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Offshore Engineer • Interactive Issue • October 2014

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4,571,739

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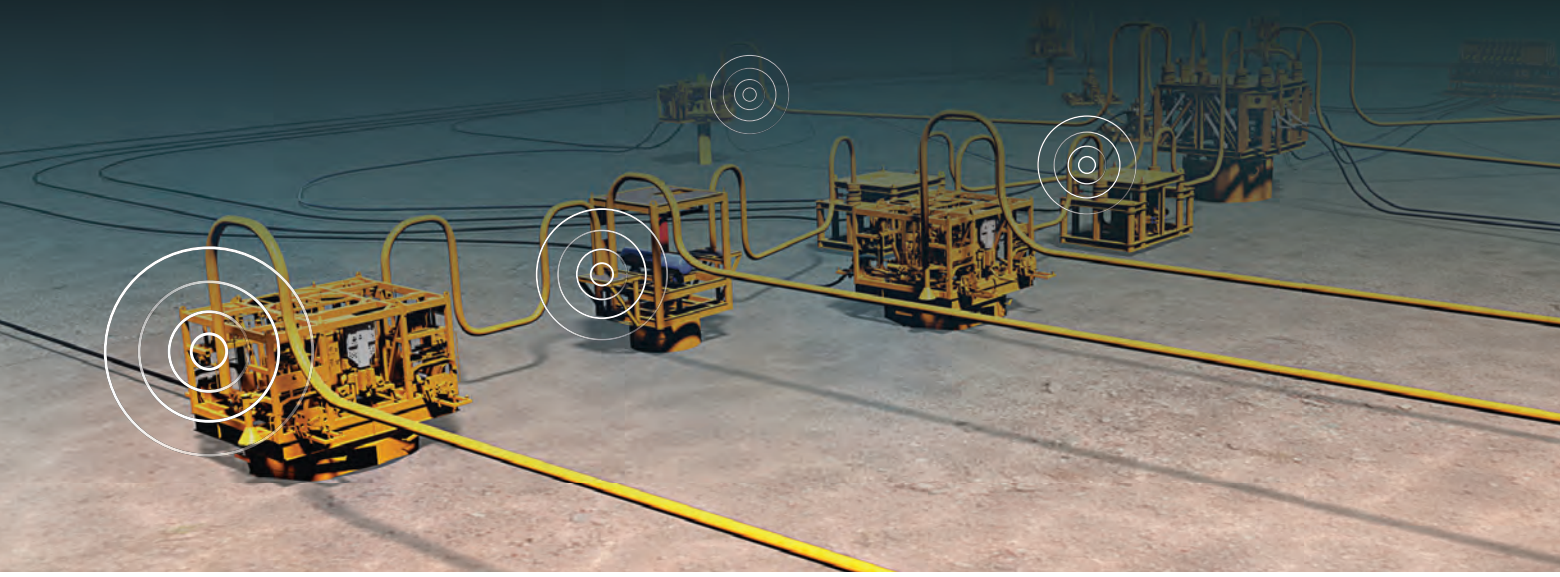

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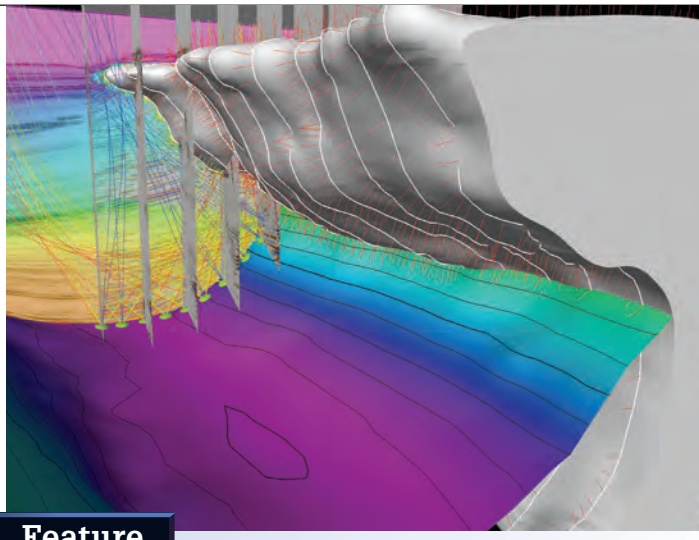

Feature

Visualization

ON THE COVER

Let's get visual. OE's October issue is chock full of interactive material, including our cover, which features Pacific Drilling's *Pacific Santa Ana* drillship. The vessel began a five-year contract with Chevron in the Gulf of Mexico in 2012 (see page 36 for more). *Cover photo courtesy of Pacific Drilling.*

Scan the cover with the Actable app and discover a deepwater formation animation courtesy of Houston-based design firm FuelFX (See page 30 for more). Use your finger or a stylus to move the animation around on your smart phone or tablet.

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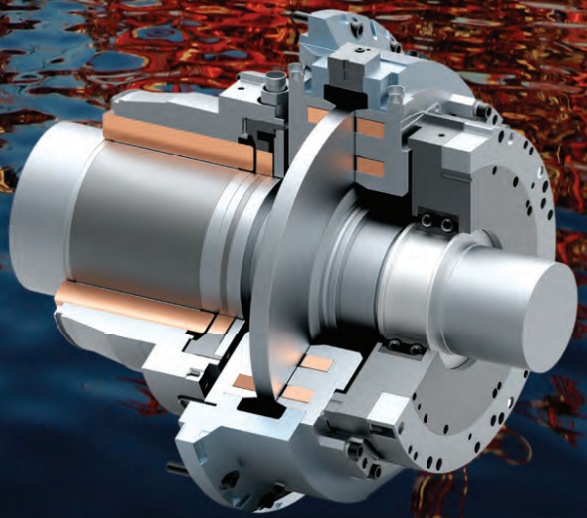

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Departments & Columns

"What do you consider to be the biggest seismic technology breakthrough of the last ten years?"

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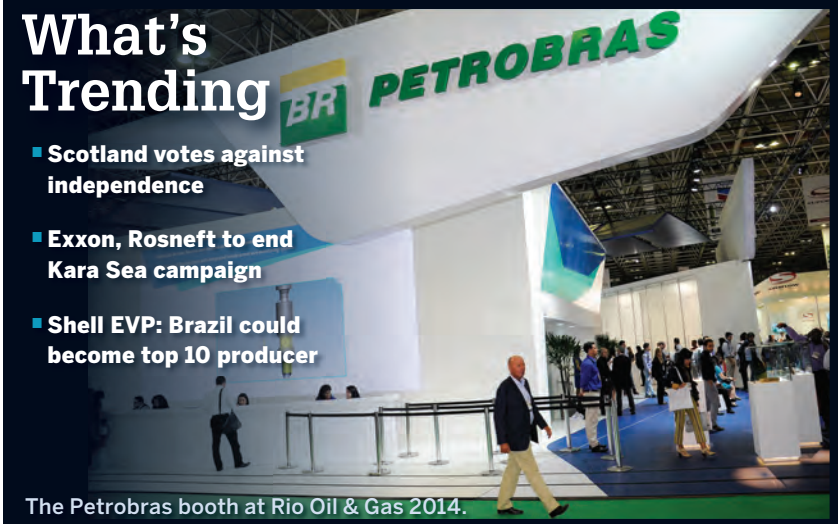
Following her recent visit to the region, Nina Rach discusses exploration off the western coast of South Africa.

The F-A gas field in Block 9 of the Bredasdorp basin, off the Southern Cape coast.
Photo from PetroSA.

Far left: Saldanha Bay. Photo by Júlio Reis.

What's Trending

- **Scotland votes against independence**
- **Exxon, Rosneft to end Kara Sea campaign**
- **Shell EVP: Brazil could become top 10 producer**



The Petrobras booth at Rio Oil & Gas 2014.
Photo from IBP.

People

Golar LNG names new chairman

London-based Golar LNG has appointed Sir Frank Joseph Chapman to the board of directors and as the company's chairman. Chapman has worked 40 years in the oil and gas industry, culminating in a 12-year period as chief executive officer of UK-headquartered BG Group.

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Voices

Seismic shift. OE asked:

What do you consider to be the biggest seismic technology breakthrough of the last ten years?

For evaluating offshore areas, an important seismic technology breakthrough has been the introduction of long, wide arrays of towed-cable arrays and the introduction of dual hydrophone/geophone or dual hydrophone/accelerometer sensors into these cables. The end result has been a significant step forward in the quality of 3D marine seismic data and in our ability to image complex geology and to evaluate subsalt prospects.

Bob Hardage
Senior Research Scientist
Bureau of Economic Geology
The University of Texas at Austin

The biggest breakthrough is not so much a technology one but a change in mindset – an understanding that while seismic provides crucial structural and stratigraphic information, a complete picture of the subsurface can only be achieved through combining different data sources. 3D Electromagnetic data is one such technology providing vital information on fluid content and hydrocarbon volumes within the reservoir. Seismic can be even more effective when combined with other technologies where the whole is very much greater than the sum of its parts.

Vincent Vieugue
Executive VP, Sales & Marketing,
EMGS

Within the last 10 years, the largest breakthrough in seismic has undoubtedly been the introduction of dual sensors (including hydrophones and geophones) in towed streamers.
This has led the way to broadband seismic solutions – now applied extensively. In addition, improved towing techniques have paved the way for improved azimuthal geometries (NAZ, WAZ, and Circle) – also improving illumination. Within seismic data processing, both improved imaging and de-multiple techniques have contributed to the enhanced quality of seismic images. Also, the quality and understanding of 4D seismic are enhanced considerably within the last decade. Finally, the introduction of electromagnetics (strictly not seismic - but a different geophysical technique) now providing commercial 3D control source electromagnetics– has become an additional tool for exploration & production.

Lars Jensen, Geophysicist,
The Norwegian Petroleum Directorate

The most important development in seismic over the last five years is the ability to acquire low frequency – i.e. broadband – seismic. This has enabled effective application of full waveform imaging techniques. Back in 2004, following results obtained through academia research (Cambridge, UK), Shell, together with Petroleum Geo-Services, was one of the first companies to develop and implement low frequency seismic for marine settings. We then deployed it onshore in 2007/8 with BGP – way ahead of anyone else. Both developments are now widely applied and offered by several geophysical service providers.

Dirk Smit,
Chief Scientist Geophysics and Vice President Exploration Technology, Shell

For me, it has to be broadband seismic, providing interpreters with bandwidth and resolution that they could only previously dream of. Taking the obvious aside, however, another seismic breakthrough is the emergence of global seismic interpretation techniques, such as Paeloscan, Age Volume and our own HorizonCube. The correlated geologic time lines of these volumes open up new ways to analyze seismic data, increasing our understanding of depositional history and enabling us to build highly accurate geologic models.

Paul de Groot
President
dGB Earth Sciences

Scan this page!

What's the biggest technological game changer of the last 10 years?
Scan this page with your smartphone or tablet and the Actable app or visit svy.mk/1qj58IT to make your voice heard. See the results in our December 2014 issue.

The biggest seismic technology breakthrough during the last 10 years is the introduction of broadband seismic. It started in 2007 when PGS launched a new streamer which enabled measurements of pressure and water particle velocity at the same time. This triggered additional research with other companies, and today several broadband seismic technologies are present. We have probably not seen the final, optimal broadband system yet, but we can definitely conclude that this is a game changer within marine seismic acquisition.

Martin Landrø, Professor of Geophysics and Seismic,
Dept. of Petroleum Engineering and Applied Geophysics, Norwegian University of Science and Technology,
Winner of the 2014 Norwegian Petroleum Directorate IOR award at ONS

Go to OEDIGITAL.COM and give us your opinion on this month's topic!

Colloquy

Nina Rach

Enhanced reader experience this month!

OE steps into the future with an interactive print issue this month. We're offering extended image galleries, videos, and other content to enhance your editorial experience all with a swipe from your smart device such as a phone or tablet.

In a collaborative effort with Quad/Graphics Inc., OE offers readers the ability to reach additional material and provide feedback beyond the static pages. All you need is the free Actable application to access the additional material.

This issue incorporates several different technologies:

QR – Quick Response codes (2D bar coding). Using any QR reader application, scan the code to go to the associated digital destination.

With the Actable application, we're also incorporating:

IR – Image Recognition – Works like a QR code, but doesn't require the bar code; it associates a unique page image (text configuration) with a digital destination.

AR – Augmented Reality – brings layers of interactivity and allows dynamic responses.

Special icons

Look for special icons in this issue, which indicate interactive content.

To access the material, download the free Actable app from the Apple iTunes store or Google Play, and scan the page to unlock exclusive material.

The Actable app is available for Apple devices running iOS 7.0 or Android devices running the 4.0 operating system or higher.

In this issue, you will find videos, photo galleries, links, and 10 reader polls interspersed with our columns and articles. The results of our reader survey will be published in our special December "List" issue.

Please enjoy our additional interactive content. We hope it helps to visualize all the splendid technologies and projects featured in this special edition of Offshore Engineer. OE

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A message from our publisher

Scan this page with the Actable app and watch OE Publisher Brion Palmer discuss our interactive issue.

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Gerald Schotman, Nederlandse Aardolie Maatschappij (NAM)

An invasion of innovation

Speeding up the rate of change in the oil and gas industry

Our industry has a big question to answer: Can it innovate fast enough to meet the global energy challenge? I believe the answer is yes – but only if it is never satisfied with its achievements and constantly seeks outside inspiration.

Our industry has made its share of technological breakthroughs over the years, many of them enabled by collaboration across company boundaries: oil companies working with service companies, for instance, or specialist technology boutiques working with established equipment manufacturers. But to accelerate the rate of change, I strongly believe that we need to look beyond our industry's boundaries. So I'm extremely interested in innovations that seem to have nothing to do with oil and gas.

"Smart everything" is a good example. The term describes the growing phenomenon of everyday objects that can sense and communicate. Thermostats, refrigerators, eyewear and even clothes now inform their owners of conditions to save time, money and energy – even when the owners are far from home.

There's also a lot we could learn from the medical sector in this regard. Contact lenses can now monitor the glucose levels in tears, and bracelets can monitor our physiological functions. These innovations are helping doctors and patients alike to manage their healthcare.

With "cognitive computing" objects will even sense our subjective states, too. They will understand the meaning of our habits and moods, our way of speaking and behaving – and they will react accordingly.

All these examples I've cited have something in common. They enable faster, well-informed decision-making – which is something the oil and gas industry urgently needs. So we need to welcome these innovations and embrace them. Shell certainly is.

> **"To accelerate the rate of change, I strongly believe that we need to look beyond our industry's boundaries. I'm extremely interested in innovations that seem to have nothing to do with oil and gas."**

Last year, Shell opened a center in the Netherlands where experienced engineers can diagnose the operating condition of key rotating equipment, such as compressors and pumps, with a system called SmartConnect. The equipment under examination, however, does not have to be physically in the center – or even in the Netherlands; it could be anywhere in the world. Thanks to SmartConnect, incipient breakdowns were detected among more than 2100 equipment trains and a significant amount of oil and gas that might otherwise have had to be deferred was in fact produced.

Shell has started using optic fibers not only to transmit data but also as sensors. Strung from top to bottom in a well, they make it possible to keep tabs on the temperatures, pressures and flow rates all along the well. Our wells are also being equipped with automated control systems. As a result, multiple stacked reservoirs can be concurrently produced through one wellbore.

Like the latest model cars, which have internet-enabled dashboards and driver-assisting systems based on a combination of sensors, Shell's offices and control rooms enable engineers to display real-time reservoir data and their analysis on screens. This instant connectivity to assets gives the engineers far more insight into reservoir behavior and enables them to optimize production.

To sum up, I see a friendly invasion of innovation into our industry delivering the technologies we need. The big question now is not "will it work?" or "will it work at scale?" but "how fast can we make this work?" OE

Gerald Schotman *is formerly the executive vice president, innovation, R&D and chief technology officer, Royal Dutch Shell. He now serves as director of the Nederlandse Aardolie Maatschappij (NAM), as of October 1. Gerald Schotman was appointed chief technology officer at Shell in 2009. Schotman was also appointed Executive Vice President Innovation/R&D during the same year, making him responsible for the technology strategy at Shell, as well as for the creation and development of new technologies. Schotman graduated as a Civil Engineer from Delft University of Technology in the Netherlands and joined Shell as a research engineer in 1985.*

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Scan this page with your smart phone or tablet to see Schotman's Next Wave of Innovation infographic.

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Umberto Micheli, Baker Hughes

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Moving beyond the babble

to ensure wellbore integrity in deepwater drilling and cementing operations

For all the technological advances that have been made in drilling and completing wells offshore, wellbore integrity remains the single, most important aspect of well construction. Without it, there is no guarantee of safety, productivity, or return on investment.

Wellbore integrity is too critical for any miscommunication or poorly coordinated efforts. Yet, the fact that it relies on technologies and methods from two disciplines—drilling (fluids) and completions (cementing)—poses a challenge. Too many wellsite disciplines fail to work together effectively and efficiently to address operator issues, even those as critical as wellbore integrity and across disciplines as interrelated as drilling fluids and cementing. In fact, it has been said that a translator is needed to help senior lab people from the two groups talk to one another.

Specific jargon and general differences in terminology among product line and disciplinary silos can hinder understanding and collaboration that could lead to breakthrough solutions. This is unfortunate, given the fact that compatibility between cement and drilling fluid systems is crucial to getting casing to depth and ensuring a good cement job that is key to wellbore integrity throughout the life of the well. The cold temperatures, weaker formations, and extreme risk and cost associated with loss of mud and compromised cement jobs in deep- and ultra-deepwater environments exacerbate the threat of heavy fluid loss, a poor cement job, and jeopardized wellbore integrity.

Yet, the tide may be turning. Three new technologies are representative of breakthroughs in wellbore integrity that can be achieved if communication and understanding among disparate groups is improved.

As is so often the case, the impetus for these technologies came from an operator with a specific challenge. The operator, who was losing significant volumes of mud during cementing and running casing in deepwater, came to Baker Hughes while investigating rheology ratios at various temperatures to ensure the drilling fluid didn't become too viscous as it became cold. Those ratios became the guidelines for developing the NSURE drilling fluid offering and also gave structure to the company's constant rheology systems. However, the real value of the fluid system was in helping to address cement placement and lost circulation, and the larger issue of wellbore integrity during cementing.

Baker Hughes has implemented fluid/cement compatibility testing during the design phase of drilling fluid and cementing spacer systems, resulting in a smoother, more efficient development process and systems with improved performance. A similar story of collaboration is behind the recently launched UltraBond cement spacer, which was designed to be compatible with non-aqueous muds, particularly those used in offshore basins. Another example is a new lost-circulation material on which the company's drilling and cementing groups are collaborating and leveraging off of one another's expertise to determine which procedures, materials, and equipment will provide the best system performance evaluation in a wide variety of applications.

Dr. Jonas Salk, developer of a vaccine against polio, may have said it best: "What people think of as the moment of discovery is really the discovery of the question." Once the right question has been discovered and asked, conversations ensue, lines of communication are opened, and projects—some of them breakthroughs—are spawned.

"Specific jargon and general differences in terminology among product line and disciplinary silos can hinder understanding and collaboration that could lead to breakthrough solutions."

The global offshore oil and gas industry can take credit for enhancing communication, understanding, and collaboration among tens of thousands of people who work across national, regional, and cultural borders every day. Effective communication and collaboration to ensure success in critical areas such as wellbore integrity requires crossing one more boundary—the silos in our own companies. OE

Umberto Micheli *is the vice president of the cementing product line at Baker Hughes. His 34-year career in the oil and gas industry includes operations, technical support, and management roles in a variety of international locations. Micheli is an active member of the Society of Petroleum Engineers.*

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Scan this page with your smartphone or tablet and the Actable app to see a video comparison of the new NSURE drilling fluid versus conventional based fluids.

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Global Briefs

A First oil at Cardamom

Shell started production from the Cardamom subsea oil and gas field in the Gulf of Mexico (GOM). Located in Garden Banks Block 427 about 362km southwest of off New Orleans, the field is tied back to the Auger platform. Shell estimates its peak production level to be 50,000boe/d. This increases Auger's production capacity to 130,000boe/d, making it the company's largest net producing platform in the GOM. Shell now expects Auger to produce for at least another 15 years.

Scan this page!

Scan this page with your smartphone or tablet and the Actable app to see how Shell's Cardamom is helping to increase Auger's production capacity.

B Martin disappoints

Statoil's Martin prospect has been plugged and abandoned. The prospect is located in Mississippi Canyon Block 718 in 2916ft water depth in the Greater Mars basin, about 205km south-southeast of New Orleans, and approximately 218mi from the Louisiana coast. Spudded on 20 April, drilling was planned to a total depth of 31,400ft to target the Miocene. While a discovery was made, it was non-commercial.

C Terra Nova resumes

The Suncor Energy-operated Terra Nova oil field, located approximately 350km southeast of St. John's, Newfoundland, Canada, has resumed production following planned maintenance on the field's FPSO facility. The Terra Nova field includes the Graben, East Flank and Far East blocks.

Discovered in 1984, Terra Nova's FPSO began production in 2002. The FPSO is a double-hulled, ice-reinforced vessel with five thrusters and a global dynamic positioning system, measuring 292.2m long and 45.5m wide. It can store 960,000bo.

D Chasing Nicaragua

Norway's Statoil and Nicaragua's DNP-Petronic signed a cooperation agreement for future oil and gas activities offshore Nicaragua's Pacific coast. The two sent a request to the Nicaraguan Ministry of Energy and Mines to begin exclusive negotations for concession contracts. This request is pending approval. According to Statoil agreements between the two companies are "in an early phase."

E Statoil adds Colombia stake

Statoil will increase its presence off Colombia through two farm-in agreements with Repsol.

Statoil will acquire a 10% stake in the Petrobras-operated Tayrona license, which spans 16,500sq km and a 20% stake in the Repsol-operated Guajira Offshore 1 license, which covers 12,200sq km. This is in addition to the 33.33% stake Statoil holds in the COL 4 license via its partnership with Repsol and ExxonMobil.

After approvals, Repsol will hold 20% in Tayrona and 30% in Guajira Offshore 1.

The initial working commitments in regards to the COL4 license include 2D and 3D seismic acquisition, with no well commitments planned during the exploration phase.

F PDVSA reforms announced

Venezuelan President Nicolas Maduro restructured state oil company PDVSA, replacing Rafael Ramirez with Eulogio del Pino.

Del Pino, former exploration and production chief, will take the reigns as the new president of the Venezuelan state oil company.

Asdrubal Chavez, former PDVSA vice president, was appointed as the minister of Energy and Oil.

Ramirez, former PDVSA president and vice president of Finance, will now serve as the minister of Foreign Affairs. He will oversee four ministries, including the Ministry of Defense.

G EMGS wins Petrobras deal

Petrobras awarded Electromagnetic Geoservices (EMGS) a US$5.5 million contract for 3D EM data acquisition in Brazil.

EMGS says all necessary permits are in place and that the acquisition will start as soon as possible.

The survey will be done using the vessel *EM Leader*, which is currently in St. Thomas.

The vessel will head towards Brazil immediately. The transfer is expected to take 5-7 days.

H Dolphins wins Senegal survey

Dolphin Geophysical has been awarded a contract for the acquisition and processing of a 7000sq km SHarp Broadband 3D survey off Senegal by Kosmos Energy.

The Dolphin high-capacity 3D vessel *Polar Duchess* has commenced operations, and is expected to complete acquisition in approximately four months. Dolphin's OpenCPS software will be utilized both on-board the vessel to produce a PostSTM Fast-Track dataset and then for the final PSTM volume at Dolphin's UK processing center.

I Angola FPSO for Eni

Eni confirmed a contract with Malaysia's Bumi Armada for an FPSO to be used on its deepwater East Hub field, in Block 15/06, offshore Angola.

East Hub will produce the Cabaca North and South-East

discoveries in Block 15/06 through 10 subsea wells tied back to the FPSO. Peak production is estimated at about 17,000bbl/d net to Eni.

Bumi Armada will convert a very large crude carrier class tanker for East Hub. It will have an external turret and mooring system, connected to 18 risers and umbilicals, have 1.8MMbbl storage capacity, 80,000bo/d oil production capacity, the ability to inject 120,000bbl/d water, and be able to handle 120,000MMscf/d natural gas.

The FPSO is expected to start operations on the field in 4Q 2016.

J Polaris wins Kenya survey

CAMAC Energy Kenya Ltd., awarded Polaris Seismic International a contract for a 2D seismic surveys partly offshore Kenya.

The survey covers 506sq km within Block L16, located partly onshore and partly offshore Kenya.

Five broad play types in the area that may extend onto CAMAC Energy's acreage include the pre-rift Permian, Lower Jurassic Karoo equivalent sequences in tilted fault blocks, Jurassic to Lower Cretaceous synrift sediments in drape and roll-over anticlines, Upper Cretaceous fans, and the post-rift Tertiary sequences that include stratigraphic plays and carbonate build-up/reef targets.

K Norwegian licensing round

Forty-seven companies, including supermajors Shell, ConocoPhillips, and ExxonMobil, applied for licenses in the Norwegian government's latest round for predefined areas (APA) 2014 on the Norwegian shelf.

The Norwegian Petroleum Directorate (NPD) said that the level of interest was aided by the number of oil and gas discoveries made in the Norwegian Sea in the last year.

The NPD will now start evaluating the applications and plans to award new production licenses in January 2015.

A total 109,205sq km was open for applications this year. Since APA 2013, the predefined areas have been expanded by six blocks in the Norwegian Sea and three blocks in the Barents Sea.

L Laggan-Tormore delayed

First oil on the Laggan-Tormore project, west of Shetland, in UK waters, is likely to be delayed from the end of 2014 to 2015.

Partner, DONG Energy's CEO Henrik Poulsen said Total, the operator of Laggan-Tormore, was reviewing delays in the construction of a gas treatment plant in the Shetland Islands, which would take natural gas from Laggan-Tormore.

The development comprises of two gas condensate fields, Laggan and Tormore, about 125km northwest of the Shetland Islands, in 120-600m water depth, which are being developed via a subsea tieback to Sullom Voe on the main Shetland Island.

Development approval was in 2010 and first production had been planned for 2014. Produced hydrocarbons will be transported to Sullom Voe via two 143km, 18in. import flowlines at a peak gas rate of 500MMscf/d.

M Shell starts Malikai work

Shell has started drilling production wells on Malaysia's third deepwater development, the Malikai field. Located 100km offshore Sabah in water depth up to 500m, it is part of the Block G production sharing contract awarded by Petronas in 1995.

The Malikai development involves 17 wells drilled from a 23,500-ton tension leg platform production facility.

Norwegian firm Norshore's first drilling and intervention vessel, *Norshore Atlantic*, has started a contract with Sabah Shell Petroleum Co. on the Malikai field offshore Malaysia.

The work involves batch drilling eight top holes in 475m water depth and is expected to run for about 75-130 days.

N CNOOC opens bidding

China National Offshore Oil Corp. (CNOOC) issued an exploration tender inviting foreign oil companies to bid for 33 oil and gas blocks.

The gas blocks cover an area of 126,108sq km off eastern and southern China.

CNOOC says all qualified oil companies may apply for data room visit and data purchase. Data room locations are in Shanghai, Guangzhou and Zhanjiang.

Data rooms will close on 31 December and bidding closes on 30 April 2015.

Blocks are available in the East China Sea basin, South Yellow Sea basin, east Pearl River Mouth basin, Beibugulf basin, Yinggehai basin and Qiong Dongnan basin.

O Mubadala spuds Manora

Mubadala Petroleum announced it began drilling operations at the Manora oil development in the northern portion of the Gulf of Thailand.

The Atwood Orca jackup spudded MNA-02, the first of 15 planned development wells, which include 10 producers and five injectors.

The MNA-02 will be drilled to 2104m total depth. The second well, MNA-01 will be drilled to 2441m.

Manora is expected to reach a peak of 15,000b/d and the drilling program is expected to be complete by 1Q 2015.

Mubadala Petroleum operates Manora with a 60% interest. Its partners include Tap Oil (30%) and Northern Gulf Petroleum (10%).

P Seismic program kicks off

KrisEnergy reported that the *S.V. Nordic Bahari* vessel began a 2D seismic survey in the Sakti production sharing contract (PSC) offshore East Java, Indonesia.

The survey program, which will acquire 1200km of data, was awarded to PT. Alamjaya Makmur Sejahtera in consortium with PT. Bahari Lines Indonesia. The 2D program is part of the work obligations under the PSC.

After completion of the 2D seismic program, PT. CGG Services Indonesia will acquire 400sq km of 3D seismic data, which is expected to commence at the end of September.

The Sakti exploration block covers 4974sq km in the East Java Sea over the western margin of the East Java Basin, Bawean Arch and the Muriah Trough. Water depths in the area range between 50-60m.

Q Northern Chayvo starts production

Rosneft began production from the northern tip of the Chayvo field, located off northern Sakhalin Island.

Chayvo will produce about 1.5 million tons of oil annually, with the northern tip of the field containing more than 15 million tons of oil and 13Bcm of gas.

Chayvo is one of three fields that comprise the Sakhalin-1 project, located in the Russian Far East. Project operator Exxon Neftegas Ltd. states that there is a phase two associated with Chayvo that concentrates on an expanded development of its natural gas resources.

R Apache hits Phoenix pay

Apache encountered oil pay at the Phoenix South-1 well, in Canning basin, 180 km north of Port Hedland, off the North West Shelf of Australia in 133m of water depth. Estimates show that there might be as much as 300MMbbl in place.

At least four discrete oil columns ranging in thickness between 85m and 151m in the Triassic Lower Keraudren formation were detected with wireline and formation pressure tools, within an overall sand-rich section 4160-4500m below sea level.

Apache says evaluation of the formation penetrated in the Phoenix South-1 is under way, and final calculation of hydrocarbon pay will depend on additional analysis.

Further drilling and evaluation is planned for 2015. ■

Contract Briefs

Technip awarded Deep Gulf contract

Deep Gulf Energy II has awarded Technip a lump sum contract for the development of the deepwater, high-pressure, high-temperature Kodiak field, in Mississippi Canyon blocks 727 and 771, in the Gulf of Mexico.

To withstand Kodiak field's high-temperature and pressure, as well as extremely corrosive production fluids, the pipeline will be bi-metallic.

This contract covers: project management; fabrication and installation of more than 12km of reeled bi-metallic flowline and riser; installation of an 11km umbilical, associated terminations and flying leads; pre-commissioning and testing for the rigid line; crossings preparation along with pre-lay and post-lay survey.

Technip's Houston operating center will perform the overall project management. The offshore installation is expected to be performed in 2H 2015 by Technip's purpose-built pipelay and subsea construction vessel Deep Blue and the Global Orion, a support vessel.

Odfjell awarded Statoil contract

Statoil awarded Odfjell Well Services a contract for tubular running services and rental services on the Norwegian Continental Shelf (NCS).

The frame agreement is for tubular running services on a selection of Statoil's installations on the NCS for a possible duration of 10 years. The contract begins in January 2015 for six years and comes with two 2-year options.

Expro lands Quad 2014 contract

BP granted Expro a contract for the Quad 204 project, west of Shetland in the UK North Sea.

The seven-year deal will see Expro provide its vertical xmas tree landing string for the installation of BP's subsea completions.

Expro's ELSA-DB (dual bore) subsea test tree systems will be interfaced with BP's subsea production system's contractor, completion provider, and deepwater drilling rig.

The ELSA-DB is is used in conjunction with vertical production tree systems. The design enables well clean-up/completion deployment from a mobile operated drilling unit prior to the installation of the vertical production tree.

WGPSN boosts Australia portforlio

Wood Group PSN secured a contract with Woodside in Western Australia.

The scope of work includes the engineering, procurement and construction management (EPCM) services on Woodside's Karratha Gas Plant Life Extension Program, as well as providing modification and refurbishment services to Woodside's Production Projects Group across all their onshore and offshore assets.

Pemex awards survey to Fugro

Mexico's Pemex awarded an offshore multi-site geophysical and geotechnical survey to Fugro and Constructora Subacuatica Diavaz, S.A. de C.V.

The contract, valued at US$31.5 million, includes offshore operations, laboratory testing and geoconsulting activities that will support design and/or installation of platforms, pipelines, jackups and deepwater facilities.

The survey is set to begin in September 2014 and expected to be complete in May 2015. ■

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A matter of course

Sarah Parker Musarra spoke with well intervention vessel providers, following a panel discussion at the 2014 Deepwater Intervention Forum, to examine the pros and cons behind using purpose built or dedicated vessels.

Helix is bringing its *Skandi Constructor*, a 120m-long dedicated intervention vessel, to the Gulf of Mexico in 2015 for spot work. Photo from Helix Well Ops.

Helix's *Grand Canyon* purpose built construction/ROV/survey vessel is an example of the company's life-of-field unit, offered as an improvement or replacement to the vessel of opportunity. Photo from Helix Well Ops.

Since the 1980s, subsea wells have gone from tie-in satellite fields, without stand-alone commercial viability, to being the sole method of development for fields such as Ormen Lange and Snøhvit by the mid- to late- 2000s.

With these increased subsea wells comes an increased need for intervention work, as they traditionally have limited recovery rates compared to their topside counterparts. Schlumberger places the differential at 25%. Gregory Brown, transaction services manager for Infield Systems, says in a recent report on the topic, that the difference in production could equate to as much as a US$20.7 billion loss annually.

In light of this, intervention activities are becoming necessary to enhance production. At this year's Deepwater Intervention Forum (DIF), held in August in Galveston, Texas, Brown as well as representatives from companies including Blue Ocean Technologies and Helix Well Ops UK presented on what is a burgeoning topic within the well intervention industry: choosing between purpose-built vessels or vessels of opportunity to carry out intervention work.

Phil Bosworth is the director of business development for intervention pioneers Helix Well Ops, a business unit of Helix Energy Solutions Group. Helix Well Ops uses both dedicated intervention vessels and vessels of opportunity for intervention work, although dedicated vessels perform the brunt of the work. Bosworth says that Helix Well Ops has completed more than 800 well interventions with dedicated intervention vessels and 19 wells with vessels of opportunity.

"We see a consistent underlying trend towards dedicated vessels, but we can do everything," he says.

Vessels of opportunity need no introduction. They are good for short well intervention campaigns in benign, emerging, and remote markets. Where the vessel of opportunity requires modular intervention equipment, purpose built intervention vessels are designed with intervention equipment integrated onto the vessel, such as subsea stacks and deployment/compensation systems, and both come at a cheaper day rate than drilling rigs.

At DIF, Bosworth discussed purpose built vessels' dedicated crews and equipment to ensure continuity; providing increased operability, and cheaper job costs. Quicker mobilization, preparation and turnaround times also result.

"There's a quick turnaround between jobs. A vessel of opportunity can take a couple of weeks," he tells *OE*. "With dedicated vessels, it's measured in hours."

Of course, cost also factors into the decision of what type of vessel to use.

Bosworth says that while the attraction of vessel of opportunity can lay in its availability, selecting such a vessel can still work against those who are trying to cut costs.

"The mere advantage with the vessel of opportunity is that there's a number of vessels you can use. And as a result, the day rates are fairly low," Bosworth says. "However, when people look purely at the day rate of the vessel, it's attractive, but the reality is that it's a lot slower. It's a bit of a false economy to an extent, although certainly it's key that they have a vessel around in their region that they can use."

However, Brown says that while he sees the market

Scan this page!

Scan this page with your smartphone or tablet and the Actable app to see Helix's Grand Canyon vessel as it departed its Turkish shipyard for final fitment in Norway.

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).

New discoveries announced

Depth range	2011	2012	2013	2014
Shallow (<500m)	104	74	71	39
Deep (500-1500m)	25	23	19	10
Ultradeep (>1500m)	18	37	32	5
Total	**147**	**134**	**122**	**54**
Start of 2014 date comparison	151	135	98	-
	-4	-1	24	54

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 2014-18

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Brazil			
Shallow	15	603.25	1,060.00
Deep	16	2,615.00	2,515.00
Ultradeep	45	13,235.25	18,090.00
United States			
Shallow	21	105.55	352.00
Deep	21	1,540.11	1,684.57
Ultradeep	30	4,160.50	4,180.00
West Africa			
Shallow	169	4,485.47	21,678.05
Deep	50	5,856.50	7,070.00
Ultradeep	18	2,055.00	3,410.00
Total	**385**	**34,656.63**	**60,039.62**
(last month)	(385)	(34,546.63)	(60,019.62)

Greenfield reserves

2014-18

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Shallow	1212	46,149.75	768,938.05
(last month)	(1214)	(46,150.75)	(770,028.05)
Deep	160	12,572.98	100,205.27
(last month)	(161)	(12,621.98)	(97,509.77)
Ultradeep	106	19,580.15	58,527.00
(last month)	(107)	(19,520.75)	(54,507.00)
Total	**1,478**	**78,302.88**	**927,670.32**

Pipelines

(operational and 2014 onwards)

	(km)	(last month)
<8in.		
Operational/ installed	40,734	(40,473)
Planned/ possible	24,806	(25,006)
	65,540	(65,479)
8-16in.		
Operational/ installed	78,739	(78,109)
Planned/ possible	49,951	(49,819)
	128,690	(127,928)
>16in.		
Operational/ installed	91,226	(89,771)
Planned/ possible	48,180	(49,233)
	139,406	(139,004)

Production systems worldwide

(operational and 2014 onwards)

Floaters		(last month)
Operational	280	(280)
Under development	40	(41)
Planned/possible	346	(340)
	666	(661)
Fixed platforms		
Operational	9,270	(9,273)
Under development	123	(128)
Planned/possible	1,432	(1,421)
	10,825	(10,822)
Subsea wells		
Operational	4,565	(4,504)
Under development	379	(406)
Planned/possible	6,527	(6,466)
	11,471	(11,376)

Global offshore reserves (mmboe) onstream by water depth

	2012	2013	2014	2015	2016	2017	2018
Shallow	6,118.71	23,494.56	45,160.09	35,778.03	28,642.82	45,844.06	26,878.66
(last month)	(6,015.73)	(23,677.58)	(45,505.78)	(36,289.61)	(29,783.64)	(44,054.87)	(26,930.42)
Deep	2,791.02	484.3	4,197.20	5,659.50	3,369.61	5,232.15	11,772.19
(last month)	(2,791.02)	(484.30)	(4,423.69)	(5,618.56)	(3,612.50)	(5,266.95)	(10,882.73)
Ultradeep	737.15	2,932.94	2,758.62	1,869.95	5,207.70	13,141.57	6,921.06
(last month)	(737.15)	(2,932.94)	(2,817.43)	(1,908.77)	(5,207.70)	(12,210.51)	(6,986.35)
Total	**9,646.88**	**26,911.80**	**52,115.91**	**43,307.48**	**37,220.13**	**64,217.78**	**45,571.91**

12 September 2014

The *Harkand Subsea*, currently in use by Blue Ocean Technology. President Neil Crawford says that during the campaign, the company has increased its riserless intervention depth record twice: first to 6700ft and now 8200ft. Photo from Blue Ocean Technology.

moving towards purpose-built monohull vessels, semisubmersible drilling rates have trended lower and lower over the last few quarters, diluting one of the strongest arguments for purpose built intervention vessels: day rate cost.

"The key selling point of monohull vessels is that it's cheaper than a semisubmersible," he says. "So a semisub is costing about $500,000 per day as compared to your monohull vessel, which is about $250,000-$300,000 per day."

Bosworth, however, says that that the substantially greater efficiency of the monohulls does counter this lowered rate. Brown points out that the decline in the semisubmersible day rate has contributed to the erosion of the market for intervention vessels. Also adding to the industry's discomfort, he says, is the nullification of Total's two-year, US$250 million contract with Aker Solutions for the *Skandi Aker*.

"If it had gone well, you would have seen some real positive indicators. Basically that asset, which was almost a flagship for this new breed of intervention vessels, is now not working," Brown explains. "Over the last six months or so the market took a bit of a step back, and a lot of the positivity that was there has been eroded somewhat. That fuels my conservative outlook in terms of where this sector is for the next couple of years."

Total canceled the contract in June. The *Skandi Aker*'s capacity utilization had only been 37% due downtime from repairs. In 2010, the year *Skandi Aker* was built, the 157m-long vessel was named "Ship of the Year" at the SMM Hamburg maritime convention. Capable of working in 3000m water depth, it was the first intervention vessel to be classified under DNV GL's WELL-Notation, meaning it can take oil onboard.

Brown notes that the industry is particularly hesitant to

choose companies without a proven track record of success.

"That gives those [experienced companies] a really big lead over new entrants in this sector, where I've heard a lot of people struggling to pick up some market share. They have an awful long way to go. So, while there are some positive fundamentals, it's important to say those fundamentals are not addressable by everyone," he says.

Gulf of Mexico

Neil Crawford, president of Blue Ocean Technology, also presented at DIF. Talking to *OE,* Crawford acknowledges the success of dedicated vessels in the North Sea, but warns against thinking that the issue is merely that of dedicated versus vessel of opportunity. Crawford points out that Blue Ocean is the only company doing riserless work in the ultra-deepwater (greater than 4000ft) Gulf of Mexico – and they are using vessels of opportunity. He says that using purpose-built vessels from the North Sea sector in any other waters might not be the best solution for every operator. Other regions might need specialized equipment.

"There's a lot of focus on these big vessels coming out of Norway. They might be state-of-the-art for the North Sea, but not necessarily for the rest of the world. They are very capable, but [the vessel] is just your work platform – if it's carrying anything you don't need, you're paying for it and not using it," he says. "If you're going out and doing IMR or ROV work, it's a very expensive vessel at that point." And in that instance, operators would pay for the systems that they do not need if they try to use an intervention vessel for tasks other than dedicated work.

Crawford says that the choice of vessel ultimately comes down to economics, but that intervention equipment should remain at the heart of the discussion.

"I'm not dismissing [purpose-built vessels]. It's there to facilitate the delivery of the system onto the well," he says. "Because you have a big vessel with a whole bunch of equipment on it, it doesn't mean you can get more work done downhole. It's all about that little tool string you run into the well."

Beyond cost, there is availability to consider. Vessels of opportunity simply outnumber dedicated vessels, at least in today's market.

"The real advantage is the number of vessels available to use," says Helix Well Ops' Bosworth of vessels of opportunity. "If you have low-frequency or single well jobs in emerging markets where there's availability issues with the dedicated or life-of-field vessels then the vessel of opportunity is ideal."

The life-of-field concept vessel is Helix Well Ops' own. It attempts to combine positive aspects of both purpose-built and vessels of opportunity while remaining more economical for non-intervention activities than dedicated intervention vessels. The life-of-field vessel is a construction vessel with classed intervention equipment. Bosworth says that the intervention systems for the life-of-field concept are likely not going to be built on spec. However, the vessels already exist in the fleet.

Market outlook

Despite Brown's conservative outlook, he still sees some positive indicators in the intervention market.

"The fundamentals of demand are really quite positive," he says. "The operational base of subsea wells is increasing year-on-year. The industry is moving towards deeper and deeper water, and with drilling rigs as your alternative to using a monohull vessel being in relatively tight supply, there is still a good opportunity here if you can prove that you can do it." OE

Rig stats

Worldwide

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	107	100	7	93%
Jackup	425	372	53	87%
Semisub	190	159	31	83%
Tenders	32	22	10	68%
Total	**754**	**653**	**101**	**86%**

Gulf of Mexico

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	30	28	2	93%
Jackup	93	72	21	77%
Semisub	29	24	5	82%
Tenders	N/A	N/A	N/A	N/A
Total	**152**	**124**	**28**	**81%**

Asia Pacific

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	14	11	3	78%
Jackup	115	106	9	92%
Semisub	38	27	11	71%
Tenders	24	15	9	62%
Total	**191**	**159**	**32**	**83%**

Latin America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	26	26	0	100%
Jackup	9	7	2	77%
Semisub	37	37	0	100%
Tenders	2	2	0	100%
Total	**74**	**72**	**2**	**97%**

Northwest European Continental Shelf

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	1	0	100%
Jackup	50	49	1	98%
Semisub	46	42	4	91%
Tenders	N/A	N/A	N/A	N/A
Total	**97**	**92**	**5**	**94%**

Middle East & Caspian Sea

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	1	0	100%
Jackup	107	95	12	88%
Semisub	3	3	0	100%
Tenders	N/A	N/A	N/A	N/A
Total	**111**	**99**	**12**	**89%**

Sub-Saharan Africa

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	31	30	1	96%
Jackup	26	20	6	76%
Semisub	18	15	3	83%
Tenders	6	5	1	83%
Total	**81**	**70**	**11**	**86%**

Rest of the World

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	4	3	1	75%
Jackup	25	23	2	92%
Semisub	19	11	8	57%
Tenders	N/A	N/A	N/A	N/A
Total	**48**	**37**	**11**	**77%**

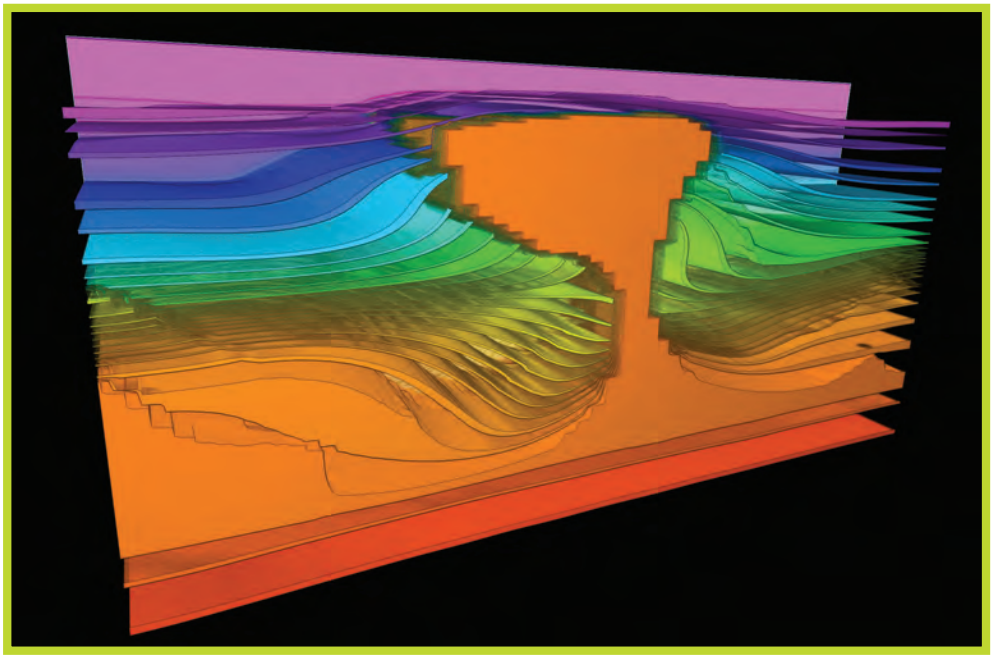
Source: InfieldRigs

12 Sept 2014

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

An industry look at visualization technology

Claudio Paschoa discusses visualization technology with representatives of TGS, Petroleum Geo-Services, and Schlumberger.



Test image of Petrel structural modeling. Photo from Schlumberger.

Visualization technology is used to interpret, through 2D and 3D imaging, complex subsurface geological structures, view fluid movement pathways in hydrocarbon bearing reservoirs, optimize placement of wellbores and visualize surface and subsea facility design implications. Visualization technology was used by the oil and gas industry in the 1980s and 1990s, through dedicated interpretation workstations. By the 2000s, enhanced visualization technologies were periodically introduced, including hardware and software. Geoscientists needed new and effective ways to explore the large quantities of seismic data showing geologic formations and also showing well data rock properties that are acquired through seismic surveys. The reservoir models, traditionally characterized by 2D maps and cross-sections, became fully populated 3D earth models with geological, geophysical, and petrophysical properties, all captured within a 3D visualization environment. Visualization and depth imaging of 3D seismic data are some of the key elements of a rapid technological and qualitative evolution in the remote sensing of the subsurface.

The main aim for interpreters is to better understand the structural content of their datasets, incorporating all the available information in one integrated display. 3D visualization data processing requires massive computing power, due to the volume sizes, particularly pre-stack, which typically involves orders of magnitude greater than standard data viewing. However it is now possible for data processors to quality control (QC), visualize and interpret seismic data in an immersive, multi-volume and collaborative visualization environment, in real time, enabling rapid, informed, strategic and cost effective decisions.

Petroleum Geo-Services (PGS), headquartered in Oslo, Norway, has a specialized seismic data processing division that uses visualization technology as one of its core products. Suhail Butt, geophysical support manager for PGS' Cairo office, holds over 20 years' experience in processing and imaging. Alastair Lewis, the depth imaging manager for EAME/CIS based in Weybridge, has over 15 years' experience, and has been with PGS since 2010. Together they explain PGS' outlook on visualization technology.

Schlumberger provides many services to the oil and gas industry, including seismic data processing and visualization technology. Clark Chahine, technical marketing manager—geophysics, at Schlumberger Information Solutions, gives some insight into Schlumberger's approach.

TGS, headquartered in Asker, Norway, also provides seismic data processing and visualization technology. Jim Howell,

director, global imaging sales, explains TGS's work on visualization technology development.

OE: Could you tell us what visualization software and depth imaging technology you use for pre-salt formations?

PGS: The key visualization tool used to construct our depth imaging velocity models is a proprietary product called PGS holoSeis, which is developed and maintained by our in-house software group. In addition, PGS holoSeis is the front-end to accompanying technologies such as the PGS hyperBeam platform that can deliver rapid cycle depth imaging using our Beam imaging algorithm.

SLB: The Petrel E&P software platform enables 3D and 2D visualization of any geological information, including pre-salt formations.

TGS: TGS uses PRIMA software for time processing, visualization and interpretation, and ImageZ software contains the tomography and migration algorithms used during depth imaging. Both of these packages are TGS proprietary software. A module known as PrimaViz provides full 3D workstation visualization and interpretation capabilities.

OE: How does the quality of seismic acquisition affect visualization and does the visualization software optimize the seismic acquisition data quality?

PGS: Visualization is not affected by the quality of seismic acquisition, however, good visualization tools can better determine the quality of data acquired and processed. The exception to the above statement is in today's ever demanding environment of data acquisition where data volumes are increasing rapidly and where multiple data gathering programs are conducted over the same field prospect. Integrating all this data into one "seamless" experience is a huge challenge.

SLB: The quality and type of the seismic data acquired influence the visualization of a geological object, especially in a complex salt environment. The Petrel platform allows users to load and visualize any seismic data type. It features processes to clean the signal and extract crucial seismic measurements directly into the project, such as seismic attribute and post and pre-stack processing tools. This helps enhance the image beneath the salt and accurately delineate salt boundaries.

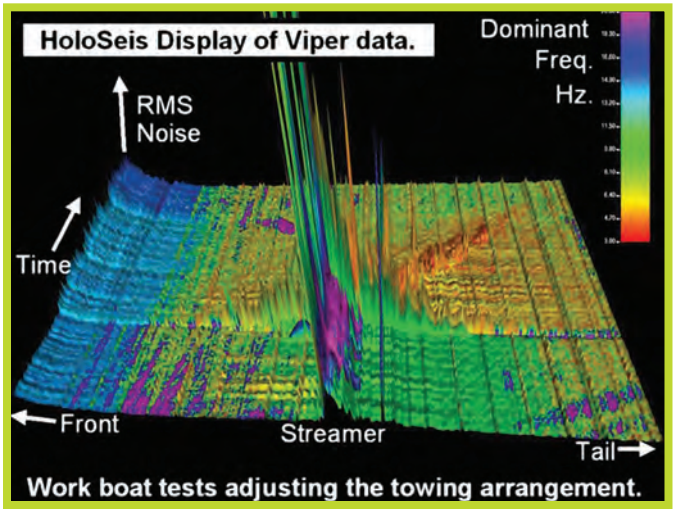
TGS: Receiving seismic data that was acquired with acquisition parameters suited for the geophysical (e.g. correct sampling, good signal to noise ratio, proper fold, sufficient bandwidth) and geological objectives of the area is always beneficial, but the proper handling of the data during time preprocessing (e.g., de-noise, de-multiple, broadband processing, regularization) is critical to optimizing the quality of the data for both imaging and visualization. The visualization software would not optimize the acquisition data quality, but properly acquired and processed data would look better through all stages of imaging and interpretation.

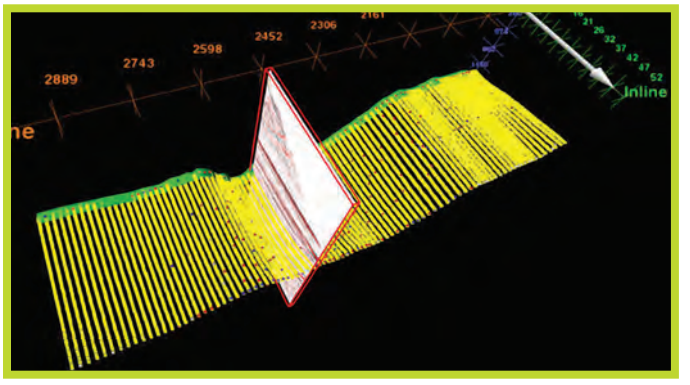
OE: How do the technologies work, what algorithms and inversions do you use?

PGS: PGS holoSeis does not contain processing or inversion algorithms beyond simple functions such as attribute smoothing, editing and QC analysis. It does, however, integrate into the wider PGS processing package where all the algorithms required for seismic processing, imaging and inversion reside. As datasets become ever larger, it is no longer efficient to process using desktop workstations and therefore the batch algorithms are optimized for cluster technology, allowing the user's desktop to focus on visualization demands only. However, seamless integration between data visualization and batch processing is essential and PGS hyperBeam is the ultimate culmination of that integration effort.

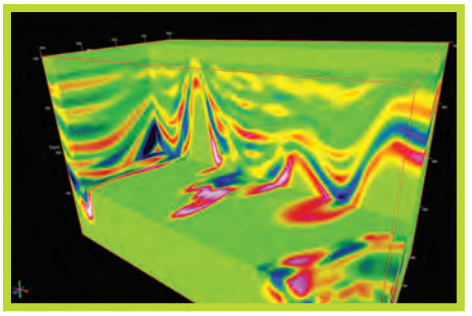
SLB: There are various algorithms and inversion processes used to enhance the image in this environment. Using a combination of seismic attributes, such as spectral or structural decomposition, based on unique edge detection attributes, users can blend results and visualize geological features more clearly. Using pre-stack data, in context, within the same environment as interpretation is undertaken, enables asset teams to get the most out of their seismic by looking directly at the source data. For example, by stacking on the fly and visualizing in 2D and 3D simultaneously. users can discretize the noise and remove it to enhance the image.

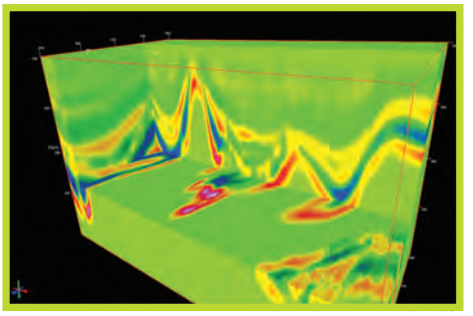
TGS: Specific to imaging around salt, the technologies applied during imaging and visualization would be using the optimal anisotropic depth imaging and migration approaches that solve the imaging problems specific to any given dataset. Approaches throughout the depth model building and final migration stages normally include titled transverse isotropic modeling, dip guided or image guided tomography, TTI Kirchhoff, TTI reverse time migration (RTM), and potentially TTI beam migration. Subsalt updating via RTM delayed image time analysis (DIT) is also used. Orthorhombic



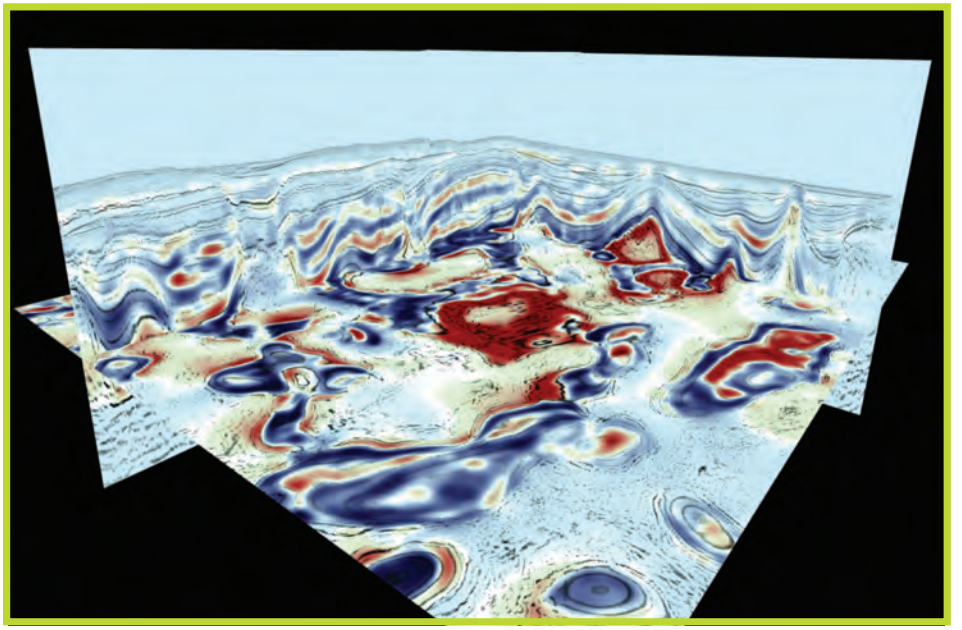


Above: PGS' holoSeis shows the depth residual at selected offsets (red seed points) has been picked at each sampled xline and interpolated by the visualization system.
Left: holoSeis display of Viper data. Images from PGS.





Left: Angola, Velocity update from Image Guided tomography. Right: Angola, Velocity update from conventional tomography. Images from TGS.



Example of visualization utilized during fast track pre-stack depth modeling and migration in frontier area: Sediment flood migration with supra salt velocity overlay. Data is from the TGS Olho de Boi multi-client 3D, deepwater Campos Basin.
Image courtesy of TGS and Dolphin Geophysical.

modeling and migration (Kirchhoff, RTM, or Beam) might also be utilized.

OE: What advantages do these visualization technologies bring to pre-salt formation characterization?

PGS: The advantage these visualization technologies bring is the ability to interpret the key geological markers and review the spatial consistency/integrity of the interpretation in real-time. In addition, new auto-tracking technologies enable the interpreter to pick a few "seed" locations on key events and allow algorithms to scan the volume to make the interpretation over the entire volume. In challenging areas such as pre-salt, this strategy, while providing a good initial guess, is not often good enough for a final interpretation, but the ability to rapidly view the data and make adjustments is essential.

SLB: Salt structures can take any kind of shape, therefore it is very important to be able to visualize the pre-salt formation from every direction and angle possible. In Petrel, for example, the 3D visualization is native, so you are able to fly through your pre-salt formation to visualize the full complexity of a reservoir.

TGS: TTI modeling and migration exhibit better imaging in complex geologic areas with steep dips, both the pre-salt sediments and sub-salt are better imaged. Image-guided tomography provides a more stable, structurally consistent velocity depth model. DIT is used to tune the image both at the salt base and in the sediments below. Orthorhombic modeling and migration may be used in the more complex areas that exhibit azimuthal anisotropy (fracture and stress zones).

OE: How long have you been using these visualization technologies and can you give us example(s) of pre-salt fields where the technology was used?

PGS: PGS holoSeis has been used for over a decade to visualize data in all hydrocarbon-bearing regimes in the world, onshore and offshore. Recently, Brazil, Gulf of Mexico and West Africa have seen the most consistent and concerted exploration activity and successes, but not without their own imaging challenges. PGS works for all major oil companies and have visualized data from all producing oil provinces and frontier exploration areas.

SLB: It has been in use for more than five years. The Petrel platform is used in the Gulf of Mexico, offshore Brazil, Angola, and the Barents Sea, as well as in onshore projects in North Africa and Europe for depth imaging studies and to interpret pre-salt structures. It is used by independent, major, and national oil companies alike. The platform optimizes pre-salt visualization, interpretation, modeling, and decision-making.

TGS: Prima and ImageZ software has been in use for over a decade, although new or updated interpretation and visualization modules are released regularly by the TGS research & development group. These technologies have been used in Brazil (Campos and Santos Basins), Angola (Blocks 35, 36, and 37), and over the majority of the central Gulf of Mexico and deepwater fields where TGS or their proprietary clients have data.

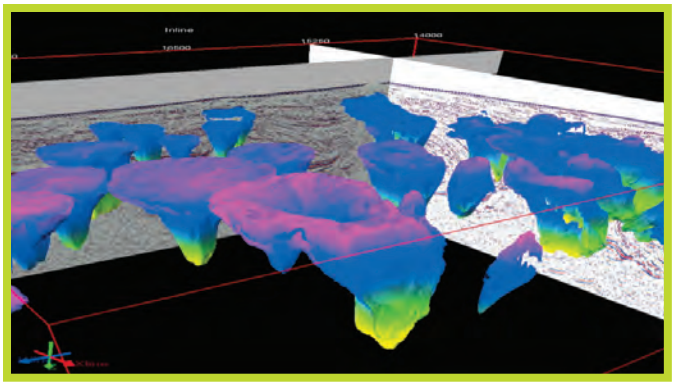
OE: How is the imagery interpretation done after the image is produced and how long does the process, from receiving the data to producing and interpreting an image actually take?

PGS: The time taken from receipt of field data through to imaging and final interpretation can take 6-18 months. The length of time is a function of the data volume and geological complexity – which can impact the complexity of the image processing workflow and the time required to interpret. Unfortunately, neither is an exact science, which can often lead to undesired project delays while un-foreseen challenges are overcome. In

addition, the regular improvement in imaging technologies implies interpretation can be significantly affected in some cases. As a result, interpretation in challenging geological regimes evolves over time as more and more uncertainty in the image is resolved with ever better imaging tools.

SLB: The interpretation and the processing of the image (seismic) is an iterative process. To get the best image, interpretation needs to be done to apply depth-imaging algorithms and get a clearer image, then a new interpretation is done and another depth imaging step is run, and this goes on until we get the best quality possible. The interpretation is done in the Petrel platform relatively quickly, depending on the size of the area to interpret, then it is seamlessly sent to Omega geophysics data processing software to get the new depth image even sharper and more accurate. When the data is acquired offshore, a first pass processing is done on the boat, which provides the first image. Then the iterative loop starts. This can take a few weeks or months, depending on the complexity of the subsurface. But today, because the tight link between the interpretation and visualization undertaken in the Petrel platform and the Omega processing software, this time is hugely reduced.

TGS: Once the very first depth images are available, the interpretation begins and becomes an iterative process until the imaging objectives are achieved. The length of the process depends on the size of the processing area, density of the acquired data, and complexity of the area from an imaging and interpretation sense. Large regional multi-client 3D surveys can take up to one year or more to process and interpret from start to finish, while smaller prospect level reprocessing projects could take roughly half of that time.



Example of PrimaViz 3D visualization. Image from TGS.

OE: Is the interpretation done in real-time with the client involved?

PGS: Interpretation of the final image is almost exclusively done by the client. The exception is during the velocity model building stage where interpretation required to control model compartments can be conducted in real time. It is typical for a client to send interpretation and imaging specialists to PGS' offices for up to one week, during which time the client knowledge is integrated into the model building process. Interpretation updates can be then migrated in real-time and the impact upon imaging assessed.

TGS:The client is normally always involved in the interpretation, as they have the best insight into the geologic details of the area. The picking can be done in real-time either by the interpretation group at TGS (with client input) or by the client. OE

Narrating data

Software that can turn your oilfield data into readable reports is coming to an oilfield near you. Elaine Maslin found out how this technology could help create articulate oilfields.

When people talk about visualizing data it usually refers to how data is displayed visually, on screens, in infographics, and perhaps in 3D.

The idea is to help an engineer see the data more clearly and quickly, in order to carry out analysis, or make decisions.

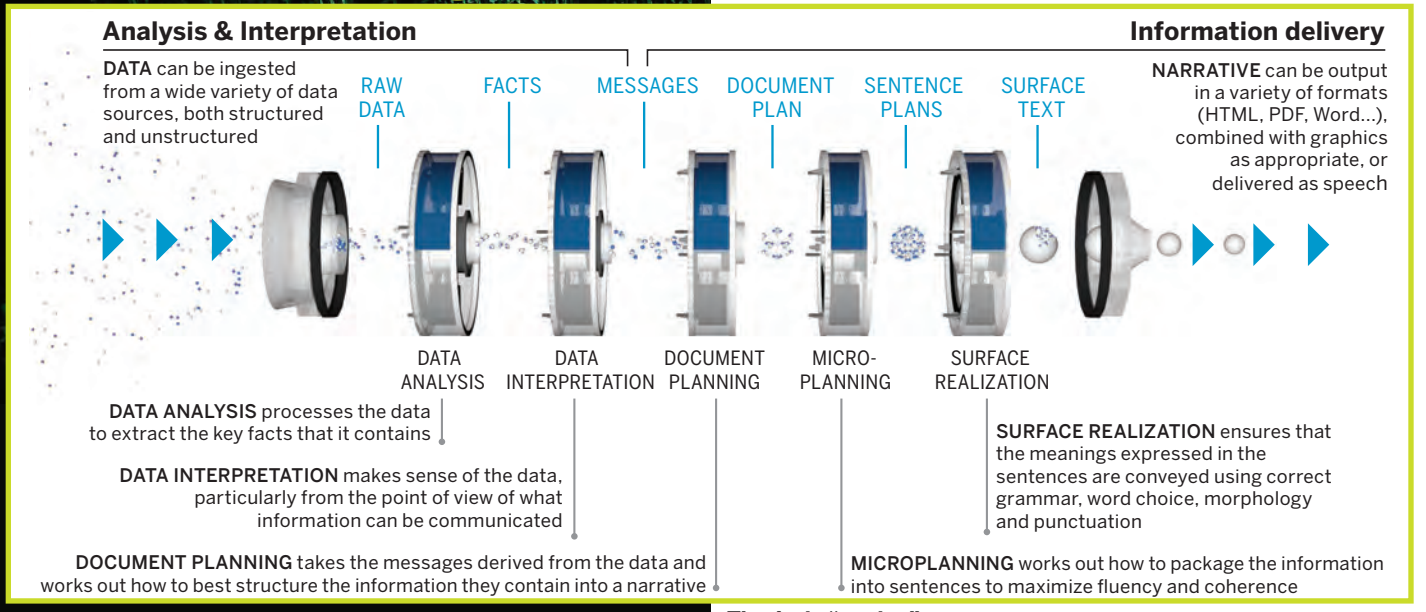
As more and more data is generated from the oilfield, from electric subsea Xmas trees, pipeline or mooring integrity monitoring systems, rotating equipment monitoring, environmental data, downhole pressure and temperature gauges, hydrocarbons streams, and so on, the need to not only gather, but also collate, analyze and make decisions based on the data also increases.

Data mining companies are already helping to analyze this data, looking for trends. But what if software could be used to collate, analyze, and then also present, in seconds, reports in narrative format, tailored to a specific audience, based on the data and analysis (work, which would take a human hours)?

Technology to do this has been developed, over three decades, and is now being used by an operator in the US Gulf of Mexico. Its origins is in natural language generation (NLG), a subfield of artificial intelligence. Unlike natural language understanding (NLU), which takes language and turns it into data, NLG takes data and turns it into language. NLU, as a research area, started in the 1960s. NLG then developed in the 1980s. Professor Ehud Reiter and Dr Robert Dale have been involved from the start, from when they were both researching the field at their respective universities, Harvard and Edinburgh as PhD students in the 1980s, before joining forces in the 1990s.

"That is when we started looking at how to take machines and produce language. There was very little interest in the problem at that point," says Dale, now chief strategy scientist

How the NLG engine works



The Arria "engine" Image from Arria.

and chief technology officer, at Arria. At the time, an early NLG engine was developed to create weather reports based on meteorological data collected by students.

In 2008-9, Data2Text, a University of Aberdeen spin-out company, led by Reiter, was launched. In 2012, Arria bought 20% on the firm, before taking it over completely in late 2013. Now, the Arria NLG engine is used to write 5000 weather reports a day across the UK for the Met Office, where previously the company only created 60.

"The fundamental goal of the technology is to take data and turn it into text, or voice," Dale says. "It involves a two-step process. First, the data, such as raw sensor data, is turned into information (through reasoning), and then the information is turned into written text or narrative (communication). In the first step, the engine does analysis to identify patterns and trends and turn that into information. For example, if a piece of equipment stops working, it will look at why that is happening and what other machines are around that, to determine what is happening. The information is then turned into text to tell a story." Both the reasoning and communication require knowledge "as a fuel" to enable it to interpret and present the data and information. "What significance is a particular sensor sparking a certain alert going to have and at the same time as another sensor going off? This is the kind of knowledge, gained from subject matter experts that the software embodies."

Dr. Robert Dale

Professor Ehud Reiter

For the oil and gas industry, the firm has started out providing its technology for discreet equipment areas, specifically, an exception-based alert system on rotating equipment on a platform in the Gulf of Mexico. When an alert indicates a temperature or movement threshold has been breached, the NLG system kicks into action. It has 77.6 million sensor points that could be relevant, which it assesses, analyzes and then feeds into a 500 word report, describing what is happening, and why it has come to this summary, all in 60-90 seconds. "Normally, that could take the relevant expert 2-3 hours," Dale says.

The processing power is based on a standard Intel desktop computer. The engine knows how to analyze the relevant data, including associated machinery, and how to understand what information is important and reportable. It knows how to put together a story to explain the data, emphasizing what is important. It knows how to package up information into sentences of the right size, and it knows the rules of grammar and the right terms to use.

Further applications are planned in the Gulf of Mexico context and ultimately Arria sees a scenario when Arria NLG would be used not just on particular pieces of equipment, but across platforms as a whole, enabling any level of report to be produced, from specific equipment analysis, to a performance summary for the entire platform, each written for a specific audience, at the touch of a button.

"Anywhere where there is a lot of data and people are struggling to deal with that data is where this technology could be useful," Dale says. "At the moment we are doing some work looking at electrical submersible pumps, and drilling reports is another area people seem interested in. We are starting with components, but you could imagine how you could aggregate that information, then look at chains of equipment and then the entire platform, correlating and integrating that information for a complete report of the system, creating an articulate oil and gas field."

While it might sound relatively simple, the research to get the engine to where it is has taken years, drawing on technologies developed in artificial intelligence, data analytics, and natural language processing, and has involved a number of blind alleys. For example, in an early explorations of the technology, it was thought that a template could be used into which the data is inserted to create the written report. But, when perhaps not all the data expected was available, the report would be left with gaps. The commercial version has systems that detect what information is available, and also what is the most relevant information that needs to be presented, and then produces the report, organizing the presentation of the material appropriately.

"The holy grail of this space is being able to use machine learning to automatically lean how to tell a story based on data," says Dale, using data, reports, and statistical techniques to look at correlations between stored data and textual content. But that is 10-15 years away, he says. An element of machine learning, is used by Arria, but the basis of the technology is on telling the system how to interpret the data it is given, to turn it into information and then from information into text.

Gaining and incorporating the knowledge from the subject matter experts also sounds like a lengthy process, but, Dale says, using corpus analysis, a type of linguistics methodology, existing, human-authored reports, can be scanned and "reverse engineered" to aid the process. In fact, this process can reveal tacit knowledge the subject matter does not think to reveal, perhaps because they think it is "obvious," making it a valuable part of the process. The application already has general knowledge embedded about language – it just requires any specific language, pertinent to the application, adding any specific terminology or linguistics required to suit the application.

So what are the safety safeguards? Dale is keen to point out that the human is still a crucial element in such a system, when it comes to mission critical applications. The report makes a recommendation about what an action should be. The human still needs to safeguard the right action is taken. "If it is a mission critical situation it is important to have a human in the loop," he says. "The reports are produced for the human to decide what to do."

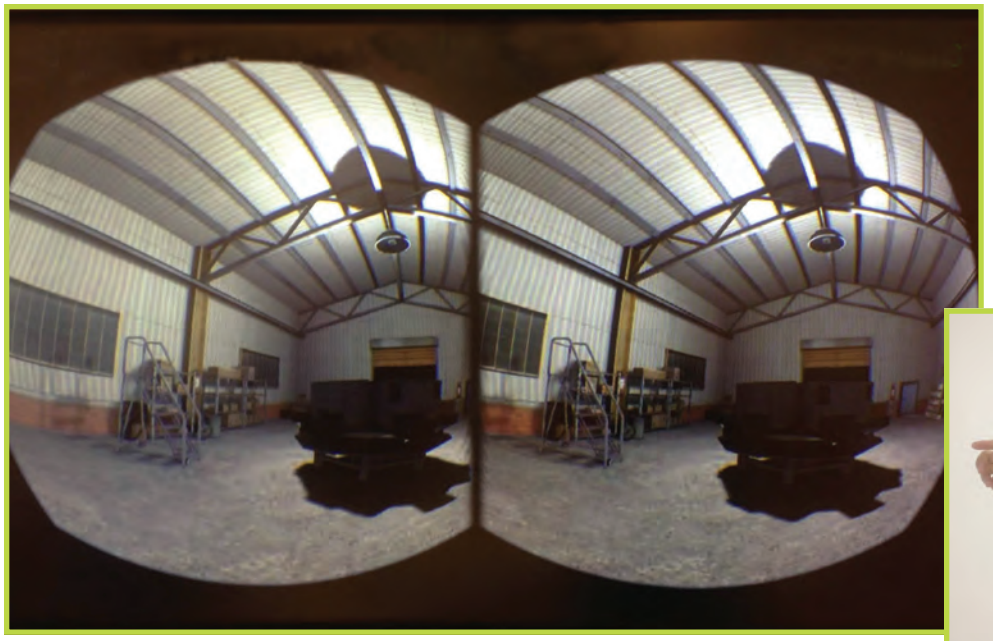
"Another question that comes up is 'isn't it better to have just graphs and charts.' To some extent it is horses for courses, but graphs can become unwieldy and to someone not used to those graphs and charts will just see a collection of graphs and charts," he says.

While the technology has been in development for 20-30 years, it is only now, as data is becoming ever vaster, that the NLG engine will come into its own, Dale suggests. "At the time (we produced the first weather forecasting engine) there simply wasn't a lot of data around and it wasn't economically viable to automate report production. Fast forward and now the situation has completely changed and the technology has commercial benefit. The amount of data you have to deal with has a bearing on what is achievable. More and more data, at ever-finer granularity, is emerging every day. The more finely grained data gets, the more operations have to be performed to get from data to information. And there is no sight of that changing. The challenge for us is to scale our techniques to deal with this." OE

Scan this page!

Scan this page with your smart phone or tablet to see Dr Robert Dale discuss Arria NLG at SPE in Dubai.

Changing realities



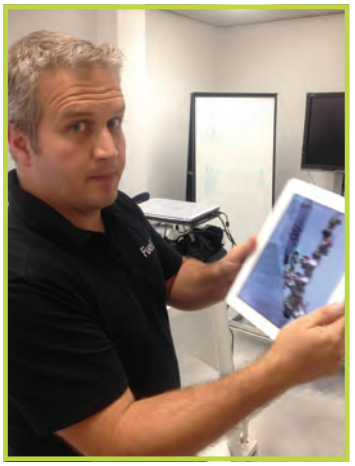
Oil and gas companies are turning to new high-tech gadgets for workplace solutions. Audrey Leon spoke with Houston-based FuelFX to see how this new reality can be implemented.

FuelFX's Oliver Diaz demonstrates the Oculus Rift system.
Photos by Audrey Leon/OE.

In order to reach the next generation of engineers, the oil and gas industry will have to speak their language by using high-tech gadgets, apps, and even video games.

"It takes 10,000 hours to be an expert at something," says Oliver Diaz, president and CEO of multimedia and design firm FuelFX. "Most young adults have played over 12,000 hours of games by the time they are 21. What are they experts in?"

Reality in the oil and gas industry is already changing, and it's getting more virtual. In 2013, Maersk Oil launched its web-only video game "Quest for Oil" with the purpose of making the oil and gas industry more accessible. Maersk Oil CEO Jakob Thomasen told OE last August that the company's goal was to inform, educate, inspire, engage and create a dialogue. "We hope that a game like this can create some awareness about the industry and how exciting it is to work here, that we have jobs in the future, and that you can have the world as your playground."



FuelFX CEO Oliver Diaz shows off one of the company's custom iPad apps.

Many companies currently provide simulated training options. Kongsberg Maritime, Maersk Training, Rolls-Royce, and GE all offer solutions for DP course training (OE: May 2014), for example. This type of immersive and interactive training can help adapt workers to the facilities on which they will work, before they ever set foot on an offshore rig or before they every get behind the controls of a crane that may lift a two ton topside module into place.

FuelFX is one company aiming to help translate the oil and gas industry through use of 3D modeling, animation, and motion graphics solutions that can be displayed through apps created for portable devices, such as tablets or smartphones. It is also developing training simulations that can be run through wearable peripherals, such as glasses. The peripherals utilize augmented reality (AR) technology, which allows the user to see both the real-life environment and also the scenario designer wants them to see.

FuelFX, which began in 2007 as Bullfighter Design, rebranded in 2013 with the industry in mind. FuelFX's Vice President of Business Development Gavin McMillan says 80-90% of its current business is from oil and gas. And the company has already worked with BP – helping to illustrate Macondo – Nabors, and Schlumberger.

McMillan, himself, studied mechanical engineering at the University of Texas at Austin, before pursuing a master's degree in visualization science from the Texas A&M University.

Laughing, he says, "I had a very renaissance education. I studied pretty much everything under the sun." That varied

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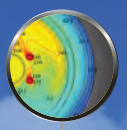
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Better together, but questions remain

Scotland voted to remain part of the United Kingdom in a historic referendum, held 18 September. Sanjoy Sen gives his view.

Alistair Darling and the "Better Together" campaign overcame a late scare in the opinion polls and have emerged triumphant in a hard-fought independence referendum duel.

Up to a month ago, a "no" vote might have been considered a mandate to maintain the status quo but the last-minute pledge from "Team Westminster" (arguably instrumental in swaying the result) appears a game-changer in Scottish and UK politics.

What these changes entail remains to be seen, but Scotland certainly looks set to take on much greater responsibilities via a new "devo max" settlement. Upon independence, the oil and gas sector would have formed the largest sector (almost 20% of GDP) of the Scottish economy; as "devo max" is thrashed out, it could feature strongly in discussions.

To date, powers have essentially been devolved to Holyrood (e.g. health) or reserved to Westminster (e.g. defense); could oil regulation and taxation now transfer fully to the Scottish Government or, uniquely, could it come under a joint UK-Scottish arrangement? The latter introduces greater complexity in countries with federal systems of government (the direction in which the UK may now be heading); Newfoundland and Canada have witnessed some spectacular clashes over oil revenues and management.

Over here, relationships could vary depending upon who's in power; expect an SNP Scottish government and a Conservative UK government to be somewhat less aligned than if Labour regains power in both Holyrood and Westminster sometime soon. Note also that devolution could complicate matters for regulatory bodies (such as the under-construction Oil & Gas Authority) which must seamlessly pick up the workload to maintain investment and safety.

UK Prime Minister David Cameron. Photo from 10 Downing Street.

The "no" campaign's late pledge included protection of the Barnett formula; this would effectively preserve the system by which most taxes are pooled prior to distribution across the UK. Oil revenues currently contribute to the pool; if Scotland demands greater rights over these, is there a disconnect with Barnett?

And if Scotland successfully argues for exclusive oil revenues, how will it cope with global oil price instability? One potential compromise is partial tax devolution (e.g. with the 32% supplementary charge solely to Holyrood) whilst also retaining a form of Barnett.

Although little discussed during the referendum campaign, decommissioning remains the industry's "elephant in the room."

While industry body Oil & Gas UK project a total spend of £35 billion, experience to date suggests this could escalate rapidly. If tax revenues are devolved to Holyrood, is it possible that tax relief liabilities are also?

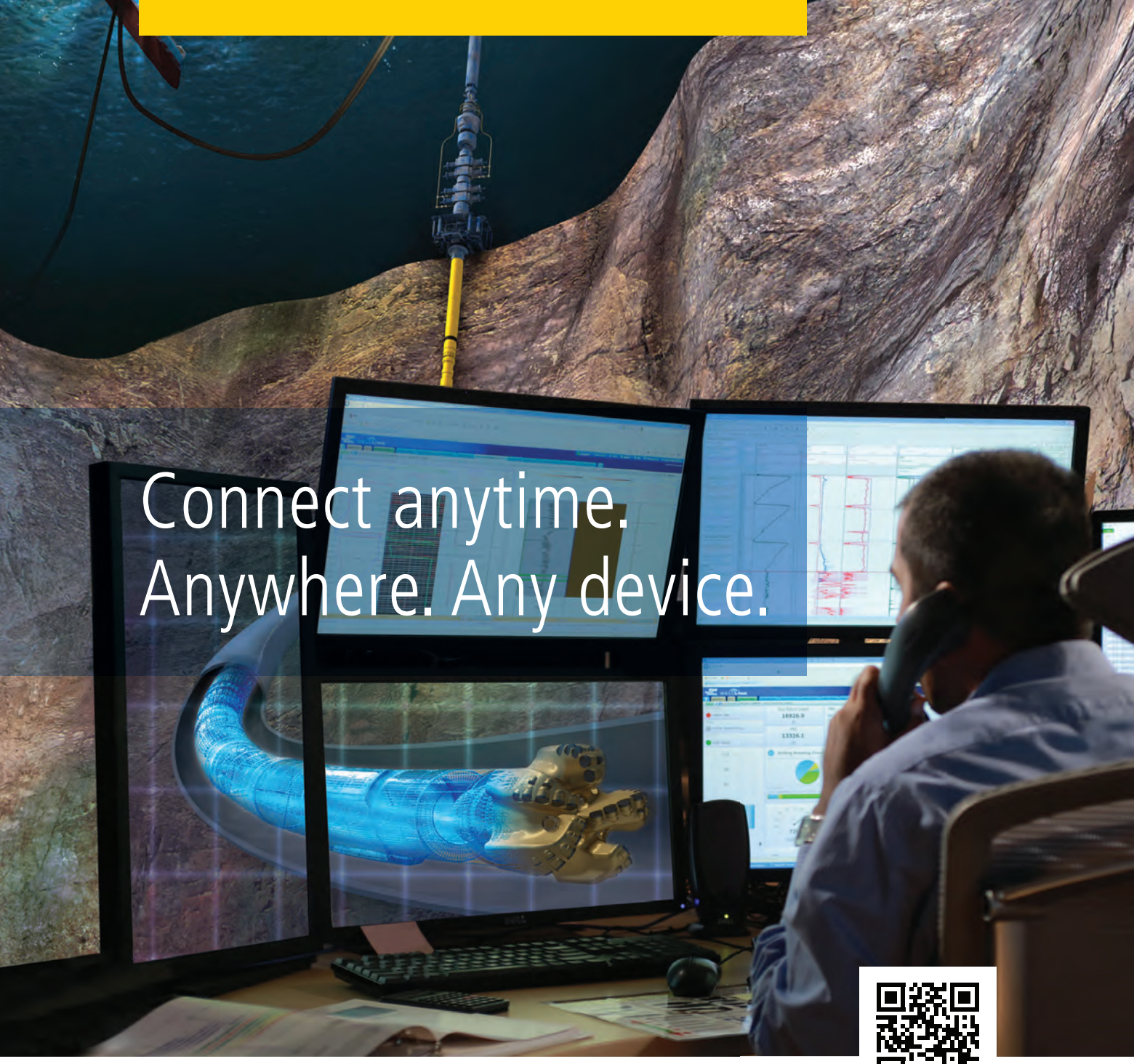
While the "yes" campaign contended oil would form merely a bonus within a buoyant overall economy, "no" warned of a declining and volatile resource. Today's stark facts are undisputed, however, and remain unchanged by the referendum result. Production is half the 1999 peak, exploration lies in the doldrums and operators face spiraling costs associated with mature asset integrity and marginal developments.

Aberdeen has recently seen redundancies and pay cuts with the supply chain under pressure to slash costs. All is not doom-and-gloom, however; current West of Shetland developments could catalyze further frontier exploration whilst the North Sea experience and technology is in demand worldwide.

Fundamental to the future of the UK (or Scottish) Continental Shelf is the successful implementation of the Wood Report. While its fundamental concept (Maximum Economic Recovery, MER) was welcomed by both UK and Scottish governments, its application could prove challenging; industry insiders have described Wood as a bigger issue than the referendum itself. Striking the balance between encouraging cooperation and sanctioning against those who don't could prove an early test of Holyrood diplomacy.

While not the momentous event that a 'yes' vote would have been, these are nevertheless unique and never to be repeated times; Scotland (and the rest of the UK) will never be the same again. Opportunities and challenges await as Scotland negotiates its newly-devolved powers and oil may well be at the center of them. OE

Sanjoy Sen, is a chemical process engineer with 20 years' experience primarily in the UK North Sea. He holds an MSc degree in petroleum engineering from Heriot-Watt University. He recently attained a distinction in his LLM in oil and gas law at the University of Aberdeen.



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Improved reservoir monitoring using towed-streamer seismic

Schlumberger's Patrick Smith reviews technological developments that are increasing the accuracy of 4D seismic reservoir monitoring.

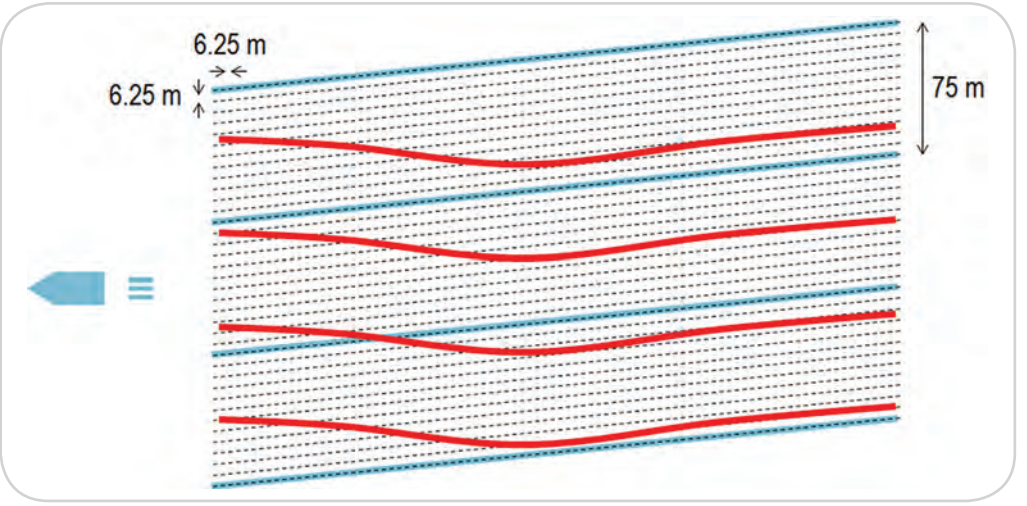


Fig. 1: Schematic representation of the reconstruction of a multi-measurement shot record. The red lines represent the streamer locations of a previous baseline survey. The pale blue lines represent multi-measurement streamers at 75m spacing. The dotted lines represent the dense 6.25m x 6.25m grid of traces generated by the wavefield reconstruction process. This dense grid of traces can be accurately interpolated to the receiver positions of the baseline survey streamers. Image from Schlumberger.

Continuous improvement in the quality, reliability and consistency of surface seismic imaging technology has led to an increased use of the time-lapse (4D) method to monitor changes in producing hydrocarbon reservoirs. This approach involves acquisition of 3D seismic surveys at intervals from before and during production of a reservoir. Differences between the repeated seismic images can indicate subsurface changes in pressure or fluid content, leading to improved reservoir management decisions, identification of flow barriers, and location of untapped compartments suitable for infill drilling.

However, the effect of these changes can be very subtle and may be masked by inconsistencies between the acquired surveys. Minimization of variability in the acquisition and analysis processes is essential for reliable delivery of repeated seismic images in which the only differences are due to subsurface changes.

Marine time-lapse projects require a stable seismic source with an accurately known signature and stable receivers with known characteristics. Source and receiver locations should be accurately repeated from one survey to the next. Changes in environmental conditions such as tides, water velocity, and wave heights should be accounted for. In addition, data processing of newly-acquired datasets must match that of previous vintages and be completed with rapid turnaround; otherwise the value of the data may not be realized in time to support drilling schedules.

The Q-Marine point-receiver marine streamer seismic system, introduced in 2000, was designed to maximize time-lapse survey repetition accuracy. IsoMetrix marine isometric seismic technology, launched in 2012, builds on the technology introduced by Q-Marine and, through its multi-measurement streamer reconstruction, has the capability to take repeatability to an unprecedented level of accuracy. Meanwhile, robust and efficient workflows have been developed to deliver reliable and timely results from data processing.

Repeatable in-sea equipment

The Q-Marine system provides several features designed to maximize the repeatability of in-sea equipment performance and positioning between vintages of surveys. The calibrated marine source (CMS) solution removes shot-to-shot variations in the source signature due to factors such as pressure, array geometry, and dropouts. In addition to compensating for relative differences due to such source variations, CMS helps to remove absolute variations between surveys. In addition, it also benefits imaging and inversion processes, such as amplitude-versus-offset inversion, and rock property characterization by accurately collapsing low-frequency source bubble energy.

Point-receiver acquisition enables the application of advanced digital technology that effectively attenuates many types of noise that typically affect sensors in towed streamers. The Q-Fin marine seismic streamer steering system is used to adjust the position and depth of streamers during

a survey, and the capability to attenuate high levels of noise allows deployment of more powerful steering devices that exert stronger lateral forces. The dynamic spread control (DSC) system uses current information and data from a dense in-sea real-time acoustic positioning network to automatically and independently steer vessels, sources and streamers to achieve an accurate repeat of a previous survey. During a repeat survey in the North Sea, despite less predictable ocean currents and higher natural feather relative to the baseline survey, DSC enabled 95% of source positions to be within 2.5m of planned positions. Streamer feather angle was repeated within a margin of less than 2.5° for 95% of the time. A further benefit of point-receiver recording is that filters can be applied to emulate the spatial frequency response of previous surveys acquired using conventional hydrophone arrays.

Corrections for variations in sea level due to tides can be applied either using tide table predictions, in which case correction for atmospheric pressure is advisable, or from differential global positioning system (DGPS) tide height measurements, which typically provide 10-15cm accuracy. Wave height correction can be calculated and applied during data processing to address perturbations in the seismic measurements induced by the roughness of the sea surface, which become significant once other survey repetition challenges have been addressed. Variations in seismic velocity through the water layer resulting from factors such as temperature or salinity can be accounted for using measurements from a moving vessel profiler on the seismic vessel to derive a unique space- and depth-variant water column velocity for each sail line. Accurate survey repetition minimizes the need for statistical matching processes, and deterministic time-lapse processing workflows have been developed that take advantage of this to ensure that the 4D seismic measurements are accurate from surface to below the reservoir.

Multi-measurement streamer reconstruction

With modern steering technology, source locations can be repeated from one survey to the next to within around 2m; however, even with streamer steering, it can be difficult to consistently repeat receiver locations. It is common to minimize receiver positioning errors by deploying streamers at half the spacing of the baseline survey, but this increases cost. The introduction of multi-measurement streamer technology enables data acquired with economically feasible streamer separations to be accurately reconstructed at user-defined locations and datums. Two or more multi-measurement surveys may be reconstructed at common locations, and these surveys will benefit from the broader spatial and temporal bandwidth provided by the new system. A multi-measurement monitor survey may also be reconstructed at the receiver locations, and with the same essential characteristics, of a previous conventional marine streamer dataset.

The multi-measurement system—IsoMetrix technology—is based on a unique point-receiver streamer system that combines hydrophones with calibrated accelerometers that measure particle acceleration in the seismic wavefield. For each seismic shot record, the measured pressure (P), vertical (Z), and crossline horizontal (Y) components of the pressure gradients are combined to create an estimate of the full 3D broadband seismic wavefield sampled on a 6.25m-by-6.25m point-receiver surface grid. Figure 1 shows how this densely sampled grid enables accurate computation of a set of "virtual" streamers that match the exact positions of those from a previous survey.

The new system allows streamers to be towed further apart and deeper than conventional arrangements, delivering data of equal or better bandwidth. A 2013 Barents Sea survey saw multimeasurement streamer data acquired at 23m tow depth to minimise ambient noise. Streamer steering was used to closely match the locations of an earlier Q-Marine, hydrophone-only, sail line acquired at 8m depth with a similar configuration.

The IsoMetrix dataset was processed to simulate the Q-Marine data and, as shown in Figure 2, the results show a close match between the two datasets, with no coherent energy in the difference section that might adversely influence 4D analysis. OE

Patrick Smith *is a senior area geophysicist with Schlumberger and has more than 34 years of experience in seismic processing. He has worked with time-lapse data since 1991 when the first commercial monitor surveys were acquired in the North Sea. Smith has worked extensively with both Q-Marine and IsoMetrix time-lapse projects. Based in Norway, he provides support to time-lapse seismic processing teams worldwide. Smith holds a degree in geophysics from the University of Reading.*

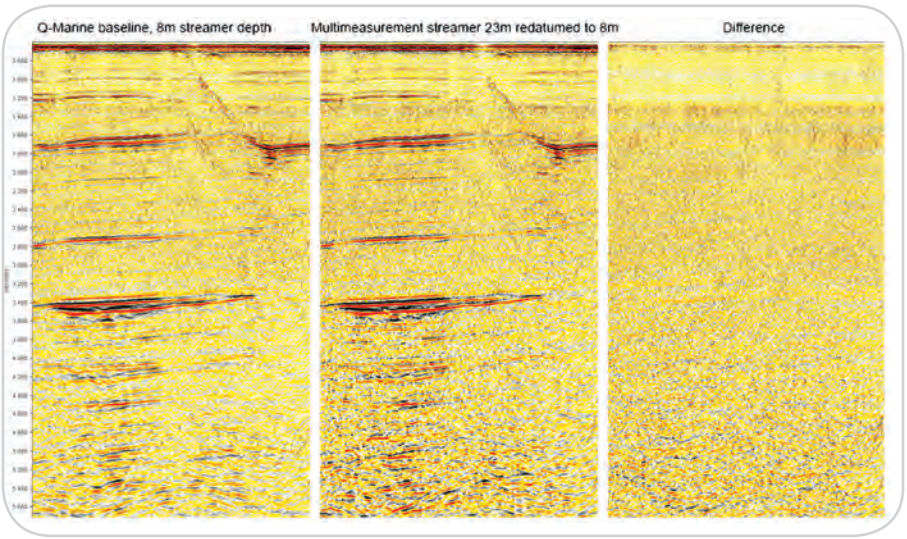


Fig. 2: Fine isometrically-sampled seismic data provides the possibility to separate and remove interference such as noise from nearby seismic activity, drilling, or oilfield vessels, reducing non-productive acquisition time in producing fields that may have several such sources of noise. The new system provides broadband data with enhanced signal-to-noise ratios including in the low frequency range (e.g. between 2 and 8Hz), which benefits both 3D and 4D inversion processes that can help to indicate rock properties. Fine-scale isometric subsurface characterization means that interpretation attributes can be generated independent of the orientation of viewing. This translates into more detailed representations of subsurface structures and stratigraphic variations, and enables a new level of insight into the geology from seabed to reservoir. Image from Schlumberger.

Chevron and Statoil are launching new solutions to a growing challenge in the Gulf. Bruce Nichols reports.

Keeping the 'window' open

After decades of theorizing and experimenting, the Gulf of Mexico is about to see the commercial application of two proposed solutions to a problem that is worsening as waters and wells get deeper: narrowed or non-existent "drilling windows" between pore pressure and formation strength.

Chevron's solution is dual-gradient drilling (DGD) using the purpose-built *Pacific Santa Ana* drillship and the GE (Hydril) MaxLift pump placed on the seabed. The system will undergo testing in an upcoming exploration well.

Statoil's solution is different, but relies on the same principle. Dubbed ECD-M, for equivalent circulation density management, it is controlled-mud-level drilling with the mud return pump built by Enhanced Drilling (AGR) placed part way down the riser rather than on the seabed. The system is slated for its first Gulf run at Statoil's Perseus prospect in De Soto Canyon Block 231. Statoil expected to spud Perseus by the end of 3Q 2014.

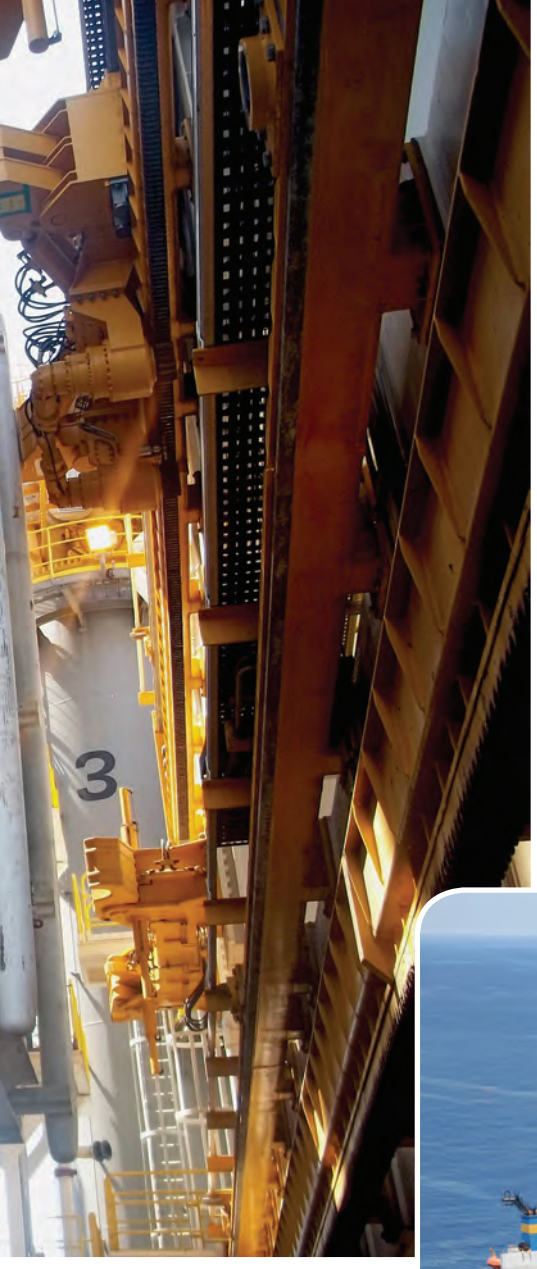
There have been variations on the dual-gradient, managed-pressure-drilling theme since the 1960s, including joint industry projects, several tests and a number of partial applications on the Norwegian Continental Shelf, the Gulf of Mexico, offshore Asia, and Cuba. But the commercial imperative wasn't there to force widespread adoption.

"Dual-gradient has always been the dream of any educated deepwater drilling engineer," said Robert Ziegler, general manager of engineering services drilling at Cairn India, and a pioneer who has run his own tests of an AGR system offshore Cuba. "When you design your wells, you realize that the biggest problem you have is the water column and the need (in conventional drilling) to have a single fluid from the surface to the zone you want to control," Ziegler said.

The mud between the seabed and the surface, necessary in single-gradient drilling, shrinks the drilling window – the margin between pore pressure and formation strength – and drilling starts "with one hand tied behind its back," as Ziegler puts it.

Now, with wells getting ever deeper and more difficult to drill, there may be a stronger business case for change. Chevron's project manager for dual-gradient drilling implementation, Ken Smith, outlined the challenge at the 2014 Offshore Technology Conference (OTC). Starting 15 years ago, narrowing windows began creating problems for drilling conventionally, most notably by requiring many more casing strings, each one narrower than the previous one, resulting in cementing troubles, tight down-hole tool tolerances and narrower-than-desired completions.

"Today, it's only gotten more challenging. We routinely drill nearly 'undrillable' wells," he said, citing wells more than 30,000ft in total depth drilled in waters more than 6000ft deep with mechanical risk indexes above an astronomical 9000. The newest rigs are now capable of drilling to 40,000ft, capability that will be needed to reach the industry's growing portfolio of ultra-deepwater projects. But the technological advances that have enabled drilling beyond 30,000ft are



The GE (Hydril) MaxLift pump aboard the *Pacific Santa Ana* drillship.
Photos: Pacific Drilling.

less effective deeper down, he said. "We are nearing their limits to deliver today's oil targets in deepwater," Smith said. "It's time to change the game."

Mud weight versus pore pressure, fracture gradient

The basic problem is that the weight of the drilling fluid in the wellbore must stay within limits as the drill bit passes through varying geologic strata on its way to target depth. If the mud weight is too heavy, it can fracture a formation and cause collapse of the wellbore as mud flows out into the neighboring strata, a phenomenon called "losses." If the mud is too light, it can't prevent uncontrolled intrusion of water, oil or gas into the wellbore, a phenomenon called "kicks."

If mud weight becomes too heavy or too light, as the well deepens from one strata to another, drilling has to stop and casing has to be cemented in to stabilize the hole, taking up drilling time and money.

Generally, in conventional single-gradient drilling, the deeper the well, the more casing strings have to be set. And because each string has to pass through the previous one, the casing – each string of which extends all the way to the surface – shrinks in diameter as the well deepens. This could mean the well can't reach the target zone at the desired diameter, making the production string too small to produce economically, and the well, in effect, un-drillable.

Dual-gradient or managed-pressure drilling offers a way forward. If the mud level in the marine riser can be dropped, the pressure gradients in the wellbore start at a lower level, in effect widening the drilling window.

In the Chevron-Pacific DGD case, the relevant gradients start at the seafloor. In Statoil's ECD-M, gradients while drilling can start as deep as 1100ft below the surface, the depth at which Statoil has chosen to place its pump in coming tests. In both cases, the mud load is lighter.

The *Pacific Santa Ana* drillship at Chevron's Anchor prospect in Gulf of Mexico.

The Chevron system fills the wellbore with drilling mud up to the seafloor. There, the MaxLift pump circulates the mud back to the surface via a separate mud return line. The riser from the seafloor to the rig is filled with seawater equivalent weight fluid – eliminating the additional mud weight.

Statoil also uses a pump and mud return line, but the pump is attached to the riser 1100ft below the surface. Mud fills the riser up to a level set by the pump and then circulates up a mud return line to the surface. The rest of the riser is filled with air, which does not require a handling system.

"We don't call it dual gradient. It's zero gradient because there aren't two fluids," said Uno Holm Rognli, Statoil's vice president of drilling and wells for the US offshore.

Different goals lead to different systems

The difference in systems is because Statoil and Chevron are coming at the problem from different starting points. Chevron wants to maximize the window and reduce the number of casings or intermediate liners required.

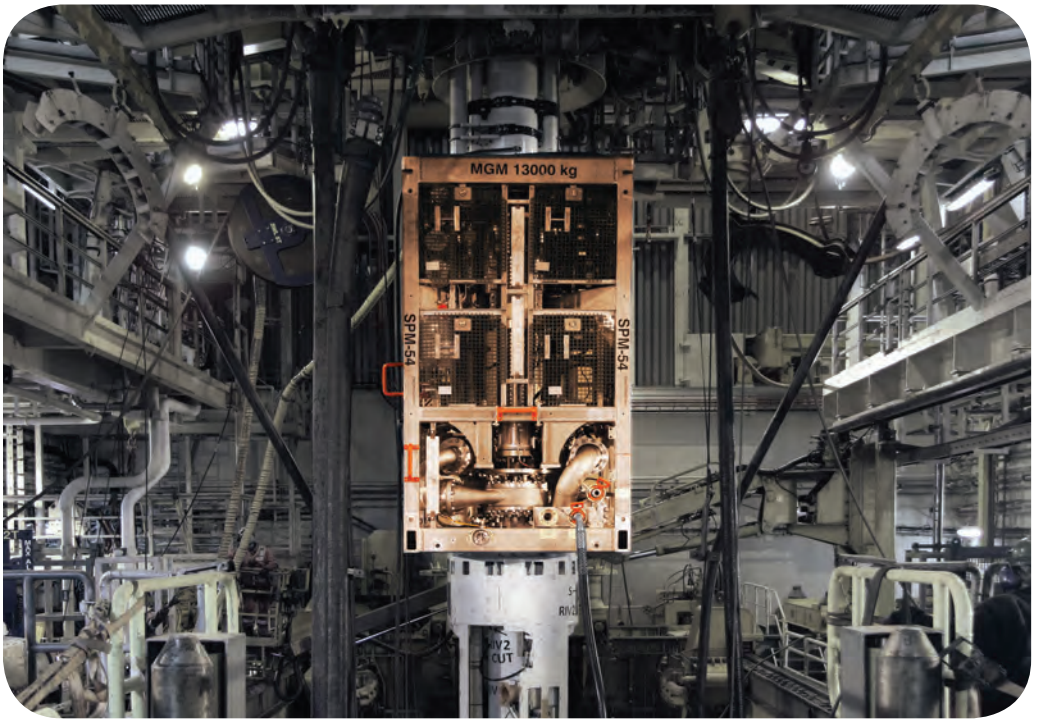
Statoil's goal is more modest: to stay within the narrow window that is available by eliminating fluctuations between static and dynamic circulating pressure, an issue in conventional drilling. If it saves having to install extra casings or liners, that's an added benefit. "We want to simplify it," Rognli said.

Statoil engineers chose 1100ft for the pump depth because they consider that adequate for now. "We could put it deeper, but it would mean a longer umbilical, a longer mud return line. So everything gets more expensive," Rognli said. Deeper placement of the pump is under study, but "we are starting carefully," said Roger Stave, senior technology advisor to Enhanced Drilling.

In both the Chevron and Statoil systems, the drilling window, in effect, starts closer to the seabed rather than at the surface, reducing the impact of water depth. It's almost as if the rig were on land.

Statoil employs centrifugal pumps in a series of three, attached to the riser. "We're using the same pump as those used for riserless mud return (RMR), and they have been around several years, on a lot of wells," said John-Morten Godhavn, a Statoil researcher and managed pressure drilling specialist.

Riserless tophole drilling, Ziegler says,



The Enhanced Drilling (AGR) pump on the *COSL Innovator* semisubmersible at Statoil's Troll Field off Norway. Image: Enhanced Drilling.

is – in essence – the oldest dual-gradient approach because there is no marine riser. But it is unusable for taking a well to total depth. Chevron's seafloor-based MaxLift pump is quite different. It is an innovative positive-displacement powered by seawater.

GE MaxLift pump key to Chevron DGD

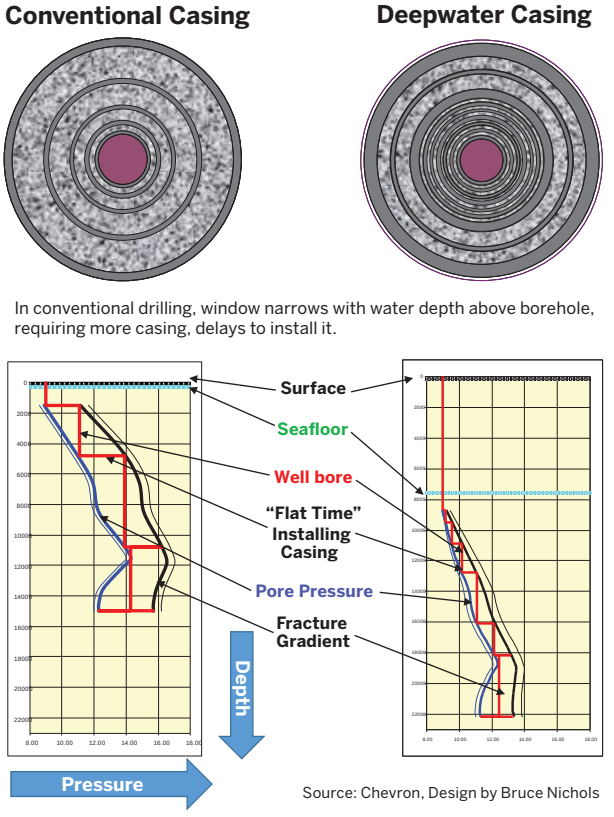
The GE MaxLift pump has six, 80gal chambers, each divided by a diaphragm. Seawater pumped from the surface provides hydraulic force to move the diaphragm back and forth, alternately pulling mud from the well and pushing it to the surface. The system can achieve 1800gal/min. Powering it with seawater minimizes electrical equipment sitting several thousand feet underwater. There are still electronics involved, as the valves that open and close, directing flows of mud and seawater, are electronically controlled.

Both systems are more than just pumps and return lines. In the Chevron-Pacific system, the pump is placed atop the lower marine riser package. A solids processing unit (SPU) sits atop the pump to ensure that solids are small enough to pump without plugging the mud return line. A subsea rotating control device sits above the SPU, providing a mechanical barrier between the wellbore and the riser. It allows temporary over-balancing during system operations, while protecting the wellbore from pulses that could "break the window" downhole.

The *Pacific Santa Ana* – purpose-built for DGD – has three separate fluid systems, one for handling drilling mud, another for the seawater-like fluid in the marine riser, and another for the seawater powering the pump. The moon pool was redesigned for handling the 450,000lb MaxLift pump in addition to the usual subsea equipment.

The Statoil system – designed for retrofitting on existing rigs – uses Enhanced Drilling's 29,000lb EC-Drill controlled-mud-level system, modified riser joints, MPO's Delta Seal Riser Module with quick closing annular, a riser gas handler system, and Coriolis sensors for early kick detection.

Whereas Chevron's business case revolved around drilling in ultra-deepwater, Statoil had two goals – to drill more efficiently in ultra-deepwater and to extend the life of fields in shallower Norwegian waters. Both Statoil goals require overcoming bottomhole pressure issues, but in the case of mature fields offshore of Norway, the problem is that years of production have sharply cut formation pressures and increased mud-loss incidents.



In conventional drilling, window narrows with water depth above borehole, requiring more casing, delays to install it.

Source: Chevron, Design by Bruce Nichols

Statoil's Enhanced Drilling system meets two needs

At the Troll field last March, Statoil used an ECD-M retrofitted semisubmersible, the *COSL Innovator*, to drill a depleted formation, punching a horizontal well 12,500ft and reducing mud losses 75%. "Troll came up as a kind of first use because they had a special need," Rognli said. "What they are using is this system to take down the mud level in the riser, to drill with lower pressure, still using water-based muds."

Troll is in relatively shallow water, at just over 1000ft deep, so the pump in the ECD-M system could be placed close to the seafloor, filling most of the riser with air. "We pulled the fluid two-thirds of the way down the riser, and we got an effect greater than if you'd filled the riser with seawater to the seafloor," Stave said.

Maersk Developer at Statoil's Martin prospect with Mars and Olympus on the horizon behind. Image: Bruce Nichols.

An advantage of the Chevron system is that, should the marine riser part for some reason and mud circulation be lost, the mud in the well is sufficient to maintain control, acting as a fail-safe.

Statoil considers its system fail-safe as well, but for different reasons. Its risers are equipped with dual annular sealing devices, which can be activated quickly to trap pressure should a sudden loss of circulation arise.

"But the annulars are not part of well control. We add the annulars to avoid getting into well-control situations. If a well-control situation arises, then we will isolate the riser and our controlled mud level system by closing the BOP and handle conventionally," Godhavn said.

Both Chevron and Statoil say they are proceeding step-by-step and that full implementation of their systems will unfold gradually. "We are going slow to go fast," Jacquemin said.

The Chevron-Pacific and Statoil systems were a hot topic at OTC. The title of one panel session was, "Is Dual Gradient Drilling Ready for Prime Time?" The answer appears to be "yes," assuming regulatory approvals and successful demonstrations in the Gulf of Mexico.

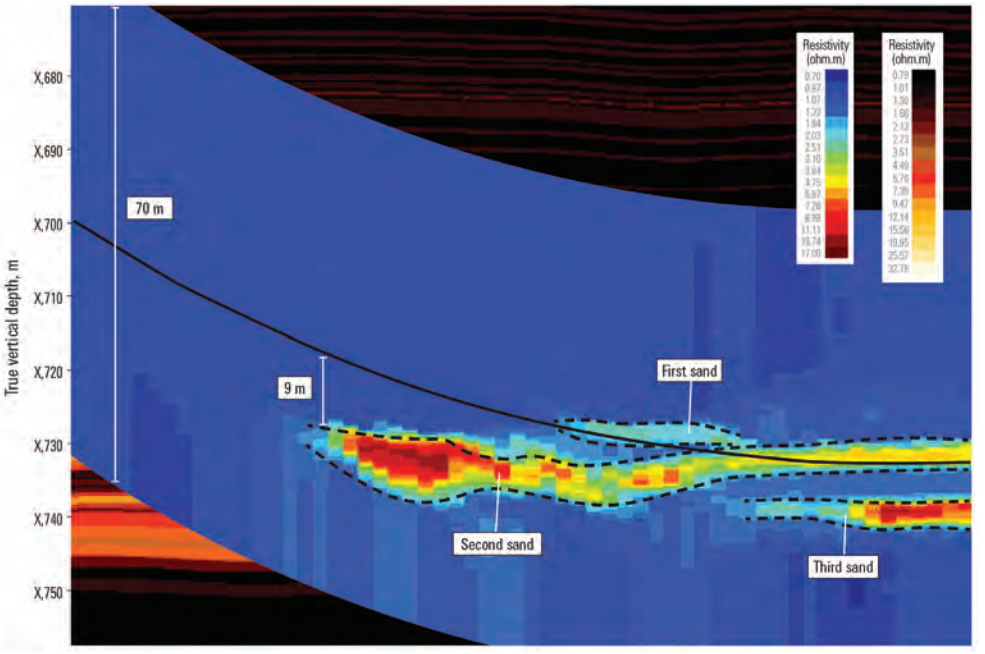
"Oil has never been easy, but it's certainly getting more and more difficult to find and access, and the technology that makes it easier is usually welcome, especially now that you have different techniques, different price ranges, different people helping the technology develop," Jacquemin said.

He mentioned Weatherford, which has the back-pressured managed pressure drilling system that Statoil has used off Norway. Weatherford also contributed the subsea RCD to the Chevron-Pacific DGD system. Jacquemin also mentioned Transocean, which offers a system called Controlled Annular Pressure Management (CAPM). That system was ready for a test in the Gulf, until the Macondo disaster forced a delay, Jacquemin said.

"It's no longer about theory. It's really happening," Jacquemin said. "Now we've drilled. We can show pictures. We go to conferences and talk about case studies. It's exciting." OE

Mapping while drilling goes live

In May 2014, Schlumberger announced the introduction of its GeoSphere reservoir mapping-while-drilling service. Claudio Paschoa discussed the new technology with Jean Seydoux, well placement and reservoir positioning program manager for Drilling & Measurements, Schlumberger, based in Brazil.



Real-time landing results show the detection and mapping of three sand bodies. The sand bodies are clearly not continuous and are thinner than expected, as indicated by the GeoSphere service map. Image from Schlumberger.

Logging while drilling (LWD) was conceptualized as early as 1920, but it was not until decades later, in the 1980s, that the first commercial services were introduced.

"Well placement has always been a challenge in drilling operations," Seydoux says. "Even back in the 1980s, physicists were experimenting with technology that could help them visualize reservoir structures, including the use of gamma rays. Emphasis on well placement really started in the 1980s, with the first generation of measuring while drilling (MWD) and (LWD) tools. In the 1990s, imagers were used to get a better idea of the structure around the borehole. The first real breakthrough is considered to have been (Schlumberger's) PeriScope bed boundary mapping service, which allowed drillers to identify formation markers away from the borehole without crossing.

Jean Seydoux

"The new GeoSphere service is the next logical step and also a step change in capability, by allowing drillers to probe five to ten times deeper into a reservoir," Seydoux continues. "The breakthroughs that led to this technology's development, allowing a depth of investigation (DOI) in excess of 30m, were the development of distributed multi-tool architecture in a bottom hole assembly (BHA), along with more powerful transmitters, a directional sensor (PeriScope), full azimuthal capability, powerful computational capabilities and the unwavering dedication of a range of experts.

"The development of this technology took over 15 years, from first idea to commercial reality, and involved more than 20 researchers from different fields," Seydoux adds. "The physics was the catalyst of the design of the measurements, signal processing, and antenna structure. The hardware was also vital for standard tool development, along with mathematical computation and inversion (the other half of the technology). Important questions needed to be answered, such as how to make sense of the measurements and how to evaluate and diminish geological uncertainties."

With a deep range of investigation drilling teams can use LWD technology/the GeoSphere service to reduce drilling risks and accurately land wells. In addition, the real-time reservoir mapping-while-drilling service enables accurate positioning of wells within target reservoirs, away from fluid boundaries, leading to increased reservoir exposure, as well as allowing geoscientists to refine their seismic interpretation and geological and structural models.

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measurements, GeoSphere reveals subsurface-bedding and fluid-contact details at in excess of 100ft (30m) from the wellbore. GeoSphere can map a reservoir top, allowing a clear, real-time view of the reservoir. With this data, operators can land wells in choice locations and avoid the loss of lateral exposure or creating sumps. Exposing more of the lateral section ultimately shows much more detail of the area surrounding a reservoir, greatly increasing the level of information available to drilling teams in real-time, aiding operational decision making processes by resolving the reservoir and its boundaries.

By combining the reservoir mapping data with seismic interpretation, GeoSphere can be used to update seismic models for increased understanding of reservoir geology and accurate predictions about formations ahead of the bit.

There are three main applications for the GeoSphere service, but there can be as many applications as there are geologists and fields," Seydoux says. The three main applications are: landing a well can be optimized to reduce the number of pilot wells and improve the planning of horizontal wells; geosteering, with respect to the main reservoir features and fluids contact; and increased reservoir structure understanding.

The three main components of GeoSphere are: a BHA that is tailored to the application; real time connection and data transfer from rig to a client's office (otherwise well placement is not possible); and a well placement team in client's office to provide mapping of formation structure in real-time using powerful computational clusters around the world. To make best use of the service, it is important to have a fully engaged client team (geology and geophysics and drilling), Seydoux says.

"The mapping-while-drilling service has many advantages over logging-while-drilling as LWD tools provide formation evaluation (FE) information in a very shallow DOI around the borehole (cm or < m)," Seydoux says. "This new technology (RMWD), provides a structure with resistivity around the borehole up to 30m. It is a much larger area and provides additional information not previously available. It is still complementary with LWD, with integration of information as a key aspect. Another important advantage is the link to seismic. Because the technology DOI is greater than the seismic resolution, seismic data can be refined and better understood, especially while looking at some of the features on a seismic scale, Seydoux says.

By increasing the confidence in the knowledge of the environment drilled, the mapping while drilling helps increase rate of penetration (ROP), improve wellbore stability and hole quality, and optimize well placement. Seydoux pointed out that "the key is knowing earlier and making the right decisions. RMWD also helps the overall drilling operation to allow for a smoother borehole. It provides better dogleg control and decreases unwanted corrections in trajectory (going from reactive to proactive mode). By detecting and avoiding potential problematic formations (shale or other), it helps avoid side tracking and offers better entry angle control. This is a reservoir mapping technology that benefits both drillers and geologists and geophysicists."

There were many challenges to overcome in developing the MWD service for commercial use, as it involved proving the viability and efficiency of different technologies. In order to attain well placement optimization it was necessary to have a more extensive understanding of reservoir characteristics.

"Four major advances make this new tool an effective technology for reservoir imaging. First, the tool modularity enables simultaneous radial depths of investigation in excess of 30m. Second, a broad range of measurement frequencies accommodate a wide range of formation resistivity. Third, the antenna design offers a full directional access to the resistivity tensor acquired at each spacing and frequency. Finally, a powerful real-time inversion method exploits the richness of the measurements and their deep depth of investigation, providing unparalleled support for the interpretation of complex reservoir structures," Seydoux says.

The individual transmitters and receivers provide flexibility in the ways that the new system can be incorporated into the BHA. The multiple spacing between transmitters and receivers, along with multiple frequencies, provide the best approach to address well placement in complex formations. This helps to correctly establish the location of oil water contact (OWC), while at the same time unveiling the geometry of the reservoir, including estimating reservoir

The GeoSphere reservoir mapping-while-drilling service tools consist of a transmitter and two receiver strings.
Photo from Schlumberger.

thickness, and characterizing geological block structures. The capability to produce deep directional resistivity measurements is vital for drilling wells in complex reservoirs and leads to a tighter integration with other reservoir measurements such as petrophysics and seismic imaging.

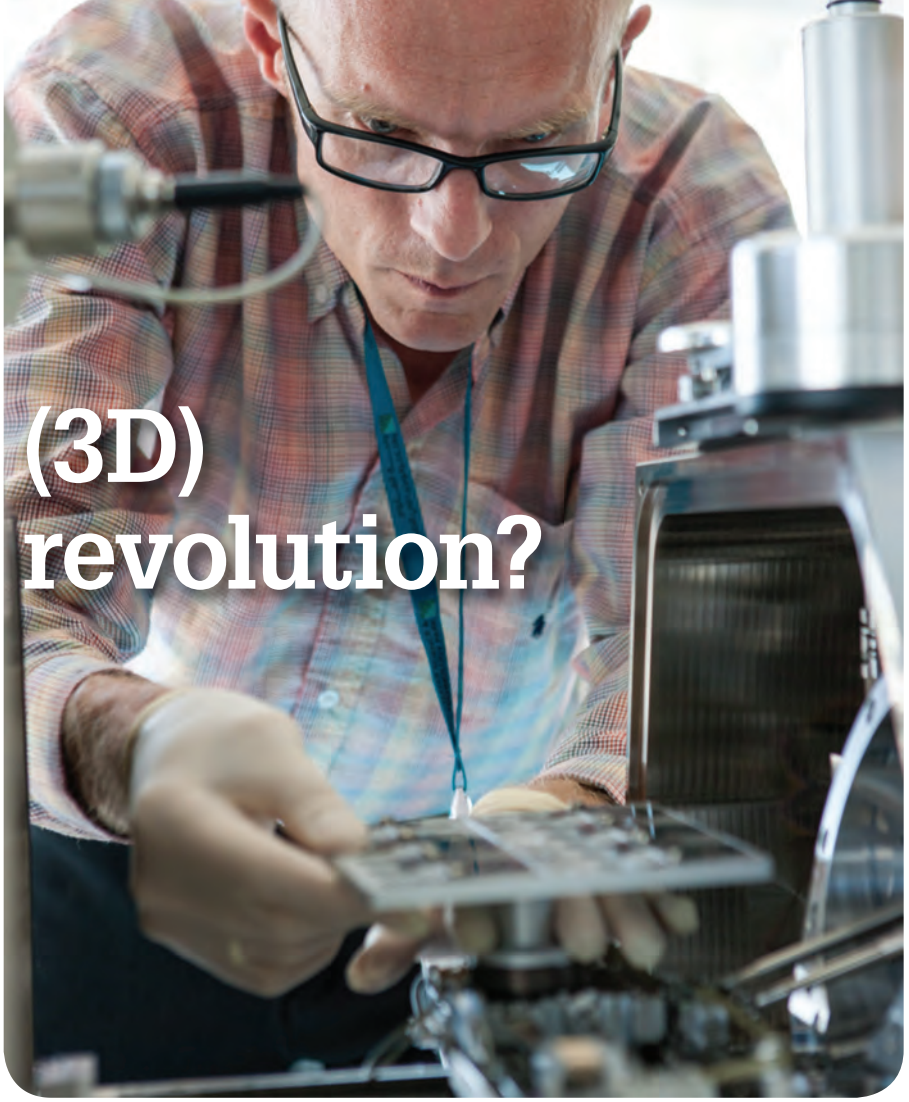
"This is a first to the market technology and it was very important to have it right from day one. The system has been through extensive testing with more than 150 jobs completed until commercialization. We have a range of applications that are very much extended and new, harder challenges can be addressed. It is important to understand how challenges can be solved by this robust product," Seydoux says.

"Mapping-while-drilling technology has been used in deepwater offshore Brazil since late 2008. We began with offshore post salt runs in the main basins (Santos, Campos and Espirito Santo), including carbonate formations. We also undertook an extensive one-and-a-half year campaign for one client with more than 30 applications of landing and navigation," Seydoux says.

Seydoux sees many future uses for the mapping-while-drilling service in Brazil. "The position of GeoSphere's RMWD service in Brazil is strong, and it has become the standard technology to use for Brazil. Having an enhanced reservoir structure and model in 3D around the borehole opens the horizon for a better integration with seismic and petrophysic measurements, which is the key to decipher the reservoir and its properties. Pre-salt applications are also under investigation." OE

3D or additive printing has caught the world's imagination—with the potential for human bone replacements and even bio-ink being mooted. Elaine Maslin found out more.

The third industrial (3D) revolution?



Maersk Oil's digital core laboratory in Qatar. Photo from Maersk Oil.

In a relatively short space of time, 3D printing has shot from being a quirky concept to a manufacturing method available on the high street.

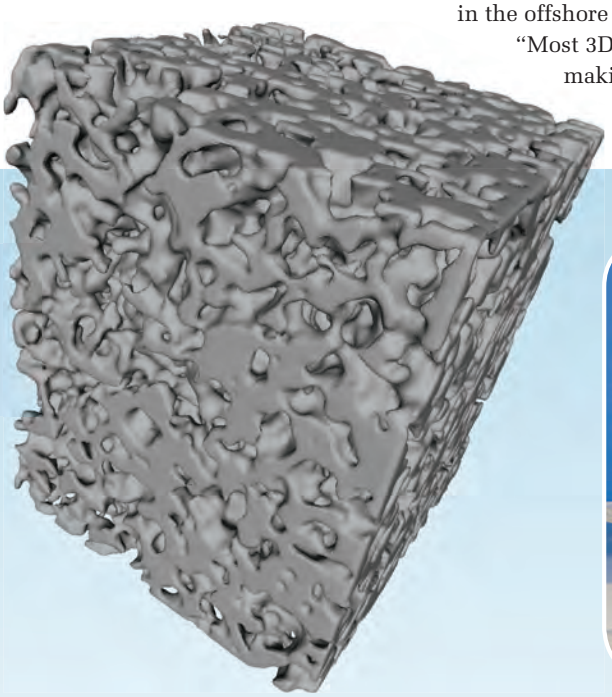
According to market insight firm Canalys, the size of the market, including 3D printer sales, materials and associated services, reached US$2.5 billion globally in 2013. Canalys predicts that this will rise to $3.8 billion in 2014, with the market continuing to experience rapid growth, reaching $16.2 billion by 2018.

Until recently, the scope of such technologies for use in the upstream offshore oil industry has generally been viewed as a tool for prototyping and modeling, or simply as a fun piece of technology to have on your booth at industry events. But, the potential to print using minerals, or metals, aided by advances in scanning and computational technology, is opening up more options.

Maersk Tankers, a division of A.P. Moller Maersk, has discussed having onboard printers that are able to print off spare parts. GE is already using 3D printing to manufacture jet engine fuel nozzles, which are normally made from a number of smaller parts welded together, using cobalt chromium alloy "dust," created by turning molten alloys into powder through gas atomization, mechanical milling, spray forming, and other methods, and a direct metal laser melting machine.

According to Monica Schnitger, from market intelligence firm Schnitger Corp., there is not much additive manufacturing in the offshore sector yet.

"Most 3D printing today is still making plastic parts, which don't meet temperature or pressure specs for



Scan this page!

Scan this entire page with your smartphone or tablet and the Actable app to see an interactive version of the 3D model at right.

At right: A large-scale 3D rock model created using CT scanning and modelling software.
Image from Professor Franek Hasiuk.

Far right: A selection of Maersk Oil 3D printed core samples. Photo from Maersk Oil.

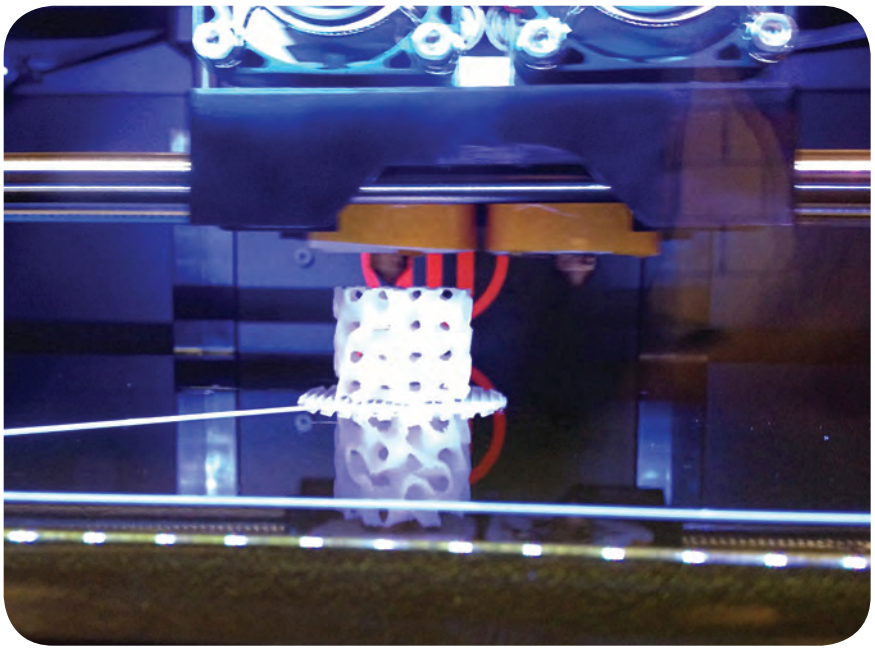
offshore applications," But, she adds: "Flame retardant high performance thermoplastics, more cost-effective metals and matching printer technologies are being introduced by all of the major players, so we should see more activity soon."

Evolution

The technology has in fact been around since before the 1980s. It has taken a combination of advances in computing and software and the release of a number of patents to help the technology reach its commercial potential. Much of the evolution of the technology has come from biomedical research (printing bones or other molecular, biological structures), as well as circuits and electrode fabrication, according to a UK Government's Intellectual Property Office.

It was the biological applications for 3D printing that first caught the attention of Professor Franek Hasiuk, a geology professor at Iowa State University. Professor Hasiuk previously worked at a super major as a geochemist. He had been looking into core networks—the physical arrangement of reservoir rock structures that can hold oil and gas in place. When he moved into academia he continued his research using computerized axial tomography (CT), which led to reading papers about CT in medical research, and the potential to make bone implants using 3D printing. This in turn made Hasiuk think about the possibility to do the same for core samples, which could then be used to perform experiments and test modelling.

"It is difficult to get core samples because they are hard obtain. But in addition, each sample is different, heterogeneous—even 1cm apart is different in a sample—so you cannot get a perfect sample. With 3D printing we can create a sample for reservoir research," he says. Samples are based on CT scans of rock samples, which are then put through algorithms to create a sample, which can be printed out. He is creating samples as 5-10 times magnification, but he wants to get to 1-1.



Additive printing underway. Photo from Professor Franek Hasiuk.

The work requires multiple gigabytes of data, and high computing power, to obtain the information needed, from which the 3D printing files can be computed. Samples produced, in plastics, so far include sandstones from Ohio, at 20% porosity and 2 Darcy, a higher porosity but moderate permeability limestone, and an Austin chalk sample, with high porosity but extremely low permeability.

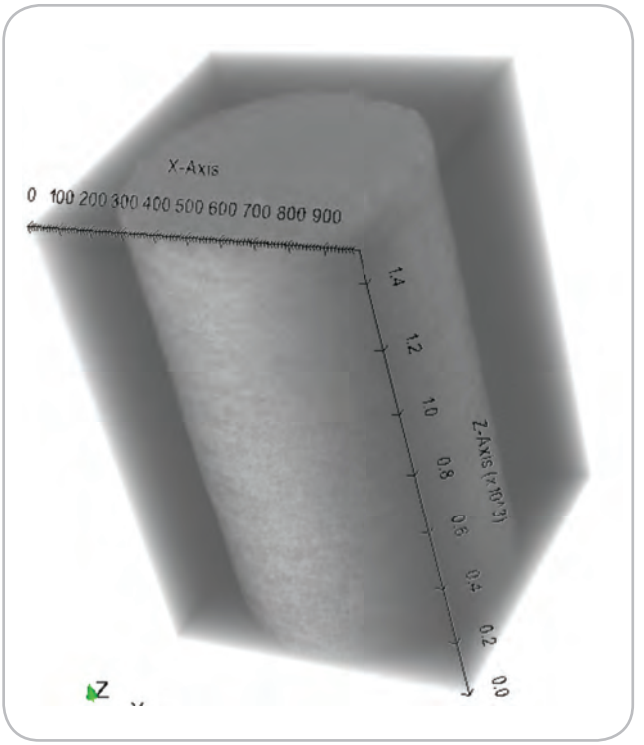
Aiding reservoir sweep

Maersk Oil's Qatar-based Digital Core Laboratory, which opened in January this year in Doha, is among a number of operators also using the technique to produce digitized core samples to aid reservoir visualization and understanding.

Theis Solling, the laboratory manager, says being able to print scale samples helps better visualize and understand the pore architecture—how heterogeneous it is or isn't for example—in order to understand where the oil is and how it moves. "Having rock model digitization is a great advantage and 3D printing is one extension of that, so you can really show the properties of the pore architecture," he says.

While you can use numerical data to describe the attributes of a particular core sample, having a printed model aids the visual understanding, Solling says. "This can be highly valuable," he adds, "for offshore supervisors in particular, to help decide water sweep programs. It can help to explain why you need polymer injection or why we might want to block larger pores after a first water sweep to make sure you get a better sweep through the reservoir."

The laboratory is part of a 10-year, US$100 million investment by Maersk Oil in applied research in Qatar, focusing on improved oil recovery, enhanced oil recovery and the marine environment. 3D printing has also been used in connection with Maersk Oil Qatar's corporate social responsibility program, by using the technology to help archaeology research at in the UNESCO world heritage site in northwest Qatar.



Above left: A 3D-printed core sample. Right: A 2D core sample visualization.
Photos from Professor Franek Hasiuk.

Samples for testing

Hasiuk wants to take 3D core sample printing a step further, by building virtual samples from the ground up, based on CT scans, but modelled to create homogenous samples and then printed and used to calibrate reservoir models through physical testing. You would be able to specify porosity, permeability and surface area, then print it for testing in a laboratory before calibrating a numeric method, Hasiuk says. It is work in progress.

A further development could see purely computer-based models, or "digital rocks," which recreate and model samples in order to better understand fields. But Hasiuk says by printing models you are better able to prove the quality of the process.

As patents on 3D printing lapse, particularly Selective Laser Sintering and methods which enable the use of minerals in 3D printing, further doors will open, he says, both enabling printing with different materials, but also enabling control of surface texture. This could allow much more accurate surface physics.

Printing on site

Chris Anderson, director, innovation and applied technology at Wipro Technologies, based in California, says: "The obvious potential for 3D printing or additive manufacturing in the oil and gas industry is printing onsite, which would open up the potential to lower costs and increase staff safety."

This could be beneficial, as increasing numbers of fields are in more and more remote, deep, and politically and geographically hard to access places, with storage and logistical hurdles. "There would also be benefits in not having to transport parts, and being able to tailor the parts on site to the particular application," he says.

But, he adds: "Right now, there are a lot of hurdles. Some of them are just mechanical issues, around the printing. There is a very limited capability to print with multiple materials in the same printing run. Most are able to print a single material and print different parts and then assemble them later. Also, the time and expense printing a single object can take hours or days. There is also a lot more finishing and post-printing work that needs to be done.

"There are also legal issues, some to do with IP, some with warranty. As far as I know, people are still trying to address how you might keep a warranty valid if you use 3D printed parts printed yourself. Even a simple part swap might negate a warranty. I think all these things will be resolved, but I don't think they this will happen until they are tried."

A potential scenario could be original equipment manufacturers signing off specific CAD designs that allow users to print to a specification, which can then be signed off or verified to be meeting the specification through a measurement and materials point of view.

Some of the issues could be resolved around using an enterprise resource planning (ERP) system, which contains information including when and how something was discovered to who the vender is, who the pattern makers are, suggests Anderson. "When you are looking at adopting 3D printing as a significant part of the procurement puzzle, you will have to think about treating the design as a piece of the inventory, looking at how they are stored, who the author is, what permissions there are, how to test it, how to make sure they are aligned to original equipment manual and warranties. Essentially, if you have people printing parts on site, it will either be done in an organized manner, or as needed, which can lead down a route to where no one has any idea about what is operating on your asset."

Another big piece of work will be assessing what can and cannot be 3D printed and when it might make economic sense to do so, something Wipro is looking to help firms manage. The total cost of a part, including transportation and storage costs, spillage rates, down-time, and HSE risk, etc., now need to be taken into account, Anderson says. "There are a lot of variables to look at – how much it costs to buy a part, get it on site, keep it on site, and deploy it. Understanding all that, as well as understanding where we are technologically with 3D printing, allows us to see what is possible in terms of what is proven (in terms of printing, IP, and warranties) and from that we can create a list of what is possible and where 3D printing could be more cost effective than purchasing and transporting a part on site."

"I think that as the technology improves, it is possibly going to make more and more sense to print things locally, especially when you look at costs and risks associated with transportation to some of the sites where our industry is working. But it will take a while." OE

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Worth 1000 words

By Sarah Musarra Parker

For rig crews sitting miles away from the coastline – and sometimes on the other side of the globe from their home offices – communication can be difficult.

Barry Calnan, of Houston's 3d-Printing Solutions (see Spotlight, page 93), points out that 3D printing can help close that gap between the inland office and the coastwise platform, at least from a communications perspective. Companies can use 3D printing to replicate pieces of equipment found on the rig, like a blowout preventer (BOP), to allow them to collaborate more effectively. It's a visualization tool that triggers clear communication, along with serving as a manipulatable model that allows for employees be exposed to large equipment quickly, easily and at low cost. The same cannot be said for training on the real thing.

"They've got the equipment there; they can take it apart and they can say, 'We need to look at this today and make sure this is functioning properly.' It's much easier than bringing the actual pieces [onshore]," he says. "Communication offshore is so important. Equipment can be changed and upgraded and training is ongoing."

In addition, viewing a 3D print of an engineered design – from the newest rig worker to the highest executive occupying a corner office – allows everyone to see an issue and its possible repercussions immediately. 3D-printed models, some replete with stress or flow analysis, can be printed to allow quick analysis of a problem.

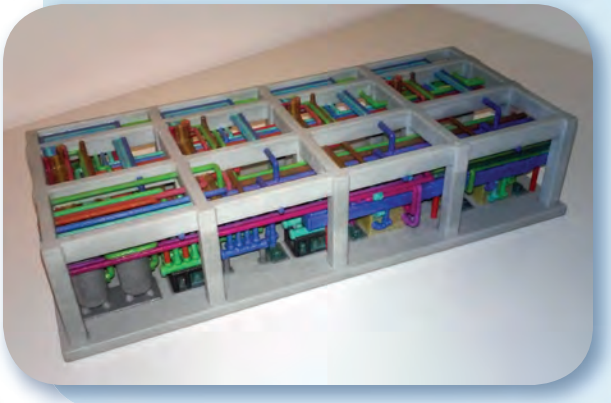
In a part's more nascent stages, seeing a 3D-printed, visual solid model can speed up the engineering process by allowing engineers to check functionality.

The entrance of 3D printing into the industry also helps address the so-called "crew change" that will occur with the wave of industry retirees. "The younger generation is used to video games and are used to a tactile and interactive interface. They really catch on to 3D models. That's been proven," he explains. "That's why people use it in training. If you are on a rig, you can actually print a connector, put the connector in front of the guys, disassemble it, and give them their instructions.

"They've got their manual and their model."

However, while Calnan is pleased to see the industry embracing 3D printing as associated with visualization, safety and communication purposes, he is ardent in that the technologies can be used for much more.

"Companies have gone from seeing models like toys to seeing them like tools," he said.



Top: A model of a valve body showing stress analysis, left, along with a companion part showing specific manufacturing instructions in color.

Middle: Calnan created a model depicting detail of a turbine blade, left, which shows stress. His other model shows design intent.

Bottom: A pipe layout model which was used to find problems with a design before construction.

Photos from Barry Calnan.

Print-to-use

Companies like GE and Maersk, who have begun to forge ahead in printing parts directly on metal printers, are attracting industry attention, but there are a lot of misconceptions and misinformation. Calnan says that this type of printing would be ideal for a specialty or a legacy part that needs to be repaired.

"Are they going to put a 3d printer on a rig? Probably not for quite a few more years. But the driving factor that is what can really be effective," he says. "The companies have not jumped onboard because it has to be a proven procedure, has to be a proven manufacturing tool for them to really want to sink their money into it."

Calnan points out that while companies might not be able to print, for example, a BOP, they can print its components. Before exploring that route, he suggests companies do some homework to learn how 3D printing can be the right tool to meet its objectives; what pieces or equipment could be printed; and, importantly, if the skillsets necessary for wide-scale 3D printing is readily available on their staff.

"There are some cases where standard manufacturing is always going to be cheaper, like for very large objects. But for specialized objects, you can't beat 3D printing as long as you can match the materials," he says. "The biggest mistake companies can make is purchasing too little of a machine or the wrong machine for what they need, capacity and material-wise. It may not match what they're trying to accomplish.

"You may also need to have more than one technology to accomplish what you're looking to do. Most people think 3D printing is just one thing. It's many, many tools." ■

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A stabilizing influence

When the Varg A monotower offshore Norway required stabilization, IK came up with a novel, remote, subsea solution. Elaine Maslin found out more after hearing about the project at the Underwater Technology Conference in Bergen earlier this year.

The clamp on deck, with the Varg A monotower in the background. Photos from IK.

Varg A is something of an anomaly on the Norwegian Continental Shelf (NCS). It is a dwarf compared to some of the other offshore giants there.

Yet, its stability was still crucial to the operator of Varg Talisman Energy Norge AS. Varg A is a monotower, normally unmanned wellhead platform, piled to the seabed in 84m water depth, through four grouted sleeves, with oil produced via the *Petrojarl Varg* production vessel.

The field, discovered in 1984, is about 200km west of Stavanger in the Norwegian sector of the North Sea and has been operating since 1998. It is destined for a new lease of life after Talisman took it over in 2005 and started drilling new wells in the area.

In March 2013, Talisman through scheduled monitoring discovered that a crack had developed around the circumference of one of its four foundation piles, indicating there was vertical movement between the pile and the sleeve, raising uncertainty over the structural integrity of the platform. Talisman moved fast to find an alternative to permanently stabilize the facility and went to Stavanger-based IK Norway for a solution.

A task force of specialist engineers from IK and Talisman performed a pre-study, in which several repair options were defined and reviewed. The thorough concept evaluation performed in the study was crucial for the project success, says IK's project manager, Kenneth O. Rosén.

Based on the study, IK Norway was tasked with finding a diverless arrangement, which had to be completed by Autumn of that year, without needing to stop production on the platform. It would mean temporarily fixing and elevating the effected sleeve, then permanently securing it, taking into consideration environmental loads, installation loads and safety.

IK's solution was a remotely and hydraulically operated clamp, capable of taking a 1600-tonne load, to elevate the sleeve, and then, to permanently secure the facility, producing 35, 300mm-diameter structural plugs, and the means to install them—all by August of the same year. It was a unique, fast, and challenging, but ultimately successful project, Rosén says.

"We had never made a clamp like this before and I do not think it has been done anywhere else in the world either,"

The clamp being lowered into place.

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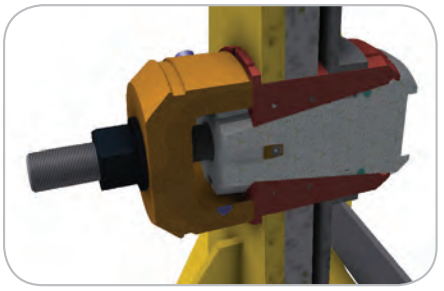
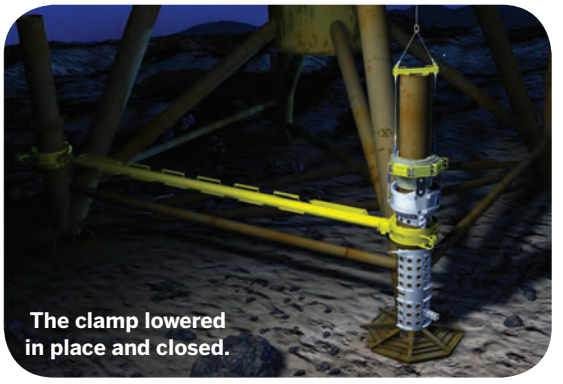


A cross section of one of the 35 plugs.

he says. "It was a very comprehensive and intense project and new challenges came up all of the time. A safety and risk review highlighted the risk of the sleeve buckling, so we developed shear plugs to stop this from happening during the elevation, but then we needed a new tool to install these shear plugs subsea. The concept for permanently securing the platform required 35, 300mm diameter plugs, weighing 250kilos each. We had to make a new tool to drill through the steel and grout, in order to install these. To make sure the plugs were installed correctly, we built a 7m-tall fixation template, with a common docking interface on each of the 35 plug slots, for which the drilling and installation tool, guided by the ROV, could latch.



The clamp lowered in place and closed.

"The critical element was being able to specify and design the equipment, while carrying out the necessary procurement and quality control, as well as manufacturing and testing in the available time."

Clamp

A key part of the project was the clamp. IK looked at a number of options, taking into consideration operational constraints, as well as manufacturing limitations, ease of installation and operation.

The final design comprised, in effect, of two parts – the upper clamp, to grip on to the pile, and a lower split clamp that closed around pile sleeve, all to be hydraulically controlled, via ROV panels, using an ROV. To meet the project deadline, manufacturing started before the design was complete, using early design information to order materials. Manufacturing was also carried out off IK's own promises, at a quayside manufacturing facility, in order that the 50-tonne clamp could be shipped directly offshore, instead of needing road haulage, which would require permissions, adding to the project timescale. Another manufacturing challenge was sourcing components, at a significantly busy time of the year, which meant IK had to source components from across Europe, because some of its usual suppliers were already fully booked.

Plugs

The plugs, to permanently secure the pile, were made using carbon steel and include wedges, to enable them to be torqued tight by an ROV. This was no mean feat. "We needed to be able to handle the plugs on deck in a controlled manner, drill and insert the plugs accurately subsea while managing the buoyancy once each 250kilo plug was released

by the ROV," Rosén says.

A fixation template was designed and fabricated with uniform docking interfaces, to allow the ROV to position itself and then drill and place each plug correctly. A drilling tool was then developed, to drill through the steel and concrete sections of the sleeve, grout and then pile, including dealing with weld beads, and removing swarf from the bit. A 300mm-diameter hole saw was developed, with special profile cutting teeth to handle the sleeve, pile and grout. Before deployment, it was tested off the quayside, using a work class ROV, which helped refine the tool and make any improvements where necessary. Despite initially not seeming a critical part of the project, the drill tool, and ancillary equipment, was key, Rosén says. "When we started, we thought the clamp would be the most critical element, but the drill alone could have been a nine month project," he says.

Offshore campaign

Project execution was fast. Just the month after the project team was set up, detailed repair concepts were established, and by mid-May a preferred option was chosen following evaluation, which included looking at operational constraints and procurement and manufacturing. The fixation template and clamp started fabrication in June with ancillary tool development and tested in July, before early August factory acceptance testing and offshore mobilization mid-August.

The offshore campaign started in August and lasted around five weeks in total. First, the fixation template was installed and initial drilling carried out, through the sleeve. Then clamp was lowered into place and closed to pull up the sleeve. The holes were pre-drilled through the sleeve to reduce the operational time it would take to drill through the piles. The sleeve was then jacked up, and the holes drilled through the pile, ready for the plugs to be inserted.

"A lot of engineering, testing and planning went in to preparing as much as we could before we went offshore to reduce the amount of time it would take to insert the plugs—as the more plugs inserted the more secure the structure would be," Rosén says. "As soon as we start drilling through the pile, there would be no going back." By mid-September, the campaign was complete, with the platform's structural integrity successfully secured.

Team working was a critical part of the project, Rosén says. "Managing such a big project in such a short period of time requires team work," he says. "Everyone, all the companies involved, in different locations and from different cultures, working together towards a common goal, with an ethos where you share problems, to solve them. Talisman had a very proactive approach in this respect. You also need people who are prepared to take on a challenge and put other things aside, because it's not all straight forward."

Engineering consultancy Atkins provided verification services and DeepOcean was the subsea contractor. The clamp and auxiliary tooling is now in storage and Varg A is safe and stable.

The partners on Varg are Talisman Energy Norge AS, with 65%, Petoro (30%), and Det norske oljeselskap (5%). OE

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Telecommunications of the future

The rapid expansion of oil and gas telecommunications systems in order to facilitate the development digital oilfields in increasingly remote locations, enhance safety, and maximize data use, was the theme of a conference on oil and gas telecommunications organized by SMi Group in London. Meg Chesshyre reports.

High-speed, fiber optic submarine communications systems are critical infrastructure to facilitate the digital oilfield of the future, says Mike Constable, CEO of Huawei Marine Networks, a turnkey submarine cable system supplier, and a joint venture with Global Marine Systems, at the Oil & Gas Telecommunications conference in London.

"The oil majors and field developers recognize that it is not just oil or gas flowing from their reservoirs. It is data," he says. An increasing amount of data is created, tracked and analyzed in order to optimize field operations in one way or another. Intelligent devices are capturing vast amounts of data, but a significant portion of this data is getting stranded in the field and not getting distributed effectively back to the shore. This is the critical infrastructure gap that subsea fiber optic cables that connect to offshore platforms eliminates.

"Broadband data communications is rapidly emerging as the single most reliable technology to support the digital fields of today and certainly of the future," Constable says. The drivers are similar to the global drivers of internet connectivity. Efficiencies, reduction of cost, profitability – all of these elements are critical to the exploration of today. Increasingly field developers are incorporating fiber-based infra-structure into their planning for new field

Statoil has installed a permanent reservoir monitoring solution on the Snorre field. Such systems produce data, which needs transporting. Photo from Statoil/ by Harald Pettersen.

developments, in addition to retrofitting brown fields.

He stresses the reliability of the systems. "We design these networks with 99.99996% reliability." Subsea fiber optic networks are not affected by atmospheric or climatic conditions. Bringing fiber to the platforms eliminates the digital divide between onshore and offshore.

OPEX reductions

There are OPEX reductions from remote monitoring. One field developer indicated that they had reduced their head count offshore by about 25% once they had fiber to platforms, a significant OPEX saving, and a health and safety benefit there as well.

Real time access to data accelerates decision making, and more significantly it is facilitating the new big data or data heavy technology that is coming today. One of the big data technologies that is on the horizon and being actively invested in now by a number of organizations, is permanent reservoir monitoring or 4D seismic systems. Sensors on the seabed transfer data back to the platform, and from the platform to shore enabling reservoir engineers to model their reservoirs more efficiently.

Companies like Statoil, Shell and Petrobras are putting in these systems now. Statoil, for instance, expects that the PRM systems on the Norwegian sector Snorre and Grane will result in 30MMbbl additional production. Not every field is suitable, but it is certainly technology that is ramping up.

"Data is here, and is here to stay," Constable said. "It is just getting bigger. It is more complex and the management of that is set to be a significant requirement for operators. It is also an integral part of the digital oilfield. Fiber-based submarine cable infrastructure is certainly the most effective and reliable solution for bringing the benefits of high speed broadband connectivity to offshore platforms, and the key to achieving these benefits is through the skilled resources, the project planning, and the collaboration between the experts that build these systems and the customers."

Frontier communications challenges was the theme taken up by Berry Mulder, team leader "Frontier Automation" for Shell Projects and Technology. He said that Shell and the oil and gas industry are going to more and more remote and inhospitable areas, such as the Prelude floating LNG facility off the coast of Australia, Arctic, and sour operations. "We have generalist people on board, who have to do expertise jobs, which means they have to get support from remote experts, so remoteness becomes a connectivity collaboration issue."

An additional challenge in-Arctic locations is that human beings are just not designed for work outside at -40°C. A lot of activities are still manual. More automation, taking the humans away from the hazardous activities, would help. Working at high temperatures and at high levels of protection is also a considerable challenge. For high sour operations people have to go into the facility already wearing breathing apparatus, eliminating the risk there would not be time to put on a gas mask in the event of a sudden leak.

Tracking people has special challenges to convince field workers to wear their tag and because it means that a lot of expectation of reliability is put upon the system. In an emergency, it helps the rescue crew if they know where you are so they can pick you up.

Mulder says there is a need to use more information technology in process facilities. "How can we equip field workers with what is available today outside? We hire the brightest people from universities and then give them metal tools to work on electrical systems."

Robotics developments

On the robotics side, ROVs have been successfully deployed for seabed operations for many years, so why not put wheels on the ROV and make it drive around? Enter the Sensabot inspection robot, which is to be deployed next year in the Kashagan field in the northern Caspian Sea. Working in this field is challenging due to the area's extreme climate and the high concentration of hydrogen sulfide gas present in the Kashagan reservoir. It can be used as a first responder if the H2S alarm goes off, rather than sending in a human being, which means "we can recover faster, restart operations faster, get to the root cause faster," Mulder says.

Sensabot features a mobile robotic base with a sensor boom tipped with inspection sensors. It can operate in extreme temperatures and explosive and toxic atmospheres. A human operator remotely drives Sensabot and uses its sensors to inspect pipes, fittings, and valves. The robot is small enough to go almost anywhere a human worker can

go and will be equipped to detect obstacles in its path. Sensabot is designed to meet IECEx Zone 1 standards for explosive environments and ANSI safety standards for guided industrial vehicles.

Another robot initiative is PETROBOT, a three-year European Union (EU) project set-up in September 2013, together with a consortium of 10 European companies led by Shell. PETROBOT will involve partners from the Netherlands, the UK, Sweden, Norway, Switzerland, and Germany. The EU is contributing €3.7 million to the €6.2 million project. The plan is to develop two types of inspection robots, to inspect pressure vessels while taken out of service, and to inspect storage tanks while in-service; with two main focus areas – to develop remotely deployed inspection tools for industrial environment, and the develop a market for these tools.

Petroleum Geo-Services' seismic survey vessel Atlantic Explorer. Photo from PGS.

But, Mulder points out, robots need connectivity everywhere, as would a human. "We don't want a situation where it drives into a black spot, and someone has to go in and push it out again." Low latency was also important. "We need local coverage including in vessel connectivity for robots," he says.

"At some stage I thought my job was developing new technology for Shell. Right now it is more like developing Shell to use new technology." More stuff becomes available all the time, but it is about convincing people to use it smartly, he says.

"I'm trying to organize networks of young people, basically because the older people see this stuff, don't get the click and it doesn't happen. They have to be the decision makers, so I'd like to generate a network of younger people, who say, of course we want this, a supply chain of younger people that says: you have this problem, you have the network. I know how to design it." OE

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Sat-comms developments

Customized data communication solutions are required in the offshore industry, particularly for rigs and seismic vessels, where data collected is needed in real-time onshore for processing.

Airbus Defence and Space's sales subsidiary, Marlink, last year installed a high throughput link on Petroleum Geo-Services' (PGS) seismic survey vessel Atlantic Explorer. The link provides Ku-band very small aperature terminal (VSAT) services based on a 12 Mbit/s dedicated return link. It was an upgrade to Atlantic Explorer's existing Sealink customized VSAT service also supplied by Marlink, and has subsequently been in successful use on the vessel.

"This project represents the very cutting-edge of what is known as customized VSAT; the kind of services used by the offshore industry because every platform and vessel has different requirements. This kind of high-level connectivity is not an off-the-shelf product," says Airbus' Tor Morten Olsen.

Following the recent creation of Airbus Defence and Space (a division of Airbus Group created by combining Cassidian, Astrium and Airbus Military), the company launched the AuroraGlobal high throughput services for government, maritime and enterprise markets earlier this year, as a response to increased bandwidth demand. The new portfolio of high throughput services – featuring Ku-, X-, and Ka-bands – gives increased throughput, without the need to change antenna systems.

Airbus says Aurora can provide enhanced X-band capabilities and performance for civil and government uses, increasing throughput up to four times more than current services using existing terminals, and enabling greater throughput via new smaller terminals, in line with growing operational needs.

In the maritime market, the next generation Ku-band VSAT service can be used without the need to replace existing antennas. The new maritime VSAT offering features twice the previous data volume allowances and twice the previous data speeds, with unlimited L-band back-up service, as well as the new XChange platform, without having to invest in a new VSAT antenna.

Airbus Defence and Space will also deliver Global Xpress high-speed broadband services through its worldwide distribution channels in the near future. A strategic agreement signed last December with Inmarsat covers the maritime sector, as well as the government and defence sectors, initially in Europe.

The new VSAT offering includes the latest XChange, to enable a simple switch between VSAT and MSS. The latest XChange includes a "bring your own device" Wi-Fi solution, allowing vessel operators to provide crew with voice and Internet services direct to their own smartphones, laptops and tablets.

Airbus Defence and Space has also entered into an agreement with satellite service provider, Intelsat, bridging maritime VSAT services to Intelsat's open-architecture, High Throughput Satellite (HTS) Epic platform. The agreement will provide global satcom services with secure access to Intelsat's global Ku-band satellite capacity and terrestrially managed network IntelsatOneSM.

Epic has the potential to enable 25-60 Gbps throughput – around 10 times that of traditional satellites. Each Epic spot beam can support Airbus Defence and Space maritime users with 1m antennas featuring up to 290Mbps downlink speeds and uplink speeds up to 225Mbps. ■

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Adding bandwidth

Andrew Lucas discusses how advanced VSAT capabilities are essential for offshore communications.

With the development of the world's first Ku band very small aperture terminal (VSAT) systems in 1985, real-time broadband communications became more seamless and portable for companies working in remote and harsh environments such as oil field drilling and exploration. However, reconfiguring bandwidth to accommodate changing environments or operations has been costly, taking days or weeks to process. Additionally, companies are often unsure of the amount of potential bandwidth they will need on a regular basis and choose to lease less than optimal bandwidth required. So what's the solution? Advanced VSAT.

Advanced VSAT accommodates rapidly changing operational requirements including rapid transmission of large files such as drilling logs, allowing remotely located experts to resolve local issues through the provision of high definition video and aide disaster relief efforts by utilizing dynamic bandwidth management architecture. The technology upgrade replaces older, less efficient equipment with new and higher performing devices offering a far more automated infrastructure.

Advanced VSAT allows each location on the network to use the maximum bandwidth available, without incurring the traditional costs associated with dedicated bandwidth. Utilizing dynamic bandwidth allocation enables unmatched processing capacity and a substantial increase in information rates than prior solutions. With an advanced VSAT platform, bandwidth upgrades no longer require two to four weeks but can be accomplished in a matter of hours. At the conclusion, rates can be lowered back to pre-event levels or kept in place for future use.

Harris CapRock partnered with Comtech to deploy its advanced VSAT solution based on single channel per carrier (SCPC) technology, which leverages the versatility of a network management system that dynamically reassigns satellite capacity on demand subject to the remote site's traffic profile. The technology enables users to achieve information rates exceeding 160 Mbps per outbound and 15 Mbps per return. This provides benefits such as unprecedented speed in capacity increases and an increase in connections of all remote sites in real time. It also allows communication service providers to deliver better efficiencies and resiliency, while improving network performance and reducing field service dispatches.

A Harris CapRock technician prepares a stabilized antenna system for advanced VSAT deployment. Photo from Harris CapRock.

Implementing the latest modulation techniques, from advanced quality of service (QoS) to adaptive coding modulation (ACM), helps to ensure the highest quality of service with minimal jitter and processing latency for real-time traffic, priority treatment of mission critical applications, maximum bandwidth and higher satellite link availability.

Recently, a company with a fleet of deepwater drilling vessels sought to upgrade its communications system, requiring access to more bandwidth to allow complete voice, video and data applications.

The operator's outdated time division multiple access (TDMA) system was replaced with Harris CapRock's SCPC-based advanced VSAT solution. Harris CapRock fitted the sites with dual-band antennas and larger BUCs, enabling higher throughput speed options and true "on demand" services for the customer, such as HD video support, real time streaming, scheduled event planning and live video surveillance.

Since upgrading, the operator has experienced global coverage in which it can transit from one geographical market to another without required site visits, saving time and money. The advanced VSAT solution has proven its ability to seamlessly provide communications to these rigs globally as well as other deepwater drilling and production companies.

The future

Over the last 20 years, the communications industry has seen a drastic increase in bandwidth requirements, number of systems onboard rigs, number of offshore remote personnel, complexity of offshore rigs, assets moving into new regions such as deepwater and ultra-deepwater, and automation and data acquisition requirements.

Once new automated systems are deployed, a few years of proving the value and reliability of the technology will be needed before a decrease in headcount is recognizable. However, while it should yield a lowered demand for operational personnel, it's expected to see an increase in the number of technical personnel to support more sophisticated systems used for data gathering. For example, an average rig today could have anywhere from 300,000 to 400,000 data gathering points, and of those, approximately 30,000 to 40,000 are being read while less than 1000 are actually being reported back.

Investing in next-generation satellite communications technology enables companies to access the maximum amount of resources available to meet their daily, hourly and even by-the-minute needs. Communications providers are continuously implementing the latest technologies to provide businesses with optimal results and solutions. OE

Andrew Lucas *is chief technology officer for Harris CapRock. He has over 20 years' experience in the satellite communications industry. Before serving as chief technology officer for Harris CapRock, he served as business manager for Schlumberger Global Connectivity Services (GCS) until its acquisition by Harris Corp. in 2011.*

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- ☐ 03 Operations Management
- ☐ 04 Geology, Geophysics, Exploration
- ☐ 05 Operations (All other operations personnel, Dept. Heads, Supv., Coord. and Mgrs.)
- ☐ 99 Other *(please specify)*_____

2. Which of the following best describes your company's primary business activity?
(check one box only)

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- ☐ 22 Independent Oil & Gas Company
- ☐ 23 National/State Oil Company
- ☐ 24 Drilling, Drilling Contractor
- ☐ 25 EPC (Engineering, Procurement., Construction), Main Contractor
- ☐ 26 Subcontractor
- ☐ 27 Engineering Company
- ☐ 28 Consultant
- ☐ 29 Seismic Company
- ☐ 30 Pipeline/Installation Contractor
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(check all that apply)

- ☐ 700 Specify
- ☐ 701 Recommend
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- ☐ 703 Purchase

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(check all that apply)

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- ☐ 102 Drilling
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- ☐ 104 Topsides, jacket design, fabrication, hook-up and commissioning
- ☐ 105 Inspection, repair, maintenance
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S31OS1

Testing the waters

Elaine Maslin reports on Subsea 7's new autonomous inspection vehicle and an AUV specification that has been put out for tender by French major Total.

Subsea 7's AIV. Images from Subsea 7.

Life-of-field autonomous underwater vehicles (AUV), able to remain subsea for long durations and perform inspection, and potentially intervention operations, has been a dream for the offshore oil and gas industry.

Two such dreams are nearing reality in Europe, where an autonomous inspection vehicles (AIV) has been put through its first offshore trials on a North Sea field, and an AUV specification has been put out for tender by French major Total.

The AIV is the work of Subsea 7. A life-of-field concept, Subsea 7's aim is for the AIV to be deployed from a basket-based launch system, which could be positioned on the seabed, a platform, or vessel, from which it could be sent on inspection missions without the need for a tether or support vessel, as is the case for ROVs. Its difference from an AUV, says Subsea 7, is that it has intelligent decision-making capabilities, using development partner SeeByte's complex navigation software, which, using sensors, can recognize subsea infrastructure configurations. By comparing what it sees to its world model, the vehicle knows where it is and complete its mission. It can also hover on station, making it useful for riser and pipeline analysis.

It is a project that has been in development for about six years, with tank testing and then trials in Loch Linnhe, and offshore Peterhead, Scotland. July saw the system successfully complete its first offshore mission, in the North Sea for Shell, from Subsea 7's *Normand Subsea.*

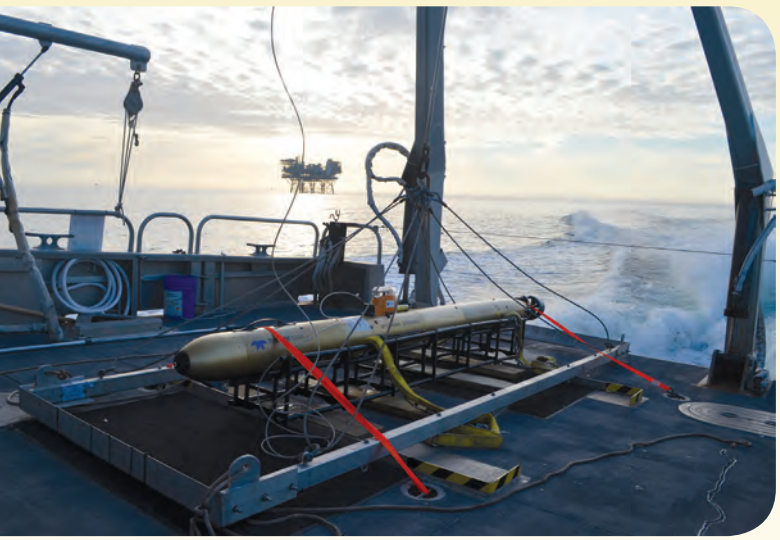
"The field operational tests were part of an ongoing proving and acceptance of the Subsea 7 AIV as part of Shell's 'new technology integration process,' and the trials anticipate the development of future AIV applications with which to support the inspection of Shell's subsea facilities," Subsea 7 said.

For the purposes of the trial, the AIV system was incorporated into the vessel's deployment systems and launched through the vessel's moonpool. The trials were conducted in parallel with planned inspection tasks being conducted by Subsea 7 ROVs, which were also deployed from the vessel.

The trial included a series of deployment and recovery missions, with autonomous subsea launch and basket dockings, fully autonomous navigation and inspection activities.

"Data was also obtained and will be used to supplement and support final further development activities within the ongoing AIV program," Subsea 7 said.

The AIV has been designed using computational fluid dynamics and has a unique station-keeping system and remote decision-making software. The MK-1 specification was rated to 3000m water depth, and could run for 24 hours, or a 40,000m excursion, depending on conditions. A future development of the AIV could see intervention equipment added, increasing its capabilities and potential applications.



One of the AUVs in a sling. Photos from UTEC.

AUV's survey Apache's assets

UTEC Survey's Australian business unit completed a major infield inspection covering 550km of pipelines and 20 infield structures, off northwestern Australia using its Gavia autonomous underwater vehicles (AUV).

The work, for Apache Energy, on its North West Shelf pipelines, started in mid-June using two Gavia AUV systems, equipped with a full suite of survey sensors, deployed from the *Yardie Creek* vessel. The inspection was completed in under four weeks.

UTEC operated the two AUVs on a "back-to-back" basis – when one system returned from a mission, the next one was ready to go immediately. In some cases the operational up-time in a given day was improved by as much as 40% through the "back-to-back" use of the AUVs.

The *Normand Subsea.*

Pipeline inspection AUV

Total E&P, which has long been working on AUV technology under the Deep Offshore Project, with Chevron and others, has developed a full specification for an AUV system capable of performing a complete pipeline inspection, according to a presentation at this year's Underwater Technology Conference (UTC) in Bergen.

It is a key requirement for Total and many other operators with subsea infrastructure. Total's Subsea Intervention Specialist Amin Nasr, said at UTC in June, that Total has more than 3000km of offshore pipelines, all requiring inspection services as part of the firm's asset integrity management.

Total's vision is an AUV, deployable from a number of platforms, with a mission specific sensor payload gathering critical data. A pipeline inspection AUV specification has been put out to tender, Nasr told UTC, and a feasibility study is underway to incorporate the future developed system into a wider scope project, as a "resident AUV system" in one of Total's new developments offshore West Africa.

"We have developed a specification; we have launched a tender for system development between major AUV service providers. According to our planning, the system should be ready early 2016," Nasr said.

Inspection requirements and challenges

According to Total's specification, the pipeline inspection AUV would need to perform pipeline integrity inspections and would need to perform buried pipeline detection, free span detection and measurement, seabed condition and buckling surveys, pipeline movement detection, damage assessments, debris identification, and corrosion surveys, Nasr said. The AUV's capabilities would need to include subsea navigation, visual inspection, sonar inspection, pipeline tracking and pipeline feature identification.

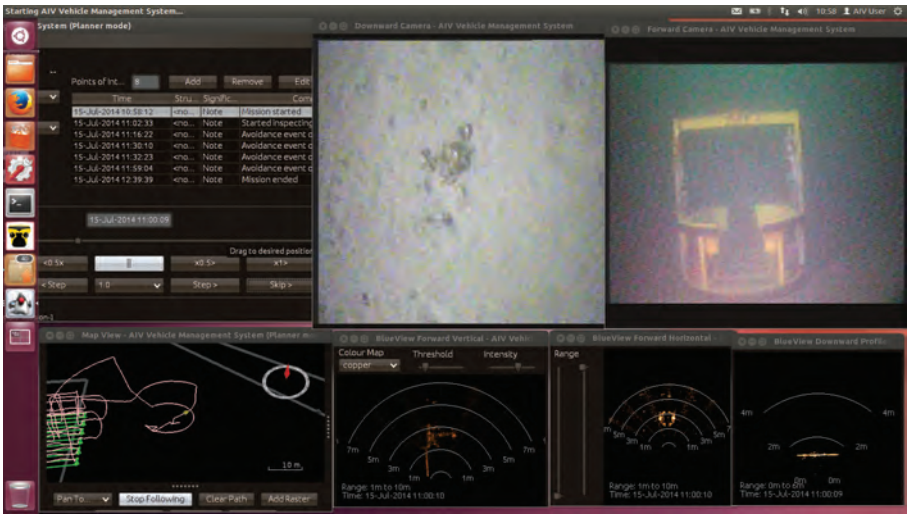
"The advantages of an AUV is being faster, at 3.4-5knots, and better data quality," Nasr said. "They could operate in a bigger weather window, and most importantly reduce the size of and even eliminate the need for a support vessel. To do this, we need to close the technology gaps and develop new philosophies for pipeline inspection. The technology gaps are in navigation, visual inspection, free span detection, and corrosion surveys, which

The AUVs are low logistic modular Teledyne-Gavia Offshore Surveyor AUVs, which travel at up to 4knots in 4-1000m water depths. The AUVs are positioned with INS aided via LBL/USBL or emulated USBL. For the operation, the AUVs were fitted with INS module c\w Kearfott T24 and ROVINS-90, aided by RDI 1200 kHz DVL, a sonar module, nose cone stills camera and obstacle avoidance sonar, control module including acoustic modem for USBL aiding and MST 900/1800 kHz side scan sonar, two battery modules and a propulsion module.

UTEC Australia General Manager Simon Hird said: "AUVs are a developing technology. Our AUV Center of Excellence in Houston is constantly striving to deliver new and improved capabilities, some of which were applied on the Apache project. The quality of data gathered and presented from an AUV survey is astonishing in terms of visible detail."

As well as the Apache project, offshore Australia UTEC has involvement in the Saipem Ichthys pipelay project; a long term contract to provide survey and positioning services on Woodside's *Nor Australis* operations support vessel; recent completion of a major subsea inspection program in Bass Strait, and a geotechnical investigation project relating to the Ichthys development. ■

UTEC's Gavia AUV.



Screenshot composite photo taken during the AIV trials, showing the AIV docking into its basket autonomously, sonar imagery and a still from the monitoring work class ROV.

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have never been done by AUV before."

Sensor power and payload requirements, control, maneuverability, and complexity of operating fully autonomously, are also challenges, he said.

Navigation has traditionally been vessel-based acoustic positioning, with a pre-determined route and ROV visual piloting. The challenge with this approach is ability to perform real-time feature-based navigation to pipeline features and not being able to operate without a surface vessel, Nasr said. An alternative, AUV-based approach, is to use pipeline recognition and subsea features positioning, using an onboard-stored map on the AUV. SeeByte in Edinburgh has already been working on such a system, which is used in commercially available ROVs, including SMD's MKII Quasar. FMC Schilling Robotics uses its own Station Keep visual recognition technology.

Challenges with such a system include "blind spots," where there are a lack of seabed features, which would make the auto tracking difficult. A solution could be tridents installed on the seabed to aid navigation and this is seen as being future standard practice, Nasr said.

Another challenge is visual inspection. This is usually carried out using a video streams, using three video cameras, two located on booms, to show the pipeline to seabed interface. This uses a lot of data and power for continuous footage, as well as lighting and the need to be close to the pipeline. Nasr said an alternative is to use HD stills cameras and strobe lighting synchronized to each photograph. The images would then be mosaicked to create a continuous, geo-referenced image of the pipeline.

For free span detection, mechanical profilers (or dual beam multibeam echosounders) are used, and sonar processing. But there is a need for faster surveys, Nasr said. He suggests using laser scanners, creating a 3D rendering of the pipeline and seabed relationship, or high frequency sonar (multibeam) offset from the pipeline, with bathymetry and sonar backscatter processing. The benefit of a laser scanner would be not having problem with frequency management. The challenge is understanding laser scanners underwater, Nasr said.

For corrosion surveys, a direct stab of the cathodic protection anode is currently used, which has autonomous identification, stab accuracy and reference cell location challenges, Nasr said. An AUV-based option would be contactless cathodic protection using data harvesting—with a sensor transmitting data which can be harvested by the passing AUV.

An outline specification

Total's outline specification incorporates using HD stills cameras to visually inspect the full length of the pipeline, in conjunction with a strobe light, with high frequency multibeam sonar, taken at a fixed offset and consistent aspect angle reference from the seabed. These would be used to identify damage or anomalies, debris, and pipeline features, through post-processing of laser or multibeam data.

Pipeline tracking would be via visual recognition and or laser/multibeam data in real-time. The AUV would need to perform buried pipeline detection, and free span detection and measurement, using laser scanners or multibeam echosounder. It would also need to detect global and local buckling, and pipeline movement, using post processing of imagery, AUV navigation and laser/multibeam cross sectional profiles, Nasr said.

Cathodic protection surveys would be a requirement, to assess coating damage and anode condition, including anode current output. The AUV would need to perform seabed conditions using post processed laser or multibeam cross sectional profiles.

Finally, Total has an outline specification for mission reporting. It says the AUV's system would need to include providing a comprehensive inspection report, standard ROC and sonar inspection type deliverables, as well as mosaicked, geo-referenced HD photographic data, geo-referenced sonar mosaic, 3D rendering of laser or multibeam echosounder cross sectional data, and GIS format delivery.

Nasr says such a system should be able to travel a minimum 100km in one mission. "The sensors and technology are available, but the challenges are to accommodate them to meet AUV pipeline inspection needs," he said. He hopes the outline specification will provide guidance on operator requirements to the AUV industry, but that it could need to be modified to meet improvements in sensor capability, and changing integrity management requirements from operators or regulators.

Future systems

"For future systems, we could have a docking station for communication and power, linked to a host platform (a field resident system). The AUV will send its data for evaluation and collect new mission details," Nasr said.

Optic transceivers could also be incorporated into subsea processing systems and downloaded at short range at 10-50mb/s data rates. This would also allow the AUV to be controlled real time, wirelessly.

A key function will be hydrocarbon leak detection, he says. If it detects a leak it will abort its mission and either return to look at it again to better characterize the leak, or resurface or go to a docking station to report the incident. Riser inspection could also be a future addition.

The next step would be simple tooling, he said. "If we are able to control it, you could have assembly tooling to do assembly tasks. The ultimate goal is to reduce the work of the support vessel." OE

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Meeting demand

GE launched its new technology center and a new deepwater vertical Xmas tree at this year's ONS. Meg Chesshyre learned more.

GE Oil & Gas launched its deepwater, high-pressure and high-temperature vertical Xmas tree (DVXT), at the ONS conference in Stavanger in August. The DVXT subsea vertical tree is an adaptable system for installation by a simple support vessel, with a tree mandrel that can accommodate drilling BOP or completion riser.

Mike Wenham, subsea trees senior application engineer, says that the DVXT is a new configuration of tree, providing flexibility and customization, relying heavily on proven technology, using core established products. It targets the North Sea, west of Shetland, East and West Africa, the Gulf of Mexico, and Asia Pacific.

The inauguration of GE's new technology solutions center, including a half-size model of its new deepwater Xmas tree.

Scan this page!

Scan this page with your smartphone or tablet and the Actable app to learn more about GE's new DVXT xmas tree, geared to meet the challenges of deepwater projects.

GE is hoping to meet an anticipated growing demand for subsea Xmas trees. Subsea production offers a significant growth opportunity and technical challenge, says Christopher Phebus, engineering director, Subsea Products & Projects, GE. He says that subsea production in 2012 was 9% of the total hydrocarbon production, but this is anticipated to be at least 15% by 2020, and that some industry experts are pegging that at around 50% by 2035.

The DVXT is a 5in. x 2in. tree designed for up to 3000m water depths, 10,000-15,000psi pressure, and a temperature range of -18°C to +151°C. It has an estimated 53-tonne weight (dependent on the specification), and is optimized to fit a 16ft x 16ft moonpool to accommodate older rig specifications. The tubing head spool has an estimated weight of about 32-tonne, again dependent on specification.

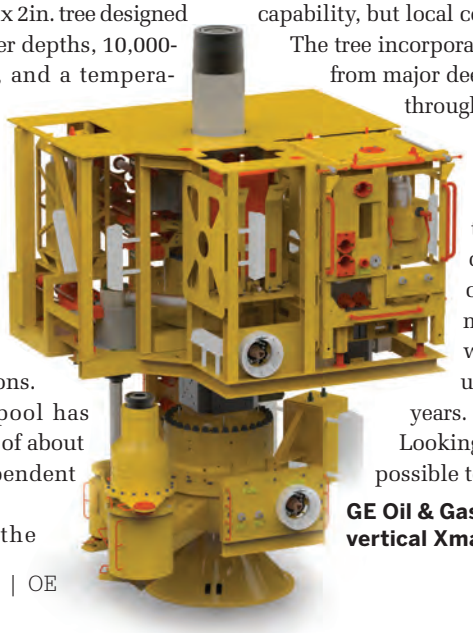
Deployed with the company's next-generation remote electronics canister—the SemStar5-R—the DVXT incorporates the latest in communication technology and is designed to achieve higher subsea reliability, extended service life and improved environmental monitoring. Already a market leader with communications out to 220km, at depths of up to 3000m, the ModPod subsea control module is designed to complement the DVXT's modular layout and enables an even more flexible communications network.

"We've focused on maximum re-use of existing design," Wenham says. "It is predominantly packaging. These trees have to go into Africa. We flat pack them and build them locally."

The DVXT's frame has been designed to be modular, which means it can be easily built in developing countries, where there might not be quite the same manufacturing capability, but local content requirements.

The tree incorporates requirements from major deepwater operators, through early engagement. GE has focused on lowest installed cost with flexible installation techniques and delivery times, for a core tree with minimal customization, of within 18 months. The unit's design life is 30 years.

Looking ahead, it will be possible to incorporate new technology into the tree as it comes along, Wenham says, "whether that be flowmeters, intelligent trees with strain gauges, or virtual flow metering."



GE Oil & Gas's new deepwater vertical Xmas tree.

To meet future manufacturing requirements, GE invested US$20 million in its facilities in Montrose, Scotland, with two new horizontal borers and associated cladding and inspection rigs. The upgrade was completed in July 2013. GE also has existing capability in Singapore and is building a new facility in Batam, Indonesia, which already has orders for the new DVXT trees.

Technology Solutions Center launch

GE Oil & Gas also inaugurated its new $5 million Technology Solutions Center (TSC) in Stavanger, Norway, during ONS. Sitting opposite GE's existing Subsea Systems facility in the port of Dusavik, it features a combination of interactive digital displays, live demonstrations and scale models, including GE PII's intelligent pigs, the Safire 2.0 multiphase flowmeter and the newly launched DVXT. State-of-the-art training facilities and meeting rooms are also located on-site.

The center brings together the numerous GE Oil & Gas business units including Subsea Systems, Drilling & Surface, Turbomachinery Solutions, Downhole Technology Solutions, Measurement & Control (including PII Pipeline Solutions), and Lufkin. The center also draws on the expertise of other GE businesses operating in the oil and gas space, including Power Conversion, Intelligent Platforms, Digital Energy (Energy Management), Distributed Power and Water & Process Technologies (GE Power & Water), Transportation and Lighting. OE

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Active magnetic bearings (AMB) are helping to make subsea gas compression possible. Joaquim Da Silva, François Carrere and Frédéric Ponson of SKF Magnetic Mechatronics, explain the engineering process involved to create the AMBs needed for this complex project.

Collaborative design with magnetic bearings

Subsea gas compression enables both improved energy efficiency and lower costs to help offshore operators to recover the remaining reserves in the existing gas fields.

To enhance efficiency in this application, it is now possible to operate and control the rotation of the subsea compression units using active magnetic bearings (AMBs).

AMBs offer a number of advantages, including high performance, a small footprint, high reliability, and advanced monitoring capabilities suitable for unmanned installations.

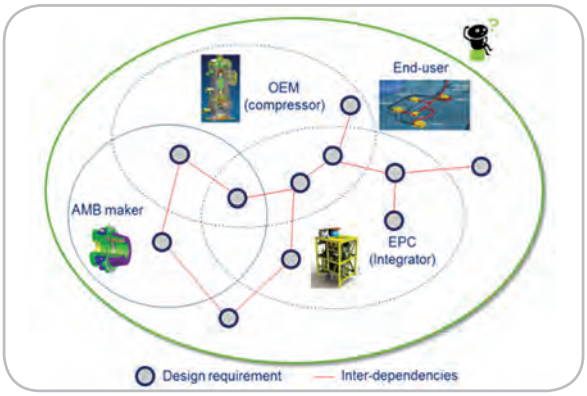
However, the application of AMBs within compression units requires a long and complex development and validation methodology involving several multidisciplinary engineering teams, comprising the AMB supplier, the compressor original equipment manufacturer, engineering, procurement and construction companies, and the end user.

To simplify development, traditional "black box" specification should be replaced by a collaborative design approach.

Collaborative design dynamics can be modeled as a kind of distributed network with nodes, each representing the design stakeholders. Each participant is responsible for several design requirements, solutions and decisions, all of which are highly interdependent. The dynamic of this network is strongly affected by the relationships between design participants. Requirements and interdependencies must be well defined, particularly the sharing of technical communication/information between the different members of the project, especially by means of appropriate modeling/simulation tools that are able to loop on the requirements issued by the stakeholders.

Ormen Lange land facility seen from the air. Photo: Svein Roger Ivarsen/Shell.

The project development phase was deployed using M2S2 (Multiphysics/Multiscale System Simulation). This methodology provided all project stakeholders with behavioral models, each a compromise between the details of physical behavior and complexity.

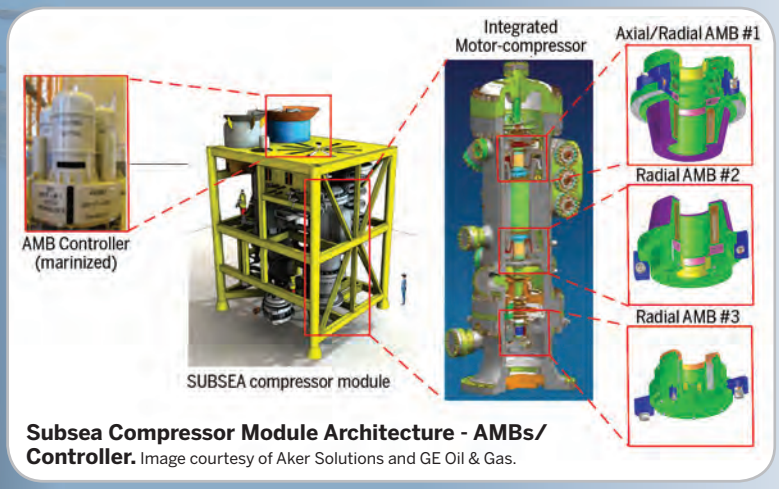


Collaborative design interdependencies (network).
Illustrations courtesy of SKF.

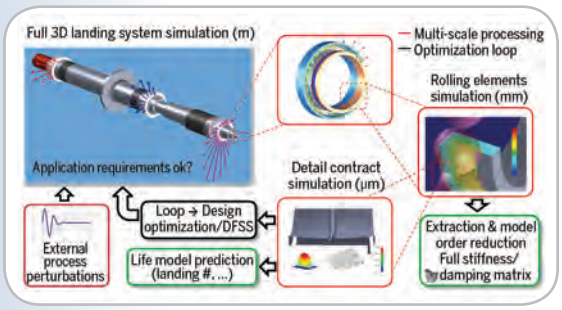
The Ormen Lange pilot project

The subsea compression station at Ormen Lange comprises a "main module" equipped with two or four 12.5MW subsea compression units. The integrated vertical motor-compressor (max speed 11000 RPM) is equipped with AMBs (three radial bearings and a thrust bearing) linked to a variable speed drive, a separator module, a cooler, and a liquid pump.

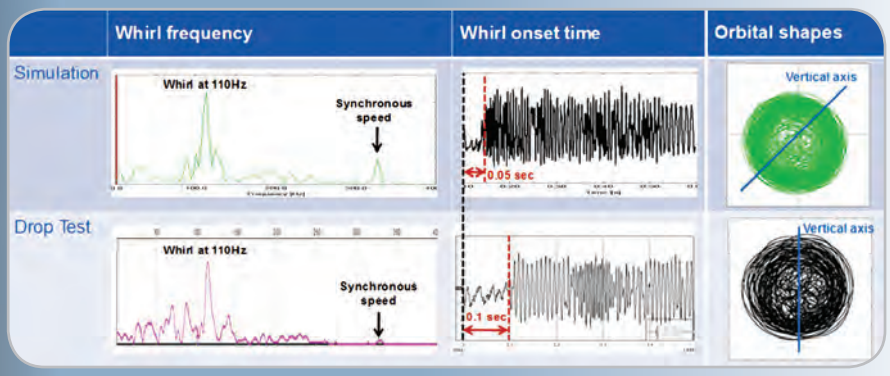
The motor compressor is equipped with three main active magnetic bearing modules



Subsea Compressor Module Architecture - AMBs/ Controller. Image courtesy of Aker Solutions and GE Oil & Gas.



Workflow of the Backup Bearing function design using Multiphysics/Multiscale Simulation.



Simulation results and drop test data comparison (position signal K1 bearing).

(cartridges) where one of the challenges was to use canned bearings for protecting the stator coils (bearings and sensors) from any contaminant present in the cooling gas. One of the issues to be addressed was the validation of predictive behavior of the thrust bearing and auxiliary bearing during the production life cycle of the machine; constraints and specification of axial load during rotor drop and external force perturbation were given by the compressor maker as well as the axial bearing load capacity of 45kN, whereas the radial bearings 1 and 2 had a 16kN load capacity and the radial bearing 3 had a 7kN load capacity.

The designers faced a wide range of challenging physic fields, including mechanical, electrical, magnetic, thermal and many others where the electrical time constants (< microseconds to milliseconds) are usually much smaller than mechanical ones (several milliseconds to seconds). Taking into account all these phenomena in numerical simulations requires using extremely detailed models, and different types of solutions resulting in a calculation process that is prohibitive in terms of both cost and calculation time. M2S2 provides an answer to this problem. It allows the superposition of the different physical and scale domains, providing both an overview of the system and the ability to zoom in on specific areas to predict system behavior.

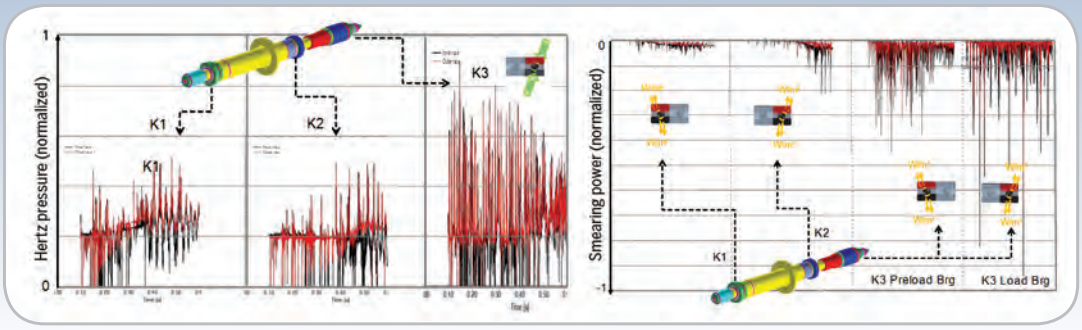
Backup bearings can be considered as an "airbag" for machine integrity. During rotor drop, part of the "mechanical phenomena" that occurs is measured in the range of the system's spatial scale, particularly in terms of rotor/stator interaction. Process and rotor/stator perturbations are applied in real-time to backup bearings, generating extremely complex phenomena (friction, deformation, heating) inside the bearing itself, all occurring within very different spatial scales that range from micrometers to centimeters.

An SKF in-house tool called BEAST (BEAring Simulation Tool) provides a fully geometrical 3D model incorporating tribology and contact mechanics (which also takes into account the effects of small-scale geometric variations, such as surface roughness). BEAST is based on multi-body techniques with special focus on local contact problems and allows for studies of dynamic behavior of all bearing components to be carried out under general loading conditions. Principal output data from BEAST relates to the movements of all bearing components, the contact forces between the components, and the forces with the environment. BEAST also provides detailed data from the contacts regarding smearing power, lubricant film thickness (of any type), pressure distribution, slip-speed distribution, transient temperature distribution, wear and many other factors.

Tools validation

Tools validation was achieved by building a reduced scale compressor test-bench, carrying out a landing test campaign, and finally comparing the data collected with the simulation results. The shaft of this test-bench (200kg) was designed for supercritical operation and therefore needed to be flexible. In contrast to the full scale compressor, the test-bench rotor was configured horizontally, driven by a motor on the shaft end bearing. Bearings 1 and 2 were flexible mounted angular contact bearings that act in radial direction only, while bearing 3 was an angular contact bearing supporting radial and axial loads.

During the landing test campaign, the axial loads were generated by the magnetic thrust bearing, situated between bearings 1 and 2. This axial load was applied in direction of bearing 3 and immediately generated a forward whirl.



Hertz pressure and smearing power simulation results (deceleration phase + variable axial load).

Validation was performed by comparing simulation results with experimental data collected during the landing test campaign. Comparisons were made on the following quantities; "orbital shapes" correlation, "spectral content of the position signal" and "whirl on set time" during the rotor deceleration phase. In both cases there is a peak at about 110 Hz, which is the frequency of the whirl trajectory seen in the orbit. The previous results showed an extremely good match between the simulation and experiment.

Once tools were validated, the designs were analyzed. The most relevant parameters were the pressure and the smearing power for the three backup bearings. The simulation results showed excessive pressure and smearing power specifically on the backup bearing 3 (mainly due to the high radial loads induced by shaft bending). This observation was particularly important, especially taking into account the extreme high peak values that are inaccessible for most multi-body or FEM commercial codes. This is only possible if the code has a special focus on local contact problems.

To validate and quantify the impact of different design parameters, the previous results showing excessive internal bearing pressure and smearing power were compared with experimental data obtained during a test campaign of cumulated 20 landings. Evidence of internal damages that could be attributed to the high values of pressure and smearing power predicted by this advanced simulation tool.

Full scale compressor pilot

When the motor-compressor pilot unit was tested at full speed and full load, five landings were successfully performed and no damages to the rotor, seals or auxiliary bearings were recorded. The observed whirl direction and amplitude matched the simulation prediction 100% (<75% clearances). The post-analysis performed by the compressor maker on auxiliary bearings confirmed no external/internal damages. The information sets and knowledge gathered during this study helped SKF establish the first generation model for backup bearing life prediction, called Landing Life Model L2M, a tool for advanced bearing health assessment and a program of condition monitoring tool development that is now under progress.

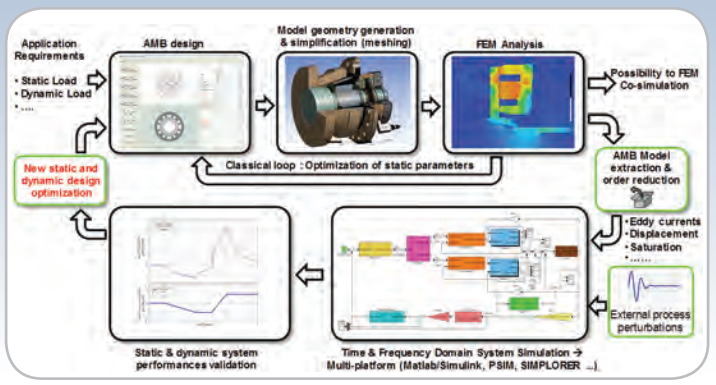
Dynamics response of thrust bearing

Much has been written on the modeling of non-laminated (solid) axial bearings, including eddy currents induced in a solid magnetic frame; however, in most cases the proposed model is defined only in frequency domain and is only valid regarding small air gap variations. Even if it is very helpful to use these simple analytical models during the development phase of a new axial magnetic bearing, they do not allow the time response of the thrust bearing while facing a rapid transient and high amplitude force to be predicted. These types of disturbance are usually encountered when the compressor is operating near the surge line or in other abnormal process conditions. In case of high speed centrifugal compressors of several MW power, some extreme conditions can cause variations of several tens of kN in only a few milliseconds.

One answer to this problem is using a "co-simulation concept." This method involves coupling finite element analysis software with a multi-domains dynamic system simulation software (such as Simulink, SIMPLORER). This method requires powerful computation and simulation time is usually very long.

The solution currently proposed and applied to the design of thrust magnetic bearing used in Ormen Lange motor-compressor is based on an "identified reduced order-model" taking into account following physical quantities (identified from FEM model);

- Magnetic diffusion (eddy current in a large frequency bandwidth)
- Magnetic Saturation (high current level)
- Large magnetic air gap variation (large displacement)
- Complex geometry (E, C and hybrid geometry of stator/rotor axial bearing)

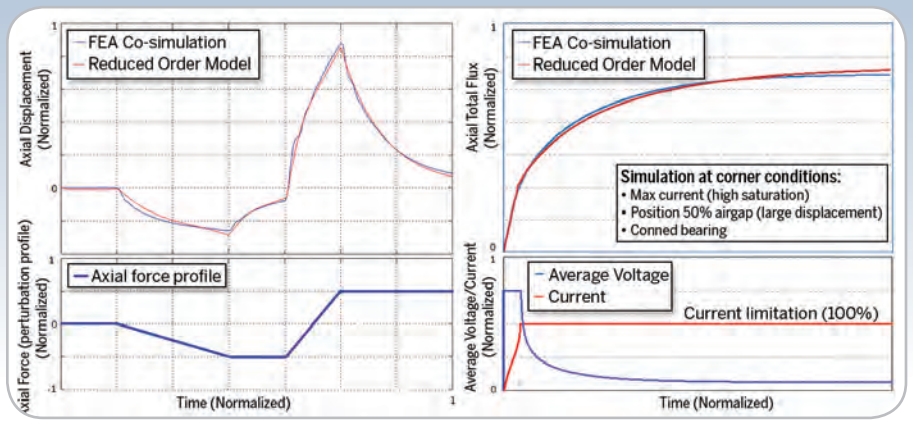


Multiphysics thrust bearing system simulation/optimization using "Reduced Order-Model".

The proposed method is based on advanced nonlinear fractional model identification:

Step 1 - Model structuration using physical system knowledge: This model uses geometry segmentation to generate an equivalent reluctances network. Elements to consider are; geometry type (E, C, hybrid shape), canned or un-canned bearings, impact of the magnetic environment (frame), magnetic materials characteristics, and large air gap.

Step 2 - Nonlinear fractional identification: The geometry segmentation is used to generate the associated reluctance matrix. All equivalent inductances are then calculated by inverting the reluctance matrix combined by windings properties. For each impedance element (i) the fractional model identification process has to be performed (eq. 1 left-side expression) where



FEM versus "Identified Equivalent Reduced Order-Model" simulation results.

the fractional exponent is the analytical solution of the diffusion equation for a semi-infinite medium. This parameter is used as the optimization parameter during the identification process.

Step 3 - Synthesizing: Once the fractional transfer functions are identified, it is necessary to synthesize them as an integer order. Real (integer) systems typically have non-integer behavior over a given frequency band. The non-integer integrator is in fact limited to a defined frequency range (fmin-fmax). The synthesis of non-integer order integrator is then based on a recursive distribution of a finite number of poles and zeroes (eq.1 right-side expression). The nonlinearities such as large air gap variation and high current level inducing a large magnetic saturation are taken in account. These physical quantities have a significant impact on the representativeness and model accuracy.

Results obtained using identified nonlinear fractional model

The total magnetic flux response to a maximum step of current (with fixed rotor position 50% of the total air gap / canned bearing) was recorded, as was the position response to a profile of a specific external force perturbation. Data showed that the total magnetic flux converged with the same dynamics of its steady state value, while the position reacted properly to the external force perturbation.

These results showed that the method proposed in this paper predicts with great accuracy the dynamic and static response of the thrust magnetic bearing. Moreover, one of the most interesting benefits is the simulation time efficiency, which opens the way to implement this model in a Hardware-in-the-Loop process for real-time simulation purpose.

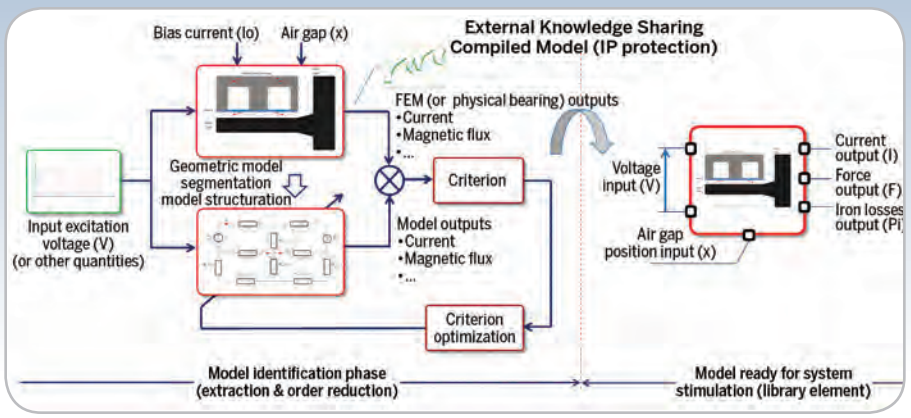
Conclusion

The collaborative design approach applied to oil and gas motor-compressors equipped with AMBs, in particular for subsea application is a powerful and efficient tool to collect and consolidate the specification of the project among the different project partners and key players. By limiting iterations in design as well as identifying clearly the technology readiness levels needed for each of the single components and subsystems, it offers the opportunity to define better design specifications, reduce the time for testing and qualification and ultimately reduce

the cost of development of the project. An approach based on numerical models called M2S2 could become one of the cornerstones of the collaborative design process when applied to AMB solutions for the oil and gas industry.

Two examples have been presented to illustrate this approach. In both cases, the outcomes of M2S2 tools are "super models" that can be transferred to the partners to enable them to better assess the key working load parameters impacting on the robustness of the complex system and consequently provide a finer understanding of the design parameters and their tolerances. M2S2 achieves this by significantly improving the flow and share of information between partners.

Collaborative design offers a new perspective on managing projects for complex oil and gas projects. We also believe that it illustrates the nature of future relationships and new business models for oil and gas compressors equipped with AMBs. OE



Model identification workflow for a very simple axial bearing geometry.

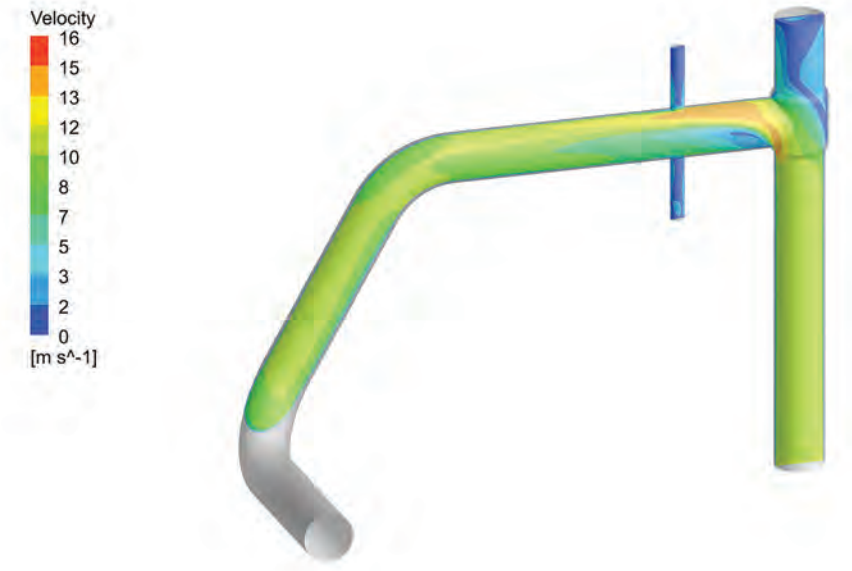
Joaquim Da Silva *serves as head of research and technology at SKF Magnetic Mechatronics, France. He received a master's in electrical engineering from the Conservatoire National des Arts et Metiers (CNAM), France and a PhD in control and signal processing from the Univesité d'Orléans, France.*

François Carrere *is a technical leader for SKF Magnetic Systems, covering subsea projects like Ormen Lange Pilot project and the Asgard Compression Station. He has over 30 years' of industry experience. He earned a doctorate in electronic and automation in 1982.*

Frederic Ponson *serves as engineering manager for SKF Magnetic Systems. He has a MsC in mechanical engineering and heat transfer. Since 2009, he has been in charge of product engineering for magnetic systems for industrial, and oil and gas applications.*

Multiphase corrosion risk analysis

Paul Ellerton business unit manager at Apollo discusses how to identify corrosion risk using multiphase flow assurance tools.



CFD on a tubing hanger.

Aging assets have a greater need for more routine maintenance inspections. Offshore inspections, particular those involving subsea pipelines, can be time, resource, and cash consuming.

Transporting unprocessed multiphase fluids from wells or satellite platforms via steel pipelines to the processing platform is common on many developments, but can lead to flow assurance issues.

In a recent maintenance inspection in the North Sea, there was suspicion of corrosion and wax build-up in an oil export pipeline. The 20km-long, 14in. diameter pipeline had been operational for 20 years, with little in the way of physical inspection. Due to its length, a full inspection of the pipeline was impractical, so the operator decided to target inspection at the perceived worst case locations.

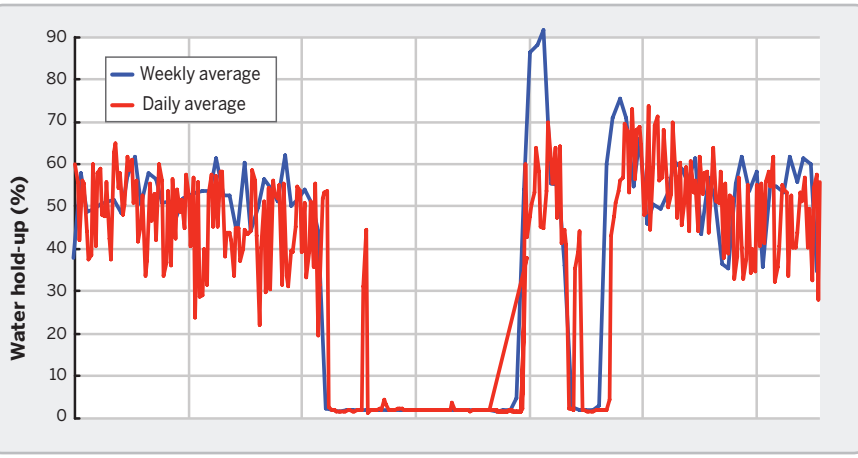


Fig. 1: Pipeline hold-up predictions using different input frequencies. Images from Apollo.

Diver inspection was carried out at several low-points, where it was thought that the combination of high temperatures and water held up in the line would cause localized corrosion issues and loss of wall thickness. Ultrasonic wave testing showed almost no loss of material in the line at any locations. Due to the length of pipeline service, almost no corrosion seemed unlikely, which led the operator to question if the inspected locations were actually worst-case locations.

A study was commissioned to conclusively understand whether the pipeline was in a good state of repair or if the perceived likely high-corrosion locations were incorrect. Apollo carried out a staged multiphase simulation program to develop an accurate picture of what had happened over time, what was going to

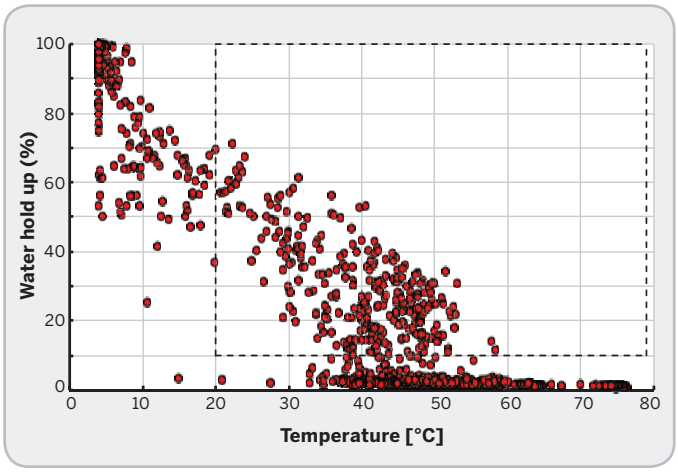


Fig. 2: Water hold-up against temperature graph at a specific location to highlight the time spent in the corrosion risk region.

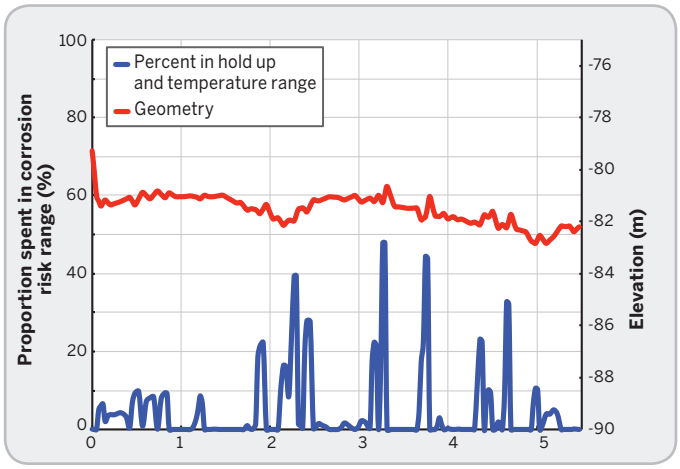


Fig. 3: Plot highlighting risk regions on a section of the pipeline length.

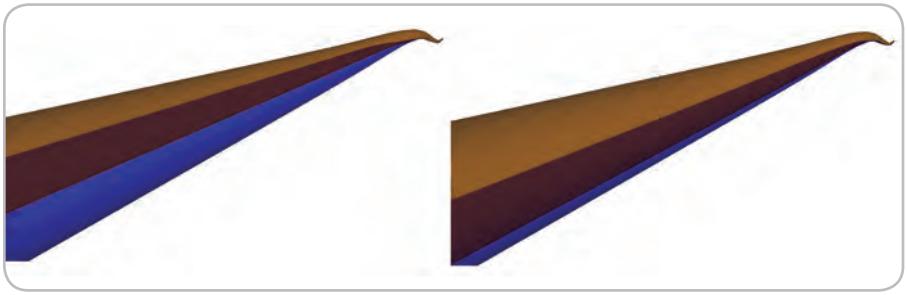


Fig. 4: CFD images showing how hold-up (water in blue, oil in brown) altered at a specific location over time.

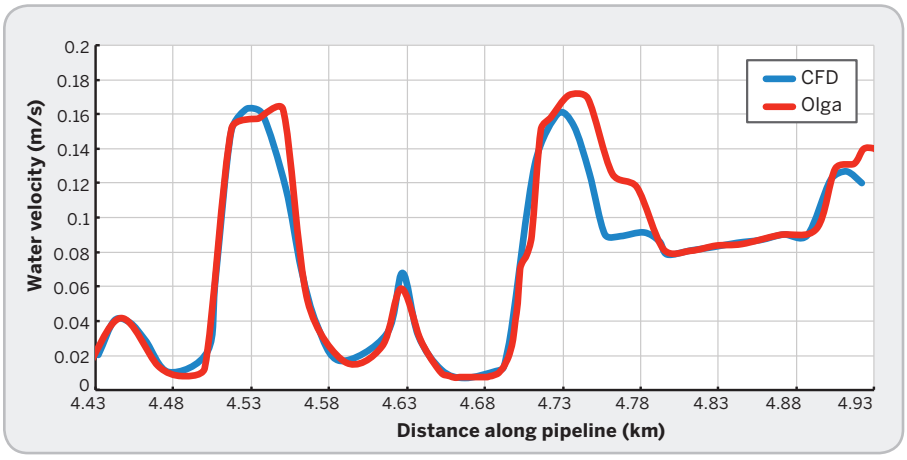


Fig. 5: Plot showing the velocity match between OLGA and CFD for the same section of pipeline

happen in the future and how the pipeline inspection program could be improved.

Tools

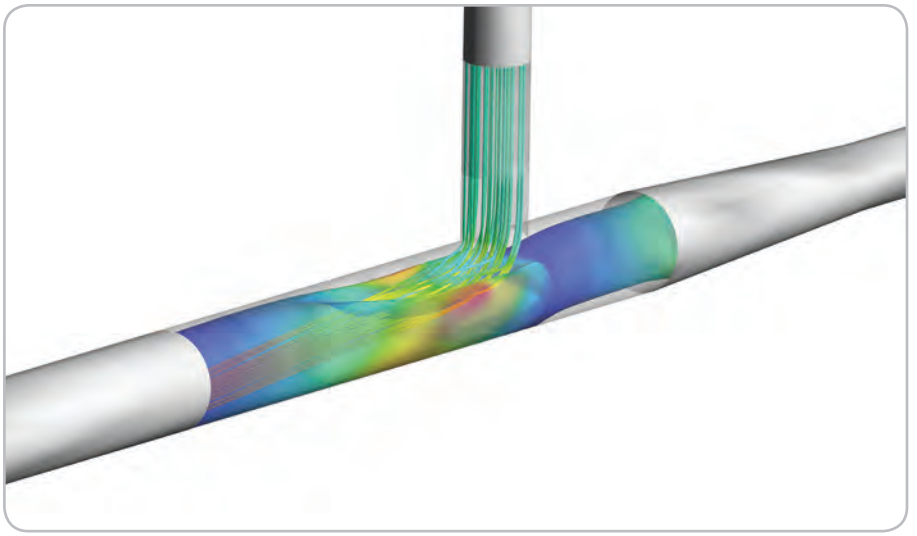
There are many pipeline corrosion prediction tools available. When used in the right application they can lead to accurate wall-loss predictions. The algorithm-based tools are often conservative and give an overall picture of wall-loss, as opposed to location specific information. Apollo's technique to corrosion diagnosis is built on a staged flow assurance approach to identify a "region of risk":

1. Undertake dynamic hydraulic modelling
   a. Sensitivities to validate method (frequency of data used) and match to operational data
   b. Analyze temperature, liquid hold-up and amount of time spent in region of risk to determine multiple points of interest
2. Carry out Computational Fluid Dynamic (CFD) modelling to confirm findings at points of interest
3. Review water and solids build-up and conclude on several likely locations
4. Recommendations and apply learnings.

The first stage was carried out using OLGA transient flow assurance software. A steady state approach can be used to give a good indication, but in reality the flow conditions take weeks or months to attain equilibrium – an important factor when trying to understand which areas are at the highest risk. The operator had 15 years' daily production data, including oil and water rates. A simulation was carried out replicating the conditions in the pipeline throughout its history, including line flushing at known intervals. Each stage of the production history was simulated with the end of a flow period used as the input for the next.

Amongst the many sensitivities required to validate the work was one on the frequency of flow data to be used. This highlighted the importance of using weekly (results used for every three days) as opposed to monthly flow data. Performing the simulations at less frequent rates (monthly) tended to over-predict the amount of water hold-up in the pipeline, in this case. Specific pipeline corrosion prediction tools will base the results on the average results over a period of time, whereas a detailed approach gives specific contact time for the water.

Figure 1 shows the effect on hold-up amounts using input data at different frequencies for a particular location. The analysis which used more frequent data points was more accurately predicting



Flow analysis using CFD.

the movement and slugging of liquids.

Corrosion risk regions

To understand corrosion risk regions, the hold-up data needs to be married to temperature data. Corrosion will be worse when the surfaces are wetted during production and at elevated temperatures. During shut-ins, water will gather at low points, which would usually be associated with corrosion. However during a shut-in the pipeline cools to ambient sea conditions and the corrosion risk can be lower. The relationship between hold-up and temperature was derived for each position along the pipeline throughout its production history.

Figure 2 shows the relationship at one particular location, where every dot represents a data point throughout the location's operational period. For the conditions in this system it was determined that corrosion will be highest at temperatures above 20°C and with water hold-up greater than 10%. At this location, it was shown that it had only been in the risk region for a fifth of its operational life.

An overview showing the amount of time each location spent in the risk region is plotted in Figure 3. From this work a number of points of interest along the pipeline were chosen based on their time in the corrosion region of interest. Further work highlighted that if free water was present (i.e. water does not have to be held up to cause corrosion) then all locations would have a similar corrosion risk.

A transient hydraulic analysis was undertaken using the 1D predictor tool OLGA. CFD analysis was used to understand if there were localized differences caused by momentum of the fluids or turbulence that would alter hold-up and highlight different corrosion risk areas. The CFD analysis conducted matched closely to that seen in the OLGA simulations for both hold-up and velocity predictions. Figure 5 shows the close match between CFD and OLGA in terms of velocity.

One of the reasons for the strong correlation between the CFD and OLGA results was because of the low fluid velocities contained within the pipeline. At higher flow rates you might expect more movement of the fluid phases and, as both approaches differ in the calculations of their interaction, you would start to see a small deviation in result predictions.

If the CFD results had matched poorly with those from OLGA, then the OLGA metrics would have had to be adjusted. The CFD analysis can give more accurate predictions of velocity at point locations, where increases in velocity would reduce the risk of stagnate water and corrosion. The close match in this case demonstrated that the highlighted risk regions were appropriate.

Finally, analysis was undertaken to determine the amount of wax in the pipeline for pigging purposes. Testing had indicated the total amount of reduced volume in the pipeline, but it did not discern whether this was standing water or solids. Although hydraulic software includes wax deposition models, the timing of events offshore during analysis led to a more hands-on approach. An iterative method was undertaken to estimate the amount of standing water by gradually altering the internal diameter of the pipeline. The method matched the results from the subsequent pigging operation with the difference in the amount removed believed to be due to solids left in the pipeline.

Avoiding pitfalls

The UT monitored locations were shown to have covered a good representation of where the highly corroded sections would be, although several other locations were highlighted as potentially having a more corrosive environment. The work highlighted the potential pitfalls in using engineering judgment for inspection purposes. But, although the locations were shown to be a good representation in this case, it could have been quite different. By inspecting the bathymetry of the pipeline, it may seem that there are obvious locations. However, analysis showed that corrosion can happen at other less intuitive places i.e. just offset from the lowest points or where there are multiple low points gathered. There is no recommended obvious place to carry out corrosion inspections.

To ensure relevant inspections are carried out, it is recommended that, prior to any offshore planning, a simulation program similar to the example above is carried out – as standard. Detailed upfront work can pin-point where the potential issues are in order to reduce mobilization time and costs.

It should always be understood that no simulation can fully represent a real inspection. However, staged encompassing analysis can take weeks to perform and give great insight into not only what has happened, but also why and so in turn can be used as a preventative method for reducing issues in the future. By viewing physical inspection results in light of the simulation program, the prediction methods can only become more accurate, which in turn will bear cost benefits throughout the industry. OE

***Paul Ellerton**, business unit manager at Apollo, is a chartered engineer with over 10 years' experience in the energy industry. His specialization in flow assurance has been used in advanced analysis to develop practical engineering solutions globally for subsea and topsides applications. Ellerton has a master's degree in CFD analysis.*

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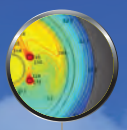
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Upstream prospects stay bright for West Africa

N. Foster Mellen analyzes West African transactional activity and drilling rig data, which indicates a promising future for the region.

Continuing strong upstream transaction activity in West Africa bodes well for the oil and gas industry. According to data from Derrick Petroleum, EY has seen an average of more than 50 transactions per year in West Africa (Fig. 1) since 2006, with reported deal value averaging more than US$6 billion per year.

Notably, however, deals with reported transaction values have only accounted for about one-third of all deals in the region during the same time period (January 2004 – August 2014).

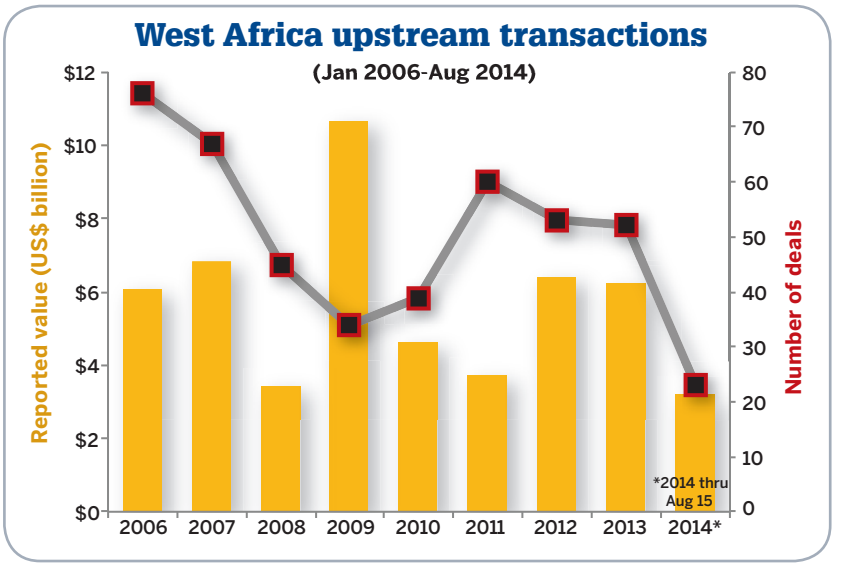
National oil companies (NOC) have played a major role in West African upstream transaction activity, particularly Asian NOCs, but also from elsewhere in Africa, the Middle East, Latin America and the former Soviet Union.

Including transactions involving the relinquishment of leases back to host governments, transactions with NOCs as acquirers represented about 20% of all transactions in West Africa since 2006. "Big oil" – the integrated majors along with the other large international oil companies (IOCs) – accounted for another 20% of all deals since 2006. The smaller, more-nimble and more-focused regional specialists accounted for roughly another 15% of all upstream transactions, with the remaining 45% made up of smaller independents and local firms.

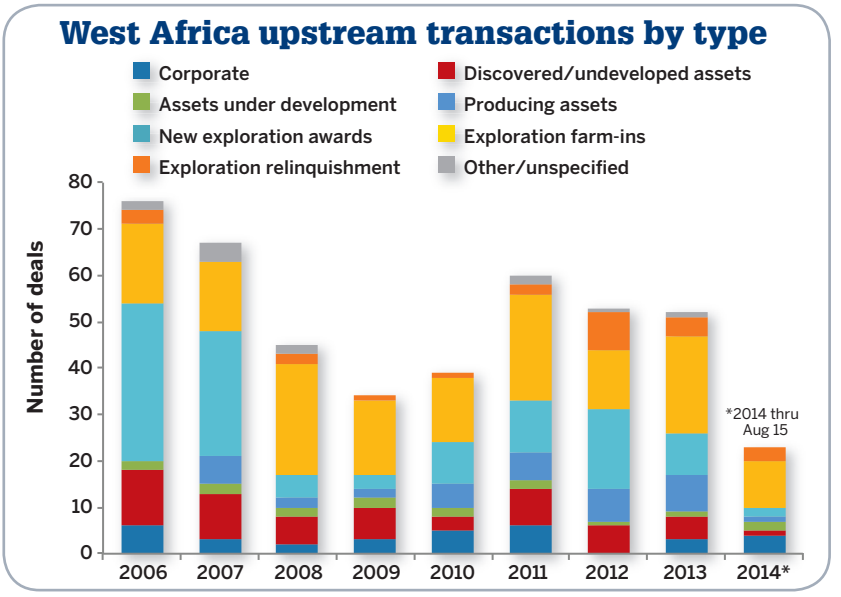
The Derrick data by deal type shows the maturation of the region since 2006. Transaction activity in the early years is dominated by new exploration awards and then, in turn, followed by increasing farm-in activity and the inevitable relinquishment of some blocks. A new round of exploration awards can also be seen starting in 2010.

Like historical oil and gas production in the region, deal activity has been concentrated in the central sub-region, anchored by Nigeria and Angola, along with Gabon, Congo, Democratic Republic of Congo, Cameroon and Equatorial Guinea. However, the Derrick data (Fig. 2) shows that transaction activity has increased in the other two less-explored West African sub-regions – the West African Transform Margin (WATM) and the Senegal Basin – particularly so in the last few years. The WATM includes Benin, Ghana, Guinea, Ivory Coast, Liberia, Sierra Leone and Togo. The Senegal Basin includes Guinea-Bissau, Mauritania, Senegal and The Gambia.

While there has been some petroleum activity in these less-explored sub-regions as far back as the 1950s, the recent high-impact discoveries in Ghana and the Ivory Coast have brought new attention and optimism

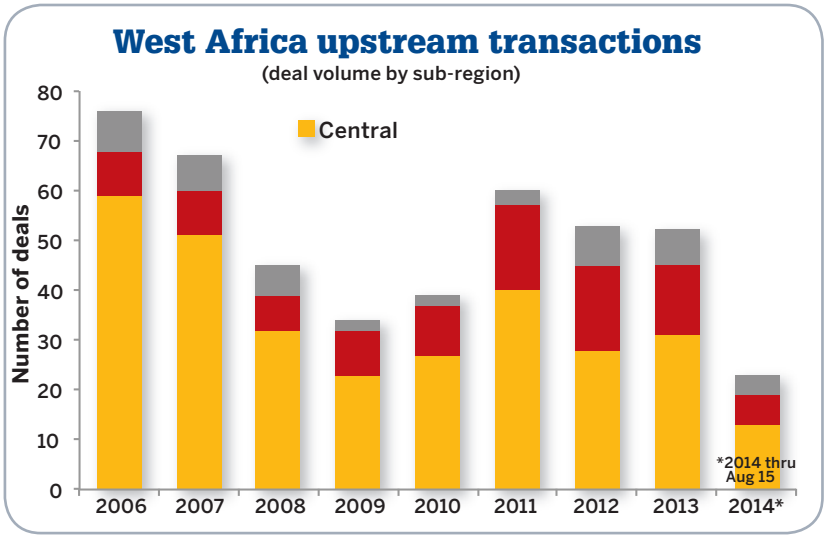


West Africa upstream transactions, January 2004 – August 2014.
Source: EY analysis of data from Derrick Petroleum.

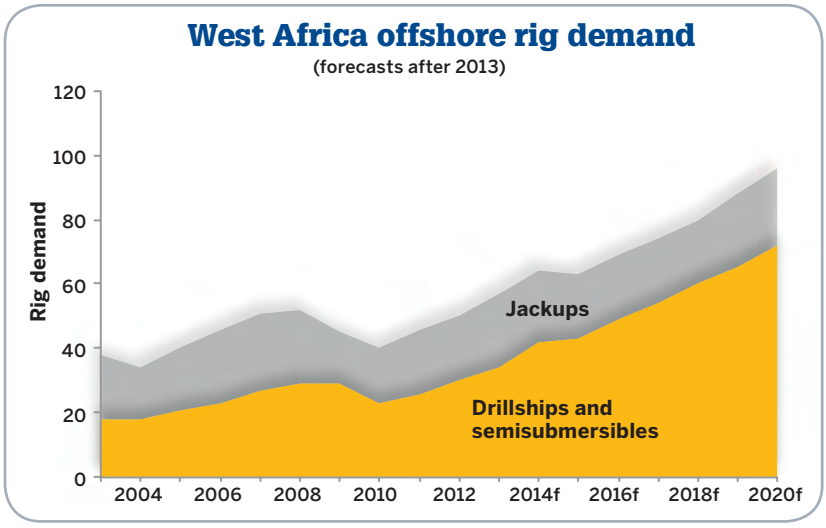


West Africa upstream transactions by type.
Source: EY analysis of data from Derrick Petroleum.

to these sub-regions (Fig. 3). Transaction data substantiates this shift into the new frontiers of West Africa, heralding the ramp-up of further exploration and development activity in the two sub-regions, notably in Ghana, Liberia, Senegal, Guinea, Sierra Leone and Guinea-Bissau.



West Africa upstream transactions (deal volume by sub-region).
Source: EY analysis of data from Derrick Petroleum.



West Africa offshore rig demand (forecasts after 2013).
Source: EY analysis of data from Morgan Stanley.

Potential resources by sub-basin

Confidence in the sub-regions' resource potential is underpinned by the recent US Geological Service (USGS) resource estimates for the West African region. According to the USGS, the Senegal basin could contain almost 5 billion bo and more than 39Tcf of natural gas. The WATM could contain more than 18 billion bo and more than 151Tcf of gas. Mean resource estimates from the USGS indicate that the two sub-regions contain almost 10 billion bo (2.4 billion bbl for the Senegal basin and 7.3 billion bbl for WATM) and almost 79Tcf of gas (18.7Tcf for the Senegal Basin and 58.1Tcf for WATM), along with almost 2.5 billion bbl of natural gas liquids. While these estimates are substantially smaller than the resource estimates for the central sub-region's mean oil resources of more than 65 billion bbl and more than 134Tcf of natural gas, they nonetheless are very attractive, particularly for the small-to-mid-sized independents.

A promising period for the region

For the global oil and gas industry, 2013 was not a particularly fruitful year for discoveries; according to energy analyst consultancy firm Wood Mackenzie, total discoveries were less than 17 billion boe, well below the 26 billion boe average over the previous 10 years. But 2013 was a productive year for Sub-Saharan Africa, with the region accounting for almost 40% of the year's total global discoveries. Notably, in 2013, West Africa had three of the year's 10 largest discoveries:

- Cobalt International Energy's Lontra discovery off Angola, estimated at 900MMboe
- Afren Plc.'s Oro discovery off Nigeria, estimated at 775MMboe
- Eni's Nene Marine discovery off Congo, estimated at 700MM boe

Success in the region has continued in 2014, with notable finds reported in Gabon (Eni and Harvest Natural Resources), Ivory Coast (Total) and in Congo (again by Eni).

Offshore drilling activity

Offshore West African drilling activity is expected to continue to ramp-up (Fig. 4). Analysts at Morgan Stanley see demand for floaters (e.g. deepwater drillships and semisubmersible drilling rigs) more than doubling over the 2014-2020 period, while demand for the jackup drilling rigs that work in shallow water remains relatively flat. Despite the strong increases in rig demand over the next five to six years, rig supply is expected to be more than ample, given the strong newbuild order backlog.

Exploration and early-development activity in West Africa looks set to ratchet up over the next 12 to 18 months, with hopes for a Jubilee-type success in offshore Ghana in the nearby TEN development (Tweneboa-Enyenra-Ntomme) and as the IOCs and smaller independents push into the less-explored areas.

However, the recent regional health crisis with the Ebola virus looms over the region. Particularly in the short-term, it is expected to dampen oil and gas activity in the region, primarily limiting movements of personnel and equipment. Containment of the virus should limit the adverse impacts on oil and gas industry activity, but a failure to contain the virus could have devastating consequences for the region, including longer-term implications for oil and gas industry investment and activity in the region. OE

N. Foster Mellen *is a senior strategic analyst in Ernst & Young's EY Knowledge group. He has worked as an energy analyst since 1977, and holds a master's degree in development economics. Prior to joining Ernst & Young in 1999, he was with London's Petroleum Economics (PEL), analyzing developments in the international oil and gas markets. Prior to PEL, he was a consultant to the US Department of Energy.*

West Africa: The continued story of the "Haves" and the "Have-nots"

Jeremy Berry examines the trend occurring off West Africa where exploration success continues to be confined to those countries that already have significant production.

West Africa, from Morocco in the north to Namibia in the south, produces about 6% of the world's oil (averaging 5.2MMbo/d in April 2014; *EIA's International Energy Statistics*).

West African production grew through the 2000s, reaching 5.5MMbo/d in 2010, but since then has shown an 8% decline to today's volumes. However, the region as a whole is responding, with 14% of the current global offshore rig count active in Africa, up from 7% in 2004. The number of rigs active offshore Africa doubled in 2010, and has continued to climb through to the current day (Fig. 1).

Considering the news flow, one might assume that this increase in rigs could be driven by activity in new exploration areas, such as Namibia, Morocco, Mauritania, or Liberia. However, these frontier basins tend to share rigs (to minimize mobilization costs) and their contribution to the overall rig count is minimal, and will remain so until more positive results needing aggressive appraisal drilling materialize. The reality is that by far and away the most active areas are where the petroleum systems have been proved to work and production, infrastructure and local support services are readily available (see table 1).

Country	Rig months	Max Rigs
Angola	237	18
Nigeria	186	14
Congo	61	5
Cameroon	43	3
Gabon	34	4
Ghana	20	2
Equatorial Guinea	16	2
Cote d'Ivoire	10	3
DRC	9	1
Mauritania	8	1
Morocco	5	1
Togo	4	2
Namibia	4	1
Senegal	3	1
Liberia	3	1

The activity levels seen in Table 1 are reflected in the number of developments approved and coming on stream in the more active countries. Amongst key examples are:

- In June 2014, the CLOV development in Total-operated Block 17, deepwater Angola, started production. With a production capacity of 160,000bo/d, this is the fourth FPSO on the block.
- Eni's West Hub development in Angola Block 15/06 is expected to start-up in 2014, producing up to 80,000bo/d. The final investment decision (FID) on the neighboring East Hub was made in November 2013.
- In February 2013, FID was announced on Mafumeira Sul in Chevron-operated Block 0, offshore Angola. Production of 100,000bo/d is expected to start in 2015.
- In July 2012, FID was announced on the Lianzi field operated by Chevron in a unitized area between Congo and Angola. Production of up to 46,000bo/d is expected in 2015.
- The Egina field in Nigeria was approved for development by the Nigerian authorities in 2009, with production of up to 200,000bo/d due to start in late 2017.
- In April 2014, FID was announced by Total for Kaombo in Angola ultra-deepwater Block 32. Production is due to start in 2017 at up to 230,000bo/d.
- In May 2013, the Ghanaian authorities approved the Plan of Development for the TEN (Tweneboa, Enyenra, Ntomme) fields. First oil is scheduled for 2016, with a maximum production capacity of 80,000bo/d.

Equally significant is the scale of success of exploration drilling as illustrated

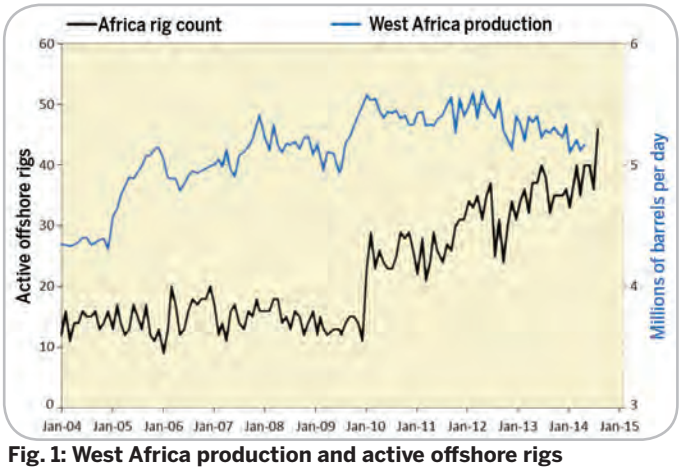


Fig. 1: West Africa production and active offshore rigs (Jan 2004 – July 2014) showing increased rig count responding to production decline. Source: EIA and Baker Hughes.

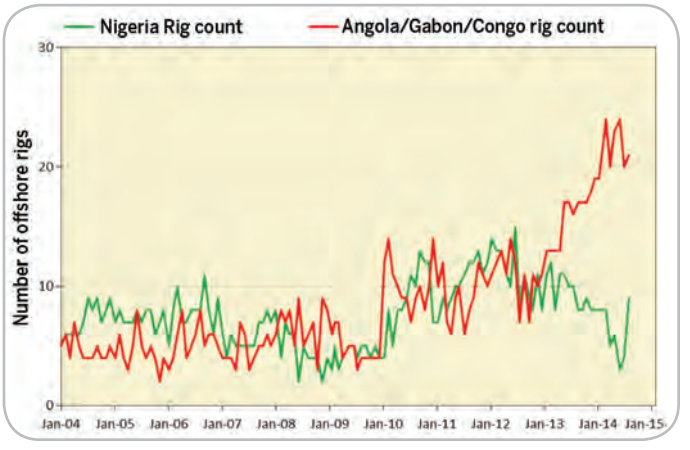


Fig. 2: Rig count in Nigeria and West African pre-salt play countries showing recent divergence in numbers of rigs. Source: Baker Hughes Rig Count.

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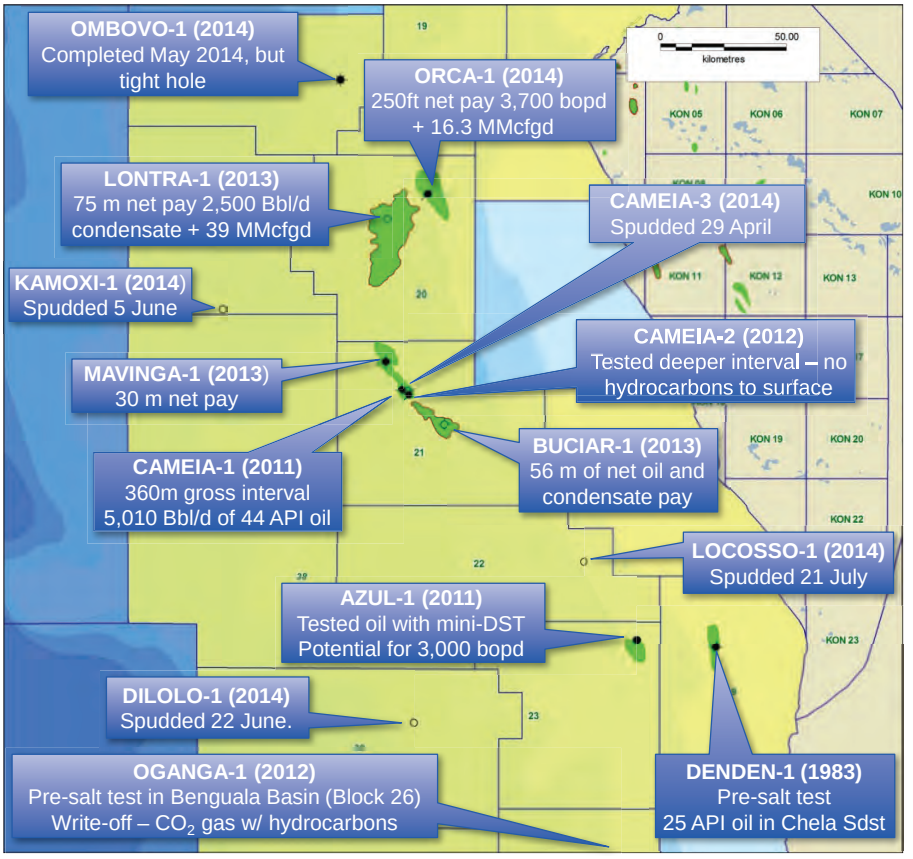

Fig. 3: Kwanza Basin activity. Source: Deloitte Petroview.

by the number and size of discoveries announced in the already proven basins, against a backdrop of continued disappointment on the frontier margins:

- In June 2013, Maersk completed Cubal-1 in Angolan Block 16 as a discovery encountering oil in four zones, appraising shortly thereafter. Cubal-1 is reported to have discovered resources of 300MMbo (Sonangol Annual report 2013).
- In August 2013, Total completed the Diaman-1 deepwater pre-salt exploration well offshore Gabon. The well encountered 160-180ft of net pay containing gas and condensate.
- In November 2013, Afren completed the Ogo-1 exploration well in OPL 310, offshore Nigeria, encountering 216ft of net pay containing light oil and condensate rich gas. Estimated (P50) recoverable resources are quoted as 774MMboe.
- In February 2014, Eni completed appraisal well Nene Marine-3, offshore Congo, testing a pre-salt clastic reservoir containing wet gas/light oil which flowed 5000bo/d on test, with the operator estimating in place volumes of 1.2 billion barrels of oil and 1Tcf of gas.
- In April 2014, Total completed the Saphir-1x well in Cote d'Ivoire and announced an oil discovery having encountered some 125ft of net pay containing light oil.
- In July 2014, Eni announced that the Nyonie Deep-1 well in Gabon was a significant gas and condensate discovery with initial estimates of in place volumes stated as 500MMboe.

The most significant current trend in the whole of West Africa is the dramatic increase in the number of wells targeting the pre-salt in Angola, Congo and Gabon, driven by the success of the play in the conjugate margin in Brazil. Figure 2 shows the number of rigs increasing threefold in the pre-salt play countries, in the last 18 months, this being offset by a proportional reduction in the number of rigs in Nigeria over the same period.

Although Maersk was the first company to make a pre-salt discovery in the Kwanza basin with Azul-1 in Block 23 in 2011, it was not long before Cobalt began their intensive drilling campaign with seven successful wells completed in Blocks 21 and 20 to date (Cameia-1, -2, -3, Buciar-1, Mavinga-1, Lontra-1 and Orca-1). Operators in other Kwanza Basin blocks awarded in 2011 have now also started drilling, with wells completed or underway by Eni, Repsol, ConocoPhillips and Statoil (see Fig. 3) and a further 5-6 exploration wells planned this year.

Notwithstanding the fields currently being developed in the Congo Basin, the potential and expectation of the pre-salt play in the Kwanza Basin could not come at a better time for Angola as production stubbornly remains below 1.8MMbo/d, down from highs of 2+MMbo/d in recent years. A similar story is emerging to the north, in Gabon, there is an effort to encourage activity to turnaround their production decline. A recent license round has seen the entry of a number of new players (including Marathon, Repsol, Petronas, Noble, Woodside, and Impact) and exploration drilling is beginning to bear fruit with Diaman-1 and Nyone Deep-1 discovering considerable hydrocarbon resources.

West Africa is therefore a story of the "Haves" and "Have-nots." Exploration success, for the time being at least, continues to be confined to those countries that already have significant production. Despite ease of access and encouraging fiscal terms, the frontier countries are struggling to find the reservoirs that will move them from the "Have-nots."

The only possible concern with many of the West African pre-salt discoveries to date, is the preponderance of gas and condensate being found. In Gabon, significantly more gas and condensate would need to be found to commercially justify any development; while in Angola the current production sharing agreement terms do not grant international companies any rights to the gas. Given the costs involved with these deepwater wells, it is unlikely that operators would maintain their enthusiasm for the play under the current terms if gas/condensate continues to dominate the hydrocarbon mix. OE

Jeremy Berry serves as global business development director at Gaffney, Cline & Associates. His primary technical strength is in the geosciences. Berry has an in-depth understanding of sub-Saharan Africa.

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Paenal shipyard takes shape

SBM Offshore's Paula Farquharson-Blengino provides an inside look at the company's Angola shipyard, a joint venture between partners Sonangol and DSME.

While driving along the dusty road from Angola's capital Luanda en-route to Paenal shipyard four hours away, what struck me is the bustling business done by street vendors while smiling children play at their feet. The city is rapidly changing. Partly-finished skyscrapers are growing up in prime locations where previously tin-roofed shacks stood as luxury boutiques and international businesses – including key oil companies - move in. However, the proof of the progress is beyond the city lines.

At a certain bend in the road approaching the town of Porto Amboim the skyline opens up to the sea where a vast floating production, storage and offloading vessel serves as an unmistakable landmark for the shipyard.

Porto Amboim Estaleiros Navais, known as Paenal, is a joint venture company between the state-owned national oil company Sonangol, SBM Offshore, and third partner DSME, which joined a year after the initiative began in 2007.

Within five years this former wild expanse of beach developed into a world-class fabrication and integration yard. The young shipyard has built a reputation with two FPSOs – destined for production offshore Angola – having berthed at its quay where module integration and the final stages of refurbishment took place.

Paenal was established to meet Angola's need to develop manufacturing technology and integration of modules in FPSOs. With its 2500-ton heavy lift crane (HLC), inaugurated last year, combined with a 490m purpose-built quayside, the yard is fully commissioned and can accommodate the installation of topsides into mega FPSOs. The yard is capable of producing up to 10,000-ton of modules per year, which represents approximately two million man-hours per annum.

In July, the FPSO *N'Goma* sailed away to the Eni-operated Block 15/06, where mooring operations by the *SBM Installer* vessel have been completed and hook-up operations and acceptance testing is to follow.

Further cementing Paenal's position in the oil industry was its successful fabrication, lift and integration of a 1836-ton module onto the *CLOV* FPSO in December 2013, for French oil major Total followed by Angola's first naming ceremony at the yard. It was quite fitting that the French giant, which celebrated its 60th Anniversary in Angola, gave the young yard a foot in the industry door. The lift also made the record books as the first ever topside module integration performed in Africa, thanks to Paenal's heavy lift crane, Jamba.

Total's FPSO project was the first to put Paenal in the news when *CLOV* pulled up quayside in November 2013 and set a record for Paenal and Africa by being the first FPSO to berth at a West African quayside.

In addition to FPSO projects, the fabrication of two well-head platforms – at 3200 metric tons each – is currently progressing at Paenal. Both are destined for the Mafumeira Sul field in Block 0 offshore Angola. Paenal, in consortium with DSME, was awarded the project by Chevron and work under the Angolan scope began in May 2013, with a first steel cutting ceremony.

With Angola being the newest player in pre-salt oil and gas exploration and looking to raise production from a

Scan this page!
Learn more about the Paenal yard.
Scan this page with your smartphone or tablet and the Actable app.

The region of Kwanza Sul was chosen for the excellent location, close to Port Amboim, for the availability of local labor and the support of the local authorities.

Vasconcelos announced several initiatives, including offering deep water and ultra-deep water blocks off the south of the country next year, as the African producer pushes for its target output.

In July, the minister attended the naming ceremony for *N'Goma* FPSO at Port Amboim saying "Paenal is indeed a yard that closes a gap in terms of local content. For Angola, it represents an instrument that will allow and has already facilitated the transfer of knowledge and technology, while always focusing on training and the employment of more Angolans to contribute towards the sustainability of the oil industry related activities in Angola." SBM Offshore employs over 1700 people in its Angolan operations (including Paenal) and has been established in the country since 1997. The company began serving the Angolan market in 1968, with the delivery of the first catenary anchor leg mooring (CALM) buoy. The shipyard at Paenal was a natural progression in the company's strategic investment in the country.

Paenal is the first yard in West Africa with the capacity to facilitate mega FPSO vessels. Images from SBM Offshore.

Paenal's people

The qualified and trained workers are the result of a long-term investment over the past eight years by partners SBM Offshore and Sonangol. A training school was set up in 2008 and has since trained 420 local people from the Port Amboim area. Previously unemployed or working as fishermen or farmers, they are now skilled welders and fabricators employed by the yard.

The knock-on effect of a stable source of work for a vulnerable community has profoundly transformed not just the workers but the livelihood of entire families and local businesses that live to the rhythm of Paenal. The yard is the biggest employer in the region with a workforce of over 1200 employees.

"The fact that Paenal is a fabrication shipyard with 85% Angolan nationals employed represents a success story in the development of the country's facilities and infrastructure. We continue to strive to develop the yard's full potential and to grow its personnel," says Jean-Philippe Rodigues, SBM Offshore Business Development Senior Vice President in Angola.

In line with the partners' plan, the yard is becoming a thriving hub and is attracting other businesses and support services, which is also fostering growth for the community; in part by Paenal giving preferential consideration to local suppliers. Among the companies to set up operations in Port Amboim since the yard opened are Friedlander Angola, Conduril - Engenharia S.A., Heerema Marine Contractors, PANALPINA and PIC. OE

current average of 1.75-2MMb/d next year – and sustain this until 2020 – the opportunities for Paenal are wide open.

Earlier this year, at the World Petroleum Congress, Angolan Petroleum Minister José Maria Botelho de

Yard achievements

- **22 July 2014:** Following Paenal's completion, on schedule, of its scope of work *N'Goma* FPSO sails away from the yard to Eni operated Block 15/06 offshore Angola. Mooring operations by the *SBM Installer* vessel are currently taking place.
- **18 July 2014:** Eni hosts the naming ceremony for *N'Goma* FPSO at Paenal.
- **June 2014:** Two of *N'Goma* FPSO's modules, which were fabricated at Paenal, the sulphate removal package and the hot oil Pump, were successfully lifted and integrated onboard.
- **17 June 2014:** *N'Goma* FPSO berthed at Paenal's 490m quayside at Port Amboim. This is SBM's first FPSO at Paenal.
- **5 December 2013:** Total hosts the naming ceremony for FPSO *CLOV* at Paenal.
- **November 2013:** module M122, weighing 1836 tons – fabricated at the Paenal yard – was lifted onto FPSO *CLOV* by the HLC Jamba.
- **November 2013:** Total's FPSO *CLOV* pulled up quayside to set a record for Paenal and the country by being the first FPSO to berth at a West African quayside.
- **July 2013:** Inauguration of Jamba HLC, heaviest lift crane in West Africa. Paenal is the first and only fully fledged fabrication and integration yard in Africa.

Scan this page!

See a slideshow of photos from the N'Goma FPSO naming ceremony on 18 July 2014.

On the horizon

Alan Thorpe examines the latest offshore construction vessels to enter the market.

The *Island Performer* on sea trial.
Photo from Ulstein.

This Spring, Norway's Ulstein Verft delivered the subsea construction vessel *Island Performer* to Norway's Island Offshore.

The flexible, state-of-the-art RLWI (Riserless Light Well Intervention)/IMR (Inspection/Maintenance/Repair) vessel will serve her first five years for FTO Services, which is a joint venture between FMC Technologies, Edison Chouest Offshore and Island Offshore in the Gulf of Mexico (GoM).

The vessel is customized to suit the scope of work in the FTO contract, in which RLWI and IMR are the main tasks. It is able to perform operations at depths down to 3000m, and is expected to start this charter at the end of this year. However, prior to going to the GoM, it will be utilized in Norway's RogFast project, in which the scope of work will be to investigate the sea bottom.

A large intervention tower is placed over the 8m x 8m main moon pool. It is equipped with a 250-tonne AHC (active heave compensated) offshore crane with a below-deck winch, and carries two deepsea work ROVs, one to be launched through a dedicated moonpool and the other from the starboard side.

Island Performer is the next generation subsea vessel from Ulstein, with large accommodation, storage and lifting capacities. It meets the highest standards for station keeping, redundancy and dynamic positioning (DNV GL class notation DYNPOS AUTRO, equivalent to DP3). Additionally, operability in DYNPOS AUTR (DP2) operational mode is maximized due to the 'Operation+' feature with a three-split configuration on main machinery. This setup allows the vessel to retain system integrity and to continue operations uninterruptedly even after a substantial single system failure.

A shelter deck stretches all the way past the main moonpool and aft to the main crane. This increases the operational window for moonpool work and offers a shielded space for various equipment. Arranged on the shelter deck is a multi-skidding system for handling 100-tonne skidding pallets. The design also includes a heavy-load cargo deck for transporting equipment for a multitude of operations and construction work.

It has been developed and built according to the latest international regulations in which safety and comfort are two key issues. The vessel is equipped with resiliently mounted tunnel thrusters, and it carries the DNV GL class notation Comfort Class, COMF-V1, which ensures that noise and vibrations are kept at minimum. SCR (Selective Catalytic Reduction) catalysts are installed for all engines. An ESD system (Emergency Shut Down system) is installed in order to automatically close down systems in case of a hydrocarbon leakage. *Island Performer* has room for 130, and in case of evacuation, each of the lifeboats on the starboard and port sides can accommodate everyone on board. Carrying the patented Ulstein X-Bow, the vessel has reduced speed loss in head seas, resulting in reduced fuel consumption and emissions to air.

Meanwhile, two of the Island Offshore PSV fleet are currently alongside at Germany's Lloyd Werft, Bremerhaven undergoing conversion to specialized vessels designed to revitalize low-performance oil sources. Both vessels arrived in 2013 and are under extensive conversion for a charter to Schlumberger, which is an active partner in the conversion work. The two vessels involved are the *Island Centurion* and the *Island Captain*.

The two 20m-wide Schlumberger ships were built at Norway's STX OSV Brevik Shipyard (now VARD Brevik) in

OLE JAN DEVELOPS SOFTWARE TO SECURE SAFE OFFSHORE OPERATIONS

No structure is stronger than its weakest part. To avoid disasters in offshore oil and gas field operations, it is essential that the strength analysis is done before the structures are put into operation.

Ole Jan Nekstad, product director at DNV GL, holds a vital part of those analyses. Through DNV GL developed software, he enables the industry to calculate the risk from wind, wave and fatigue impact, something that will determine the safety, lifetime and profitability of the total operation. The software is called Sesam, and is a complete and user-friendly tool for designing and analyzing offshore and maritime structures.

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The two Island Offshore vessels in Lloyd Werft. Photo by Alan Thorpe.

The VARD newbuilding facility on Norway's west coast. Photo by Alan Thorpe

2011-12 for Island Offshore. They belong to a series of UT 776 CD supply vessels for general deck or liquid cargo transport and boast 1000sq m of deck area. They are driven by four RRM Bergen C25:33L 6ACD main engines.

Two later ships in the same series, *Island Contender* and *Island Crusader*, are billed as the first offshore supply vessels to operate in DP2 mode without using diesel and with Rolls-Royce designed lean-burn, gas-powered engines.

Keppel Singmarine wins BP contract

Keppel Singmarine, part of Singapore's Keppel Offshore & Marine, has secured a contract from Baku Shipyard LLC to design and carry out fabrication and outfitting works for a subsea construction vessel (SCV) which, when completed, will be deployed for the Stage 2 development of the Shah Deniz field that lies some 70km offshore Azerbaijan in the Caspian Sea.

The SCV is a project that Baku Shipyard recently secured from BP Exploration (Shah Deniz) Ltd., the operator of the Shah Deniz gas field development. It is the first major contract secured by the shipyard since its inauguration during September 2013.

Baku Shipyard, in Baku, Azerbaijan, is a joint development among Keppel O&M, the State Oil Company of Azerbaijan Republic (SOCAR) and Azerbaijan Investment Co. (AIC). Keppel O&M, SOCAR and AIC own 10%, 65% and 25% share respectively in the yard. Keppel O&M is responsible for management and operation.

Keppel Singmarine's work scope includes the design of the vessel, the fabrication of the hull strips and outfitting them with equipment and systems at its yard in Singapore. The hull strips will be shipped to Baku Shipyard for integration with other components fabricated by the shipyard, and completion after commissioning works and sea trials. The SCV will be built to the proprietary design by Marine Technology Development, the ship design and development arm of Keppel O&M.

The SCV will provide essential support for the construction of subsea structures which will form the biggest subsea production system in the Caspian. Designed to work in 2.5m significant wave height (Hs), the vessel will be equipped with a DP system, a 750-tonne heave compensated crane for 600m deep subsea operation, an 18-man two-bell diving system, and two work-class ROVs.

Ultra Deep chooses Chinese yard

Singapore's Ultra Deep Solutions ordered a dive support/construction vessel from China's Shanghai Zhenhua Heavy Industries (ZPMC). The contract includes an option for a second vessel.

The newbuild is based on the Red Class 6027 MT design DSCV, and will have a DP3, 142m long subsea/dive support/ construction vessel notation

Delivery of the first vessel is planned for early 2017. The vessel will be an 18-man twin bell unit and was designed to operate down to 4000m water depth. The vessel was designed in collaboration with Norway's Marin Teknikk.

It will have Unique Hydra's 18-man twin bell saturation dive system. It will also have a 400 VLT over a reinforced moonpool area. The vessel also has two, 250 hp work-class ROV designed to work to 3000m installed in ROV hangers inside

the vessel. In addition, it will have a 400-tonne crane, which is rated to 5200m single fall and 3200m dual fall, and an open deck of 1500sq m, which will be strengthened to 10-tonnes/sq m.

VARD goes large

Norway's VARD, a wholly-owned subsidiary of Italy's Fincantieri S.p.A, operates 10 shipbuilding facilities, including five in Norway, two in Romania, two in Brazil, and one in Vietnam. VARD is currently constructing an OSCV 12-designed offshore vessel for Norway's DOF Subsea. The vessel is designed for subsea construction and pipelaying, IRM and ROV services up to 4000m depth. The vessel, classed by DNV GL, is 160.9m in length and has accommodation for 140 people. This vessel is due for delivery next year, when it will be DOF's largest vessel.

DOF Subsea also has two 146m (120 man accommodation) offshore vessels designed for subsea construction and pipelaying, IRM and ROV services down to 3000m depth, both due for delivery in 2016.

In June, Norway's Solstad has confirmed an order with Norway's VARD Group for a newbuild, large subsea construction vessel. The firm contract comes after Solstad signed a letter of intent (LOI) during March with a major international offshore contractor to build and operate the vessel, including a LOI with VARD to construct the vessel. The LOIs that were notified to the Oslo Stock Exchange have now been converted to firm contracts.

The new VARD 3 19 design vessel will be developed by VARD Design in Ålesund and is claimed to be the largest in the Solstad fleet.

The 180m-long vessel will have a 550-tonne top tension vertical lay system to enable the installation of large diameter flexible pipes in ultra-deepwater environments. Featuring a deck area of more than 2500sq m, the vessel will have a beam of 33m and be installed with a 900-tonne AHC offshore crane and a 4000-tonne under-deck carousel for storage of flexible pipes, cables and umbilicals.

Construction on the vessel's hull will be carried out at VARD Tulcea in Romania, while outfitting will take place at VARD Brattvaag in Norway. Following delivery of the vessel, which is scheduled for the 2Q 2016, the client will charter the vessel for a minimum of eight years.

Also in June, Norway's Rem Offshore signed a contract with VARD for the design and construction of a new immensely powerful offshore construction and anchor handling vessel with 400-tonne bollard pull capacity.

The vessel, a VARD 2 06 design, will be one of the most powerful anchor handling vessels and is aimed at supporting ultra-deepwater operations worldwide. It will be powered by two 4MW main engines and two 2.2 MW auxiliary engines powering a hybrid-electric power plant. The vessel will be DP2-equipped and have two main propulsion shafts driven by an electric motor fed by the main engines with boost capabilities from the auxiliaries. A pair of tunnel thrusters fore and aft and a retractable thruster on the bow will also be outfitted.

The vessel comes at a total contract price of NOK800 million and will feature an A-frame as well as a 150-tonne AHC offshore crane and accommodations for 90. The hull of the vessel will be built at VARD Tulcea in Romania and then shipped to VARD Brattvaag in Norway for final outfitting. Delivery is planned for 1Q 2016. OE

Efficiency on a daily basis

With the digital oilfield, experts at a remote monitoring center can analyze data, put it into context and assist the engineers and operators on the platform. Photo from ABB.

Technology is there for companies to use and take advantage of, but is it being used as much as it could be to gain insight into operations. Gregory Hale takes a look.

It wasn't too long ago when the operators of a floating production, storage and offloading (FPSO) vessel off the coast of Angola needed to become more efficient and integrate video surveillance into its process control system.

The reason was simple, as video is critical for safety control and monitoring in such a hazardous area, operators thought everything should be available over the control system.

"By working with the control and instrumentation systems provider to implement the critical process control system, we were able to add in a video encoder and the system was able to migrate from analog CCTV to IP networks," says Thomas Nuth, at US-based global vertical manager at networking provider, Moxa Inc. That meant the process control systems and IP video systems could seamlessly integrate to achieve alarm-to-video monitoring. With this improvement to alarm handling, users could search for event images in a minimum of time, Nuth said.

When it comes to producing on the platform, it's all about efficiency: Achieving consistent daily production while maximizing process capabilities.

Industry consultant McKinsey & Company agrees. "The rapid progress of technology such as big data and analytics, sensors, and control systems offers oil and gas companies the chance to automate high-cost, dangerous, or error-prone tasks," the company said in an article this Spring.

"Most oil and gas operators are starting to capture these opportunities and would do well to accelerate their efforts," the firm continued. "Companies that successfully employ automation can significantly improve their bottom line. While automation offers many potential benefits in the upstream value chain of exploration, development, and production, some of the biggest opportunities are in production operations, such as reducing unplanned downtime. Given the oil and gas industry's substantial increases in upstream capital investment, optimizing production efficiency is essential. Automation creates several opportunities to that end: Maximizing asset and well integrity, increasing field recovery, and improving oil throughput."

"With the substantial production volumes of offshore production platforms, even small improvements in production efficiency will have meaningful financial impact, as additional throughput translates directly into more revenue," the company said.

Making the connection

With operators facing more challenges in subsea production as they get into deeper water, they will need higher levels of automaton as they run into connecting with disparate systems.

"It is getting more complex," said John Oyen, business development manager for ABB's North America Oil, Gas & Petrochemical business unit. "It is a simple process you are controlling, the fluid flow from the well head, to the separations, and what goes on at a platform, in theory, it is relatively simple, but complex because of the volume, because

In subsea production, as operators get into deeper water, they will need higher levels of automaton to achieve greater efficiency. Photo from ABB.

of the pressures, because of the temperatures, because of where it is where you are operating."

Add in working with different systems that must talk to one another and you need a system that can bring all the data together for engineers and operators to use for their purposes.

"You may have a programmable logic controller (PLC) running your process control, you are going to have lots of little skids that have some modular areas that will have some form of a PLC," Oyen said. "The same thing goes from the electric side. With your power generation, your generator controls could be a GE, or they could be Siemens or Wartsila or a GE turbine, then you need the repository for all the data related to how that platform is operating from the equipment for process control. Also, you need to know the flows and how well your separators are running and your tank level. As we go forward, as the capabilities become greater and greater so do the HSE requirements and compliance which used to be voluntary now becomes mandatory."

Levels add up

But the layers of the levels of efficiency continue to mount as production ramps up. To keep the production flowing, there are reservoir management systems for the subsea wellheads the production side has to interface with via the control system.

So whether the control system is a Rockwell, Emerson, Honeywell, Siemens, Yokogawa, GE or ABB, the user also will contend with data from systems by Schlumberger or Halliburton on what is going on from below the wellhead.

"That becomes key when you get into a well management system because you are having to look at how you have laid out those wells, how you have laid out your process equipment, how you are doing your well flow tests so you know where you are getting water breakthroughs, all your ratios between gas, oil and sediment and which well is doing what," Oyen says. "Pretty much you are getting an aggregate of your main separator, so you know how much gas you are producing, how much oil you are producing, how much sediment you are producing and how much water. It is a lot of guys working in concert with each other. It is a lot of data from a lot of different systems, so it is how do you pull that data in a meaningful form so the engineers can take action?"

Technology and Collaboration

Technology is there for companies to use and take advantage of, but the big question remains as to whether they are using it to gain as much insight into their operation. There are the people doing data analytics to get the right information about the various processes and then report on it, but the next level up will be a collaboration from the platform to experts on land.

That could be where the digital oilfield comes into play. Data can come from the platform and go to a remote monitoring center onshore that could be working with half a dozen to a dozen assets, platforms, production areas in a region. They can have experts look at the data and put it into context and assist the engineers and operators on the platform to help them keep the platform up and running, avoiding any unplanned downtime as a result of a process upset.

"You have a lot of companies that have their wish list of what they want to occur," Oyen said. "They are watching the companies and will take advantage of what feel comfortable with for the project they are developing. There are some companies that move along, some take more risks than others, and some that don't want to take any risk at all. The costs to operate offshore are tremendous, the rewards are great, but the risks are great."

People power

Technology shows great potential to advance capabilities offshore, but it always comes down to people and how quickly, or slowly, they incorporate these new skill sets.

"I am talking to one operator and they are doing a platform and you talk about a different way to do things about integrated process control, safety, electrical and telecoms and how that can streamline interface management and reduce risk. The guy said, 'this is my last project before I retire, I don't want to do anything different. I want to do it the way I have always done it.' Hard to get past that one," Oyen says. "It's all about the personalities and who wants to learn or who wants to head into retirement."

However, with newer people coming into the industry, they will see and use technology much differently. But, with more established companies, with the bigger players like ExxonMobil, BP and Shell, they have their own way of doing things and you will follow their guidelines, Oyen said. "But you have some of the smaller guys and they need to rely on their engineering partners to do the design and give them a platform that will meet some criteria," he said. Since they don't have the staff, and are not as big, they can look at new and different ways of doing things.

Whether big or small, thinking new and different may be a bit of a risk, but if the calculations are correct, the rewards will truly benefit the user. That is the case with the FPSO off the coast of Angola. In that case, the user was also able to build another video viewer into their distributed control system (DCS) workstations based on open platform communication, Nuth said. That allowed for greater levels of communications from different systems.

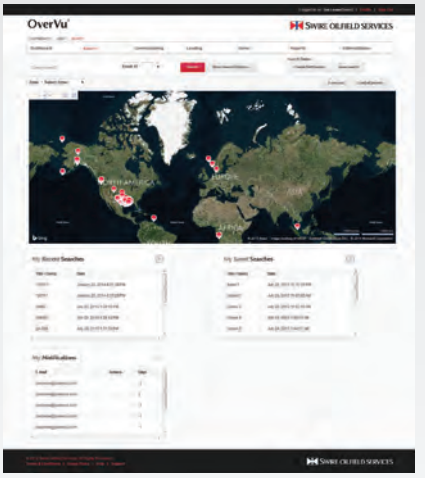
When the DCS receives an alarm notification, it sends an event trigger to the surveillance server, and the video surveillance system immediately retrieves video streams from the relevant unit and initiates recording and playback functions. At the DCS control center, a built-in viewer allows engineers to review event logs and corresponding video, which enhances alarm response and overall safety. **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.

Solutions

Track and trace solution showcased

Swire Oilfield Services showcased its new full-service track and trace solution called OverVu at ONS 2014 this 25-28 August in Stavanger, Norway.



Developed to tackle the multi-billion dollar problem of lost, misplaced and delayed equipment in the oil and gas industry, OverVu allows companies to identify, locate and track assets and equipment across the globe through a web browser.

The system uses global positioning system (GPS), radio frequency identification (RFID) and other automatic identification (auto-ID) technologies to collect all relevant movement data about any item.

It can be integrated into existing business applications and uses components compliant with international standards for identification of assets and materials, data communications and sharing events.

"We have developed OverVu in response to our own business needs and those of our customers – supply chain inefficiency is a significant issue for the industry and one that is only set to become greater as operations move into more challenging environments," said Nick Coaton, General Manager of Track & Trace Solutions, who has overseen the product's development. "Giving customers full supply chain visibility through OverVu allows them to make better, more accurate business decisions saving time, reducing operating costs and enhancing the safety of their staff." **www.swireos.com**

Welltec launches WellLIT

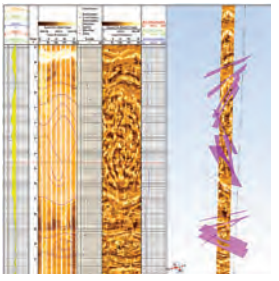
Welltec, in partnership with Saudi Aramco, has produced, WellLIT, an e-line tool designed to provide rigless access into laterals from the main wellbore.

WellLIT detects each sidetrack window depth and then directs unmodified, third-party, e-line tools into the selected lateral, while providing real time, diagnostic feedback that each lateral was entered.

WellLIT can be run standalone in vertical wells, in combination with downhole tractors for deviated/horizontal wells or conveyed on e-coil to enable CT access into laterals for clean-out or stimulation, the company said.

Seven field trials have been performed where the WellLIT successfully passed from cased hole into cased hole, cased hole into open hole, and open hole into open hole laterals on e-coil while conveying third party logging tools. A commercial version of the tool is now available. **www.welltec.com**

Schlumberger debuts Quanta Geo



Schlumberger debuted the Quanta Geo photorealistic reservoir geology service at the ONS 2014.

The new service includes a microresistivity imager that produces oriented, photorealistic, core-like images of the formation in wells drilled with oil-base mud (OBM). Interpretation of the images identifies geological features and predicts reservoir trends in 3D with a high degree of certainty.

Using the Schlumberger Techlog wellbore software platform, data acquired by the Quanta Geo service are easily rendered, creating an image of 0.24in resolution that resembles a whole core. This enables extraction of key reservoir parameters such as the structural dip, or the identification of sand body type, extent and orientation.

The Quanta Geo service has been field tested in more than 50 wells in deepwater, unconventional and carbonate environments in the Gulf of Mexico, West Africa, North Sea, North America and Australia. **www.slb.com/qgeo**

Trelleborg shows 30k psi seal

Trelleborg Sealing Solutions unveiled its Multi-Contact Turcon Variseal seal at ONS. The new seal has been developed to replace multiple chevron seals or V-stack type products in subsea valve stems requiring a high-integrity sealing capability. It includes a series of single-acting spring-energized seals housed within a U-shaped Turcon polytetrafluoroethylene (PTFE) based material seal profile.

The seal is designed to provide integrated redundancy, helping to extend the flex life of seals in high-pressure applications while providing better performance and lower operator costs. With the addition of anti-extrusion devices, the Multi-Contact Turcon Variseal can withstand pressures of up to 207 MPa/ 30,000psi, Trelleborg said. **www.tss.trelleborg.com**

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Activity

Norwegian Energy Minister Tord Lien presents the Innovation Award to Christophe Dupuis and Emmanuelle Regrain from Schlumberger for the firm's GeoSphere reservoir mapping while drilling service.
Photo from ONS/Killian Munch.

ONS Innovation Awards

Three ONS innovation awards were presented by Norwegian energy minister Tord Lien at this year's ONS exhibition and conference, held in Stavanger in late August. Schlumberger won the innovation award for GeoSphere. The SME innovation award went to Fishbones for its stimulation system, and Tore Halvorsen, FMC Technologies' senior vice president responsible for global subsea, won the ONS special innovation award for his pioneering work in subsea technology.

In addition, Martin Landrø was awarded the Norwegian Petroleum Directorate's IOR award for his work on developing 4D seismic for mapping, production management and monitoring of reservoirs. Landrø is a professor of geophysics and seismic at the department of Petroleum Engineering and Applied Geophysics at the Norwegian University of Science and Technology.

Using deep, directional electromagnetic measurements, the GeoSphere reservoir mapping-while-drilling service reveals subsurface bedding and fluid contact details more than 100ft (30m) from the wellbore. This reservoir-scale view provides an unprecedented depth of investigation, enabling operators to optimize landing, reduce drilling risk, and maximize reservoir exposure. By integrating real-time reservoir maps with seismic surveys, interpretation of the reservoir structure and geometry can be refined, revolutionizing field development strategy.

Schlumberger's Christophe Dupuis said that the use of GeoSphere in landing applications had removed the need for pilot holes in several programs already. "Having the full view of the reservoir up to 30m lets us do very nice geosteering," he added.

The Fishbones stimulation system is an open hole liner completion that connects the well and the reservoir without the drawbacks of hydraulic fracking. Small diameter tubes/needles are installed with and protected by the liner. At depth the needles are released by pressurizing the liner and the jetting operation starts. Fluid flows through the needles and jets out through the nozzles. The needles are ejected due to the differential pressure across the liner. Four laterals are installed at each depth. Typically 40ft (12m) is achievable penetration.

The Fishbones stimulation system was installed on land in a horizontal well in the Austin chalk formation in Texas in April this year, as part of the Joint Chalk Research program setup by nine operators to qualify the process for the North Sea. Fishbones' Rune Fryer said the installation created a world record with 60 laterals created from a mother wellbore, leading to a 30 times productivity increase. Two more tests are planned in Texas this month and next, followed by three or four in the Middle East, both on land and in The Emirates offshore. The system is expected to be ready for operation in the North Sea in 2015.

Christophe Dupuis and Emmanuelle Regrain accepted the prize on behalf of Schlumberger and Rune Freyer, majority owner for Fishbones, in which Statoil Invest has an 11% stake. —**Meg Chesshyre** ■

Scan this page!
Missed ONS? Scan this page with your smartphone or tablet and the Actable app to view photos from the ONS Innovation Awards.

Aker Solutions-Baker Hughes alliance approved

Aker Solutions and Baker Hughes received the necessary regulatory approvals for its subsea production alliance announced in April. The alliance seeks to develop technology for production solutions designed to boost output, increase recovery rates and reduce costs for subsea fields.

The alliance combines Aker's strengths in subsea production and processing systems with Baker Hughes' expertise in well completions and artificial-lift technology to deliver integrated in-well and subsea production solutions that will help mitigate risk, accelerate output and extend the life of subsea fields.

DNV GL launches new JIPs

DNV GL is launching three new joint industry projects (JIPs) to advance the offshore pipeline industry. The first JIP aims to make pipeline free span intervention less costly. Free spans are gaps between the seabed and pipeline and can lead to vibrations that may damage the pipeline. The second JIP seeks to result in faster and more consistent pipeline repair. The third JIP aims to optimize the design of pipeline components faster. "Offshore pipelines are the veins on an offshore field development and represent a large part of the total investment and the value of the transported product can be enormous," says Asle Venås, DNV GL global director for pipelines. "All three cooperation projects present an opportunity for the industry to work more efficiently, either through optimized and more reliable design, faster execution of projects, or safer and more robust operation."

Spotlight

By Sarah Parker Musarra

Leaving an imprint on the industry

Barry Calnan, 3D printing manager for Houston-based 3d-Printing Solutions, has always seen things differently.

"As an engineering designer, keeping an open mind has been my best tool," Calnan says. "Maybe that comes from being a rock and roll drummer and a painter – I always question why things are the done the way they're being done."

Calnan describes himself as having to two turning points in his career, the first occurring when he was working on Bantrel Inc.'s Newfoundland Transshipment Project as a 3D AutoCAD designer. Jokingly, Calnan says that he was dispatched because the company didn't have anyone else to send. However, he was soon made the company's youngest electrical plant design system (PDS) CAD coordinator.

This early success helped him hone skills that eventually defined his career path. He continually looked for better and more economical ways to achieve a task. He said that when engineers with three times as many years of experience told him one of his ideas couldn't be done, he would just respond with, "Why can't it?"

He also learned how to liaise between the engineers and design or CAD people, which he says can be tough because many people lack experience in both areas.

"Basically, that's what I've done during my entire career," he said. "I hear what needs to be done and then go back to the design team and work with them to see how it can be accomplished."

When 3D printing began to take off, Calnan say that the transition into this line of work was a natural one. With his open-minded approach to problem solving, he appreciated having more options afforded to him.

"I'm not a 'think in the box' kind of person. Engineering is all about specifications and regulations when you design something. 3D printing takes away a lot of manufacturing restrictions and it opens up a lot of different ways of thinking about a problem," he says. Following a successful stint in Qatar as Ras Laffan Liquified Natural Gas Co.'s electrical PDS lead, Calnan joined Halliburton where his second turning point occurred when he once again thought, "how can we do this better?"

Charged with designing a downhole tool, Calnan disregarded a typical design process. He used what he calls "the manufacturing freedoms" he found through 3D printing to design a tool that couldn't be made any other way.

"Normally, you design the pads on a drill sleeve, and then try to change the pads to whatever flow dynamic they are looking for. I designed the flow and then built the tool around the flow," he said. "I just turned the design process around."

The engineering team looked at him quizzically, unable to picture what Calnan was describing.

"I had a model printed. I put it on the table and the light bulb just went off," he said, explaining that the engineers immediately understood Calnan's solution. In addition to alleviating designers of certain restrictions, Calnan learned that having a 3D printed model immediately available can be a powerful communication and visualization tool.

Ultimately, Halliburton would patent two of Calnan's designs.

In April 2008, Calnan became a partner in a 3D printing re-seller company, AGS-3D, before joining Subsea Solutions company 3d-Printing Solutions in 2010. Nicknamed the "3D printing evangelist" by his peers, he has traveled the world, as an exhibitor at prominent conferences such as the Offshore Technology Conference on how 3D printing can revolutionize the oil and gas industry. OE

For further reading, see page 48, "Worth 1000 words."

Scan this page!

Scan this page with your smartphone or tablet and the Actable app to see Barry Calnan discuss a pivotal moment in his career, made possible through 3D printing.

3d-Printing Solution's Barry Calnan has been referred to by his contemporaries as a "3D printing evangelist." Image from Barry Calnan/3DSystems.

Faces of the Industry

By Kelli Lauletta

October's Faces of the Industry profiles a leader who is expanding the footprint of LAGCOE (Louisiana Gulf Coast Oil Exposition). Angela Cring, executive director of LAGCOE, is leading the organization into its next chapter and broadening its reach beyond the show itself. While honoring LAGCOE's rich history is important, Cring and her team are not afraid of change. This change includes a vision to expand LAGCOE's mission to help people in Louisiana's oil and gas sector build a bright future and bolster its "next generation" workforce.

Blending a geology and political science degree, she embodies idealism and pragmatism in regards to how we as a society harness our natural resources. She works tirelessly to apply this passion to LAGCOE and its imprint on the Louisiana oil and gas industry. OilOnline recently spoke with Angela to learn more about her career, her perspective on the industry and her hopes for her legacy at LAGCOE.

When you were younger, what appealed to you?

I was always interested in science and fascinated with nature. In college, I discovered political science and was going in the direction of some type of natural resource policy. I thought it was a good combination of the natural and social sciences. That's how I ended up with a bachelors' degree in geology and political science.

How did you get into oil and gas?

During and after graduate school, I worked for the US Geological Survey (USGS) and National Oceanic and Atmospheric Administration (NOAA) for several years doing research. After completing that role, I fell into oil and gas in part by geographic circumstances because I was in Lafayette, Louisiana.

Were there key turning points in your career?

LAGCOE is my third career. The first career involved working for the federal government, primarily with hydrology. Next, I moved into the private sector, focusing on geohazards geology. I experienced some health issues that made it difficult to sit for extended periods of time in my role as a geologist reviewing data. Eventually, I stumbled upon LAGCOE, as I knew the previous executive director. I started in 2007, and seven years later I'm running the show.

What do you enjoy about the LAGCOE culture?

I enjoy the people. LAGCOE is like a family. Our newly elected board, as well as our membership, is a great mix of longtime volunteers and young professionals. LAGCOE is firmly rooted and many are still passionate about the industry and how our community is affected by the industry. Our current chairman-elect became involved in LAGCOE because his father was a dedicated LAGCOE volunteer. It is truly a multigenerational organization.

What is a common misconception about a career in oil and gas?

People think that you do only one thing. As an example, if you are a geologist, you only do exploration, which is not true. There are several different areas within each field. In geology, you can pursue geohazards, regulatory or environmental careers. Even within each discipline there are many avenues and options.

For engineers, many young people automatically picture themselves working for a major oil and gas company. While that is an option, there are other avenues for engineers such as working for a service, consulting or legal company. People don't have to be pigeonholed.

What advice do you have for females considering an oil and gas career?

People in the industry are more concerned about your experience level than your gender. I'm sure there are exceptions, but in general, women are certainly more accepted now than they were 20-30 years ago.

What would you tell new graduates to watch out for?

Don't pay so much attention to other people, just pay attention to yourself. I was sometimes guilty of this, too, early in my career. You can't control how well other people do their job. You can only control how well you do your job. A strong work ethic will take you far. While knowledge can be learned over time, putting in effort is what will

Scan this page!

Learn more about the LAGCOE Career Fair on October 29, 2014 by scanning this page with your smartphone or tablet and the Actable app.

Angela Cring

Angela Cring serves as executive director of LAGCOE (Louisiana Gulf Coast Oil Exposition). Originally from Alexandria, Louisiana, Cring has a B.S. in environmental geology and political science from Millsaps College and an M.S. in geology from the University of Mississippi. Cring is a 2013 Acadiana 20 Under 40 award recipient; graduate of the Leadership Louisiana 2013 Class; graduate of Leadership Lafayette Class XXIV; Chairman-elect of the Leadership Institute of Acadiana; member, Public Relations Chair and member of the Board of Directors of Junior League of Lafayette; founding member of The Giving Revolution, A Giving Circle; and member of International Association of Exhibitions and Events, Greater Lafayette Chamber of Commerce Energy Division, The 705: Acadiana's Emerging Leaders, Society of Petroleum Engineers, American Association of Drilling Engineers, and Lafayette Geological Society.

take you far. I would encourage mentors to instill a strong work ethic into younger people. We will all be better off for it in the future.

What is the top life/career lesson you live by?

In life, what we want and what we need are not always the same. Be grateful for what you have because that may be all you really need. In your career, do not be afraid to try new things and embrace change. It can be scary to go in a direction that may not be comfortable, but sometimes you end up in the best place. This certainly happened with me.

What are the key challenges in the oil and gas industry now?

Developing the next generation of leaders for the industry is a key challenge. This is a subset of the overarching workforce issue with the anticipated big crew change. Ensuring that knowledge is being successfully transferred from experienced workers to incoming workers is critical. There needs to be a shift in allowing the new generation to take on leadership roles earlier than some of the previous generations had to.

Tell us more about the upcoming 2014 LAGCOE Career Fair? Why should people attend?

The LAGCOE Career Fair offers a great way for people to get an overview of what the industry is currently seeking. The career development resources and sessions at the career fair will still be valuable to those who may not even be in the market at this time. You never know where your career will take you. A company may come looking for you. Always be ready with an updated resume and LinkedIn profile.

What do you hope to accomplish in your tenure as executive director at LAGCOE? What will your legacy be?

Whether I want it to be, it will be "change." I'm sure my staff can attest. My brain works 24/7 on thinking of what's next and how things can be improved upon. During my first few years as executive director, my motto was "ICE"–innovation, collaboration and efficiency. How can we make things better? Who can we create partnerships with? How do we execute things in a more efficient way? Many of the changes have transitioned LAGCOE from more than just a show every two years, into an organization that has value to the industry outside of just the show itself.

While Angela hated the question of how she spends her free time, she revealed that she loves to volunteer. She said in regard to volunteering, "I think it is a sickness, if I ever found a cure, I'd have a lot more time for fun." She can back it up, too. Half of her resume is filled with volunteer roles. It is fitting that she leads an organization that relies on and appreciates volunteers to take LAGCOE into the future. Angela said that she always had that innate drive to engage in activities that make a difference. We think she is well on her way. OE

Faces of the Industry features individuals who do extraordinary things for the industry and outside the industry. If you would like to nominate someone, please email Kelli Lauletta.

***Kelli Lauletta** is an HR consultant with 17 years experience. She also serves as an editor for OilOnline.com. If you have story ideas please email Kelli at klauletta@atcomedia.com.*

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Numerology

3000m The water depth at which GE's new high-pressure and high-temperature vertical Xmas tree, DVXT, is designed to operate. See page 64.

130,000boe/d

The production rate for the Auger platform after Shell's Cardamom field came onstream in the Gulf of Mexico. See page 16.

5000 The number of reports the Arria NLG generates per day across the UK for the Met Office. See page 29.

US$2.5billion The size of the 3D printing market in 2013, according to Canalys. See page 44.

160.9m

The length of the VARD newbuild OSCV. See page 84.

1920s When mapping-while-drilling was first conceptualized. See page 40.

800 The number of wells on which Helix Well Ops used dedicated intervention vessels to perform intervention work. See page 21.

1.8MMbbl The storage capacity of the tanker being converted for Eni's East Hub field FPSO. See page 16.

2014 When the *N'Goma* FPSO sailed away from the Paenal yard to Eni operated Block 15/06 offshore Angola. See page 82.

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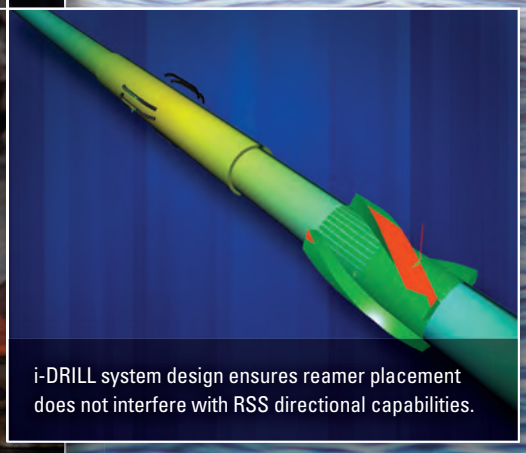
Rhino RHE

DUAL-REAMER RATHOLE ELIMINATION SYSTEM



i-DRILL system design ensures reamer placement does not interfere with RSS directional capabilities.

Dual-reamer system enlarges rathole, avoids a run, and saves 16 hours on a deepwater rig.

Rhino RHE rathole elimination system enlarged 178 ft of rathole while drilling a deepwater well in the Gulf of Mexico, saving 16 hours of rig time. The Rhino RHE system's dual-reamer process uses a hydraulically actuated reamer positioned above the MLWD tools to open the pilot hole and an on-demand reamer located near the bit to enlarge the rathole. The dual-reamer system eliminated a dedicated rathole cleanout run.

Read the case study at
slb.com/RhinoRHE

Schlumberger