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Gulf of Mexico in Focus

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OE Exclusive

Global Deepwater Review 40

Offshore Engineer • May 2015


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ON THE COVER

Bright lights, big platform. This month's cover features Pemex's Ku-S Central Processing Installation and its bridge-linked satellites in the Ku-Maloob-Zaap oilfield in the Bay of Campeche, Gulf of Mexico. OE's Jerry Lee provides an overview of how the field was developed on page 78.

Photo courtesy of Return to Scene.

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Gulf of Mexico in Focus


UNCE

Volume 40, Number 05 May 2015

Departments & Columns

"What will be the next step change in deepwater Gulf of Mexico operations?"

Online Exclusive

Remembering Macondo

Five years after the blowout at the Macondo well and subsequent fire at the Deepwater Horizon drilling rig that cost 11 lives and countless barrels of oil spilled, what is the current state of safety in the offshore industry? OE reports.

People

George L. Kirkland, vice chairman and executive vice president, Upstream, will retire from Chevron, effective June 15. He will be succeeded by James W. Johnson, effective June 16. Kirkland joined the company in 1974 and was named to his current role in 2005, and elected vice chairman in 2010.

What's Trending

- New regulations for offshore operators
- Rigs scrapping continues
- Boskalis takes more Fugro stake

Voices

Deep thoughts. While the downturn is affecting every part of the upstream oil and gas industry, innovating for the future remains a priority. OE asked:

What will be the next step change in deepwater Gulf of Mexico operations?

We expect the progression of new technology to continue, particularly in the subsea realm with new deepwater frontiers. Proactive advances in technology have enabled ExxonMobil to produce offshore oil and gas deposits in water depths that were at one time technically impossible. ExxonMobil's Hadrian South and Julia projects are examples of how advanced technology is enabling the development of ever-challenging resource locations. From leading-edge subsea processing, pumping and compression technologies to long-distance power transmission and distribution, ExxonMobil is moving subsea technology into the next generation.

Tim Arthur, Gulf of Mexico projects manager, ExxonMobil

Deepwater operations in the Gulf of Mexico will continue a trend towards greater complexity. Higher pressure containing requirements (20ksi) will drive pipeline wall thickness upwards and leave vessels with lower tension capabilities unable to participate. A move towards subsea processing (pumping, compression, and separation) will mean components being installed on the seabed will become heavier and larger over time.

Offshore installation contractors operating vessels such as the *Ceona Amazon* with high capacity, deepwater (3000m water depth) installation capability combined with the ability to upend and handle larger, complex structures will be well positioned for the increasingly complex deepwater Gulf of Mexico marketplace.

Grant Dewbre, senior vice president, business development, Ceona

With oil production in the region set to increase to 1.52 MMb/d in 2015, pipeline depths will continue to increase and specifications tighten, so reducing project risk and maximizing process efficiency will become even more critical. The accurate inspection and fit-up of pipe ends is central to this and internal weld inspection will lead the way forward. Measurement over visual inspection will be vital, providing accurate data on areas such as the re-entrant angle, root penetration or concavity. With accurate and quantifiable results any necessary action can be taken and project specifications met.

Denise Smiles, CEO, Optical Metrology Services (OMS)

A step change is already underway – in the realm of well security for the life of a well. In the Gulf of Mexico, operators are increasing the standards of acceptance for well integrity through the reliability of cement placement in well construction, barrier requirements, and life of well issues such as annular pressure build-up. As the industry reaches out further to access reserves in more challenging conditions, such as deepwater and narrow margin drilling, it is also reaching out to new and improved technical solutions. Nothing exemplifies this more than the improvement in well security standards from traditional hydro testing to new gas-tight acceptance criteria. The industry in the Gulf of Mexico is already on its way through the step change to enhanced well security.

Jim McNicol, account manager, North America, Oiltools, Archer

The Gulf of Mexico deepwater drilling programs have undergone rapid re-evaluation regarding economic viability in 1Q 2015. The precipitous fall of crude prices have supplanted the drive for frontier drilling at high costs, with measured, calculated future projects that have cost controls as a key driver. Operators are looking to the drilling contractors and service companies to assist them in mitigating some of the historic costs associated with deepwater drilling. By utilizing advanced technological services, and incorporating these services into the drilling program, operators can realize significant savings by increasing drilling efficiency, reducing risk and ultimately, cutting the number of drilling days.

The implementation of specific techniques, such as managed pressure drilling, during various portions of the drilling plan, will provide operators with more options when it comes to reaching TD within the confines of the well AFE. As the market continues to react to a volatile oil price, the need for better drilling efficiencies will only become more prevalent.

Michael Harvey, offshore region business unit manager, Secure Drilling Services, Weatherford

The next step change – and considerable challenge – is the move to higher pressure in subsea systems. The next 'rig of choice' for deepwater operations will have to accommodate high-rated equipment. Although a well may be initially drilled over 15k, the goal is for subsea safety systems and associated equipment to be standardized at 20ksi. At present, there are significant challenges in handling 20k equipment on rigs in the area. Risers will have to employ a different approach to buoyancy to handle increased size and weight. However, the hurdle for subsea test trees (SSTT) is the inside diameter of the BOP – this would constrain the outer diameter of the SSTT from growing larger, whilst still having to maintain a bore large enough to drift the subsea tree and tubing hanger plugs.

Mark Enget, vice president – North America, Expro

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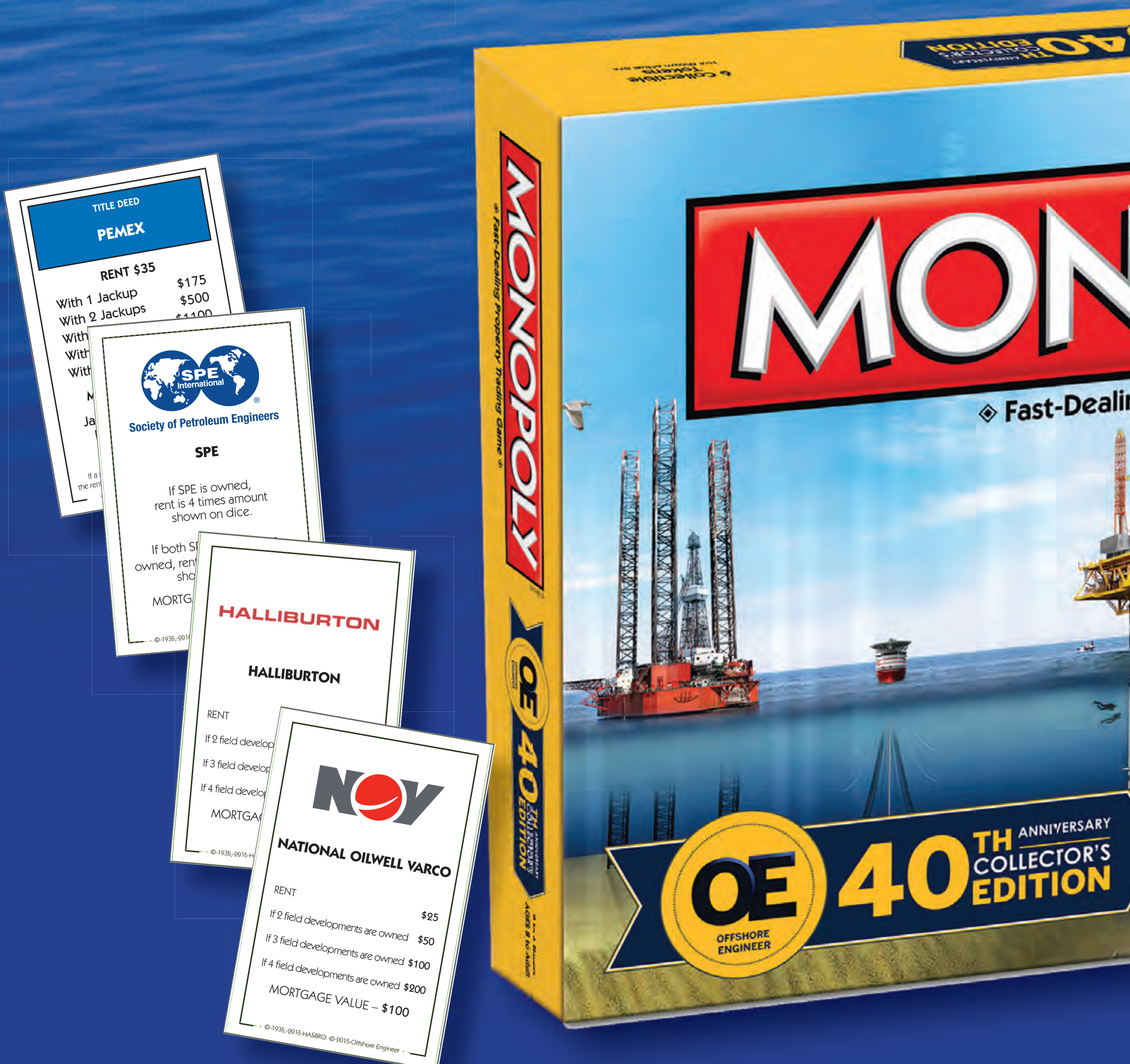

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Advance to GO

Brion Palmer

MONOPOLY is a beloved board game played by adults and children around the world. For many, it is was their initial introduction to the world of business – buying and selling assets, investing in assets, competing, and managing money. It is also a sneak peek into the harshness of the real world: taxes, jail, mortgages, and learning the value of FREE PARKING.

The OE 40th Anniversary Collector's Edition MONOPOLY game represents a celebration of the industry.

How about a bit of a different MONOPOLY experience? Hasbro and OE has teamed up to create a custom MONOPOLY game for the offshore industry: OE 40th Anniversary Collector's Edition MONOPOLY game.

The traditional MONOPOLY game with the exception of the four corners (trademark protected) and the houses and hotels (again, protected except color change) has been customized for the offshore industry.

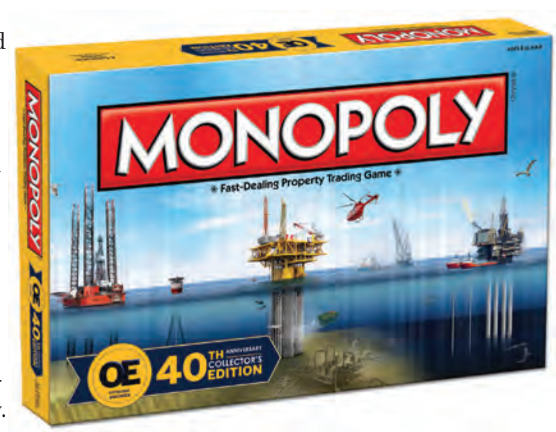
The properties have been renamed after industry companies based on their sponsorship of the project. Community Chest and Chance cards are now Exploration and Production cards and feature industry related text. Tokens include a scuba diver, drill bit, drillship, safety helmet, helicopter, and ROV. The currency has been changed from dollars to barrels of oil. All graphics (box, game board, etc.) have been dynamically designed to reflect the industry.

The OE 40th Anniversary Collector's Edition MONOPOLY game represents a celebration of the industry. The game promotes the industry. Perhaps, most importantly, the game can inspire and teach future generations about our great industry all in a fun, family-oriented manner.

The OE 40th Anniversary Collector's Edition MONOPOLY game can be purchased online at www.atcomedia.com/store/oe-monopoly.

A great gift idea for any oil and gas professional; for clients and prospects; friends, and family. Supplies are limited, order yours today.

We hope you have as much fun playing this game as we did making it. Now it is your turn. Advance to GO and collect 200 barrels of oil. OE



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BPA WORLDWIDE BUSINESS

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Undercurrents

Remembering the not-so distant past

Given that our issue's focus is the Gulf of Mexico, it is fitting that we remember the fifth anniversary of the *Deepwater Horizon* disaster. On 20 April 2010, 11 lives were lost when the Macondo well blew out, spilling millions of barrels of oil, igniting not just a fire, but change in the oil and gas industry.

Nothing would ever be truly the same. And while the moratorium in the US slowed operations for a time, it did not slow the desire to innovate, improve safety, and – most importantly – return to work.

Sure, there will be many who say, "Why even bring it up?" To quote Winston Churchill at the House of Commons, 2 May 1935:

"When the situation was manageable it was neglected, and now that it is thoroughly out of hand we apply too late the remedies which then might have effected a cure. There is nothing new in the story… It falls into that long, dismal catalog of the fruitlessness of experience and the confirmed unteachability of mankind. Want of foresight, unwillingness to act when action would be simple and effective, lack of clear thinking, confusion of counsel until the emergency comes, until self-preservation strikes its jarring gong– these are the features which constitute the endless repetition of history."

***Deepwater Horizon* response in 2010.**
Photo from US Coast Guard.

Granted, he was discussing the rising power of the Nazis leading up to World War II, but the quotation could be applied to pre-2010 era thinking in the industry. Because when the warning signs were there, they went unanswered until it was far, far too late.

And five years after the spill, BP is still paying for the error, quite literally. On 16 April, the company announced that its oil spill fund paid out more than US$5 billion to *Deepwater Horizon* claimants. That cost is part of the $28 billion BP has spent on response, cleanup, and early restoration. And, as the supermajor's court case continues in New Orleans, a federal judge ruled in January that the Macondo well discharged 3.19 MMbo into the Gulf. The ruling capped the maximum fine – $13.7 billion – BP can face for violations to the US Clean Water Act.

Last month (April), scientists at the Harte Research Institute (HRI) for Gulf of Mexico Studies at Texas A&M University-Corpus Christi reported that the Gulf, after the spill, remains resilient. "The true measure of the health of the Gulf of Mexico is how well it can bounce back," said Dr. Larry McKinney, HRI's Executive Director. "The spill was a tremendous test of that resiliency, and five years later it seems the Gulf has passed."

And, much like the Gulf is resilient, so is the oil and gas industry. While, currently, it faces a stark downturn, activity and investment remains strong in this region. To prove that, ***OE*** shines a spotlight on deepwater projects, and the development of ultra-high pressure, ultra-high temperature technology on page 104 of this issue. Additionally, ***OE*** profiles EMAS AMC's new marine base in the Gulf on page 116.

In January, the US Department of the Interior issued its proposed oil and gas leasing program for 2017-2022, with 10 sales in the Gulf of Mexico planned. At the time, director of the US Bureau of Ocean Energy Management (BOEM) Abigail Ross Hopper said: "This new approach will allow for BOEM to more effectively balance the sales while providing greater flexibility to industry to invest in the Gulf, particularly given the significant energy reforms recently adopted by the Mexican government."

And, to Hopper's point, Mexico's own energy reform has stirred interest in the opportunities that lay in its portion of the Gulf. Even in this downturn, plenty of healthy companies are likely to take a chance on new endeavors there. See page 108 for a roundup of the floating production units already in use offshore Mexico.

While many who do not remember the past are doomed to repeat it, let this fifth anniversary show how far we have come, and how much farther we have to go. And with newly proposed rules (30 CFR Part 250) from the Bureau of Safety and Environmental Enforcement heading our way, change is the only constant. OE

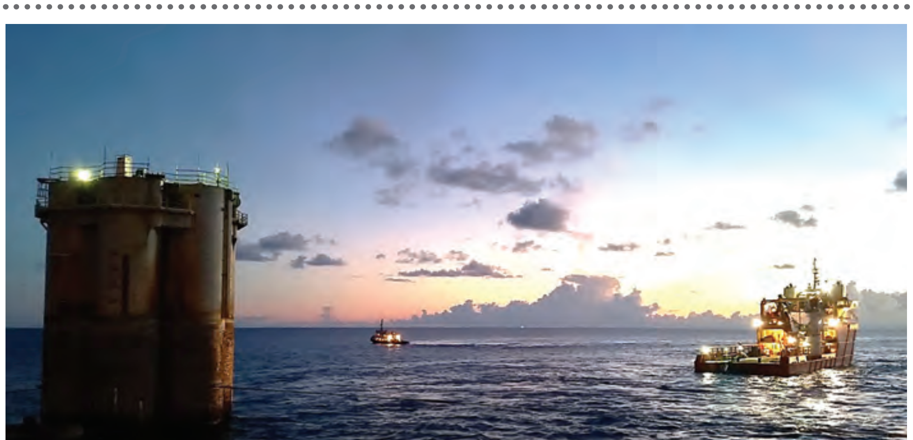

PHOTO OF THE MONTH

Hard at work — Anadarko's decommissioned Red Hawk spar in tow to its reefing site in the Gulf of Mexico. See the full story on page 112. Photo from InterMoor.

Have a photo? Submit yours at news@oedigital.com.


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Stan Bond, Hess

ThoughtStream

The need for lean

During the past decade, our industry has applied new technologies and adapted old ones that enabled us to meet the world's energy needs more efficiently, productively and safely.

As an engineer, I find these innovations thrilling, but I believe our industry has only begun to embrace the most significant innovation to transform our business. We are just now beginning to leverage lean methodologies that have benefitted other industries for decades.

Lean is about transforming leadership, planning, learning and thinking. Ultimately, it's about creating value and eliminating waste. That may not sound as exciting as a technological breakthrough, but it can result in faster development, reduced downtime, safer operations, lower costs and more profitable projects.

With a systematic approach to continuous improvement in place and, as we like to say at Hess, an *Army of Problem Solvers* who apply lean every day in their work, we have a much better chance as offshore operators to not just survive, but thrive during difficult market conditions.

It may seem that the unconventionals business — with its factory approach to drilling, completions and pad facilities — is the only obvious place to apply lean. But these same principles can be used offshore and in deepwater developments. We have seen those benefits firsthand at Hess and are actively applying them across our business. Not just onshore, but offshore in drilling, completions and developments, as well as supply chain, information technology and other functions.

People have argued that lean principles cannot be applied in larger, more complex, longer cycle-time deepwater developments due to the tailored field-development requirements. Yet, at our Tubular Bells development in deepwater Gulf of Mexico, we used lean principles to successfully fast-track the project from sanction to first oil in just three years. Extensive planning was critical to our success. In fact, we spent more time planning our wells than executing the work. We designed multiple scenarios for the field development before drilling a well. And when drilling began, we held regular meetings on lessons learned and applied them immediately to the next phase of the operation. Even in an under-appraised, challenging, high-pressure, high-temperature field, the drilling and well

We used lean principles to successfully fast-track the (Tubular Bells) project from sanction to first oil in just three years. Extensive planning was critical to our success.

placement was exceptional, resulting in higher well performance.

We are just beginning to understand and apply lean, but we believe we are formulating a deepwater execution model we will use as the basis for our other important assets and developments in the Gulf, Ghana, Australia and worldwide.

In our offshore operations we introduced the lean business planning process to focus on meeting annual safety, production and cost targets. That outlined the entire business plan on a sheet of paper, making it simple to see and understand.

As we trained our people in lean, we applied it across our business. In Equatorial Guinea, we reduced the duration of a planned turnaround by almost 50%, and applied the lessons learned in the Gulf to eliminate a high-impact turnaround. Across our offshore Americas and West Africa operations, we used lean thinking to avoid approximately 700 lifting and hoisting events, reducing operating costs and safety risks.

We have proven to ourselves and our partners that we can plan and execute a major project safely and efficiently by applying key lean principles being used onshore and in manufacturing.

Don't get me wrong. I understand the application is different offshore, especially in developments, but the rhetoric around "this won't work here" is being removed. We need to become more efficient. Lean thinking is a lot like the drive to improve safety — you never really get there, but you're always striving to be better, safer, more efficient every day.

Lean thinking has proven to be a value driver for Hess, and a lesson I believe will benefit our industry as it confronts the challenges of the global price of crude and world energy needs, now and in years to come. OE

***Stan Bond** is vice president of developments for offshore Americas and West Africa for Hess Corp., a global independent energy company engaged in the exploration and production of crude oil and natural gas. Prior to joining Hess, he held positions with BP, Vastar Resources, Arco Oil & Gas Co., and Gulf Oil. Bond has a bachelor's degree in petroleum engineering from Mississippi State University and is a registered professional engineer.*

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Opinion

James Watson, ABS

ThoughtStream

Securing intelligent systems offshore

Often I am asked – what is classification? We get this question a good bit in the offshore industry where the role of class might not be as pronounced as it is in the marine industry.

Class is one of the many stakeholders in the global safety regime. Our role is to act as the independent third-party certification and verification body, and in that trusted role, we work closely with government regulators and industry to develop and verify compliance with certain standards. We are a mission-driven organization which, simply put, is to protect life, property, and the natural environment.

In recent years, a significant focus of ABS offshore technology has been leveraging "big data" and software integrity. In our modern and interconnected world, software integrity is an increasingly important area for the safe operation of floating assets and mobile offshore drilling units.

The concept of overall software integrity is rooted in three core areas: software quality engineering, verification and cybersecurity.

The key to maintaining software integrity is to begin as early as possible in any given project. Software repair costs only increase as an asset ages. Estimates place the cost for each bug to be around $3000 in software support, which does not include potential downtime.

And in the offshore industry, where we see software integrity already becoming a major focus, an estimated 30% of errors in software are due to interface issues.

How complex are these systems? The integration of multiple pieces of hardware, from multiple manufacturers, using multiple pieces of software provides seemingly limitless concerns if the integration is not executed with sound engineering principles. For older vessels, the problem might grow exponentially as outdated software on main systems could have trouble interacting with more modern software on newer subsystems.

Historically, class society rules focus on steel and equipment. ABS has developed the Integrated Software Quality Management (ISQM) notation, which is a risk-based software development and maintenance process that can be used to verify the software installation and to monitor for consistency when software updates or hardware changes are made.

The key to maintaining software integrity is to begin as early as possible in any given project. Software repair costs only increase as an asset ages. Estimates place the cost for each bug to be around $3000 in software support, which does not include potential downtime.

ISQM focuses on the software that controls the equipment and provides a process to minimize software-related risk throughout the life of an asset. Initially, it was developed for the offshore industry, with a particular focus on complex newbuild control systems. The recent use of ISQM on the ultra-deepwater drillship *Rowan Renaissance*, the first vessel built using ISQM, helped facilitate the integration and testing of more than 35 subsystems developed by a dozen major suppliers.

Clearly, the end goal for industry is to reduce safety, environmental, and productivity risks while increasing reliability, efficiency, and productivity.

But ISQM is only the beginning. Even with high-quality software engineering, vessel owners must take a lifecycle approach to software integrity. That includes consistent verification and validation of systems and subsystems, and it also requires periodic cybersecurity risk assessments and a consistent approach to capturing lessons learned.

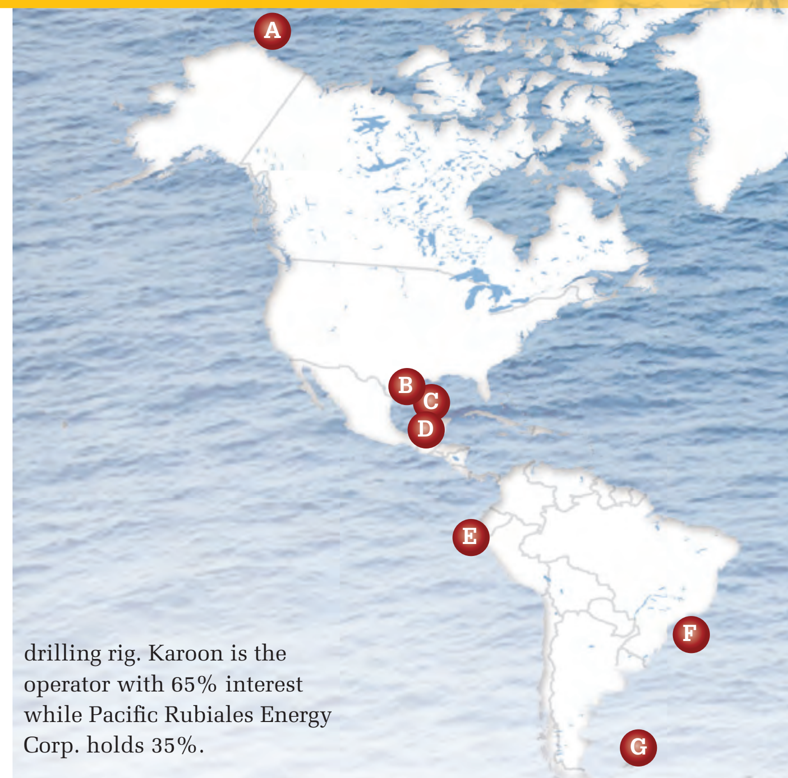
Looking to the future, as an industry we must continue discuss issues that affect our security as technology advances beyond what we thought was possible a decade ago. As we become more dependent on connected and integrated systems, cybersecurity and software integrity are key to the overall integrity of an asset. OE

James Watson is responsible for all operations of the ABS in the Western Hemisphere.

Prior to joining ABS, Watson served as director of the Bureau of Safety and Environmental Enforcement (BSEE) at the US Department of Interior, where he provided regulatory oversight for energy exploration and production on the US Outer Continental Shelf. Before becoming BSEE director, Watson served as the US Coast Guard (USCG) director of Prevention Policy for Marine Safety, Security and Stewardship.

Watson earned a bachelor of science degree in marine engineering from USCGA in 1978. He received his master of science in naval architecture and his master of science in mechanical engineering from the University of Michigan in 1985. Watson earned an additional master of science in strategic studies at the National Defense University in 2001.

Global E&P Briefs



A Shell's Arctic plans move forward

The US Department of the Interior (DOI) is reviewing Shell's Arctic drilling plans. In March, DOI issued a record of decision affirming Shell's Arctic leases from the Chukchi Sea OCS oil and gas lease sale 193 from 2008. The decision paved the way for the Bureau of Ocean Energy Management (BOEM), part of DOI, to begin a formal review of Shell's exploration plan. Shell has spent US$1 billion preparing for its return to the Arctic this summer, following a two-year hiatus.

B Statoil makes Yeti discovery

Statoil hit oil at its Yeti exploration well in Walker Ridge Block 160, 15km south of Chevron's Big Foot field, in deepwater Gulf of Mexico, at 5890ft of water. It was drilled to 25,575ft by the *Maersk Developer* semisubmersible. It expands the proven sub-salt Miocene play further south and west of Big Foot.

C Hadrian South onstream

ExxonMobil began production at Hadrian South, 230mi offshore in the Keathley Canyon area in 7650ft water. It has a subsea production system with flowlines connected to the Lucius truss spar, which began production in January. As ExxonMobil's deepest subsea tie-back, Hadrian South has an expected gross production of 300 MMcf/d and 3000 b/d of liquids from two wells.

D Abkatún restored after fatal fire

A fatal blaze erupted on 1 April and tore through Pemex's Abkatún Permanente platform, resulting in four workers killed. 301 workers were evacuated to other platforms, and production was ceased. Production has since been restored.

Pemex is expecting to reach its original production goal of 646,000 b/d of crude oil and 1.442 MMcf/d of gas. Abkatún is part of Pemex's Abkatún-Pol-Chuc complex, which is located 132km northeast from the Port of Dos Bocas between the states of Campeche and Tabasco.

E BPZ suspending Corvina well

Houston-based BPZ Energy is suspending its Corvina CX15-9D well off Peru after failing to produce oil. The well, located in Block Z-1, was drilled to 7730ft. BPZ says that 35ft of gas pay was found in the upper Zorritos non-associated gas reservoir in the CX15-9D well. Since the well failed to produce oil, BPZ is reevaluating the geologic model. BPZ is the operator of Block Z1 with a 51% interest. Partner Pacific Rubiales Energy holds the remaining 49%.

F Karoon hits offshore Brazil

Karoon Gas Australia hit oil and gas at the Echidna-1 exploration well offshore Brazil. Wireline logging is being conducted to determine the extent of the gross and net columns, including the presence of a Paleocene oil column. Echidna-1, located in exploration block S-M-1102, 20km northeast of Kangaroo, reached the planned total depth of 2379m using the *Olinda Star* semisubmersible drilling rig. Karoon is the operator with 65% interest while Pacific Rubiales Energy Corp. holds 35%.

G Premier confirms Sea Lion extension

Premier Oil's 14/15b-5 Zebedee exploration well, in exploration license PL004, confirmed the extension of the giant Sea Lion discovery. The well intersected 79ft of oil-bearing reservoir in Zebedee sands and 55ft of gas-bearing reservoir in previously undrilled Hector sands, in multiple Cretaceous formations. One of six wells planned using the *Eirik Raude* drilling rig, 14/15b-5 targeted 61-432 MMbbl gross unrisked resources. The finds in PL004, which also include oil shows in deeper sands, mark a successful start to Premier's 2015 Falklands drilling campaign.

H Pancontinental out of L10B

Australia's Pancontinental is withdrawing from the BG Group-operated Kenya license L10B and from the production sharing agreement governing L10B. Pancontinental holds a 25% interest in L10B, while BG holds 75%. L10B is immediately south of area L10A, where operator BG Group holds 50% interest, Pancontinental holds 18.75% and PTTEP of Thailand holds 31.25%.

"The blocks have similar geological features that in some cases straddle the permit boundary, while exploration in L10A is more advanced," Pancontinental says.

I ExxonMobil in EG-06 PSC

The government of Equatorial Guinea awarded ExxonMobil a production sharing contract (PSC) for Block EG-06. The block is offshore Bioko Island, immediately north of Block R and adjacent to the international border with Nigeria. Block EG-06 comprises the

areas previously known as D-8, D-9, and portions of C-10, C-11, B-10, B-11. ExxonMobil holds a participating interest of 71.25%, GEPetrol has 23.75% and the Equatorial Guinea government holds the remaining 5%.

J Big hit offshore Tanzania

Statoil has made its eighth discovery off Tanzania at the Mdalasini-1 exploration well, with an additional 1-1.8 Tcf of natural gas bringing the total of in-place volumes up to approximately 22 Tcf in Block 2. Mdalasini-1, located at 2296m water depth at the southernmost edge of Block 2, marks the completion of the first phase of the Tanzanian multi-well program. Statoil drilled the Mdalasini-1 well with a 100% working interest and operates the license on Block 2 with 65% interest for Tanzania Petroleum Development Corp. (TPDC). Partner ExxonMobil E&P Tanzania holds the remaining 35%. TPDC has the right to a 10% working interest in case of a development phase.

K Second discovery at Aasta Hansteen

Statoil confirmed its second discovery at Aasta Hansteen with the Roald Rygg prospect in the Norwegian Sea. A 38m gas column was found at well 6706/12-3 in PL602in the Nise formation. Roald Rygg is less than 7km west of the Snefrid Nord discovery, made in March, with an estimated 31-57 MMboe. Statoil and its PL602 partners estimate the Roald Rygg volumes to be in the range of 12-44 MMboe.

L Huntington ready for ramp up

The E.ON-operated Huntington field is due to return to normal operations as gas export rate restrictions are lifted. The Huntington field, produced via the *Voyageur Spirit* FPSO, has been operating under gas export rate restrictions, due to an issue with the Central Area Transmission System (CATS) since October. This reduced the rate of oil production from the field. E.ON has said that Huntington field is ready for full ramp up when unrestricted access to CATS is made available.

M Lundin spuds Barents Sea well

Lundin Norway began drilling the 7220/11-2 appraisal well in the Barents Sea South 6.5km southwest of the Alta discovery well 7220/11-1. The main objective is to confirm the reservoir model and prove the presence of hydrocarbon columns and fluid contacts. The planned total depth is 2020m below mean sea level and the well is being drilled using the drilling rig *Island Innovator*.

N Gazprom, Vietnam in Arctic collaboration

Gazprom Neft and Petrovietnam extended their collaboration on the Pechora Sea shelf. The joint oil and gas exploration, production and development projects will be at the Dolginskoye field and the Severo-Zapadnyi (North West) licensed block. The Dolginskoye oil field is 120km south of the Novaya Zemlya archipelago and 110km north of the mainland coast. The North West license block has an area of 886,000sq m with potential reserves (classified D1 according to Russian standards) estimated at more than 105 million-ton of oil and condensates, and 60 Bcm of gas.

O RIL developing MJ

India-based Reliance Industries' (RIL) MJ discovery, in the D6 block, is estimated by Deloitte LLP to have 1.4 Tcf of unrisked contingent resources offshore India, according to partner Niko Resources. D6 is located in the Krishna-Godavari basin and spans over 1.88 million acres. Dhirubhai 1 and 3 MA gas and oil fields are also located in the block. RIL is the operator of the D6 Block with 90% interest. Niko holds the remaining 10%

P KrisEnergy spuds third well

KrisEnergy drilling began on the Rossukon-3 exploration well in G6/48 in the Gulf of Thailand using Shelf Drilling's Key Gibraltar jackup rig. Rossukon-3 is the third exploration well planned for a total depth at 2276m in the G6/48 contract area, which covers 566sq km over the Karawake basin. The well lies in 208ft water depth, 1.9km west of the Rossukon-2 surface location and 1.8km northwest of the original Rossukon-1 discovery well. Operator KrisEnergy holds 30% interest in the concession. Its partners are Northern Gulf Petroleum (40%) and Mubadala Petroleum (30%).

Q Eni begins seismic campaign off Vietnam

Eni Vietnam began a 570sq km 3D seismic survey in Block 120 using the CGG *Amadeus* vessel. Block 120 overlies Quang Ngai Graben and Tri Ton Horst, which covers an area of 6869sq km in 50-650m water depth. The survey will image the carbonate and basement sections of the Ca Lang prospect and associated leads on the Tri Ton Horst. KrisEnergy holds a 33.33% in Block 120. Eni operates with 66.67%.

R Myanmar readies for exploration

Myanmar has awarded several production sharing contracts following its last bid round. Eni has signed PSCs for blocks MD-02 and MD-04, to be operated by Eni, holding 80% equity, under a joint venture with Petrovietnam (20%). Chevron subsidiary Unocal Myanmar Offshore Co. signed a PSC for Block A5 for operatorship and 99% interest. Royal Marine Engineering Co., a Myanmar company, will hold the remaining interest. India's Reliance Industries and MOGE signed PSCs for blocks M17 and M18 for 96% participating interest. United National Resources Development Services (UNRD), a Myanmar company, will hold the remaining interest. Australia's Woodside signed PSCs for blocks AD-2, AD-5, A-4 and A-7. Woodside will hold operated equity interests of 55% and 45% for AD-5 and A-7, respectively, and non-operating interests of 45% in AD-2 and A-4. Myanmar Petroleum will hold non-operating interest in block A-4. UK-based Ophir won 95% operated interest in deepwater Block AD-03.

S Apache leaves Australia

Apache Corp. agreed to sell its Australian subsidiary Apache Energy Ltd. to a consortium managed by Macquarie Capital Group Ltd. and Brookfield Asset Management Inc. for cash payment of US$2.1 billion.

The assets being acquired by Brookfield and Macquarie include Apache's interest in operated gas fields Reindeer, John Brookes and Halyard-Spar; non-operated interest in the BHP Billiton-operated Macedon field, interest in operated oil fields at Coniston-Novara, Van Gogh and Stag, and the non-operated interest in the BHP Billiton-operated Pyrenees area; interests in gas processing facilities and associated infrastructure at Devil Creek, Varanus Island and Macedon, and all of Apache's upstream acreage in the Carnarvon, Exmouth and Canning basins along with related hydrocarbon reserves, resources and production.

T Woodside hits at Pyxis-1

Woodside made a gas discovery at Pyxis-1, located in production license WA-34-L, within Western Australia's Dampier sub-basin, approximately 15km north of Woodside's producing Pluto Gas Field infrastructure. The well intersected approximately 18.5m of net gas within the Jurassic sandstone targe at a total depth of 3347m. Woodside Burrup is the operator of WA-34-Land with 90% interest. Partners include Kansai Electric Power Australia, and Tokyo Gas Pluto, each with 5% interest.

Contract Briefs

KBR wins Saudi Aramco deal

Saudi Aramco awarded KBR a six-year contract to provide project management and engineering services for existing and new offshore facilities to maintain and increase crude production levels. KBR's Saudi joint venture company, KBR-AMCDE, will undertake all in-kingdom work scopes and develop an in-kingdom center of engineering excellence to develop and train Saudi engineers. KBR's Houston and London operations centers will execute all out-of-kingdom scopes.

Seaway starts Perla job

Seaway Heavy Lifting entered into a contract with Cardon IV in Venezuela for transportation and installation of the Perla project gas production platforms complete with tie-in of the subsea infrastructure. Project management and engineering has already started and is executed from Seaway Heavy Lifting's headquarters in the Netherlands as well as from its new project office in the Woodlands near Houston.

Hercules in Eni deal

Eni signed a five-year contract with Hercules Offshore for the use of the Hercules 260 jackup rig in West Africa. The contract is expected to start in April. The dayrate will range from a minimum of US$75,000/d when the price of Brent crude oil is $86/bbl or less, to a maximum of $125,000/d when the price of Brent crude oil is $125/bbl.

Fugro wins Moho Nord ROV gig

Total E&P Congo awarded Fugro a five-year, US$100 million contract for remote operated vehicle (ROV) services and remote subsea tooling in the Moho Nord field. The contract calls for Fugro to supply four 200hp FCV 3000 work class ROV systems and innovative blowout preventer (BOP) tooling, which will be installed on board three mobile drilling units and one field support vessel. Fugro designed an ROV equipped with a BOP skid for this project to perform subsea BOP intervention and testing. Fugro is also responsible for additional ROV tasks including setting up regular fluid injection, drilling re-entry, bullseye checks and routine video monitoring, inspection, cleaning and intervention tasks on and around the BOP, in addition to alignment control during manifold installation.

Aptomar to monitor Knarr

Aptomar will provide BG Group field monitoring services at the operator's Knarr field on the Norwegian continental shelf. Under the five-year contract, Aptomar will provide 24/7 monitoring of offshore traffic and safety zones to detect and track vessels on collision course with offshore assets, as well as continuous monitoring and detection of unintended spills, and be a part of the 2nd line response team. For the project, Aptomar will establish a new marine control center at the company's headquarter in Trondheim, Norway.

WorleyParsons wins Ophir contract

WorleyParsons and its subsidiary INTECSEA will provide engineering and project management services on Ophir Energy's Fortuna project in Block R offshore Equatorial Guinea. The contract's scope includes overseeing the front-end engineering and design scopes and tendering and evaluation of related engineering, procurement, construction, installation and commissioning packages. ■

Field of View

Border bust-up won’t stop TEN

John Bradbury profiles Tullow Oil’s major TEN development offshore Ghana, its second development in the area following its success at the deepwater Jubilee field.

At the start of the year, Tullow Oil was optimistic about the progress of its TEN deepwater project offshore Ghana, saying then that it was “....progressing very well and is now over 50% complete and remains within budget and on-track to deliver first oil in mid-2016.”

However, by March, Tullow signaled that all was not that well. The company was embroiled in a maritime border dispute between Ghana and neighboring Cote d’Ivoire offshore West Africa. But, despite the dispute, Tullow says work on the TEN project will continue.

TEN comprises the Tweneboa, Enyenra and Ntomme fields in the Deepwater Tano contract area offshore Ghana. The project is operated by Tullow Oil, in partnership with Kosmos Energy, Anadarko, Sabre Oil and Gas, and Petro SA, and the Ghana National Petroleum Corp.

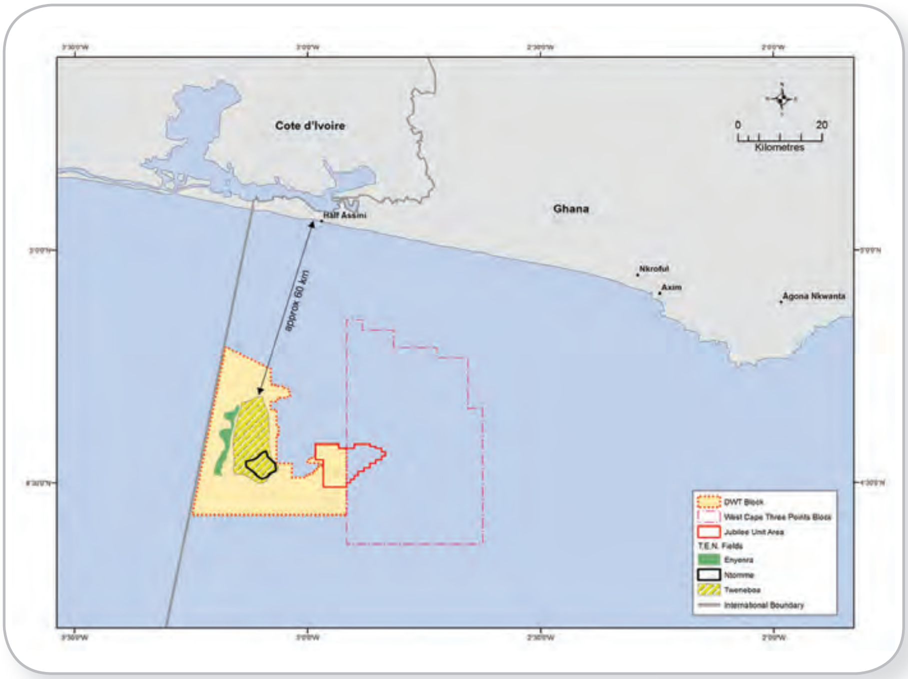
Tullow and its partners declared commerciality for the TEN discoveries in November 2012 and submitted a development plan to Ghana’s government for approval.

Consent for the project was granted by Ghana’s government in June 2013, based on plateau production via 24 wells in a water depth of 1500m (4920ft).

Cote d’Ivoire dispute

Cote d’Ivoire has sought imposition of “provisional measures” via the International Tribunal of the Law of the Sea (ITLOS) in Hamburg, seeking to suspend ongoing exploration and exploitation in a disputed area where the TEN project is situated.

Tullow says a full verdict on the dispute, which originated in 2014, is not expected until 2017 – after the mid-2016 first oil date for TEN, targeted by Tullow.



TEN project location offshore Ghana. Images from Tullow Oil.

The Jubilee FPSO *Kwame Nkrumah MV21* offshore Ghana.

Legal advisors have told Tullow that Ghana has a strong case under international law, and that the current boundary between the two countries, which follows an equidistant line, will be upheld by ITLOS. A decision on the application for provisional measures was expected to be handed down by the end of April (before ***OE*** goes to press).

“Although the arbitration process allows for an application of provisional measures, it is our view that it is in the best interest of all parties that the TEN project continues to move ahead without delay and unencumbered by legal tactics of this nature,” says Tullow’s chief executive Aiden Heavey.

Drilling

During 2011 Tullow progressed appraisal drilling at the TEN fields, shortly after producing first oil from Jubilee in December 2010.

By January 2011, Tullow was drilling a Tweneboa 3 well, 6km (3.75mi) southeast of a Tweneboa 2 well and 12km (7.5mi) southeast from the original Tweneboa 1 discovery well; Tullow reported that Tweneboa 3 had confirmed the potential of the greater Tweneboa area.
Two deviated holes were drilled off the original Tweneboa 3 wellbore, targeting different areas. One leg was drilled to calibrate very weak seismic responses and hit thin reservoir sands and 9m (29.5ft) of gas condensate pay.

A second sidetrack, targeting an Ntomme anomaly, with a strong seismic signal, encountered 65m (213ft) of gross vertical reservoir with 34m (111ft) of net gas-condensate pay, allowing the project to progress.

At the time, Tullow's exploration director Angus McCoss said the well was a bold step-out in a "vast stratigraphic trap," adding: "Confirming producible gas-condensate in excellent quality reservoirs at this location is a great result that also demonstrates the strong predictive capabilities of our seismic data and prospecting techniques. As a result, we can now move forward confidently to assess the development options for the Tweneboa and Enyenra (Owo) fields in the Greater Tweneboa Area."

Another Jubilee

TEN will sit just 30km (18.75mi) from Tullow Oil's Jubilee, another project produced via FPSO, which came onstream in 2010, and became Ghana's first deepwater development.

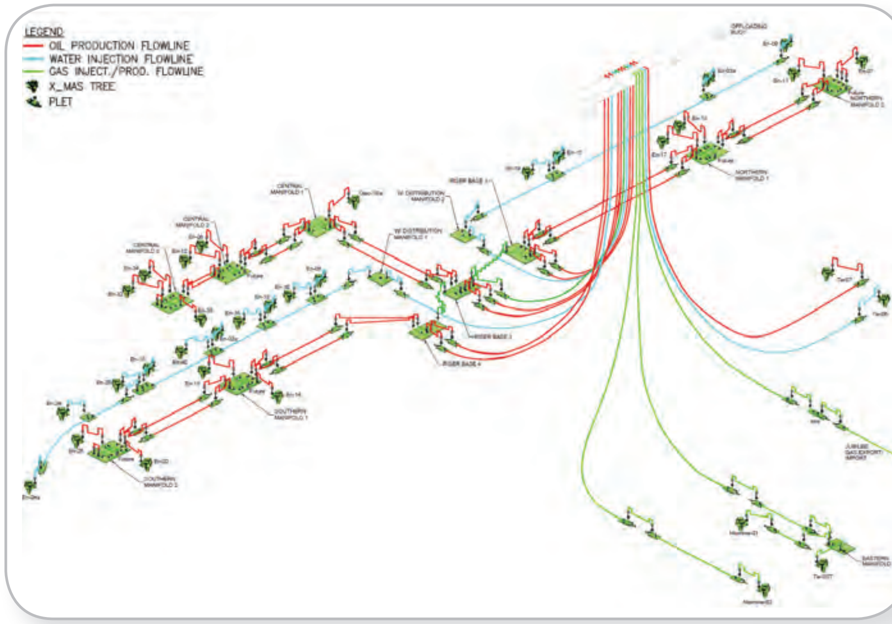
Tullow's TEN project looks set to follow hard on the heels of Jubilee. Front-end engineering and design was completed by February 2013.

Most of the major project elements have been awarded: Japan's MODEC won a contract to supply a leased FPSO for the TEN development in August 2013. The contract with MODEC covers engineering, procurement construction, mobilization and operations of the unit, and topsides processing equipment, hull and marine systems. Subsidiary Sofec will design and supply the unit's external turret mooring system.

Tullow's new TEN vessel will be a conversion of the very large crude carrier (VLCC) *Centennial J*, which is being equipped to provide plateau production of 80,000 b/d of oil, 70 MMcf/d of gas processing, and storage for 1.7 MMbbl of fluids. MODEC is due to deliver the unit early 2016, following its previous award for the Jubilee field FPSO, named after Ghana's founder, *Kwame Nkrumah MV2*1.

Sembcorp Marine's Jurong Shipyard confirmed a contract from MODEC Offshore in Singapore last October (2014) to carry out a conversion and life extension to a VLCC for the TEN project – the 22nd conversion by Jurong on behalf of MODEC. In addition to the crude processing, Sembcorp says the TEN FPSO will also have handling for 65,000 b/d of produced water and will provide 132,000 b/d of filtered and de-aerated sea water.

In October 2013, Tullow awarded contracts for subsea construction and installation for TEN to a Technip-Subsea 7 consortium worth US$1.23 billion. Technip took $723 million of the value, for provision of nine flexible risers, three flexible flowlines, and 12 flexible pipeline spools, with a total length of 48km (30mi), as well as installation of 63km (39mi) of static and dynamic umbilicals, plus installation of ten rigid well jumpers and delivery of a further six prefabricated jumpers.

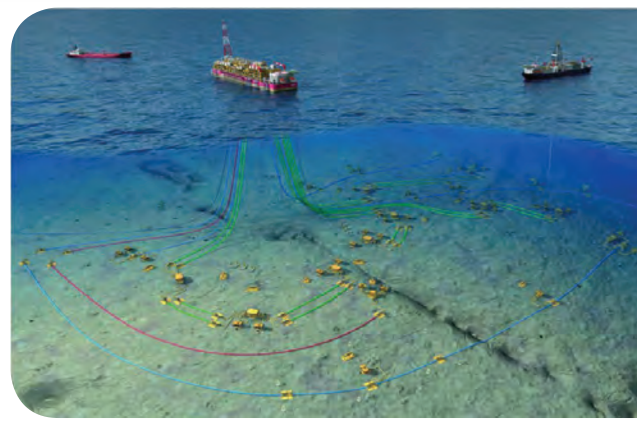


The TEN subsea layout.

Subsea 7's scope of work, worth $500 million, is for supply of flowline terminations, structural foundation piles, as well as installation of subsea manifolds, riser bases and flying leads. Much of Subsea 7's equipment will be fabricated in Ghana, where a "substantial" level of fabrication will take place. Offshore installation for the project is due to commence this year using the deepwater pipelay and heavy lift vessel *Seven Borealis*, which is equipped for both rigid S-lay and J-lay installation, and which previously debuted on Total's CLOV project offshore Angola.

FMC Technologies will supply a subsea system under a $340 million contract covering subsea trees, manifolds, tooling, subsea controls and systems integration.

Phase one of the TEN development with a capex of US$4.09 billion involves 17 wells, for Enyenra, Ntomme, water injection, and Tweneboa and non-associated gas in first phase. A second phase involves infill wells on Enyenra and Ntomme, costing a further $900 million, with first oil from this phase due mid-2018.

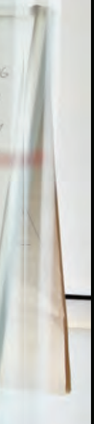


TEN project field layout schematic.

As government approval for TEN came through, allowing confirmation of pre-sanction contracts, Tullow underlined the project's local significance, specifically around building Ghana's oil sector capabilities: "The award of these contracts will enable Tullow and its partners to build on their commitment to help develop the oil and gas sector in Ghana by expanding local capability and participation in the supply chain, particularly through the in-country fabrication requirement of the TEN project," Tullow said at the time.

TEN will be the second major oil development offshore Ghana after Tullow helped to build Ghanian industry infrastructure during the Jubilee development.

Tullow Oil operates the TEN project with 47.175% interest. Its partners in the field are Kosmos Energy (17%), Anadarko Petroleum (17%), Petro SA (3.82%), and the Ghana National Petroleum Corp. (15%). OE







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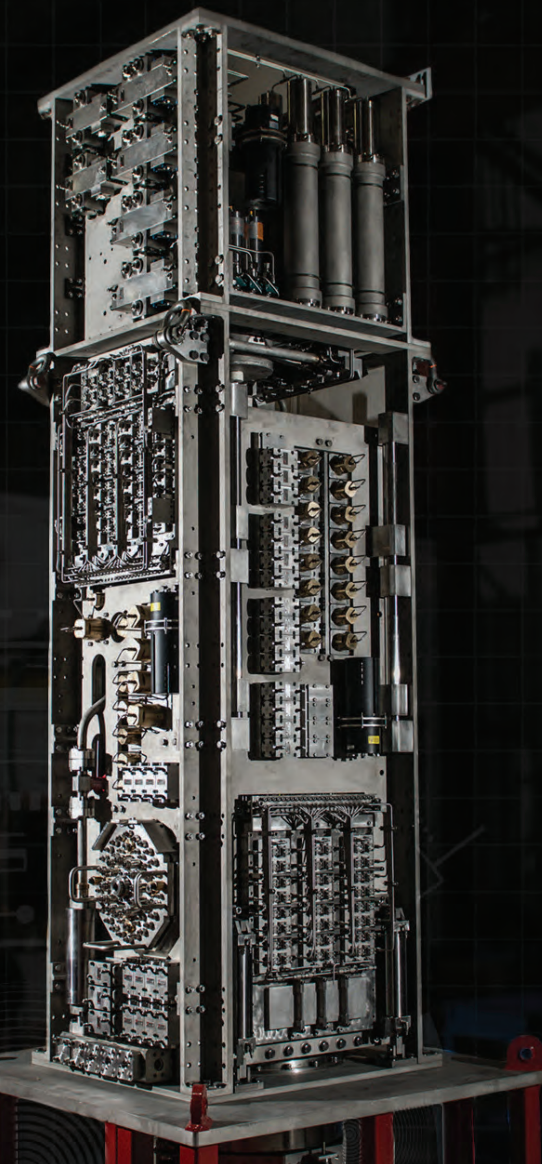
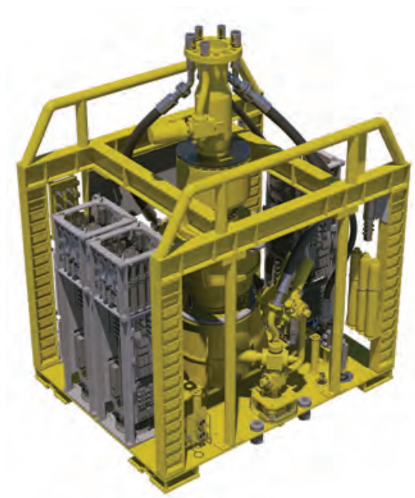


The Mark IV POD's improved reliability advances subsea control system availability to guard against costly downtime.



The Mark IV BOP subsea control system has fewer tubing connections to reduce potential leak paths, and when compared to some PODs, the Mark IV is up to 33% lighter. Our POD improvements enabled the development of an optional Mark IV High Availability (HA) configuration – the industry's first three-POD design – that provides the redundancy to eliminate stack pulls if one POD fails, improving operational availability to as much as 98%. The Mark IV's HA configuration won an Offshore Technology Conference 2015 Spotlight on New Technology award.

The Mark IV POD will be on display at Cameron's booth (3317) during this year's OTC.

Learn more about the award-winning Mark IV HA at: **www.c-a-m.com/MarkIVHA**

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CAMERON

Ready for prime time

Italy is sitting on sizeable untapped gas resources, yet it still imports a large proportion of its gas. Elaine Maslin reports from the Offshore Mediterranean Conference, Ravenna.

Chastened by low oil prices, the global oil and industry is in something of a pensive mood. In Italy, however, the mood is driven more by an eagerness to open up and exploit the country's own resources, particularly offshore.

Bordering Italy's maritime boundaries, Greece, Croatia and Montenegro have been encouraging offshore exploration through licensing rounds (Croatia's first was opened last year) and Albania, too, has seen seismic acquisition activities to scope out its resources. Major finds offshore Israel and Cyprus have been in the headlines, albeit more recently due to project cancellations and geopolitical tension.

Italy, meanwhile, has the fifth largest proved reserves of crude oil in Europe with 560 MMbo as of 1 January 2014, and it is sitting on the sixth largest gas reserves in continental Europe (at 2.1 Tcf), according to the US Energy Information Administration. However, regulatory bureaucracy and drilling bans means the resources are being left underexploited, operators and industry organizations complain, and the country is the second largest natural

- Italian gas production is mostly offshore (67%) and mostly in the Adriatic Sea, according to Franco Terlizzese, General Director of the Ministry of Economic Development.
- In 2014, there were 12 wells drill, eight of which were production wells drilled offshore. No exploration wells were drilled.
- Italy has 894 productive wells, 362 of which are offshore. The Italian offshore has 133 offshore facilities, comprising 106 production platforms, 11 subsea wellheads, and eight platforms supporting production compression or connection.
- 59% of Italy's gas reserves are offshore, 40% in Zone A, in the northern Adriatic Sea, east of Venice and Ravenna.
- 90% of Italy's oil reserves are onshore, mostly in Basilicata.

Figures from the Italian Directorate-General for Mineral and Natural Recourses.

Bruno Lescoeur, CEO Edison. Photo from Edison.

The standing room only opening plenary session at OMC 2015. Photo from OMC.

Marcelo Masera, Head of the Energy Security Unit in the Institute for Energy and Transport of the European Commission's Joint Research Centre (JRC). Photo from Elaine Maslin.

gas importer in Europe.

Italy's ability to tap its resources also has broader implications. By tapping its own resources, Italy and Europe could lower their reliance on imports, increasing energy security, Bruno Lescoeur, CEO of Italian exploration and production company Edison, told the Offshore Mediterranean Conference (OMC 2015) in Ravenna.

"The EU is rightly concerned about its energy security and the Mediterranean could contribute," says Lescoeur. "There are opportunities, for exploration and production, as well as pipelines, but also geopolitics," he said, referring to Israel and Cyprus, the Ukraine and Russia, from which Italy gets a lot of its gas, as well as the instability in North Africa, from which Italy imports a large amount of its oil. "The Mediterranean needs to become a hub for increased sustainable production."

However, no exploration wells have been drilled in Italy's offshore since 2008 (a drilling ban was imposed in 2010 following the *Deepwater Horizon* disaster in the US Gulf of Mexico) and there are no incentives to change this, only disincentives and regulatory bureaucracy, "The whole system has to be improved right down to the bottom," he says.

"The situation in the Adriatic is a paradox: Croatia has assigned its marine areas for oil and gas exploration while Italy is a mere onlooker, at activities carried out just miles away," says Guido Ottolenghi, President of the Confindustria Ravenna, Italy's offshore industry hub.

Northern Petroleum has suffered from such delays. It recently issued an update on its southern Adriatic Sea acreage offshore Italy. The company said there had been little opportunity to discuss ongoing activities due to lack of "tangible progress," primarily relating to an application to carry out 3D seismic acquisition across the Giove oil discovery (1998) and Cygnus exploration prospect. The application process started in 2012 and without the 3D seismic the firm is unable to move ahead with exploration drilling.

The award of a new license in the Sicily Channel to Northern last year had, however, given the firm hope that the Italian administration was actively progressing approvals "that had been outstanding for some years." Further hope has been given by a decision in February to rescind an additional 10.5% tax imposed on the industry since 2008, the so-called Robin Hood tax, as described by Lescoeur.

In 2013, a new area to the west of Sardinia, called Zone E, was opened to exploration by the Italian government. Some research on the area, which covers part of the Balearic Sea and Alghero Province Sea, with waters as deep as 2800m, has been carried out. According to a presentation at OMC 2015, the area contains Messinian reservoir rock and Oligo Miocene source rock. "There's not a lot of data because it's an under explored area," OMC was told. Just two offshore wells have been drilled, one 1800m deep, which reached the Miocene and Oligocene, and a second 1700m deep. According to the US Geological Survey, the area could contain 1.4 Tcm gas and 0.42 billion bbl oil, she says. There is interest from operators in the area, she says, but for now little activity.

The situation is frustrating not only for Italian explorers, but also Italian contractors, who are hopeful they could secure work in Italy's offshore. Saipem, Italy's most well-known offshore contractor, currently has virtually no activity offshore Italy at present and some of the traditional areas where the country's contractors look for work have been suffering from local tensions and even conflict.

Italy has had close ties with Libya and Egypt in North Africa, both importing hydrocarbons from both and providing services. Due to the tensions in both countries, resulting in a drop in oil output and activity, contracts have waned, if not dried up altogether, a situation further exacerbated by the low oil price.

Regulation

Regulation around offshore safety is also high on the agenda for the Mediterranean basin. EU member states have until 19 July this year to transpose into legislation new rules around offshore safety, this includes splitting the licensing and regulatory functions, integrating environmental protection measures into operator's safety case, common forms for incident reporting and measuring safety performance, outlined Marcelo Masera, Head of the Energy Security Unit in the Institute for Energy and Transport of the European Commission's Joint Research Centre (JRC).

While North Sea bordering countries already mostly conform to the proposals, drawn up in the wake of the *Deepwater Horizon* disaster in the US Gulf of Mexico, the situation is more complex in the Mediterranean.

At the moment, coordinated rules around offshore operations and regulations in the Mediterranean Sea, with many more bordering countries than the North Sea, including non-EU member states, are lacking, Lescoeur says.

"The only common rules are the ones the IoCs are imposing by themselves to their own activities," he says. "These companies are applying international best practices. We also need to change public perception. Almost all activities are seen as dangerous and polluting."

Getting offshore safety right – or not – could have significant consequences, on human life, the environment and financially, Masera says."Macondo was an alarm bell to the serious consequences (of an accident offshore) - casualties, environmental issues and financial consequences. It is not just a technical issue. This could hurt industry and all these

Quick stats

OE's at-a-glance guide to offshore hydrocarbon reserves and key offshore infrastructure globally is updated monthly using data from leading energy analysts Infield Systems (www.infield.com).

See Infield at OTC – Booth 8839

New discoveries announced

Depth range	2012	2013	2014	2015
Shallow (<500m)	75	72	68	8
Deep (500-1500m)	23	19	25	5
Ultradeep (>1500m)	36	35	12	3
Total	134	126	105	16
Start of 2015 date comparison	135 -1	125 1	90 15	- 16

Note: Operators do not announce discovery dates at the time of discovery, so totals for previous years continue to change.

Reserves in the Golden Triangle

by water depth 2015-19

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Brazil			
Shallow	9	177.75	2,363.28
Deep	16	1,616.00	2,935.00
Ultradeep	44	14,085.25	15,973.00
United States			
Shallow	15	86.3	234
Deep	17	919.27	1,280.48
Ultradeep	25	3,456.50	3,870.00
West Africa			
Shallow	128	3,909.45	17,352.22
Deep	42	4,902.50	7,340.00
Ultradeep	15	1,780.00	2,610.00
Total	**302**	**30,755.27**	**51,594.70**
(last month)	(326)	(33,558.39)	(58,128.38)

Greenfield reserves

2015-19

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Shallow	1024	43,505.45	592,331.88
(last month)	(1067)	43,896.82)	(598,706.60)
Deep	152	9,226.43	118,298.12
(last month)	(155)	(10,066.24)	(117,233.91)
Ultradeep	94	19,664.75	37,220.00
(last month)	(100)	(21,419.75)	(40,420.00)
Total	**1,270**	**72,396.63**	**747,850.00**

Pipelines

(operational and 2015 onwards)

	(km)	(last month)
<8in.		
Operational/ installed	41,047	(41,063)
Planned/ possible	24,683	(24,538)
	65,730	(65,601)
8-16in.		
Operational/ installed	81,517	(81,682)
Planned/ possible	48,901	(48,705)
	130,418	(130,387)
>16in.		
Operational/ installed	92,199	(92,532)
Planned/ possible	40,430	(40,514)
	132,629	(133,046)

Production systems worldwide

(operational and 2015 onwards)

Floaters		(last month)
Operational	266	(286)
Under development	50	(46)
Planned/possible	321	(336)
	637	(668)
Fixed platforms		
Operational	9240	(9299)
Under development	96	(85)
Planned/possible	1343	(1370)
	10,679	(10,754)
Subsea wells		
Operational	4773	(4783)
Under development	428	(378)
Planned/possible	6517	(6564)
	11,718	(11,725)

Global offshore reserves (mmboe) onstream by water depth

	2013	2014	2015	2016	2017	2018	2019
Shallow	23,738	14,066.92	40,436.02	31,255.85	19,876.13	29,803.84	26,575.60
(last month)	(23,731.56)	(14,241.40)	(41,352.36)	(31,784.66)	(19,583.11)	(29,703.18)	(27,038.55)
Deep	481.00	4445.73	4375.97	3047.51	3225.33	6760.13	12,670.66
(last month)	(480.55)	(4445.73)	(4375.97)	(3350.29)	(3225.33)	(6826.04)	(12,997.59)
Ultradeep	2928	2347.31	2116.71	3034.99	6194.26	6852.54	8028.50
(last month)	(2928.44)	(2347.31)	(2116.71)	(4504.55)	(4724.69)	(8233.33)	(8966.89)
Total	27,146.53	20,859.96	46,928.70	37,338.35	29,295.72	43,416.51	47,274.76

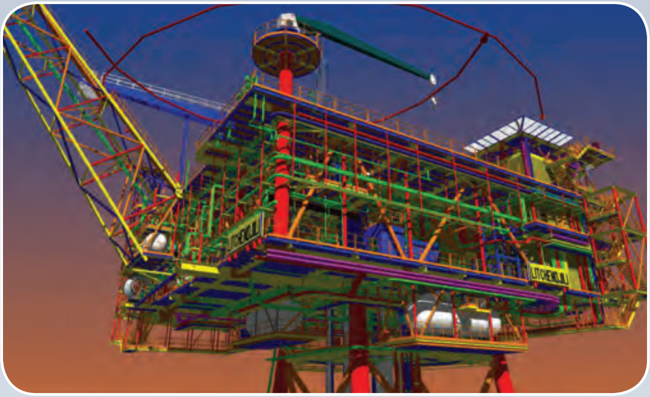
8 April 2015

energy scenarios," Masera says.

"Providing a solution is not easy. There is no silver bullet. The point is creating the right balance between industrial legislative measures that can ensure the best possible efforts are taken.

"In the EU, we have to deal with this. Eighteen months ago the European Commission proposed a directive that member states have until 19 July to transpose into legislation. News about progress and difficulties in this transposition will be heard then.

"We are dealing with complex industrial systems. Any technical system fails. We cannot be naive on this. The preventative analysis and learning from this is a key issue. The position that



Litchendjili gas and condensate development topsides CAD visualization. Images from Maris.

Looking further afield

By Elaine Maslin

Italian engineering companies could offer competitive engineering, procurement and construction services in the Mediterranean Sea, should activity pick up, but West Africa is currently the hot spot for contracts.

Founded in 1981, Milan based engineering firm Maris is currently completing a project offshore Congo and is bidding for more work with operator Eni in the region.

The firm's core focus had been power plant and oil and gas onshore facilities until 2010 when it turned its expertise mainly to the offshore sector. It is providing a full engineering scope, from front-end engineering to detailed design and then follow-on services during construction and commissioning work, on two, 900-ton, Eni-operated gas platform topsides, Clara NW and Bonaccia NW, for gas production and treatment, with 1.2 MMcm/d capacity. They are due to be loaded out for installation in the Mediterranean Sea before the end of August 2015.

Maris also provided a full engineering scope for Eni on the Litchendjili gas and condensate development topsides, currently under commissioning, in the Marine XII Block permission, 15km offshore Congo, Africa. The contract included topside, jacket, piles, pre-drilling template and the design of temporary structures, i.e. grillage, sea fastening, for the sea transport of the platform. The facilities – eight production wells (six for gas and condensate, with some gas used for platform power, two for crude) will be unmanned and remotely controlled.

The associated gas, condensate and crude will be transported via a multiphase pipeline to a new onshore oil and gas this cannot happen to us is unacceptable. This has to be tackled from the beginning." OE

FURTHER READING

Geopolitics key to Mediterranean energy future - OE Digital. The oil and gas industry can deal with low oil prices, up to a point, by making itself more efficient. In contrast, there is little it can do about geopolitics and one of the places that is most evident is the Mediterranean. www.oedigital.com/component/k2/item/8545-geopolitics-key-to-mediterranean-energy-future

treatment plant, be separated into two streams; the gas product will be directly delivered for power generation and the oil and condensate desalted and stabilized before delivery to Total's terminal in Djeno. Hydrate inhibitor will be supplied via a pipeline piggybacking the export pipeline.

Maris has also provided design services for a 90-ton, 25-person accommodation module for Pemex to be bridge-linked to the Akal-G HA-AG-1 platform in the Cantarell field, Campeche, Gulf of Mexico.

Stefano Sangermani, commercial manager at Maris, says the firm is currently bidding on work for construction and engineering on other ENI platform projects offshore Congo. "We are hoping to increase business in Mediterranean Sea projects since we think that we could be competitive in this market area due to personnel's past experience in offshore Mediterranean projects," he says. "Africa is very interesting for us, even for onshore, however, we need to monitor the evolution of the political situation, especially in the North. We would also like to work on floating production, storage and offloading vessel modules."

Massimo Baraldo, ICT manager, says the firm, which has about 80 in-house engineers, uses Hysys software for process simulation their engineering projects, producing full 3D design packages in particular using 3D PDS (Intergraph) or 3D PDMS (Aveva) , for a wide range of projects from process and mechanical engineering to electrical and instrumentation engineering, to hand to construction teams. ■

Litchendjili gas and condensate development topsides installed offshore Congo.

Rig stats

Worldwide

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	110	92	18	83%
Jackup	420	336	84	80%
Semisub	168	147	21	87%
Tenders	33	22	11	66%
Total	731	597	134	81%

Gulf of Mexico

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	36	33	3	91%
Jackup	79	58	21	73%
Semisub	24	19	5	79%
Tenders	N/A	N/A	N/A	N/A
Total	139	110	29	79%

Asia Pacific

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	13	7	6	53%
Jackup	120	98	22	81%
Semisub	35	27	8	77%
Tenders	22	12	10	54%
Total	190	144	46	75%

Latin America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	27	26	1	96%
Jackup	10	7	3	70%
Semisub	33	32	1	96%
Tenders	2	2	0	100%
Total	72	67	5	93%

Northwest European Continental Shelf

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	0	1	0%
Jackup	52	46	6	88%
Semisub	45	42	3	93%
Tenders	N/A	N/A	N/A	N/A
Total	98	88	10	89%

Middle East & Caspian Sea

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	N/A	N/A	N/A	N/A
Jackup	111	92	19	82%
Semisub	3	3	0	100%
Tenders	N/A	N/A	N/A	N/A
Total	114	95	19	83%

Sub-Saharan Africa

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	28	22	6	78%
Jackup	24	18	6	75%
Semisub	14	14	0	100%
Tenders	9	8	1	88%
Total	75	62	13	82%

Rest of the World

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	4	3	1	75%
Jackup	24	17	7	70%
Semisub	14	10	4	71%
Tenders	N/A	N/A	N/A	N/A
Total	42	30	12	71%

Source: InfieldRigs

9 April 2015

This data focuses on the marketed rig fleet and excludes assets that are under construction, retired, destroyed, deemed non-competitive or cold stacked.

Short-term uncertainties in the deep

Infield Systems' Catarina Podevyn takes a look at recent oil price movements and market conditions on the deepwater (500m+) capex spending up to 2019.

Infield System's latest deepwater forecast continues to highlight the increasing uncertainty within this market segment.

Even before the oil price decline, the landscape of deepwater investment was showing initial signs of a shift as some operators looked to reassess investment decisions on economically challenging prospects; as seen on Chevron's Rosebank development offshore West Shetland. Over 2H 2014, with a declining oil price, several capital intensive deepwater prospects were subject to reconsideration, while geopolitical conditions, particularly within the Middle East and Eastern Europe have also affected project timescales and brought additional cancellations.

Latin America

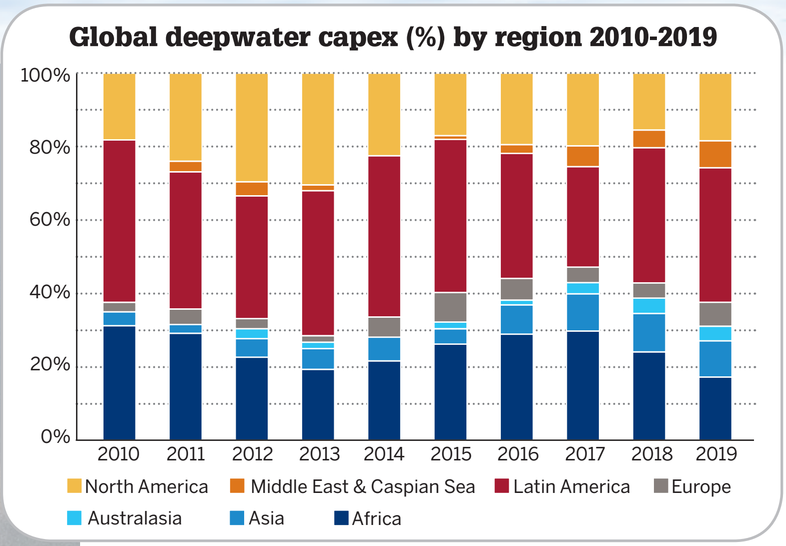
Over the 2015-2019 period Latin America, driven by Petrobras' pre-salt developments offshore Brazil, is expected to retain its leading share of the deepwater market accounting for 35% of global deepwater capex demand. Key projects are expected to include Iara Horst, at a water depth of 2230m, and the multiphase Buzios development.

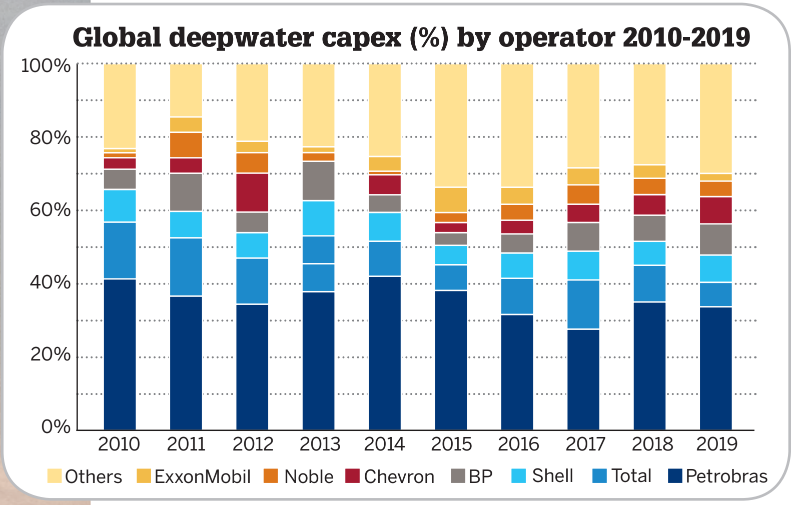
Despite remaining the key region for deepwater investment, expenditure growth is anticipated to be at a far slower rate than during the historical period; at a CAGR of 6.3% compared to 21.2% seen between 2010 and 2014, while with Petrobras' present financial difficulties, the rate of expenditure growth over the forthcoming period may see a further revision.

Increasing industry attention is also being drawn towards Mexico's deepwater prospects following energy reforms within the country. Infield Systems expects the Lakach project to be the key development taking place over the period, with October 2014 seeing Pemex award a US$290 million subsea production systems contract to OneSubsea. However, once again the full success of developing Mexico's deepwater prospects will be subject to a more stable investment environment.

Africa

The deepwater market is anticipated to remain strong offshore Africa over the medium-term as a result of a small number of giant projects already underway. Spend is expected to be driven by Angola; forming a 43% capex share of the region's deepwater market. Infield Systems forecasts a drop-off in expenditure





Source: Infield Systems OFFPEX

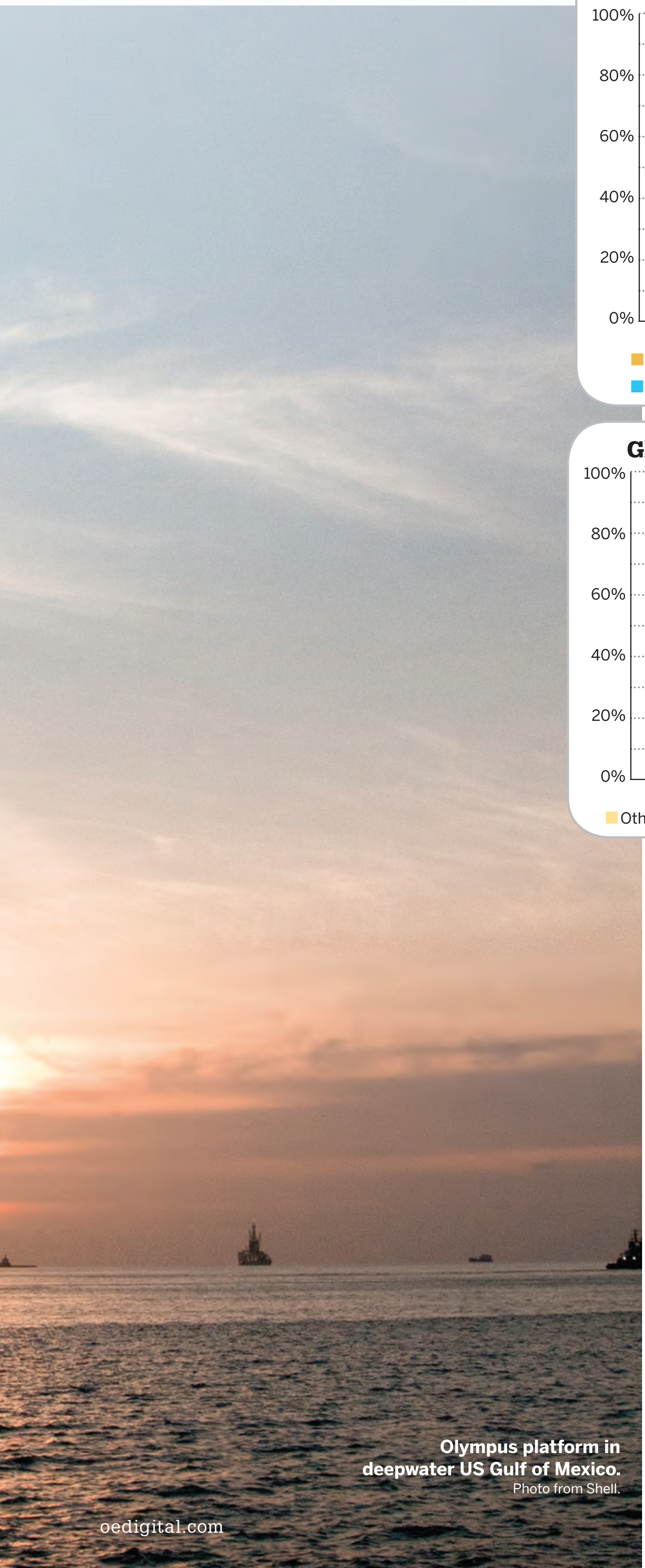
during 2019, primarily due to the anticipated completion of key projects such as Total's Egina and the Kaombow 1 and 2 developments before the close of 2018.

Offshore Ghana, deepwater investment is expected to increase by 129% over the entire 2015-2019 timeframe compared to the previous five years, with Tullow's Tweneboa (Deepwater Tano) anticipated to be the most capital intensive project. Within the East African sub-region Anadarko and the Eni-CNPC consortium are expected to lead expenditure on projects including Prosperidade and Coral (Rovuma Offshore Area 4). Infield Systems also expects deepwater development offshore Tanzania to increase from 2018 onwards, with operators Statoil and BG Group commencing capex spend.

North America

North America is expected to hold an 18% share of offshore deepwater capex demand over the 2015-2019 period; a decrease from the 25% share seen over the previous five years. While this has in part been a result of the completion of capital intensive developments such as Chevron's Jack and Anadarko's Lucius, the US Gulf of Mexico has also been affected by the oil price decline, with further delays announced on projects such as BP's Mad Dog II platform.

BP has also cited declining service costs as a factor influencing


Olympus platform in deepwater US Gulf of Mexico.
Photo from Shell.

Gumusut Kakap, which came on stream in October 2014, was Shell's first deepwater project in Malaysia in 1200m water depth. Photo from Shell.

the decision to push the development further, while with a prevailing low oil price, further delays over the remainder of 2015 may also be announced across the region. Beyond 2016, however, Infield Systems expects deepwater expenditure within the Gulf of Mexico to pick up, with a forecast CAGR of some 12.6%, between 2015-2019. Key developments are expected to include Shell's Appomattox and Stones, and the Anadarko-led Heidelberg project. Deepwater spend is expected to peak in 2019, with North America expected to become the second largest region for capex spend after Latin America.

Asia

Asia is expected to undergo some of the most robust growth in offshore deepwater expenditure over the forthcoming five years. Infield Systems' latest *Asia Regional Market Report to 2019* highlights how this pivotal global market is expected to be driven by the Southeast Asian sub-region, in particular Malaysia, with key projects including Petronas PFLNG-2, to be installed on the Rotan field, and the Shell-operated Ubah gas field development. Deepwater development offshore India, driven by Reliance's Dhirubhai 34 R-Series and the ONGC-operated Krishna-Godavari UD-1 projects, is also anticipated to be central to the growth of the region's deepwater market going forwards.

Europe

Looking towards the North West European Continental Shelf (NWECS), Infield Systems expects capital expenditure within the deepwater sector to remain steady during 2015, predominantly as a result of ongoing development of Aasta Hansteen offshore Norway. However, 3Q 2014 also witnessed a farm-down of several of Statoil's assets within the Norwegian North Sea area, including Aasta Hansteen and its accompanying Polarled pipeline, with the operator now looking to refocus strategy elsewhere.

Indeed, from 2016 onwards, Infield Systems expects deepwater development offshore Norway to decrease year-on-year through to 2018, with only the final year of forecast seeing an increase in investment. Within the UK sector, despite recent uncertainty and the forecast -63%, decrease in deepwater capex for 2015 compared with the previous year, Infield Systems expects an increase in expenditure in water depths of 500m and greater from 2016 onwards, with key projects anticipated to require investment during this time including the delayed Rosebank project. Investment is also expected to take place on other west of Shetland fields with expenditure having been pushed back during 2014.

Middle East

The Middle East region, although not traditionally seen as a deepwater area of development, is expected to see steady deepwater growth throughout the forecast timeframe, driven by projects such as Noble's Leviathan development offshore Israel, which could form 44% of the region's deepwater capital expenditure over the 2015-2019 timeframe. However, recent difficulties facing Noble and the size of the operator's current holding in Leviathan may result in delays with the project. BP's Shah Deniz two step-out wells are also anticipated to require significant investment during the period, with Infield Systems currently expecting capital expenditure on the second phase of the project to commence in 2016.

Australia

Offshore Australia, while mega-projects are expected to continue – particularly within the Greater Gorgon Area, the pace of new deepwater development is forecast to slow. The long-awaited Scarborough development has also increased in uncertainty over recent months, with operators of the JV, ExxonMobil and BHP Billiton, requesting an extension of the field's retention lease while the project partners move towards a final investment decision. Altogether, Infield Systems expects deepwater capital expenditure offshore Australasia to increase over the forthcoming five years despite the less favorable market conditions, with capex spend expected to reach a forecast period peak in 2018.

Conclusion

Altogether, Infield Systems expects the deepwater market to face a challenging time over the 2015-2016 period, with further delays anticipated as a result of the prevailing low oil price. However, over the longer timeframe, with the first gloss having been taken off the US shale oil and gas boom, and unwavering growth in energy consumption from transitional economies, exploration and production activity within deep and ultra-deepwaters can only increase.

Indeed, beyond 2016, Infield Systems expects capital expenditure within water depths of 500m and greater to see a resurgence, with the global deepwater market expected to form a 51% share of total offshore capex over the entire 2015-2019 timeframe, fueled by the high productivity of many of the wells drilled at these depths. OE

Catarina Podevyn *has been an analyst with Infield Systems since 2008, in which time she has worked across a variety of sectors and authored numerous articles and publications on a wide range of subject matter. Her core areas of expertise are within the lloating platform sector and the deep and ultra-deepwater market.*

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Carry on carbon

Carbon fiber rods are the way forward for providing umbilicals in deepwater applications, according to one leading subsea contractor. John Bradbury explains.

Outlining the benefits of using carbon fiber rods inside umbilicals rather than steel to provide bend stiffening, Lars Mehus, chief engineer for umbilicals at Aker Solutions, explained how the lighter carbon reduces strains within an umbilical installed in an ultra-deep zone.

"We have two power umbilicals that are free suspended from a vessel at 2700m (23,911ft) water depth now in operation," Mehus said, following completion of a project for an undisclosed client.

Mehus said the achievement was due to the decision to turn to carbon fiber rods to provide stiffening for umbilicals, rather than taking the traditional approach of using steel tube umbilicals.

Detailing the success of the carbon fiber application, Mehus explained Aker Solutions has two umbilicals installed at 2700m water depth. The longest is 31km (19.3mi), with a top tension 985 kilo Newtons, and still has high umbilical axial stiffness, and a "reasonable" strain value of 0.15%, Mehus explained.

Mehus outlined how using steel armoring to improve axial stiffness in an umbilical comes with a big disadvantage, by adding more weight. "In deepwater you not only have stiffness but you also add to the weight of the umbilical, so in a way you eat up the benefit you get from the actual stiffness," he says.

Mehus was speaking at the Marine Construction Europe Deepwater Development conference in London in March. "By using carbon fiber technology we have an element that has much less weight and more or less the same stiffness as steel," he explained.

Using carbon fiber can be more effective at greater water depth. He said carbon fiber rod technology is much more efficient at deep water due to its low density compared to its stiffness. (see formula below taken from Mehus' presentation)

$$\text{Steel rod} \quad \frac{W_s}{E} = \frac{(7850-1025)}{210000} = 0.0325$$

$$\text{CF rod} \quad \frac{W_s}{E} = \frac{(1600 - 1025)}{150000} = 0.0038$$

"By putting carbon fiber in the umbilical, we can reduce the strain down to a decent level, below the strain limits we have set as an acceptance criteria for the copper cable, but also leaving capacity for the other elements in dynamic scenarios, and capable of taking bending stresses," Mehus reasoned.

Conference delegates heard how the complex interplay between forces and strains imposed on umbilicals affects their fatigue life; and that the cable strain and loading can be the same in shallow and deepwater, depending on the axial stiffness of the umbilical.

Due to temperature variations, material creep, and the effects of friction in the bend stiffener area of an umbilical, it is difficult to predict loads imposed on umbilical power cores. And this in turn complicates prediction of fatigue life, Mehus told his audience.

While offering a carbon-fiber umbilical, Aker Solutions is specifically developing a deepwater umbilical stress analysis program – USAP – using a 3D finite element analysis approach, looking at linear and non-linear effects, axial strain, longitudinal helix behavior, with bell mouth and bend

POWER UMBILICALS; THE BENEFITS

- Low helix lay angle – (approx 2 degrees)
- Umbilical conduits form channels, allowing relative movement between elements
- Long lay lengths promote low radial loads and low friction forces
- High axial stiffness elements are bundled within the same lay length as umbilical elements
- Axial stiffening is achieved with tensioners within the cable cross-section
- Lack of armoring allows smaller component diameter and less splicing during manufacture
- Low weight – optimizing installation vessel choice

Source: Lars Mehus, chief engineer, umbilicals, Aker Solutions, MCE DD presentation March 2015.

Umbilical load out Moss. Photo from Aker Solutions.

stiffener modeling, and a full catenary model. The USAP research is also looking at reeling umbilicals with large center tubes, stress control, and installation and temperature impacts on umbilicals.

Aker Solutions is also looking at the process of installing umbilicals with cable splices in deepwater, where Mehus outlined further issues including strain hardening due to conductor manufacturing, hardening during conductor stranding, and conductor compaction.

Using 3D analysis more fully measures axial strain: "If we use a 2D model we will have under-estimated the strain elements," Mehus noted.

While cable splice welds impart "proper strength" in a welded zone on a cable, there is a change detected in the mechanical properties of the cable, due to the heat input. Aker has found all the copper cable strain is concentrated in a local point, where there is no ductile behavior and the spliced cable exhibits signs of a brittle fracture during a tensile test. To overcome this, the joint is reinforced with a high strength fiber sleeve outside the splice.

"We are working on improving the technology for power umbilicals, and now we have umbilicals in 2700m water depth in operation," Mehus summarized, concluding: "We have improved our design in order to have a better service condition for the cable itself, especially in the most exposed, dynamic area, and we have also developed technology to take care of cables including splices, to increase the safety of the installation." **OE**

Technology-led exploration success

For Shell, exploration isn't just about the seismic, it's about joining up the petabytes' worth of seismic dots between its global team of experts. Meg Chesshyre reports.

The importance of technology in overcoming current exploration challenges was underlined by Shell's global head for exploration, Ceri Powell, at a recent briefing at the company's learning center at Rijswijk, in Holland.

"I really think it is about more brain cells per barrel," she says. "Technology is a means to enable geologists and geophysicists to overcome the challenges that we have in the subsurface today." To this end Shell's research and development budget has averaged US$1.1 billion/yr over the last five years.

The efforts are bearing fruit. 2014 was an excellent year for Shell exploration-wise for the company, with particular successes have been in Malaysia, the Gulf of Mexico and Gabon (see below for more detail).

"We've had 11 major exploration successes, exploration discoveries, complemented by 41 near field discoveries," Powell says. The 2014 overall success rate was 80%, compared with an industry average of 40%.

Making research accessible

For Bettina Bachmann, vice president, subsurface & wells software, Shell, the importance of making research, technology and IT accessible to the explorer on the ground is key to exploration success. "The researchers make the algorithms and do the research on the pilot. We take these things and productize them."

Bettina Bachmann

The new technology is, however, valuable if it can be used by remote exploration teams, to help them make well proposals, go into bid rounds, etc.

She said that as wells became more capital intensive, Shell developed a platform model, accessible across the business, called WellVantage providing a real-time, automated data stream. The business benefits of WellVantage include: monitoring by experts being feasible for most wells, real-time data accessible to experts and around the world, global replication of best practices and faster learning. WellVantage resulted in a reduced number of people at the rig site, shared measuring while drilling/directional drilling resources for multiple rigs, collaboration between geoscientists and well delivery teams for instant decision making, and improved wellbore placement. Automation offered: improved personal process safety, consistency and repeatability of drilling operations, and increased efficiency of drilling operations.

Another challenging area for the industry is the scale of the growth in subsurface seismic data. Bachmann said that Shell was now moving from hundreds of TBytes (1000 GBytes) to more than 10 PBytes (1000 TBytes) per seismic survey. "A PByte of data is like a 250m-high pile of DVDs. A seismic survey that is acquired with five dimensions is now 20 PBytes.

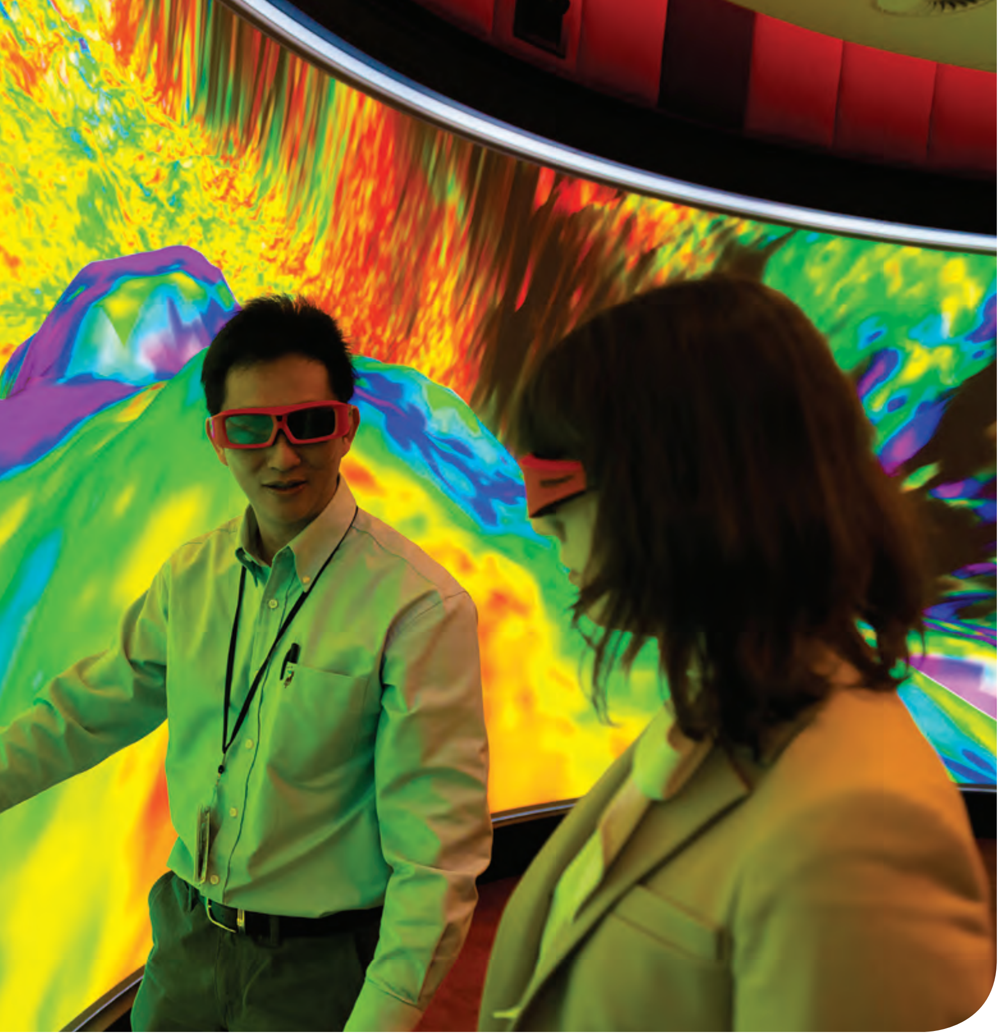
This presents challenges in terms of transport from survey location to processing site. "How you actually bring big data from A to B?" There were also challenges in processing and storage. New satellite developments, new opportunities to develop speed fiber optic communication systems, Cloud developments, and high performance computer capabilities were all being worked on.

Bachmann stressed the importance of E2E (end-to-end delivery) – from development to deployment and support. Three years ago a series of local support and development teams were set up, now numbering 26. These regional teams cover work flow support, deployment projects and data management. The teams can orchestrate the deployment of new software, making sure that the right hardware and operating systems are in place. "That way we have connected end-to-end the developers of the software with the deployers of the software. Once a year we bring them all together."

Exploration success

Shell's methods are bearing fruit, with exploration successes in Malaysia, the Gulf of Mexico and Gabon.

In 2014 in Malaysia, there were nine material discoveries. Two of the largest discoveries, the Rosmari and Marjoram gas discoveries, added 200 MMboe to Shell's portfolio, and overall Malaysia added 300 MMboe. This included a 100% track record in the near-field exploration with five out of five well successes. A cost cutting innovation in the Malaysian campaign had been the use of a shallow water rig to drill a deviated well into a deeper water prospect, thus halving the cost of the rig hire.



Subsurface imaging, but also handling the huge amounts of data now created by seismic surveys and finding ways to share it, have been part of Shell's exploration program. Photos from Shell.

In the deepwater Gulf of Mexico, a big heartland for Shell, there were four oil discoveries last year. These were: the Rydberg oil discovery, the Kaikias oil discovery, Power Nap and Gettysburg. The 100 MMboe Rydberg discovery is in the Norphlet play. Together with the Appomattox and Vicksburg discoveries, this brings the total potential Norphlet discoveries to over 700 MMboe. Kiakas is very close to Shell's existing Mars infrastructure.

In 2014, Shell discovered Leopard 1, a pre-salt offshore deep water gas discovery (200m net gas pay) in block BCD10 offshore Gabon. This is a frontier region for Shell and "potentially a very interesting new arena," Powell says. The intention is to appraise it in 3Q 2015 with the *Globetrotter II* drillship, once it has completed its current assignment drilling the deepwater Şile-1 wildcat for Shell in partnership with TPAO in the Black Sea.

The 41 near-field discoveries represent an 85% success rate. These provide, "TD to cash as soon as possible," says Powell, in areas such as Brunei, Egypt, Malaysia and Oman. "In Brunei, we are now hooking-up wells within 30 days of finishing the well." In Oman, Shell added 150 MMbbl of new oil last year from an 11-well campaign.

New plays

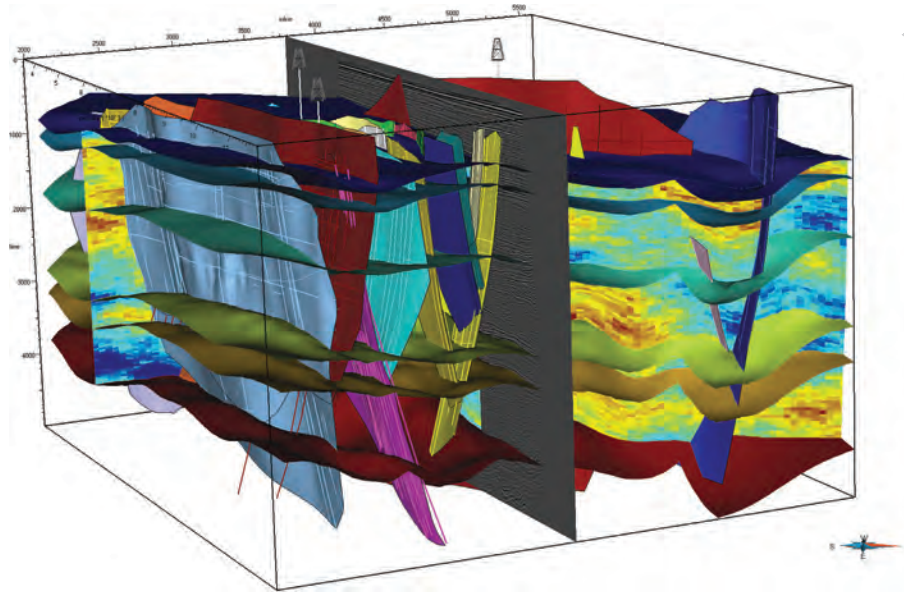
New country entries in 2014/2015 have been Namibia, Myanmar and Algeria. Shell is in the first phases of deepwater exploration offshore Namibia and Myanmar, working through geology and geophysics, and acquiring seismic.

Namibia, on the Atlantic Margin, is a good example of the global connectivity of the subsurface. There is renewed interest in exploration onshore, partly because of technological advances in seismic imaging. Shell has recently entered Algeria with partner Repsol, acquiring a licence in February 2015 in the Atlas Mountains. In Oman, the company is carrying out wide azimuthing surveys onshore. There have also been successes in Albania and Egypt.

Shell is still preparing to drill offshore Alaska, but there are no timings available at this point. It will depend upon the permitting requirements, the legislative requirements and whether Shell is confident at the senior level that it can explore safely and responsibly, the company said.

Powell is aware the hurdles ahead. "I am also very conscious of the fact that in 2015 we enter into another phase of volatility within the oil price," she says. "It's part of our job to manage through those cycles of volatility, to make sure we don't lose capabilities. We don't lose sight of the long-term." Deepwater discoveries can take eight, 10, 12 years before they move into production. OE

Structural modeling in unconventional reservoirs



Build accurate reservoir models in the presence of complex faults. Images from Paradigm.

Efficiency, cost-effectiveness and optimized analyses are crucial in upstream asset development. OE spoke with Paradigm's Indy Chakrabarti to chart the pathway to success. Jeannie Stell reports.

Given today's low oil and gas prices, exploration and production companies must strive to be ever more efficient and cost-effective in the creation, execution and analysis of their asset development plans. Companies that manage these activities successfully will outlast the bust. Those that don't will likely not survive as viable entities — as the industry has already seen.

At the start of any successful asset development plan, managers must consider the five aspects, or domains, of exploration and production. These include: processing and imaging; interpretation and data management; modeling and reservoir engineering; formation evaluation; and drilling and well planning.

This end-to-end workflow identifies: where to drill, where to land the well, the analysis of production over time, and optimized decisions about future development (i.e., where to drill next).

"At Paradigm, we have brought all of that together in a single, unifying software platform suite we call Epos," says Indy Chakrabarti, senior vice president of product management and strategy for Paradigm. "This technology allows individual applications for each specific domain to be are cross-integrated with each other through Epos."

Indy Chakrabarti

Typically, managers and geoscientists seeking new software tools for analyzing their asset environments focus on cost savings, infill drilling, and high-grading prospects. In today's economic environment, getting these management planning decisions right is crucial, as each has significant cost implications.

Conversely, overall financial concerns have very little influence over software purchase decisions. "The cost of a manager's decision about where to drill, how to get rigs, and when to contract seismic boast, is 100-fold greater than the choice of a particular software tool to help make those decisions," Chakrabarti says. "Even a 1% gain in a major asset management decision will easily compensate for the cost of any software tools. As a result, in times like these, managers tend to go up the hill, technologically speaking."

Production and enhanced recovery trends

The critical need for organizations to understand sweep efficiencies and bypassed compartments. "What did I miss?" That question is critical when margins are thinner, Chakrabarti says. "It's essential for you to have all the information that can tell you what your subsurface actually looks like," he says. The placement of an injector must be evaluated against how much oil it can actually make contact with, mobilize and push toward the recovery well.

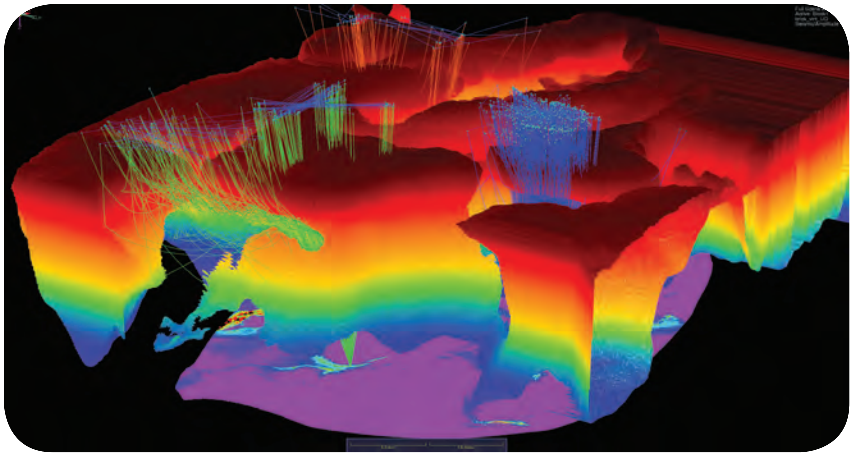
Because the subsurface is heavily fractured, compartmentalized and fault-riddled, geoscientists historically would remove complexities and simplify their image of the subsurface, treating it more like a big tank than a reservoir, Chakrabarti says.

"Then they would run production for whatever they could get. The fact that they might have placed an injector on the wrong side of a fault meant that some of the CO2 never reached the reservoir of hydrocarbons," he says.

Now, managers are very focused on how well their technical software allows them to "see" the subsurface effects of their development operations. "That clearer image of the subsurface makes a big difference when you are attempting to optimize production," Chakrabarti says.

Optimized planning and production

Targeted at solving these issues, both the Paradigm 14 and 15 software releases are pointed in the same direction — the industry's first high-definition (HD) platform. "One of the most acute problems occurs when companies acquire rich seismic data, but don't have software tools that can meet



Understaind subsalt uncertainty through illumination study.

the scale and the new user-interface changes that have to be made, and new outputs that have to be delivered." Paradigm has built a four-step solution to meet that challenge.

In step one of the Paradigm software platform, high-end computational tools use all available data to process an image and build an accurate image of the subsurface.

In step two, geoscientists can interpret the data and therefore make sense of the image, he says. "Once the image is understood, analysts can zoom into the data down to the narrowest band of the reservoir, and be able to understand the specific lithologies and variations that couldn't be seen before."

Step three is about modeling. Ultimately, geologists want to be able to create a truly accurate and detailed representation of the subsurface.

The fourth and final step is to create a simulation that can answer the question, "How much of this reservoir do I think I can produce?" Since the simulator simply runs an algorithm, a successful output depends upon the input being a more accurate representation of the subsurface.

"That's what the HD platform does," Chakrabarti says. "On one end, it receives this advanced, rich seismic data. And on the other, it outputs an accurate, granular model that can be used to forecast production." Paradigm continues to focus on very high resolution billion-cell subsurface models.

Case study

To illustrate the effectiveness of the new technology, Chakrabarti details a case study conducted to characterize, model and flow simulate a non-conventional fractured basement reservoir located offshore Vietnam.

The challenge

A new reservoir modeling and simulation workflow was needed to prove that the complex structure of the field and its properties could be represented, and its dynamic behavior reproduced. Predictions of production using standard reservoir simulators had been problematic, because different flow laws apply to fractured rocks, and inclined narrow faults are difficult to represent at field scale.

The assessment

The field contains complex intersections between faults (Y and X contact shapes, etc.), between horizons and faults (reverse faults, important offset of the basement on the flanks) and between horizons (converging small angle contacts between the top of the basement and the sediments lying on its flanks). Since results to date using standard tools had not been sufficient, the decision was made to use Paradigm SKUA modeling software to build a structural framework model that properly honors fault intersections.

The solution

For this project, only a sector scale model (12.5km by 4.5km) was studied. A total of 53 original fault interpretations were included and no faults were excluded when modeling the data with the SKUA system. Faults were loaded as fault sticks from an ASCII file.

Most of the faults had not been assigned any throw type, mainly because their throw was too small to make a decision. Some faults were identified as reverse, about 10 others were identified as normal. This extra information was used as a constraint in the SKUA modeling process.

The top basement interpretation was loaded as a CPS3 regular 2D grid (resolution 25m by 50m). The interpretation of the top of the sediment contained points (resolution 300m by 300m) loaded from the ASCII file. Contact curves between the top basement and sediments, corresponding to non-depositional curves, were used to constrain the modeling of the sedimentary layers.

Watertight models are an important prerequisite for volumetric meshing as part of the simulation workflow. Structural models generated in SKUA are watertight, meaning that they are composed of surface-delimited sub-volumes in which the surfaces are perfectly welded together without any holes. This structural model can be transformed into a set of triangulated surfaces that share nodes on the contact lines.

The modeling of the top basement and top of sediments was performed in a single operation. The contact of the sediments on the top basement was handled automatically through the use of the stratigraphic column (unconformable contact between the basement and the sediments) and the non-depositional curve. The resulting horizons were smooth and clean, while the complexity of the fault network was preserved.

To avoid very small or degenerate elements in the triangulated surfaces, which would produce holes or overlapping elements in the 3D grid, fault throws smaller than a given target refinement-based threshold (5m for the sector scale model) were merged. This was done automatically in SKUA with the creation of the triangulated surfaces.

The results

The sector scale model was generated in less than a week. No structural model had ever been built for this field before this study, as no software could properly handle representation of the faults.

By creating the structural model and performing the QC on the seismic data together with the geophysicists, many refinements and updates could be made to the existing interpretation. Questions about fault extensions within the sediments could be answered for the first time. Thanks to the preservation of all the faults in the model and the analysis of their vertical and lateral extent from the basement to the surrounding sediments, precise flow pathways were identified in the reservoir. This is critical for field development, and had not been possible using other existing tools. OE

*Data courtesy of NFR Studies.

Improved chelant stimulation sustained production gains

Halliburton Energy Services' Harvey J. Fitzpatrick, Jr. shows how wellbore stimulation fluids can increase production.

Mature fields present significant opportunities for increased production with lower overall expenditures. Opportunities for enhancing production in existing fields follow the oil industry dictum, "the best place to find oil is where you have already found it."

Many wells have production rates that are limited by near-wellbore permeability damage or restrictions to inflow caused by flow-impeding solids accumulation. These wells can be identified as "under performers"—wells whose production doesn't live up to their potential or whose production has fallen below what their reservoir pressure potential would indicate. Consider the opportunity offered by using remedial near-wellbore stimulation solutions to provide immediate economic impact by enhancing production from mature assets. Mature fields hold greater than 2.4 trillion bbl of known oil reserves and, currently, more than 70% of the world's oil and gas production comes from mature fields.

Halliburton's acidizing technology developments were commercialized as two integrated stimulation system platforms. Sandstone 2000 acidizing service fluid systems and the engineered treatment design approach used with them combined a consistent method of design with fluid systems specifically tailored to sandstone reservoir characteristics and targeted to their damage mechanisms. The Carbonate 20/20 acidizing service engineered workflow and fluid system series provided the tools to design treatments focused on carbonate reservoir rocks and flow potential characteristics for optimum results. The Carbonate 20/20 service used reservoir understanding and design tools focused on the reservoir rock characteristics to select from a suite of carbonate acidizing systems and engineered treatment processes. These technologies combined the stimulation knowledge obtained by chemical technology development and innovation in fluids formulation with a better understanding of reservoir mineralogy and flow characteristics parameters to provide a step change in acid stimulation production improvement reliability.

Many areas hold opportunities for near-term uplift in mature production if promising candidates are identified and the treatment design is suited to the well's stimulation requirements. Often, underperforming wells can be selected, but developing a stimulation treatment for them with a high assurance of success might be more challenging. More often, crucial reservoir mineralogy information required for the stimulation design is not available or is costly to obtain. Additionally, for sandstone reservoirs with moderate carbonate or highly sensitive clay content, successful acid stimulations are at greater risk. For wells with more extreme reservoir conditions (high-pressure/high-temperature), risk-weighted economics for the stimulation candidate might not be favorable because of concerns about corrosion to downhole equipment. High-temperature reservoirs or expensive metallurgies can contribute to unacceptable corrosion rates with conventional acid stimulation fluids. In this type of well, conventional hydrochloric- (HCl-) based or organic acid stimulation fluid treatments can provide a potential for gain but that might not outweigh the risk of a lost well or the cost of an unpredictable result.

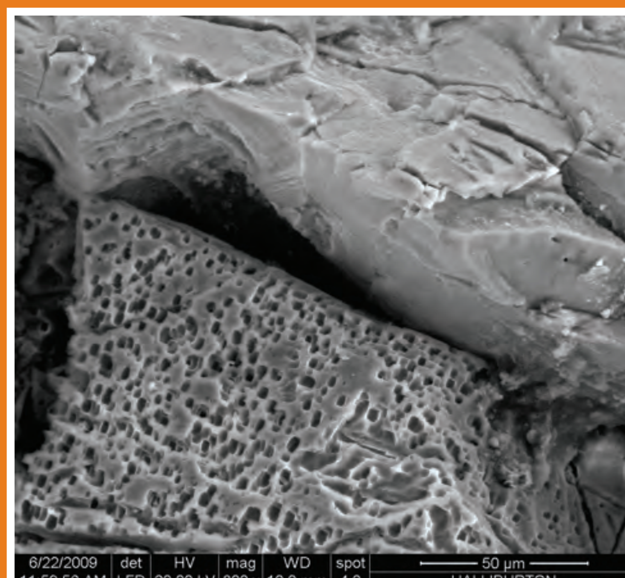


Fig. 1—Example of acid-etching properties of SandStim service. The service provides the performance of traditional HF acid blends but in a simpler and safer formulation. Images from Halliburton.

Fortunately, new chemical stimulation technology advances offer better alternatives for wells with mineralogy or corrosion characteristics unsuitable for acid stimulation and for wells with insufficient reservoir mineralogy information necessary to determine a reliable acid stimulation treatment design.

Chemical stimulation technology

Chelant-based stimulation fluids from Halliburton, such as SandStim for sandstone reservoirs and KelaStim for carbonate reservoirs, constitute the next step in chemical stimulation. Chelant technology enables more reliable

treatments deliver

sustained production results but requires less complexity in fluid selection and treatment design compared to acid-based fluids (Figure 1). Technology built into Halliburton's chelant stimulation fluids enables optimized treatments for a broad range of reservoir and well characteristics. Treatment design is less complex because chelant technology accommodates a broad range of mineralogy. The risk of collateral damage from spent fluid is significantly lower than from acid-based treatments (Figure 2). Successful stimulation is achieved more reliably.

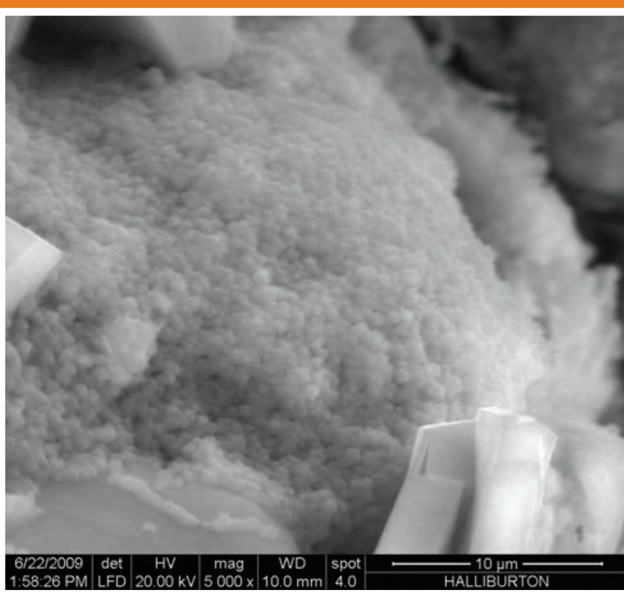


Fig. 2—Example of extensive matrix damage as a result of fluorosilicate precipitation that can be caused by conventional HF acid blends. SandStim service can remove damage in the formation with less risk of further damage or rock deconsolidation.

Hazards associated with reservoir damage, tubular and well equipment corrosion, and health, safety, and environment (HSE) concerns can be significantly reduced. Successful results are obtained with greater reliability. Chelant stimulation fluid systems provide the following benefits:

- Treatment design is simplified. Chelant stimulation technology helps reduce risks of concurrent treatment damage with solubility control for spent-treatment fluid.
- Potential damage can be minimized when stimulating formations of uncertain mineralogy.
- Heterogeneous or layered formations can be stimulated without the risk of precipitating dissolved ions or chelant-metal ion complex, with less risk of sludge formation and rock deconsolidation.
- Less risk exists of deconsolidating friable formations; these fluids can provide deeper penetration of live stimulation fluid in carbonate reservoirs.
- Their superior complexing capacity helps reduce post-stimulation damage from spent fluid precipitates.
- They can be used in wells with higher carbonate concentrations; it is recommended to use them with sandstone formations over 5% soluble carbonate content.
- These fluids can be used in a wide temperature range (120-350°F for SandStim service; 120-400°F for KelaStim service).
- Typically, they are less corrosive than traditional HCl and hydrofluoric (HF) acid blends.
- Their inherently safer chemistry has reduced HSE risks compared to traditional HCl and HF acid blends.

SandStim and KelaStim services have shown better sustained production improvement in mature wells compared to convention acid treatments in the same well or offset wells.

SandStim case study

An operator in the Gulf of Mexico (GoM) recently required removing barium sulfate scale and formation damage from a sandstone reservoir. Halliburton conducted laboratory tests to evaluate using a combination of the new SandStim_ service chelant-HF acid stimulation system placed with coiled tubing and the Pulsonix TFA acoustic stimulation service to help maximize the effectiveness of stimulation for this gravel pack completion. To be successful, the treatment was required to mitigate damage from both scale and fines damage at the gravel pack to reservoir interface while reducing or eliminating the risk of precipitation damage from spent fluid remaining in the low-pressure reservoir.

The Halliburton consulting and project management team managed logistics, personnel, and technology requirements for the operator. Pulsonix TFA service, Halliburton's fluidic oscillator stimulation technology, was selected to enhance the efficiency of contact of the treatment with the damaging materials in the gravel pack and well-reservoir interface. Pulsonix service was incorporated to place 100 gal/ft of a SandStim service fluid blend across a 167ft interval that has been in production since 1996.

The SandStim service chelant/HF-acid blend has a relatively high pH compared with more commonly used acid blends. To help reduce hazards associated with tubular and well component corrosion, Halliburton's production enhancement technology team created a corrosion inhibition testing protocol, and together with their chemical stimulation specialists, developed and tested an optimized additives package for the treatment. The well tubulars were hydroblasted to remove barium sulfate scale. Solids were not observed in high concentrations in the returns flow; however, upon draining the return fluids tank, measurements showed that 67cu ft of solids had been removed from the internal diameter of the wellbore tubulars.

The vessel support teams from Port Fourchon, Louisiana, and New Iberia, Louisiana, loaded Halliburton's marine vessel, *Stim Star III*, with approximately 72,000 gal of stimulation fluid. The vessel arrived eight hours ahead of schedule. After a safety briefing, the crew rigged up and placed the treatment using Halliburton coiled tubing with the Pulsonix TFA service.

InSite Anywhere fracturing and stimulation services software enabled multiple stakeholders to remotely view the pumping operations in real time and allowed the chemical stimulation technology team to monitor the treatment progress from the Houston Technology Center.

Using all Halliburton equipment, operating efficiency throughout 36 hours of constant pumping was 100%, and the crew set a record for stimulation pumping time in the GoM.

Because of low bottomhole pressure, the well was jetted with nitrogen to enhance flowback and fluid recovery. The cleanup flowback recovered almost 100% of the treating fluids, from which samples were taken for analysis at Halliburton's Houston Technology Center.

The operator then placed the well on the platform gas lift. Over the next several days, with an optimized choke size and gas lift injection rate, post-treatment production more than tripled the pre-treatment hydrocarbon rates.

During the entire offshore operation, no Bureau of Safety and Environmental Enforcement (BSEE) incidents of non-compliance, recordable incidents, or accidents occurred.

Fig. 3—Example core samples showing treatments with KelaStim service (left) and acetic acid (right) at 350°F. KelaStim service has less risk of formation damage than acid-blend fluids.

KelaStim service in Angola

In the offshore waters of Angola, a principal operator was losing production from one of its best wells. Well history showed various degrees of scale and halite buildup, causing a significant decrease in production. Five previous HCl-/acetic-acid blend treatments had provided only short-term increases, failing to sustain higher levels of production.

The operator engaged Halliburton to provide a stimulation design that would deliver a sustained production increase. The treatment for the tubular scaling and near-wellbore area damage mitigation had to be tailored for the removal of halite, iron carbonate, and calcium carbonate scale over a 2400ft (731m) perforated interval, with bottomhole temperatures exceeding 300°F (149°C) and a low bottomhole pressure. Because of the low reservoir pressure, slow and inefficient treatment fluid recovery had been experienced after previous treatments.

Testing on area cores revealed HCl-/acetic-acid blends to be highly reactive on the very heterogeneous lithology under reservoir conditions. Core testing indicated this acid system caused a considerable level of rock deconsolidation and non-uniform stimulation of the core flow characteristic. A different approach was necessary to optimize the treatment design for more sustained higher production by reducing fines release from deconsolidation, by providing more uniform penetration of stimulated flow area around the wellbore, and by reducing concurrent precipitation damage from unrecovered treatment fluids.

The treated cores were submitted to computer tomography (CT) analysis of the stimulated flow patterns after core flow testing to help visualize how the different treatments manifested improved flow. CT analysis helped confirm that the conventionally treated cores experienced isolated areas of high dissolution. Whereas, the chelant treatment provided uniformly distributed enhanced flow capacity throughout the core volume with little or no deconsolidation (Figure 3). Following this and other rigorous qualification testing of the treatment formulation on the reservoir cores, Halliburton proposed using the new KelaStim service. Compared to other treatments tested, KelaStim service delivered improved overall stimulation results with a range of core samples at different depths and varying mineral composition. The recommended treatment design incorporated KelaStim service combined with BioVert biodegradable diverting material to provide more uniform stimulation across the entire perforated interval.

Pre-job analysis, evaluation, and design of the treatment solution developed from accurate formation data and core analysis coupled with the technical expertise and synergy of all participants proved successful in the treatment results. The treatment was executed safely and according to design. After stimulating the well with three stages of KelaStim service separated by two stages of BioVert diverter material, production was monitored for 90 days to evaluate the long-term response.

The enhanced production realized with the KelaStim service proved to be significantly better than with previous treatments. Average daily production increased 35% during the 90 days, adding over 31,000 bo to production and US$2.6 million in additional revenue to the operator's bottom line.

Compared with previous acid stimulations, KelaStim service delivered four noteworthy technical benefits: (1) improved iron stabilization from the dissolved scale and tubing pickle to help minimize collateral treatment damage; (2) increased depth of stimulation and reduced risk of rock deconsolidation, for a more sustained stimulation effect; (3) uniform rock matrix stimulation; and (4) lower corrosion potential and greater temperature stability.

To date, the well continues to produce at a stimulated rate, and the operator is screening candidates for treatment using KelaStim service in other wells in the area. **OE**

Harvey J. Fitzpatrick Jr. *is production enhancement frac/acid product manager for Halliburton Energy Services in Houston. His 36 years of well construction and completion experience span positions including field engineering, on-site supervision, sales, global technology advisor and management.*

He is inventor or co-inventor on 14 patents and is author or co-author on 33 technical papers or journal articles and has served on a number of industry technical program committees. His BSChE degree is from Tulane University.

Advances in technologies for additives and fluids

Drilling in deeper waters calls for more advanced technology. Mark R. Luyster provides an overview of recent fluid advances for the completion phase of deepwater projects.

The industry has evolved in the last decade to further drilling and completion fluids that can attain the required density and integrity for deepwater Gulf of Mexico projects. However, the desired parameters or objectives for such systems breach the density and environmental limits, and challenge the industry to develop fluid systems that ultimately reduce the risk of failure. While proven technology reduces risk, the following article includes a few potential advances with respect to the selection of the required fluid systems and additives for these deepwater prospects, which will also require greater volumes during their development phase.

Data from the US Bureau of Safety and Environmental Enforcement (BSEE) from 1990 to present shows a relative increase in the number of discoveries between 1998-2002 (Fig. 1), approximately 32 per year while discoveries after 2002-2010 range from 8-19 or 12 per year. BSEE's data shows a marked decrease in annual discoveries after 2010 (the year *Deepwater Horizon* happened), four per year. However, BSEE's data also shows a marked increase for the water depth of these discoveries nearly 1000ft for each of the aforementioned periods starting with 1998-2002. If the same data is normalized for discoveries in water greater than 4600ft (Fig. 2) there is not only a relative increase as expected but all the discoveries for the period 2011-2013 are 100% of this baseline as they represent water depths from 5440-8553ft. It follows that the subsequent appraisal and development wells from 2003-2010 and

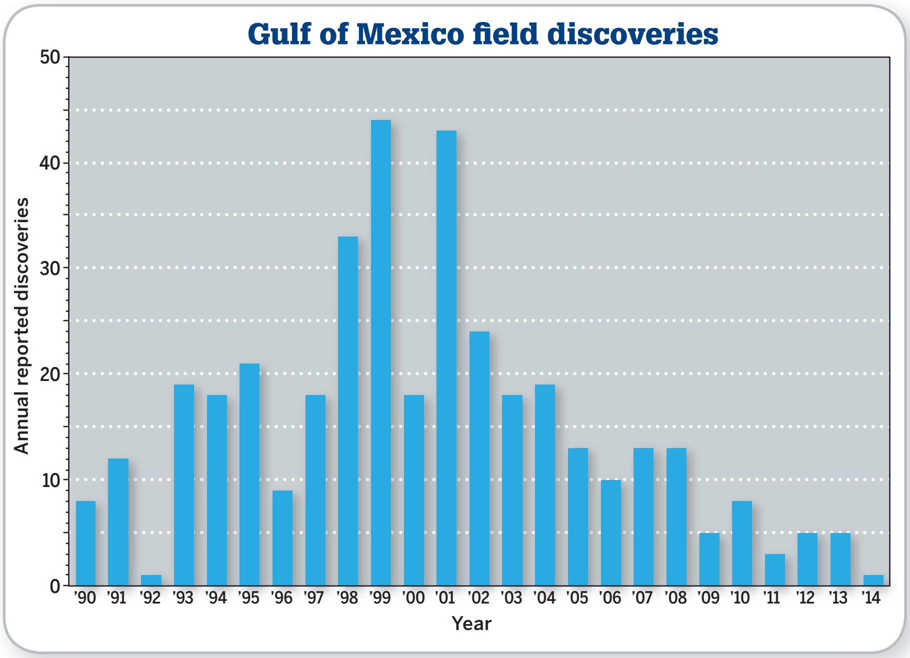


Fig. 1 - Water depths greater than 4600ft. Source: BSEE.

the near recent discoveries will require proven and new technology to develop and advance the infrastructure, drilling and completion phases. These phases may well require technology that has not been devised, which contrasts with proven technology that serves to reduce risk.

During the period between 2003-2010, the Gulf of Mexico realized exploration drilling, appraisal and development in water as deep as approximately 9575ft. Some of these prospects exhibited potential hydrocarbons/reserves estimated greater than 6 billion boe and operators projected field life up to 40 years. In the last few years, some of these prospects are now realizing initial production while several are pre-planning for their development phase. One area of technology that will play a role to successfully complete these prospects is the required fluids and the additives and products that are used to formulate these fluids; also referred to as systems. Specifically the systems required to drill and complete in the target reservoirs.

Several discoveries from the period 2003-2010 are now either advanced with respect to planning for first oil or realized first oil with one or more completions. Recent reports show more than 40 prospects that may realize first oil in the next few years. The maximum measured depth to attain the target reservoir for the appraisal and/or development wells approaches 32,000ft. These target reservoirs range in age from lower Miocene to Eocene-Paleocene to Upper Jurassic or approximately 33-65 million years to 160 million years for the latter. The reservoir temperature for the Miocene can exceed 200°F while the Eocene-Paleocene reservoirs can approach 250-270°F and the Upper Jurassic over 300°F. The uncompleted reservoir pressures for the Miocene prospects may exceed 20,000psi while the Eocene-Paleocene can exceed 22,000psi. Thus the equivalent density for these reservoirs range up to 14.5 lb/gal whereby a required drilling or completion fluid approximates 15.5 lb/gal. These reservoir parameters dictate a need for drilling and completion fluids (and their associated additives) with relatively greater density and superior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integrity to reduce the risk of failure in these deeper prospects. Their failure can result in extended non-productive time and subsequent precipitous costs for apparent reasons.

Environmentally benign drilling and completion fluids and any associated additives are primary to reduce risk in the event of unanticipated spills. With the mandate of utilizing the safety data sheet format (full compliance by June, 2016) versus the previous material safety data sheet a more uniform/identification of the substance/mixture is required. This simplicity of transparency should assist with the planning/decision process. The use of non-chloride brine as well as eliminating chloride from the internal phase of an oil-based fluid is another step towards a more benign fluid. Biodegradation of cuttings produced from oil-based fluids has potential to reduce impact and disposal costs when a synthetic biodegradable external phase is used. This is yet another advancement that can reduce the impact on the environment, land and sea.

However, when one considers the density requirements for these deepwater prospects, especially the completion phase, a very short list of commercial brines: calcium bromide, zinc bromide and formates (K, Na, and Cs) are available. To further, when one considers the relative lack of Gulf of Mexico infrastructure (e.g., dedicated tanks, lines, etc.) and the ability to supply formates at the anticipated required volumes, the list is even shorter. And considering that zinc is a priority pollutant the use of calcium bromide may be the more prudent choice.

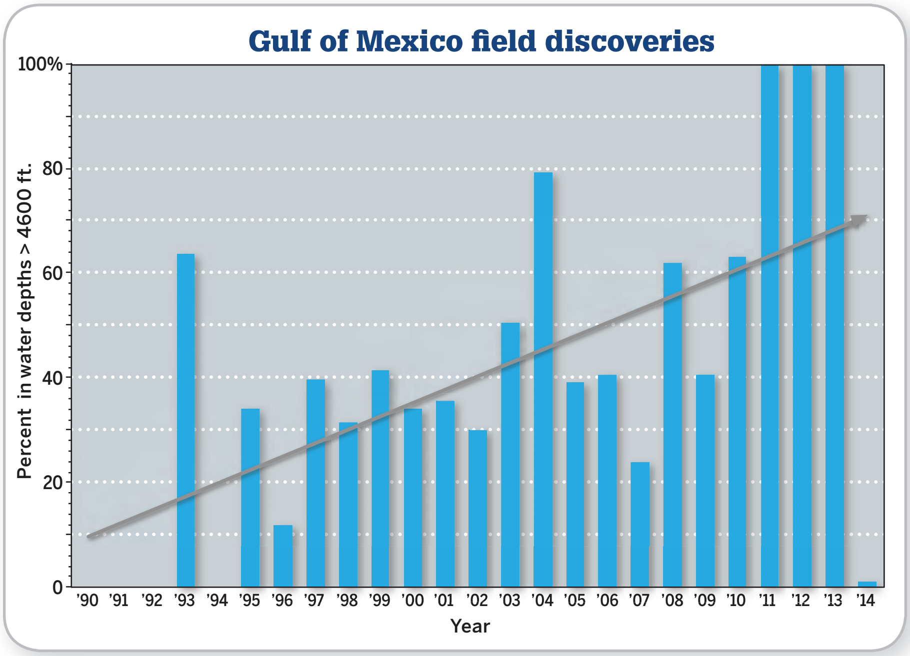

Fig. 2 - Water depths greater than 4600ft. Baseline established using deepest TLP, Magnolia-ConocoPhillips. Source: BSEE.

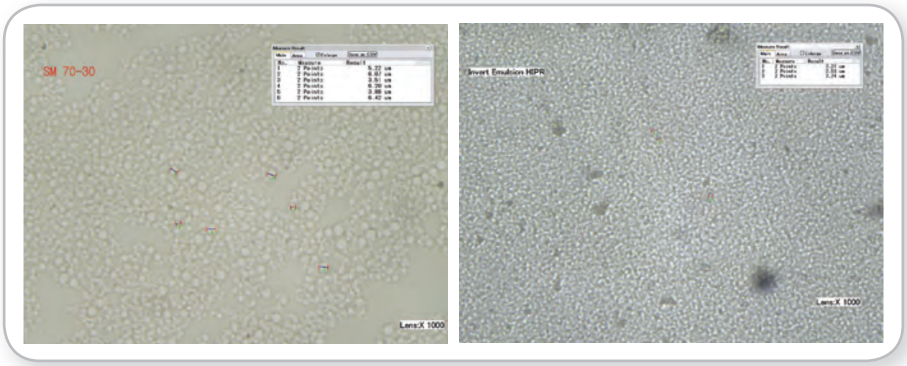

Fig. 3 – Digital images compare aqueous droplets in the oil continuous phase for a conventional 70/30 OWR (left) versus an invert emulsion HIPR 30/70 OWR (right). The HIPR emulsion provides a more uniform and compact invert emulsion with smaller droplets even at 70% v/v brine. Photo from SPE Paper 144131.

For the drilling phase, the use of calcium bromide as a base for a fluid system to drill the target reservoir is well documented (Horton, SPE68965, 2001). However, if incorporated as the internal phase of an oil-based system there are potentially more problems (e.g., gelation) than benefits (e.g., density). The combination of calcium bromide brine and non-barite weighting agents may provide a relatively higher density drilling system that is relatively benign to the environment for these deepwater prospects. In addition, the use of an oil-base system to drill the target reservoir alleges professed damage mechanisms, which include barite to attain the required density and the use of clay for viscosity as well as emulsifiers and wetting agents. However, recent advances may well alleviate these concerns. These include:

- High internal phase ratio (HIPR) oil-base systems. These systems use a unique emulsifier to attain oil-water ratios as low as 20:80 **(Fig. 3)**. At this oil-to-brine ratio a greater volume of divalent brine, which is compatible, comprises the internal phase thus this brine mass replaces a portion of the solids mass, which extends the maximum density (Lim, AADE, 2011). In addition, these systems are stable to temperatures above 300°F.
- Organophilic clay-free and lignite-free oil-based systems can mitigate damage as well as allow for more control of mitigating the ECD.

The modeling of bridging solids for a fluid system (drilling or fluid loss pill) used to effectively seal the target reservoir thus reducing losses of whole fluid and/or filtrate is well documented (Dick, SPE58793, 2000 and Chellappah, SPE151636, 2012). These solids are typically barite and calcium carbonate. The technique to model and confirm a bridging solids blend can, in part, strengthen the wellbore and alleviate pipe sticking and losses. However, the key is to manage these solids and their size distribution while drilling to the target depth.

In addition, selected solids can be added as background material to reduce losses and/or strengthen the formation while sealing induced or inherent fractures. A proactive plan is best versus

reactive as addition of solids with no prior planning can cause additional problems and even invoke reservoir damage. While these typical bridging solids are available in a variety of grades there are relatively new materials that may provide advantages for these deepwater prospects:

- Bridging solids with a greater specific gravity than calcium carbonate can be incorporated in a fluid system. For example, magnesium oxide or complexes of manganese oxide thereby increasing the maximum density of the system.
- Bridging solids can be incorporated that reduce rheological properties, such as micronized or ultra-fine barite or calcium carbonate (versus API barite) whereby the ECD of the fluid system is reduced thus the maximum density is essentially extended. The particle size distribution of these types of solids helps, in part, to alleviate sag.
- Bridging solids that are hydrocarbon-soluble (**Fig. 4**) can be incorporated into a brine-based drilling system that eventually incorporates into the residual filter-cake and then dissolve when the well is initially produced. The hydrocarbons from the reservoir provide the mechanism to partially-completely dissolve these solids. This approach may alleviate treatments used to remove the residual filtercake or costly post stimulation treatments to remove near wellbore damage.

Fig. 4 – Hydrocarbon soluble solids.
Image courtesy of Patrick Roberts of TBC-Brinadd, LLC.

Concurrent with the potential of unanticipated or uncontrollable losses while drilling or running casing; fluid loss pills are available and can be formulated to a desired texture (e.g., soft to rigid) or density (up to 20 lb/gal) and the ability to control the set time provides flexibility during the drilling and completion operations. These cross-linked pills can set in relatively low temperatures (approx. 32°F) and high temperatures (approx. 300°F).

High temperatures can invoke settling of solids as the designed fluid systems viscosity degrades. The often unanticipated degradation whereby the inherent and drilled solids can no longer suspend results in the accumulation of beds that interfere when drilling and running drillpipe. These beds, if not removed, can potentially plug the lower completion assembly (e.g., sand control screen) when running to target depth. What planning teams may request are longer test periods for simulating static and dynamic conditions in the wellbore to confirm a fluid systems' integrity. There are several mechanisms available to mitigate viscosity degradation, however, some must be carefully addressed as they can impact other desired parameters. For brine-based systems, synthetic viscosifiers are one option; however, these may impact formation damage. Wellbore temperature changes can also influence a fluids viscosity such that it is too viscous. Systems, especially oil-based, can be optimized to maintain viscosity through the temperature changes from surface to seafloor to the bottom hole whereby a flat rheology profile is maintained to mitigate fluctuations during dynamic and static conditions. This alleviates pressure spikes and progressive gels and aids in controlling the equivalent circulating density (ECD).

An appropriate fluid density will promote a mechanically stable wellbore when drilling encounters "soft" shale rock however reactive shale minerals can impart a chemically unstable wellbore. In the case of the latter the proper choice of base brine and/or additives can help alleviate. Upfront planning that includes testing, when whole core is available, for worst-case static periods can confirm the effectiveness of needed additives.

However, shale rock can be different from area to area thus a fluid system may require customizing. Soluble additives such as amine based or nanoparticles may provide sufficient inhibition in some shales. In some wells/areas the proper choice of the water activity of the brine alone can provide sufficient inhibition; however, this also limits density and unanticipated changes to the working density.

While oil-based fluids are readily lubricious due to their external phase, lubricant additives for brine-based fluids can reduce their friction nearly equivalent to oil-based while mitigating cheese and grease effects that are common due to the incorporation of fine solids, temperature and shear.

Products that are used to maintain oil-based drilling fluids properties are typically added in the field as a liquid. Some of these additives are now available as solids and this may reduce the volume required to transport, store and even reduce the number of lifts required to transfer products to a rig/platform.

Dual gradient drilling could erase the effect of water depth on offshore drilling and enable operators to reach reservoirs 40,000ft below the sea floor. This technique is similar to managed-pressure drilling and uses seawater density fluid in place of the drilling fluid that would ordinarily flow through a riser while using a denser drilling fluid at the bottom of the well to maintain bottom-hole pressure. **OE**

***Mark R. Luyster** is vice president of technology development for TBC-Brinadd, LLC, of Texas United Chemical Co. He worked for Chevron Production Co. for 13 years before assuming project and lab manager positions with MI-SWACO (a Schlumberger company). During this period he worked in China, Angola, Equatorial Guinea, East Canada, South America, Gulf of Mexico and Alaska.*

He served as global technical service manager for the completions segment for the last six years before assuming his position with TBC-Brinadd. Luyster has invented or co-invented nine US patents and has 16 applications pending that involve breakers, fluid treatments, viscosified agents, chelates, invert emulsions and delay mechanisms. He holds a B.S. in geology from the University of Akron.

Laser drilled sandstone core sample.
Images from ZerLux Hungary Ltd.

Engineers work on perforation tool

Laser-like precision

Jerry Lee and Greg App examine how lasers could be used for not just drilling, but for completions and well intervention projects, too.

The oil and gas sector is constantly seeking innovations to improve economic efficiency, particularly to decrease the high costs associated with drill bits and non-productive time (NPT). This need for continuous improvement helped spark the first phase of the Gas Research Institute (GRI) funded research program aimed at utilizing high-powered lasers for drilling. Following the release of previously classified information from the US Defense Department's Star Wars Laser technology in the mid-1990s, some in the oil and gas industry have developed an interest in harnessing the potential of laser drilling.

The primary advantage of utilizing lasers lies in cost efficiency. In traditional drilling operations, progress is often halted by the replacement of worn-out bits, stuck pipe and other inevitable malfunctions. Halting operations results in lost time and money. Another key method of reducing expenditure is the reduction of rig rental time. NPT is significantly reduced by removing the vast array of mechanical components associated with traditional drilling operations, the time associated with tripping in and out and replacing or repairing components. Efficiency is realized due to the continuity of the laser drilling operation. Once the operation begins, there is no bit to replace, and thus less cause to trip in and out. A laser drill can remain operational as long as there is an available power source.

Further progress toward commercializing laser technology was spurred by the automotive industry. This investment resulted in the cost of 1W of laser drilling power dropping from US$1000/W to less than $50/W. Another major obstacle cleared was to prove that laser drills are not limited by the type of lithology.

There were also problems with the use of fiber optic cables due to Stimulated Brillouin Scattering (SBS). "[SBS] chokes off the transmission of high power laser photons in a fiber optic cable by reflecting the energy backwards to catastrophically destroy both the fiber optic cable and laser source," says Foro Energy. However, with the introduction of SBS resistant fiber optics, the issue has been resolved. Additionally, current laser drilling developments have seen power availability increase from 1kW to 1000kW, as well as improvements in unit mobility and durability.

Yet, despite these advances, government funding for laser drilling research at institutions such as Argonne National Laboratory (ANL) has been cut. In response to this lack of government support, various private organizations have built upon the progress already made. For example, Foro Energy, the company responsible for the development of the SBS fiber optics, was formed by members of the original laser drilling research partnership between the Colorado School of the Mines and ANL.

Initially, two methodologies were considered for the laser drilling drive mechanism: rock melting or the spallation of the grains. Spallation occurs when laser-induced thermal stresses are applied to the grain causing it to fracture; however, the amount of energy applied by the laser must be low enough to keep the local temperature below the melting temperature. Depending on irradiance, or power per unit area, the laser rock interaction can cause the grains to melt or spallate.

"The most efficient way to laser drill through sandstone is spallation, where laser energy is used to break the bonds holding the grains together, creating loose sand particles," says Neal Skinner, senior scientific advisor at Halliburton. The grains are then removed to expose the next layer of rock.

"Shales also spall in a manner similar to sandstone. Limestone, however, is mainly calcium carbonate and undergoes


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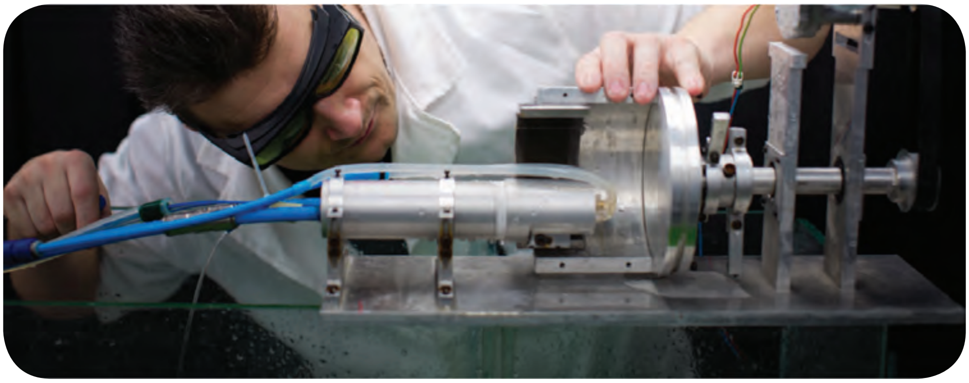
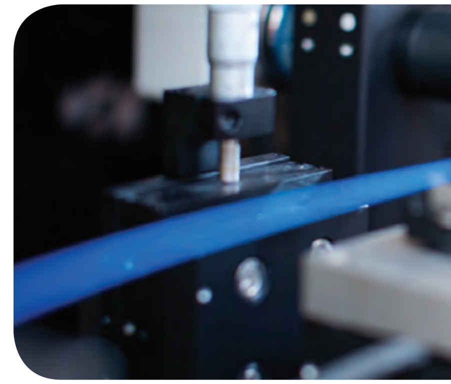
DRILLING FLUIDS



Hard scale removal test.



Fiber optics at work.

a different process for laser removal,” he explains, adding that under temperature, limestone dissociates into calcium oxide and carbon dioxide [$CaCO_3$ -> CaO + CO_2]. “Calcium oxide is a white powder and easily purged from the hole with gas or liquid.”

Contemporary application

The technology and the benefits surrounding laser drilling are enticing. However, economics are usually the governing factor when making decisions in the oil and gas industry. Currently, implementing laser drilling technology is not as cost effective as conventional drilling.

“The issue is economics,” says Dr. Peter Bajcsi, COO at ZerLux. “It simply makes no business sense to deploy lasers to drill big vertical boreholes. Conventional drilling is still more economical to drill long laterals because the technology already exists. Conventionally drilled laterals improve the productivity of the wells and even connect two pay zones, so that’s not what we’re after.”

With the associated equipment, supplies, and services being readily available, drill jobs can be undertaken less expensively by conventional methods. The industrial logistics necessary for industry-wide laser drilling applications do not yet exist. Due to this limitation, the current focus of laser technology is on well completions.

“Laser perforating has its own value proposition and is easier than laser drilling. A certain irradiance or optical power per unit area must be delivered at the rock face to make things work. With a smaller hole, there is less area so less laser power needs to be delivered downhole,” Halliburton’s Skinner says.

The Core Laser Team

The use of laser systems in completions operations is feasible because such systems can be incorporated with existing equipment. “The tool will be mounted on coiled tubing, which will sit on top of a specially customized bottom-hole-assembly,” Bajcsi explains. “The idea is that we deploy the high-power laser source from the surface and transfer the laser light through optical cables to the laser head, which is going to drill into the formation reaching into the pay zones,” The laser generator on the surface provides a steady stream of energy through the fiber optic cable transferring 60-100kW of energy, equivalent to more than 1000 streetlights.

The focused beam melts the grains and creates molten rock, which covers the borehole with a glassy layer of obsidian, fusing the borehole and increasing borehole stability. This naturally impermeable glassy layer is made permeable by ZerLux’s proprietary methodology resulting in improved communication between the reservoir and the wellbore, as well as resisting sand incursion. The specially designed laser head then flushes out the debris, which is composed of thin, brittle fiberglass. The completions operation is done underbalanced, utilizing water and nitrogen instead of drilling mud.

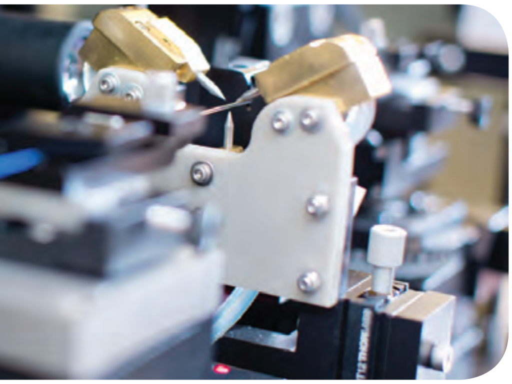
Advantages of laser completions

Perforation techniques used to complete conventional wells often cause extensive formation damage. However, laser perforation causes no formation damage, and will extend past the formation damage caused by the drilling process, thus resulting in good pay zone-well communication.

“It is believed that the high temperature gradients generated in nearby rock creates stress, which causes microscopic fissures or cracks to form, increasing permeability,” Skinner says. Due to the positive correlation between payzone-well communication and production output, overall production is improved. Additionally, laser perforation results in lower water coning, reduced sand incursion, and more precision and control than conventional perforation. Hydraulic fracturing can similarly benefit from the utilization of laser technology by creating small starting holes for the fracturing process.

“Small-scale rock-mechanics laboratory tests suggest that if it were possible to make a 1-2ft-long perforation perpendicular to the wellbore, it would allow a bypass from the [damaged zone] to create more linear, less tortuous fractures,” he says.

Though industry has seen maximum perforation depths of around 4ft, ZerLux is building a tool that could penetrate the reservoir to 10-20ft deep while maintaining a larger diameter than that created by a perforation gun. However, its limits are dependent on the length of



Panel design.

the bottomhole assembly. Additionally, the system's electronics are susceptible to heat damage when external temperatures rise above 200°C.

Offshore applications

Laser technology is not confined solely to perforations or drilling applications. It also has potential as a well intervention tool. The mediation of barium sulfate hardscale accumulation in offshore wells is often challenging due to its resilience to most conventional well intervention techniques.

"Laser light will change the physical and chemical properties of the scale and that will allow very fast removal," Bajcsi says. "No other technology can do that. Conventional milling just won't work." The accumulation of hydrates in flowlines and other subsea components is another common problem affecting offshore operations. Hydrate formation reduces production rates and can completely plug a piece of equipment. To address this issue, ZerLux developed two technologies — Blue Tube and Intra-Snake — to facilitate hydrate mediation.

The tools use a conventional remotely operated vehicle to scan equipment and selectively heat the affected area with its laser to treat the blockage without physical contact. This capability also allows hydrate plugs of varying length to be addressed, not just small plugs.

"These two technologies will allow operators to remove hydrates without entering the pipe. It is safer and much more economical than electric blankets and other conventional methods," Bajcsi says.

Although lasers cannot economically address all the technology challenges, laser technology has the potential to improve efficiency in the oil and gas industry, as well as open up new opportunities. **OE**

From Russia with tough love

Hardide reactor loading to perform the CVD process. Photos from Hardide Coatings.

Hardfacing has been given a tungsten carbide boost thanks to chemical vapor deposition technology developed in Russia. Elaine Maslin explains.

Coating technology developed in Russia using chemical vapor deposition (CVD) to coat thermally stable polycrystalline (TSP) diamonds with protective tungsten carbide has been developed for use on drilling inserts on downhole tools requiring gauge protection.

The coating, commercialized by Hardide Coatings in the UK, could be used on tool sections such as stabilizers and bent housings, as well as on logging-while-drilling tools, rotary steerable tools and downhole motor bearings.

The CVD technology, which was presented at this year's ITF Technology Showcase in Aberdeen, is used create Hardide's Hardide-D coating, which was designed to be used as hardfacing.

The CVD process is used to evenly apply a gaseous mixture of tungsten carbide heated to 500°C to materials to create a non-porous, abrasion and corrosion-resistant coating. The coated diamonds can then be brazed to the drilling tool.

"A TSP diamond is strong, but it has weaknesses that restrict its use as a hard facing," says Dr Yuri Zhuk, technical director, at Oxfordshire-based Hardide. Its poor wettability makes it difficult to bond with metal [i.e. brazing] and it also suffers from graphitization at high temperatures, which are used during its application to metal surfaces.

"By adding a Hardide-D coating, these limitations can be overcome," he says. The tungsten and carbide in vapor form crystalizes on the surface of the diamond evenly, creating a chemical bond, instead of mechanical. This then creates a pore-free surface that is resistant to high temperatures, thus preventing oxidization/graphitization, and to which metal can be bonded.

In tests, a surface coated with Hardide-D TSP diamonds was applied at 155rpm rotation, with 250kg load and 2.5Hz impacts, and showed limited wear.

"What we have developed enables diamonds to be used as a hard facing and allows them to be bonded with brazing or metal bonding," Zhuk says. "It enables a new generation of TSP diamond for hard facing."

The coating can also be used for different applications within drilling, such as on reamers and drilling heads, but also elsewhere in the oil and gas industry and across other industries.

England-based Cutting & Wear is already using Hardide-D on its TSP diamond hardfacing material, marketed as TSP Xtreme inserts, which the company says gives 200-times improvement over tungsten carbide inserts, extending the life of drilling tools.

Hardide Coatings recently announced its opening a new US$7 million production facility in Martinsville, Virginia. The plant will service existing and new customers in the oil, gas, aerospace, flow control and advanced engineering markets. The facility is expected to be operational in 4Q 2015.

Hardide has also recently invested in a 50% increase in capacity at its UK production site in Bicester, Oxfordshire. OE

Hardide coated and uncoated TSPs.

(Em)Bracing innovation

Installed in 65m water depth in 1998, the Siri platform was an innovation. Now, it has taken another innovation – taking onshore cable stay engineering design concepts for use subsea – to allow the platform to continue operation. Elaine Maslin reports.

The Siri area is close to the Norwegian Border, roughly 220km off the west coast of Denmark. The area contains five fields, Siri, Nini, Nini East, Cecilie and Stine, all producing from Paleocene sandstone reservoirs between 1800m and 2200m below the sea level.

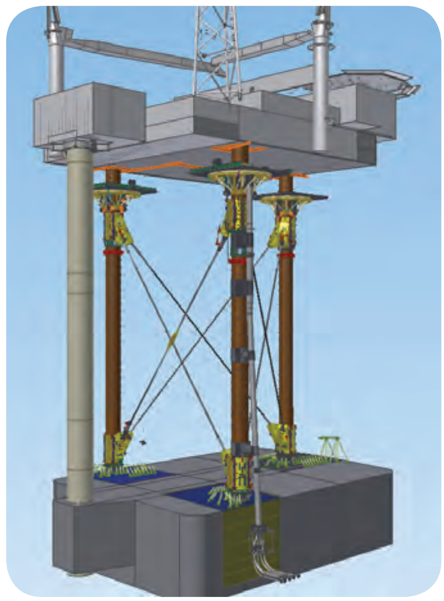
Built at the Kvaerner Rosenberg yard in Stavanger, the Siri platform, 100% owned and operated by Denmark's DONG Energy, was the first application of GustoMSC's innovative MOPUstor design, comprising a three-legged jackup with process facilities.

The structure slotted into a support structure based on a 300,000 boe capacity steel storage tank placed on the seabed, with the wellhead caisson supported from a sponson attached to the side of the jackup's tank.

In 2009, during a routine inspection, cracks were discovered in the sponson structure. To arrest further damage while a permanent repair was conducted, a temporary solution was installed, which involved positioning a beam with hydraulic jacks to support the sponson/caisson.

A number of options for a permanent repair solution were evaluated before DONG Energy chose to mature an idea put forward by engineering consultancy Atkins, which was then developed in partnership with Subsea 7.

The idea, thought to be a first for the offshore oil and gas industry, was to install cable stays between the platform legs to stiffen the three-legged platform structure, with the aim to reduce the natural period of the platform from around 6.5 seconds to approximately 3 seconds; this would reduce the platform's response to environmental loads thereby reduce movement and loading in the sponson/caisson.



Artist's illustration of the cable stay layout on Siri. Images from Subsea 7.

DONG Siri Project Manager for Subsea 7, Alan Cassie, says the project scope presented unique challenges, not least the innovative thinking around taking a product from a different industry and using it in the oil industry.

"Taking cable stays used for bridges and using them for an offshore application is quite innovative," he says. "There were a series of options that could have been chosen; however they also presented a number of challenges, but ultimately, in the end, we believe the option we chose was the right decision."

The design is based around clamps on each of Siri's legs, top (just beneath the "hull" of the platform) and bottom (on top of the oil storage tank), between which the cable stays would be diagonally installed as braces. In the final design, the clamps weighed more than 150-tonne and the lower clamps stand 6.4m from base to nose. Fabricated in two pieces, including cast sections (the clamp nose section which supports the cable anchorage), the clamps are then bolted into place using 56 M90 bolts.

The 60m-long cable stays have a 355mm outer diameter (including sheath), and 169 stranded cable, with each strand comprising seven wires.

However, unlike standard cable stays, the stays for Siri had to be designed to be water tight; this added significantly to the complexity of the assembly operation. A bespoke facility was set up in Dundee, Scotland, to assemble the stays, this included a set of articulated towers to allow the cable ends to be held vertically whilst the end anchorages were sealed with epoxy resin and wax to make them water tight.

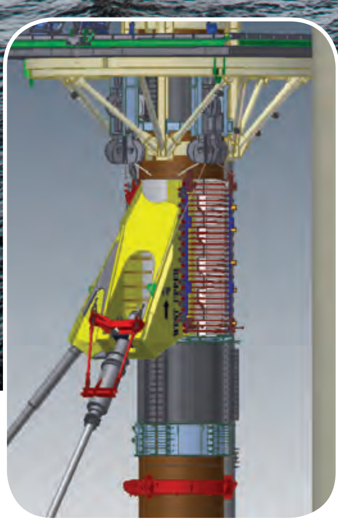
"Once the design was over the line the next challenge was to install it," Cassie says.

The dive support vessel *Seven Falcon*, with a 250-tonne crane, meant Subsea 7 had the capability to install the clamps. Offshore installation involved complex simultaneous operations between the dive support vessel and platform based operators, including rope access technicians.

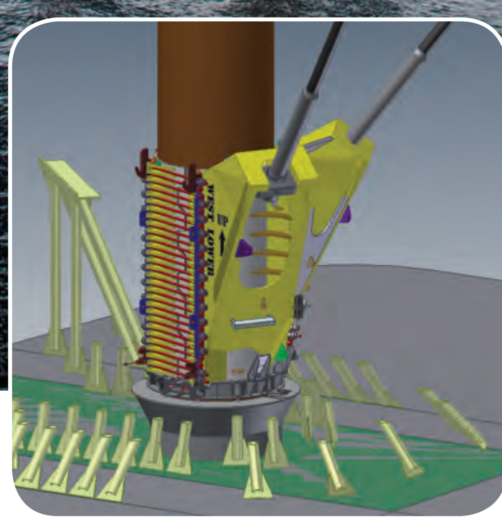
For the installation of the clamps, preinstalled guide clamps were used. Winch platforms, each weighing 150-tonne a piece and measuring 15m sq, also had to be installed at the top of each platform leg. The winches, three per winch platform, the largest with 120-tonne capacity, would be used to bring the components in to place, working with the construction vessel. A subsea winch was also used to provide supplementary hold back where needed to control the components.

Each of the lower clamps, lined with a specially selected low yield strength material, was then lowered onto guide clamps in two pieces. Divers/RAT's

Braced and ready for action – DONG's Siri platform, complete with cable stays.



Taking the load – one of the top clamps.



Each lower clamp stands some 6.4m from base to "nose".

installed the upper and lower bolts and then an automated bolt rack was used to locate and tighten the remaining 46 bolts (each bolt 90mm-diameter, 2m-long and weighing 300kg), creating a metal to metal grip between the clamp and the leg tubular.

Next, the upper clamps were installed. "The subsea installation tolerances were very tight. The upper clamps required a tolerance of 0.15°," Cassie says.

The cables were also installed from the *Seven Falcon*. Using specially designed installation aids, the operation involved complex simultaneous operations from the vessel and platform based winch operators. Key to the operation was to avoid damage to the cables, particularly the water tight duct and the threaded upper end of the anchorage.

Once in place, the tensioning was performed by a jacking system designed by Subsea 7. "Conventionally when tensioning stays, you'd use a weight jack," Cassie says. "We saw this wasn't going to work, it would take too long and we felt the risk of thread damage was too high. We decided to design our own tensioning system, which allowed the cable catenary to be removed in one stroke; avoiding possible damage as well as speeding up the operation."

The system was built into the ends of the cables. Four hydraulic cylinder rams (500-tonne each with 8/900mm stroke) extended and pulled the cable end pieces through the bearing plate – all without damaging the thread which would hold the cable in place. They were powered using a hydraulic power unit designed to be able to make sure each of the four cylinders progressed in tandem while the catenary was being pulled out.

First the stays were each pre-tensioned to 500-ton, to take the catenary out of the cable, before being tensioned to 1250-tonne. In 2012, one clamp was installed, followed by a further two in 2013 and the three upper clamps and the cables in 2014. The project, carried out over 350 vessel days using the *Seven Falcon*, completed in July 2014.

Reductions in the platform motion were achieved and, as a result, DONG was in a position to remove the restrictions on manning the 65-man platform and return to normal platform operations.

"We were very pleased with the way the procedures worked on the offshore campaign," Cassie says. "There was a lot of sensitivity around lifting these large sections of the storage tank. We had almost no shutdown period on the platform, only about 15 days to put in the clamps on the north leg because of access challenges due to the position of the riser."

Reflecting on the project, Cassie says lessons learned were: "Don't underestimate the challenge of delivering something innovative and new and don't under estimate the ability of good engineers to resolve those problems."

"Are we going to use cables in other parts of the North Sea," he asks. "Possibly not, but it is part of our tool kit now and reflects our general principle around engineering innovative solutions for mature assets, something we are very proud of." OE

The Snorre A tension leg platform. Photo by Harald Pettersen, Statoil.

Taking the load

Calibrating the 64 load cells on the Snorre A tension leg platform was a lengthy arduous task, until a new solution, installed late 2014, was found. Elaine Maslin reports.

Tension leg platforms (TLP) have become, if not a mainstream platform support design, an established design in the offshore oil and gas industry.

The first TLP was installed in 1984 on the Hutton field in the central North Sea in about 500ft water depth. The Hutton TLP demonstrated the viability of a floating platform tethered to the seabed to drill and produce with surface Xmas trees*.

Since then, TLPs have been used in water depths deeper than 5200ft. But, while they're established as a engineering option for field developments, one of the requirements for keeping a TLP safe is to have a monitoring system to make sure the tendons that tether the unit to the seabed are kept at the correct tension.

Snorre A has had such a system, but last year the system was given a complete overhaul.

Snorre A

Snorre spans blocks 34/4 and 34/7 in the Tampen area of the Norwegian North Sea, about 140km west of the Sogne Fjord, in the same region as Statfjord and Gullfaks. The field is operated by Statoil and has been producing oil and gas since August 1992 from the Snorre A TLP and from the Snorre B semisubmersible production platform in 2001.

The Snorre A TLP is an integrated production, drilling and quarters (PDQ) unit, moored to the seabed by steel tethers. Stabilized oil and gas is piped to the nearby Statfjord A platform for final processing. The oil is then loaded into shuttle tankers, while the gas is transported on to continental Europe through the Statpipe/Norpipe system.

To retain, measure and monitor the pre-tensioning of the Snorre A TLP cables, each of the four legs of the platform include constructions fitted with 16 load cells. However, these load cells require regular calibration, which means the weight of the platform must be lifted off the load cell.

Rob Loonen

Since the platform came on stream, testing and calibration of the TLP's load cells was carried out using two, 530-tonne capacity hydraulic cylinders, each weighing about 400 kilos, to perform a 21mm lift. The two cylinders would be used to lift one side (i.e. two loads cells) of each set of four load cells, before setting then back down again and moving to the other side. This meant 32 lifts – every three months, which is how often calibration is required.

In 2008, Aker Solutions started a study for Statoil to find alternative ways to carry out the process, which was not only lengthy, but also difficult, due to having to move the two 400 kilo cylinders between each of the four piles — not an easy task in the confined spaces — and due to the location of the 32 sets of loads cells.

Solution

Six years passed before a solution was found, but, the new solution now means the cylinders no longer need to be moved between the columns, with each column having dedicated cylinders, which only have to be placed once within the column to test all of the 16 load cells it contains.

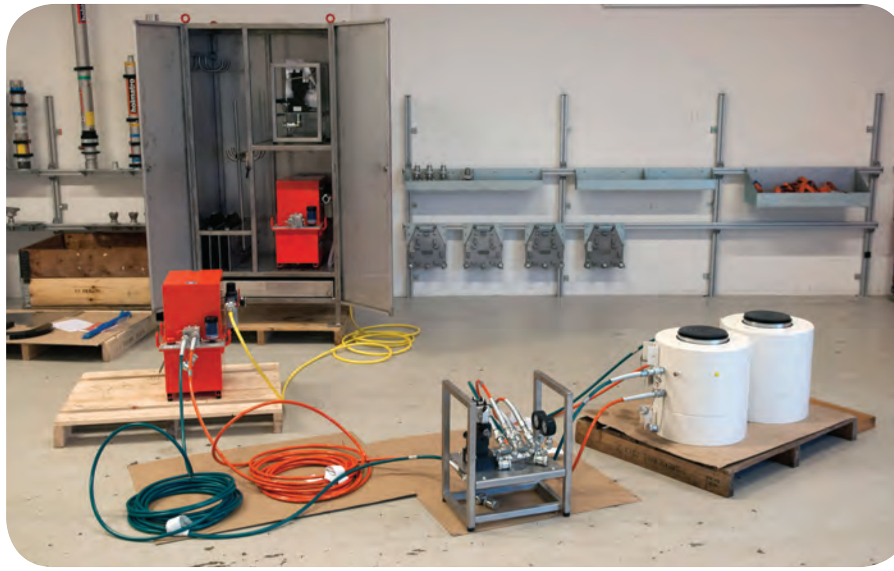
Specialist high pressure cylinder producer Holmatro, founded in 1967 in the Netherlands, was brought into the project in 2014 via its distributor EIVA-SAFEX AS. After discussions concerning the tender documentation and the solution, the firm submitted its bid and was one of two firms in the final running for the project, says Rob Loonen, sales engineer for industrial equipment for Dutch-based international hydraulic equipment supplier, Holmatro, which supplied cylinders, powerpacks, storage lockers and control panels for Snorre A.

By June, after a teleconference meeting with client Aker Solutions, Holmatro was awarded the contract and the project began, with delivery expected in December.

"The initial idea was to use single-acting cylinders," Loonen says, "but after studying the exact application, we suggested a different system configuration." Holmatro proposed using double-acting cylinders with a tilting saddle in combination with a special lowering control panel, so potential operation errors would be covered and the load could never come back too quickly on the load cell position. The 64, 536-tonne capacity, cylinders (one each per load cell) are sited next to the load cells. Due to the limited space, a lifting yoke was created by EIVA SAFEX AS to put the cylinders in place. They also produced a sea-fastening system to secure the cylinders underneath the load. For each column, one complete control set (powerpack, control panel and hoses) is kept in the column storage cabins. Each column has its own hydraulic system and a 50-kilo pump unit, so neither have to be moved between columns.

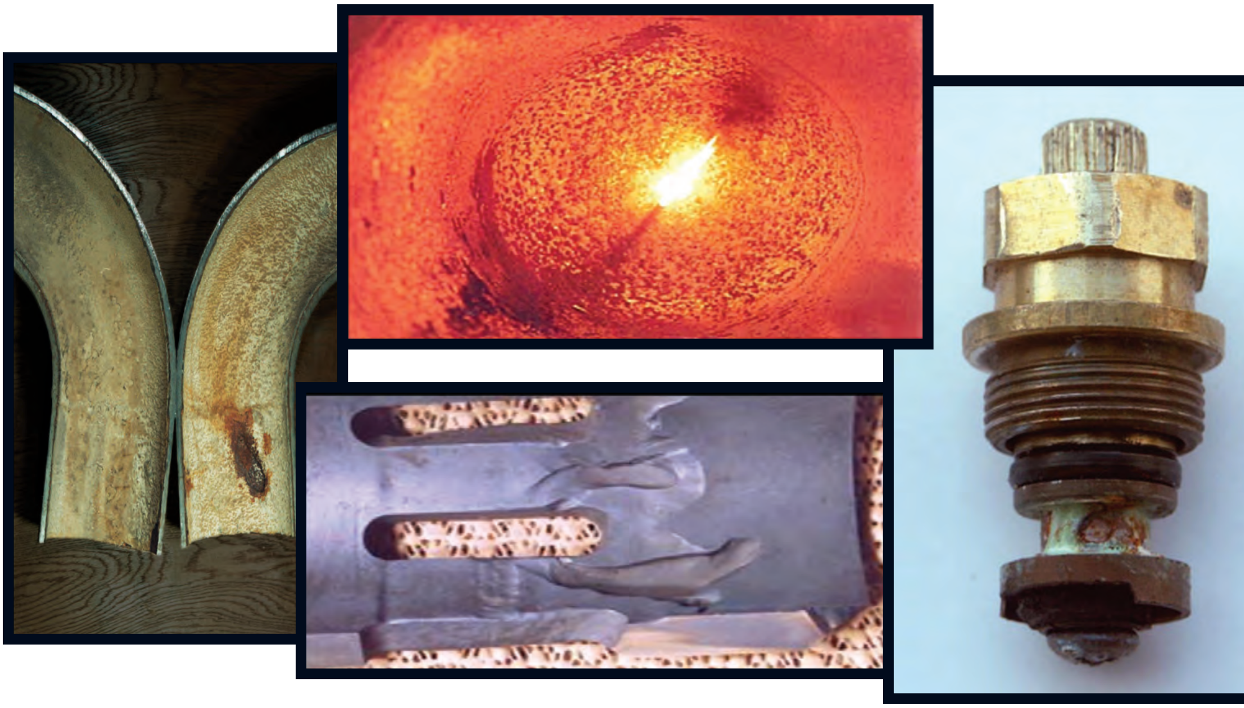
The result is that the load cell calibration work has gone from 32 lifts to eight lifts with no more equipment handling between the platform's columns. For Holmatro, it was an ideal job. While the company has about 170 standard cylinders available for the offshore sector and other industries, it also specializes in bespoke solutions.

"The nice part of this project is that it's an industrial solution," Loonen says. "We always try to help a client get the right solutions. In collaboration with our research and development, production and service departments, we place ourselves in our client's situation and participate fully in the thinking process to achieve the right solution for their usage requirements. We like to be challenged to come up with new innovative industrial solutions." OE



Above: Complete system test set for factory acceptance test. Right: Two 536-tonne capacity hydraulic cylinders, each weighing 400 kilos. Photos from from Holmatro.

*OTC Brazil, 2013, paper OTC-24512-MS by Rajiv Aggarwal and Richard Souza, Granherne.



Safety from a design consideration

Preventing corrosion is necessary to avoiding production failures. Leokadia Rucinski and Genesis' Binder Singh provide details.

As deepwater developments and ultra-deepwater operations are increasing, proactive asset integrity management is key to safety. For instance, projects at 5000ft or more, represent roughly a third of all ultra-deepwater operations globally. And projects are expected not only in deeper waters, but harsher environments, such as the Arctic.

The difficulty for both designers and operators is that the offshore environments are typically harsher, more remote and timely feedback on subsea pipelines is not readily available – compared to shallow water operations or onshore environments.

The challenge is maintaining the integrity of deep pipelines, particularly under the two extreme value conditions namely: low flow or stagnant conditions (dead legs), and impinging high velocity flows; the latter including particulate erosion and fluid cavitation. Some of the specific challenges of deepwater and ultra-deepwater drilling include mitigating high-pressure and high-temperature environments, deeper and hotter wells, and fast-moving fluids. According to SPE, planning for the presence of acidic gases, such as carbon dioxide and hydrogen sulfide, is more common in deepwater operations. The clear focus also means recognition and acceptance of the accompanying prediction and modeling challenges.

While pipeline failure can be attributed to internal corrosion around 50% of the time, external corrosion is also an issue, representing 15% of all failures.

As cathodic protection is well understood and "codified," external corrosion is more readily addressed by the proper use of existing industry standards and practices. By contrast, internal corrosion is more complex, as solutions are addressed through knowledge management and modeling. There are many

Fig. 1: (Above) A collage of somewhat unusual corrosion phenomena, many of which are now being more openly discussed in the industry.
Images from Genesis.

commercial and joint industry projects focused on corrosion modeling under continual development. Unfortunately, most if not all, tend to assess for general (uniform) corrosion only. However, virtually all corrosion problems are localized and often manifest in the form of pitting.

Why now?

Many of the industry's safety improvements have, unfortunately, been the result of accidents, or "lessons learned." Corrosion or related phenomena have been a catalyst leading to several industrial accidents: Flixborough (1974), Bhopal (1984), *Piper Alpha* (1988), Carlsbad (2000), Prudhoe Bay (2006), Richmond Refinery (2012). In a post-Macondo world, owners and operators are more readily open to considering such new approaches early on (capex phase).

Offshore corrosion case histories have not always been readily available, but the better exchanges of quantifiable data have led to software development with analytics and searchable benchmarking. (See collage, figure 1.)

The main root cause of the devasting 1988 accident at *Piper Alpha* has primarily been attributed to a failure of the permit to work. However, delving further, the planned maintenance work order was due to serious corrosion issues, which were deferred for many years to avoid interruption of production activities.

Since *Piper Alpha*, many changes have taken place in the industry, and the North Sea region has seen many successes, and hopefully a de facto alignment of the North Sea and Gulf of Mexico regions will help improve matters further, for the industry as a whole. The results of better overall fabric maintenance testing, inspection, more creative monitoring, and pipeline pigging will be a big plus.

Managing corrosion and asset integrity

Managing corrosion and the integrity of deep pipelines is a three-fold process: proactive, ongoing and reactive.

Proactive work is becoming more common and considered economically more rational. According to NACE, corrosion-related costs for monitoring, replacing and maintaining pipelines are estimated around a staggering $450 billion for the US alone. The expense shows a clear need for closer adherence to proactive corrosion management (See Figure 2).

Proactive pipeline integrity management

Proactive pipeline integrity management generally requires multiple approaches. With a design goal of a 25-year lifetime for this type of an asset, investing up front in proactive integrity management is smart for safety reasons and necessary business sensibilities. The first of these, for cost-saving reasons, is to use conventional material (i.e. carbon steel), as its properties (malleability, welding, costs, availability) are well-established. The second option is to increase the thickness of the pipe, however, this is often costly and usually avoided for the viability of project.

However, if the fluids prove challenging, the pipeline can be lined with an upgraded metallurgy, such as nickel-chrome-molybdenum alloy. For instance, if, the calculations show an accelerated corrosion rate (usually in excess of 10mm/y) or an expected loss of mechanical integrity within an unacceptable (often pre-determined time frame), then corrosion resistant alloy (CRA) may be considered. In the latter scenario, the alloy may be mechanically sleeved, clad or welded to the internal diameter. Thus, the CRA acts as a barrier between the high-pressure, high-temperature, high-velocity multiphase flows. The selection of a CRA can be challenging and choices must be made between stainless steels, duplex and nickel based alloys. It is important to realize that the higher alloys are more resistant to localized corrosion (pitting and crevice criteria per the commonly accepted PREN, CCT, CPT, and cyclic polarization techniques).

But most importantly, none are entirely immune, and often can be made to corrode under physical and electrochemical upsets outside the design envelope. This type of simulation is often referred to as corrosion under excursions (CUE). To meet this, we again revert back to the idea of risk and the ALARP condition, where the risk of a corrosion failure or issue is deemed to be as low as reasonably practicable.

The major problem that arises in this scenario is localized corrosion (pitting by common use-age), and as mentioned earlier, modeling can be conducted to analyze this risk, which can be considerable. Still, it is an attractive and cost-effective methodology, provided the data are sensible and corroborated by appropriate field or inspection data. The field data can be used analogously to nearby fields. Reliance on parallel laboratory data is fine, but should be supported by pragmatic inspection or monitoring data, where feasible. Any proper qualification of modeling and chemical treatments must be performed with realistic controls, ideally comparing uninhibited, inhibited and modeling trends.

The fourth solution is coatings for the interior of the pipe. To date, this isn't a truly viable option since transported

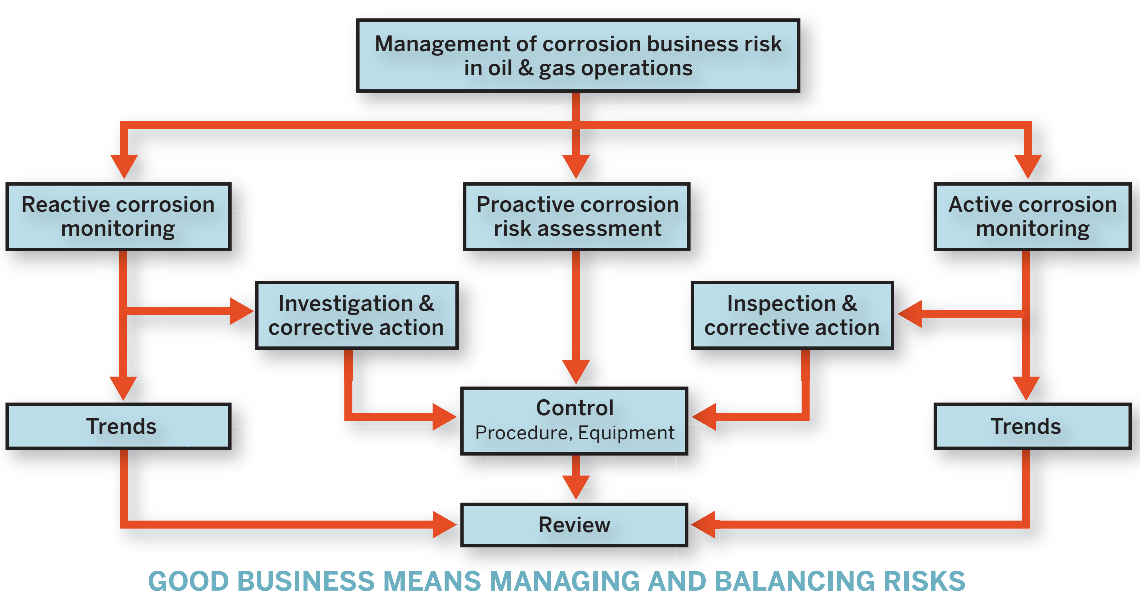


Fig. 2: Comparative routes for best corrosion and integrity management. The centerline proactive is always the best option. Source: Genesis.

EPIC

breakdown deposits would degrade and/or clog the system, by creating further secondary localized corrosion cells. However, it is an option that is still being considered and coating companies are reformulating products for high-temperature and high-pressure environments.

Of course, in principle the major benefit of using CRAs is that operators don't need to use chemicals or inhibitors. For steel alone, it is always required to have an acceptable inhibitor efficiency (typically 90-97%), and an acceptable availability (often 90-98%) for the steel/inhibitor combination to work. Prolonged periods without an inhibitor can pose a problem if new corrosion initiation cells are created or old ones are re-activated. A well-selected and applied CRA, by comparison, simply does not require that type of maintenance.

Ongoing management

Ongoing monitoring after installation plays an important role to check for the corrosion condition of a pipe or a riser. There are different assessment methods: probe, coupon, monitoring spool pigging, advanced mapping and guided wave technology, to name a few. However, there is no confident way to look at the status of subsea infrastructure. Most of the inspection is conducted visually, either subsea via ROV or from the topsides of the platform, where access is better. Often a change in monitoring technique depends on the data and trend assessment. That's where intelligent (or smart) pigging comes into play. Pigging captures and records full length information for future trend analysis and risk-based inspection planning.

> **"Pipeline failure is attributed to internal corrosion about 50% of the time"**
>
> Binder Singh, Principal Integrity Engineer, Genesis Oil and Gas.

Coupons, which calculate the material loss more directly, can also be used effectively on topsides and may have application for the subsea, too. Likewise various probes, which are designed to withstand high pressure and high temperatures, can be used to measure near instantaneous metal loss (i.e. ER, LPR, potential probes). Similarly, U/T mapping and guided wave technologies are gaining ground in terms of application. Through calibration and qualification with blind controls and artificial defects is always recommended by independent third-party to verify reliability and accuracy. The growth of these and other methods all have a way of better making the case for integrated or total integrity management programs. Most, if not all, such plans ultimately save money and offer a good ROI, but it's the improvement on existing methods and tools which are likely to provide the differentiators to capture and monetize safety and integrity management.

Overall, the subsea environment is difficult. As noted earlier, failure can also happen on the exterior of the pipe, but the biggest concern may be at the touch down zone of the steel catenary riser interface, as it connects to the pipeline. In this scenario, there can be dangerous corrosion/erosion flow at the inside of the bend; and a possible weakness in CP current delivery under shielded areas of the outside-especially if unusual microbial (MIC) activity can occur. This combination while a low-risk phenomena, can have high risk consequences if it occurs, and a plausible asset threat due to proximity of the safety critical riser component. The challenge illustrates the importance of relevant monitoring and close visual external inspection, matched by carefully internal monitoring. In principle, both can be conducted subsea by ROV with appropriate tooling.

The way forward

Deepwater operations have increased internal corrosion control, safety, and cost challenges. Starting corrosion control at inception ensures a stronger corrosion risk assessment and therefore, better lifecycle integrity management.

To date, the regulations for specific corrosion control and monitoring are still in the infancy stage, but the industry is moving forward and companies see high value in implementing integrity management programs. For instance, the role of corrosion management is strongly implicit in the North Sea and Gulf of Mexico regulations, and may be spelt out more clearly in the future.

Cultivating a safety mindset at the start of projects is crucial to ensure the participation of materials and corrosion engineers. From a mechanical integrity perspective, it is very important for engineers to think carefully beyond immediate design codes of practice since corrosion and degradation can kick in fairly soon after startup depending on the aggression of multiphase production fluids. And once engineers collectively accept the subtleties of materials performance as opposed to materials selection, the industry may be well on the way to more effective and reliable solutions all-round. Within the industry, we can expect to see a convergence in regulations, combining the goal-setting standards of the North Sea and the Gulf of Mexico, with an emphasis of the principles of inherently safe design, integrity management (IM) programs, HAZID, HAZOP, and better interpretation of ALARP. OE

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Offshore heavy oil economics

Jeannie Stell looks at offshore heavy oil development economics with an eye on the current low-price environment.

Even as onshore unconventional hydrocarbon developments fall victim to the downward spiral of oil and gas prices, offshore heavy oil developments continue to prove promising for significant group of exploration and production companies. This is especially true for state-owned entities unconcerned with sustainable revenues. Although the cost of exploring and developing offshore heavy oil is high due to the difficulty of producing, transporting and refining heavy oil, major international energy companies continue to develop heavy oil fields in an effort to replace reserves. For example, despite the current crude price drop, China continues to develop its heavy oil reserves because its state-owned companies are not particularly concerned with profits, unlike their peer publically held companies. Heavy oil, typically defined as <22° gravity API, represents a valuable resource, but defining the potential proves to be problematic as total-resource reports vary greatly. According to Chevron, heavy oil comprises about 50% of known oil resources but represents just one in 10 bbl of production. New global investment to develop this 8 trillion bbl resource could double production output by 2025, reports the company. According to estimates by London-based Visiongain, a business-intelligence provider and trading partner with the US Federal Government, on average up to 20% of the world's remaining oil could be sourced from onshore and offshore heavy oil deposits. The company predicts that the global market could reach more than US$50 billion this year, with production reaching more than 6 MMb/d. The majority of the billion-dollar price tags will be spent for cold heavy oil projects because many of the world's largest heavy oil markets have well-established cold heavy oil projects, states the company."As reserves of lighter crude oils dwindle and the rate of new discoveries decreases, oil and gas companies are increasingly looking to alternative hydrocarbon sources to plug the gap," reports Robin Ray, energy analyst for VisionGain. "Heavy oil is one of those sources."Such heavy oil plays offer significant growth and investment opportunities as international companies join to form partnerships for development. In the long run, as commodity prices recover, energy demand grows and major conventional oil discoveries become increasingly rare, the economics of heavy oil should steadily improve.

Today, more than 30 countries are known to possess recoverable heavy oil reserves, according to Halliburton. "Led by Canada and Venezuela (Canada's heavy oil deposits rank second only to Saudi

At a glance:
Top 15 heavy oil markets
(includes onshore and offshore)

Brazil	Indonesia	Oman
Canada	Iran	Russia
China	Iraq	Saudi Arabia
Colombia	Kuwait	USA
Ecuador	Mexico	Venezuela

Source: Visiongain

ExxonMobil expects its 52-well Hebron development project offshore Newfoundland to bring in first oil in 2017. Photos from ExxonMobil.

Arabia in total oil reserves, active heavy oil-producing countries also include the US (California), Mexico, Brazil, Russia, Indonesia, China, Colombia, Ecuador, Iraq, Kuwait, Saudi Arabia, Chad and Angola," reports the company.

For now, many of the major exploration and production companies are continuing to eke out profits as they work offshore heavy oil exploration and developments.

Brazil

In February 2015, Petrobras discovered new oil accumulations in offshore concession BM-C-35 (exploratory block C-M-535) found in the Campos Basin post-salt layer (*OE: March 2015*). The discovery was made while drilling well 1-BRSA-1289-RJS, also known as 1-RJS-737, and informally known as Basilisco. The well was drilled at a water depth of 2214m and about 143km from the city of Armação dos Búzios on the coast of Rio de Janeiro. Heavy oil has been found at 3190m and at 3521m. The consortium of concession BM-C-35, operated by Petrobras (65% interest) in partnership with BP (35%), are testing the extension of the discoveries and the concession's exploratory potential.

Also, Brazil's Parque das Conchas project, a Shell development, is continuing and is notable as the first project field development incorporating subsea oil and gas separation and subsea pumping for the company. During two development phases, the fields were developed by 13 wells tied-back to the centrally located *Espirito Santo* FPSO, moored in 5840ft of water. The first phase developed four fields, and the second phase will develop the fifth field. The double-hulled *Espirito Santo* FPSO has enough power and heat delivery systems to drive the system and process heavy crude oil. With a production capacity of 100,000 b/d, the *Espirito Santo* facility will process heavy crudes that range from 16° to 24° gravity API.

Canada

In late 2014, ExxonMobil tapped Cameron for the supply of large-bore wellheads, production trees and risers to be installed at the 52-well Hebron development project offshore Newfoundland. First oil is expected in 2017. The Hebron heavy oil field near Terra Nova, Hibernia and White Rose fields is about 220mi offshore the eastern coast of Canada's Newfoundland and Labrador in the Jeanne d'Arc basin about 302ft deep, and is estimated to contain between 400 and 700 MMbbl of recoverable resources (*OE: November 2014*). The project includes the Hebron, West Ben Nevis and Ben Nevis fields from four reservoirs, including the Lower Cretaceous Ben Nevis, the Lower Cretaceous Avalon, the Lower Cretaceous Hibernia and the Upper Jurassic Jeanne d'Arc reservoirs. Production will begin in the Ben Nevis, Hibernia and Jeanne d'Arc reservoirs on the Hebron field, with gas storage in the Ben Nevis reservoir of the West Ben Nevis field. Oil production is expected to be enhanced via water injection, and produced gas will be used for artificial lift. Hebron includes a stand-alone gravity-based structure consisting of a single main shaft to encompass the wells, support the production and living topsides, and separate the produced oil, gas and water, as well as treat produced water and compress gas. Produced oil will be exported via a looped pipeline and two loading points to offload to ice-strengthened tankers.The Ben Nevis and Hebron fields are expected to produce 80% of the 20°API heavy oil on the project. Oil production capacity is planned for 119,506 to 176,115 b/d with treating capacity of 188,694 to 283,041 b/d of produced water for disposal overboard. Gas will be compressed at a rate of 53.0 to 70.6 MMcf/d. Storage capacity is 1.45 MMbbl.

China

Peng Lai 19-3 in the Bohai Bay is China's largest offshore oil field. The Bozhong Block 11/05 play is found in 75ft water and produces 21°API heavy oil. ConocoPhillips (49% interest) operates the project for its partner, Chinese state company CNOOC (51%). The field was development with an installation of a 24-slot wellhead platform and the leased, barge-type *Bohai Ming Zhu* FPSO that includes processing and storage facilities, accommodation quarters, power generators and a flare. The *Bohai Ming Zhu* FPSO is capable of processing up to 45,000 b/d and storing more than 360,000 bo.

Morocco

Cairn Energy has updated its JM-1 exploration well offshore Morocco. In the Upper Jurassic, the well confirmed the presence of heavy oil over a 110m gross interval as tested in the 1968 MO-2 well, 2km from JM-1. The company plans to correlate core and log data with other wells on Cap Juby to assess the hydrocarbon potentials.

UK

EnQuest is further developing its program for heavy-oil play Kraken found in the UK sector of the North Sea on Block 9/2b. EnQuest (45% interest) operates the field for its partners Celtic Oil (30%) and Nautical (25%). Development drilling will begin during 2H 2015 with the *Transocean Leader*, a mid-water semisubmersible. EnQuest's program for Kraken during 2015 includes installation of subsea hardware, including manifolds for the first drill center, two templates for the second drill center and installation of the mooring system for an FPSO. **OE**

FURTHER **READING**

For further information on offshore heavy oil developments, see "Spotlight on Latin America" at oedigital.com.

Developing KMZ

Jerry Lee provides an overview of Mexico's Ku-Maloob-Zaap (KMZ) heavy oilfield in the Bay of Campeche.

Pemex's Ku-S central processing installation at the Ku-Maloob-Zaap oilfield in the Bay of Campeche offshore Mexico. Photo from Return to Scene.

Heavy oils are typically composed of long, high molecular weight compounds. These oils are characterized as having less than 20°API gravity, and low gas-oil-ratio (GOR). The low API and low GOR results in a fluid that is higher in density and very viscous. These qualities are problematic for field production, as the fluid is then less mobile, resulting in greater effort required for extraction; however, heavy oil accounts for triple the volume of reserves as compared to conventional oil and can, therefore, be a significant source of production when fields can be produced economically. Such is the case in the Gulf of Mexico with the Petróleos Mexicanos' (Pemex) Ku-Maloob-Zaap (KMZ) field.

Found in the Bay of Campeche, KMZ is 150km northeast of Ciudad del Carmen, Campeche, off the coast of Mexico, near the states of Tabasco and Campeche.

KMZ is comprised of five fields: Ku, Maloob, Zaap, Bacab, and Lum and Zazil-Ha. These fields total an area of about 121sq km, and sits below an average 100m water depth. Hydrocarbons are produced from multiple zones: Kimmeridgian, lower Paleocene, upper/middle/lower Cretaceous, and middle Eocene reservoirs [2]. From the main fields, Maloob and Zaap oil is about 13°API while Ku oil is about 22°API [1]. In total, reserves are estimated around 4.9 billion bbl.

Early history

The Ku field was the first of the five fields to be discovered. In 1979, the Ha-1A well discovered hydrocarbons at the Ku field. Production followed in 1981 [2,3]. Following the Ku discovery, Maloob was discovered next in 1984 and Zaap followed in 1991. The field became the second largest producer for Pemex following the Cantarell field, producing an average of 247,000 b/d of crude, and 152.5 MMcf/d of natural gas.

Redevelopment

Taking lessons learned from Cantarell field, Pemex made the decision to redevelop the KMZ field so that it would not suffer the same rapid decline seen at Cantarell. As a result, in 2002, Pemex planned an expansion of the Ku-Maloob-Zaap project that would involve drilling additional wells and pressure maintenance systems for the field. Like the Cantarell field, KMZ utilized nitrogen injection to maintain pressure in the reservoir. The success

of the investment has been seen over the years as production tripled from 2004-2013, resulting in KMZ overtaking Cantarell in July 2009 as Mexico's largest crude producing field. In addition to adding more wells, the 2002 expansion project would include 32 new pipelines and 17 new platforms: separate platforms for telecommunications, production and a compression center, four accommodation platforms, four production platforms, and seven drilling platforms.

Four drilling platforms were contracted to a joint venture between Empresas ICA Sociedad Controladora and Fluor for US$169 million. The platforms were completed in August 2005. Swecomex delivered the Ku-S production platform at the field in 2006. That same year saw the installation of the two accommodation platforms, HA-KU-S and HA-KU-M by Keppel. Production platform, PB-KU-A2, was delivered in October 2007 by Dragados Offshore.

Further investment was made at the field in 2005 when Pemex opted to add a floating production storage and offloading (FPSO) vessel to the field. The *Yuum K'ak naab* FPSO, the first in the Gulf of Mexico (Petrobras' Cascade/Chinook took the title of first FPSO in the US Gulf of Mexico in 2011), began production on 18 June 2007. The $758 million vessel, owned and operated by BW Offshore was contracted with Pemex for 15 years. This vessel has the capability to handle 600,000 bo/d of both oil types, process 200,000 bo/d, and export gas. By 2008, average field production stood at 706,100 b/d of crude, and 272.8 MMcf/d of natural gas.

Nitrogen injection began at KMZ in 2009, along with McDermott's delivery of the drilling platform, Maloob-C [3]. In 2011, Pemex installed gun barrel technology in the field to improve the quality of crude, an investment of $1.75 million. By 2010, KMZ production averaged 839,200 b/d of crude and later peaked at 927,000 b/d in 2013.

By 2013, KMZ produced an average production of 863,800 b/d of crude, and 405.1 Mcf/d of natural gas, bringing cumulative production to 4.2 billion bbl of crude and 2 Tcf of natural gas. As the top crude producing field, Pemex invested another $2.61 billion in 2014, bringing the fields total development cost to over $20 billion. OE

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Making light work of sand removal

Desanding to stop wellbore tubing clogging-up is nothing new, but FourPhase has developed their own technology to keep the flow going. Neil Meldrum explains.

A DualFlow system.
Images from FourPhase.

Conventional oil and gas accumulations are found in sedimentary sandstone and carbonate rock formations. Unconsolidated sandstone reservoirs are susceptible to sand/fines production when permeability is 0.5-8 Darcies.

These sand/fines particles become dislodged during the production process, giving rise to solids production. The debris then accompanies the water and oil flowing through the tubing to surface. Historically, without intervention, the wellbore eventually becomes partially or completely blocked.

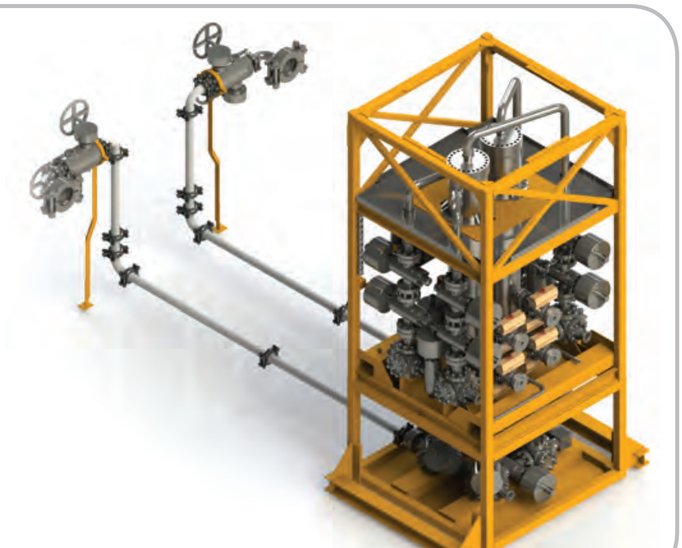
Remedial measures include reducing – or choking back – the flow rate, gravel packing, installing downhole sand screens or injecting chemicals into the formation to strengthen artificially. However, these processes reduce production and could create threshold velocity.

The transported sand may then accumulate as a stationary dune, which can cause partial or complete blockage of the wellbore and potentially a complete shutdown of the production separator.

There are two methods to prevent this happening. First, produce at the maximum flow rate to get the sand, oil, gas, and water to topside where the separator is mounted, and second, use barriers downhole in order to prevent the sand entering the wellbore.

Gravel packing, chemical cementing and sand screens provide this initial downhole sand barrier. However, over time, the sand erodes these barriers and moves into the tubing. Typically, sand is heavy, which means it is not very mobile and eventually starts collecting in the tubing, restricting flow and eventually clogging up. So you need something to clean it out.

FourPhase has developed a dual cyclone solids removal system called DualFlow. The unit, which comprises two cyclone pressure vessels comprised of 1.4507 (APM2327), used in parallel so one can be isolated and flushed while production continues through the second. The unit removes solids from the production flow, by using centrifugal forces internally to accelerate and separate the sand, allowing a higher production flowrate, stopping solids accumulating either in the wellbore or production separator(s). It includes real-time information logging, recording flow



A DualFlow system overview.

rates, pressure, temperature, and solids removed. Its dynamic range is 20 micron to 5mm solids. Standard DualFlow units are rated to either 5000psi or 10,000psi as required.

The system, which weighs 8500kg and has a 200 x 200 x 328 cm footprint, has a smaller footprint, at one third of the size of existing units on the market; uses Super Duplex piping and a carbon steel frame; and is 99.8% efficient. FourPhase also supplies its own X-Flow choke manifold, which has directional control and a reversible flowpath. It can be used for well clean-up or kick start applications or permanently installed in the production facility.

Production from the well is routed to the DualFlow unit and the flow rate increased so as to allow enough velocity and energy in the fluid in order to lift the accumulated sand/fines particles from the wellbore. The weight of the accumulated solids in the unit is typically 20-200 kilos/hr – flowrate dependent.

Norwegian energy giant Statoil chose FourPhase's solution for the Gullfaks C offshore installation, in the Norwegian Sea. Gullfaks started production in 1986. Initial recoverable reserves were estimated to be 2.1 billion bbl.

Production peaked at 605,000 b/d in 1994 and is now about 110,000 b/d, with a 62% recovery rate. Intended production recovery is aimed at 74%, with part of this being achieved by using sand control technology.

Gullfaks C is known for its challenging solids production, which has resulted in reduced production rates due to wellbores having to be choked back and even shut in. Choking back means having to reduce wellbore flowrate to reduce the amount of sand produced, while shut-in means no flowrate because downhole tubing is plugged with sand.

Historically, sand is handled by locating a sand trap at the entrance to the test separator. This trap usually handles 1-5% of total sand production, corresponding to 0.3-1.5 kg/hr of sand per well.

Statoil's well 34/10-C-19 at Gullfaks was drilled and completed in 1993/94, and recompleted in 2002. It was found that the sand rate rapidly exceeded the acceptable solids rate (ASR) limit after clean-up, with well flow being choked back. This occurred because the flow was too low to lift the sand up to the surface, to the topside-mounted separator, which would result in sand accumulating in the wellbore over time and a sand plug being formed.

A sand clean-up is required once this happens. Conventionally, coiled tubing (CT), or snubbing, is used to establish flow into a test separator.

CT is run into the hole with a circulating nozzle, going to the bottom and circulating the solids. The CT is tied-in to the riser and connected into the DualFlow, to separate out the solids, and returning either through the redundant Xmas Tree or tied directly into the test separator if available.

The test separator is not always accessible at the tie-in points. So FourPhase has used the wellhead service wing with both master valves closed and the production wing open. Without coiled tubing, pressure support is needed in the reservoir to lift the solids.

But, using CT is a relatively expensive process, costing some NOK 20-30 million (approx. US$3-5 million), equivalent to having a solids removal system on a rig for a whole year. Snubbing involves running the drill string on a pipe string using a hydraulic workover rig at even greater cost.

A sand clean-up in Gullfaks' C-19 had been carried out almost every second year since it came online. The process also has disadvantages, including sand separation possibly being insufficient, a new CT rig having to be mounted for each well, having to send the sand to shore for handling, and the clean-up operation conflicting with other operations in the area.

Up to 2012, Statoil had used a desander during CT cleanout on C-19 that took out about 50% of the sediments, but the well was sending more sand, from the wellbore, than the production facility could handle. In 2013, DualFlow was introduced, which routed the production from the well to the DualFlow unit. The flowrate was then increased to allow enough velocity and energy in the fluid to lift the accumulated sediments from the wellbore. The DualFlow unit measured the accumulated solids, which were 20- 200 kilos/hr, depending on flowrates. Online flushing of alternate cyclone vessels ensures the well remains in constant production while being cleaned.

Over the last two years, a total 15,000kg of solids has been removed from C-19 alone. Two well bores were also being treated going to press. In total, FourPhase has removed 37,000kg of solids from 14 different wells from the start of the operation in Gullfaks.

In 2013, Wintershall took over the operatorship of Brage from Statoil. However, a Brage well suffered badly from solids production and was shut-in.

FourPhase mobilized early to kick-start the well and potentially be hooked-up for further solids removal. The well was successfully kick-started and some 7-tonnes of solids was removed from the wellbore without CT or snubbing.

FourPhase's solids removal system kick-started the blocked well without downhole intervention. The DualFlow took out the solids upstream of any topside process units. The well is now the second-best producer on the whole field, contributing to 10-11% of Brage's total production. OE

***Neil Meldrum** is business development manager at FourPhase. Before joining the company he held managerial positions in product development, marketing and business development both in small technology companies and large integrated service companies in the UK and internationally. Prior to this, he gained field and operations experience in land seismic, permanent downhole monitoring and well testing. Meldrum gained an MSc in Technology & Management in the Oil & Gas Industry from the University of Aberdeen.*

Building blocks for an electric subsea future

Electronic subsea control modules are being designed to go deeper – and be smaller and lighter. John Bradbury takes a look.

New generation subsea control systems being rolled out to the offshore industry could one day become the key building blocks for both new and brownfield developments.

That is the proud assertion of a senior engineering research manager who suggests his company's new subsea electronic control modules and actuators could be capable of managing most deepwater subsea field scenarios.

But, these are not super-heavyweight, giant pieces of hardware. Rather, they are modular, small – modest even – and configurable.

Einar Winther Larssen, a research and design manager within Aker Solutions' corporate technology organization, describes these new units as "Next generation subsea electronics and actuation platforms," which will have wide-ranging applications. "I think these types of systems will be suitable for all [subsea] systems in the future," Larssen says.

Aker Solutions's offering is based on its Vectus 6.0 subsea control unit released in September 2014, and its El-drive actuator system.

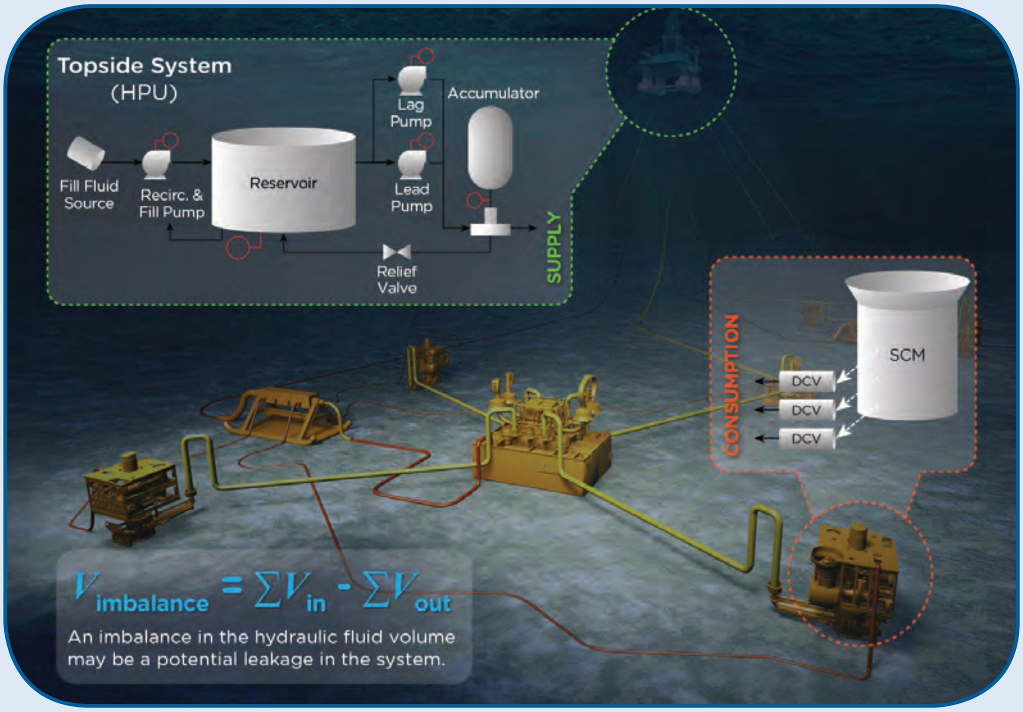
Vectus comes with an electronics module, auxiliary and power supply modules, while the electronic actuator is also offered in a small, modular package. Both are designed for deepwater.

Larssen foresees deployment of these new units in a variety of subsea scenarios: in production and workover systems, in subsea pumping and compression applications, and within the "subsea factory" concept Aker Solutions has been promoting across the industry.

The hardware can be used without performing too many mechanical changes Larssen says, using configurable software

Enhanced IM of subsea control systems

Claire Zhao and Dharmik Vadel, of Clarus Subsea Integrity, discuss condition monitoring as a proactive approach to minimizing downtime.



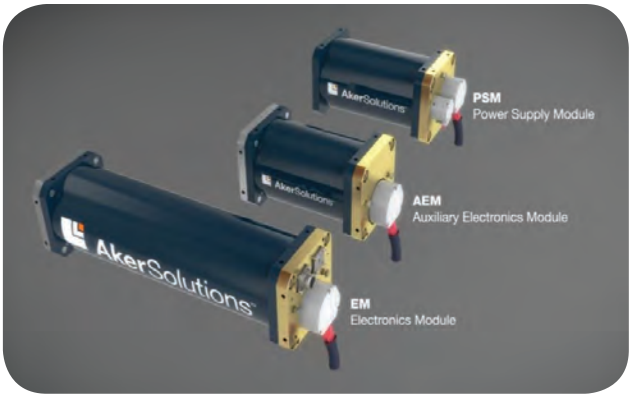
Hydraulic fluid mass balance.
Photo from Clarus Subsea Integrity.

Control system failure is one of the top contributors toward unplanned shutdowns in offshore subsea production systems. Current practice includes a reactive approach to failure management including equipment replacement or a retrofit solution, which can be costly. Condition monitoring of control equipment using existing operational data can provide leading indicators of equipment degradation and potential failure. This approach enhances visibility of equipment health, estimates time to failure and increases

that is available in stackable parts, describing the technology at the Marine Construction Europe - Deepwater Development conference in London in March.

Explaining the virtues of Vectus controls, Larssen said they represent a next-generation subsea control system, offering a number of benefits: Less deployment effort and risk, through planning and configuration tools, and modular architecture.

Enhanced operational features include subsea electronics module (SEM) and maintenance, and advanced condition monitoring systems. Improved performance is provided, Larssen says, through better processing power, interface capacity, and networking capabilities.



Aker Vectus control system pulled from Larssen MCE DD 20154 presentation; NB low resolution. Image from Aker Solutions.

Aker's new electronic drive unit is 85cm-high, and can be mounted either horizontally or vertically. The unit has an API class 4 standard interface, modular design, and it can be installed in up to 4000m (13,120ft) water depth, with up to 2700 Nm (Newton metres of torque) maximum torque available. A subsea gearbox on the unit has an API rating from class 7 to class 4, suitable for ball valves, from 2-20in; in a 7in and 3/8in latched configuration for use on Xmas trees; in

production uptime via planned equipment replacement. Three key performance indicators are discussed below including hydraulic pump performance, subsea control valve utilization and digital communications efficiency to demonstrate the benefits of condition monitoring.

The hydraulic system, from the hydraulic fluid pumps topside to the directional control valves (DCVs) subsea, forms the cardiovascular system of a production system. The pumps are the heart of the hydraulic system and are the source of the fluid supply. Frequency and duration of pump operation to maintain required pressure are indicators of system performance. An operational norm can be established by trending pump runtimes and cycles over a period of time. An increasing trend of pump usage translates to a growing demand for hydraulic fluid downstream. With no significant changes to system configuration, such as startup of additional wells, a leakage in the system can be a logical conclusion requiring further investigation.

The DCVs and their companion actuators are on the opposite end of the hydraulic system. Similar to muscles in the body requiring blood to function, the DCVs are the consumers of hydraulic fluid. Wear on the DCVs is known to cause hydraulic fluid leakage over time. As there are no remediation methods available, they are operated until leakage rates reach critical levels and the hydraulic system can no longer provide sufficient pressure to actuate valves. The entire subsea control module (SCM) is then replaced. By trending the accumulated DCV operation cycles over time, the wear out date can be estimated allowing advanced planning for replacement hence avoiding unplanned shutdown. DCV operations can also be used in fluid leakage analysis.

Combining pump performance with DCV utilization, it is possible to begin identifying imbalances between the hydraulic fluid demand and supply. Each DCV controlled actuator is designed to consume a fixed volume of hydraulic fluid during each operation cycle. The pump runtime can be converted to hydraulic fluid volume output. The imbalance is thus determined by comparing the total volume output by the pumps to the total volume consumed by the valves. Such imbalance may indicate a leakage in the system. If additional flow information can be made available in the hydraulic system, such as on the hydraulic distribution systems, the location of leakage may be narrowed by performing localized mass balance within distribution system branches.

If the hydraulic system is symbolic of the cardiovascular system, then the digital communication system represents the production nervous system. As systems age, response time to commands typically increases, commonly referred to as "sluggish control response." This is often misdiagnosed as a software issue, whereas in reality it is due to decreasing efficiency in the electrical/optical components. Success and failure to execute a command from topside are recorded as success and error messages. Communication efficiency is determined by dividing the number of successful messages by total messages recorded. Moreover, the degradation rate can be used to predict noncompliance with the emergency shutdown response window based on data trends.

These monitoring algorithms serve as a step improvement in proactive management of control system health and aim to increase uptime by predicting failure and planning mitigation. A condition monitoring approach also improves the understanding of operational performance and practices and serves as a valuable input in future design of new or retrofit systems. **OE**

Claire Zhao *is a senior engineer at Clarus Subsea Integrity Inc., with four years of experience in risk based integrity management, non-destructive evaluation techniques and riser engineering. Her project experience includes working with major operators in the Gulf of Mexico providing integrity management support and solutions. She holds an M.S. in structural analysis of monuments and historical constructions and a BS in civil engineering.*

Dharmik Vadel *is a vice president at Clarus Subsea Integrity Inc. He co-manages technical and commercial areas of Clarus, a recent spin off from 2H Offshore. In his 10 years of service, Dharmik has managed multi-platform SURF integrity management projects and focused on delivering integrity engineering solutions. Vadel holds an MS in environmental engineering from Oklahoma State University and a bachelor's degree in civil engineering from REC Calicut India.*

HIPPS (high integrity pressure protection systems) applications, and it can be deployed as a linear process actuator.

Other potential applications are suggested for electronic manifolds in double expanding branch valves, and in electronic chokes.

Single side low-voltage and dual redundant high-voltage actuators have been developed. Both feature communications and motor control processors, and motor drivers.

Fitted with dual motor and gear oil systems, the drivers are made using a high-volume production method – to ensure component standardisation. They feature thermal management through direct convection to sea water.

Gearboxes have been tested at up to 1800 Nm with continuous operations, and feature a tailor-made motor unit with life time testing successfully completed. The drive unit is designed for predictable fabrication and qualification units have been built on a production line with fully traceable components. A contract manufacturer has been used for electro-mechanical component production to secure knowledge retention in a cyclic market.

Turning to the economics of the units, a study looking at the performance of a medium-sized subsea production system using electric branch valves and chokes indicated potential lifetime savings of US$25 million through less hydraulic fluid consumption, less power consumption, and faster start up times — meaning less lost production time from a well.

Also the electrical system offers the potential for faster failure detection through enhanced monitoring, Larssen explains.

During 2012, Larssen said Aker Solutions undertook a subsea equipment mapping exercise and determined that valves and drivers were among the most important components in any system. He noted: “Leakage rates for new subsea valves are quite high.”

To prove these new systems, Aker Solutions carried out shock and vibration testing of the electronics, with three stages used before a qualification build. Finite element analysis (FEA) was also used to examine and modify the design.

Test results

- No resonance frequencies on board level with amplification above 5, and below 500Hz.
- No resonance frequencies with amplification above 5, below 250Hz.
- No notching during a two hour random vibration test.

Sub-module qualification tests have been conducted for the gearbox and motor unit, systems testing has been undertaken, and a system pre-qualification test. Formal system qualification testing has also been performed, providing increased confidence in reliability and reduced risk for the unit.

Future applications for these units are foreseen in HIPPS and Xmas tree actuators: So far, a proof of concept system has been built and tested on a 7in and 3/8in valve. Aker Solutions already has its I-Con subsea control system, and SubseaWeb — its subsea architecture concept offering a means of monitoring and controlling subsea systems, using OPC (open process control) connectivity, and transmission control protocol and internet protocol systems.

With the new hardware, however, the company believes it has the enablers for a fully electronic subsea system. OE

Putting hydrates under high-pressure

While methanol/glycol cleaning could be considered the primary removal method, its efficiency in open water is limited. BOURBON has started using high-pressure water jet cleaning as an alternative.

Removing potentially consolidated hydrates from subsea infrastructure is a concern for the oil and gas industry.

Hydrates are concretions, similar to "ice" in particular pressure and temperature conditions, which can form on subsea infrastructure in deepwater. Hydrates can affect the operation of equipment by restricting movement of parts, so they need to be removed periodically.

Cleaning at these depths is carried out using heavy duty or ultra-heavy duty underwater remotely operated vehicles (ROVs), which most commonly apply methanol to dissolve the hydrates. While this can be highly effective, methanol treatment has its disadvantages.

This primary method for cleaning involves pumping the methanol from a floating production system, and diverting the subsea injection point by re-routing piping and installation hoses to "attack" the subsea equipment.

An entire cleaning operation might require more than 10-20,000 liters of methanol, because the effectiveness of using methanol when cleaning the exterior of equipment is reduced by the diluting effect of the seawater.

Due to the volume required, the injection of methanol directly from an ROV-borne skid, typically containing 15 gal bladders, was disregarded.

BOURBON has developed a method using a high-pressure water jet, using local sea water, to remove the hydrates, avoiding using chemicals. The company performed its first water jet cleaning operation using the inspection, maintenance and repair vessel *BOURBON Trieste,* working with its ultra-heavy duty ROV. The job was done on a subsea Xmas tree in 1400m water depth offshore West Africa in 2013/14.

The project involved nearly two year's preparation between the parties. BOURBON first tested three types of nozzles to find the most effective design for the job – a pointed nozzle proved better at cleaning than one with a flatter end or a rotating nozzle. The nozzles were tested and demonstrated to the client before BOURBON personnel embarked on the operation.

The first part of the operation involved using a low-pressure jet (10-20 bar) created by a Zipjet pump, to remove the loosest layers of concretions. The remaining hydrates were then removed using a

The *BOURBON Trieste* lifting the Schilling heavy duty work class ROV.
Images from BOURBON.

high-pressure jet (300-800 bar) generated by a Dynaset pump, in several stages.

In both cases, the ROV positioned the jet 1.5-2m from the subsea equipment, and then gradually approached it to a distance of 50cm. The pressure from the jet could be adjusted by the ROV operator during cleaning up to a maximum level, which was set before the ROV was sent down. The highest pressure setting used was 500 bar, which is able to deal with nearly all hydrate deposits.

The nozzle was located at the end of a "wand," a rod attached to one of the ROV's robotic arms. At the same time the ROV hung on to the subsea infrastructure with is grabber arm. Precise indications on structure architecture were given by the client, this meant the wand could be controlled very precisely to clean even the most difficult-to-access parts of the equipment, accurately, safely and with no risk that the jet would damage it.

During this entire process, the client was also able to follow the operation from the FPSO in real time by viewing the images from the video cameras on the ROV. That meant the client was able to provide instructions, verify that the operation was progressing smoothly and call a halt if they had concerns – or when they were satisfied that the cleaning process had met their requirements.

The operation removed all of the hydrates, while protecting the lines and cables on the structure. Since then, BOURBON has successfully carried out this cleaning process several more times for the same client. The frequency of such operation depends on the density of shallow gas in the seabed.

While the project was a success, it is unlikely that the technique will completely replace low pressure methanol cleaning across the oil and gas industry in the near term, despite the lower cost, environmental risks and time savings, due to operators being more familiar with methanol cleaning, which is perceived as being less risky for the subsea assets.

A growing track record of success, improved knowledge and technological advances are likely to promote wider use of the water jetting technique in the future.

Field operators could also adopt a hybrid approach to hydrates cleaning if they remain concerned about the risks, using high-pressure jets to complete the bulk of the cleaning process and then turning to methanol cleaning for the most sensitive areas of the subsea infrastructure.

Whatever technique is used, removing hydrates is a delicate business. But, as confidence in the ability of ROV operators to use high-pressure jets grows, the established trend towards greater use of this method will only become stronger. OE

Operations underway in the deep.

All terrain trenching

Subsea trenching has become more versatile with Fugro and SMD's Q1400. Mike Daniel explains.

It is important to bury wind farm cables, oil umbilicals and pipelines to protect them from damage, particularly in the crowded, relatively shallow waters off European coasts.

A 2009 report by the International Cable Protection Committee suggests two-thirds of all telecommunication cable breaks are caused by ships' anchors and commercial fishing trawlers. Unburied cables and pipelines present a serious hazard for trawlers which can lose gear or even be pulled under.

Seabed geology varies widely and two types of tractor based system are used for trenching. Conventional systems are deployed from separate vessels, using water jetting for loose granular soils and chain cutting for hard clay and boulders.

Fugro collaborated with Soil Machine Dynamics (SMD) over the design of an innovative, all-purpose trenching system. The Q1400 provided interchangeable water jet and chain cutting skids, which can be exchanged onboard the vessel while at sea.

The Q1400 trenching system can perform jet trenching in soils of up to 100kPa shear strength, i.e. sands and softer clays. For medium and harder clays up to 500kPa, the mechanical chain cutter is used. Jetting speeds are usually 300-500m/hr, but with chain cutting that falls to 100-200m/hr. The Q1400 can operate in 10-3000m water depth.

In jet trenching mode, the Q1400 has a total available power of 1459hp - 1000hp of this is delivered through variable speed drive electric motors to direct-drive water pumps. The jetting tool has twin-legged parallel jet swords and can trench up to 3m deep in soil conditions from 5-100kPa using 2m or 3m jetting swords, with the Q1400 system capable of accommodating pipelines, cables and umbilicals up to 900mm in diameter.

With pre-laid rigid pipe the trenching jet legs fluidize the soil on either side of the pipe causing it to sink into the seabed. For trenching pre-laid flexible pipes the Q1400 uses a 150hp, 2m x 400mm chain cutter and two loading arms, which can take flexibles, cables and umbilicals up to 250mm diameter.

Backfilling can take place at the same time as jetting. Separate water pump systems can either backfill or keep the trench open depending on the client's needs. The method of backfilling depends on the soil type. With chain cutting it backfills naturally, because as the umbilical or cable is trenched with the chain cutter the trench, which is very

Launching the Fugro Q1400 trenching system. Photos from Fugro Subsea.

narrow relative to its depth, will normally partially collapse back.

The vessel deck transfer system has been developed by Fugro and SMD to enable the trenching team to change between cutting and jetting modes. The cutting or jetting skids are switched via a fixed pallet attached to preinstalled skidding beams, which allows changes to be made while at sea, without a crane, and in under 18 hours. The Q1400 launch and recovery system (LARS) uses an A frame equipped with cross beam winches and cursor. The LARS is certified by Lloyds to sea state 6, allowing operations to continue even in a heavy swell up to 3m significant wave height.

Once deployed, the trencher's tracks are used to run it along the seabed for both jetting and cutting operations. Thrusters can be used for adjusting its position, lifting the trencher off the seabed to aid movement in very soft soil; they can also be used to hop along the seabed.

The *Fugro Saltire* has been adapted to take the Q1400 and operates as a dedicated trenching support vessel. The trencher is normally operated in conjunction with a Fugro work class FCV 3000 ROV for pre- and post-trenching surveys, as well as route clearance if debris is found along the cable paths. Fugro's second trencher, based in Montrose in Scotland, can be deployed for projects as required on alternative vessels.

In 2014, Fugro's trencher successfully undertook the trenching and burial of inter-array cables for CT Offshore at Gwynt y Môr wind farm off the North Wales coast. Cables were trenched in the hardest soil area of the wind farm in a minimum water depth of 11m — where ploughing was deemed too difficult — with a mixture of soils and hard clays interspersed with boulders and cobbles, gravels and sand.

The Q1400 has the maneuverability and compact size to be able to trench right up to the cable protection system, which minimizes the need for rock dumping or matressing, potentially saving on cost.

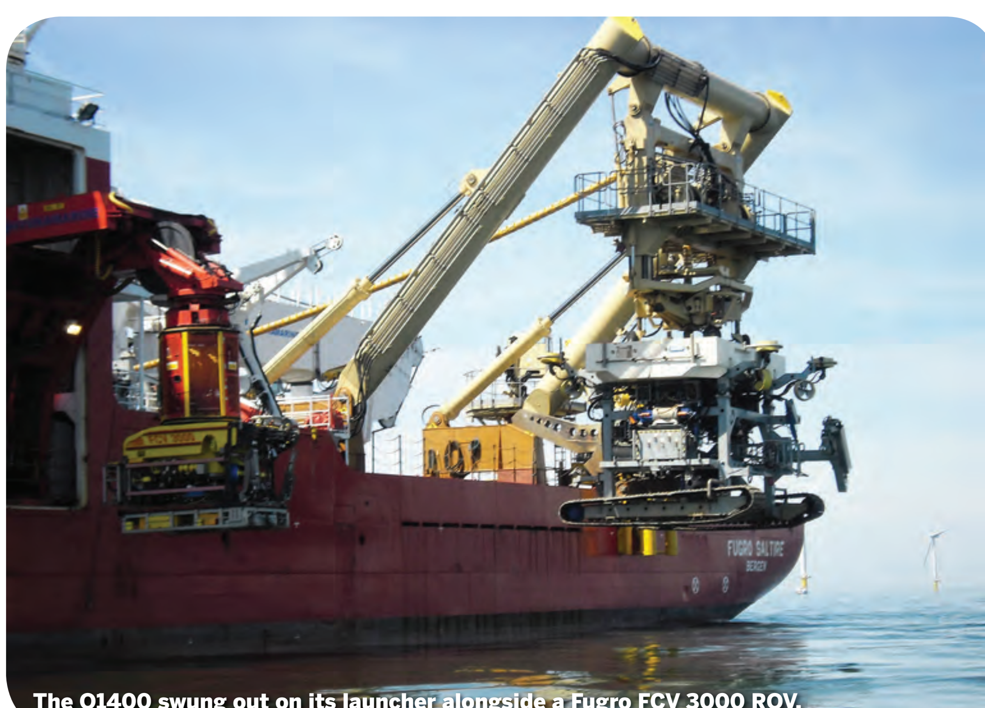
The system had cut its teeth successfully in September 2012 at a wind farm offshore Skegness on the UK's east coast. This involved post-lay trenching of 16 x 120mm-diameter array cables over a distance of around 16km to a trench depth of 1.2m. The work involved mechanical cutting through 300kPa soil consisting of cobbles, flints and chalk with boulder clay, at speeds between 100 and 150m/hr. Despite the difficult terrain overall performance exceeded expectations with array cables being completed from deck to deck in less than eight hours.

Fugro has also carried out oil and gas trenching projects. The first in 2013 was at the Corrib gas field off Western Ireland and involved jet trenching an umbilical from the shore to an offshore installation, a distance of 16km. The umbilical was successfully trenched in a single pass to the required specification, at speeds ranging from 400 to 800m/hr.

The next project, involved chain cutting for a replacement 10km umbilical between a North Sea oil platform and the subsea production manifold. The work involved cutting at 100m water depth in mixed soil conditions with sand and hard clays.

Chain cutting was also needed on a major new field 70km North-East of Aberdeen. Here a 4.5km umbilical was successfully trenched over five days in September 2013. Probably the most challenging oil project was chain cutting on the Bittern field in 2013, 200km east of Aberdeen. Here two umbilicals of 2km and 20.8km respectively, had to be trenched into hard clays at a water depth of 95m. Despite the challenges of the long distance and a very hard seabed, trenching was completed only six days at speeds between 120-200m/hr. OE

***Mike Daniel** is Business Line Manager for trenching and cable installation with Fugro Subsea Services. He has been involved in the subsea industry for over 33 years, starting in 1981 on early North Sea offshore oil and gas pipeline, umbilical installation and burial projects. He was at the forefront of UK offshore wind farm cable installation where he took his experience from oil and gas to the fledgling wind farm business.*



The Q1400 swung out on its launcher alongside a Fugro FCV 3000 ROV.

Plastic fantastic

Polymer-lined pipe has been around since the 1990s, but its potential has yet to be fully tapped, according to those behind JIPs to extend use of this technology. Mostafa Tantawi and David Whittle explain.

Polymer liner insertion into carbon steel pipe.

The UK oil and gas industry is in the midst of some troublesome times. The new, lower price of Brent oil, averaging US$45-60/bbl during the last six months, has seen drastic measures taken to make cost savings and reduce operational spend.

Operators are being challenged to investigate new ways of implementing cost reductions to oil and gas producing assets. Key to addressing these challenges is innovation, and investment into research and development must continue to help maximize the recovery of remaining hydrocarbon reserves.

Extensive research and development has gone into developing pipeline polymer lining solutions, which have the potential to offer considerable cost savings as well as significant operational and technical benefits. These developments have been driven by both industry and consultancies, in an effort to achieve wider understanding of the significant benefits that polymers bring.

Lined pipelines and the traditional alternatives

Pipelines typically form a major proportion of the development cost of a subsea project, particularly for long subsea tie-backs. The costs, which include procurement, fabrication and installation, are mainly driven by the pipeline material selected and method of installation.

A significant part of the cost of maintaining a subsea pipeline is incurred attempting to combat internal corrosion. Carbon steel is traditionally selected for the fabrication of risers and flowlines, with protection from corrosion and erosion afforded by the "thickening" of the pipe, through the addition of a corrosion

Butt fusion welding of polymer pipe. Photos from Swagelining.

Senior development engineer from Swagelining Limited's Technical Development Group machining the polymer lining to accept connector technology.

allowance and introduction of a corrosion inhibitor into the product.

However, for ambient water injection service, the application of a polymer lining system is now becoming the benchmark. Where water injection service requirements are more extreme and in hot sour hydrocarbon service environments, corrosion resistant allow (CRA) lining and cladding, or even a solid CRA, is commonly specified to handle the corrosive nature of the transported product. This method, however, has significant implications on the procurement, scheduling and installation costs of a subsea pipeline.

Polymer lining

Polymer lining technology was introduced to the oil and gas subsea sector in the mid-1990s. Installation is achieved by pulling an extruded polymer pipe through a reduction die to temporarily reduce its diameter. While in this reduced state, the pipe continues to be pulled through the constructed carbon steel carrier (outer) pipe, before being released and reinstated to its initial size so that it fits tightly to the host. Lengths of liner up to 1500m have been installed in single operations.

Following the completion of this insertion process, bespoke flangeless connector technology is used to join together lined pipe sections at the field joints.

Polymer-lined subsea pipelines are traditionally installed by reel lay, J-lay and in bundles. Existing connector technology restrictions have excluded the application by S-lay until now, but new developments are allowing this to be considered as an option.

Technical overview

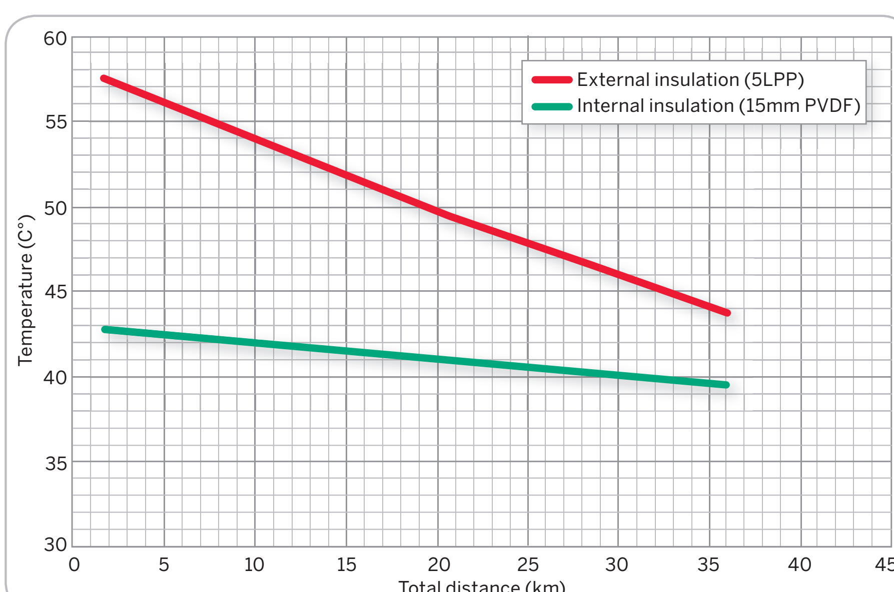
The technical benefits of plastic lined pipelines are vast. Polymers are corrosion resistant, which immediately negates the need for corrosion inhibitors throughout the life of the pipeline or the requirement of a CRA derived pipeline.

Polymer liners are currently favored in the majority of subsea water injection pipelines in the North Sea due to the cost effective corrosion resistance and reliability, with a significant increase in the number of operators recognizing the technology in recent years.

Polymer lining can also allow for potential unprocessed (production) water re-injection service, which saves on the requirement for topside de-aeration equipment. With an increased need for hotter water injection temperatures, different types of higher performing polymer materials are now available to fulfil varying service requirements.

Until now, high performance grades of polyethylene, predominantly polyethylene (PE) 100 have been used for the vast majority of lining applications. PE 100 is suitable for use in water injection service up to 60°C, where long lifetimes can be expected in the relatively benign conditions of treated seawater for example.

At higher temperatures, up to 85°C, and where an option for produced water re-injection may be required, a more chemically resistant polyethylene such as PE-RT (polyethylene of raised temperature resistance) can be used.



Indicative example of steel temperature for external 5LPP system vs. 15mm PVDF internal liner (based on case study conducted by Xodus Group Ltd. Inlet fluid temperature = 60°C) Graphs from Xodus.

installation of polymer liner into steel string.

Polyethylene materials may be considered for hydrocarbon applications but as service environments change as temperature increases, above 50°C the properties of 'engineered polymers' such as polyamides and polyvinylidene difluoride (PVDF) may be preferential.

The technology's internal pipeline corrosion protection has great potential for usage in hydrocarbon pipelines using engineered polymers. It is recognized that the use of polymer liners in subsea production pipelines has yet to be fully developed and that there are challenges in this arena, which must be resolved before polymer lining can be considered in every service application, but these are now being seriously considered by operators worldwide.

Theoretically, in hydrocarbon service, the threat of liner collapse exists, due to the permeated pressure gas build-up in the annular gap between the polymer liner and the inner wall of the carbon steel pipeline. Additionally, the issue of potential liner swelling when in contact with hydrocarbons needs to be considered.

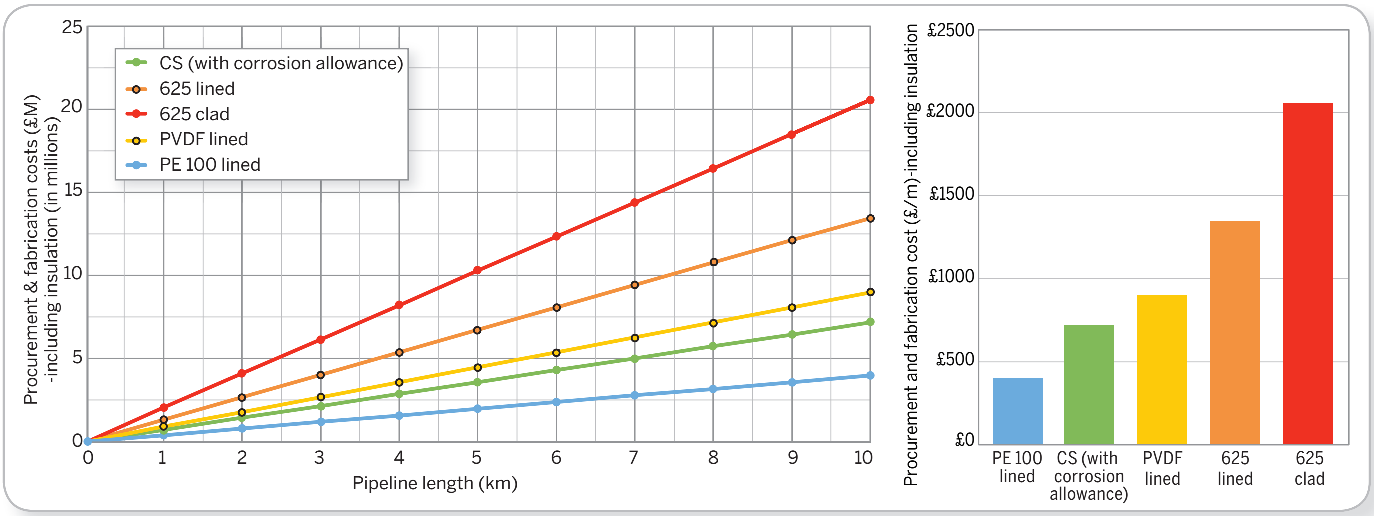
Work to address this is currently being carried out by Swagelining (a UK-based specialist in the design and installation of polymer linings), which has recently embarked upon a joint industry project (JIP) with The Welding Institute (TWI) and Saudi Aramco. This JIP will examine the extent of corrosion incurred in a variety of polymer lined pipelines when subjected to a hot sour hydrocarbon environment.

Swagelining is also currently carrying out technical qualification programs with operators, identifying how polyethylene performs with higher temperature injection water and considering the effects of chemicals used for enhanced oil recovery (EOR).

Using polymer liners in hydrocarbon pipelines can deliver significant technical advantages. Not only are they fully corrosion resistant, polymer liners are also relatively smooth compared to steel and metallurgic alloys. The low roughness of polymers minimizes the pressure drop across the pipeline, which is maintained along the lifetime of the pipeline, unlike steel/CRA roughness which degrades due to erosion and corrosion.

The elastic nature of polymers is also more tolerant to both fluid and particle erosion. These fluids often contain debris and deposits, which can accumulate on the inner wall of a pipeline, causing flow restrictions and occasionally, blockages. It is envisaged that the adhesion between fluid deposits, for example wax and hydrates, and polymer material is lower than that of steel, which decreases this blockage risk and reduces pigging frequency requirements.

An additional advantage for regular hydrocarbon service is that polymers have good heat insulation properties and add significantly to the thermal performance of a pipeline system. For example, a layer of polymer between 10-15mm will have a significant effect on the pipeline overall heat transfer coefficient, greatly reducing the outer insulation



A typical procurement and fabrication cost comparison between polymer liners and alternative corrosion resistant methods (includes indicative pipeline insulation). Graphs from Xodus.

requirement of the pipeline. While a 12in carbon steel buried pipeline with a 5LPP insulation system can typically have a U-value of 3 W/m^2K, a 15mm PVDF liner will result in a U-value around 4 W/m^2K. This can provide substantial cost saving, as the cost of outer insulation is often higher when compared to the cost of carbon steel.

The insulating impact of the inner polymer liner on the inside of the pipe will also result in a reduced steel temperature, which will also enhance the mechanical behavior of the pipeline, minimizing thermal expansion and propensity for global buckling. An indicative example of the reduction in steel temperature when utilizing a PVDF polymer liner is presented in the figure below.

Economics advantages

The use of polymer liners in subsea pipelines can result in substantial cost reduction for both capital expenditure (capex) and operational expenditure (opex). The cost of procurement and fabrication of a PVDF lined pipeline for service application to 130°C is about 50% cheaper compared with the equivalent CRA clad pipeline. In low temperature applications (for example <60°C), where a PE liner can be used, the cost of procurement and fabrication can be 80% cheaper than the equivalent clad pipeline and 40% cheaper than carbon steel pipeline with corrosion allowance. (Figures presented are representative of a 12im X65 pipeline and are indicative only).

Further opex reductions will be achieved by negating the need for corrosion inhibitors, frequent pigging and energy (pumping) costs. These savings are measured across the total life of a pipeline, and adopting at the early stages of a project means that IRM costs can be drastically reduced throughout the average life span of a pipeline.

installation of polymer liner into steel string.

Risk reduction

Corrosion is a critical problem that can lead to major pipeline failure, and in some cases total shutdown, if not monitored and managed properly. This impacts the operator's business with down time, loss of supply and the significant cost of remedial work.

Further to the impact on an operator's schedule and bottom line however, is the dramatic consequences which can result from pipeline failure. Polymer lining technology stops corrosion being incurred from the outset, which is one of its most important benefits.

Polymer lining technology performs to the stringent health and safety standards that the oil and gas industry demands, allowing pipelines to be constructed and installed within a low risk environment and affording lifetime protection.

Conclusion

The future seems bright for the usage of polymer linings for affordable internal corrosion protection. With the average cost of installation and maintaining a pipeline accounting for around 35% of a typical subsea tie-back project, it is little wonder that such efforts are going into research and development activity and cost saving measures.

The ongoing work being undertaken by operators, and the interest being shown by the industry indicates that the message is getting across and polymer lining is being considered as a serious alternative.

Is polymer lining technology finally shaping up to its promise? OE

__Mostafa Tantawi__ is a senior pipeline engineer at Xodus Subsea. He has over four years' experience in subsea engineering and pipelines mechanical design. He has an MSc in Subsea Engineering.

__David Whittle__ has over 40 years' experience in the pipeline industry, in various engineering capacities in the UK and internationally for organizations including British Gas and Subsea 7.

Whittle joined Swagelining in 2009 at the inception of the company as business development director. He works with new and existing clients to determine future industry requirements for polymer lining technology across a range of projects in subsea and onshore pipeline systems.

Making a 'smart' pipe

By Elaine Maslin

Researchers at Norway's SINTEF together with a consortium of industrial partners have developed technologies to enable real-time condition monitoring reports from within pipelines to be transmitted to shore.

The Research Council of Norway-supported SmartPipe technology carries out condition monitoring in real time. This is achieved by installing belts around the pipelines packed with a multitude of sensors which measure pipewall thickness, tension, temperature and vibration.

The sensor belts are at 24m intervals along the length of the pipeline. A thick insulating layer of polypropylene covers the outside of the steel pipe construction, and this is where the electronics are concealed. It is also through this layer that wireless data transmissions can be sent either onshore or to the production platform.

The SmartPipe was launched in 2006 and is being conducted in collaboration with Bredero Shaw, Force Technology, Siemens Subsea and ebm-papst.

Last autumn, 200m of SmartPipe pipeline was laid in Orkanger harbor, Norway, for sea trials. The trials were a success and SINTEF has since performed "reeling tests," to see if the electronics, within the pipeline, would survive the reeling process.

"Pipes are stretched and deformed during such tests, and because the electronics are vulnerable to bending, some of the sensors were destroyed," says SINTEF Project Manager Ole Øystein Knudsen. "But now that we know what happened we can make some small modifications to better protect the electronics."

The next step for SmartPipe is pilot phase. According to Knudsen, an American oil company is interested in using the technology in a trial. "The company contacted us following the Gulf of Mexico accident," Knudsen says. "Initially, they started their own project because they anticipated the future introduction of stricter pipeline monitoring regulations. But when they discovered that SmartPipe had come further down the road, they contacted us. We think this could be a commercial winner."

SmartPipe launched in 2006, in collaboration with Bredero Shaw, Force Technology, Siemens Subsea and ebm-papst. Photo from SINTEF.

The researchers see a number of benefits of using SmartPipe. Since many pipelines also carry produced water from the reservoir, they are vulnerable to corrosion. This is counteracted by adding small concentrations of inhibitor substances. However, errors in concentrations may occur and it may be some time before they are discovered. This may mean that a pipeline has to be decommissioned earlier than planned. Current pipeline condition monitoring by means of inspections and checks is also expensive. The new system will make it possible to identify errors at an early stage and make adjustments.

Another important consideration is the monitoring of free-span sections of pipeline. In areas of undulating seabed, free-span sections may start to swing in response to marine currents. "The new pipes mean that we can measure fatigue development and thus get accurate estimates of pipeline lifetimes," Knudsen says. ■

Shallow water hazards

Protecting, inspecting and repairing pipelines in the shallow waters of the Middle East isn't as easy as it sounds. Elaine Maslin reports.

The Middle East region is home to around 85,000km of pipelines, or about 2.5% of the global total pipeline assets, representing, theoretically, a relatively small issue to deal with when it comes to pipeline inspection and maintenance.

However, it is not the reality in the area, as Manoj Kulshrestha, McDermott Middle East, explained at Subsea Expo held in Aberdeen earlier this year.

Pipelines in the region are predominantly in shallow waters and prone to damage. The seabed is also quite hard, making burial costly and often uneconomical on projects.

Earlier development of fields in the regions has not been systematically planned and coordinated, often with multiple operators following an individual design approach, creating a "spaghetti of pipelines, cables and umbilical in the field, crisscrossing each other."

Manoj Kulshrestha

Statutory guidelines regarding movement of marine traffic around pipelines, vessel anchorage and loading areas are not well established. There is no well-defined protection philosophy. Some of the unburied pipelines are even sometimes without concrete coating.

Fishing activities in the region are not fully controlled — fish traps can often be found on pipelines and cables — and there are no concrete abandonments plans, which means non-operational pipelines are also left in-situ, unpreserved. Environmental guidelines are still immature, Kulshrestha says.

More than 50% of pipeline damage is caused by anchoring (21%) or impact from anchor or dropped objects (30%) while a large proportion of the remainder damages is the result of corrosion (26%), according to a probability analysis of damage to offshore pipelines by ship factors, by Liu, Hu and Zhang, presented to the Transportation Research Board annual meeting in 2013.

In the Middle East, the causes are no different, Kulshrestha says. The damage is caused by anchor handling tugs,

McDermott's DP2 offshore construction support vessel *Thedbaud Sea* in the Middle East. Photos from McDermott International.

drilling rigs, construction vessels and accommodation barge activities, as well as heavy oil and LNG tanker traffic, and fishing activities, which mainly cause cable or umbilical damage.

To prevent damage, operating companies are looking for security shields in the form of radar surveillance around critical offshore assets. Satellite surveillance of vessel operations and information sharing between operators is also prevalent in the region.

"In spite of all preventive measures in place, any damage to subsea pipeline is distinctive and requires a careful engineering assessment prior to any major intervention," Kulshrestha says. "Absence of advanced engineering evaluation may lead to unwarranted repairs and production delays." Kulshrestha says a majority of companies in the region do not employ resources and software to perform such advanced analyses, nor do they have contractual provisions to engage consultants instantly.

McDermott is promoting emergency preparedness, including performing emergency pipelines repair system (EPRS) studies and maintaining repair equipment. Further, Kulshrestha recommends sharing such assets, under an emergency pipelines repair system club, and having long-term contracts for use of vessels to mobilize the EPRS equipment.

Kulshrestha says an EPRS should target for total preparedness and comprise of; detailed emergency response manual, procedures, installation engineering, repair spread, repair ancillaries, and installation aids.

McDermott led an EPRS study for one of the major operators in North Field offshore Qatar. It is the world's third largest non-associated gas reservoir, discovered in 1971, with some 885 Tcf, he says.

In order to assess repair requirements, types of non-corrosive damages are categorized as: gouges; gouge on weld; dent; gouge in dent; dent in weld; abrasion; anchor drag (i.e. displacement); displacement with dent and gouge; crack and crack-like flaws.

To create the repair mythologies for the manual, an assessment of all the possible damage scenarios for all distinctive sections of pipelines is performed, with acceptance limits for dents and gouges created. Anchor dragging (the most prominent damage cause) is simulated using finite element analysis tools and all the results knitted into a decision making process through a flow chart.

A decision making tree is then adopted to aid an operator's decision making on intervention or continuing operation, with time frames included for repair to reduce any loss in production.

While the EPRS offers a framework for emergency pipeline repairs, it does have limitations, however, Kulshrestha says. Primarily, this is based on generalized parameters, while in reality each damage occurrence is unique and can be impacted by the specific location or environment it is in. Some damage therefore requires sensitivity checks and explicit analysis before any intervention.

The industry also lacks codes and practices for EPRS he says, something which need to be developed in the future. OE

End dimensioning of pipe ends at an onshore pipe coating yard.

Images from OMS.

Ensuring the integrity of fatigue-sensitive SCRs

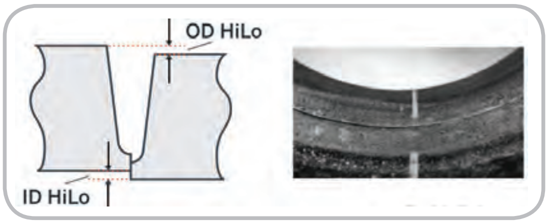
Denise Smiles, of Optical Metrology Services Ltd (OMS), discusses how to correct internal HiLo misalignment between butted pipes.

Deepwater oil and gas pipeline projects present many challenges. As deepwater oil field developments increase around the world, fixed facilities are not always a viable option. Floating production systems are therefore increasing in number, which require unsupported riser designs.

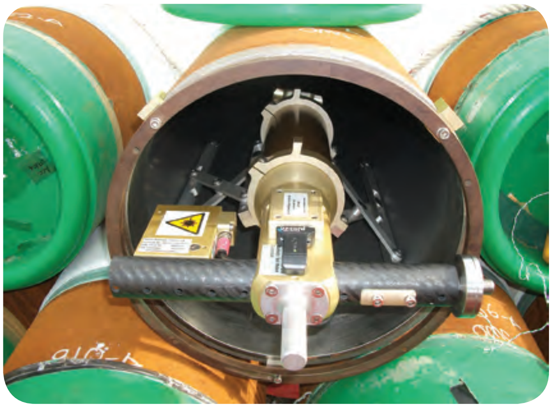
However, these unsupported risers are subject to significant loads from ocean tides, storms, currents and swells, creating a highly dynamic environment for the steel catenary riser (SCR). This, in turn, necessitates design and fabrication processes that mitigate stress and fatigue factors. Ensuring the integrity of fatigue-sensitive SCRs is therefore one of the most challenging aspects of deepwater development.

A number of highly critical aspects of the pipe fabrication process must be guaranteed to be correct. One of these is the internal HiLo misalignment between butted pipes.

Minimization of HiLo contributes to a good weld and decreases stress at the weld joint. Typically the HiLo is required to be less than 0.5mm in fatigue-sensitive pipeline sections. In engineering terms, this is a considerable challenge, particularly given that the pipe used in these applications is often seamless, which means it inherently has wall shape and thickness deviations.



Internal HiLo misalignment between butted pipes.



OMS' automatic pipe end dimensioning tool.

One method of dealing with HiLo misalignment is to counterbore the pipes, but this might not be a viable method of controlling pipe geometry due to cost considerations or to limitations on pipe wall thickness. If counterboring is not viable, how can a pipeline contractor ensure that the pipe fit-up, welding and pipelaying processes run smoothly with minimal interruption?

To help prevent these kinds of bottlenecks, save costly delays and to minimize project risk, pipe end geometry can be captured, recorded and analyzed. Automatic, laser-based measurement tools can be used to measure geometrical features of pipe ends, normally performed onshore, although this process sometimes has to take place on a cargo barge. This measurement data, if used correctly, can then help to ensure that pipes delivered into the bead stall will fit together easily and within the welding specification requirements. Better weld quality will lead to fewer cut outs and repairs, reducing costs for the pipeline contractor.

The measurement tools can be used to measure the inner diameter (ID), outer diameter (OD) and wall thickness (WT) of pipe ends in rapid time. Typically, several thousand ID and OD measurements of a pipe end can be measured simultaneously in less than 10 seconds, enabling hundreds of pipe ends to be measured in one shift. In some circumstances, pipe ends can be measured in stacks. This means less time on site and less pipe handling (reducing costs), thus minimizing delays and costs for the pipelay contractor. Laser measurement tools are also very accurate (typically to 0.05mm).

Data from laser measurement tools can be made available to pipe optimization software, which will include some sort of simulation or sequencing software. SmartFit, the winner of a Queens Award for Innovation in 2014, is a system developed by OMS for managing pipe preparation and fit-up in readiness for welding prior to pipelaying. Used predominantly in the oil and gas industry, this system ensures accurate fit-up of

pipes prior to welding and laying in trenches, thus preventing environmentally damaging leaks. In parallel, OMS has developed bespoke laser measuring equipment and methodologies with supporting software, for optimizing pipe fit-up. The service reduces costs for customers through faster pipelaying and improves quality by eliminating misaligned pipe ends.

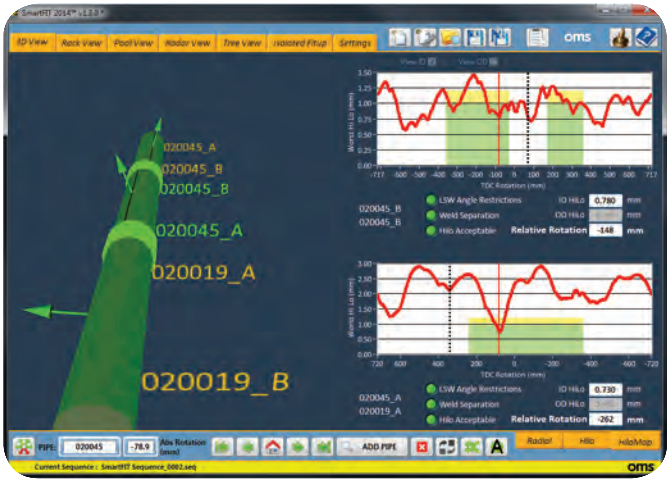
Each pipe end is measured, identified and entered into the pipe optimization software, which analyses the fit-up of pipes and allows the operator to mark the best rotational position on each pipe end. In the bead stall, these marks are aligned to immediately achieve the best rotational position so that misalignment is minimized and the project HiLo is easily achieved.

Any problem pipes that won't fit at a specified HiLo are also indicated and can be re-sequenced or removed completely so that fit-up problems do not occur in the bead stall. Production delays due to misaligned pipes are avoided.

Experience shows that with typical flowline HiLo limits — and using typical seamless line pipe that has not been counter-bored — fit-up issues can occur regularly. For a HiLo of around 1.0mm to 1.2mm, problems are likely to occur every 10 to 20 pipes (this varies according to the exact type of pipe). Using pipe optimization software enables the required HiLo's to be achieved in the bead stall without trial and error. It also identifies problem pipes in advance, so that this can be removed from the pipe welding sequence, therefore avoiding any problems in the bead stall.

Elements of pipe optimization can be deployed in various ways to suit the practicalities of different production processes, both onshore and offshore. OMS has applied the system aboard a wide variety of pipelaying vessels and spool bases around the world.

Pipes being unloaded from a supply barge to the pipelaying vessel.



The SmartFit software has the ability to sequence single and multiple pipe ends (i.e. doubles, triples and quads).

Case Study: Offshore pipe fit-up

In 2014, OMS was asked by a pipeline contractor to provide pipe fit-up services for a deepwater pipelaying project off the coast of Australia.

Project details

- Pipe size: 16in nominal/406.4mm x 21mm + 3mm CRA (corrosion resistant alloy)
- Quantity: Approximately 1100 pipes
- HiLo permitted: 1.0mm internal maximum
- Long seam weld control: Top 90°, separation of 100mm (minimum)

The customer had already carried out end dimensioning of the pipes prior to OMS' involvement. After measurements were taken, the customer deemed the pipes to be satisfactory and within the manufacturing specification. Welding of the pipes began offshore on the pipelaying vessel, with a target of 40 welds per day. Unfortunately, this target was not achieved due to poor pipe fit-up leading to excess HiLo. The peak weld rate at that time was approximately 15 welds per day.

OMS deployed a team of three operators direct to the pipelaying vessel. This meant that there was no opportunity for upfront analysis of pipe measurement data or reporting. Pipes were measured onboard the pipelaying vessel and support barges. One OMS software operator was required per shift to manage pipes into the bead stall. Two OMS measurement operators were required per shift until all the pipe profile measurement data had been collected (after which they were demobilized).

OMS numbered the pipes in the pipe stack (prior to beveling) to sequence the pipes ready for the riggers to collect. No extra pipe handling was required here, as only planned pipes were moved. Rotation marks were then applied to the pipes once they were placed on the ready rack.

Using pipe optimization software, it was found that most of the pipe joints would fail the acceptable HiLo criteria in multiple positions. However, the project HiLo could be achieved at certain positions when the pipes were rotated. In the following example, possible misalignment was 0.4mm at best rotation, but up to 1.3mm at worst. Result: 300% increase in weld rate.

All pipe joints sent through to the bead stall were within the client requirement of 1mm HiLo. The weld rate was increased to an average of 40-45 welds per day — an increase from the initial rate (i.e. 15 welds per day) of 300%.

In addition, OMS was able to assist with traceability issues, including identifying any pipe numbering duplicates or errors. OMS not only helped speed up the welding process through the time saved in lining up the pipes, but also helped to reduce the number of weld repairs and cut-outs. OE

*Since joining OMS in 2006, **Denise Smiles** has been actively involved in the execution of many deepwater oil and gas projects that required improvement of dimensional tolerances, fit-up solutions in the firing line and delivery of specific pipeline architectures to ensure best fit-up with difficult pipes, including Gorgon (Chevron), Quad 204 (BP), Wheatstone (Chevron), Ichthys (Inpex), Jack & St Malo (Chevron), Julimar (Apache) and Laggan-Tormore (Total). Smiles was appointed CEO of OMS in 2014. She holds an MA in business administration and management.*

Increasing the tension

Maritime Development's four-track, 75-tonne tensioner. Photos from Maritime Developments.

By Elaine Maslin

Maritime Developments, based in Peterhead, Scotland, has released its first four-track, 75-tonne pipeline tensioner, not long after shipping out the third of a 50-tonne version of the unit, which took center stage at Subsea Expo in Aberdeen in February.

The firm, set up 15 years ago, sold its first TTS-4/140 Series, 50-tonne, four-track pipelay tensioner in 2013. The design was patented in July 2014, ahead of the 75-tonne version unveiling earlier this year.

The four-track caterpillar track system for installing or recovering pipe, flexibles, umbilials and cables in two- or four-track mode has been designed so it can be used horizontally, hung off vertically, or on a ramp, as well as containerized for shipping. In horizontal mode, one of the 4m-long tracks can open to load pipe, maintaining one track at the base to centralize the load. In horizontal mode, which can be harder to load pipe due to vessel motion, but it is no longer necessary to have a centralizing track, two of the tensioner's tracks can open out to load pipe, which may have end termination pieces on it.

Derek Smith

The V-shaped caterpillar tracks grip the product with failsafe hydraulic cylinders. The maximum pull force is rated at 51-tonne in four-track mode (0.09 coefficient of friction), and 25.5-tonne in two-track (0.09 CoF). Payout speed on 50-600mm outer diameter product varies up to 900m/hr (at 60Hz) with 10-100% digital tension control.

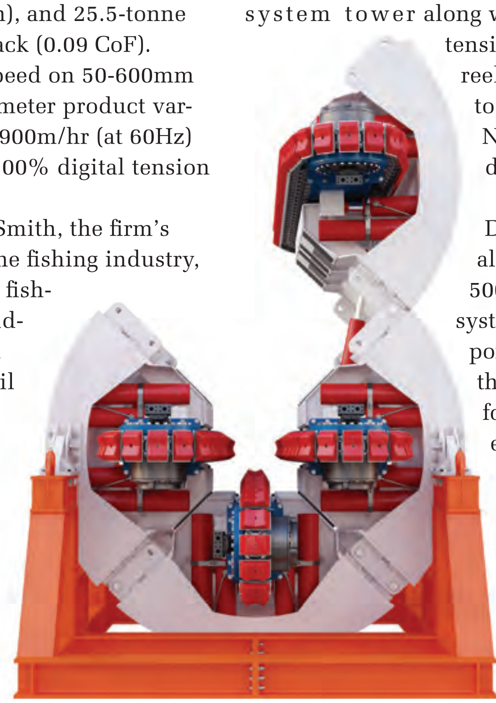
Derek Smith, the firm's CEO, started out in the fishing industry, building winches for fishing vessels and providing port services, but diversified into the oil and gas sector, and now provides back-deck equipment including winches, tensioners, and reel drives, mostly serving the <150-tonne line pull market place, in <500m water depth, acknowledging that the market above that level is already well served. By July this year, the firm will have supplied a full back-deck spread to one vessel.

In some areas, the industry could learn from fishing, he says, especially around control systems. "Operating systems on fishing vessels are very sophisticated," he says. Fishermen put acoustic devices on their nets which transmit to a transducer on the hull, the signals from which are then used to automatically control the geometry of the nets by control tension. Smith thought this could be used in the industry, on equipment which didn't have accurate constant control systems, by floating equipment on load cells, with the operator just dictating what he wants the system to achieve. The firm has developed its own software, in-house, for its systems.

While the fishing industry systems are sophisticated, they are built to be robust and easy to use, with simple interfaces and reduced decision making requirements, whereas in the offshore industry the systems need more technically adept staff to operate them, Smith says.

The business recently secured the first order for a portable overside vertical lay system (PVLS) from a leading installation contractor. Maritime Developments will deliver a bespoke vertical lay system tower along with a four-track tensioner and a multi reel drive system to support a major North Sea field development.

Maritime Developments has also delivered a 500-tonne reel drive system (RDS) in support of a project in the US. It was the fourth RDS order executed by the business since the product's launch in 2013: three 400-tonne systems have also already been supplied.



The 75-tonne tensioner with one track opened out for loading product.


a better way to view
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Spotlight on the Gulf

Ultra-HPHT, other technologies advance despite oil price drop, but actual deployment in Gulf of Mexico could slow. Bruce Nichols puts it in perspective.

Anadarko's Lucius Truss Spar, located in 7100ft of water, in Keathley Canyon 875, 236mi offshore in the Gulf of Mexico. Image from Anadarko/Robert Seale.

One question arising from the plunge of oil prices to US$50 from $100-plus is whether the slump will slow development of the ultra-high pressure, ultra-high temperature (u-HPHT) technology needed to produce the deepest recent discoveries in the Gulf of Mexico.

The answer appears to be that any slowdown will be slight, though field deployment – key to long term advances – could slow if prices stay at $50. Lower prices could delay Lower Tertiary projects not yet sanctioned like BP's Kaskida, Cobalt's North Platte and Anadarko's Shenandoah.

For now, u-HPHT technology development is still high on the capital investment to-do list, especially for big companies, and it is likely to stay there barring a more severe price drop, analysts say.

"They remain focused on it, very much so. Oil prices really haven't impacted that. The technology has really got to work. They're looking long term. This hiccup is not stopping that," says Imran Khan, Wood Mackenzie's senior research analyst for the Gulf of Mexico.

The reason: Unless and until some game-changing breakthrough occurs, "you can't make new Lower Tertiary projects work at these oil prices," Khan says. In a recent report, Wood Mackenzie estimated breakevens as high as $70-$80/bbl for Kaskida, North Platte and Shenandoah.

BP is pursuing Project 20K to develop subsea equipment that can withstand Lower Tertiary pressures of 20,000psi and temperatures as high as 350°-400°F. BP has been quiet about progress, and spokesman Brett Clanton declined an update. But he said, "We're still moving ahead."

FMC Technologies has had more to say about its efforts, suggesting that the main challenges are solvable by shaping existing materials and tools to the task, developing industry standards for new systems and proving they will work reliably in the field as well as the laboratory.

"The full process involves years, not months," says Patrick Kimball, FMC Technologies spokesman, but he noted the effort has been underway since at least 2012. Prior to the price drop, FMC Technologies' estimate was 20k, 350°F equipment would start being installed in 2017 or 2018.

There are challenges that go beyond developing standards and designing and proving new production systems.

The Seals challenge

One area is elastomer seals. Existing elastomers meet current wellhead pressure and temperature standards, no more than 15,000psi or 275°F. But it has been hard to find elastomers that tolerate both hotter hydrocarbons and colder seawater at depths of 10,000ft.

"The challenge with those materials is you can either get them to work on the high side or the low side but rarely both," says Elliott Turbeville, FMC Technologies global materials manager. "When you get above 350°F, it gets even more challenging to even get them to work on the high side."

FMC Technologies already relies on metal-to-metal seals as primary barriers, but elastomers have been valuable as secondary or tertiary barriers. So the problem continues to be worked, and the company is optimistic a solution will be

found soon, Kimball says.

On the metals side, Turbeville says the issue is not to find new alloys that will work. Existing steel and nickel alloys should serve equipment needs. The issue is validating the metals for the more challenging u-HPHT deepwater environments, and testing has thrown some curves.

Agreement on how to do testing, which standards to apply, is as important to industry adoption as the materials themselves. There is a debate over the need to use fracture mechanics as part of a new design code rather than the pressure-based calculations traditionally used to validate designs.

"You need to understand the real fracture toughness of the material in the prescribed environment and you need to determine, based on that fracture toughness and the types of flaws you could have in that material, what the life of that component will be," Turbeville says.

There aren't many laboratories capable of doing that, he says. Lots of labs can do it in ambient air. "Our challenge is we need to do it at 400°F with 180,000 ppm of chlorides and high H_2S, and that's where the challenge comes in," Turbeville says.

One way to withstand high pressures is to build equipment with thicker, heavier walls, but there is a need to keep wellheads, manifolds, flowlines and other components as light as possible so that construction vessels can heft the pieces and install them on the seabed.

Because there are limits on ability to control weight while withstanding higher pressures, more capable construction vessels will be required.

The need for heavier lift vessels

"Redesign of all of these components is going to have a knock-on effect in terms of the vessels that you need to deploy it, the cranes on board, the things you use to lower them to the seafloor, the rigs," Kimball says.

There are other metals issues. Operators are seeing unexpected failures in high-strength, corrosion-resistant nickel steels, even in less challenging environments than u-HPHT, and there is a need to overcome that concern, Turbeville says.

In the case of carbon manganese steel, increasing pipe wall thicknesses to withstand higher pressures threatens one of the material's advantages, field weldability, Turbeville says.

"There may be an opportunity there to develop new alloys that are high strength and highly corrosion-resistant," Turbeville says. "And it may be we just have to get creative with our engineering of existing alloys to figure out how to use them safely in ways we don't presently have to do."

So far, the industry has been able to sidestep u-HPHT issues in Lower Tertiary developments by advancing in increments. FMC Technologies has had a 20k wellhead for some time. Cameron has built a 20k blowout preventer.

The Gulf's earliest Lower Tertiary developments, Shell's Perdido, started up in 2010, and Chevron's Jack/St. Malo, brought online this year, are Lower Tertiary projects whose particular characteristics allowed development with technological advances that were more incremental than revolutionary.

Just because a Lower Tertiary development is u-HPHT at the well bottom in the reservoir doesn't mean it will present u-HPHT conditions at the wellhead, says Sean Shafer, consulting manager at Quest Offshore Services. Combinations of existing equipment can solve problems.

"There are ways to mix and match," he says.

Next LT projects in 2016

The next Gulf of Mexico Lower Tertiary projects are scheduled to come in 2016, ExxonMobil's Julia and Shell's Stones, and both rely on further incremental advances as well as carefully modulated, relatively small first steps.

Bottomhole temperature and pressure data haven't been made public, Shafer says, but the two projects wouldn't be proceeding if they presented insurmountable challenges.

Still, there is caution, he says. Even in manageable conditions, there are uncertainties about the productivity of the Lower Tertiary. There are questions about permeability and porosity and, despite high bottom-hole pressures, projects require subsea boosting to accomplish production.

At Julia, ExxonMobil, which has estimated 6 billion bo in place, is reducing risk by tying back to Chevron's Jack/St. Malo and initially aiming to produce just 34,000 b/d. Shell estimates Stones has 2 billion bo in place, but will start by producing 60,000 b/d.

More recently, BP, Chevron and ConocoPhillips have joined together to develop the Tiber and Gila discoveries and the Gibson prospect, possibly with a single hub serving all three developments, Shafer says.

"The idea is let's put something out there that's a bit smaller, produce from wells, see whether the production profile falls into our assumptions," Shafer says. "This is really about feeling out the Lower Tertiary."

Both Stones and Julia involve technological advance, of course. Stones will

Chevron's Big Foot semisubmersible floating production system on 14 March was towed into the Gulf of Mexico from Kiewit's Ingleside, Texas, yard, one of six major projects scheduled for startup in 2015. Photo from Chevron.

feature the US Gulf's second floating, production, storage and offloading vessel with a disconnectible turret system, lazy wave risers and polyester moorings (*OE: September 2014).* Julia will feature the Gulf's first high integrity pressure protection system, which is intended to isolate equipment downstream of the wellhead from higher pressures. It is technology proven elsewhere in the world but likely to be important for future Lower Tertiary developments.

Even if oil prices hadn't dropped, development costs using technology already available had become a big issue. Service companies as well as oil companies like BP, Chevron and ConocoPhillips are teaming up to cut development costs. A recent example: FMC and Technip, have formed Forsys Subsea to increase efficiency of field design and construction and thereby help control costs.

Lowering contractor costs may, in fact, soften the impact of lower oil prices, Wood Mackenzie said in a recent report, making it economical in future years to move forward with developments currently too costly to pursue.

Sampling, boosting advances

Other production technology advances in the Lower Tertiary include the subsea sampling system and single-trip multi-zone frac-packs employed at Jack/St. Malo and the various subsea boosting systems being employed at Perdido, Jack/St. Malo, Julia and Stones.

In drilling technology, Statoil and Chevron are leading the way in trying to commercialize ways to reach deeper targets with fewer casing strings and more control of borehole pressure. Statoil is deploying Enhanced Drilling's EC-Drill system. Chevron opting for dual-gradient drilling (*OE: October 2014*).

Statoil has put the EC-Drill system on the *Maersk Developer* and has employed the system on at least one well, Perseus, which turned out to be non-commercial. Statoil also used the *Developer* to drill Yeti, where it made a discovery in late April. The *Developer* moves next to the Thorvald prospect.

Statoil, which has used EC-Drill in shallower water wells offshore of Norway, has declined to discuss EC-Drill's performance on deeper water prospects in the Gulf. "They want enough time and experience to sort out what it does and doesn't do well," says Jim Schwartz, Statoil's spokesman in Houston.

Chevron has been preparing for months to commercialize its system using the DGD-equipped drillship the *Pacific Santa Ana*. But so far the company has not discussed results. It is unclear whether the technology was used on the recent discovery at Anchor or a subsequent prospect, Sicily.

While research and experimentation continues in Lower Tertiary technology, development hasn't slowed yet in the deepwater Gulf's more familiar Miocene trend.

By the end of this year, six major projects – all tapping parts of the Miocene and-or nearby Pliocene – will have come online, if all schedules hold, Anadarko's Lucius, Chevron's Big Foot, Exxon Mobil's Hadrian South, Noble's Big Bend-Dantzler, Deep Gulf's Kodiak and LLOG's Delta House.

Next year, Anadarko's Heidelberg and Noble's Gunflint, also developing non-Lower Tertiary geology, are scheduled to come online. Further out, Hess is working toward first production at Stampede in 2018.

SBM Offshore's Turritella FPSO will be the second deployed in the Gulf of Mexico for Shell's Stones development.

Images from SBM Offshore.

Development surge in Miocene

"From a development point of view, this year, we don't see a slowdown in activity. We see a higher level of spend," Khan says. "Part of the reason is just the number of projects in the final stages of being brought online."

And u-HPHT technology is not the only area of innovation. Upcoming 2015-16 projects focus on new ways to increase efficiency and cut cost.

Anadarko is pursuing the design-one, build-two concept with nearly identical spars at Lucius and at Heidelberg, the latter due online next year. LLOG is advancing standardization in development of its Delta House hub and surrounding fields.

In future Miocene activity, Shell is moving forward with front-end engineering and design for its Vito discovery, and BP has filed a long-awaited revised development plan for Mad Dog 2 aimed at reducing development costs.

But how fast those projects become reality depends on the future direction of oil prices.

BP has won regulatory approval for its new Mad Dog 2 plan, featuring a semisubmersible production platform rather than the originally planned spar, but executives have told investors the project probably will be delayed and re-evaluated again.

And future exploration – the necessary lead-in to developments beyond the 2015-16 surge — is less certain. Companies are slowing the pace as a significant number of rigs go off contract this year and next, Khan says.

Both the Baker Hughes and US government tallies of rig activity in the Gulf – though using different methodologies and including both exploration and development drilling – fell by more than 20 in 1Q 2015, Baker Hughes' to 35, the government's to 47.

"On the exploration side, our view is it's likely to plateau or maybe pull back marginally. We've had some pretty good years in terms of discoveries the last three years. It's been a nice uptrend, but we see that plateauing off," Khan says. OE

Tracking floating production in Mexico

Bruce Crager profiles some of the floating production vessels already being used offshore Mexico, and highlights what is yet to come.

FPSO *Yùum K'ak'Náab* is currently operating in the KMZ oilfield in the Bay of Campeche.
Photos from Pemex.

Pemex currently has over 232 fixed production platforms in water depths shallower than 200m with no hydrocarbon production in water depths deeper than 200m.

There is a huge offshore development contact between US and Mexico. It stretches from the US-Mexico land border on the coast SSE into the east-central Gulf to the "donut hole" where the US and Mexico have signed a boundary treaty to divide their portion. Cuba is the other party to this area and treaties are still being negotiated for its boundaries.

Pemex assigned 169 blocks to CNH, which will be offered for leasing. Most of these blocks are offshore.

Due to the relatively shallow water depths and the relative closeness of producing blocks to shore, there is only one floating production facility installed offshore Mexico, the FPSO *Yùum K'ak'Náab*. There is also one large FSO and three well test vessels.

The FPSO *Yùum K'ak'Náab* (YKN) vessel was converted from a tanker to an FPSO in 2007 by BW Offshore. It is currently operating in the KMZ oilfield in the Bay of Campeche. The vessel is one of the largest FPSOs in the world and can store up to 2.2 MMbbl. It is turret moored in 100m water depth and cannot be disconnected in hurricanes. The process system includes the capability for 200,000 b/d processing as well as blending, mixing stabilized heavy and light oil of API 13 and 21, from other locations. It has an oil throughput of up to 600,000 b/d. It can also handle 120 MMcf/d of gas including H_2S in the gas phase (approx. 400 ppm). The gas is sweetened with an amine plant and used for fuel.

The FSO *Ta' Kuntah* is operated by Pemex in the Cantarell Field in the Bay of Campeche. The vessel was converted from an ultra large crude carrier (ULCC) tanker and installed in 1998. The vessel was originally owned and operated by MODEC, who sold it to Pemex in 2013. It can handle 800,000 b/d and store up to 2.3 MMbbl. The vessel is permanently moored in 75m of water using a SOFEC external turret that is connected to two flexible lazy-S risers. *Ta' Kuntah* has both side-by-side and tandem offloading capabilities and can offload from both locations simultaneously.

The FPSO *Crystal Ocean* was built in 1999 by Kvaerner Govan and is owned by Rubicon Offshore. It is one of the smallest FPSOs in the world and one of the few to have a dynamic positioning system. The vessel can handle up to 40,000 b/d and uses DP3 with a disconnectable turret. It is operated as an extended well test (EWT) vessel by *Blue Marine* for Pemex.

The *Toisa Pisces* is a well test and servicing vessel owned and operated by Sealion Shipping Ltd It was first used in Mexico in 2002 and has a length of 106 m with a 27-m beam.

The *Bourban Opale* is another well testing vessel that is owned by Bourban Ships AS and operated by Sealion Shipping Ltd. The vessel started working in Mexico in 2006 and has a length of 91m with a breadth of 19m.

FSO *Ta' Kuntah* is operated by Pemex in the Cantarell Field in the Bay of Campeche.

FPSO *Crystal Ocean* is operated as an EWT vessel by Blue Marine for Pemex.

Future FPSO Plans

Pemex has plans to add a number of FPSOs in the future. A replacement FPSO for FSO *Ta'Kuntah*. The *Ta'Kuntah* is located in the Cantarell field, which is beginning to produce water. One solution is to remove the existing FSO and replace it with an FPSO able to handle water production.

Pub/Issue	Offshore Engineer_May
Size	B: 8.5 x 11.125 T: 8.125 x 10.875 L: 7 x 10
File Name	MMM

Above: *Toisa Pisces* Well Testing Vessel is owned and operated by Sealion Shipping Ltd.

Right: *Bourbon Opale* Well Testing Vessel is owned by Bourbon Ships AS and operated by Sealion Shipping Ltd.
Photos from Pemex.

The produced water would be removed from the oil, cleaned to meet discharge requirements and dumped overboard.

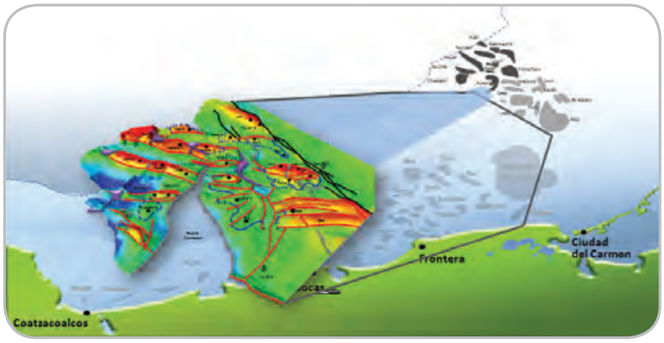
The Ayatsil-Tekel field development will produce heavy crude oil from several fields discovered between 120-145km northeast of Ciudad del Carmen, a 1100sq km region in the southern Gulf of Mexico. The FPSO being designed for this development will handle crude from 16-21° API gravity, be able to process and treat 50,000 b/d of water and compress and dehydrate 25 MMcf/d of gas. It will be able to handle the sour crude with H_2S up to 24% mol and CO_2 up to 18% mol. Crude from adjacent platforms with be blended on the FPSO. Associated gas will be used for fuel on the FPSO with some fuel gas going back to the fixed platforms. The double hull vessel will be moored in 120m water depth using a disconnectable turret to avoid hurricanes. It will be able to store at least 1.5 MMbbl of crude. The contract for the *Ayatsil* FPSO is scheduled to be signed by the end of 2Q 2015.

In addition to the FPSO, the field will require a EWT vessel capable of processing and separating up to 15,000 b/d of crude with densities of 6-14° API gravity. The processing system will be able to handle H_2S up to 30% mol and CO_2 up to 20% mol, and be able to store 500,000 bbl while on location. The vessel will use a hybrid DP2 system for station-keeping and operate in 80-700m water depths. The contract for this EWT vessel is scheduled for signing by the end of 1Q 2015.

A subsea well will be drilled and completed at each location, which will be tested prior to the arrival of the EWT vessel. A drilling rig will complete the well, including a downhole pump, and install a subsea tree. Subsea installation vessels will then install a production riser, control umbilical, and power cable for the downhole pump between the subsea tree and a buoy that will connect to the EWT vessel when it arrives. While the vessel is testing this initial well, a drilling rig will drill and complete a second well, and install a separate subsea tree. A second set of production riser, control umbilical, and power cable will be installed and connected to a second buoy.

When the first well test is complete,

the EWT vessel will move to the second well, connect to the buoy, and begin testing this well. A drilling rig can then go back to the first well, recover the subsea tree and downhole completion, and plug and abandon the well. The first set of production riser, umbilical, and power cable along with the associated buoy can also be recovered. All of the recovered equipment can be refurbished and reused on a future well. This "leapfrog concept" will be continued for years at locations in varying water depths. It is expected that each well will be tested for at least six months.



The Ayatsil-Tekel region will be the site of EWT operations.
Image from Pemex.

Other FPSOs are likely to be required for other locations offshore Mexico. This includes any deepwater locations such as those near the Mexico/Texas border. As Pemex contracts with other operators as partners, it is likely that these operators will bring floating technology with them for Mexican projects. In addition, the Round One lease sale should result in leases won by a number of international operators, who bring experience with floating production systems and subsea tiebacks.

Conclusion

Mexico has a rich history of offshore production based on many years of Pemex activities. In the past, these fields were located in shallow water and were developed using fixed platforms with pipelines to shore in most locations. As new operators move into the Mexican market and as new fields are developed in deeper waters, it is likely that the use of floating production systems, particularly FPSOs, will increase. OE

Since 2010, Bruce Crager has served as executive vice president, expert advisory group for Endeavor Management located in Houston. He leads the firm's group with a focus on offshore, subsea and marine activities. He has 40 years' experience in offshore drilling and production, primarily in management positions. Since joining Endeavor, Bruce has consulted for many clients, including Addax Petroleum, Afren, Audubon Engineering, Barra Energia, Cal Dive, Cameron, ENI, Maersk Oil and Gas, Petrobras, Pemex, Ridgewood Energy, Shell and VAALCO Energy. Bruce holds a BS in Ocean Engineering from Texas A&M University and was selected as a Distinguished Graduate of TAMU's Zachary Department of Civil Engineering in 2008. He also holds a MBA from the University of Houston, has co-authored 4 patents, and has written numerous technical and management articles.

Red Hawk spar flies home

InterMoor's Dusan Curic discusses the decommissioning of Anadarko Petroleum's Red Hawk spar in the US Gulf of Mexico, a job that involved several industry firsts.

The world's first, and so far only, cell spar is also the first spar upended and moored without using construction vessels or derrick barges. Anchor handling tug supply (AHTS) vessels were utilized instead of the conventional methodology. This is the first producing spar decommissioned and the first spar turned into an artificial reef or "reefed" FPS hull and the deepest floating platform decommissioned in the Gulf of Mexico. All these are synonyms for Red Hawk Spar, a former FPU installed by Kerr McGee, an Anadarko predecessor company, and now an artificial reef in Eugene Island block 384 offshore Louisiana.

Top: With holes cut into the hull, Red Hawk spar is being tipped underwater. Above: Red Hawk Spar was towed vertically to its reefing site. Images from InterMoor.

Red Hawk's productive years

Red Hawk spar began its first life in 2004 when it was installed in 5300ft of water in Garden Banks block 876 by horizontal wet towing from Ingleside, Texas, upended to a vertical position and moored using a chain-polyester-chain system with suction pile anchors. Anadarko found itself in a position as the lease holder on a field that was soon to expire. A decision on the platform's decommissioning had to be made. When the time came to decommission the spar, it was determined that simply reversing the steps from the installation procedure–ballast the hull to a horizontal attitude and tow it back to shore–was not the best solution.

Decommissioning

A totally different approach was taken thanks to Anadarko's experience with fixed platforms which had been included in the US Bureau of Safety and Environmental Enforcement (BSEE) Rigs-to-Reefs program. When a suitable location was found in 430ft deep Eugene Island block 384 and after BSEE and the Louisiana Department of Wildlife and Fisheries agreed that marine life would benefit from converting the Red Hawk hull into an artificial reef, the planning phase for the decommissioning was ready to begin.

Anadarko teamed up with two main contractors, Versabar for the topsides lift and InterMoor, an Acteon company, for integrated decommissioning engineering and offshore execution. InterMoor's scope included ballasting and deballasting of the Red Hawk hull, mooring disconnect and recovery, hull tow and finally, hull reefing at EI384. Ballasting and deballasting were performed remotely from McDermott's

Topsides being lifted off towing.

Derrick Barge 50 (*DB50*), while Edison Chouest Offshore's AHV *Kirt Chouest* was used for mooring disconnect and mooring recovery. InterMoor has not only supported multiple projects for Anadarko prior to Red Hawk, but also was involved, at the time as a division of Technip, in the installation of Red Hawk. Todd Veselis, general manager of Permanent Moorings for InterMoor, said that engineering manuals from Red Hawk installation were still shelved in his Houston office when the decommissioning engineering started. That knowledge and experience was certainly beneficial to the project.

Mooring disconnect

The mooring system on Red Hawk had only one windlass and one 800ft long work chain located on the topsides to service all six mooring legs. To reduce the loads during mooring disconnect the work chain had to be removed prior to the topsides lift. The work chain was cut in three pieces and paid out on three mooring legs, thus effectively lowering the tension in the entire mooring system. At that point the system was slacked to facilitate topsides removal. However, the platform still needed to remain storm safe throughout the topsides lift. High capacity C-link connectors were procured and used to connect work chain segments to top chains and additional analysis proved that the hull could sustain a 10-year return storm with or without topsides. Tugs were hooked up to provide station keeping while the mooring disconnect was completed.

Ballasting and deballasting

Limited access to the spar during key activities required a remote ballast/deballast system for all operations. The variable ballast control system was located on the topsides. The connections between the hull and topsides had to be removed prior to topsides lift. The spar hull was 560ft long, 64ft in diameter and assembled with six outer cells connected to the center cell. There were void tanks on top of each cell with variable ballast tanks under them. Each had an air-over-water system that was open to the sea at the bottom. Pumping air pushed water out and reduced the draft, while venting air would let more water in to lower the spar. The hull first needed to be ballasted low enough for Versabar's heavy lift vessel *VB10000* to hook up and lift the topsides. After that, the hull needed to be deballasted to reach a tow draft of 400ft to enable the spar to enter the 430ft deep reefing site. To facilitate the required draft variations, InterMoor set up three different systems on *DB50* and the spar: an air ballast/deballast system, a water ballast system and a water deballasting system.

Pumps, compressors and manifolds were staged on the *DB50* and connected to the tanks in the spar hull through water and air hoses. Ballasting continued during the four-hour topsides lift operation to maintain the draft as the weight was gradually taken by *VB10000*. The lift required very calm seas as this was *VB10000*'s first topsides lift from a floating platform. Therefore, the motions of the two bodies had to be adequately managed. Free of its topsides, the hull was then deballasted in two stages. First, the water deballast system pumped water out of the provisional ballast tanks. Submersible pumps and deballast hoses were preinstalled into provisional ballast tanks, and a generator was transferred to the top of the hull after the topsides were removed to power the pumps. After mooring lines were disconnected and temporarily laid on the seabed, compressed air was then pumped into the variable ballast tanks from the *DB50* to raise the hull to the 400ft draft. Since the windlass and work chain were no longer available, the *DB50* assisted in the mooring disconnect by lowering each top chain through the chain stopper with its crane. Once the *Kirt Chouest* hooked into the top chain below the surface, an ROV cut a sacrificial sling and the AHTS vessel laid each line on the bottom for recovery after the hull was towed from the field.

Towing and reefing

The 70mi tow route from Garden Banks 876 to Eugene Island 384 was laid out to minimize pipeline crossings, maximize the hull's distance from other platforms, and maintain adequate bottom depth clearances during the final approach to the proposed reefing site. The tow route was pre-surveyed several months ahead of the tow to verify information obtained from public databases as well as to account for any seabed objects or anomalies. With some convenient seas assisting from the stern, the tow lasted less than two days.

Once at the reefing site, the tugs reconfigured into their station keeping arrangement. The crew was transferred to the spar to vent the air from variable ballast tanks until the spar was sitting firmly on the seabed in a vertical position. A highly skilled rope access crew was then transferred to the spar to prepare the hull for the reefing operations. Once complete, all air valves for variable ballast tanks were left open and the crew transferred back to the *DB50*. One tug disconnected from the hull and the other two pulled in the planned reefing direction until the hull began to free flood. The hull gradually pivoted around the bottom edge of the two cells and in less than 10min it laid on the bottom in a horizontal position. During the sinking the tugs powered off and paid out work wires, which were then disconnected from tow rigging with ROV assistance.

This methodology sets precedence for other floating structures nearing the end of their design life. Valuable experience was gained, not only for the companies involved with the reefing of Red Hawk but for the offshore oil and gas industry as a whole. Paramount to the entire operation was the very high safety standard achieved. **OE**

***Dusan Curic** served as the project manager for InterMoor for four years and has more than 10 years' experience in the oil and gas industry. Curic previously worked as an engineering project manager and assistant project manager where he was responsible for developing engineering plans, approving engineering deliverables and managing engineers and designers from various disciplines. Curic received a master's degree in mechanical engineering from the University of Novi Sad, Serbia, and in ocean engineering from Florida Atlantic University.*

EMAS makes waves in the Gulf

EMAS' marine base in Ingleside, Texas.
Photo from Lanmon Aerial/EMAS AMC.

EPCIC contractor EMAS AMC is betting on the deepwater Gulf of Mexico, bringing not only its newbuild vessel the *Lewek Constellation*, but investing and upgrading a sprawling marine base in Ingleside, Texas. Audrey Leon reports.

The Gulf of Mexico is an area of opportunity for many, but this is especially true for EMAS AMC, which was formed when Singapore-headquartered EMAS acquired Norway-based Aker Marine Contractors AS in 2011.

In less than four years the company has grown exponentially. EMAS AMC has made a substantial commitment to the Gulf of Mexico, as it now holds nearly 350 employees (including 140 engineers) at its Houston office and 400 contract and full-time staff at the 120-acre EMAS marine base in Ingleside, Texas, near Corpus Christi. It boasts multiple contracts for notable clients in the Gulf of Mexico such as Noble, Anadarko, Enbridge, Talos and Eni.

EMAS AMC took over the spoolbase at Ingleside in 2013 from Helix with the intent of making it a "one-stop shop" thereby speeding up project timelines." Chris Tam, regional head, Americas, at EMAS AMC says the company acquired the facility because it is firmly committed to reel-lay as part of its business strategy and the *Lewek Express* vessel is part of that strategy.

EMAS AMC's pipelay and construction vessel, the *Lewek Express*.

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An artist rendering of the Reel Barge concept. Image from EMAS AMC.

"There's no point in having reel-lay vessels without a spoolbase," Tam says. "We decided the Ingleside spoolbase was fit-for-purpose and, at the time we acquired (mid-2013), it was already operational. This helped us springboard to immediately being able to service our clients using the *Lewek Express*."

EMAS continued to improve the spoolbase, which has a deepwater slip measuring 700ft long, 300ft wide and 32ft deep. And, Tam says, because of the large real estate available, EMAS was able to include a fabrication facility on the site. The facility would be able to fabricate PLEMs, PLETs, in order to eliminate the critical path items typically seen in fast-track deepwater Gulf of Mexico projects.

The marine base also offers pipe spooling, logistics and fabrication including jumpers and manifolds. The company says this enables them to give faster turnaround by performing elements for most tie-back projects themselves. To date, upwards of US$55 million has been spent on improving capabilities at the marine base. And Tam says the company continues to work with the Ingleside community on job creation, training, and community services.

In addition to the marine base, EMAS AMC has positioned four offshore construction vessels in the Gulf and will relocate two more over the next four months. The vessels include the *Lewek Toucan* DSV, *AMC Ambassador* (working for Noble), *Lewek Falcon* (working for Enbridge on Walker Ridge), the *Lewek Express* (working on Eni's Appaloosa), Reel Lay Barge (RB1) (at the marine base), *Boa Sub C* (working for Noble), and finally, the company's latest, the *Lewek Constellation*.

A *Lewek* of all trades

The *Lewek Express* is guaranteed to see a lot of action in the Gulf over the next few months. The vessel, which EMAS calls a Swiss army knife – in terms of capabilities – worked on Eni's Appaloosa project, its fifth for the Italian explorer. The installation campaign began in February and ended in March. Fabrication of a single PLET finished 1 February.

EMAS says the project scope included installation of 21.5mi of 8in pipe from a subsea PLET to the existing Corral platform. EMAS was also tasked with installing an 8in jumper and will conduct pre-commissioning for the pipeline. In April, the team installed a jumper and completing the offshore scope to allow Eni full access to pigging operations from the Corral platform.

The *Lewek Express* went to work at the Talos Phoenix field expansion project in March to complete the second of two campaigns. Talos Phoenix is located in Green Canyon 237 at a water depth of 1900-2600ft. The *Lewek Express* handled offshore installation including 9150ft of 4in rigid flowline, 6in jumper metrology and installation, pre-commissioning and hydrotesting of the flowline, a flexible installation, and 6000ft of 4in umbilical.

The *Lewek Express* will next begin working for several Noble Energy projects in April and May to install umbilicals. At Big Bend, the *Express* will install 113,000ft umbilical; at the Big Bend Gas Lift project, a 36,000ft umbilical, and at Dantzler, a 43,471ft umbilical. Also in May, the vessel will work along with the *Lewek Falcon* on the Anadarko K2 tie-back. The scope of work includes 2200ft of pipeline stalking, fabrication and installation, as well as 2300ft of umbilical installation, PLET/PLEM design and fabrication, flowline jumper and well jumper fabrication and installation.

Charting a *Constellation*

EMAS AMC christened its flagship vessel *Lewek Constellation* in Rotterdam back in March *(OE: April 2015)*. The vessel is an ice-classed, DP3 multi-lay offshore construction vessel with ultra-deepwater

pipe laying and heavy lift capabilities. The 3000m-water depth rated, 78.27m-long and 46m-wide vessel was initially conceptualized in 2009 and her hull was successfully launched in 2012.

Its inaugural job was a project of opportunity installing a platform for a Vaalco field off West Africa before it headed to The Netherlands for the installation of the lay tower.

The *Lewek Constellation* boasts an 800-tonne Huisman multi-lay system, including a tower which can tilt from 60° to 90°, able to support both rigid and non-rigid pipelines, a 3000-tonne Huisman offshore heavy lift crane at the stern of the vessel, two Schilling work class remotely operated vehicles (WROVs) and a portable reel system which reduces mobilization time. The portable reel system, which uses a spooling barge to transfer reeled product to the vessel, allows the vessel to work in field, or in close vicinity without returning to the spool base. The *Lewek Constellation* arrived in the Gulf of Mexico on 11 April 2015 and after lay trials scheduled for mid-May, the vessel will work on the Big Bend, Dantzler and Gunflint subsea tieback. The total scope includes over 80mi (130 km) of pipe-in-pipe flowlines and over 56mi (100 km) of umbilicals in up to 2200m water depth.

The multi-lay OCV *Lewek Constellation* in transit. Photo from EMAS AMC.

Following the news that the company won another $65 million in new contracts Lionel Lee, parent company Ezra's Group CEO and managing director said in early February, "despite the current challenges faced by the oil and gas industry, our tendering activities continue to be promising and with *Lewek Constellation* becoming fully operational by 1Q 2015, we continue to strengthen our subsea tieback and SURF capabilities."

"Despite the current headwinds faced by the oil and gas industry, our tendering activities remain healthy," Lee said. "We sit in the value chain where it is more resilient." OE

OE REGION

OFFSHORE DENMARK

Danish horizons

Contents

On the cover – On board the *Maersk Interceptor*. Photo from Maersk Drilling.

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A wide horizon

With its rich maritime heritage, the Danish offshore industry still finds ways to expand, create value and produce profitable returns for its customers, says Offshore Denmark managing director Mogens Tofte Koch.

Denmark has long been a maritime nation. Danish Vikings sailed the world centuries ago. The country was among the first to become a maritime trade nation and fishing has been a natural occupation.

Since the 1960s, the offshore oil and gas industry has also been playing an increasing role in the nation's maritime activities and the industry has become a strong part of the Danish economy. In 2012, Danish North Sea oil and gas production generated more than DKK 25 billion for the Danish state. In addition, the sector generates income taxes, employment, exports and technological innovation.

The country ranks number 32 in the world among net exporters of crude oil due to its North Sea resources. Denmark expects to be self-sufficient with oil until 2050 and a net exporter of natural gas up to 2025.

Flexibility and innovation have been key attributes of the Danish supply industry from the start. It was Danish fishermen, using Danish ingenuity, who modified their fishing boats and acted as supply ships for the Dan field—Denmark's first offshore producing field.

Meanwhile, the offshore supply industry has grown considerably as companies began supplying the Danish oil and gas sector and continued to develop and manufacture sophisticated, high-quality products for use in harsh environments. The sector's capability, together with the Dane's Viking spirit, has taken the Danish industry into the global market.

Mogens Tofte Koch

Technical

The development and use of new technology is also a well-known Danish trait. With limited natural resources, Danes have to be innovative and get the best out of what it has, thus driving its engineering skills and entrepreneurialism.

As an added bonus, Denmark's technical universities and maritime schools support Danish businesses, technology developments and high-end manufacturing. With the new oil research center at Danish Technology University, an additional knowledge base will be created to attract highly qualified researchers who can further raise education levels and prepare students for industry. Many Danish universities are directly involved in developing projects with Danish companies.

Recruitment of highly skilled workers with the necessary skills for the oil and gas industries can be a challenge, but for decades the Danish educational system has provided its population with broad and thorough training, resulting in much needed manpower for Denmark and its neighbor countries.

Renewables

Denmark's offshore energy expertise is not limited to oil and gas. Denmark is already a leading country in wind power technologies, and Danish companies play an important role in wind park projects throughout the world, including major installations in China, America and Europe.

Government policies ensures that renewables have been and will remain firmly on the agenda. In February 2011, the Danish Government announced its Energy Strategy 2050, which aims to make the country fully independent of fossil fuels by 2050. The government targets 50% wind power in the electricity system by 2020.

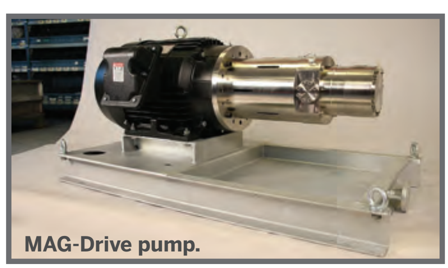
However, today's world still needs oil and gas as the global population and wealth continue to increase because alternative energy resources are not sufficient to replace hydrocarbon-based energy. As a result, Denmark and the world will be dependent on oil and gas for years to come and the challenge to secure energy supply is huge.

Right now, the very low oil price is adding to those challenges, stopping some new developments, as well as slowing interest in investing in new technology due to the perceived financial risk. Yet, I am convinced that the Danish offshore industry will find ways to expand, create value and produce profitable returns for its customers. ■

Chemical Inhibitor system. Photos from Danfoss.

Danfoss driving subsea pumping technology

The subsea factory could be here sooner than many believe and Danish firm Danfoss is helping drive the innovation that will make it happen. Emma Gordon reports.



MAG-Drive pump.

Danish pumping technology is at the forefront of industry efforts to make standalone subsea production facilities, also known as subsea factories, a reality during the next five years.

The concept is widely acknowledged as a potentially economical and practical way to exploit remote reservoirs, as well as those in harsh and deepwater environments.

As part of this drive, Danfoss High Pressure Pumps has been working with Statoil since 2013 to adapt its chemical liquid pump (CLP). The CLP has been developed, assembled and tested at Danfoss' Nordborg site in South Jutland, for use at depths of around 3000m as part of a subsea hydraulic power unit (SHPU) to control subsea Xmas tree valves.

Danfoss, which has more than 40 years' experience developing and producing axial piston pumps, completed the axial piston pump redesign to Statoil's specifications in 2014. It was already the subject of more than 20 patents and is using super duplex steel, carbon-reinforced polyetheretherketone (PEEK) thermoplastic, as well as highly corrosion-resistant metal alloys for the springs.

Two third-party organizations tested the pump: Netherlands-based Seatools and DNV GL. It achieved technology readiness level (TRL) four. This means its ability to meet the operator's requirements, including a stipulation that it would run in the subsea environment without maintenance for 20 years, has been validated in the laboratory.

"Using the SHPU, which really will be the first of its kind, means the umbilical to the Christmas tree only needs to house communications and power," says Michael Klysner, Danfoss High Pressure Pumps global director of oil and gas. "Everything else is catered for on the seabed, meaning a much smaller, simpler and cheaper umbilical—reduced from around 25cm in diameter to about 7cm."

Work is continuing on the development of international standards for this subsea technology, but no other pump is qualified to the exacting Statoil criteria or able to fulfil the API 674 and 675 standards and the relevant NORSOK specifications, he says.

Each pump has pistons running forward and backward against an angled swash plate with integrated port and valve plates controlling flow in and out of the assembly. When the swash plate pushes the pistons up, pressurized fluid is pumped out of the bore.

"Our pump is proven to work in extreme circumstances and hostile environments," Klysner says. "Compared to competitors' topside units, it's much smaller and lighter. It weighs just 275kg compared to 25-tonne and uses 20 times less space."

In 2005, Danfoss took the axial pump principle and adapted its equipment in line with the international API 675 and 674 standards.

"Our track record is encouraging," he says. "The first API-standard pump was commissioned in a closed-drain system in Vietnam in 2007 and has not needed maintenance since."

He adds that discussions are underway with two operators working together to modify the pumps for subsea chemical injection, which is another step toward standalone subsea production systems that could be tied back to an FPSO or facilities onshore.

Michael Klysner

"This is a massive opportunity," Klysner says. "The cost saving to put everything on the seabed is so big compared to traditional developments that it is fast becoming a real area of focus for the industry.

"I believe when the sector gets over some hurdles around storage and instrumentation, things will start to move very fast. We could even see platforms on the seabed as early as 2018," he says. ■

The *Maersk Voyager* drillship.
Photos from Maersk Drilling.

Drilling deep

Maintaining a modern fleet with long-term contracts while setting drilling records is Maersk Drilling's way of doing business. Eloise Logan spoke to the firm's chief technology officer.

From its humble origins in 1972, with just two semisubmersibles and two barge rigs, Maersk Drilling, has grown to secure about 3% of the global offshore drilling market, with a fleet comprised of 23 drilling rigs, including drillships, deepwater semisubmersibles and high-end jackups.

The latest in the fleet's expansion, the firm's fourth XLE-design ultra-harsh environment jackup rig, is under construction, and the firm recently broke a drilling record in the Norwegian North Sea.

Yet, it's not all smooth sailing for drillers, as Frederik Smidth, Maersk Drilling's chief technology officer, acknowledges. The firm's ambition is to contribute to group revenue a profit (NOPAT) of $1 billion from operations that are entirely incident-free by 2018—an ambition made more challenging by the current oil price climate.

Nonetheless, Maersk Drilling is well positioned to weather the storm, Smidth says. The company is a member of a successful group rooted in another industry. Although both shipping and the oil sector are cyclical, the cycles differ, thus offering the company a nicely diversified portfolio of assets. Maersk Drilling's fleet is modern, advanced and efficient, and the company has been successful in securing long-term contracts for its rigs.

Fredrik Smidth

"It is quite obvious that the market, and the dayrates, have gone down," says Smidth, who marks his 25th year with Maersk Drilling this year. "This is hard to quantify exactly, though, since there are not many new contracts that have been fixed. But there are very few contracts out there and some newbuilds coming on to the market in the next six months may struggle."

Fortunately, this is not an issue for Maersk's recent newbuilds. The three XLE-class ultra-harsh condition jackups and its latest ultra-deepwater drillship, *Maersk Voyager*, are all on long-term contracts.

The new drillship, delivered February 2015, will start a long-term contract (3.5 years plus 1-year option) with Italy's Eni and partners Vitol and state company GNPC for offshore Ghana this July. *Voyager*, the last of four sister drillships, will be working on the Offshore Cape Three Points (OCTP).

Developing the next generation of rigs

It not just about contracts—it's also about cutting edge technology that will enable exploration in the most challenging reservoirs including those with high-pressure, high-temperature (HPHT) environments. Maersk Drilling is cooperating with BP on its innovative 20K HPHT project. The firms have agreed to develop, over two years,

Maersk Drilling, a member of the A P Møller-Maersk shipping and offshore group, was established in June 1972, when Maersk Storm Drilling Co. and Atlantic Pacific Marine Corp. were formed to own and operate two semi-submersible drilling rigs and two barge rigs. The first of these was, briefly, a partnership with a Norwegian company to operate the Maersk Jutland rig, but the drilling operation soon became fully Maersk-owned.

Maersk Drilling is an important player in the Middle East, where it has a partnership, Egyptian Drilling Company (EDC), with Egyptian General Petroleum Corporation. EDC owns and operates a fleet of more than 55 land rigs and five jackup rigs in the region.

The Maersk Integrator jackup.

next-generation systems and tools for deepwater exploration and production so BP can tap reservoirs with pressures up to 20,000 psi and temperatures up to 350°F.

Since the conceptual engineering partnership was announced in February 2013, BP in Houston and Maersk Drilling in Copenhagen are the two teams working on the project. Mid-2014, Maersk placed orders for four blowout preventors (BOPs) and two risers from US-based GE Oil and Gas. The equipment will be delivered and deployed on two Maersk Drilling-operated 20K drilling rigs by the end of 2018.

Smidth says the BOP contracts were signed in advance of any rig construction contracts because Maersk wanted to ensure the BOPs and risers were ready when required. They will not be retrofitted to existing rigs.

"We don't think that existing rigs would be suitable," he explained. "For the 20K project, the BOP has to be bigger and heavier. All the piping needs to be rated for that pressure, and the mud pumps, too." GE is designing the BOPs and risers, with input particularly regarding on safety and off-time deliveries, from Maersk and BP staff based in GE's Houston office.

The current thinking is that the two rigs dedicated to the project will be drillships due to the size and cost requirements. If they had been semisubmersibles, they would have needed to be extremely big and heavy, Smidth explains.

The majority of known HPHT areas are in otherwise benign locations, such as the US Gulf of Mexico, Mexico, the Mediterranean and the Caspian Sea, so the new drillships will not have to contend with hostile conditions outside of water depth and HPHT.

Rig market: Costs have to come down

Meanwhile, Smidth says that while the slump in the oil price is putting operators under pressure, in his opinion the rise in cost levels during the past 10 years is hard to justify. This escalation in costs was right across the value chain.

"We haven't seen a crash in prices of newbuilds, and the cost level certainly has to come down. The industry has to realize that," he says.

He notes that rigs were just beginning to be stacked and that if there was a "shake out at the bottom" of the much older rigs that had been kept alive and were now 20-30 years old, it would be "a good thing."

Maersk Drilling is committed to its strategy of maintaining a fleet of high-quality, highly efficient rigs. In late February, Maersk Drilling set a drilling record in the Norwegian North Sea of 800 ft/hr. The jackup was the Maersk Innovator (built 2003), working for ConocoPhillips on Eldfisk. Innovator is contracted to ConocoPhillips until Feb 2017 (plus two one-year options). ▪

The XLE class: First two built on spec

The first two XLE jackups were built on spec, Smidth says, while the third unit had a firm contract before construction began. As the world's largest jackups, they are designed for extra deep water and hostile conditions. The rigs can drill in up to 492ft (150m) water depth and are intended for year-round operations in the North Sea.

The new rigs are designed to meet all the rules and regulations for the northern part of the Norwegian sector, but will also be well suited to the northern UK North Sea, the east coast of Canada, and the southern areas of Australia and New Zealand.

The first two XLE-class jackups, Maersk Intrepid and Maersk Interceptor, built in 2013 at Keppel FELS in Singapore, are both working on long-term contracts in the southern Norwegian North Sea.

Interceptor is contracted to Det Norske Oljeselskapet for the Ivor Aasen field development until December 2019, plus options (two one-year options), while Intrepid is contracted to Total Norge for the Martin Linge field on a four-year contract, with options (three one-year options).

The third identical XLE, the *Maersk* Integrator, was launched in Singapore mid-February. The delivery voyage on board semisubmersible OHT's heavy load carrier Hawk 2 began on March 2. The rig should be ready to start work June 1, Smidth says.

While under construction, Integrator was under long-term contract for four years firm, with options (two one-year options), with Statoil for development drilling on the Gina Krog field in the Norwegian North Sea. Like the two earlier XLEs, Integrator was built at Keppel FELS. The fourth XLE, yet to be named, is under construction at Daewoo Shipbuilding in South Korea and is due for delivery in 2016. The yard move was driven by lower costs offered at Daewoo, according to Smidth.

XLE4 is not identical the previous three XLEs, having had some modifications based on requirements BP for an already-secured five-year contract to carry out plugging and abandonment work on the Valhall field.

When XLE4 starts the work in 2016, it will provide accommodation for 180 in one-person cabins. The previous three XLE class jackups have accommodations for 150, also in one-person cabins. ▪

Innovation in intervention

Welltec's well tractor has transitioned from an unlikely vision to a solid reality now deployed in deepwater wells. *OE* explains.

Sometimes it takes an outsider to pinpoint how matters can be improved. A case in point was illustrated when, 25 years ago, a young, Danish MSE student looked at the oil industry and wondered if interventions could become more efficient.

Jørgen Hallundbæk saw a need and was determined to address it by inventing a new way of intervening in wells. Thus was born the e-line deployed Well Tractor that could deploy logging tools into horizontal and highly deviated wells without the use of heavier intervention methods like coiled tubing or drill pipe. Industry workers thought it couldn't be done, but Hallundbæk, who studied at the Technical University of Denmark, believed in his idea and in transforming the industry.

Today, the Well Tractor has become standard equipment to many operators. Denmark-based Welltec, the company that was set up to develop the tool, says a 10ft-long Well Tractor is basically able to do the same work as a coiled tubing unit, but faster, safer, more cost-efficiently and with reduced size equipment (reduced footprint) with fewer manning requirements (reduced manhours) and just an e-line unit. Today, its use is now being deployed into ever deeper waters.

Establishing well access at almost 4000ft water depth

An operator in the Gulf of Mexico planned to set a lock-open sleeve across a failed subsurface safety valve. The operation was conducted as a riserless light well intervention (RLWI) on a subsea well in a water depth of 3991ft. The downhole conditions were unknown because the well had not been re-entered since it was put on production.


Jørgen Hallundbæk

After multiple failed attempts with slickline, a Well Tractor and Well Cleaner RCB milled through the obstruction, tractoring past the previous slickline hang up depths. At 5727ft, a blockage was encountered. The Well Cleaner RCB removed it before further cleaning the well down to 7590ft before becoming stuck.

The toolstring was worked free and recovered to surface where the bit was found packed with solid debris and the bailer sections filled with dense, hard packed asphaltenes, which had not been expected. The operator concluded that these deposits would likely be present throughout the well and decided to analyze the samples instead of attempting to mill out potentially tens of thousands of feet of deposits.

Being able to access the well and recover samples provided valuable information about the downhole conditions, which enabled the operator to make an informed decision on how best to proceed. This operation was achieved in a world record water depth for RLWI e-line operations and was the first time asphaltenes had been recovered using e-line cleaning tools.

Ultra deepwater RLWI clean-out

Since then, Welltec has beaten that record significantly. At 8087ft water depth in the Gulf of Mexico, the Well Cleaner PST was used to clean above a plug to confirm the fishing neck was clear.

Welltec's solution provided several benefits over slickline, including larger recovery volume, CCL depth correlation and the ability to indicate whether the fishing neck was clear for the pulling tool. Further debris was suspected above the plug, so the Well Cleaner RCB was used to retrieve the debris before the Well Stroker was run to fish the plug because the slickline was unable to do so.

The above shows that RLWI in ultra-deepwater works and that the boundaries of what can be achieved in the industry are constantly pushed. It's only a matter of changing the game and believing in an idea. ■

Harnessing energy

DONG Energy has taken on the offshore wind market—and it is winning. Elaine Maslin explains.

In a short period of time, Denmark has not only spread its international oil and gas exploratory wings, but also its offshore renewables expertise.

Its industry spawned Dangren Vindkraft, known today as Siemens Offshore Wind, as well as turbine manufacturer Vestas, and Danish vessel operator A2SEA. Fabricator Bladt Industries turned its hand to renewables as well, recently taking over the former TAG offshore wind turbine foundation facility on Teesside, northeast England, with Germany's EEW SPC.

A common thread is an involvement with DONG Energy, which has fast become the leading player in offshore wind. The firm, which started life as the state-owned Danish Oil and Gas company, has grown into a Danish utility company, now 59% state-owned. Today, exploration and production and wind power are its biggest business units, representing 39% and 47% of the business, respectively, as a share of earnings before interest, tax, depreciation and amortization.

But the wind division is growing fast. "We are the global leader in offshore wind, with 33% of the installed capacity (or 2.5GW)," said Brent Cheshire, managing director for DONG Energy Wind Power and country chairman for DONG Energy in the UK, while speaking to the NOF Energy conference in northeast England in mid-March. The next biggest offshore wind operator is Germany's RWE with 12%, he said.

The UK has become a key part of DONG's offshore empire in oil, gas and renewables. The firm has an extensive portfolio in oil and gas west of Shetland, including stakes in Total's Laggan-Tormore development, which is a new subsea infrastructure-based hub in the west of Shetland region. Its portfolio also includes Rosebank, a major floating production project currently being reassessed by operator Chevron and its partners, as well as its own discoveries.

Offshore wind is a major part of the business. Despite only amounting to about 3% of UK energy supplies, offshore wind's contribution to the energy market in the UK is growing fast. Currently, a 4GW is operational offshore and another 1GW is under construction in UK waters, Cheshire said. Another 12.5GW of capacity has been approved to be constructed, and a further 5.2MW is awaiting consent. If completed, the projects would total some 22GW.

DONG is already heavily invested in UK offshore wind, with 10 offshore wind farms in operation, seven of which it operates, and the Burbo Bank project in Liverpool Bay with Vestas turbines, which is now under construction. Another two are in development or moving forward, including the 330MW Walney Extension Offshore Wind Farm that includes 7MW Siemens turbines, off Cumbria, and the 1.2GW deep offshore Hornsea Project One, offshore Yorkshire. And a there is scope for more, including the 580MW Racebank Offshore Wind Farm offshore Norfolk, Cheshire said. DONG's target is to have 6.5GW installed by 2020.

In fact, to make offshore wind competitive in the energy market place, companies must maintain a pipeline of projects so that suppliers can standardize equipment, modularize and drive down costs, Cheshire said.

"We have to drive costs down and we are driving costs down," he said. DONG has been

A2SEA's new wind farm installation vessel, the Sea Installer. Images from DONG Energy.

looking to reduce costs by 40%. If achieved, offshore wind would become competitive with combined cycle gas turbines or coal power with CCS by 2023, he said. With a market price on carbon, the economics would be further improved.

Savings can be made in both the capex and opex phases, Cheshire said. Capex risk can be reduced by optimizing site selection by focusing on seabed conditions, distances from shore and costs of transmission, for example. Too many early sites were not optimum and have resulted in additional costs, according to Cheshire.

By having a constant pipeline of projects, costs can also be reduced by making processes more efficient by creating production lines. Suppliers can also standardize equipment such as sub-stations. DONG is working with engineering consultancy firm, Atkins, on an optimized design for five sub-stations. "Maybe some are too big, but on a cost basis it makes sense," he said.

DONG is also working with the Carbon Trust on suction bucket designs for foundations, to make installation more efficient. The first has been installed with a 6MW turbine offshore Germany. "It is a lot smaller and quieter to install," Cheshire said, noting that noise is a concern for marine life, particularly when it comes to piling operations.

"In operations and maintenance, we have been designing new, fast, crew-change vessels," Cheshire said. The market has provided new solutions, too, including A2SEA with its latest installation vessel capable of carrying eight turbines. DONG bought the vessel in 2009 with turbine manufacturer Siemens joining as a partner in 2010, allowing DONG to commission new vessels and reduce costs. The move is a reflection of DONG's willingness to take a direct role in projects, from in-house engineering and design through operations, to help keep costs down.

Cheshire called for more involvement from the local supply chain, rising from 10% in 2010 to 50% by 2018-2020 on the likes of Hornsea Project One. Such efforts are now aided by Danish companies. For example, Siemens is building a new factory in Hull, East Yorkshire. Vestas' has a blade plant on the Isle of Wight. And Bladt will have a manufacturing facility in Teesside.

"The opportunity is very large. It has been building and is continuing to build, and there is a real pipeline of projects up to and beyond 2020," Cheshire said. "Costs are being driven down. We are looking at standardization, we are looking at a modular approach, and it is beginning to work. But still, more needs to be done." ■

e-l-m Kragelund's 2LS system. Image from e-l-m Kragelund.

A tight grip on pipehandling

Pipehandling can be costly if it goes wrong. e-l-m Kragelund is ready to take its pipehandling solution to the global market place.

An increasing focus on safety in the offshore and onshore industries, especially during pipe-handling activities from the manufacturing plant to quayside delivery and loading, has driven Danish firm e-l-m Kragelund's most recent development—its 2LS forklift load stabilizer.

The 2LS, of which some 100 units have already sold, mostly in the Scandinavian market, is the result of a project started 10 years ago for a client in Norway who wanted to reduce the number of accidents involving pipes falling off forklifts.

Now, other regions are seeking improved safety standards and the company has its sights set on sales in America, southeast Asia and Scotland. "In recent years, other markets have increased their safety focus, and this, combined with the need for lower costs have made LS2's features more sought after," says Per Thomsen, area sales manager for e-l-m. "The Scandinavian countries have been first movers within safety. Now the rest of the world shows a growing interest."

The 2LS range, with a capacity up to 35,000kg, has been designed so that it grips loads better, enabling safer and faster transport through narrower lanes in pipehandling areas and on rougher surfaces.

Each unit is comprised of two hydraulically operated arms that lower from vertical, at which position the forklift can be used for usual daily tasks, down to 102°, i.e. below horizontal. The arms are mounted on the forklifts' forks (including telescopic forks) via a vertical section, and can move up or down to accommodate varying loads. The units can also be mounted on wheel loaders.

The unit can squeeze and fixate each single part of the load at the same time, avoiding the risk of lost goods due rubber fenders on the arms that enable direct contact to all pipes, casings and drill pipes, ensuring stability at all times.

As a result, forklift operators can drive faster because the pipes are fixed, Thomsen says. "The driveways for the forklift truck can be narrower, as the pipes in the handling situation can be lifted above the racks. If you have a rough surface, you normally have to drive very slowly. With our 2LS attachment, you can drive considerably faster."

The most commonly used forklift in the industry is a 16-tonne capacity vehicle with a 1200mm load center. Smaller forklifts are used for more specialist pipe or tool handling. E-l-m offers a full line of 2LS additions, from 2.5-ton through 35-ton. The biggest extension holds pipes that have up to 50cm- diameters.

In 2015, e-l-m will be targeting America, as well as Southeast Asia and Scotland. The US, particularly, will be a key focus due to the massive effort around developing the country's shale resources, Thomsen says.

e-l-m, which started life as a small hydraulics business about 40 years ago, has offices in Denmark, with sales representatives in Denmark, Sweden and the US. For now, the company employs about 100 workers. ■

Rigtools eyes expansion

Danish entrepreneurs are taking on the rig tool market. Emma Gordon explains.

When Rigtools was set up five years ago, it was something of a hobby for two entrepreneurial Danes. Now, the pair are eyeing rapid year-on-year growth. Building on early commercial success has seen the firm's drilling tools deployed globally.

Rigtools' technical manager, Per Krogh, and managing director, Micki Bjerregaard, met on a rig in the Norwegian Continental Shelf (NCS) where they saw the need for an improved bottomhole assembly (BHA) wash tool design.

Krogh says the firm, set up in 2010, provides tools designed to simplify increasingly complex drilling operations and, at the same time, enhance efficiency, maintain safety and improve environmental conditions for rig crews.

Rigtools' product was the BHA wash tool, a metal ring with center-facing high-pressure water nozzles that is installed on top of the diverter or bell nipple, and cleans the drill string components while the assembly is pulled out of the hole. The process is remote-controlled and continuous, so no personnel are needed in the high-hazard red zone for manual cleaning.

Currently, the Randers-based business sells and rents a range of drilling equipment, including 10 products developed in-house, including its certified clamp for handling lifting subs.

Rigtools is also on the brink of signing a deal with a US-based company that will help the firm supply up to 50 of its shaker screen-cleaning units annually for international operations. The technology has been used on the NCS since 2012.

According to Krogh, the ventilated shaker screen-clean machine is fast, efficient and helps extend mesh life. Its use means rig crews do not have to manually pressure-clean the screens, thus reducing their exposure to mud and chemicals.

Per Krogh

The demands of the business mean Krogh, who also works as a senior drilling supervisor, spends much of his onshore rotation and some of his time offshore running Rigtools along with Bjerregaard, who is now based in Brazil as a drilling manager. This leaves neither with much free time—a sacrifice Krogh is quick to dismiss as essential for the company's development.

"We just love it. We both have this [entrepreneurial] spirit. You need to be willing to give everything to get your own company going, and we're doing just that," he says.

Krogh adds that the lean business model, with both founders working part-time and eschewing global, yet costly, manufacturing bases in favor of local Danish firms, keeps operating costs down.

And while the client roster already includes the likes of Maersk Drilling; Shell in Malaysia, Qatar and Norway; Statoil and TAQA Bratani, the team's sights are set on accelerated growth.

In December, fellow Dane Roland Boysen joined the company as chief commercial officer to devise and implement this strategy, encompassing product development, the evolution of the rental business that currently accounts for around 10% of revenue, and building the international agent network.

Despite the low commodity price, Krogh is bullish when talking about the organization's prospects. "Even more so now, the challenge for the industry will be to improve efficiency," he says. "Businesses are facing cuts, but there is still room for companies like us who help increase safety and efficiency, as well as make the conditions better for the rig crews."

Brazil, an area where Rigtools has experienced some success already and where Bjerregaard is based, will be a geographical focus for the company. However, plans for an office are not yet in development.

Meanwhile, the Danish Energy Agency is set to announce awards in the seventh licensing round. When asked if Rigtools has aspirations to grow its business closer to home in a region currently accounting for only around 1% of revenue, Krogh says, "We haven't really had much focus on [the Danish sector] so far, but it is something we want to do, particularly when we can do so from position of strength." ■

Rigtool's bottomhole assembly wash tool. Images from Rigtools.

Ramboll spreads its American wings

Engineering firm Ramboll is bringing its Danish values to its newly acquired American businesses. Meg Chesshyre sets out the details.

When Danish engineering consultancy Ramboll acquired Houston-based Excel Engineering in October 2013 the move gave it an entry into the US oil and gas market—and beyond.

Excel Engineering has been operating in the Houston oil and gas market for 20 years, and worked on projects globally, completing more than 1400 projects. The acquisition added about 50 American oil and gas experts to Ramboll and new projects in the Mexican Gulf of Mexico, including brownfield modification work on Pemex's Abkatun-D platform in the Tabasco field in the Bay of Campeche.

The contract, completed in 2014, was for detailed design work needed to add two gas compression trains to Abkatun-D. Both are now operational.

Two other recent contracts for Ramboll have been for PDVSA on the PetroUrica joint venture in the Orinoco oil belt in Venezuela and for Petrobras on SAL/Itau in Bolivia. The PetroUrica project involved the detailed design of a modularized plant to blend heavy crude with a diluent and pump it to upgrading facilities. The SAL/Itau project involved the detailed design of an extensive gas compression facility to supply gas in to the Brazilian gas domestic markets.

"These are pretty typical of our projects," says Crispin Richards, Ramboll Oil & Gas US president since April 2014. "We have excellent engineers and effective project leadership. It means we are able to adapt rapidly to evolving client objectives. We can also furnish a whole team that speaks Spanish, which is good for our South America clients."

Ramboll is also addressing the African market from Houston. "We do support for the African market. A lot of it is maintenance driven."

Crispin Richards

The Houston-based organization, now 60 strong, has been renamed Ramboll Oil & Gas US, and is part of Ramboll's 1000-strong oil and gas division.

Richards, who took over as president from Excel Engineering founder Mostafa Jamal when the latter retired in 2014, says that the integration into the Ramboll organization is now complete and that the merger has gone very well. He is enthusiastic about Ramboll's Danish values. The international consultancy was founded in Copenhagen in 1945.

"They have an enduring business model with a strong sense of teamwork and community. The whole Ramboll Oil & Gas leadership team gets together on video once a month to coordinate our global delivery platform," he says.

In a further US corporate move last December, Ramboll acquired the US-based global consultancy, ENVIRON, adding more than 1500 environmental and health-science specialists in 21 countries. The acquisition positions Ramboll among the top 10 leading environmental consultancies globally with 2700 experts working within environment, health and water divisions, worldwide, and a total staff of nearly 12,500 employees in 35 countries.

The US is Ramboll's fourth largest market. Richards sees natural synergies between Ramboll and the newly acquired environmental arm. "They dovetail nicely into each other," he says.

Also, the shale gas market is an area of potential collaboration. Ramboll, through Excel Engineering, has considerable shale gas experience, and is now exporting this expertise into Europe. Excel Engineering has been involved with shale gas since the pioneering days. ■

Abkatun-D US fabricator Kiewit was contracted by Dresser-Rand to design and build two compression train modules (*pictured, images from Ramboll*) for the Abkatun-D platform in the Mexican Gulf of Mexico. Kiewit awarded Ramboll (then Excel Engineering) the engineering and drafting for the two new modules.

The multi-deck modules each weigh about 1160-tonne. The heart of each of module are two GE LM2500+ gas turbines each driving a Dresser-Rand VECTRA 40G compressor. Each module can compress up to 144 MMcf/d of sour gas (H_2S and CO_2). Ramboll's work included the structural, piping, instrumentation and electrical design of the modules and incorporation of the balance of plant facilities into the modules. The balance of plant equipment included scrubbers, air coolers, firewater piping, seal gas and fuel gas conditioning, relief systems, and interconnecting electrical equipment and instrumentation.

The 50,000-hour brownfield scope of work was particularly challenging due to space constraints, Richards says. For example, access had to be provided to the turbines powering the compression systems that were located in the middle of the modules. This involved building a special trolley tracking system. "We adapted pretty well on the fly," he says. ■

P-scan goes deeper

Exploration in deeper waters is driving technology development, not least in subsea inspection. Meg Chesshyre reports.

Denmark's FORCE Technology, with its P-scan system, is a key player in the specialized NDT nondestructive testing technology (NDT) subsea inspection market.

The company was formed in 1939, as the Danish Welding Institute, to perform X-rays on pressure vessels. Now, FORCE Technology is looking to take technology first developed in the 1980s into ever deeper waters.

Ole Nørrekær Mortensen

FORCE's proprietary Subsea P-scan enables inspection of subsea structures, such as tension legs, jacket structures, monopiles and pipelines, for fatigue cracks, welding defects and corrosion mapping. Based on a magnetic wheel scanner, the P-scan can be fitted with a wide selection of ultrasonic probes and/or eddy current probes, depending on the type of application, such as crack detection, corrosion mapping or weld inspection. The ultrasonic probes detect cracks in the full volume of the objects, and the eddy current probes detect surface-breaking cracks.

The main purpose of the inspection is to verify that no service-induced indications are present in the welds. Welding defects can also be detected, but it is normally assumed that their size is below the original acceptance criteria and therefore will not be taken into consideration during development of an inspection procedure.

FORCE Technology developed the first diver-operated subsea ultrasonic inspection system in the mid-1980s. In the late-1990s, requirements for performing inspections in deeper waters led to the development of the first remotely operated vehicle system to enable subsea inspection depths of 1000m.

"Presently, we operate down to 1000m, but we are working on getting down to 3000m," says Ole Nørrekær Mortensen, who has served as a project manager for the Advanced NDT Global division of Force Technology for the past 14 years. The next generation of the technology is comprised of phased array ultrasound, which will provide more information about the condition of the subsea structures and allow for faster inspection. FORCE Technology is developing 3D results presentations—an upgrade that is due to be available by the end of 2015—which would replace 2D.

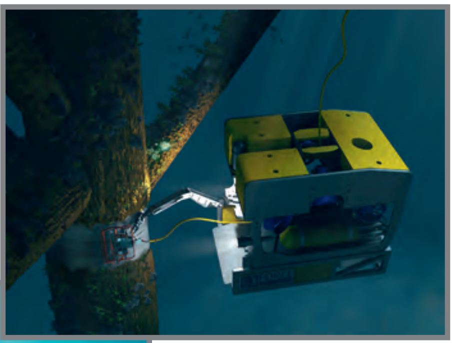
Diver-based pipeline scanning. Images from FORCE Technology

Tether string weld inspection specialists

Tether string weld inspection is also an area of expertise for FORCE, demand for which is increasing, Mortensen says. "There are a lot more platforms of this type, and they are all coming of age. The timing depends on the design life of the tension-leg platforms (TLPs) and the requirements from authorities and classification companies."

FORCE Technology has already carried out an inspection of Statoil's Heidrun and Snorre A platform tethers in the Norwegian sector of the North Sea and of MC Offshore Petroleum' Jolliet TLP in the Gulf of Mexico. The first inspection for Heidrun was in 2003, and FORCE Technology will revisit the platform this year as part of an on-going inspection program. The Jolliet inspection in 2012 was the first in the region for the US Coast Guard and the client before any legislation was in place.

During the past decade, FORCE Technology's subsea inspection system has proven its ability to perform valuable inspection on various tether string welds and has at least the same capability as the inspection system used to perform inspection during production. The inspection system is fitted with 16 ultrasonic channels that can include any type of ultrasonic probe, shear wave, compression wave, creep wave or time-of-flight diffraction. The probes can be combined arbitrarily as required by any inspection procedure. The inspection system also allows for the addition of up to eight eddy current channels.



An ROV performing a Subsea P-scan.

Based in Brøndby, near Copenhagen, FORCE Technology has grown during the past 75 years through mergers and acquisitions to employ about 1400 people throughout its various business divisions. About 40-50% of its income is derived from its NDT business, about half of which is focused on offshore activities. The NDT department has about 250 employees, and the advanced NDT department, which focuses on subsea, employs 30. The firm also operates subsidiaries in Sweden, Norway, China and Singapore. ■

Ice spurs innovation

Viking Life-Saving Equipment is taking PPE to the limit. Meg Chesshyre explains.

Viking's polar liferaft is ready for use—even at -58°F.
Photos from Viking Life-Saving Equipment

Arctic exploration is leading to a continuous process of innovation around equipment, but also for the clothes crew need to wear in harsh environments.

For Denmark's Viking Life-Saving Equipment, innovation and improvements in personal protective equipment (PPE) has meant pushing the boundaries to meet the harsh weather conditions, often going beyond regulatory requirements including putting new immersion suit designs through the most rigorous sub-zero test conducted to date.

Benny Carlsen

"Arctic/polar is a particular focus area for the company, and a niche market," explains Benny Carlsen, vice president of offshore with Viking. The company was founded in 1960 in the west coast fishing port of Esbjerg to make liferafts to counter loss of life in the North Sea fishing fleet. After the terrible loss of life through drowning incidents suffered by merchant sailors during the Second World War, the populace voiced its general frustration that not enough was being done to prevent this otherwise avoidable fate. In response, director Tage Sørensen founded Viking Life-Saving Equipment (then called Nordisk Gummibådsfabrik) to manufacture liferafts for fishing vessels.

One of Viking Life-Saving Equipment's key product groups for the offshore industry is its immersion suits. The latest, known as the Viking PS5002, has been developed to meet polar-conditions and independently tested at temperatures as low as 62.6°C (144.68°F), Carlsen says. This is one of the most rigorous sub-zero tests ever conducted on this type of PPE, and was verified by Copenhagen-based FORCE Technology.

"We work with Gore and other material manufacturers all the time, and check that all materials are suitable for -60°C," Carlsen says.

Currently the company's PPE equipment is supplied on a regular basis for projects in Russia, Norway and the Canadian Arctic regions, and testing programs are ongoing. Testing authorities include DNV and Lloyds, as well as at Force Technology.

The new PS5002 multi-layer suit, constructed with a PU-coated nylon outershell and a thermal quilt liner system that builds on 30 years of immersion suit design, features a double layer of insulation that offers protection from extreme cold. The integrated inherent buoyancy keeps as much of the wearer's body as possible clear of the freezing water, so the suit can be worn without a lifejacket. The double-insulation layer design extends the length of time the wearer can be expected to survive.

Someone has to test them – Viking Life-Saving Equipment's combined harsh environment immersion suit.

Also new to the PS5002 is Viking's high visibility yellow. Both the extended survival time and higher visibility can be decisive factors in a part of the world that experiences around-the-clock darkness for much of the year. According to SOLAS guidelines, an immersion suit of this type should be capable of being donned in five minutes or less at temperatures as low as -30°C (two minutes in regular temperatures). The packed PS5002 immersion suit was refrigerated at -60°C for 24 hours before being removed and put on by a test person.

In every instance, the suit was put on well within the allotted time. The extreme test temperatures are also in response for the need for the equipment to withstand being stored in a container on deck. Following testing, each suit was assessed for signs of damage, including cracking, dissolution or changes in mechanical qualities, but none was discovered.

Viking's suits and other safety equipment are used globally. The company has seen a steady increase in the use of Viking's products in polar regions by both offshore and commercial shipping, but Carlsen admits it is hard to tell what will happen in the immediate future with the falling oil price, as the breakeven price on Arctic operations is obviously higher than for other projects.

Viking is the only marine safety equipment manufacturer to offer a full package of products for polar conditions, ranging from suits and lifejackets to liferafts, containers, evacuation systems and lifesaving appliances (LSA). The upgraded PS5002 is the latest in a line-up of innovations keeping Viking's range up to speed with developments in both the Arctic and Antarctic regions.

Privately-owned Viking is headquartered in Esbjerg, Denmark, and has 2000 employees worldwide. Annual turnover is around DKK1.7 billion. Products are manufactured at facilities in Denmark, Norway, Bulgaria and Thailand. ▪

Securing the offshore target

Peter Welander shows how a solid cyber plan will buttress safety and uptime.

Coming soon to a theater near you: Platform of Death: The exciting story of a small group of offshore oil platform workers, starring Tom Cruise and Keifer Sutherland, as they struggle for survival while their platform is under attack by cyber terrorists. Cut off from the mainland with all means of escape eliminated, our heroes try to stay one step ahead of unseen criminal hackers trying to set the platform ablaze.

Does that sound like an exciting movie, or a little too close to reality? Offshore platforms, like pipelines, refineries, and onshore drilling sites, provide tempting targets, thanks to the high revenues they produce along with the potential for dramatic fiery disasters. For better or worse, what disasters there have been are attributed to other causes, but the potential for problems caused by cyber threat actors remain. Are offshore platforms any different than similar onshore facilities? Are they subject to a higher level of threats? Are they, or should they be defended differently?

The short answer to those questions is no, to the extent

that offshore facilities are not much different than their onshore counterparts. They all pump, process, and store flammable products. But deeper examination reveals a more nuanced situation. Yes, offshore platforms are different; they remain isolated with limited communication and with a wealth of threats packed into a very small space. Offshore platforms have high production costs. Even a simple platform in shallow water cost US$50,000 per day to operate, while a semisubmersible in deepwater can easily run up to $400,000 or more per day. When production stops, those costs pile up fast.

Platforms do not seem to be specifically targeted by hackers, but that can change in a heartbeat. Cyber security defensive strategies apply, although the ability for an operator to implement them might be different when working offshore.

"Challenges, such as hiring and maintaining qualified cyber security staff and being able to provide the necessary operations and engineering context, have stalled efforts to go beyond static defenses like firewalls and network segmentation," said Michael Assante, leader of the global cyber skills development program at the SANS Institute for power, oil, gas and other critical infrastructure industries. "Traditional ICS protection strategies are failing to keep up with the emergence of ICS targeted cyber threats. It is important that mission-critical assets like offshore platforms have the capability to monitor remote and onboard network traffic for misconfigurations and suspicious events.

"Platforms often require remote diagnostics and troubleshooting with various network connections back to engineering expertise. Having the ability to monitor those connections and rapidly spot changes from expected baseline communications is an essential capability. Understanding the underlying control system's behavior and interactions between devices is a view that should be shared by operations staff and industrial cyber security professionals," Assante said.

LIMITATIONS OF ISOLATION

It's obvious to state, but offshore platforms are isolated. Anyone who needs to reach the platform has to have safety training and appropriate personal protection equipment, and taking people back and forth requires planning and scheduling. The ability to communicate is also limited given that all data, whether production statistics, a Microsoft Windows security update, or a movie on Netflix, has to be carried by a satellite link that may be little better than a residential Internet connection. Platforms relatively close to the shore might have a fiber-optic connection, but even those can be slow depending on the configuration.

First and foremost, the limited human resource options on a platform normally precludes keeping a cyber security expert on a permanent basis. This is arguably the most significant single element of the larger discussion. At the same time, the conventional wisdom says it is not practical to support a platform remotely due to the bandwidth limitations. So where does that leave an operator?

"When I was with BP, there were times when we knew we would have to do some upgrades, even simple Windows updates, and we would have somebody on the phone talking platform operators through the process, or we would have to send somebody out there," said Graham Speake, chief product architect for NexDefense. "If it's a vendor upgrade, doing that remotely is difficult. So a vendor would send a service engineer out, and he'd have to go through the whole process: book the helicopter, get training in offshore safety, and get all the equipment; it's not a quick process."

Graham Speake

Each platform is different, and the mix of resources and limitations can be all over the map. Eric Cornelius is consulting director for Cylance and has also spent much time on platforms. "I've seen some platforms that have pretty good bandwidth, and some that don't," he said. "That leads to a lot of interesting security decisions that have to be made because most platforms do not have a resident security guru on site. That brings up the question of how much automation we can get away with in a platform environment versus having to send somebody out to make all sorts of little changes. We also know that complexity is the enemy of security, but in this case, we might have to tolerate a little more complexity to avoid the headache of having to shuttle manpower back and forth. Even if you have people available, there's the timeliness of the matter.

"We've grown so accustomed to our security teams being able to take action and the result of that action being felt instantaneously. So how do we stomach it when somebody says, 'We'll get right on it,' and knowing that it could be two or three days before the change is made. You have to bolster the system ahead of time to be able to tolerate that amount of downtime, because if it is truly a security event, there needs to be some kind of mitigation strategy in place to contain the event for the time it takes to get the personnel out there," Cornelius said.

BANDWIDTH'S IMPACT

Why is bandwidth so important? Why don't the same communication limitations impede a hacker and actually make defense easier? Cornelius offers a clear example scenario: "The lack of bandwidth primarily affects the security personnel's ability to gain visibility into what's actually going on. Let's say a third-party engineer comes in from his contracting firm to do some sort of logic update or maintenance. He brings his thumb drive, inserts it into the system and creates a malware outbreak. So the malware spreads and starts to cause problems. More traditional operational troubleshooting will have to occur, undertaken by the on-site personnel. Only once they determine that a security event has happened will they loop the security team into the situation. Whereas if we had a higher bandwidth connection, say to the onshore facility, I would have been gathering a lot more logs and putting them into an alerting system within my site. I, as a security practitioner, even if I were not on the platform, would have been the one to identify the incident and it would have happened much sooner."

With more conventional security infrastructure, such as would be available on a similar onshore facility, it would be easier to spot a malware outbreak before more damage is done. But what about the idea that the same limited communication might slow down the invader? Speake said that's true, at least to some extent, assuming the invader is actually coming from the outside. "What's your biggest threat vector," he asked. "Is it the external person, or someone on the inside? You've got to look at both. Certainly to the external one, the limited bandwidth helps the defender. But an attacker can see where the route is going and then adjust. Even with low bandwidth, there's a lot he can still do to map out the network. A skilled attacker won't mind taking a week, a month or more to map out the entire network if he really wants to get in.

Those may be the nation state kinds of hackers, but we're seeing more of that happening."

THREAT GOALS

Typically attackers with a purpose are trying to accomplish one of three basic things:

- Disrupt production
- Cause some sort of disaster
- Steal information

Each of these requires specific skills and generally they escalate in necessary sophistication. A hacker might try to get business intelligence about how a platform is performing for a variety of reasons. That kind of effort might require getting into the networks on the platform, but it might be easier to get it from the onshore networks after it has been forwarded. Such invaders like to come in quietly, gather information and get out unnoticed. With the limited bandwidth of platform to shore communication, trying to move large amounts of data is easy to spot so that kind of information will likely end up extracted from onshore networks.

Matt Luallen

RESPONDING TO AN INCIDENT

So what happens when network monitoring shows abnormal traffic and there is no approved cause to account for it? That's when an incident response plan comes into play. The plan needs to be specific and clear. Network profiling tools should be able to give operators a detailed indication of what is happening. If it is possible for operators to call for onshore assistance, they can describe exactly what the problem is to shorten the time necessary to formulate a solution.

"The incident response plan has to reflect the capabilities of the people on the platform," Luallen said. "What if the incident is beyond their ability to respond? What is the response time to get a physical response in the environment, which means bringing somebody to the platform? Even an unsophisticated attacker is going to be aware that you're using this remote satellite linkage to maintain your connection, so he knows if he's discovered, it could take hours, days, maybe even weeks to send somebody to the platform. In a crisis situation, the limited bandwidth is going to hurt."

Cornelius stressed the importance of planning and practicing.

"The security guy comes to the platform a few times each year and works on training the operators, works on implementing the systems that we're going to rely on for incident detection and mitigation, gets them all configured, and then when he leaves, he tells the operators, 'If you see this, call this guy. If it escalates further, call this other guy. This type of problem warrants the IT guy coming out. This other type of problem warrants more severe action.' You need to have all those scenarios thought out, have the approaches you're going to take for each scenario pre-defined, and then exercise those approaches with your personnel so that when something does happen, it's a practiced routine and not a hair-on-fire emergency," he said.

Disrupting production by causing a controller to crash or lose its program is probably the easiest task. Matt Luallen, co-founder of Cybati said there are many ways for that kind of hacker to get critical information.

"I decided to do some OSINT (open-source intelligence) on drilling operations," he said. "I searched for proceedings from vendor conferences and found that some operating company was excited about using some kind of product, or how they had moved from wired devices to wireless. As part of the presentation, they had photos of open equipment cabinets, which showed a SCADA pack that was controlling all the logic on this platform. I was able to identify what was in the rack, and one of the six recognizable devices was in the Digital Bond Basecamp project. It didn't even get to be tested because it got 'bricked' within minutes when the security engineer started doing the assessment. Now I have this photo in the vendor proceedings, showing what hardware is in use, the photo was never meta-data filtered,


ABB

and they used a GPS driven camera, so I can tell the exact location. I know there are devices in use with known vulnerabilities. I know there is a wireless connection, and I know exactly where it is. It might be a physically secure installation with a locked cabinet, but I don't have to get in there to start tampering. The photos and story gave away far too much information."

So if a hacker followed Luallen's scenario, it might indeed be possible to get into the network and cause the SCADA pack to dump its program and shut down whatever its running. But, that is a long way from creating an explosion or environmental disaster because there are safety systems on the platform to prevent those sorts of small disruptions from escalating into a big incident, right?

In theory, yes. A hacker who has gained access to the basic process control systems of a platform might be able to change setpoints or otherwise disrupt normal production, but the safety instrumented system (SIS) functionality should be separate and unreachable. It should prevent a disruption from becoming a disaster, but the reality might be different.

"Control engineers would never bet the safety of the equipment under control and of their co-workers on engineering and administrative safety controls designed to mitigate potential hazards that come from probabilistic failures and improper decisions," Assante said. "Losing the integrity of your production systems to a cyber compromise introduces a difficult to anticipate and mitigate safety risk as the intruder can maliciously operate the system or modify set points to create dangerous conditions. Physical separation of dedicated safety systems from the control system provides a level of protection against anticipated accidents and some attacks. A disturbing trend has been the integration of safety system components and control systems leveraging common networking infrastructure. A good control system anticipates potential failures and unsafe conditions, but an adaptive and intelligent threat can unbound the problem."

FINDING A SOLUTION

The problem is clear: Bad things can happen on a platform and the individuals out there probably do not have sufficient training on dealing with a cyber incident. Nonetheless, they are the ones who will have to deal with an incident and they might not be able to count on help from the folks on shore as quickly as necessary. That sounds like a pretty awful scenario, but new tools have been emerging that could make the situation more positive.

One of the first steps of creating a cyber defense posture is understanding your networks and all the assets on the networks. The next step is to characterize the kind of communication that should be happening in normal operation. Industrial networks, particularly those on offshore platforms, tend to be static as far as configuration and functionality go. When a control system is working well, there is little incentive to modify it beyond maintenance and replacing failed devices. Monitoring communication should present a picture that does not change much from day to day, and any changes that happen should be easy to identify.

New tools have emerged that help establish how networks should be performing and call attention to traffic that does not fit the profile. These tools allow platform operators to use them effectively after a bit of training.

"There are many ways to do traffic profiling," Cornelius said. "You're looking for the destination and source of traffic, you're looking for the amount of data being transmitted over the

network, time of day, frequency of communications, all those things that tend to be, (a) fairly static under normal operating conditions, or (b) directly attributable to an operator action. We needed to turn up the pressure, turn down the pressure, or modify setpoints. That will have a direct effect on the traffic and the nature of what you'll see in the environment. Those are easy to look for with commercial off-the-shelf technologies. It's also easy to send logging information out even through the limited bandwidth available."

Profiling tools do more than simply identify when an operational change or a cyber intrusion has taken place. There are other reasons why traffic might change, and one of the most basic is some sort of misconfiguration. "Misconfiguration is a high percentage of the things (these tools find) because that's the thing that normally goes wrong," Speake said. "People put in a new controller because something has failed and they don't look at everything that's going on, they get the switches wrong, and rather than communicating between A and B, it starts sending out broadcast messages. One thing that isn't quite right by itself might not be a big issue, but if two or three people have put something in incorrectly, those three incorrect devices can cause a bigger problem. If a device sends out enough messages, it might give you a denial of service and shut down a platform just because something has been misconfigured. Trying to do something remotely takes a lot longer, and it is much harder to do." Having a profiling tool on the platform makes it easier to spot.

Luallen sees similar issues when users start monitoring network traffic. "Once everything is configured correctly, the challenge is taking a tool that's viewing what's happening and matching it with a good change management program," he said. "Ultimately, you can't have cyber security without a good change management program. Otherwise you'll look at every strange item and wonder if it's a misconfiguration. If there isn't a clear purpose, you look what it's doing: It's impacting this cyber device that has this type of control capability. Given that situation, what is our procedure? Do we shut down operations? Do we contact somebody? Is there a potential loss-of-life scenario? Could it affect our revenue? How do we manage it? Those are variables that the operator has to figure out and include in an incident response plan."

GOING FORWARD

The possibility threat actors could seriously disrupt a platform is becoming more real and companies should extend the range of incident responses beyond what might seem to be the most extreme scenarios.

"As an operator, you might have to choose which systems you think you can defend, which platforms are the most profitable, and shut down the rest," Luallen said.

This is no action thriller movie — reality is far scarier.

"If one control system has been attacked, they probably all have. All your communication channels might be compromised," Luallen said. "Determine what is essential for this operation, so you can maintain your process, even if you have to do it manually with people, if you have to fall back to a defensive position to stop this attack from occurring. If you see a tornado coming, you go to a place that you believe is safe, that can withstand the effects, and you want to have all the things you'll need there to manage." OE

Peter Welander is a freelance writer and editor specializing in industrial automation.

Security seeks parallel existence with safety

Gregory Hale highlights the importance of both safety and following proper security protocols.

Safety, physical security, cyber security: Trends in the offshore environment show a similar pattern in terms of how each end up applied, except all are at different levels of application.

For safety, just look at the Pemex dehydration and pumping platform in the Gulf of Mexico that sustained an explosion and fire in early April. While investigators are still searching for the cause of the blast that killed four workers, left three missing and 45 injured, the end result could have been much worse.

Within a week after the fire, Pemex said it expected to restore 80% of production within a week or two after that, according to exploration and production director Gustavo Hernandez. Estimated production of 646,000 b/d of crude and 1.4 Bcf/d of gas in the region will not suffer from the blast and resulting fireball that hit the processing platform, he said.

One of the reasons the blast was not more severe was because workers could turn off the feeder lines. Safety planning and preparation paid off.

When it comes to safety, to contain a complex process, a manufacturer must understand the standards and design and implement management systems to:

- Understand the risk, which involves predicting problems, including predicting the risk of possible accident/loss scenarios, establish the appropriate design and the right layers of protection to control risk to a tolerable level
- Control risk factors every day, which involves controlling the original design by maintaining the established layers of protection and managing changes to the design using integrated management systems
- Analyze actual problems and determine weaknesses in the system, which involves identifying weaknesses in design and management systems and weaknesses in risk understanding through root cause analysis of actual problems (losses and near-losses)

The April Pemex blast on a dehydration and pumping platform in the Gulf of Mexico showed that incidents will happen in a dangerous environment. There were at least four fatalities in the incident and three workers missing, but it could have been worse. Photos from Pemex's Flickr page.

CYBER VIEW

When a user violates safety procedures on the platform, he or she clearly hears about it, but what about any breaks in security protocols?

Awareness about cyber security is growing, there is no doubt. But awareness and action are two different things. These days, it would be safe to say security is much like safety was 10-20 years ago. Security wags, however, want to accelerate that understanding to get the same level as safety, but that only comes with training and top management understanding the threat situation and being willing to pay.

Let's face it, the attack environment has changed and is more sophisticated than it was even two years ago. An intruder's goal is to steal intellectual property, pilfer key data and/or disrupt production.

Security, like safety, all boils down to four key factors:

- Prevention
- Preparation
- Response
- Recover

That all works and is a good baseline, but it also goes beyond just having technology and data points.

Technology will not fix a problem unless the right processes and the right best practices are in place. Technology will help enable people to make the right decision. But the security culture has to be on a par with the safety culture to protect against a cyber attack. Even with multiple technology protective layers, users need to enforce

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Pemex-Plataforma Abkatun A Permanente close-up.

a strong security culture that reaches every level.

"The threat is continuously evolving," said Eric Knapp, director of technology and solutions at HPS. "Stuxnet was really the beginning and the threat has been evolving ever since."

The Stuxnet campaign, as ISSSource reported, ended up conducted by the US and Israel to disable the uranium enrichment plants outside Natanz, Iran, by causing the control system to run wildly out of control causing severe damage to centrifuges.

"Targeted attacks are becoming more complex and sophisticated," Knapp said. "Awareness needs to take place not only in technology, but also with personnel."

"Having data is not everything, there is the people aspect also," said Alberto Matucci, general manager, Global Products & Quality at General Electric at the Oracle Industry Connect in Washington. "If we use the same approach we used in the 80s, we will not go anywhere. Industry today is working with the same mindset of 20 years ago."

That means agility and the ability to understand the environment and what is happening remains paramount.

"The ability to pivot and change on a dime is incredibly important," said Mike Sicilia, senior vice president and general manager for Oracle's Primavera global business unit at the Oracle conference.

Understanding the environment and being able to change directions quicker than a seal not wanting to be dinner for a great white shark remains vital for users. But before they can make any decisions, they need to know what they don't know.

"You have to understand the risk appetite; understand the baseline and how (the user) can get that to match up with the risk appetite," said Mike Spear, global operations manager for industrial cyber security lifecycle solutions and services at Honeywell Process Solutions.

The first thing is to start with standards, but that ends up being a good starting point. Talking about security standards, Scott Aaronson, senior director of National Security Policy at the Edison Electric Institute, said at the Oracle Industry Connect, "If you require a 10ft fence, all an adversary needs to do is bring a 12ft ladder."

Standards can only take the user so far. However, once an operator understands the cyber risk scenario, they can then develop a plan they can follow and that works across the entire enterprise. They have to understand:

- Managing risk is a shared responsibility.
- Security requires cross functional cooperation.
- Risk management is a continuous process.
- Secure manufacturing and development practices are essential.
- Security must be built into systems.

PHYSICAL SECURITY LINK

Physical security has always been linked to cyber security, which also hooks up with safety to ensure a smooth running operation on any offshore platform. All areas keep machines safe against man and man safe against machines. It is a given you can't have any one without any of the others. A tightly knit triumvirate.

When talking about security threats as they appear to utilities, it was easy to connect the same thing to offshore platforms.

"Physical security and cyber security: It is not just about cyber anymore," said David Batz, director of Cyber & Infrastructure Security at the Edison Electric Institute. Physical security attacks came to light two years ago when an electric substation fell under attack where intruders came in and shot out 17 giant transformers that funnel power to California's Silicon Valley.

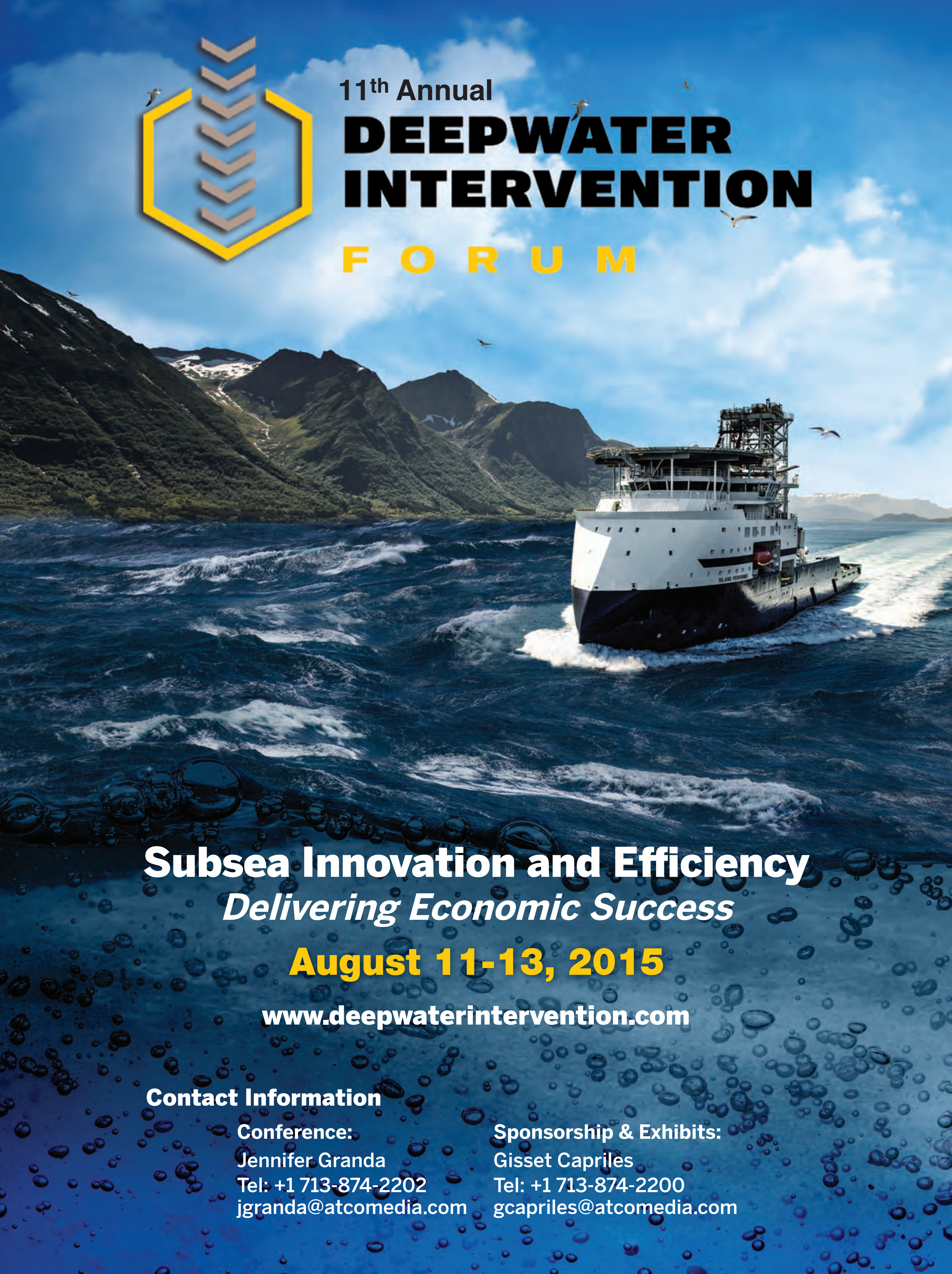
In safety, it is clear manufacturers will invest in higher safety compliant systems.

In the end, manufacturers' main goal is to make product and not deal with anything that throws them off track. Security remains the ever-changing, fly in the ointment for engineers on the platform. It evolves and does not sit still and you may never realize how much it really saved your organization.

"Security is a process," Knapp said. "The more awareness you have, the more gaps you realize you have."

Safety has proven time and time again that it works and it saves time, money and lives. So does security. OE

Gregory Hale is the editor and founder of Industrial Safety and Security Source (ISSSource.com) and is the contributing automation editor at Offshore Engineer.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Subsea realities

Uncertainties, not least the oil price, are weighing on today's industry leaders. The need to be disciplined is key, leaders told Eloise Logan ahead of this year's Underwater Technology Conference in Bergen.

Industry confidence has taken a knock, says Elisabeth Tørstad, CEO of DNVGL Oil and Gas, with the main reason being the continuing slump in the oil price, followed by a weak global economy and uneconomic gas prices as well as tougher competition.

She says that research from the international certification and classification society shows that between October 2014 and January 2015, survey respondents planning to increase their company's capex dropped from 40% to 12%, while those planning to reduce headcount increased from 26% to 47%.

In response, Tørstad recommends that service companies maintain a keen eye on efficiency and innovative cost management in the current climate, but without this having a detrimental effect on future business. "We need to work smarter," Tørstad, one of the keynote speakers at this year's Underwater Technology Conference (UTC) in Bergen, says. Dr. Helge Hove Haldorsen, director general, Statoil Mexico, broadly agrees.

Blast from the past

Bergen's Underwater Technology Conference has published all its conference papers from 1982 to 1996. Elaine Maslin took a look.

Fully enclosed, atmospheric-pressure working environments are to be built on the seafloor to help maintain and perform intervention operations on the fast-paced, deepwater subsea production systems of the future.

Ernie Sjoholm presented CanOcean's system at the 1982 UTC. Image from Ernie Sjoholm

At least that was the plan in the mid to late 1970s. High oil prices were driving investment in technologies that could enable production from what was then considered deep water and out of diver range. The one-atmosphere system was one of the hot topics at Bergen's second ever Underwater Technology Conference (UTC) in 1982.

The one-atmosphere system was a logical idea, to transport operatives from support vessels to enclosed, dry-tree, one-atmosphere working environments, on the seafloor via an adapted diving bell type system.

Initially, the idea was a success. In 1979, first production started from a nine-well dry, one-atmosphere system, built and installed for Petrobras on the Garoupa field offshore Brazil as an early production system, by Lockheed Petroleum Services, which later became CanOcean.

But, another concept, underwater robots, which also seemed like sci-fi in 1982, were emerging at the same time, and fast.

Ernie Sjoholm presented CanOcean's system at the 1982 UTC. He's now retired, living in Richmond, Vancouver. He reflects: "The whole logic behind one atmosphere assumed it was not cost effective to operate beyond diver depth. That is where it came into its own, but then underwater robotics came and stole the show. It is a smarter way of doing it, I have to admit that. At the time, in the late 1960s, when the (one atmosphere) concept was first tabled at Lockheed, it seemed like the smart way to do it.

"When remote pulling in of lines into drilling templates and setting and retrieving control pods remotely came along, the one-atmosphere system just wasn't viable anymore."

Lockheed Petroleum Services' parent company had developed submarine rescue systems, using the same technology, i.e. landing on a submerged one-atmosphere container, pumping out the water from the connection to create a one atmosphere door to let people in or out. "The natural progression was to say you could put the Xmas tree in the submarine and then you can send a normal guy down with onshore experience," Sjoholm says.

Shell, Texaco and Union Oil dabbled with the one-atmosphere idea in the Gulf of Mexico, installing shallow water test installations, and Burma Oil considered it for the North Sea. In 1973, Petrobras leaped into the deep and signed up for the system for the 400ft deep Garoupa field. While the water depth didn't prohibit a platform (a platform was built later on the field), Petrobras was keen to get early production and it was willing to spend some US$200 million to develop the system, says Sjoholm.

"In the early days of the 1970s, there was a need to come up with a way to produce when you get out to 1000-2000ft water depth," he says. "Everyone was interested in doing that. The companies wanted to test it on small shallower fields. CanOcean went from about 12 to 400 staff after the order. They were heady times.

"There was some pretty novel sealing technology involved and we needed of course to pull in pipelines into these chambers and seal them," he says. Lockheed used large volume submersible pumps and a breathing system developed for space travel — effectively routine equipment, Sjoholm says.

A system for up to 4000ft had been under consideration by the firm, which at that time would have covered all known developments in the Gulf of Mexico, North Sea and most of Brazil. But it was not to be. "By that time, the industry was totally committed to putting down templates and completions remotely," Sjorholm says.

"It was an interesting chapter in developing subsea oil and gas production, but a chapter that closed logically and essentially for good reason. You never know, things like this system maybe could influence future projects. You need to know your history to look forward." OE

"Since you can't just cost-cut your way to greatness, new technology and new business models are needed to create the 'new and improved' E&P 2.0 that we so desperately need to stay competitive at a lower oil price."

Dr. Helge Hove Haldorsen

Show more discipline

Haldorsen, who is also 2015 president of SPE International, will give the opening speech at UTC. He calls on the industry to be more disciplined, "especially in the good, but also in the bad times," pointing out that "in this way, the industry helps itself to less 'boom and bust'."

He sees the future with deepwater – and subsea -- oil production meeting an increasing proportion of global oil demand. "Brazil, West Africa, East Africa, the Gulf of Mexico (US and Mexico), Europe and the Arctic will ramp up..."

However, he cautions, "Deepwater developments do... have a DNA that can be troublesome — the long lead-time between discovery and first oil. If the 'new normal' for oil prices is rapid ups and downs, companies may be drawn in the direction of assets with capex flexibility more than to assets with long lead times."

Another speaker at UTC, Margareth Øvrum, who is the executive vice president for technology, projects and drilling for Statoil, stresses Statoil's commitment to using subsea wells in the future when this is the best and the most cost-efficient solution. says.

Earlier this year, Statoil awarded three contracts for feasibility studies related to the implementation of subsea processing factories.

Pointing out that future resources are further from land, at greater depths and in colder and harsher environments, she says, "Subsea processing technology and the subsea factory will be vital to realize Statoil's business opportunities in these locations, and we are working on standardized module sizes and interfaces."

Competitiveness is key

Øvrum calls on "the entire industry" to work hard on its competitiveness. The best response to the challenge of today's low oil price environment, she says, is to make projects as profitable as possible "even in such a scenario." She emphasizes cooperation with suppliers, "so that both supplier and operator can deliver cost-efficient developments throughout the value chain."

But perhaps there is some light further down the oil price tunnel, says Keisuke Sadamori, director of energy markets and security at the International Energy Agency (IEA) in Paris and a keynote speaker at UTC.

"The market is in the middle of a correction that has yet to run its course," he explains. "Today's low oil price environment was brought about by the relentless rise of North American supply, faltering demand growth and OPEC's decision in November 2014 to defend market share as opposed to price."

When asked how long it might be until the industry will see any upturn, he replies, "Oil prices are likely to remain in a lower range until there are concrete signs of supply tightness. The balances in our 2015 *Medium Term Oil Market Report* indicate that lower oil prices will translate into reduced supply growth later this year, resulting in a rebalancing that could support an uptick in prices." OE

Solutions

Siemens, Statoil launch subsea hydraulic power unit

Siemens and Statoil jointly developed and qualified a subsea hydraulic power unit (SHPU) for use in offshore fields to provide hydraulic power at the well site. The SHPU supplies low-pressure and high-pressure control fluid to the subsea control modules. The subsea control module operates the hydraulic valves, the downhole safety valve and downhole chock/sliding sleeve. The hydraulic power unit can be used in the event that the umbilical fails and also as an alternative to the hydraulic lines in the umbilical. The power unit has successfully completed the qualification process, in which it has passed function tests under hyperbaric pressure equal to a water depth of 500m.
www.siemens.com/energy/subsea

ABB introduces Azipod D

ABB unveiled a new addition to its Azipod electric propulsion offering, the Azipod D, which provides designers and ship builders with increased design flexibility in order to accommodate a wide range of hull shapes and propeller sizes, as well as simplicity of installation of the propulsion units. The Azipod D requires up to 25% less installed power. ABB this is due to its new hybrid cooling, which increases the performance of the electric motor by up to 45%. Other benefits of the Azipod D propulsion system also include superior maneuverability, competitive investment cost, ease of service and maintenance, and a significant performance increase compared to mechanical thrusters. ABB's Azipod D propulsion power ranges from 1.6-7MW per unit. **www.abb.com**

Schlumberger debuts ACTive Straddle

Schlumberger released the ACTive Straddle coiled tubing (CT) real-time multiset inflatable packer at SPE's ICoTA conference in March. The ACTive Straddle provides the functions needed to isolate and treat multiple zones on a single run without coming out of the well. The inflatable packer is conveyed with CT into vertical, deviated or horizontal wellbores enabling multiple treatments in a single intervention. The CT fiber optic real-time telemetry provides downhole measurements to optimize fluid placement, ensure accurate depth control, monitor packer pressure during setting and unsetting, and enable precise flow control and setting tool manipulations.

During field testing, more than 147 inflation and deflation multisetting procedures were performed. The ACTive Straddle inflatable packer was also field tested in more than six interventions in challenging onshore and offshore intervention conditions, including the Middle East and the North Sea. **www.slb.com**

Total goes virtual with AVEVA

Total E&P Norge chose AVEVA's activity visualization platform (AVEVA AVP) to support training activities on its Martin Linge topside platform in the North Sea.

The software platform allows owner operators to tailor and repurpose design models for training, simulation and operational readiness activities. "Total required a captivating advanced training solution to provide an accurate and realistic environment to familiarize staff early, thoroughly and safely prior to deployment on-site in the North Sea," says Derek Middlemas, AVEVA COO and head of enterprise solutions. "While the facility is still under construction, the ability to perform realistic training scenarios in a virtual environment is important for initial safety familiarization activities. Later, such training methods provide a risk free environment to practice more complicated and hazardous training scenarios throughout the life of the platform." **www.aveva.com**

Tenaris launchs BlueCoil

Tenaris launched its next generation of coiled tubing, BlueCoil, at ICoTA in March. Tenaris developed BlueCoil technology using innovative steel designs and proprietary manufacturing processes. The end result is a coiled tubing string with an improved operational performance over conventional coiled tubing. BlueCoil products provide a higher strength as well as more fatigue and environmental resistance throughout their entire structure. **www.tenaris.com**

Activity

Cortland opens Houston area facility

Cortland Co. opened a synthetic fiber testing and fabrication facility in Sugar Land, Texas. The company is a global designer and manufacturer of engineered synthetic ropes, heavy-lift slings, electro-optical-mechanical cables, and umbilicals. The new facility will conduct destructive testing and recertification of synthetic fiber ropes and slings up to 1.3 million lbs. In conjunction with tensile testing, Cortland will conduct tension-tension fatigue testing up to full machine capacity with high-fatigue-rated components. Additionally, new 100hp pumps are available to test at high cycle rates not typically found in high-capacity test equipment. The new 13,000sq ft location will house complete testing equipment and fabrication services with room to expand. ▪

Cortland Co.'s new facility in Sugar Land, Texas, brings new capabilities to the Gulf Coast. Photo courtesy of Cortland Co.

Shell makes US$70 billion BG offer

Shell Oil made a US$70 billion cash and share offer for UK-headquartered deepwater and LNG-focused BG Group in what is one of the first supermajor deals since the early 2000s. The move, which offers a 52% premium to BG Group's share price, based on a 90-day trading period, is expected to close in early 2016. If completed, the merger would make the combined Shell-BG entity larger than BP and Chevron in market value. The deal will add some 25% to Shell's proven oil and gas reserves and 20% to production, including LNG and deepwater assets in Brazil and Australia, and enable an increase in asset sales up to $30 billion during 2016 to 2018. Shell CEO Ben van Beurden said the deal would create the largest producer of LNG among international oil companies.

Aker, Fjord form WellSep alliance

Aker Solutions and Fjords Processing have formed WellSep, an alliance to develop technology and capabilities for advanced wellstream separation and treatment solutions for the subsea and topside oil and gas industry. The alliance will apply Aker's subsea processing experience and testing facilities and Fjords' topside and onshore separation technologies to provide complete solutions. Both companies will contribute dedicated teams, with Aker serving the subsea market, while Fjords focuses on the topside segment. Fjords Processing, previously known as Aker Process Systems, has in recent years strengthened its position by acquiring the separation specialist companies Opus Maxim and Separation Specialists Inc.

ACMA celebrates 40th anniversary

Alan C. McClure Associates (ACMA), a naval architecture and engineering firm, celebrated its 40th anniversary on 1 April 2015. Founded in 1975 by Alan C. McClure, Houston-based ACMA provides a wide variety of engineering and design services to an international clientele. Projects include drilling rigs, floating production systems and support craft for the offshore petroleum industry. Other services include project management, legal, arbitration consulting, surveying and negotiations.

Siemens opens Houston headquarters

Siemens opened its new oil and gas headquarters in Houston. Siemens' managing board member Lisa Davis, who leads Siemens' oil and gas and power generation businesses, will be based in the West Memorial Drive office in Houston's energy corridor as will Siemens' oil and gas and marine business unit.

Ceona, Seaweld form Ghana partnership

Ceona entered into a joint venture with Seaweld Engineering, which will act as a strategic partner for offshore deepwater construction projects in Ghana. The JV allows Ceona to extend its operations in West Africa and build upon the success it has already achieved in the region. The agreement will see Seaweld Engineering supporting Ceona in delivering its full line of products and expertise in Ghana. The companies have been working together since late 2014 and officially registered the JV by the petroleum commission in Ghana in March 2015.

TAM International opens Norway office

Houston-based TAM International opened a new office in Norway to support the company's current business and seek further growth. Colin Graham has been appointed Norway country manager. Graham's primary focus in this new office will be to increase the company's sales and rental business. He has worked for TAM for over 19 years. He opened the TAM Dubai office in 2004 and worked there to grow the business for more than 10 years. ▪

Significant Achievement Award winner Gordon Ballard

Offshore achievements in the spotlight

The offshore energy industry's highest achievers and most successful companies were recognized in mid-March at the 2015 Offshore Achievement Awards, with Gordon Ballard, chairman of Schlumberger UK, receiving the Significant Achievement accolade.

"I am very happy to receive this significant recognition. I have been a proud member of the SPE for almost 34 years and have had the wonderful privilege to work with some of the best minds and talents within our industry," said Gordon Ballard, VP Industry Affairs and Chairman at Schlumberger UK, received the Significant Achievement Award.

Supported by OE, the annual awards are organized and hosted by the Society of Petroleum Engineers (SPE) Aberdeen Section and recognize exceptional performance across a range of categories.

The 12 awards celebrate individual achievements, company performance and significant innovations in safety and technology.

Great Large Company and Great Small Company were awarded to Proserv and Merlin ERD respectively, while Maersk Oil picked up two awards including the Outstanding Graduate Program, a new category for 2015.

It was also a successful night for Murray Kerr of SengS Subsea Engineering Solutions, who not only received the Young Professional Award, but was also highly commended by the judges in the Inspiring Leader category.

"During these challenging times it has become too easy to lose sight of the hard work, commitment and success of companies and individuals that continues to happen," said Ross Lowdon, chairman of SPE Aberdeen. "The awards have allowed us to take some time out to acknowledge and celebrate talent in the sector and SPE Aberdeen is proud to support such an important event in the industry calendar. ■

Proserv named "subsea company of the year"

Proserv was named company of the year at the 2015 Subsea UK Awards. During the past 12 months, Proserv marked a number of milestones including a series of contract awards which expanded its manufacturing facilities and launching a new subsea technology. Proserv also secured major investment to help ensure its future sustainable growth and success.

The event, which was attended by over 850 people, closed the opening day of Subsea Expo in and was sponsored by Forum Energy Technologies, Costain Upstream, Genesis and SETS, in which the achievements of various subsea companies were recognized on 11 February 2015 at the Subsea UK Awards.

David Lamont, CEO at Proserv, said: "It is a real privilege to win this award particularly during what has been a very challenging time for the industry. Against this backdrop, we have continued to evolve through a robust business strategy focused upon building on our market-leading position, track record and delivery of world-class products and services." ■

Moving forward. Despite the current oil price climate, projects like the Gullfaks wet gas compressor, shown here at OneSubsea Processing Horsøy, before load out earlier this year, are going ahead. Photo from Statoil/Harald Pettersen.

Gullfaks marks new milestone

OneSubsea delivered the world's first subsea multiphase compressor to Statoil for the Gullfaks South field in the Norwegian sector of the North Sea.

The subsea multiphase compressor (depicted above) enables boosting of unprocessed wet gas production fluids, while eliminating the need for an upstream separation facility or an anti-surge system, making it the industry's only true wet gas compressor. It is expected to increase the recovery rate for the Gullfaks South Brent reservoir by 22 MMboe. The system will be tied back to the Gullfaks C platform.

Since October last year, the wet gas compressor station has been through the final system integration tests at Horsøy outside Bergen.

By April, the compressor station was due to have been installed 135m deep on the seabed, 15km from Gullfaks C, on to which power and control modules will be integrated. The package, from OneSubsea consists of a 420-tonne protective structure, a compressor station with two 5MW compressors totaling 650-tonne, and all necessary topside equipment for power supply and control of the plant.

Following its installation, an umbilical will be installed, as well as the modules within the compressor station. Everything will be hooked up to the Gullfaks C platform this summer, with start-up scheduled for this autumn. ■

Faces of the Industry

By Kelli Lauletta

This month's Faces of the Industry focuses on Joe Rovig whose oil and gas career journey propelled him from a rig hand in Colorado to president of the NOV Rig Systems business segment. Rovig was in the right place at the right time after the mega merger between National Oilwell and Varco. He and his team played a key role in making industry history in shifting how drilling rigs are designed and manufactured.

OilOnline visited with Joe in his Houston office. Joe shares a major career crossroad story, talks oil prices, offers advice to those impacted by layoffs, and gives his take on activity in the Gulf of Mexico.

How did you get into oil and gas?

I grew up in western Colorado where the two best-paying industries were coal and oil and gas. I applied to both. The oil and gas industry called me in the morning and the coal industry called me in the afternoon. I took that oil and gas job because I liked seeing blue skies. I started my career as a worm (rig hand).

I worked my way up to driller before I was 21 and then moved into rig management. I moved around a lot as the industry was contracting in the mid-to-late 1980s. I hit a career milestone in 1986 that was also a major crossroad for me. I was asked to relocate overseas, which was probably the smartest move I ever made. At the time, the international market was more stable, and I became a country manager in Malaysia. This role elevated my position, exposed me to many more management challenges and increased my visibility in the company.

Tell us more about your day-to-day role at NOV.

I look after our rig business. NOV Rig Systems is a segment within NOV that has 20,000 people working in 130 locations globally. We design, manufacture, commission and support drilling rigs of all sizes and the equipment used on those rigs.

What is the most interesting part of your work?

It's that moment when I get to see it all come together in the shipyard or a rigup yard. It is amazing to look at the equipment we've designed, manufactured and pulled together into this complete drilling system. We get to create assets that our customers can run for 40 years. That is the most rewarding and exciting part of my job.

Do you have a career peak that you'd like to share?

The business of building drilling rigs was historically very challenging, particularly for the offshore segment, which tended to come in late and over budget. In 2006, working with the shipyards and drilling contractors, we were able to change the model by shifting to more standardization and improved processes.This new way of managing and executing projects led the rig industry to achieve "on time" and "on budget" status regularly. We fundamentally moved the main contracting to the shipyard, agreeing to a design where multiple copies of that same rig could be fabricated – bringing continuity to the process. In the past, designs weren't frozen before the start of construction without clear lines of responsibility.

Are there any lessons learned along the way?

Surround yourself with really good people. I have a really great team. Most people who work their way up, have done so by having a very strong team. Sometimes people will create a great team, but through bureaucracy or management style, will not empower them. However, it is critical to take it the full step – give them responsibility, hold them accountable and be there to support them when they make a mistake.

NOV has grown significantly and has a business story of its own. We are the world's largest small company. It is that backdrop and culture that allows us, as managers, the freedom to empower our people. It's part of who we are. People want responsibility from the shop floor to the corner office. Let your people know that you trust and value them.

We noticed that you are well traveled-is there any place that left a lasting impression? Why?

I have a soft spot in my heart for Asia. In the 18 years that I lived and worked overseas, I've spent eight of those years there. I lived in Malaysia, Thailand, Indonesia and Singapore. It is a very dynamic, vibrant culture with a business climate that includes great people with an entrepreneurial spirit. The culture includes a desire for service that you don't see much in other places. It is one of my favorite parts of the world.

Oil prices are still on everyone's mind, what's

Joe Rovig

President, NOV Rig Systems

Joe joined NOV in 2002 and has served as Group Vice President of Global Operations, Vice President of the Eastern Hemisphere, Director of Service and Repair and Senior Vice President of the Offshore Drilling Equipment group within NOV Rig Systems. Prior to joining NOV, he worked for two drilling contractors in various positions, both domestically and internationally. His internationally-based positions cover twenty years of experience with multiple locations in Asia and Europe.

your take and how is it impacting your business?
There are multiple factors depressing oil prices – the US dollar foreign exchange rate, market share scenarios with OPEC, and fundamental supply and demand. We are reaping the benefits of higher than expected production, particularly in the shale plays, which has led to an oversupply. Also, the global economies aren't doing as well. There a lot of things that have to get better before the price of oil goes up.

As oil companies reduce budgets, it impacts drilling contractors, which in turn impacts us. We size for what the market gives us. Within our rig equipment side we are fortunate to still have a reasonable backlog which allows us a level of stability in these challenging market conditions. With a slow-down, we are shifting our engineering resources to ramp up research and development projects. We currently are working on two rigs of the future for onshore and offshore. They both have specific new technology to improve capacity and efficiency. Our engineers love to work on the "new stuff."

The industry is bracing for more layoffs. What advice do you have for those who are impacted?
Don't take it personally. We are in a cyclical business and are currently going through a market correction. I've been laid off once myself, it lasted two weeks because I remained flexible. Be prepared to move geographically or even down in structure to stay in the game. This is a great industry in which to make a career. Younger people have the greatest ability to be flexible and stay in this business. This business will grow again very soon with loads of opportunities. The world's population is growing, and the energy we are currently producing today is depleting. For the medium to long term, a lot of this energy will have to be harnessed from oil and gas. This industry has a growth profile for the next 30 to 40 years. Right now, we are weathering a correction storm.

Can you give us a snapshot on what's happening in aftermarket now?
Aftermarket is under pressure, as is all our business, but in comparison it is still relatively stable. While we have seen rig fleets come down especially in the North American land market, they haven't come down too drastically from a global perspective. The assets that are staying employed are the newer and more advanced units, which requires our support. We are starting to see benefits in our survey and repair business as companies are looking to extend the life of equipment versus replacing it coupled with our SPS (Special Periodic Survey) business.

What are some rig market trends for the US and Mexico side of the Gulf?
If you step aside from the oil price pressure, there is some interest in deep 20K operations. It's the early days, but there are fields in the Gulf of Mexico that will require newly-designed products to reach that operating window. Deregulation in Mexico will also result in increased activity. Even before deregulation, Pemex was looking at upgrading their fleets. A lot of new jackups are heading into the marketplace for the first time in a long time. Mexico is under the same oil price pressure as everyone. It will be more subtle, but there appears to be a commitment to bring in newer technologies. On the US side, the shallow offshore marketplace still is challenged. Deepwater projects are continuing, but are under a lot more scrutiny. As far as bringing on new projects whether in the UK, Brazil or US GOM, they have exceedingly higher hurdles to get across before CAPEX will be approved.

What are some key contributions you would like to be known for?
I'd like to be known for being part of a team, that in our segment of the business, made industry history. We merged two companies, National Oilwell and Varco, at a time when the market was depressed. We were ideally positioned when the market improved to bring capacity and technologies at a time when the market really needed it. The growth that we've had from 2006 to today is tremendous. The ability to have that growth and execute at the level that we have achieved has been extremely rewarding. Being a part of that industry chapter makes me very proud. OE

***Kelli Lauletta** is an HR consultant with 17 years experience. She also serves as an editor for OilOnline.com. Kelli can be reached by email at klauletta@atcomedia.com.*

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Numerology

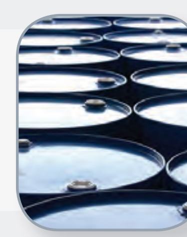
129% The growth in deepwater investment offshore Ghana from 2015-2019, according to Infield See page 41.

1000 street lights generate a comparable amount of energy to what is transmitted through fiber optic cables to perforate rock. See page 62.

50% of known oil resources are comprised by heavy oil, but only account for one in 10bbl of production. See page 76.

21% of pipeline damage in the shallow waters of the Middle East is due to dropping anchor. See page 96.

6 billion bbl The estimated amount in place at ExxonMobil's Julia oil field. See page 105.



US$70 billion The offer Shell made to purchase BG Group. See page 152.