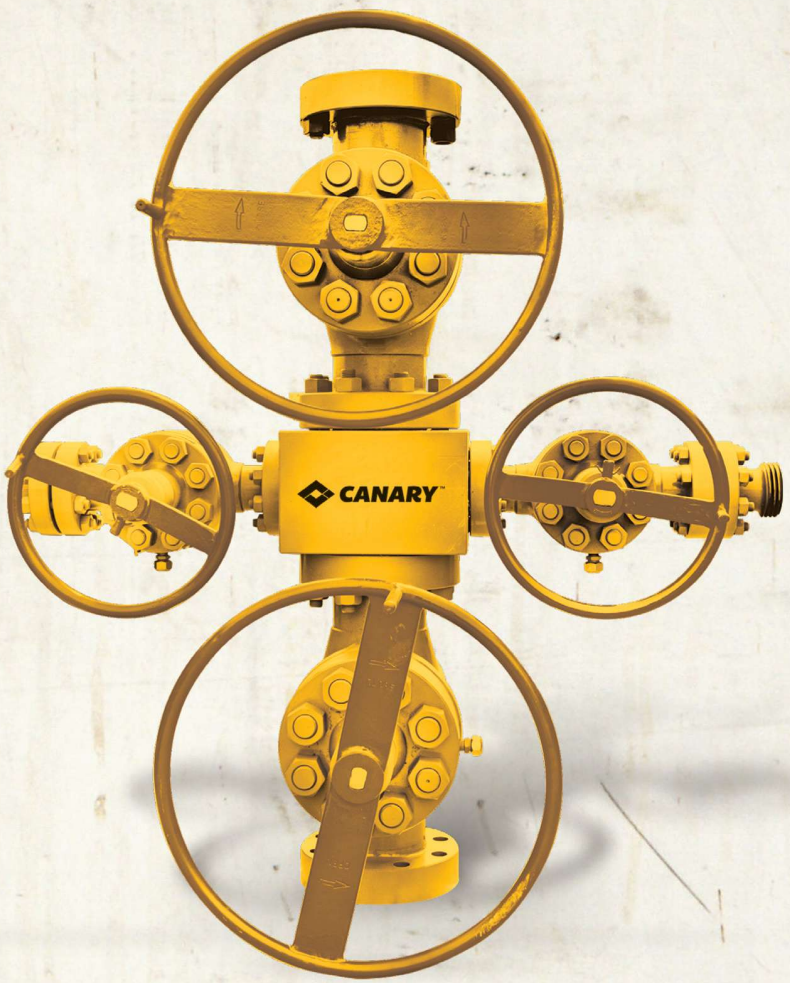

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Counties' bounty

You only need three reasons to understand why rising US gas production is going to keep natural gas prices low for years to come.

Those reasons are Susquehanna, Greene, and Washington counties in Pennsylvania. Like the real estate mantra that bleats location, location, location as a key to success, these three counties, plus Wyoming and Bradford in northeastern Pennsylvania, are the main drivers in rising onshore natural gas production.

And more is on the way. In fact, the Pennsylvanian Marcellus shale as a whole should peak at 566 MMcm/d (20 Bcf/d) in natural gas production by 2019, roughly double current levels in fewer than six years.

Those three Pennsylvanian counties sit atop sweet spots in the Marcellus shale. Sweet spot drilling accounts for 20% of Pennsylvania's horizontal wells, according to Cameron Horwitz, director of E&P Research at Houston-based US Capital Advisors. However, Horwitz discovered sweet spot drilling has a disproportionate impact on gas supply after a 2,000-well regional study. Pennsylvanian sweet spots – sort of the Hershey kisses of the Marcellus shale – include one example in which production from just 50 dry gas wells in Susquehanna County is on track to generate EURs of 396 MMcm (14 Bcf) per well.

"These sweet spot areas we've identified … will be the driver of (future) US gas supply," Horwitz said. "Even at $4 gas we have a lot of work to do here, likely over two decades, so it's just a very bright future to look forward to."

Susquehanna and Bradford counties alone generate about 80% of the total amount of gas produced daily in the legendary Barnett shale. But those two counties in northeastern Pennsylvania are just one element in a larger theme.

"We see about 200 Tcf [5.7 Tcm] in the Pennsylvania Marcellus shale that is still viable at a $4 gas price or less," Horwitz said. "That's about 30,000 remaining drilling locations. If you think about the 85 rigs still running in the play and 1,500 wells drilled each year, that is

roughly 20 years left of gas, even if gas prices stay sub-$4 throughout that whole time."

Take note, conventional gas drillers and dry gas-oriented E&P firms in the Rockies, Midcontinent, and Texas: In Susquehanna County, one Cabot well produced 198 MMcm (7 Bcf) of gas in 13 months. At an average 566 Mcm (20 MMcf/d) for a year, it is the best producing Marcellus well to date. According to Horwitz, Cabot's Susquehanna County wells are generating EURs that average 368 MMcm (13.8 Bcf) per well, followed by Chief Oil & Gas LLC at 303 MMcm (10.7 Bcf). Decline curves on one Cabot well are on track to produce 1 Bcm (40 Bcf) over the life of the well. On average, a $10 million dry gas well in Susquehanna County produces a 110% internal rate of return (IRR) under present pricing and breaks even at $1.95 gas.

Horwitz defined the Marcellus gas sweet spots as areas that produce an EUR of 227 MMcm (8 Bcf) or greater, with wells economic at $3 gas. Using these criteria, Pennsylvania has two emerging sweet spots at opposite corners of the state. In the dry gas northeastern Pennsylvania sweet spot, Wyoming County leads the way with average EURs north of 311 MMcm (11 Bcf). Most of the activity is in the northern half of the county.

Neighboring Susquehanna County is second with average EURs of 255 MMcm (9 Bcf).

The second sweet spot, in the wet gas area of southwestern Pennsylvania, is led by Greene County, with EURs per well averaging 229 MMcm (8.1 Bcf). Within the Greene County dry gas core, operators have drilled multiple wells that have generated decline curves suggesting EURs of 340 MMcm (12 Bcf), roughly double the "average" Marcellus well. Operators with the best well results in Greene County include Rice Energy, which is generating average EURs of 348 MMcm (12.3 Bcf), and EQT, with a per-well EUR average of 334 MMcm (11.8 Bcf). At a $7 million well cost, Greene County dry gas wells produce an IRR of 95% at $4 gas and break even at $2.05 gas.

The gas play grades into a wet gas zone in neighboring Washington County. Here, wells produce a stream that is

40% liquids before NGL processing. Range is the largest operator in the wet gas zone, though privately held Rice Energy is reporting leading Washington County EURs of 292 MMcm (10.3 Bcf) per well, while EQT is second with an average 258 MMcm (9.1 Bcf). A $7 million Washington County well produces a 77% IRR at $4 gas and an aggregate $40 NGL barrel. The break-even for a well in the wet gas portion of the Marcellus sweet spot is 40 cents.

"Gas is essentially being subsidized by the liquids," Horwitz said. "Gas is almost insensitive to gas prices in this part of the play."

Horwitz pegged current production out of the Pennsylvanian Marcellus at 283 MMcm/d (10 Bcf/d).

"Pretty amazing when you consider that three years ago production was less than 1 Bcf/d [28 MMcm/d]. That's a compound average growth rate of more than 125% each year – pretty incredible," Horwitz said.

Horwitz's Pennsylvanian scorecard shows 12,000 horizontal wells permitted and 6,000 horizontal wells drilled during the last six years. Operators were permitting 200 to 300 wells per month at the peak in 2011 to 2012.

"We've subsequently seen a slowdown in some of that activity to 100 to 200 wells per month on average, and we've seen a pretty significant high-grading as to where that permitting activity is taking place," Horwitz said. "Counties such as Bradford, Susquehanna, Greene, Lycoming, and Washington have taken a disproportionate share of that activity."

Marcellus rig count has been range-bound between 80 and 100 wells since August 2012 and is currently slightly above the midpoint in that range. "This will probably hold true for the next couple of years," Horwitz said.

Also holding true is the rising flow of Marcellus natural gas, an event that has national implications for future domestic gas production and for natural gas pricing.

Airport drilling

Pittsburgh International Airport already serves as a bustling gateway for the busy tri-state area. Now its subsurface will be equally lively. In 2013 Consol Energy leased 8,807 acres of mineral rights beneath the airport from Allegheny County and the Allegheny County Airport Authority, and Consol plans to aggressively develop those rights. "Early indications are the airport offers stacked-play opportunity," said Nicholas DeIuliis, president, Consol Energy Inc. "We will drill 40 to 45 Marcellus wells on that property." Upper Devonian potential also exists; that would be additive to the already hefty Marcellus resource base.

Consol figures that the lease bonus, capital expenditures for drilling, and taxes and royalties will amount to a $1 billion project for the county. The operator's plans call for six well pads, and drilling will begin in mid-2014.

This deal is just one of the strategic thrusts that are reshaping Consol. The venerable firm has been in business since Abraham Lincoln was president, and its longevity is a testament to its willingness to reinvent itself and grasp new opportunities. Just 10 years ago, Consol was a traditional coal producer. Natural gas was an afterthought, said DeIuliis. Eight years ago, Consol formed CNX Gas to grow its gas business, and three years ago it acquired Dominion Resources' Appalachian E&P assets. This past October, Consol announced the sale of five of its West Virginia coal mines.

"Today we are an E&P business with a best-in-class legacy coal position," he said. "There's no doubt that the change we are seeing is sweeping through our region as well." Energy from shale represents a once-in-a-generation opportunity to breathe new life into the region's manufacturing sector. "The Marcellus and Utica gas fields are impacting everything from electric generation to fueling the American manufacturing renaissance to future export opportunities," he said.

In the Marcellus, Consol currently runs eight rigs with its partner Noble Energy, and it plans to operate at least that many in 2014. Five rigs are at work in West Virginia, and the company expects to have 75 wells drilled by year-end 2013 in the Mountain State.

Consol's assets also include 300,000 acres that are potentially commercial for the Upper Devonian. It announced a discovery in the Burkett shale that came onstream in June 2013 at 85 Mcm/d (3 MMcf/d) and has exhibited remarkably flat declines in its initial production. Consol also continues to seek bolt-on acreage opportunities that are synergistic, an example of which is the farm-in it recently took on 80,000 Marcellus acres in West Virginia from Dominion Transmission.

The transition to a natural gas producer from a coal producer has been dramatic for Consol. It produced 1.4 Bcm (50 Bcf) in 2005 and doubled that to 2.8 Bcm (100 Bcf) in 2010. Consol estimated 2013 production at 4.8 Bcm (170 Bcf), and it expects to grow those volumes some 30% year-on-year in 2014 and the two years following.

Largely untold is the capital investment that goes with this growth. "If you look at Consol Energy in the next 10 years, nearly $7 billion in capital spend will be dedicated to the Utica and Marcellus plays in Ohio, $7.5 billion to the Marcellus in Pennsylvania, and $14 billion in the Marcellus in West Virginia," said DeIuliis. "That's nearly $30 billion pumped into the regional economy in 10 years."

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HARTENERGY

Protecting offshore operations from ice hazards

New ice management system helps operators keep Arctic offshore drilling and production facilities safe.

Terry Kennedy, ION Geophysical

Every year, blue-white glaciers inching down the western slopes of the 100,000-year-old Greenland ice sheet plunge icebergs into Baffin Bay. Slowly melting fragments drift south in the Labrador current along the eastern coast of Canada, heading eventually toward strategic offshore oil facilities on the Grand Banks of Newfoundland. Icebergs and jagged rafts of sea ice threaten the safety of drilling rigs, platforms, oil tankers, and FPSO vessels.

"Iceberg Alley," as the area is known, has seen more than 500 collisions between icebergs and ships. The *HMS Titanic* went down a few hundred miles from the Hibernia oil field, site of the world's largest offshore platform. Hibernia's gravity-based structure is reportedly designed to withstand a collision with a 1-million-ton iceberg, but no one actually wants to test its durability. Over the past few decades, therefore, operators and service companies working off the coasts of Labrador and Newfoundland have devised clever ice management strategies.

Ice management teams prevent icebergs of all sizes from colliding with rigs and other costly facilities. To locate, track, and predict potential ice hazards in a timely manner, ice specialists require reams of detailed ice, weather, and ocean information. Commercial vendors have developed electronic ice navigation and data management systems. But many of these tools suffer from shortcomings, especially when faced with chaotic, unpredictable ice conditions. ION's new Narwhal technology represents a step-change in integrated ice data access, visualization, and decision-making efficiency.

As more nations such as Russia open ice-infested waters to exploration and drilling, more operators will need to implement effective ice management operations.

Effective ice management operations

Whenever pack ice or an iceberg threatens an offshore operation, ice management teams can either move the operation or move the ice. Mobile operations such as seismic acquisition find it much easier to dodge the ice. Fixed or relatively fixed facilities such as drilling rigs and FPSO vessels are more complex and costly to move. Every minute the drillbit stops turning or oil stops flowing, asset owners are losing money. This is why every offshore operation in ice-prone waters has a formal ice management plan specifying procedures for almost every conceivable situation. Judgment and sound decisions, of course, are critical pieces of the puzzle.

Ice management vessels (IMVs) are tasked with keeping ice out of the operational area. During a drilling operation off the coast of Greenland, a 1,500-m (4,920-ft) iceberg floated south past a rig. Two days later, a storm shattered the berg into 150 pieces and drove them back north. A handful of IMVs had to pick their way through potentially lethal debris, lassoing fragments with ropes or special nets and towing them away or shoving them off course with their propellers (a technique called prop washing) to ensure the safety of the rig.

The Hibernia platform can withstand a direct collision with a 1-million-ton iceberg. (Image courtesy of Hibernia)

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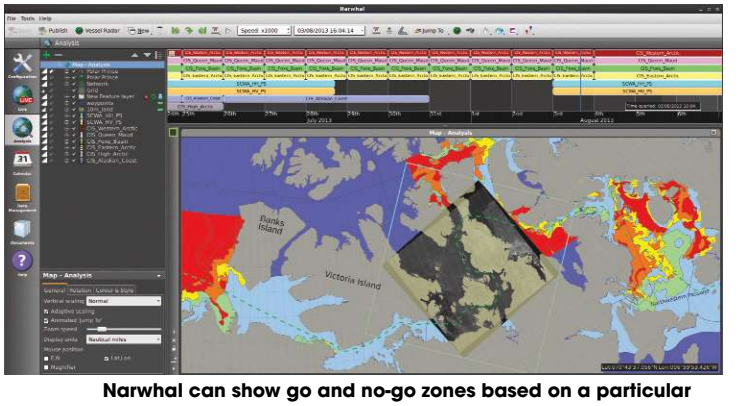
Sometimes nature gets out of control, and some part of the operation must be removed from harm's way. During a heavy ice season off the Grand Banks one year, IMVs defended an FPSO vessel while the semisubmersible rig was towed away for a couple of days until the threat passed. At a cost of perhaps US $1 million per day, operators are loath to take this type of action.

On another occasion, an iceberg had grounded in shallow water 16 km (10 miles) away. In the middle of the night, after sitting harmlessly for days, the berg started to drift toward a tanker offloading oil. To comply with HSE requirements outlined in the ice management plan, the tanker was disconnected and moved away while IMVs deflected the danger. At 5:30 a.m., the partner who owned that particular shipment called to understand exactly what had happened. He had to explain to management why they were paying the overnight carrying charges on 860 MMbbl of oil.



Narwhal can show go and no-go zones based on a particular vessel's ice classification. (Image courtesy of ION Geophysical)

Lost time always impacts the bottom line. Effective ice management seeks to mitigate ice risks while reducing downtime to the absolute minimum. An experienced ice observer, rapid access to diverse ice data, and efficient ice management technology are essential to success.

Efficient ice management technology

Anticipating ice threats as early as possible depends on live radar, satellite images, aerial photographs, weather reports, bathymetry, ice and navigation charts, and other information. In the past, ice analysts printed fax reports, plotted hard copy maps and images, and sifted through piles of data scattered about the bridge.

Early ice navigation software combined electronic ice charts, satellite images, and radar on a single computer. However, data files had to be downloaded from various sources via FTP and manually checked for quality. Some data was not geo-referenced or timestamped, making it difficult to visualize, overlay, and correlate one piece with another. Some data such as vessel positioning, weather, currents, and sea temperature could not be accessed. Ice analysis was therefore slow and inefficient.

ION's own ice observers, working extensive seismic surveys in Arctic waters since 2006, became frustrated with existing software's inability to automate, integrate, or visualize critical ice data. As a result, ION's Concept Systems group developed Narwhal for Ice Management, a patented and fully integrated system that automatically downloads, updates, timestamps, and geo-references every ice product available. With unlimited layers, ice specialists correlate, analyze, and visualize all of the ice, weather, radar, and ocean data required to make informed decisions in rapidly changing conditions.

One of the most valuable features is the "trafficability" or routing capability. Every offshore vessel has an ice rating, indicating the concentrations of sea ice it can safely navigate. With vessel ratings and maps of current ice conditions, the software graphically displays – and continually updates – go and no-go zones. This allows ice management teams to determine appropriate routes for tankers and supply boats to traverse icy waters from producing fields to the mainland, ensuring safety and minimizing fuel costs.

The calendar feature in Narwhal can animate ice movements and other changes over any selected period of time. It can run backward or forward in time, even projecting ice trajectories a day or two into the future. At the end of an operational season, ice analysts can visually review ice incursions and towing incidents using the calendar feature to help meet reporting requirements, study ice behaviors, and fine-tune parameters for the next season.

Additional capabilities include multivessel data sharing and visualization, automated alerts for approaching ice, and the ability to track birds and marine mammals in ecologically sensitive areas.

Growing Arctic activity

Declining reserves from mature fields, growing demand for oil, and retreating sea ice have sparked new activities, with six of the eight countries with Arctic territories granting energy companies offshore exploration licenses despite the enormous challenges. To optimize ice defense strategies and ensure the safety of personnel, facilities, and the environment, operators must make timely, well-informed decisions. Reliable ice management technology will be critical to ensuring the industry's ability to safely explore, develop, and produce in this delicate but harsh environment. E&P

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Arctic offshore pipeline design challenges

Ice creates unique challenges in design and installation considerations in the Arctic offshore.

Mike Paulin, INTECSEA

Several developments have taken place in regions characterized by seasonal ice cover, including the US Beaufort, North Caspian, and Sakhalin Island. These projects incorporated pipeline transportation systems that are a cost-effective, safe, and reliable mode of hydrocarbon transport to shore. Ice gouging is one of the key design issues that affect engineering considerations with respect to strain-based design, target burial depth requirements, cost, and safety. Other challenges that must be considered include strudel and hydrodynamic scour, thaw settlement of permafrost and frost heave, and upheaval buckling. These considerations also may influence design requirements.

Ice gouging

It is generally accepted that Arctic pipelines would need to be trenched to some depth below the mudline to protect the pipeline from ice keels (Figure 1). Ice gouging of the seafloor (sometimes referred to as ice scouring) is a near-shore feature for most of the northern continents. Sea ice is driven by wind and current forces and tends to pile up, creating pressure ridges when the ice moves. Pressure ridges have keels extending below the water surface, which move with the ice sheet. Occasionally, these ice keels intrude into water

FIGURE 1. Ice keels gouge the seafloor when in water depths shallower than their draft. (Images courtesy of INTECSEA)

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depths less than the ice keel draft and form a gouge in the seafloor.

As an ice keel passes over any point in the seabed, vertical and lateral stresses are applied to the soil at the keel base, resulting in some distribution of vertical and lateral soil displacements with depth beneath the ice keel. The movement of the soil also loads or moves the pipelines in the trench. The configuration of the pipeline after gouging, and hence the strain in the pipelines, depends on the pipeline properties, the soil characteristics, and the depth of the pipeline as well as the soil displacements. The soil displacements induced at the pipeline depth due to ice gouging and resulting strains in the pipeline must be calculated. The burial depth of the pipeline must be sufficient so that the maximum predicted ice gouge will result in pipeline strains within acceptable levels.

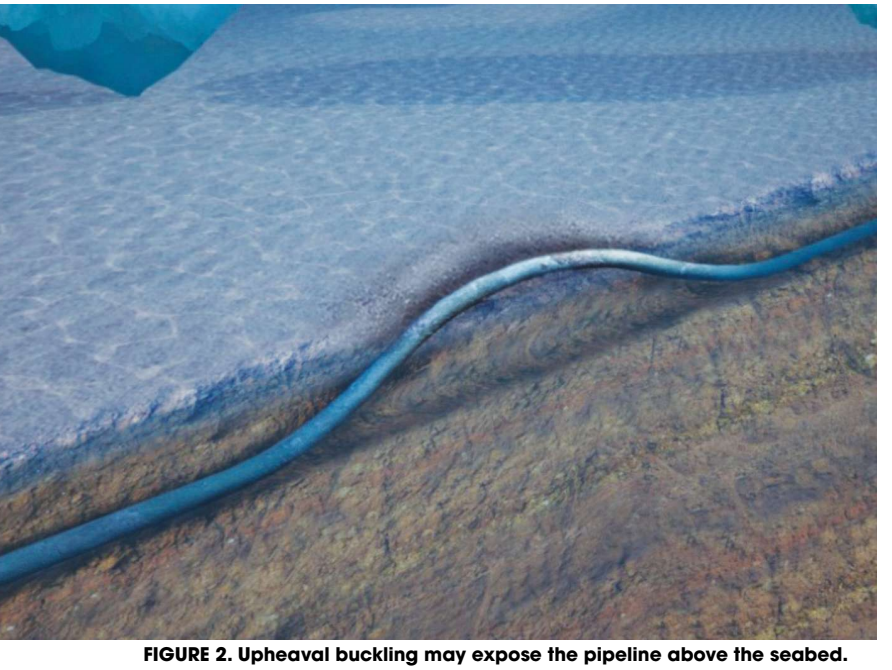


FIGURE 2. Upheaval buckling may expose the pipeline above the seabed.

Strudel scour and hydrodynamic scour

Nearshore Arctic zones typically develop a bottomfast ice sheet during the winter season. If an onshore river flow encounters such an area during the spring breakup, the river water will overflow the bottomfast ice sheet in the nearshore zone. This overflow water will spread offshore and drain through tidal and thermal cracks or seal breathing holes in the ice sheet. If the drainage rate is high, hydrodynamics (high-velocity currents) of the draining water at the seafloor can scour seabed sediment (leaving a circular or linear scour in the seabed), which can potentially expose and impose current loads on a pipeline. These are known as strudel scours, and they usually occur in 2 m to 8 m (6 ft to 26 ft) depth offshore from river deltas. It is unlikely that every drain hole in the sheet ice produces a scour in the seafloor. The deepest scours are found in shallow water – 2 m to 3 m (10 ft) deep – where the strudel flow is sufficiently powerful to excavate the seafloor sediments immediately below the ice.

If a strudel scour happens on top of a pipeline, there is the possibility that the scour could result in an unacceptable pipeline span. In extreme conditions, the pipeline span could possibly experience hydrodynamic loads from the water flow, and vortex-induced vibration effects may need to be checked.

Thaw settlement and frost heave

If permafrost was continuous and uniform in terms of soil and ice conditions along the pipeline route, and if the pipeline was operated at a constant temperature along the route, then differential thaw settlement and its effects would not be an issue as settlement would be uniform along the pipeline. These ideal conditions do not exist in practice. Irregular, discontinuous ice-bonded permafrost soil conditions are more common, and pipeline temperature can vary along its length.

When the pipeline becomes operational, the temperature of the pipeline will typically increase, thereby warming surrounding soil and creating a permafrost thaw bulb. The extent of the thaw bulb, the soil type, ice and moisture content, and the stratigraphic profile are the primary factors that determine the potential for differential thaw settlement along the pipeline alignment. If the thaw settlement area is adjacent to an area that is thaw-stable, the differential settlement can induce considerable strain in the pipeline and must be accounted for in design, which can be analyzed through geothermal analyses and finite element modeling.

Upheaval buckling

A buried steel pipeline will try to expand longitudinally when operated at a temperature and pressure higher than that experienced during installation. A long buried pipeline is not free to expand due to the restraint provided by the surrounding soil and thus will develop a locked-in axial compressive force. If the buried pipeline

has some residual vertical curvature, possibly due to trench bottom irregularities during installation, the tendency of the axial force near the high points of these trench irregularities will be to buckle the pipeline upward (Figure 2). If the upward force exceeds the downward force due to the combination of the resistance of the soil cover, the pipeline stiffness, and the pipeline self-weight, then the pipeline will move upward and may become exposed above the seabed. This phenomenon is known as upheaval buckling and has been frequently documented for offshore pipelines.

The immediate effect for Arctic offshore pipelines is that the pipeline could have less burial depth or even become exposed at the seabed, which increases the risk of interaction with ice keels. Problems associated with upheaval buckling may include high bending stresses and loss of protective soil cover but may not directly cause a leak or exceed other limit states. However, upheaval buckling is an undesirable condition that must be considered in design. Upheaval buckling analysis must be carried out to determine the minimum backfill thickness over the pipeline for the selected design parameters and maximum allowable vertical variance (prop or imperfection) of the installed pipeline profile.

Pipeline design, construction implications

The design of offshore pipelines in Arctic and northern ice environments must evaluate environmental and geotechnical load effects for potential large deformation ground movement events that may affect pipeline mechanical integrity. Evaluation of the system demand and system capacity influences engineering design considerations that may impact the construction and operational phases.

The first two design issues listed above happen over very limited distances of the nearshore portion of the pipeline and have been addressed in existing pipeline design. Upheaval buckling can happen anywhere in the pipeline (and also in non-Arctic pipelines) if conditions are conducive to buckling. Installation procedures have been implemented on past projects – such as Northstar – to minimize the risk of upheaval buckling. Thaw settlement or upheaval buckling may govern nearshore burial depths as well as trench/backfill design, whereas ice gouging would govern burial depth in deeper waters. It is generally felt that these considerations can be designed for in future projects.

Pipelines have been designed, constructed, and are operational in Arctic (e.g. US Beaufort) and subarctic regions (e.g. Sakhalin Island). The pipelines operating in the true Arctic are in relatively shallow water depths and fairly close to shore. Developments further offshore in deeper water will require additional consideration to aspects related to pipeline design, in particular with respect to burial for protection against ice gouging. Pipeline burial for protection in water depths from approximately 20 m to 40 m (66 ft to 131 ft) will be a challenge given the more severe gouging in these water depths. Modern gouges up to 3 m deep in the US Beaufort and 5 m (16 ft) deep in the Canadian Beaufort have been found. Conceptual development of specialized trenching systems to permit burial to the required depths has been evolving, and advanced technology may need to be developed to allow projects to proceed. E&P

Acknowledgment

This article is based on OTC Paper 24607, which was presented at the Arctic Technology Conference in Houston in February 2014.

References available on request.

Using fluorescence for oil spill detection and mapping

Airborne or AUV-deployed optical sensor systems enable oil spill detection in the Arctic.

Greg Mooradian and **Dean Richter**,
QinetiQ North America

As oil exploration and development in Arctic waters expand, there is a recognized need to mitigate potential oil spills associated with the expansion of this activity. There is a developing requirement to remotely detect oil on, in, or under ice-covered waters during both summer and winter months. The Arctic is a challenging environment that includes extreme weather as well as extended months of no sunlight. The objective is to postulate a remote sensor that can rapidly and reliably detect and map oil under the polar ice.

Sensor deployment

There are two possible deployment platform-based standoff sensor architectures: airborne and AUV. The associated predicted performance and deployment scenarios for both are discussed here.

The airborne high-search-rate spectral fluorescence/reflectance lidar (SF/RL) has the potential to detect and geolocate oil beneath the Arctic ice as well as accurately measure ice thickness. The pod-mounted SF/RL sensor can be flown in both fixed and rotary-wing aircraft, either manned or unmanned. As the aircraft flies forward along its search track, the SF/RL spot is continuously scanned on the surface (snow, ice, or water) and generates an ice thickness and oil detection map that is geo-referenced to ground coordinates (Figure 1).

For a nominal aircraft altitude of 610 m (2,000 ft), a ground speed of 125 knots, and a scan angle of ±50° from nadir, the area coverage rate (ACR) is approximately 336 sq km/hr (130 sq miles/hr). Using state-of-the-art components, reliable oil detection is predicted through an average 4 in. of snow and 2.43 m (8 ft) of Arctic ice.

The AUV-borne sensor uses a smaller, low-power version of the SF/RL sensor, operating between the seafloor and the base of the ice, searching for oil trapped under the ice, settling on the seafloor, and/or drifting in the water column (Figure 2). The AUV-borne sensor sweeps out a 55-m (180-ft) swath, and the model predicts detection at a nominal depth of 23 m (75 ft) below the ice.

Illuminating oil

This sensor depends on the principle of fluorescence, whereby a small portion of the green illuminator beam (nominally less than 1%) is absorbed by the oil and converted to longer wavelengths of yellow to orange to

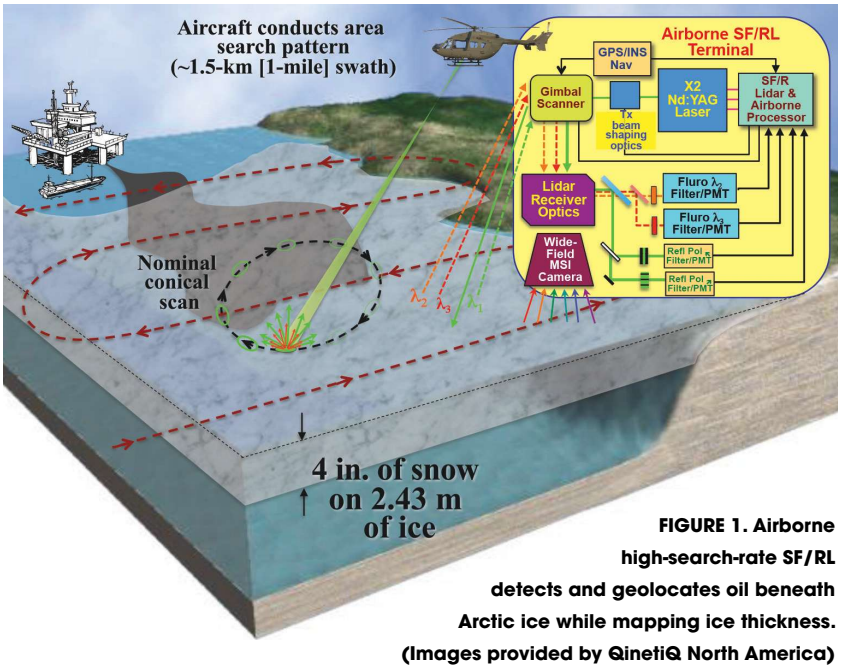


FIGURE 1. Airborne high-search-rate SF/RL detects and geolocates oil beneath Arctic ice while mapping ice thickness. (Images provided by QinetiQ North America)

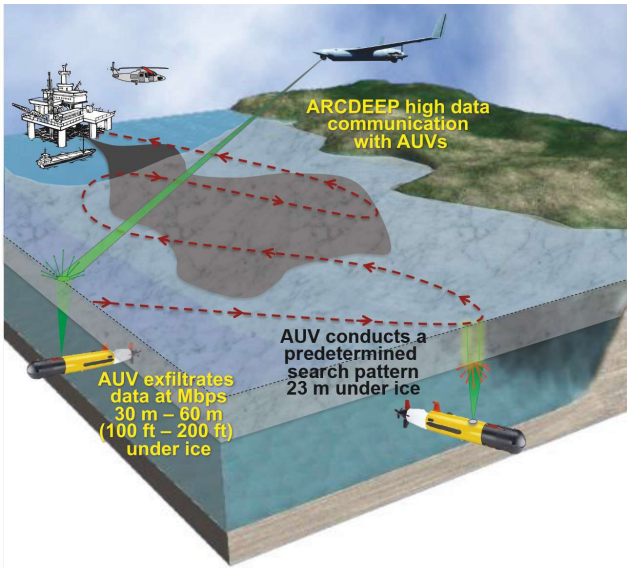


FIGURE 2. An AUV-borne SF/RL sensor detects and geolocates oil beneath Arctic ice, and ARCDEEP enables high-rate data exfiltration while at depth.

red fluorescence. If there is no fluorescing material in the path, then there is no optical signal in the fluorescence spectral bands, and therefore no oil is reported as detected. The specific quantum yield for oil fluorescence is dependent on a number of factors, including excitation wavelength, type of crude oil, age of the oil, and concentration. The performance model assumes a conservative 0.5%.

The 532-nanometer (nm) green laser excitation wavelength was selected not only because of the compact and reliable short-pulse neodymium-doped yttrium aluminum garnet (Nd:YAG) lasers available at that wavelength but also to minimize natural fluorescence of other material in the path. While the quantum yield at 532-nm excitation is less than the UV or blue, propagation through the ice and water is better at 532 nm, and there are fewer naturally fluorescing materials in the path to cause false signal returns and noise clutter. For example, chlorophyll within seawater has low absorption in the green and fluoresces at around 670 nm to 690 nm (where the ice/water attenuation is high).

Fundamental to the viability of either the airborne or the AUV-borne SF/RL sensor is the requirement for an extremely low false-alarm rate while maintaining a high search rate. Both the in-band laser reflectance return and the fluorescence spectral signature must be processed to enable sensitive detection and discrimination of any oil beneath or trapped in the ice. The SF/RL operates in a time-domain laser radar mode. This mode processes the fluorescence return and reflectance at both polarizations vs. time – the distance from the transmitter – to approximately 0.3 m (1 ft) resolution.

AUVs also could be used as the oil detection sensor platform, conducting a preplanned search pattern to cover a specified region of interest (Figure 2). The AUV payload is a smaller and simpler upward-looking version of the airborne SF/RL, mapping the subsurface of the ice sheet to detect oil present under or captured in the ice. The AUV sensor payload is composed of a small, 1.5-watt short-pulsed (less than 5 nanoseconds) Nd:YAG laser with a 2-in. diameter lidar receiver operating at a ±50° angle from nadir. At 23 m below the ice at 4 knots with a 30-Hz laser, the bottom of the ice is sampled every 3.5 m (11.5 ft) for an effective swath of 55 m for an ACR of 0.4 sq km/hr (0.15 sq miles/hr).

The concept of operations for the AUV search pattern would depend on many factors, including the local environmental condition (solid or broken ice cover), subsurface current at depth, and the nature of the oil spill.

Data retrieval

The conventional way to retrieve sensor data from an AUV is to either physically retrieve the data from hard drives onboard the AUV or for the AUV to come to the surface and download the data via a radio frequency to a satellite or relay aircraft. However, collecting the data by physically downloading it from the AUV can interject unacceptable latency in the time to collect, process, and interpret this data. This delay could be critical in a time-sensitive oil spill scenario. Likewise, the ability of the AUV to come to the surface may be severely limited or prevented by the Arctic ice cover.

In the future, however, the AUV platform may have the ability to exfiltrate large amounts of data in a short amount of time directly through Arctic ice and snow to a relay aircraft. This can be done while the AUV operates at depth without delaying or disrupting the oil detection search mission. The Arctic relay communications, data exchange, and enhancement protocol (ARCDEEP) system could enable two-way blue-green laser communication data transfer between underwater assets – other AUVs, fixed nodes, or gateway buoys under the ice – and airborne platforms at 100 Kbps to 30 Mbps, depending on the environment, time of day, and season (Figure 2). E&P

Acknowledgment

This article is based on OTC Paper 24590, which was presented at the Arctic Technology Conference in Houston in February 2014.

Creating a more accurate drilling modeling tool

Design platform decreases length of drillbit development cycle and can be used on multiple drive systems.

Mary Hogan, Associate Managing Editor

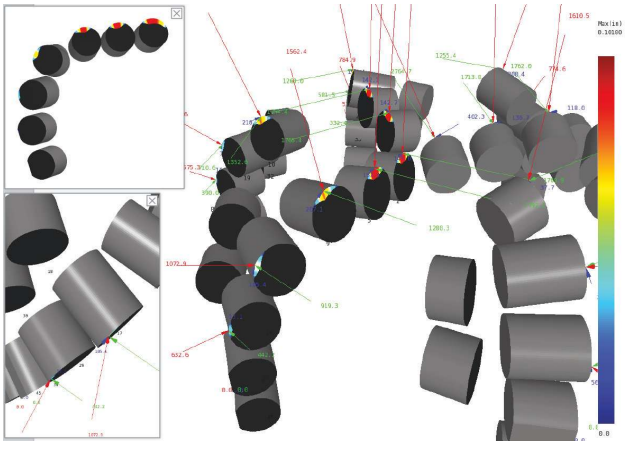
When Smith Bits, a Schlumberger company, introduced the IDEAS integrated drillbit design platform, the company sought to create a more accurate drilling modeling tool that also could be used to increase the speed at which the drillbit product development cycle was completed. The drillbit product development cycle, which has historically been extremely long, includes three primary phases: design, manufacturing, and field-testing.

"Just one product iteration can take several months," Wiley Long, drilling optimization manager for Smith Bits, said. "Without a good drillbit design tool, multiple iterations may be required to create a successful design. By using the IDEAS platform to help us design bits, we are able to complete the field-testing phase in the virtual drilling environment."

The IDEAS platform won the drillbits category of Hart Energy's 2009 Meritorious Awards for Engineering Innovation. Previous drillbit design platforms performed bit design without considering the drillstring or the bottomhole assembly (BHA). "The IDEAS platform, however, is capable of modeling the dynamics of the entire drillstring from bit to surface," Long said. "This results in a bit design that works in harmony with the entire drilling system."

The design platform also incorporates a proprietary method to account for the interaction between the drillbit and formation. Unlike other design platforms, which use formulas that estimate the forces at the bit and its cutting elements, the IDEAS platform incorporates polycrystalline diamond compact (PDC) cutter scrape tests and insert indentation tests performed on rock samples. The forces generated from these tests are then integrated into the design platform to provide a realistic representation of bit-rock interaction.

Since its introduction, the design platform has been fully embedded into the company's engineering culture. The company also has created an internal service that allows field-based engineering and sales teams to quickly request and receive the platform's studies for their local drilling applications. "The IDEAS service exists so the engineering teams around the world can quickly select and validate the drilling products, BHA configurations, and drilling parameters used in their local drilling applications," Long said. "The results of each simulation are provided in user-friendly charts and tables so they can be easily interpreted, analyzed, and presented."



To accelerate the development of rolling PDC cutter technology, the IDEAS drillbit design platform enabled engineers to optimize placement of the rolling cutters on bit blades to ensure reliable cutter rotation. Integration of these cutters was determined by examining the effect different geometric orientations had on three cutter characteristics: durability, appropriate balance of driving force, and aggressiveness. (Image courtesy of Schlumberger)

When selecting PDC bits to be run on the Schlumberger PowerDrive Archer high build-rate rotary steerable system (RSS), which is capable of creating very high dogleg severity when compared to other RSS tools, special consideration must be taken when selecting the bit design. Smith Bits created a workflow to ensure that all bits planned to be run with the RSS meet strict IDEAS-based selection criteria. "The selection process ensures that the best bit is used in terms of drillbit stability, steerability, and ROP," Long said. Since first using the RSS and the design platform in 2012, the company has successfully completed customer run objectives 97% of the time. EP

Multiple attenuation: strategy that addresses current challenges

A proposed plan recognizes real and prioritized open issues and defines and addresses challenges. (Part 1 of a two-part series)

Arthur B. Weglein, M-OSRP, University of Houston

The demand for new and improved capability in removing multiples is driven by the portfolio of the petroleum industry and by current and anticipated future exploration trends. For example, the industry moved to deep water roughly 30 years ago. With that move, highly effective multiple-removal methods that were being applied industry-wide suddenly bumped up against their assumptions when applied to deepwater plays and failed. As an example, deconvolution is based on 1-D and on statistical assumptions, the latter not satisfied in deep water.

Since then, the overall industry trend to explore in progressively more complex and remote areas, with ill-defined and difficult-to-estimate subsurface properties and increasingly complex plays, is a constant that motivates the search for capabilities that will not require subsurface information. Methods that require various forms of subsurface information include F-K, radon, and feedback demultiple methods.

The inverse scattering series (ISS) provides the opportunity to achieve all processing objectives directly and without subsurface information. The current ISS internal multiple attenuation algorithm has a unique capability to predict the exact phase (time) and approximate amplitude of all internal multiples at once, automatically, and without subsurface information. These properties separate the ISS internal multiple attenuation algorithm from all other methods, make it the high-water mark of current internal multiple effectiveness, and explain its stand-alone capability. That is, those ISS properties and strengths are what all other current demultiple methods do not possess and cannot deliver.

Several researchers have developed ISS free surface multiple elimination algorithms and internal multiple attenuation algorithms. Field data applications have demonstrated their effectiveness.

However, at every period in the history of E&P, the arrival of new capability to address the latest set of challenges has encouraged industry to explore in yet more daunting circumstances – situations never previously imagined, let alone considered, and beyond current capability to accommodate. That will once again demand a new and fundamentally higher level of capability and effectiveness.

The petroleum industry's current worldwide portfolio of both conventional and unconventional onshore plays and of increasingly complex offshore plays with new and unforeseen challenges has returned and rejuvenated an interest in multiple removal (and a demand for substantially increased effectiveness). Multiple removal has come back to center stage, both for petroleum industry sponsors and as a key and fundamental research project for the Mission-Oriented Seismic Research Program (M-OSRP) at the University of Houston.

Marine

Early marine field data examples of the promise and delivery of ISS free surface multiple and internal multiple algorithms can be found in papers, abstracts, theses, and the Mississippi Canyon data tests in Weglein et al. (2003) pages R69 and R70.

Those algorithms were recently employed on data from offshore Brazil, and the results were reported (Figure 1). One of the conclusions in those field data tests at Petrobras was that "no other method was able to show similar effectiveness in attenuating the internal multiples generated by the salt layers."

Onshore

Several authors have described the motivation, evaluation, and comparison of different approaches to the removal of internal multiples on complex synthetic and onshore data. Fu et al. (2010) concluded, "[The ISS internal multiple algorithm] performance was demonstrated with complex synthetic and challenging land field datasets with encouraging results, where other internal multiple suppression methods were unable to demonstrate similar effectiveness."

Good news

At the 2013 post-convention Society of Exploration Geophysicists (SEG) Internal Multiple Workshop, nine of the 11 presentations described and exemplified the industry-wide impact and standalone capability (for complex offshore and onshore plays) of the ISS internal multiple attenuator. ISS internal multiple attenuation has become fully mainstream within the petroleum industry.

Remaining challenges

With all this "good news," what could be the problem? Industry's portfolio/trend and focus today (and for the foreseeable future) makes it clear that a large and significant gap exists between the current challenge for the removal of free-surface multiples and internal multiples and the collective capabilities of the worldwide seismic exploration community. The specific issues are that (1) the multiple generators and the subsurface properties are ill-defined and increasingly complex, and (2) too often the multiple is proximal to or interfering with the primaries. The latter serious and significant issue can occur in many marine environments and frequently occurs with onshore plays. That type of challenge of removing multiples proximal to and/or overlapping primaries (without damaging primaries) is well beyond the collective capability of the petroleum industry, service companies, and academic research groups and consortia to effectively address. It is not an issue that new and more complete data collection and acquisition will by itself address. The industry simply doesn't have the theory and fundamental concepts in place today that are needed for algorithm development, implementation, and application. That's the basic reason it is unable to address the challenge it currently faces. That's the bottom line.

To adequately address the current industry challenge, researchers will need to predict exactly the phase and amplitude of all internal multiples and thereby surgically remove the multiples at all offsets directly without subsurface information and without damaging primaries. No one today is able to provide that for marine applications, let alone for the even more challenging onshore plays.

There is a need for new basic concepts and fundamental theory development that must begin with a frank and forthright recognition of the problem, its economic moment and significance, and the current technical gap. New concepts and algorithms will need to be produced, followed by addressing the practical application and implementation issues.

The plan

At the 2013 SEG International Conference Recent

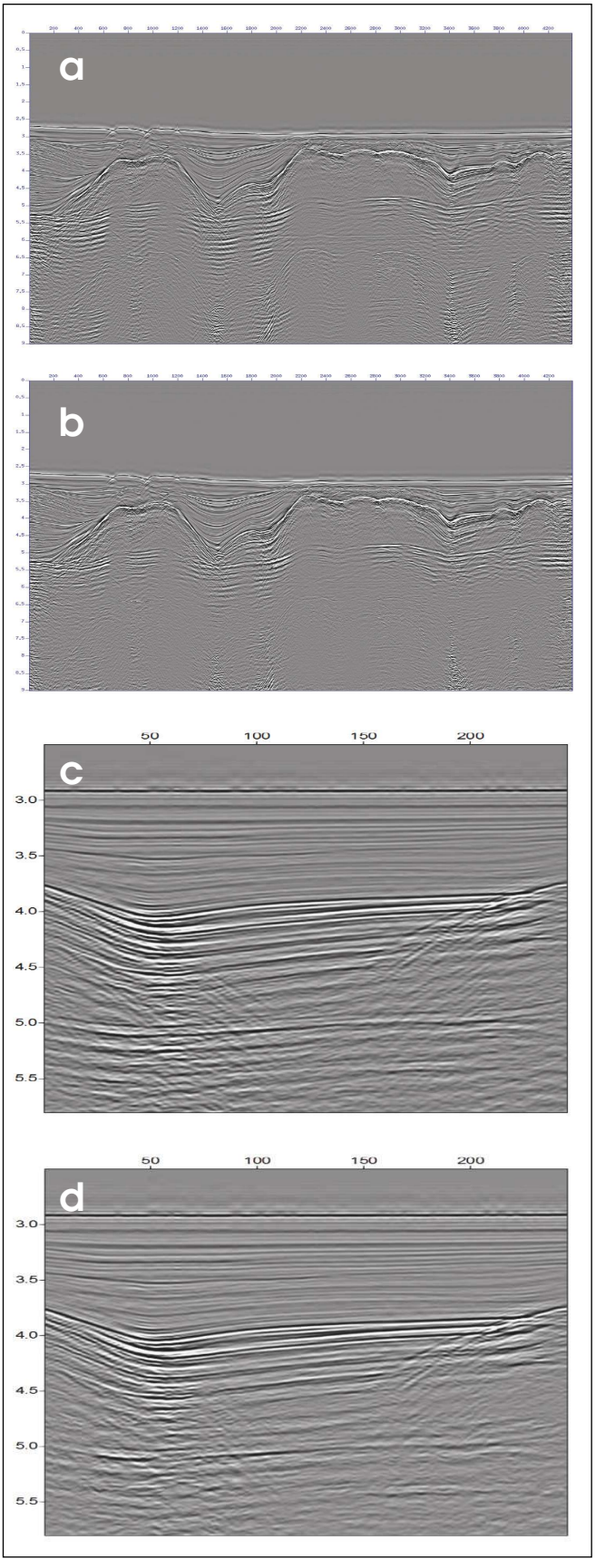


FIGURE 1. Stack before (a) and after (b) free surface multiple removal; common offset sections before (c) and after (d) internal multiple attenuation. (Data from Ferreira, 2011; image courtesy of M-OSRP)

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Photo credit: Rob Ruhoff, VISIT DENVER

Advances and the Road Ahead Session, M-OSRP proposed and described a three-pronged strategy it will pursue as a direct response to that challenge. It will have the potential to provide the necessary step-change increase in capability and respond effectively to this pressing problem. The level and magnitude of the challenge and the potential for opening and delineating new petroleum reserves and achieving improved drilling success rates all underlie the commitment to developing and delivering fundamental new concepts and algorithms that offer a step-change increase in capability. Multiple removal has returned from being viewed as a relatively mature subject and project that helped M-OSRP "pay the rent" and is back to occupying center stage as a major research project and focus.

The three-pronged strategy to respond to the current open issues and pressing challenges in removing multiples is as follows:

- Develop preprocessing methods for predicting the reference wavefield (wavelet and radiation pattern) and producing deghosting data (in particular for onshore and ocean-bottom acquisition) that are direct and do not require subsurface information;
- Develop internal multiple elimination algorithms from the inverse scattering series; and
- Develop a replacement for the energy minimization criteria for adaptive subtraction that derives from, always aligns with, and serves the inverse scattering series free surface and internal multiple algorithms.

This strategy represents a consistent and aligned processing chain with one single objective: providing a direct and practical solution to the removal of all multiples without requiring any subsurface information and without damaging primaries. E&P

Acknowledgment

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References are available on request.

EBS allows company to dive deep

Predictive analytics in real time offer opportunity to change course before incidents occur.

Amy Logan, Senior Editor, Production

On Feb. 4 the Olympus tension-leg platform – Shell's seventh and largest floating deepwater platform in the Gulf of Mexico (GoM) – produced its first oil in the company's Mars B development. The project was unique in that it is the first in the GoM with infrastructure significant enough to potentially expand the life of the greater Mars field to 2050 or later. But it also was important because it produced its first oil remotely, as engineers worked onshore to man the operation.

Working remotely in a deepwater operation is no easy task, according to Tom Moroney, deepwater technology deployment and geosciences delivery manager for Shell Upstream Americas. That is why he has spent the last several years on a mission to find both a predictive and prescriptive technology for Shell's deepwater operations that would allow personnel – onboard or off – to manage the operation. His solution: predictive analytics through exception-based surveillance (EBS).

At the recent ARC Industry Forum 2014 Moroney spoke in a session titled "Predictive Analytics Bring a New Dimension to Situation Awareness." He said Shell's EBS system has been instrumental in helping the company manage its vast amount of data for daily operations.

"On any given day we have 6,000 events running, sensing 17,000 instruments being evaluated," he said. "Each event has between 10 to 10,000 data points per day, per instrument. Some of this data is consumed second by second as it comes in from the offshore facilities.

"We're executing more than 310,000 calculations per day, so in total we're consuming approximately 430 million data points per day. This is all done in real time by analytics – a hand doesn't have to touch it. Then what's presented to us and elevated to the engineers are the things that need to be acted on."

Predictive and prescriptive analytics

In deep water, every minute and every cent counts. A simple human error could have a lasting negative effect on production, the environment, or on the overall operation. That is why Shell sought a solution that would automate operations to the extent where "we could move away from a world where everything is dependent on who showed up at a desk and what that individual did," Moroney said.

But automation wasn't enough for Shell and its operations. Rather than waiting until after an incident had occurred to deal with it, Moroney said he wanted a solution that would alert engineering or operational personnel in real time to an impending problem or anomaly so they could prevent it before it happened.

"We wanted to create the capability that the equipment, wells, and reservoirs were talking to us in real time, telling us when interventions needed to happen," Moroney said. "We wanted to be in a position where we were closing that loop in a lot faster time cycles than we were historically."

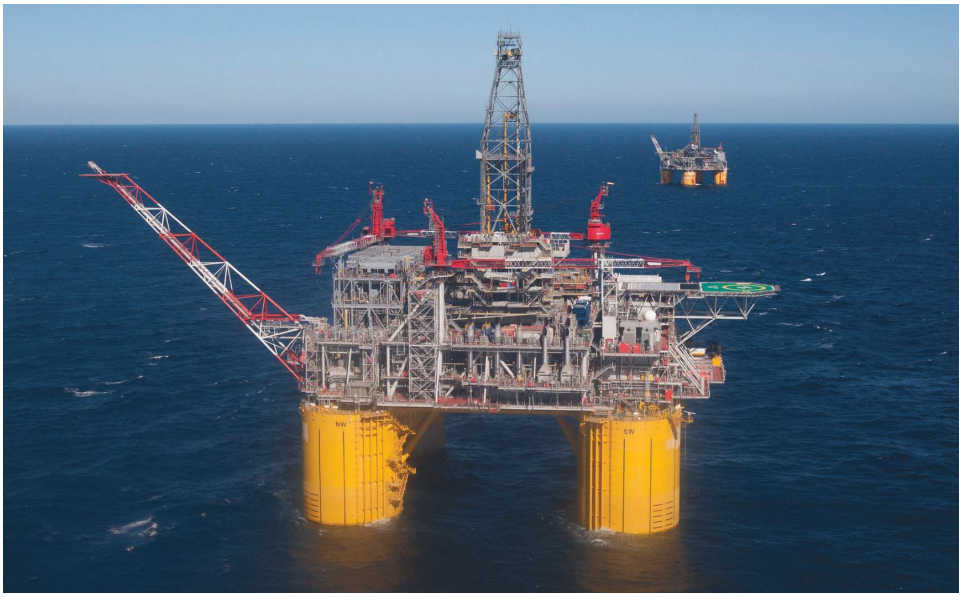
In addition to the detailed surveillance required of the new technology, it would need to be capable of capturing on file every manual and report ever made for Shell's operations, and it would need to be searchable and accessible.

"We wanted to prevent people spending their time looking for information or looking for data and extracting manuals," Moroney said. "So we made it all electronic, increased availability and interpretation time, and minimized transaction time."

Real-time monitoring of big data

For Shell, the advantage to choosing a solution capable of predictive and prescriptive analytics was that it could meet all of its criteria and quickly sift through the vast amount of data the company had stored, producing the most pertinent information fast and in real time. The EBS melded perfectly with Shell's enterprise vision called its "smart solutions platform," Moroney said.

"It is all about how we consume data and how we make that data available all the time to the operational and engineering personnel," he explained. "It starts with some very basic reporting queries – the type of technology that's been around for decades. The [EBS] capability that we've implemented in deep water really positions us in the realm of descriptive and diagnostic analytics; it helps us understand those emerging conditions and trends in equipment and well performance. Essentially, [it supplies us with] smart assets – smart wells, smart topside equipment, smart reservoirs."



Shell is using its EBS technology to communicate with its newer deepwater projects such as the Mars B Olympus tension-leg platform shown in the foreground. EBS allows the wells to "talk" to Shell in real time, helping the company predict and isolate incidents before they happen. (Image courtesy of Shell)

After the EBS system predicts where the next malfunction or anomaly may occur, Moroney said Shell will then decide how to react to the potential incident.

"We were working and conducting our business in a very reactive way – very much a firefighting way," he said. "[With EBS] we wanted to be able to put [all of our data] in the system so we can drive rigorous, detailed surveillance consistently across our entire asset portfolio."

Implementation and customization

Once Shell had its EBS predictive analytics system up and running, Moroney said it "got very precise" about how the data could be applied "across the time and role continuum."

"We looked at the kinds of activities that happened in minutes and hours, the kinds of activities that happened in days and weeks, and we got very disciplined about the language that we use," he said.

That "language" included terms that would clearly indicate what type of situation the EBS was predicting and what type of action would be required for resolution. The terms were kept simple so there would be no mistaking what was taking place and what might be required. They included:

Alerts: "These are trends that are beginning to present themselves in a piece of equipment," Moroney said, adding that they also inform the team what "multivariant level of analysis" should be done to best understand the situation. "Alerts are developing in threatening conditions that, if not understood and remediated, will wind up in lost production or a piece of equipment being taken down for an overhaul."

Events: "An event is when we do an action because we have an alert," he said.

In one case, Moroney described receiving an "alert" from Shell's Mars fuel gas compressor. The alert identified an issue with a radial bearing vibration. "The bottom line here was that we were able to avoid a change-out in equipment," he said. "We did some early investigation and wound up saving more than [US] $500,000 in repairs. Through this alert and the subsequent analysis and intervention [or 'event'], we identified best practices that we were then able to replicate across all the compressors."

Shell also amended its workflow orchestration in the EBS system to ensure a more efficient handoff between personnel, Moroney said. This allowed the operators, engineers, and supervisors to pinpoint the last stage where work had occurred and pick it up from there – an aspect of EBS he called "situational awareness."

"We have a collaborative working environment that we call 'the bridge,'" he said. "The equivalent is the New York Stock Exchange; someone can step into that room and get an instantaneous sense on what's going on [in this case] with our deepwater production system out in the [GoM] and down in Brazil."

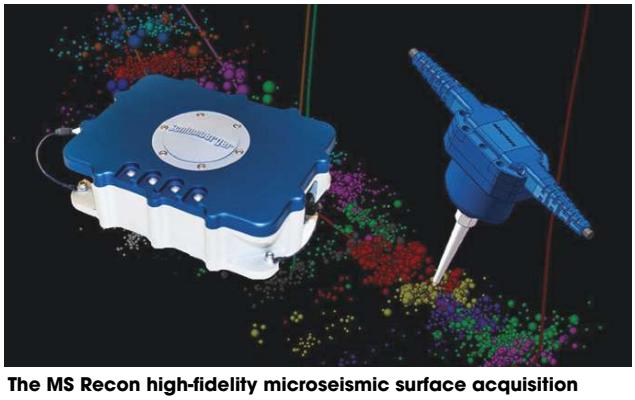
'The proof is in the pudding'

Moroney said Shell implemented EBS in early 2010, and since then it has proven its worth by saving the company at least four times what it cost.

"The proof is in the pudding," he said. "This sets up a fantastic foundation to an age of predictive and prescriptive analytics, and we see it as a continuous journey that is going to transform how we manage and operate our production systems in the upstream and then our downstream operations as well." E&P

Microseismic system improves signal-to-noise ratio

The Schlumberger MS Recon high-fidelity microseismic surface acquisition system provides improved imaging of hydraulic fracture geometry by optimizing the microseismic signal quality, according to a Schlumberger product announcement. The product is for surface and shallow-grid microseismic surveys. It is designed to address the challenges of detecting small microseismic signals emitted during hydraulic fracturing at the surface and near-surface locations by improving signal-to-noise ratio during acquisition, said Joseph Elkhoury, vice president and general manager of Microseismic Services at Schlumberger. The microseismic system features a proprietary geophone accelerometer and ultra-low-noise electronics to produce a wide range of signal detectability. GPS-synchronized data are acquired continuously and transmitted to a real-time operations support center. In field trials in a horizontal shale completion, data analysis showed the system improved the sensitivity to smaller microseismic events by boosting signal-to-noise ratio more than twofold compared to the conventional system, the release said. *slb.com/MSRecon*



The MS Recon high-fidelity microseismic surface acquisition system optimizes the microseismic signal quality for surface and shallow-grid microseismic surveys. (Image courtesy of Schlumberger)

Twin sealing on PRT boosts resilience, long-term deployment

First Subsea Ltd. integrated the Hyperlast 101 Twin Sealing system with its range of pipeline recovery tools (PRTs) used to recover subsea flowline and gas export production pipelines to the surface. The twin polyurethane seals increase the PRT's resilience and scope for long-term deployment in deep water and ultra-deep water. The sealing system includes the primary and secondary composite Hyperlast 101 seals in combination with an internal check valve for shallow and deepwater applications. The tool's Ballgrab pipe-grip mechanism is suitable for loads of more than 1,200 mt. The PRTs are designed to handle API 5L and DNV 450 pipelines with diameters of 2 in. to 48 in. at both low and high sealing pressures. The tool's modular design allows a number of optional modules to be added, including a dewatering seal, ROV-friendly hot stab, pig catcher, and check valve. *firstsubsea.com*

Narrow laser enhances sensitivity for acoustic sensing

Applied Optoelectronics Inc. has made an ultra-narrow linewidth laser available for acoustic sensing applications, the company said in a press release. The new sensing laser uses an external-cavity design to produce a spectrally pure beam. The ultra-narrow linewidth of less than 100 kHz is approximately 500 times narrower than comparable distributed feedback lasers without the external cavity design; this allows the construction of acoustic sensors with better pressure sensitivity. This technology can be used in distributed sensors that are introduced within a wellbore to monitor pressure and temperature. It also can be used in seismic applications for higher-resolution reservoir mapping or for near real-time monitoring of hydraulic fracture propagation, the release said. *ao-inc.com*

Service provides more accurate knowledge of fracture height

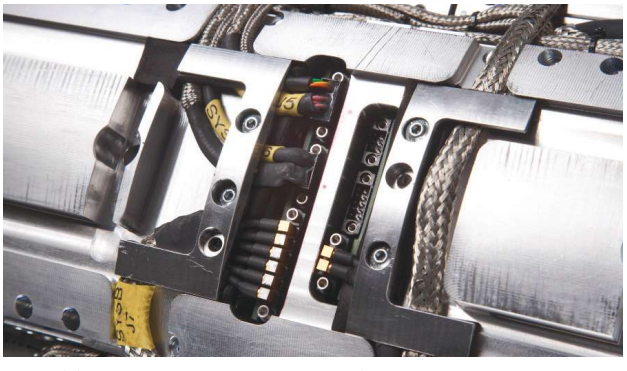
FracHeight service from Pinnacle Technologies, a Halliburton service, is a hybrid tool that combines fiber-optic wireline-conveyed microseismic receivers with Pinnacle's downhole tiltmeter sensors that directly measure the formation movement associated with fracture dilation. Determining fracture height can sometimes be a challenge when relying on microseismic monitoring alone, the release said. In multistage fractures where shallow microseisms clearly exist, identifying the cause – whether it's the actual fracture opening, natural fractures, a result of a critically stressed zone shearing, or some other mechanism – sometimes requires additional information. By incorporating microdeformation measurements made by downhole tiltmeters, the service provides definitive evidence of fracture dilation for more accurate fracture mapping with insight on actual fracture deformation as a function of depth. Improved knowledge of the subsurface allows for better asset development and increased completion and fracture efficiency, the release said. *halliburton.com*

Technology suite fights ghosting at three stages of processing

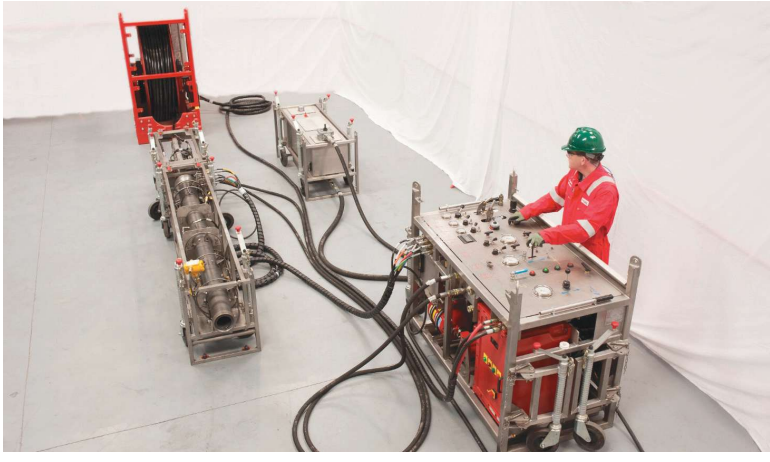
Geotrace has developed a technology suite of deghosting techniques called HDBand. The suite focuses on the recovery of low and high frequencies to produce clean, sharp, and high-resolution seismic images, especially in marine reservoir applications. The marine deghosting techniques are designed to be flexible and applicable at three key stages of a processing sequence: pre-imaging; post-imaging; and post-stack for various streamer configurations at constant, slant, or variable depths. A pre-imaging application can improve the resolution for better velocity analysis and a more detailed final image, the release said, while a post-imaging application can be efficient and cost-effective for amplitude vs. offset/amplitude vs. angle and inversion applications. For reservoir characterization, a post-stack application can be cost-effective when prestack data is not available. HDBand works with other techniques such as Q compensation and spectral whitening. *geotrace.com*

Tool offers alternative for subsea communications, control

The Artemis 2G (A2G) subsea electronics module from Proserv is a subsea controls and communications tool that frees operators from the constraints of an existing brownfield umbilical by finding additional signal capacity to enable a cost-effective field upgrade or extension, according to a Proserv product announcement. A2G also offers high-speed copper-based multidrop networks as an alternative to fiber-optic infrastructures within the subsea production system. The module provides accessibility for remote usage through its webpage interface from subsea to desktop and offers advanced configuration and diagnostics to deliver adaptable communications. The system has been developed as an evolution of the company's suite of subsea control modules and is compliant with the latest ISO 13628 part 6, API 17F, and Subsea Instrumentation Interface Standardization. It can be used with existing networks and technology. *proserv.com*



The A2G subsea electronics module finds additional signal capacity to enable cost-effective field upgrades or extensions. It is compatible with existing networks and technology. (Image courtesy of Proserv)



The Flexi-Coil Extended Reach offers an alternative for riser and flowline blockage remediation by using miniaturized coiled tubing principles. (Image courtesy of Paradigm Flow Services)

Coiled tubing system extends reach for blockage remediation

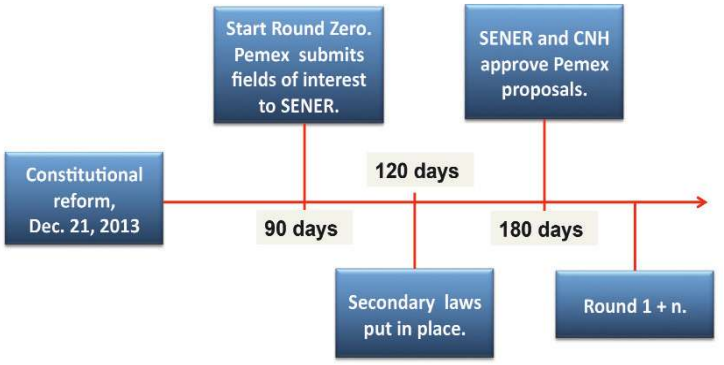
Paradigm Flow Services launched its Flexi-Coil Extended Reach for riser and flowline blockage remediation and internal inspection. While conventional methods for remediation are limited because of difficulties to overcome bends and safely navigate beyond 200 m (656 ft), this miniature coiled tubing system has been proven in tests up to 2,000 m (6,562 ft), a Paradigm press release said. The system can be deployed *in situ* into risers and flowlines and provides a safe solution to unblock these lines when working from an FPSO unit. It can carry out high-pressure jetting and chemical and nitrogen injection over long distances to de-sand, de-wax, and depressurize hydrate plugs, the release said. Rather than disconnecting risers and bringing another rig on site to carry out conventional coiled tubing for the remediation of production systems, the Flexi-Coil system allows the shut-in line to be left *in situ* and entered using existing facilities, reducing the risk for operators, said Rob Bain, Paradigm's managing director. Paradigm also can attach monitoring devices and retrieve and analyze debris to provide assurance on operational success. *paradigm.eu* E&P

Mexico says 'bienvenido'

After 75 years of Pemex monopoly, Mexico will welcome foreign investors.

Rhonda Duey, Executive Editor

Since Dec. 21, 2013, all eyes have been on Mexico. That was the day the Diario Oficial de la Federación announced a constitutional amendment ending 75 years of Petróleos Mexicanos's (Pemex's) state monopoly on oil and gas in the country. Since then numerous conferences and meetings have been held to discuss what this means for the world at large, examining the minutiae of details as Mexico moves into the early stages of opening its reserves to foreign investors.



Mexico has an ambitious plan to attract foreign investors. (Information courtesy of CNH)

But in the macro view, "This is a great achievement," said Duncan Wood, director of the Mexico Institute at the Woodrow Wilson International Center for Scholars, during a Mayer Brown conference. "We should not diminish the impact of what has happened here."

What has happened is significant indeed – Mexico is moving from being one of the world's most closed markets to a much more open system. This has been accomplished by the reform of three constitutional articles. Article 25 introduces the concept of "Productive Enterprises of the State," according to information from the Comisión Nacional de Hidrocarburos (CNH). Article 27 provides entitlements of E&P by means of productive enterprises of the state and by private companies. Article 28 creates the Mexican Fund of Petroleum for stabilization and development through payments and the management of government cash flows.

Few argue against the need for the reforms despite considerable opposition within the country. Declining production and limited opportunity for growth have hobbled Pemex's ability to adequately produce the country's vast reserves. In fact, of all of the rigs currently being operated in the Gulf of Mexico (GoM), only 5% are working for Pemex, according to Marcial Nava at BBVA Research USA.

Additionally, many of the resources lie in shale formations or in deep water, plays that require deep pockets and vast technical know-how.

Finally, the closed nature of the market has hindered Pemex's ability to exploit the country's reserves, said Jesus Reyes Heroles, a former Pemex CEO, at the Mayer Brown event. "You have a national oil company that is not allowed to partner with other companies to pursue its opportunities," Heroles said. "It has limited in a dramatic way Pemex's capacity to comply with its objectives. It gradually made Pemex lose a lot of opportunities and to lag behind other oil companies in terms of know-how and technology."

Next steps

What will happen next is a bit murkier. But according to the CNH, here is what is being planned:

- Within 90 days of the constitutional reform, Pemex will submit to Secretaria de Energia de Mexico (SENER) its selections for "Round Zero," in which the company selects the fields it would like to continue to operate;
- Within 120 days, the Mexican congress will determine secondary laws to uphold the new reforms;
- Within 180 days, CNH and SENER will resolve Pemex's Round Zero proposals; and
- After that, Round 1+n will be launched, in which foreign investors will be able to bid on Mexican licenses.

Foreign opportunities

Any company interested in investing in Mexico's oil and gas will need to ask the obvious question – what is the prospectivity? Alfredo E. Guzman, president of Compañia Petrolera Altamira, gave a talk at the American Association of Petroleum Geologists International

Conference and Exhibition in Cartagena, Colombia, in 2013. In his talk he outlined Mexico's riches.

The country, Guzman said, has five major producing provinces. The Southeast and Tampico provinces are prospective for oil, and the Sabinas, Burgos, and Veracruz basins are prospective for gas. Other provinces also have potential, including the deepwater GoM.

"Despite this natural rich endowment, Mexico is the only country in the world among those considered to be oil-rich that has consistently lost production and reserves in the last 10 years," Guzman said.

Opportunities for foreign companies are numerous, as spelled out in "Mexico Rising: Energy Reform at Last?" published by Atlantic Council. Chief among these are joint venture opportunities with Pemex. "Pemex will be able to bolster its income flow by keeping those projects that are most lucrative while spreading risk (and hence capital requirements) to areas where it lacks comparative advantage," the report stated.

Perhaps the lowest hanging fruit can be found in mature fields. The report noted that Pemex's "desperation" to minimize production declines resulted in fields that have only partially been developed. "It has not invested in readily available techniques to enhance recovery," the report stated. "These mature fields – the 'bitten apples' that Pemex identifies – provide the most likely investment opportunities for midsize international companies and the most likely source of production increases in the near future."

Mexico's deep waters also should provide opportunities for foreign investment. Pemex already has had success there, with recent discoveries on the Mexican side of the

Oil rush risks: security concerns in northern Mexico

By **Zoe Wakefield**, Salamanca Group

Despite the significant domestic opposition to the prospect of foreign investment in Mexico's energy sector, President Enrique Peña Nieto's proposed constitutional reforms were approved by Congress and a majority of Mexican states in late 2013. As the legislation is drafted, foreign oil and gas companies will be lining up to gain access to the country's vast proven reserves and promising unexplored territories. However, despite the potentially attractive investment environment, the security situation in northern Mexico is likely to prove a significant concern for future investors. In the short to medium term, Peña Nieto's proposed holistic approach to security issues is unlikely to reduce the levels of risk in the region.

Due to the location of key drug cultivation and trafficking routes, the northern states of Sinaloa, Durango, and Chihuahua – the "Golden Triangle" – along with Sonora, Coahuila, Nuevo León, and Tamaulipas continue to see high levels of drug-related violence and cartel presence. Even though the operations, assets, and personnel of large corporations have thus far not become a deliberate target for the cartels, companies that are considering operating in the area should be aware of the significant security risks caused by high levels of crime. Criminal activity in the region involves gun violence, bombings, kidnapping, human trafficking, extortion, vehicle and cargo hijacking, and money laundering in a climate made more hazardous by entrenched police corruption and the emergence of armed self-defense groups. As the drug cartels have been forced to broaden their range of enterprise due to former president Felipe Calderón's "War on Drugs" strategy, energy infrastructure and related businesses have been exposed as vulnerable to theft, extortion, and the kidnapping of Mexican employees (foreign nationals tend to not be targets of kidnappers).

For example, if the hydraulic fracturing boom is going to be extended to Mexico from Texas to exploit the half of the Eagle Ford shale field that lies in the Burgos basin in the states of Tamaulipas, Nuevo León, and Coahuila, operators will be pitching themselves into the middle of inter-cartel conflict between Los Zetas and factions of the Gulf Cartel. Pemex has been historically handicapped in the Burgos basin as a result of drug-related violence.

It also is important to note the moderate risk of civil unrest in the northern regions of Mexico. The reforms to the energy sector itself are a key subject of passionate national protest along with other structural reforms. Industrial action over wages is also a common occurrence, and Mexican unions tend to be very militant. Protestors regularly block transport access to major highways, regional cities, and border crossings.

As such, it is crucial that while some of the regulatory barriers may be lowered in the short term to operating in northern Mexico, companies should recognize that significant security challenges remain. Early recognition and appreciation of the security environment should be built into any new Mexico engagement strategy alongside the broader commercial and legal considerations highlighted by the energy reforms. In this regard, intelligence-driven security solutions involving ongoing monitoring of local political, security, and transnational dynamics and sophisticated community relations building will continue to be an invaluable consideration for future investors as they seek to become part of Peña Nieto's energy revolution. ■

A shale boom in northern Mexico could revolutionize the area's economy.

Perdido basin, and it announced its fifth deepwater success in late January 2014. According to BBVA Research, companies with established operations in the deepwater US GoM should be able to take advantage of the 1+n and later licensing rounds to gobble up deepwater acreage.

"Large US and foreign multinational companies with economies of scale and the technological expertise have the biggest competitive advantages in deep and ultra-deep drilling," a report from the research firm stated. "For example, Shell recently announced plans for a 9,500-ft [2,895-m] ultra-deep well in the Gulf. Exxon, BP, Chevron, Hess, and Anadarko are also going to be immediate contenders."

Added Gabino Castillo, region manager, Americas, with CGG, "Deep offshore should be the priority for opening as we understand that the government is looking for technology and finances from private companies to explore and develop these resources."

Geophysical contractors stand to benefit from these reforms. Atlantic Council noted that the lack of development in deep water provides opportunity for seismic surveys to help assess the resource potential. "A second near-term opening for international companies in Mexican oil and natural gas will be producing seismic studies for the government," the report noted. "The government will require a high quality and massive amount of survey material in addition to Pemex's largely two-dimensional inventory to market new acreage effectively."

Companies like CGG are already in Mexico. CGG has primarily been offering marine services since 2005, including seismic processing and reservoir characterization. Castillo said that Pemex scientists recognize the value of the information provided by seismic data and well data. More studies will be needed to have a deeper understanding of the deepwater potential.

"CGG has developed a leading multiclient library on the US side of the GoM," said Luc Schlumberger, executive vice president of multiclient and new ventures for CGG. "We have designed our projects to meet the geological, technical, and operational challenges of this basin, which naturally extends into Mexico. As an example, we are currently engaged in the acquisition of a new generation of wide-azimuth surveys tailored to provide our customers with the best seismic images under the complex salt structures. We would be delighted to bring this experience into Mexico and develop a multiclient library there as soon as the regulatory framework is in place."

And then there's shale. Geology has a funny way of not respecting international boundaries, and the Eagle Ford shale is no exception. The play extends south of the Rio Grande, offering mouth-watering opportunities to shale players active north of the border.

"Underexplored" doesn't begin to describe Mexico's shale assets. Ranked sixth in the world for shale gas and eighth for shale oil, the country authorized the drilling of three shale wells in 2012. That same year, 9,100 wells were authorized in the US, according to BBVA.

BBVA reported that the Burgos basin, which houses Mexico's side of the Eagle Ford, is estimated to hold 9.7 Tcm (343 Tcf) of technically recoverable reserves. However, it noted that geologic complexities might make the play more challenging to the south.

Opening the Mexican border to oil and gas commerce has interesting ramifications. Simply replicating some of South Texas's success in Mexico could have an enormous impact on that country. Texas Railroad Commissioner David Porter told the *Pleasanton Express* that while Mexico's production had declined by about 1 MMb/d, Texas's production has almost doubled.

"I think it will be very beneficial for Mexico to start producing some of the shales and getting a lot more companies active and involved with our horizontal drilling technology," he said.

Added David B. Leaverton, public affairs supervisor for Pioneer Natural Resources, "We believe these reforms will bring great economic benefits to the people of Mexico as well as lead to greater energy security for North America as a whole. While full implementation of these reforms will take time, Pioneer will continue to assess any future opportunities in Mexico that might arise as a result of this significant development."

Opening up Mexico's Eagle Ford shale to development could have a significant impact on the economic situation in the region, one of the poorest in North America. "Faster economic growth in the border will narrow the socioeconomic disparities between Texas border cities and big metro areas like Houston, Dallas, or Austin," reported BBVA. "If these border towns effectively seize the opportunity, the US-Mexican border could see one of the most dramatic transformations in history. The upside for Mexican border towns could be even greater if economic prosperity allows them to eradicate the bad reputation created by drug trafficking and other illegal activities."

Remaining challenges

With all of the hype surrounding the new energy reforms, it's important to note that there is plenty of opportunity for things to go wrong. Atlantic Council lists seven challenges that could impede or even derail progress:

- Managing expectations;
- Delivering competitive exploration terms;
- Building effective regulators;
- Clarifying the value proposition for the power sector;
- Cutting the cord with Pemex;
- Trusting the market; and
- Managing local content requirements.

"Change of this scale is courageous, but implementation will be hard," the report noted. "Although Mexico has a long history of energy development, it will be creating entirely new regulatory regimes for oil, gas, power, and energy transportation. Attracting private investment will require Mexico to execute on these reform plans with a speed and efficacy that would challenge any nation." E&P

What will reform mean for Pemex?

The number of Mexican monopolies is set to decline with the country's passage of energy reform.

Jennifer Presley, Senior Editor, Offshore

If one were to look at major oil and gas players as one big happy family, then Petróleos Mexicanos (Pemex) would be the cousin with the sweet pad on the beach in Mexico that everybody wanted to live with but nobody could because his house rules prohibited it. But now – with the passage of energy reforms in December 2013 – the old rules are no more, leaving Pemex and the rest of the family to wait while the new house rules are hammered out by the Mexican Congress. But what will the new – and long-waited for – changes mean for Pemex now that it will no longer be the only player in Mexico's hydrocarbon-rich fields?

No easy road to change

"Mexico is probably – until the reforms are implemented – one of the most closed countries for the oil and gas industry," Jose Valera told attendees during a recent Mayer Brown conference. "Every single barrel of oil produced in Mexico is under a state monopoly. The private sector participates only as a vendor of goods and services or as a contractor."

Valera – a partner in Mayer Brown's Houston office and co-director of the firm's oil and gas law practice – added that for Mexico, the significance of the reform being enacted into law is hard to overstate and that the "political consensus we see in Mexico today behind these reforms bodes well. Time will tell in practice how this is going to work, but all indicators are good."

For former Pemex CEO Jesus Reyes Heroles, the reform is "great, great news." Speaking at the Mayer Brown event, Heroles said that the "energy reform for those of us not only waiting but working for a reform like this to happen – in my case for the past 20 years – is great news because the government and political parties – the main political actors – did not go the easy road of a false reform. They went to the real issue, which was the constitutional reform. It is a game changer."

Changed game, more money

The Mexican government needs to quickly grow the economy, and this created the need for higher investment, according to Heroles.

"You need to open the energy sector to attract more investment to the sector itself and to make the economy more productive, more efficient to attract more national and foreign investment into other sectors also," he said.

The new laws end Pemex's monopoly and encourage the state-owned company to enter into partnerships with companies to facilitate the development of the state's resources.

"The elimination of exclusivity is really the major thing," he said. "It will open up additional resources to come into the energy sector of Mexico. The second major change – in my view – allows Pemex to partner with anybody it considers adequate to pursue its strategic plans.

"And this was critical because it is an oddity in the world context that you have a national oil company that is not allowed to partner with other companies to pursue resources in the best way possible," he said.

These new partnerships could, according to one Pemex executive, pump an additional US $35 billion in outside investment into the country's oil and gas plays. As reported in the *Houston Chronicle*, Froylan Gracia Galicia, executive chief of staff for Pemex, told attendees at a conference on Mexican energy reform held in Houston recently that the company has estimated that it expects its capital budget to expand from $25 billion to $60 billion as a result of the joint ventures it anticipates forming with international partners in the coming years.

Pemex's first exploration agreements with international companies are expected as early as year-end, as reported in *Bloomberg*. In the interview with Pemex CEO Emilio Lozoya, it is noted that the company will initially focus on mature and deepwater fields to establish these new ventures. Russia's Lukoil was one of the first to ink a deal when it signed a cooperation

agreement with Pemex for exploration and production in Mexico in January.

Meeting needs, new contract schemes

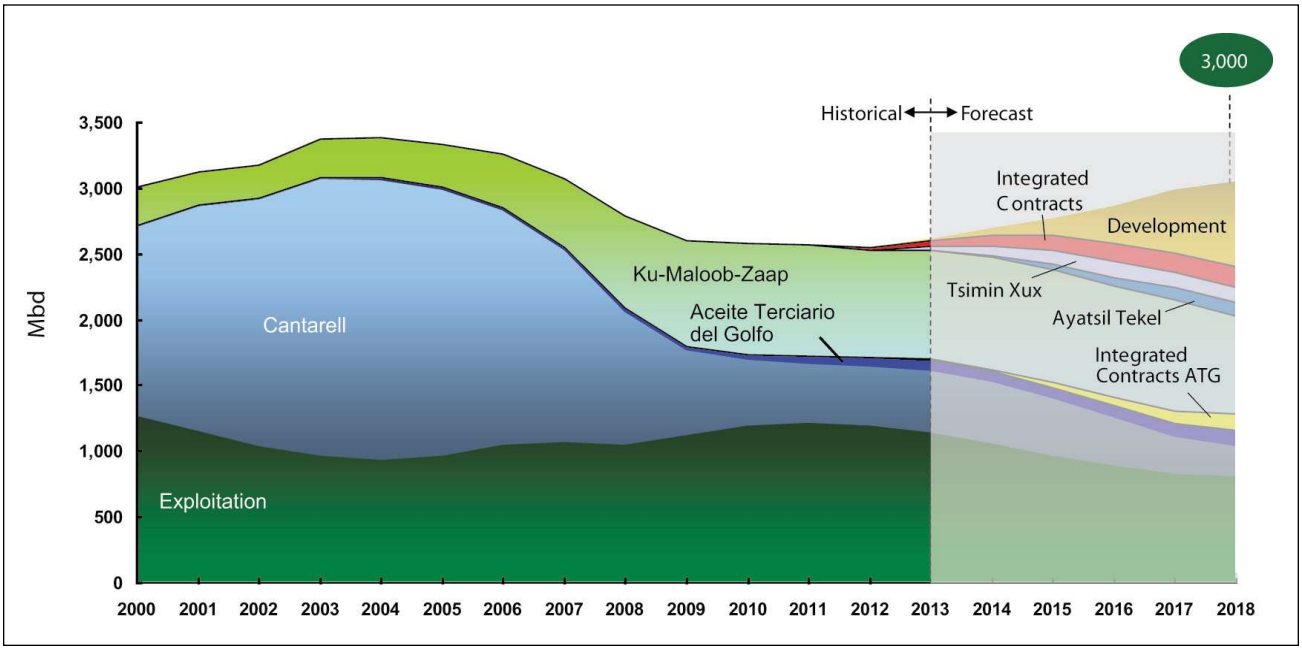
For current Pemex CFO Mario Beauregard, the new laws will help the company meet its needs through the significantly expanded budgets while also bringing many other positives to the country.

"Pemex is not exempt to current global industry challenges like rising financial and technological resources that are required to carry out exploration, exploitation, transportation, processing, and distribution activities," Beauregard said in the company's recent year-end results call.

ties in the national oil and gas industry along the entire value chain," he said. "These opportunities will be shared between the Mexican state and the operators in industry – including Pemex – through different types of contracts, which will be designed based on international best practices followed by countries with developed oil and gas industries."

Gone are the days where the only contract option was for the supply of services and goods. In addition to the familiar service contracts, investors also will have four new types of contract schemes available, including profit sharing, production sharing, licenses, or a combination of the four.

"We would like to highlight that Pemex will be



After a severe production decline, Pemex managed to stabilize production through EOR techniques and is anticipating future growth. (Image courtesy of Pemex)

"In spite of the vast resources that Mexico still counts on, the complexity of these resources has changed. Moreover, growing domestic demand for energy and fuels and the economic activity that cheaper energy has fostered in the United States increased the need to modernize the Mexican energy sector."

In addition to the increase in private investment, he noted that the reform will "foster job creation, increase production of hydrocarbons, and boost Pemex's transformation into a more efficient, profitable, and competitive company on par with the major oil and gas companies in the world.

"The energy reform offers new investment opportunities in the national oil and gas industry along the entire value chain," he said. "These opportunities will be shared between the Mexican state and the operators in industry – including Pemex – through different types of contracts, which will be designed based on international best practices followed by countries with developed oil and gas industries."

Gone are the days where the only contract option was for the supply of services and goods. In addition to the familiar service contracts, investors also will have four new types of contract schemes available, including profit sharing, production sharing, licenses, or a combination of the four.

"We would like to highlight that Pemex will be required to participate on each and every one of these contracts," Beauregard said. "Additionally, all of the operators – including Pemex – will be able to release their annual reports on their financial reports with the expected benefits from these contracts in line with international best practices, thereby complying with the most advanced registry and audit standards broadly implemented worldwide."

Many challenges lie ahead for the company and for the development of the country's natural resources. Overcoming challenges is a standard part of building not just comfy beach houses but new modern-era economies. E&P

Mexico's post-reform business opportunity

Oil services to see opportunities in the second half of 2015 while opportunities for operators follow later this decade.

Richard Mason, Chief Technical Director

US oil and gas companies are whistling a little James Taylor following Mexico's historic energy reform legislation in December 2013, particularly that line about "It sounds so simple, I just got to go."

No doubt opportunity abounds in a market that could witness a quadrupling of oil and gas investment to US $80 billion annually by 2020 – with roughly half of that originating from foreign investment – according to oil services analysts at Barclay's Capital.

North of Mexico's border the main question centers on how fast that opportunity unfolds for US-based energy companies. It may be a case of properly managing expectations.

"We estimate it could easily take two or three years to really see the first business opportunity materialize under this new framework," said Alexandra Leon, Mexico City-based associate director for IHS's Latin America-Downstream Oil. Leon does not expect any rise in Mexican oil production from the reform package before 2018.

"It is not just a matter of the opening and allowing for private investment," Leon said. "It is how and under which conditions."

Certainly when new production comes, it will entail international implications.

"The reform is really quite breathtaking in its scope and its ambition," said David Goldwyn, president for Goldwyn Global Strategies LLC, at a February 2014 Houston conference on Mexico's energy reform. "If it succeeds it will move Mexico to be a strategic supplier of oil by 2022. If you look at [International Energy Agency] projections, they expect non-Opec will peak by about 2022 – and they are not counting increased production from Mexico's reform – so really good timing for the rest of the world."

Like university students facing last-minute spring break choices, the issue for the oil and gas industry will be getting there.

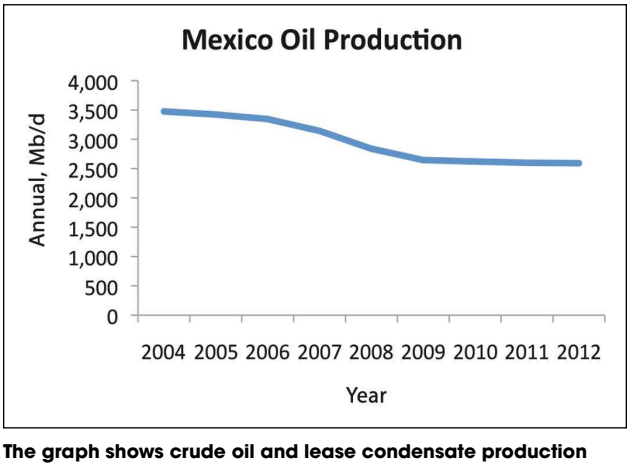
If all goes well, oil services firms could see movement toward increased Mexican business volumes in the latter half of 2015, though the timeframe is likely the latter part of the decade for US-based oil and gas operators. In the meantime, US producers may find an indirect economic opportunity in exporting excess domestic gas into the Mexican market for power generation or industrial use under the new and independent pipeline system operator that reform creates.

Reform impacts

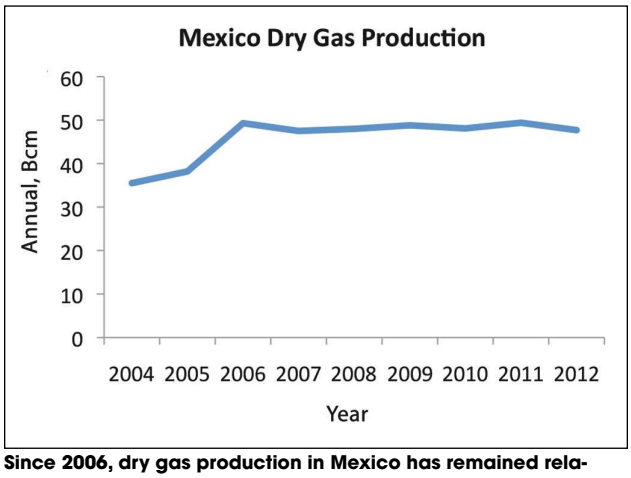
There has been a flood of seminars, white papers, and analyses on Mexico's energy reform in early 2014. At least two have included discussions that energy reform would provide a $1 trillion boost to the Mexican economy over a 10-year period.

The Mexican government is downplaying estimates of that magnitude since they often apply US-centric metrics and fail to account for differences in exchange rates, labor rates, and other cross-border tangible and intangible factors.

"It is not the type of numbers we are discussing in Mexico," said Dr. Maria de Lourdes Melgar Palacios, Mexico's undersecretary of hydrocarbons, during a press conference following a Houston presentation on Mexico's energy reforms in February 2014. "We do see significant potential for the entire reform. We are talking about



The graph shows crude oil and lease condensate production from 2004 to 2012. (Data courtesy of EIA)



Since 2006, dry gas production in Mexico has remained relatively flat.

$10 billion per year, in round numbers, but we are talking for the entire country and not for a specific area."

Lourdes Melgar said energy reform will provide an increase of 1% to Mexico's $1.17 trillion GDP by 2015, or about $11.7 billion, and 2.5% of GDP by 2025.

Still, by any metrics, energy reform in Mexico is massive in scope and patterned in many ways on energy reform in Norway that created both a national stabilization fund and spun off the state-owned oil and gas firm into an independently operated Statoil. Furthermore, momentum south of the border is real. Energy reform, though not without controversy, follows federal reformation and liberalization in education, fiscal matters, and telecommunications. Adding energy to other sector reforms will place Mexico among the more significant geopolitical and economic players in Latin America this decade.

"In the hemisphere, if this works, Mexico is in the pole position," Goldwyn said. "Only Colombia has a more competitive framework. Colombia is working; Mexico is on paper. Brazil, Venezuela, Bolivia – and everybody else – had better watch out because this is a huge opportunity close to market, close to infrastructure, close to export capacity. It is huge."

Why do it?

Mexican oil production has been on a steady downward trend for a decade, dropping from 3.4 MMb/d of oil in 2004 to 2.5 MMb/d of oil currently despite significant investment. At the same time, natural gas imports are rising after natural gas production peaked in 2009 and rolled over. Lourdes Melgar noted that almost half of Mexico's electrical generation is tied to natural gas, which is also in high demand for the nation's manufacturing sector. Finally, Mexico imports and subsidizes 49% of its gasoline, while petrochemical imports have grown from 41% of chemicals in 1997 to 66% currently.

But while the focus in the US has been on upstream oil and gas, the main focus in Mexico is electrical generation.

"Our electricity rates are noncompetitive," Lourdes Melgar said. "It creates difficulties not just for the domestic population but hampers Mexico's economic competitiveness. Residential and agricultural rates are 25% higher than comparable rates in the United States," despite subsidies that keep rates 73% lower than nonsubsidized market rates. Mexico's industrial users are paying electrical rates 84% higher than in the US.

Lourdes Melgar said electrical rate subsidies for residential customers and agriculture consume 0.75% of GDP, while as much as 20% of electricity is not paid for.

"What is happening is companies are beginning to wonder whether to come to the United States or go to Mexico, and of course with the abundance of cheap energy, some are making the decision to come to this side of the border [Houston]," Lourdes Melgar said.

What will it mean in practice?

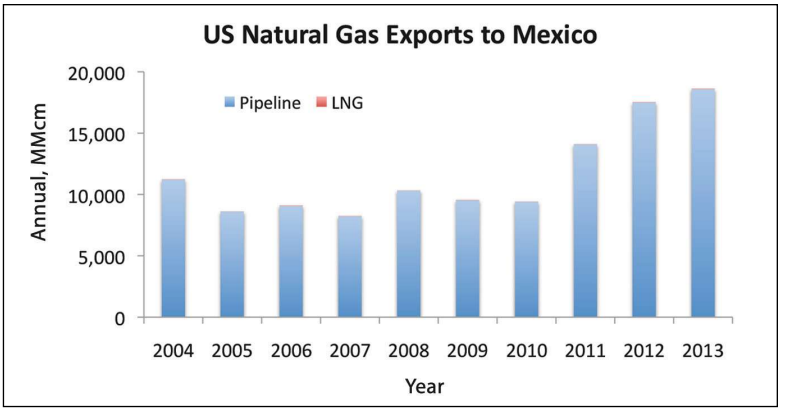
That's the background. The transition still faces significant challenges. First up are the secondary laws, which should be finalized in April 2014. These will govern the types of contracts such as profit and production sharing, service contracts and licenses, and the technical aspects of how each contract operates. Each must be tailored to encompass specific types of fields, whether deepwater, tight formation, or mature conventional fields, and be broad enough to encourage development in a market where commodity prices can vary widely.

What's next?

Next up is what Pemex will retain during Round Zero as it moves to become an independent state-productive enterprise. Those nominations will be known at the end of March 2014. Early indications are that Pemex will retain deepwater assets, where it can partner with international oil companies and access technical and operational expertise, and Mexico's conventional mature basins, where an influx of capital can reverse production declines and generate quick cash. Whether Pemex wants to retain access to tight formation gas in the northern part of Mexico is debated both ways by observers. Additionally, Pemex will retain exploration entitlements for three to five years in areas where it has made commercial discoveries or exploration investments.

The Comisión Nacional de Hidrocarburos will make the determination by Sept. 17, 2014, on which entitlements Pemex will retain based in part on what Pemex can develop technically before opening the process to external bidding in the second half of 2015.

Second, and perhaps more challenging, is creation of the regulatory framework to guarantee transparency in



Natural gas exports from the US to Mexico almost doubled between 2010 and 2013.

contract awards and a level playing field in energy. The regulatory agency will be independent and budgeted separately from the energy sector, but it must first hire and train technical staff within a tight timeframe.

Third, security goes without saying, particularly in northern Mexico within the arc of Eagle Ford shale geology. But, according to Peter Schecther, director of the Adrienne Arsht Latin America Center for the Atlantic Council, the perception of challenging security issues should be tempered by the fact that US financial rating agencies raised Mexico's credit rating to the coveted A3 grade from Baa1 in February 2014.

"Mexico is going to strengthen a North American energy market that is going to reduce long-term dependence on the Middle East," Schechter said during a February 2014 conference on Mexico energy reform in Houston. "That, in Washington, is a political statement that really garners a lot of interest, not to mention the fact it is going to reduce a lot of pressure areas such as immigration because, as Mexico's economy improves, there is going to be a lot less migration to the United States. Mexicans are going to want to stay in Mexico."

The advice for oil and gas companies who want access to oil and gas development in Mexico is to take time now to understand the massive arc of change in Mexico's legal oil and gas framework and work to establish cross-border relationships in preparation for opening the energy sector in the second half of the decade. E&P

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HARTENERGY E&P

Great expectations prevail in Mexico

While productivity is expected to remain flat in 2014, the future looks bright for the big four service companies.

Amy Logan, Senior Editor, Production

When Mexico announced the passage of its energy reform legislation, the international E&P community rejoiced at the possibilities. International oil companies (IOCs), in particular, would soon have access to Mexico's abundant and recoverable oil and gas reserves. For the four large-cap oilfield services companies – Schlumberger, Halliburton, Baker Hughes, and Weatherford – the news meant two things: a slow 2014 in Mexico, and a potential spike in investors who have great expectations for 2015.

Short-term slowdown

According to the companies' 4Q 2013 earnings reports, production in Mexico is expected to remain flat in 2014 as the country's congress spends the majority of the year working out the legislation details and Petróleos Mexicanos (Pemex) determines which E&P assets to retain and which to share in joint ventures.

However, Halliburton and Schlumberger both stated in their 4Q earnings calls that they had significant work already planned for Mexico and would be able to report gains to that end by 2015. Schlumberger's Chairman, President, and CEO Paal Kibsgaard said his company had already seen strong activity on land in Mexico, and he expected the country's reform to turn out "very positive for us, suggesting a solid gain in market share."

David Lesar, chairman, president, and CEO of Halliburton, said the company expected 2014 "to be a challenging year" in Latin America, with slower activity expected in Mexico due to its transition.

"In Mexico, reduced activity levels on land are expected to continue through the first half of 2014 as we transition from our prior South Alliance 2 projects to already-identified new opportunities in the country," Lesar said.

Like Halliburton and Schlumberger, Baker Hughes has projects in Mexico that will keep it well positioned for future business in the country, according to Martin Craighead, chairman, president, and CEO. However, he said in 2014 the company plans to "reduce [its] exposure to markets [in Latin America] where activity is uncertain and collections are doubtful. "We will replace those reductions with other opportunities in the region that provide lower risk and higher margins," he said during the company's 4Q earnings call. "The result will be less working capital and a more stable mix of business going forward."

For Weatherford, which has a lot of other changes planned for 2014, Mexico appears to be the least of its worries. In the 4Q earnings call, Bernard Duroc-Danner, the company's chairman, president, and CEO, said that while the company's North American activity was expected to be stronger than anticipated, particularly in 2Q 2014, its Latin American business was not, especially in markets such as Mexico, Colombia, and Brazil. "Although the prognosis in Latin America is excellent long-term – Mexico in particular – 2014 is expected to be a down year," he said.

Each of the four CEOs expressed some uncertainty where Mexico's future was concerned, but they remained optimistic about what it could mean for their service companies going forward. After all, each had worked with Pemex in the past and present and had knowledge of the country's geologies and proclivities.

Windfalls expected in the long term

According to multiple investor sites such as Seeking Alpha and Barron's, the stock in these four service companies is prime for the picking. Investors anticipate the companies' shares will pay off starting in late 2014 into 2015. It is a widespread belief that it will be these four service companies that are called upon initially by the IOCs that win bids for work in Mexico – onshore and off.

"The integration of technologies and services, the ability to buy in scale, and the ability to discount bundled services gives the large-cap stocks a significant advantage in a more cautious growth environment," said Credit Suisse investors in an "Investors' Soapbox" column titled "Big oilfield-service names sitting pretty," published Feb. 20 on Barron's website.

Sarfaraz Khan, a research analyst whose article, "Mexican reforms: Time to buy these oilfield services titans," was published on Seeking Alpha's website, was especially keen on the potential for future success at Schlumberger and Halliburton. "The two were already eyeing more than [US] $8 billion worth of large integrated projects in Mexico," he wrote. "The new price targets on these firms represent a 30% upside."

Khan's article, published Aug. 29, 2013, foreshadowed the events in Mexico that would result in the govern-

ment's decision to move forward with reform and events that would be announced in Halliburton's 3Q 2013 and 4Q 2013 earnings reports.

"[In 3Q 2013] we announced the win of the largest incentivized project contract [in Mexico], called Humapa," Lesar said in the 4Q earnings call, referring to the fee-for-barrel contract in Mexico's Chicontepec basin. The Humapa block contains 341 MMboe in proven and potential reserves spread across 128 sq km (49 sq miles) of land.

"I am pleased to say that based on the preliminary tender results, we are also positioned to win Mesozoic 1 – the largest of the integrated megatender projects," he added. "These large contract wins will result in higher revenues in Mexico, but the mobilization for them will take some time. We are strongly committed to Mexico through this transition period." Khan didn't mention Baker Hughes in his article – he couldn't have yet known about the company's exploration and development contract in the Soledad field in Mexico, which was firmed up in 4Q 2013.

"This begins a 35-year production enhancement agreement, leveraging our success on the neighboring Coralillo field where we used new technologies and project management capabilities to triple production in less than four years," Craighead said in his earnings statement.

Pemex weighs in

Access to that new technology is critical for Pemex, according to CEO Emilio Lozoya, who spoke March 3 to a crowd attending a CERAWeek 2014 dinner. He said the cost to produce a well continues to climb, but Pemex's production has hit a plateau, causing the company to lose money on its investments.

Using the knowledge gleaned from its service company partners and now by joining forces with IOCs, Pemex has an opportunity to learn new production techniques and grow its resources, he said. A little healthy competition won't hurt Pemex. Instead, he said it will help provide employment in a country that desperately needs it, and it could potentially reduce the number of people attempting to leave the country for better opportunities across the border. "What people need in Mexico are jobs," he said. "That's what we want for our people."

Employment impact of Mexico's energy reforms remains a mystery

By **Bruce Peterson**, Korn Ferry

The major reforms regarding privatization of Mexico's oil and gas industry are exciting news to international companies looking to invest in this lucrative market. As one of the world's top producers of hydrocarbons, coupled with its central location in the Eagle Ford shale play, Mexico has tremendous onshore and offshore resources that have gone untapped for more than 75 years. This historic legislation is destined to benefit Mexico and the worldwide oil and gas industry in terms of employment opportunities. But these benefits will not surface as soon as one might think.

Currently, energy talent and employment in Mexico are focused on the upstream sector, primarily because Petróleos Mexicanos (Pemex) has been the country's sole employer for this market since 1927. Oilfield service companies such as Schlumberger, Halliburton, and Baker Hughes have been in Mexico for years, working with Pemex from the drilling and completion sides of the business. Since these companies already have infrastructure in place, it is natural to assume that once the reforms' details are made clear and approved by the Mexican Congress, upstream expansion via international investments (and ultimately jobs) will immediately follow.

In truth, the extent of international investments and job growth will be unknown for quite a while. A lot of technology and infrastructure pertaining to the E&P sector must be reviewed and processed. For example, Mexico has not built its deepwater infrastructure off the Shelf like the US has into the Gulf of Mexico. This must be examined before companies can be retained to construct new offshore wells. It may take several years to collect relevant seismic data and drill enough test wells before major production can begin.

Furthermore, the current reforms will require partial use of local content – goods and services within Mexico – to further develop the upstream sector. The legislation currently being negotiated will outline the required percentage split between local content and out-of-country resources. Once these details are known, it will take the global upstream market two to three years to fully understand the new regulatory environment and obtain legal opinions on whether or not investment makes sense.

As a result, it is difficult to predict the exact types of talent needs and number of job opportunities for the upstream market that will arise from these reforms. It is safe to predict that there will initially be a high premium on technical skills followed by an emphasis on engineering and construction skills and ultimately on operational skills. Since the US talent pool is currently at capacity within the upstream sector, it also is safe to assume that the resulting talent requirements to service the expansion in Mexico will come from an international pool that includes enticing candidates from the US as well as countries such as Australia, Canada, the UK, and others.

Employment impact is a bit more optimistic, though, for the midstream and power generation sectors. The reforms will enable Mexico to shift from coal to a gas-fired power generation strategy, thus requiring construction of many new, smaller-sized gas-powered natural gas plants. Comisión Federal de Electricidad (CFE), the government-owned electrical utility, lacks the pipeline infrastructure to support such a shift, so additional talent to build this infrastructure will be required.

Mexico already has a fairly solid regulatory environment in place for midstream power generation. This presents opportunities for pipe manufacturing and construction companies to immediately come into Mexico to support this build-out once the legislation passes. Expect to see a rise in talent needs in any area touched by complete build-outs of pipeline infrastructure and gas treating facilities.

In the end, the reforms will result in a talent market consisting of Mexican citizens and outside professionals – both from the upstream and midstream sectors. Extensive training and development will be essential for Mexican citizens to be successful in exploring for and producing oil and gas and operating the new infrastructure. It will require forming strategic partnerships with international companies to gain the knowledge and skillsets necessary for Mexico to realize its energy goals. ■

Conversely, Lozoya said there was a distinct lack of engineers in Mexico, a trend he hopes will change once the IOCs and service companies help increase production in the country. Right now, educated engineers are finding jobs with other companies that can pay higher salaries. It's just one more reason he is ready and willing to learn from the other companies interested in bidding for work in Mexico and turning things around for Pemex. "You can imagine, after 75 years, people are very excited – especially about the opportunity to earn more money in salary," Lozoya said. For the past 75 years Pemex has had a monopoly on oil and gas production in Mexico, a monopoly put in place in 1938 when Mexico legislators sought to reduce influence from the US.

Analysts seem to agree on one thing: There is a bright future ahead for those service companies that are already positioned as some of the most knowledgeable about Mexico's prospects. Both risks and rewards are there to share, and ultimately Lozoya says it will be Mexico and its people that win the day. E&P

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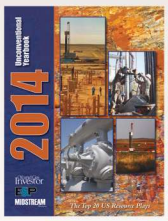

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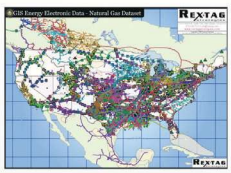

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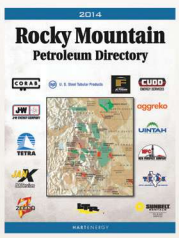

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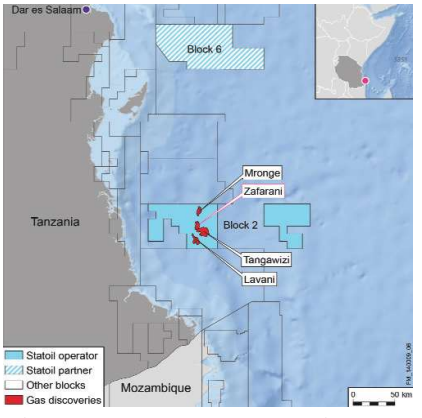
AFRICA

Statoil confirms major Tanzanian gas find

Partners ExxonMobil and Statoil have confirmed a big gas find after testing at the deepwater Zafarani discovery offshore Tanzania. Statoil declared that two intervals tested in the Zafarani 2 well have provided sufficient technical data to underpin a commercial LNG development for the region. Testing on two separate intervals in the Zafarani 2 well drilled in Block 2 offshore Tanzania yielded a maximum flow rate of 1.9 MMcm/d (66 MMcf/d) of gas, which was constrained by test equipment, and confirmed good reservoir quality and connectivity, Statoil said in a statement. Testing was carried out in a water depth of 2,400 m (7,872 ft) at a location 80 km (50 miles) from the Tanzanian mainland.



After testing at the deepwater Zafarani discovery offshore Tanzania, ExxonMobil and Statoil confirmed a big gas find. (Image courtesy of Statoil)

CGG completes Benin geomapping

CGG has completed an onshore countrywide airborne geophysical survey of the Republic of Benin, the company said in a press release. The survey program was commissioned by the government of Benin to enhance the development of the country's natural resource sector. The data were acquired from May 2013 to October 2013. They have been processed and are in the final stages of geological interpretation.

ASIA-PACIFIC

Bauer-12 well hits oil in Cooper basin

The Bauer oil field in PEL 91 has increased in size after the Bauer-12 appraisal well encountered oil, Beach Energy said in a news release. The well intersected the primary Namur Sandstone target 3 m (10 ft) high to prognosis with 5 m (16 ft) of net oil pay. An additional 4-m (13-ft) oil-bearing interval also was intersected in the overlying McKinlay Member. These results have extended the areal extent of the field, with preliminary mapping adding 2.5 MMbbl to the 2P reserves of Bauer, Beach said in the release. As a result, Bauer-12 will be cased and suspended as a future oil producer.

MIDDLE EAST

Jura discovers gas, condensate in Pakistan

Jura Energy Corp. has discovered gas and condensate at the Ayesha-1 exploration well in the Badin IV South block in Pakistan. The Ayesha-1 well was completed in the B sands of the Lower Goru formation of Cretaceous age. During a short test on a 33/64-in. choke, the well flowed gas at a rate of 321,000 cm/d (11.34 MMcf/d) with a wellhead flowing pressure of 1,998 psi, Jura said in a press release. The condensate-to-gas ratio was in the range of 10 bbl/28.3 Mcm to 12 bbl/28.3 Mcm (10 bbl/1 MMcf to 12 bbl/1 MMcf) with minimal water cut production.

Tethys hits oil onshore Oman

Tethys Oil has made an oil discovery onshore Oman at exploration well B4EW6. The exploration well was drilled on a previously undrilled structure onshore Oman and has tested flow rates in excess of 2,200 b/d on a 33/64-in. choke from the Lower Buah formation, the company said in a press release. B4EW6 was drilled approximately 13 km (8 miles) south of the B4EW4 discovery. The new B4EW6 well constitutes the best flows encountered from the Lower Buah outside the B4EW4 area so far, the company said. The well is hooked up to the production system to undergo a long-term production test.

EUROPE

Langlitinden well strikes oil

Partners in an exploration well in the Norwegian sector of the Barents Sea have made a new oil discovery on the Langlitinden prospect, but it looks unlikely to be commercial. Operator Det Norske declared that the 7222/11-2 Langlitinden well encountered oil after drilling in PL 659 in the Barents Sea. Based on preliminary analysis of well results, Det Norske said the volumes proven in this well were insufficient to justify a field development.

Total finds oil at Norwegian Trell prospect

Drilling at the Trell prospect offshore Norway has encountered an oil-bearing interval that is thought to

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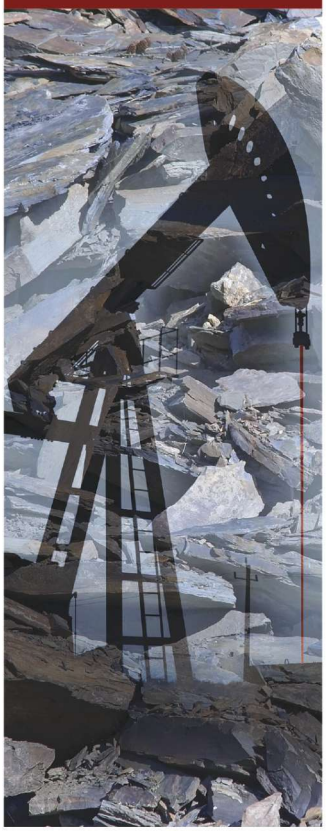			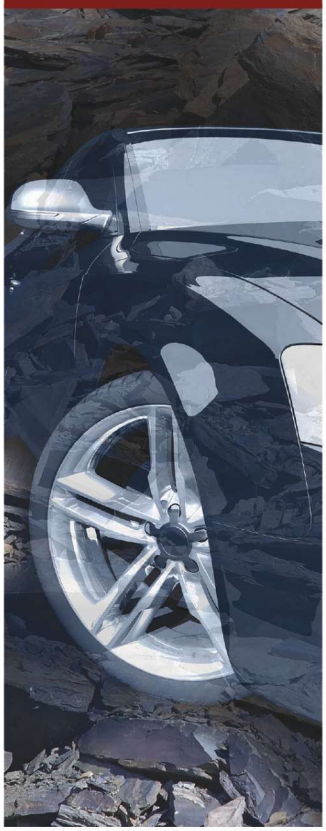
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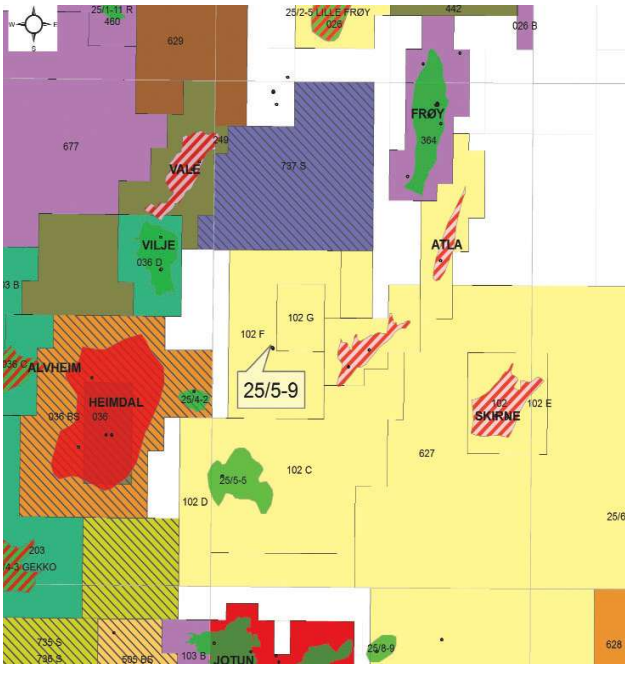

The 25/5-9 Trell prospect well, which was drilled close to Norway's Heimdal field, encountered a 21-m oil column. (Image courtesy of the Norwegian Petroleum Directorate)

contain up to 12.5 MMbbl. Operated by Total E&P Norge, the 25/5-9 Trell prospect well has been drilled close to Norway's Heimdal field. The well encountered a 21-m (72-ft) oil column, of which 19 m (62 ft) is of good reservoir quality in addition to an oil/water contact point. Preliminary estimates suggest that the find contains between 3.1 MMbbl and 12.5 MMbbl of recoverable oil. Drilling partners will assess the discovery along with other nearby prospects for further evaluation, according to the Norwegian Petroleum Directorate.

NORTH AMERICA

Devon sells Canadian conventional assets

Devon Energy Corp. has entered a definitive agreement to sell the majority of its Canadian conventional assets to Canadian Natural Resources Ltd. for US $2.8 billion. The sale excludes the company's Horn River, Lloydminster, and thermal heavy oil assets in Canada. Proved reserves associated with the divestiture totaled approximately 170 MMboe as of Dec. 31, 2013. The transaction is subject to customary terms and conditions and is expected to close early in 2Q 2014. Upon close of the transaction, the company plans to immediately repatriate the proceeds to the US for use in the repayment of debt incurred to finance its Eagle Ford acquisition.

GULF OF MEXICO

Stone Energy encounters oil with Cardona in GoM

Stone Energy Corp.'s deepwater Cardona well (MC 29 #4 well) encountered 26 m (84 ft) of net oil pay in the development section of the well at Mississippi Canyon 29 in the Gulf of Mexico, according to a company press release. The company is running casing to protect this zone while drilling the exploration section of the well. The Cardona success extends the productive zone of the Mississippi Canyon 29 TB-9 well to the adjacent fault block to the north.

SOUTH AMERICA

Americas Petrogas hits more oil in Vaca Muerta

Americas Petrogas has made another oil and gas discovery at its Agua de Afuera (ADA.x-1) Vaca Muerta formation unconventional vertical shale exploration well, which is located on the Los Toldos II block in Neuquén basin, Argentina, according to a news release. A five-stage hydraulic fracture stimulation in the Vaca Muerta shale formation was conducted on the vertical well. The ADA.x-1 well was drilled to a total depth of 3,448.5 m (11,311 ft) in late 2012 and drilled through 340 m (1,115 ft) of the primary target Vaca Muerta shale formation with oil and gas shows through most of this shale section. Hydrocarbon shows also were encountered in secondary targets such as the Agrio, Quintuco, and Tordillo formations.

Petrobras hits oil in Transfer of Rights area

Petrobras has confirmed it has established further reserves of good-quality oil on two of its largest presalt discoveries after drilling new wells. The state-owned operator said in a press release that it completed drilling the wells on the Florim and Entorno de Iara discoveries in the Transfer of Rights area in the Santos basin. Well 3-BRSA-1215-RJS (3-RJS-725), informally known as Florim-2, confirmed the discovery of good-quality oil (29°API) in carbonate reservoirs of excellent quality below the salt layer at a depth of 5,412 m (17,757 ft), having reached a total depth of 5,679 m (18,633 ft). The other well, 3-BRSA-1172-RJS (3-RJS-722), is informally known as Entorno de Iara 2 and also confirmed the discovery of good-quality oil (26° API) in carbonate reservoirs of excellent quality below the salt layer at a depth of 5,116 m (16,786 ft). The well confirmed a 526-m (1,726-ft) thick oil column, it said. The exploratory phase of these areas is expected to be complete by September 2014. According to the Transfer of Rights agreement, Petrobras could declare the area commercial by then. E&P

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PEOPLE

Dale Addessi has been appointed technical manager at Jaguar Exploration Inc.

John E. Bonn (left) was chosen as Southcross Energy Partners LP's president and COO.

Diamond Offshore Drilling selected **Marc Edwards** as president, CEO, and a member of its board of directors.

Judson F. Hoover has taken on the role of CFO for Breitling Energy Corp.

Apache Corp. named **Alfonso Leon** executive vice president and CFO and **Tom Chambers** senior vice president of finance.

David Robinson joined New Zealand Energy Corp.'s board of directors and became CEO for the company's New Zealand business.

William Jacob Management Inc. named **Ron Horton** vice president of operations, **Charles Lee** vice president of business development for production facilities, and **Michael Hutto** vice president of structural engineering and design.

Sudhendu Kashikar (left) joined MicroSeismic Inc. as vice president of completions evaluation services.

Valentin Zaccaria (left) became director of R&D for Drillmec Inc., and **Mark Galagaza** (right) became director of aftermarket services for Drillmec Inc. in the Americas.

Phil Conway joined Rose & Associates as vice president of client solutions.

CBM Asia Development Corp. selected **Keith Potter** to be vice president of operations.

Genesis RTS welcomed **Cesar Gongora** to its team as global director of real-time operations.

Warren Resources has made **Saema Somalya** senior vice president, general counsel, and corporate secretary.

Karim Amin (left) became the head of the Siemens Oil & Gas sales unit.

Liv Hovem took on the role of DNV GL's director for Europe and Southern Africa.

Nanne Hemstra has been appointed to head up dGB Earth Sciences' new Brazil office as executive vice president for Brazil.

Elisse B. Walter, former chairman of the US Securities and Exchange Commission, was elected to Occidental Petroleum's board of directors.

EnQuest PLC appointed **Neil McCulloch** (left) president of the company's North Sea business.

IHS Inc. named **Mark Settle** (right) senior vice president and chief information officer.

Seatronics Ltd., an Acteon company, promoted **Phil Middleton** (left) to deputy managing director.

Hoover Container Solutions made **Matt Matis** (right) director of sales for the Gulf of Mexico.

Murphy Oil Corp. promoted **Walter K. Compton** to executive vice president and general counsel, **Kelli M. Hammock** to senior vice president of administration, **John W. Dumas** to vice president of corporate insurance, and **Allan J. Misner** to vice president for internal audit. **K. Todd Montgomery** was elected vice president of corporate planning and services.

Sonardyne International Ltd. promoted **Anthony Gleeson** (left) to vice president for Asia.

Willard Painter joined Powell Valves as corporate director of quality.

Chesapeake Energy Corp. added **Miles Tolbert** to its team as associate general counsel for environment, health, and safety.

HB Rentals made **Kristian Magar** (right) director of HSE.

LDD, an Acteon company, appointed **James McGovan** vice president of sales and marketing.

Somesh Singh became the chief product officer for Paradigm.

The Intervention & Coiled Tubing Association European Chapter appointed **Kelly Murray** (left) chair of the organization and **Andrew Louden** (right) vice chair.

Peter Falconer (right) was appointed head of life-cycle management for Atkins' subsea integrity team.

Aggreko North American made **Bruce Pool** managing director.

Richard Hawes took on the role of exploration advisor and chief exploration geologist for Emperor Oil Ltd.

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COMPANIES

CoorsTek Inc. opened a new ceramic proppants manufacturing plant in the Coors Technology Center in Golden, Colo. It will produce lightweight ceramic proppants and has received all regulatory approvals, including air permits.

Aqualis Offshore established offices in Abu Dhabi, UAE, and Bahrain. The Abu Dhabi office's main fields of work will be project marine warranty, field installations, engineering design, engineering warranty, construction supervision, and rig moving for jackups. The Bahrain office will primarily provide support for the shipyards and vessel operators in the country.

Artificial Lift Co. has relocated its headquarters from Great Yarmouth, UK, to Houston. The company's offices and warehouse total 2,600 sq m (28,000 sq ft) for engineering, manufacturing, operations, and general support services.

Momentive Specialty Chemicals Oilfield Technology Group opened a transload facility to provide resin-coated proppants. The facility is located in Odessa, Texas, for service in the Permian basin.

DNV GL opened a new laboratory in Singapore for testing, qualification, and assessment for oil fields in harsher environments. The laboratory has service areas focused on microstructure, megastructure, laboratory testing, and field services. The facilities include a 2500KN Dynamic Testing Machine, a floor long enough to accommodate full-length 12-m (39-ft) line pipe testing, and a 1.3-m (4.3-ft) Gantry Cutting Machine.

ADVERTISER INDEX

Selecting the best EOR technique

Operators should consider EOR in the early stages of field-development planning to maximize asset returns.

Tomi Owodunni, Schlumberger

With operators investing increasingly in hard-to-reach hydrocarbons, a greater emphasis has been placed on recovery optimization. Technological advances have made economical the additional recovery of identified reserves, the planning for which should be considered as early as possible in the life of a reservoir.

Buoyant oil prices, the growing international demand for oil, and declining oilfield productivity all highlight the need for improved and accelerated recovery. The global average oilfield recovery factor is approximately 40%. This results in large volumes of unproduced yet identified hydrocarbons.

For decades the industry has been employing a number of different EOR techniques, but generally only in large land fields that can support a large infrastructure and justify a major investment. Although the fundamental physics of EOR – how to mobilize oil within the pore system – are well known, we are now seeing significant advances in other enablers such as reservoir characterization, reservoir-scale monitoring, well placement, smart completions, and new EOR agents. All of these developments provide the opportunity to make EOR more successful.

North America has the largest number of EOR projects today, but operators in the oil-rich Middle East are launching similar schemes. In addition, giant oil fields are now being considered for EOR earlier in their life cycles. This is an important point: Rather than considering EOR as part of a reactive, late-life field strategy, consideration is being given to the most suitable EOR methodology during the earliest stages of field development. This proactive approach will save money, boost ultimate recovery, and ensure maximum return on investment.

Making the right selection when it comes to EOR techniques is crucial. There are a number of different choices in this regard, including chemical methods, miscible and immiscible gas flooding, and thermal recovery methods. The correct choice of EOR strategy goes a long way toward optimizing eventual recovery.

Advanced reservoir simulation software is the most reliable approach in selecting the best EOR technique for a particular field. A predictive reservoir model is a must for understanding the dynamic behavior of reservoir fluids, including EOR agents, and for optimizing injection and production options. Three-phase 3-D simulations are used to model EOR techniques. The Petrel E&P software platform and ECLIPSE reservoir simulation software can be used to create multiscale reservoir models that deliver greater predictive and analytical power. This improved reservoir characterization is essential for optimal EOR technique planning.

Running through different EOR scenarios digitally is an ideal way to mitigate the risks associated with these decisions and will increase confidence in reservoir strategy and recovery planning. Major unknowns such as formation heterogeneity can be evaluated using multiple iterations with different parameters. It is possible to compare expected costs and project economics with the base case of continued production without EOR. If the simulation indicates that the project meets technical and financial requirements, then it can be used to design subsequent pilot projects.

Buoyant oil prices, the growing international demand for oil, and declining oilfield productivity all highlight the need for improved and accelerated recovery.

EOR projects are currently among the most complex and difficult undertakings in the upstream industry. Success lies in improving the efficiency in every step of the process by synchronizing diverse measurements, applying advanced technologies, and integrating knowledge across multiple domains. Comprehensive reservoir simulation supports efficient decision-making at every stage of the EOR workflow, from concept selection to full-field implementation. E&P

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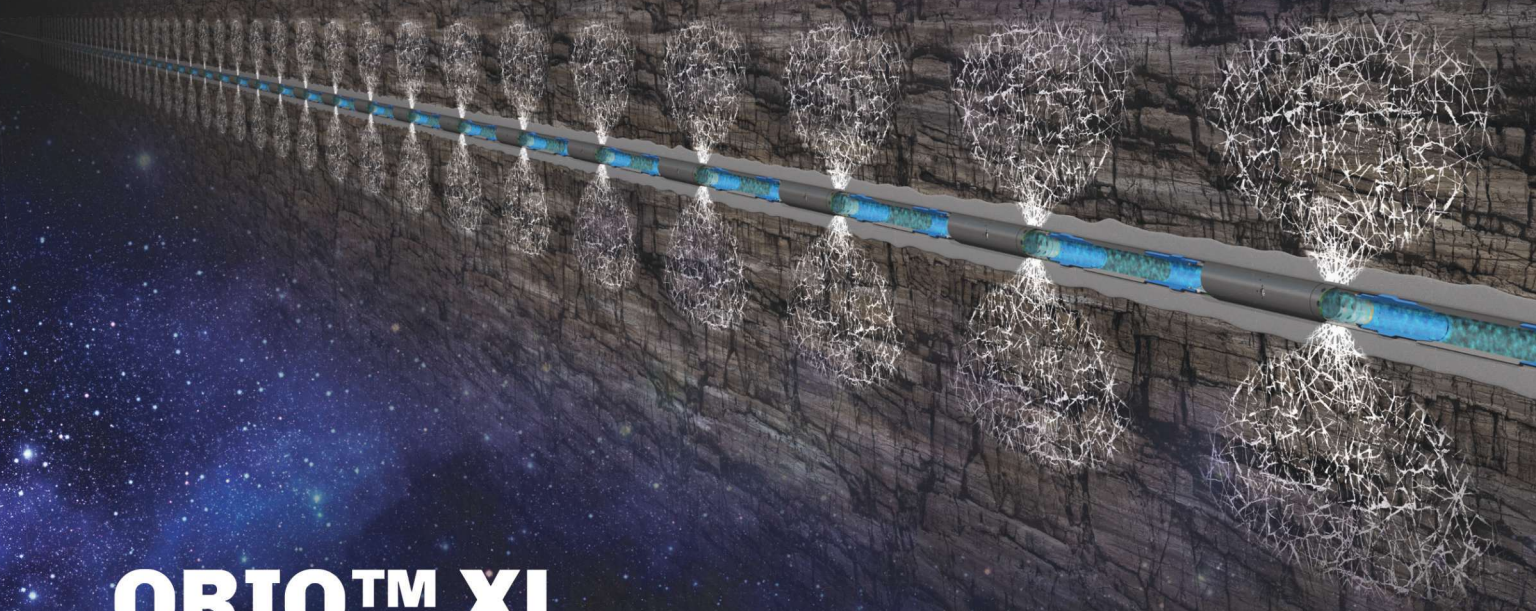

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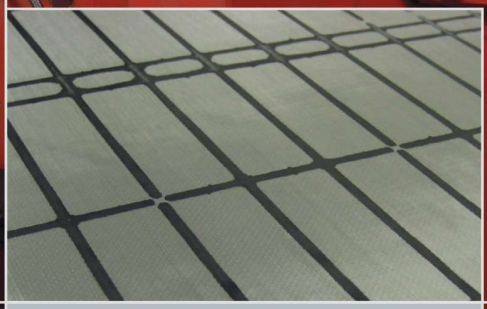

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