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Features

ON THE COVER

ROVs are just like us.
Oceaneering International provides *OE*'s April cover, featuring the Magnum remotely operated vehicle (ROV) taking a "selfie". See more of Oceaneering's latest underwater technologies on page 36. *Image from Oceaneering.*

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What's Trending

Highs and lows

- EIA: GoM production set for record high in 2017
- Petronas delays PFLNG 2 amid slump
- Obama pulls US Atlantic lease sale

People

Shell man joins Statoil

Ex-Shell CEO Jeroen van der Veer has joined Statoil's board of directors. Van der Veer joined Shell in 1971, and later served as CEO from 2004 to 2009.

Photo from ING Group.

Webinar

Strategies for Integrated Asset Optimization

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OPINION

Undercurrents

A paradoxical industry

I present three statements that seem a given in today's industry; technology development takes too long, technology adoption is slow, and when it comes to a crisis, it is technology that the industry looks to in order to reduce costs, increase productivity, extract more reserves. This is an industry of paradoxes. On the one hand it's one of the most technologically advanced, working with pressures, temperatures and environments few others have to deal with. The industry is able to directionally drill thousands of feet beneath the ocean floor with a high degree of precision, thanks both to advances in drilling technology and subsurface imaging.

On the other hand, "we're luddites," two senior industry professionals told the Industry Technology Facilitator's (ITF) Technology Showcase in Aberdeen mid-March. Colette Cohen, senior vice president, UK and Netherlands for Centrica, and BP's John Peak, vice president of EOR, were talking specifically about adoption of big data, the internet of things, and the intelligent oilfield.

"Companies like Amazon use computer power and robotics more effectively than we do," said Centrica's Colette Cohen.

"In the 1970s, the only other industry more computer intensive was NASA," Cohen said. "Companies like Amazon use computer power and robotics more effectively than we do." Peak made a nice analogy: "We are stuck in a world of Spitfire pilots looking at the instrumentation. Compare that to modern day fighter pilots, they don't look at data, it's too voluminous; they rely on algorithms."

"On the plus side, because everyone else has been doing it, we get to steal it," Cohen said. "There's technology we could rapidly deploy in our own industry if we were a little bit more open. The internet of things is a large opportunity. We are good at getting data, but we are poor at making use of it."

Peak agreed. "Cheap sensors means the volume of data has increased exponentially," he said. "In the 1990s, we had 10 bits per second mud pulsed telecommunication, now its GB/sec from distributed fiber optics. It is a huge opportunity, to get real-time data to help reservoir management, production enhancement, and improve facilities integrity."

And BP has put some of this data to good use. Its "BP Well Advisor" program has been deployed to almost 30 rigs around the world. By looking at data across its well set, it's effectively eliminated stuck pipe events and saved a lot of money, Peak said.

Centrica has taken technology from other industries', i.e. FLIR cameras, to identify weeps and seeps offshore. Cohen also highlighted the use of drones, for inspection, but suggests they could be used more proactively, potentially carrying equipment to normally unmanned installations. "3M has intelligent paint in the automotive sector we could use to change our approach to corrosion management. There's stuff out there if we open our eyes," she said.

But, this is also about risk and IP. Peak pointed to BP's Low Sal technology, which took decades to develop, because BP kept it in-house. By using partners, he thinks similar projects could be cut down to 10 years, but even that is too long, he said.

However, even now, despite showing enthusiasm for a new technology, firms don't show willingness to try it, partly due to bureaucracy, says WellSENSE's Dan Purkis, winner of the SPE Offshore Achievement Awards Significant Contribution accolade (see page 63 and watch for our profile on him next month). This points to a wider issue. Technology isn't the silver bullet for an industry with cultural and behavioral challenges.

"Technology is not the answer to all the challenges," said Paul White, Director of Subsea Technology, GE Oil & Gas, at the event. "But we must make a choice about using technology." OE

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The Barrel

Stop selling us short

Recent increases in crude prices and oil stocks belie the reality that exploration and production activity continues to weaken and there is no prospect of it improving in the near future. Spending on oilfield drilling and services has fallen further, hundreds of jobs are disappearing every month, and for most companies cash is running down or out. Only the fittest companies are going to survive this downturn.

"Perhaps there should be a ban on short selling crude contracts, similar to the ban on short selling banking stocks."

The outlook for 2017 is, however, better than many analysts had predicted. The fact that all oilfields decline, and if there is little or no money spent on them they decline faster, is beginning to show in production numbers.

The long anticipated 4 MMb/d from Iran that was expected to swamp the market will take some time to appear because Iranian oilfields have had little investment or technology applied to them in recent times. Concerns about imploding emerging markets oil demand also appear to have calmed.

Schlumberger summed up the situation nicely in a recent presentation:

"E&P activity continues to weaken. We expect this to continue well into the second half of the year (2016). The market will return to growth when the production deficit becomes pronounced. The recovery in service activity will lag higher oil prices by some time. The longer E&P investment is below production replacement needs, the sharper the market recovery will have to be to meet demand."

If you are looking for an accurate prediction of short-term oil prices, I suggest you consult an oil trader or hedge fund manager, because it's their derivative contract activities that have driven prices down to levels that don't make sense from any economic perspective. These bets are predicated on news flow and the direction of the herd rather than fundamentals. This is well illustrated by the recent 40% rise in oil prices driven by a 15% reduction in the number of short positions when Russia started talking about the potential of a production freeze (a suggestion that is of little value when those offering it are already producing at maximum levels).

The market will recover, but it's impossible to predict when with any accuracy. In the interim, we have to live with continuing trauma.

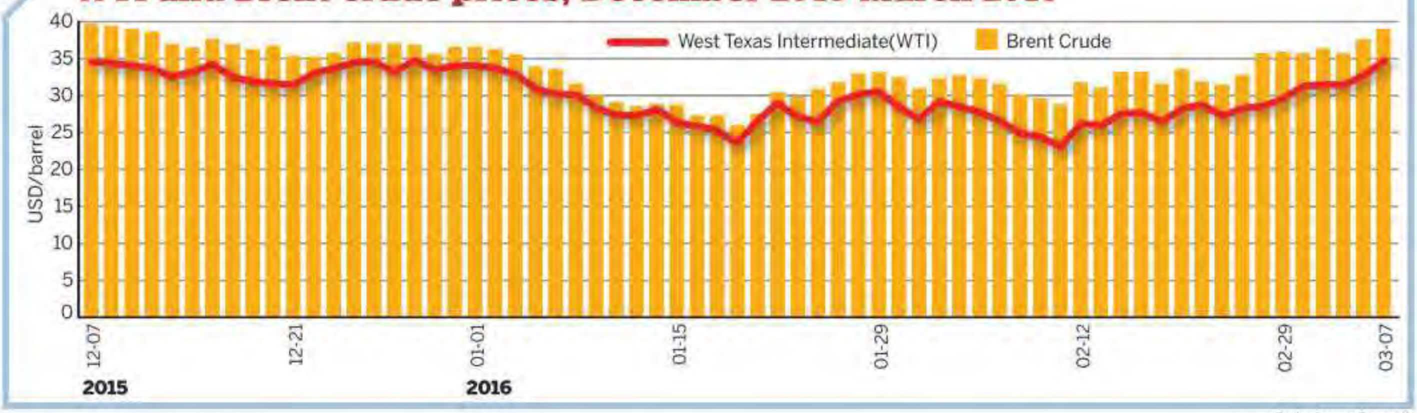
The unfortunate consequences of making long-term decisions based upon short-term prices are that it is catastrophic for many companies and the people involved, it damages the industry, and makes it really hard to ramp up activity when the market needs it. Much of the damage is irreparable, e.g. when key infrastructure is decommissioned or core expertise leaves the industry permanently.

The late founder of Simmons & Company, Matt Simmons, used to refer to oil and gas as "industrial oxygen" – an apt description of its critical role in so many aspects of our lives.

Perhaps there should be a ban on short selling crude contracts, similar to the ban on short selling banking stocks that was put in place during the banking crisis. This would stabilize crude prices and avoid the partial dismantling of the industry that is currently underway. It would also enable the determination of a sensible, long-term energy policy. **OE**

***Colin Welsh** is head of international energy investment banking at Simmons & Company International, part of Piper Jaffray. He studied accountancy, economics and law at the University of Aberdeen and qualified as a Scottish Chartered Accountant with Ernst & Whinney (now EY).*

WTI and Brent crude prices, December 2015-March 2016



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Global E&P Briefs

A Obama cancels Atlantic lease sale

The Obama Administration rescinded a proposal to drill off the US Atlantic Coast in 13 areas, due to current market dynamics, strong local opposition, and conflicts with competing commercial and military ocean uses.

"We heard from many corners that now is not the time to offer oil and gas leasing off the Atlantic coast," said Sally Jewell, Secretary of the Interior.

B Big Foot set for late 2018

Chevron has pushed back first production from its deepwater Gulf of Mexico Big Foot development to 2H 2018.

Production was delayed when the tension leg platform's (TLP) subsea installation tendons suffered damages last June.

"The collapse of the tendon was due to a failure of connection between the temporary buoyancy modules and the tendons. The initial site recovery work is complete and the TLP has been moved to a safe location and inspection work has confirmed that all well and the subsea templates can be reused along with most of the components of the recovered tendons," said Jay Johnson, executive vice president, Chevron.

Fabrication of new tendons for Big Foot and required temporary insulation equipment is expected to commence in Q2 2016.

C Shell's BC-10 output grow

Shell began oil production from phase 3 of its Parque das Conchas (BC-10) development offshore Brazil, in hopes of adding up to 20,000 boe/d.

Phase 3 at BC-10 comprises five producing wells in two Campos basin fields, Massa and O-South, in addition to two water-injection wells.

Subsea wells at the development connect to the *Espirito Santo* floating production, storage and offloading (FPSO) vessel, which has a processing capacity of 100,000 boe/d, and sits more than 150km off Brazil.

D More pay at Libra

Petrobras hit "good quality oil" in a new well in the northwest area of the giant Libra field, in the pre-salt Santos basin offshore Brazil.

Well 3-BRSA-1305A-RJS encountered a 270m oil column and high-quality reservoirs in communication with previous wells in the area.

The Libra consortium performed two drill stem tests on two different intervals that confirmed excellent productivity from the reservoirs and 28° API oil, similar to wells 2-ANP-2A-RJS and 3-RJS-731.

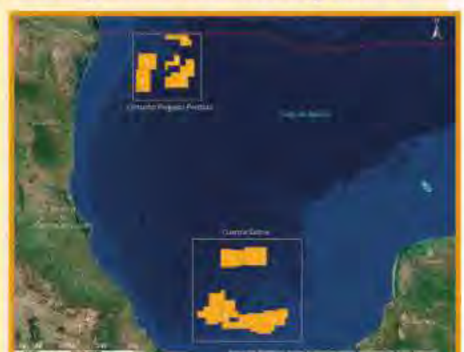
The Libra consortium is composed of operator Petrobras (40%) and partners Shell (20%), Total (20%), CNPC (10%) and CNOOC (10%).

E Mexico's deepwater auction set

The fourth phase of Mexico's Round One will go forward in early December, announced Mexican President Enrique Peña Nieto at Houston's IHS CERAWeek.

The long-anticipated fourth phase of Round One will auction off 10 deepwater blocks, including four blocks on the Mexican side of the Perdido Fold Belt.

"This decision demonstrates and confirms the commitment of the Mexican government with the energy reform implementation, in a fast and decisive way," Peña Nieto said. "Regardless of the oil price in the short-term, Mexico is decided to have the technological, financial and of risk management capability that the global oil industry has already developed for this type of large-scale projects."



F Polarcus begins 3D seismic series

Polarcus has begun a 3D seismic project offshore Brazil for Chariot Oil & Gas.

Utilizing the *Polarcus Alima*, the project will cover about 785sq km over the BAR-M-292, BAR-M-293, BAR-M-313 and BAR-M-314 licenses in the Barreirinhas basin, and will take about 30 days to complete, said operator Chariot (100%).

This is the first of three 3D seismic projects, estimated to take seven months, which will fulfill all of Chariot's commitments on the licenses.

G Danish Licensing Round success

Sixteen new oil and gas exploration licenses in the Danish North Sea have been granted under Denmark's 7th Licensing Round, pending Parliament approval.

The licenses were awarded to eight operators: Ardent Oil (4), Wintershall (3), Dana Petroleum (2), DEA Deutsche Erdoel (2), DONG E&P (2), Hess

(1), Hansa Hydrocarbons (1), and Edison International (1).

The permits offer a six-year exploration period with the right to 30-year extension for fields put into production. Total work programs include two unconditional wells and up to 24 contingent wells.

H Drilling begins on Johan Sverdrup production wells

The first of 35 production wells for Statoil's Johan Sverdrup's development was spud by Odfjell Drilling's *Deepsea Atlantic* semisubmersible.

A total of eight wells will be drilled through the predrilling template before the rig is relocated to drill injection wells on three locations on the field.

The Johan Sverdrup project, offshore Norway, is using an integrated drilling services concept, with Baker Hughes providing the main deliveries together with Odfjell Drilling.

J Lukoil weighs Baltic opportunity

A Kaliningrad-focused Lukoil subsidiary won the right to explore for oil and gas in the Russian sector of the Baltic Sea. The area includes the D33 oil field, which was discovered in 2015, and contains recoverable oil reserves of 21.2 million tons.

Kaliningrad is a Russian-controlled enclave between Poland and Lithuania, with coastline along the Baltic Sea.

K Success at Zohr test

The first production test at Eni's Zohr 2X appraisal well delivered some 44 MMcf/d of gas, offshore Egypt. The Zohr 2X well, Eni's first appraisal well on its giant Zohr discovery, indicates a potential to deliver up to 250 MMcf/d in a production configuration, roughly 46,000 boe/d.

L Dana spuds Manatee-1

Dana Petroleum started drilling operations at the Manatee-1 exploration well, offshore Cameroon. Manatee-1 is in the southwestern corner of the Bakassi West block in shallow water in the prolific Niger Delta basin. The well will be drilled using Paragon M825 jackup rig to a depth of 1550m, and is expected to take up to 45 days.

M Kosmos grows Tortue potential

The Greater Tortue Complex offshore Mauritania has the potential to create a new "world-scale" LNG development, said Kosmos Energy following the results of its latest appraisal well.

The firm said the results of its Ahmeyim-2 appraisal well, near to the Tortue-1 discovery well, had pushed the resource estimate for the Greater Tortue Complex from 17 Tcf to 20 Tcf Pmean gross resource estimate.

I Goliat achieves first oil

Production has finally started from Norway's first Arctic oil field, at the Goliat floating production facility, in the Barents Sea. The facility was originally scheduled to startup in 2013. The 180 MMbo field, in PL 229, will produce 100,000 b/d once all 22 of its subsea wells (12 production, seven water and three gas injection wells) are online. Currently, 17 wells have been completed. The 360-420m water depth project is based on a powered-from-shore, via subsea cable, cylindrical floating production facility, sitting 85km northwest of Hammerfest, offshore northern Norway. Eni (65%) operates PL 229 with partner Statoil (35%).

Global E&P Briefs

The Ahmeyim-2 well was drilled about 5km northwest, and 200m downdip of the Tortue-1 discovery well. The well encountered 78m (256ft) of net gas pay in two "excellent quality" reservoirs, including 46m (151ft) in the Lower Cenomanian and 32m 105ft) in the underlying Albian.

N Gas flows from Zora

Operator Dana Gas began production at its Zora gas field offshore the Sharjah coastline, United Arab Emirates. Zora is in the Sharjah Western offshore concession, covering 1000sq km.

The field, in which Dana has invested US$150 million (AED550 million), is expected to achieve a flow rate of 40 MMcf/d. Dana Gas said.The Zora field 2P reserves remained steady at 31 MMboe.

The Zora field comprises a tilted fault block structure, which straddles the Sharjah / Ajman territorial boundary. The structure has a closure of some 25sq km and is fault and dip closed.

The gas is being transported through a subsea pipeline to a newly built onshore gas processing facility by Dana Gas located in the Hamriyah Free Zone in Sharjah. Dana Gas operates Zora with a 100% interest, and will manage the field, gas sales and purchase agreements.

O Rosneft spuds Vietnamese well

Rosneft Vietnam spud the PLDD-1X well offshore Vietnam, in Block 06.1, where it holds 35% of the project.

PLDD-1X is 375km from the coast on the shelf in the Nam Con Son basin. The well will be drilled with Japan Drilling's *HAKURYU-5* semisubmersible drilling rig to about 1380m.

Rosneft expects recoverable reserves of natural gas to be an estimated 12.6 Bcm, and 0.6 tonne of gas condensate, which can be developed by subsea completion and tied-back to the Lan Tay platform in Block 06.1.

Following the drilling of PLDD-1X, Rosneft will drill another exploration well in block 05.3/11, also in the Nam Con Son basin, where Rosneft holds 100% operatorship.

Rosneft also plans to shoot broadband 3D seismic of its existing Block 06.1 operatorship later this year to enhance ongoing production recovery and explore potential in deeper prospects.

P Lundin hits at Maligan

Sweden's Lundin Petroleum has discovered "significant gas shows" in the Maligan exploration well in Block SB307/SB308, offshore East Malaysia.

Contracts

Williams gets Appomattox work

Williams Partners will provide Shell and Nexen Petroleum with deepwater gas gathering services to the Appomattox development in the US Gulf of Mexico.

Williams will provide offshore gas gathering services to its existing Transco lateral, which will provide transmission services onshore to its Mobile Bay processing facility. Williams Partners also plans to make modifications to its Main Pass 261 Platform and install an alternate delivery route for customers from the platform to the existing Destin Pipeline for transportation to another onshore processing facility.

Emerson wins Culzean gig

Emerson Process Management won a contract to automate the Maersk Oil Culzean gas field development in the North Sea.

Emerson will provide a range of project and support services including system design and engineering, configuration, testing, installation and commissioning. Emerson will provide automation services and technologies for three offshore platforms as well as for an onshore observation facility that can support remote operations if needed. Emerson will also provide measurement and control technologies, as well as asset management and machinery health monitoring technologies.

An operator training system will support both engineering and workforce training to help bring the production online safely and quickly. Emerson's UK base in Leicester will support this project.

Fugro lands Walney survey

DONG Energy has appointed Fugro to perform offshore pre-construction surveys at the Walney Extension offshore wind farm off the UK's Cumbria coast.

The survey will provide detailed

The well was drilled with the West Prospero jackup rig to a total depth of approximately 1380m, and has been plugged and abandoned.

Lundin Malaysia holds 65% working interest in SB 307/308, with partners DYAS (20%) and Petronas (15%).

Q Total in Sri Lankan study

Total has signed a joint study agreement (JSA) with the government of Sri Lanka covering two ultra-deepwater exploration blocks, JS5 and JS6, off the country's East coast.

The JSA will start with a two-year period for data acquisition and for processing and interpretation. If this study is successful, Total has a right to negotiate a production sharing agreement with the government of Sri Lanka.

In addition, the Sri Lankan government will receive a ground rent of US$1/sq km for the entire acreage of the JSA, valued at about $48,825/yr.

R China offers 18 offshore blocks

A total of 18 blocks are up for bid for exploration in 2016 to international oil and gas companies wanting to partner with operator China National Offshore Oil Co. (CNOOC).

The blocks cover 52,257sq km over in five different basins: Bohai Bay, South Yellow Sea, Yinggehai, Qiong Dongnan, and the Pearl River Mouth basin (East). Of the blocks up for bid, the Pearl River Mouth East basin holds the most with nine blocks. A data room will be open until June, and companies or consortia will need to submit offers by October.

S Gorgon achieves first LNG

Chevron has begun production from its Gorgon liquefied natural gas (LNG) and condensate project on Barrow Island off northwest Western Australia.

"This is the result of the collaboration of hundreds of suppliers and contractors and many tens of thousands of people across the world during the project design and construction phases," said Chevron Chairman and CEO John Watson.

The Gorgon Project is supplied from the Gorgon and Jansz-Io gas fields, within the Greater Gorgon area, between 80mi (130km) and 136mi (220km) off the northwest coastline.

It includes a 15.6 MTPA LNG plant on Barrow Island, a carbon dioxide injection project and a domestic gas plant with the capacity to supply 300 terajoules of gas per day to Western Australia.

The Chevron-operated Gorgon Project is a joint venture between the Australian subsidiaries of Chevron (47.3%), ExxonMobil (25%), Shell (25%), Osaka Gas (1.25%), Tokyo Gas (1%) and Chubu Electric Power (0.417%).

information to the Walney Extension project team, including additional geophysical data to ensure the seabed is clear of obstructions, including unexploded Second World War ordnance.

Fugro will use *Fugro Helmert* to survey the main wind farm site. The *RV Discovery* and *Fugro Valkyrie* will also be deployed at the wind farm site as well as on the export cable route.

OneSubsea awarded WND supply gig

BP and partner DEA awarded OneSubsea a contract to supply subsea production systems for the West Nile Delta Giza/Fayoum and Raven fields, situated offshore Egypt.

The scope of supply includes large bore subsea trees, manifold systems incorporating high-integrity pressure protection systems (HIPPS) for the high-pressure Raven field, connection systems, and controls systems, along with project engineering, management and testing.

"This is the third award to OneSubsea that will utilize the jointly-developed large-bore tree already being deployed to other BP projects," said Mike Garding, OneSubsea CEO.

Trelleborg receives Shah Deniz order

Trelleborg has been awarded an order for thermal insulation and corrosion coating services for phase II of BP's Shah Deniz project, contracting directly to Azeri firm BOS Shelf.

Trelleborg will supply in excess of 1000-tonne of its Vikotherm P7 high temperature insulation material, over a period of five years. To facilitate the order, Trelleborg will support BOS Shelf in establishing a custom coating facility, as well as installing two polyurethane dispensing machines and a site-specific laboratory at BOS Shelf's facility in Baku, Azerbaijan.

The contract is expected to run until approximately 2022. ▪

Egypt's breadbasket

Italian major Eni has found what could be the biggest gas deposit in the Mediterranean and the company is eager to develop it. Jerry Lee reports.

Italian major Eni made waves when it announced what could be the largest discovery in the Mediterranean Sea, the 30 Tcf lean gas deep water Zohr field offshore Egypt.

For a country that has seen much turmoil in recent years, the news was welcome. For an operator who has been present in Egypt for over 60 years, Eni's commitment could pay off and then some.

The project could be a beacon of hope in today's cash-strapped, low-budget industry. Analysts Wood Mackenzie expect Zohr to be the biggest project sanctioned globally in 2016, with an estimated budget of over US$14 billion.

At the time of the initial Zohr discovery last August, Eni CEO Claudio Descalzi said: "This historic discovery will be able to transform the energy scenario of Egypt in which we have been welcomed for over 60 years."

Near miss

Eni's Zohr discovery lies in the Nile Delta basin off Egypt in the Block 9 (Shorouk block), close to Cypriot waters, however, a previous operator missed its opportunity to make the discovery.

"Royal Dutch Shell previously operated this acreage, under the North East Mediterranean (NEMED) licence," Joseph Gatdula, GlobalData's senior upstream analyst told ***OE***. "Shell looked at the Oligocene, Pliocene and Upper Messinian (Upper Miocene) areas, but focused on the clastic sands that comprised the known plays. They also drilled well Kg-70-1 in the southwest corner of the Shorouk license, which did not provide compelling evidence to continue exploration."

Shell completed extensive 2D/3D seismic campaigns, and drilled nine wells in the area, but the play proved uncommercial. "They relinquished the block because they completed studies, which did not consider the Miocene carbonates where Zohr was found," Gatdula says.

However, following a string of recent giant gas discoveries in neighboring countries, including the Leviathan and Tamar fields, offshore Israel, and Aphrodite, offshore Cyprus, Eni became interested in similar geological models in Egyptian waters, wrote Marco Alfieri in a blog post for Eni's website.

EGYPT Nile Delta

The Zohr discovery, in the Shorouk block, offshore Egypt.
Image from Eni.

The starting point

"Eni's explorers [began looking] for similar structures with the same "play concept," on the assumption that the oil system discovered in the Eastern Mediterranean might also extend to Egypt," Alfieri wrote in a blog post for Eni's website. "However, on the basis of the evaluation work made by the IEOC (International Egyptian Oil Co., an Eni subsidiary) team in Egypt, and with the lack of available seismic data, what emerged was an area in block 9 where there appeared to be a "high regional" situation: not the classic theme in Miocene sands like Leviathan, Tamar and Aphrodite or the Nile Delta, but a huge bio-structure. A "reef," as geologists call it."

With previous successful exploration activities in similar play structures (Venezuela's Perla field and Kazakhstan's Kashagan field), the company developed the Zohr play concept, said Eni in a September 2015 presentation.

Eni submitted its bid for the Shorouk block in February 2013, as part of Egypt's 2013 Bid Round, and was notified of its success that summer. Shorouk, 100% operated by IEOC, spans 3752sq km with water depths ranging from 1200-1700m.

Eni and Egypt signed the lease on Block 9 in January 2014, and, despite having only reprocessed the available 2D seismic data, and having failed to find a partner for the project, a decision to drill was made. The *Saipem 10000* drillship was brought out to the field in June 2015, spudding the Zohr-1X NFW exploration well on 3 July 2015, three years ahead of an original schedule; simultaneously, 2942sq km of 3D seismic was also acquired, two years ahead of schedule.

Discovery

Drilled in 4757ft (1450m) water depth to the target depth of 13,553ft (4131m), the well hit a 2067ft (630m) hydrocarbon column with 430m of net reservoir pay, and a gas-water contact at 4055m. The reservoir was found to have excellent reservoir characteristics, and initial estimates placed the reservoir potential at up to 30 Tcf of lean biogenic gas in place (5.5 billion boe), Eni said in October 2015. The Zohr discovery displaced Noble Energy's Leviathan field, offshore Israel, in the Levantine Basin, as the largest gas field in the Mediterranean.

The *Saipem 10000*. Photo from Saipem.

According to Wood Mackenzie, Zohr was one of the largest discoveries in 2015, with some 3960 MMboe recoverable.

After the discovery was announced, Eni put into motion its plan to appraise the field and fast track the development. In February, Eni announced that it has been granted the Zohr development lease and the firm's target is to bring the field online in Q4 2017 – just two years after discovery.

Appraisal

The first appraisal well on Zohr, the Zohr-2FX NFW well, was spudded in January, again using the *Saipem 10000*, 1.5km southeast of the Zohr discovery well. It is in 4800ft (1463m) water depth, downdip from the discovery well on the flank of the Zohr structure.

It was drilled to 13,684ft (4171m), where a 1614ft (455m) hydrocarbon column was found, along with 305m of net pay. Formation evaluation confirmed the same gas-water-contact as well as connection to discovery well Zohr-1X NFW, confirming Zohr as a single massive natural gas tank.

Production tests from the appraisal well delivered some 44 MMcf/d of gas, constrained by the surface equipment, from 120m of the reservoir, Eni said in early March. This would enable Eni to achieve up to 250 MMscf/d (46,000 boe/d) production, the firm said. Eni plans to drill a further three appraisal wells this year, to fully delineate the field.

"The flow test seems to really validate that Eni is working with a substantial resource with excellent flow characteristics," says Andrew Jackson, market research and database manager, Quest Offshore.

Development

Eni says its fast-track development will take the form of a subsea tie-back, thanks to the production system simplicity enabled by Zohr's lean gas.

A multiphase development plan is likely when taking into consideration Eni's aggressive fast-tracked development plan, Jackson says.

"The quick realization of such a large project will be possible through cooperation with Petrojet, Enppi and Saipem contractors," announced Eni in a 21 February 2016 release.

Jackson says the field will be tied back 130km to the Temsah platform, operated by Petrobel (Belayim Petroleum), an IEOC and Egyptian General Petroleum joint venture. From the platform, the gas will be transported onshore, via existing export pipeline, to utilize existing facilities, as well as a gas treatment plant currently under construction.

According to Quest's projections, phase 1 of Zohr's field development program will initially begin with the start-up of 4-6 wells in Q4 2017, producing an estimated 700 MMscf/d to 1 Bscf/d by the end of 2017, and gradually ramp up, with the aim to produce 2.7 Bscf/d by 2020, Jackson says.

In order to meet Eni's 2020 production goals, phase 2 of the development would need to see additional wells come online.

"We believe that this phase 2, which is really more of a ramp up on the existing fast-track, rather than a distinct second phase, will encompass up to 18 further production wells and further step out of infield flowlines and umbilicals from the phase 1 drill center," Jackson says. "Currently, phase 2 models estimate an additional 30km of infield flowlines and subsea production umbilicals may be required, and make use of the existing 130km tieback infrastructure. We are likely to see phase 2 startup in 2H 2018."

If five wells are initially brought online in 2017, Quest estimates that Eni would need to bring online approximately 4-6 wells each year to reach the 2.7 Bscf/d target.

According to Wood Mackenzie, Eni plans a fast-track phased development with around 800 MMscf/d of production in the first phase, from late 2017, ramping up to 2.6 Bcf/d by 2019. But, the firm warns: "Meeting this ambitious timeline will be challenging."

Activities

By Q4 2015, no awards for subsea production equipment have been given, however, awards are projected to come in 1H 2016 to meet Eni's schedule for Q4 2017 production.

"There is a potential for the contracts for subsea production systems, as well as subsea production umbilical manufacturing and installation activities, for phase 1 and 2 to be awarded all together," Jackson says." **OE**

Proof of concept

This year, Allseas' Pioneering Spirit mega-vessel is finally due to set out into the seas to perform its first heavy lift. Elaine Maslin provides an update.

***Pioneering Spirit*'s twin-hull mounted lifting beams.**
Photos from Allseas

For as long as it's been a concept, Allseas' *Pioneering Spirit* super heavy lift vessel has been described as a mega-vessel.

But, it should also be called a megaproject, a term usually associated with massive field developments with multi-billion dollar investments, with all the connotations – complexities, delays, awe – that come with the moniker. For example, the latest plan for the vessel includes the addition of a 5000-tonne long reach crane.

The massive, twin-hull €2.4 billion (US$2.7 billion) single lift platform installation, removal and pipelay vessel measures some 382m-long and 124m-wide. It is designed to lift up to 48,000-tonne topsides and up to 25,000-tonne jackets, as well as doing deepwater pipelay work. The vessel, a concept few thought could be realized since its creation in 1987, was finally delivered to Allseas and transported to its berth at the Maasvlakte, near the mouth of Rotterdam harbor, for the installation of its 16-beam topsides lifting system, just over a year ago, after three years' construction in South Korea.


Edward Heerema

The *Pioneering Spirit* was due to start its working life in summer 2015, lifting the beleaguered 13,000-tonne, Talisman/Repsol Yme topsides offshore Norway. And then, start the first topside lift in Shell's four-platform Brent decommissioning program, the 23,000-tonne Brent Delta, in the UK sector of the North Sea this year. A platform installation was also on the cards as well as pipelay work on the shelved South Stream project, through the Black Sea. In addition, the firm is also scheduled to install the Johan Sverdrup topsides for Statoil offshore Norway in 2018-19.

But, by mid-year it was clear both the Yme and Brent Delta removals would be set back, as work installing the complex lifting gear was taking longer than expected. The platform installation job, on Husky Energy's White Rose offshore Newfoundland, Canada, was also taken off the near-term job list, after Husky is likely to set the project back to beyond 2020, as the operator adjusts to the current US$30/bbl oil price.

Edward Heerema, Allseas' founder and president is sanguine and eager to put this beast – possibly the most keenly awaited vessel in the industry – to the test.

In retrospect, gradually it was clear the mega-vessel would not make its planned operational timetable, he says. They simply underestimated the amount of work that would be involved in installing, commissioning and testing the 16 lifting beams that sit on the vessel's bows, not least because of some 2500 km of electric cabling, terminations, hydraulics, etc., that power this hugely, interconnected complex system. The design means each of the beams can move in three directions independent of the others, in combination with the ship's ballasting systems, to compensate for motions as a structure is lifted or lowered. It's far from simple and comes complete with redundancy.

In-Depth

Quick stats

See Infield at OTC Booth #4676

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	2013	2014	2015	2016
Shallow (<500m)	72	72	53	3
Deep (500-1500m)	19	29	15	2
Ultradeep (>1500m)	34	12	13	2
Total	125	113	81	7
Start of 2016	127	114	72	-
date comparison	-2	-1	9	7

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

Reserves in the Golden Triangle

by water depth 2015-19

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Brazil			
Shallow	9	30.75	333.28
Deep	11	1204.00	1595.00
Ultradeep	41	11,598.00	12,833.00
United States			
Shallow	11	66.15	144.00
Deep	20	982.27	1058.48
Ultradeep	23	3157.50	3020.00
West Africa			
Shallow	124	4063.45	16,851.22
Deep	37	5407.50	6350.00
Ultradeep	17	2150.00	2610.00
Total	284	28,628.87	44,461.70
(last month)	[illegible]	(28,876.97)	(44,541.70)

Greenfield reserves

2015-19

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Shallow	942	35,201.08	482,880.62
(last month)	(982)	37,816.14)	(502,542.59)
Deep	143	9471.93	118,532.62
(last month)	(144)	(9676.93)	(118,522.62)
Ultradeep	88	17,210.90	44,560.00
(last month)	(90)	(17,367.90)	(44,700.00)
Total	1,173	61,883.91	645,973.24

Pipelines

(operational and 2015 onwards)

	(km)	(last month)
<8in.		
Operational/installed	42,095	(42,302)
Planned/possible	24,250	(24,495)
	66,345	(66,797)
8-16in.		
Operational/installed	83,458	(83,639)
Planned/possible	48,839	(49,549)
	132,297	(133,188)
>16in.		
Operational/installed	95,106	(94,172)
Planned/possible	44,996	(45,081)
	140,102	(139,253)

Production systems worldwide

(operational and 2015 onwards)

Floaters		(last month)
Operational	272	(273)
Construction/Conversion	52	(51)
Planned/possible	309	(313)
	633	(637)
Fixed platforms		
Operational	9260	(9291)
Construction/Conversion	97	(85)
Planned/possible	1377	(1411)
	10,734	(10,787)
Subsea wells		
Operational	4872	(4880)
Develop	421	(424)
Planned/possible	6396	(6451)
	11,689	(11,755)

Global offshore reserves (mmboe) onstream by water depth

	2014	2015	2016	2017	2018	2019	2020
Shallow	14,528.97	20,949.72	39,811.33	16,372.41	15,986.26	22,801.80	25,454.94
(last month)	(14,528.22)	(20,973.15)	(39,799.62)	(16,690.08)	(16,521.25)	(23,774.11)	(29,719.19)
Deep	4469.26	1085.18	5491.04	2221.55	4423.30	6210.09	12,063.71
(last month)	(4469.26)	(1085.18)	(5491.04)	(2221.55)	(4592.11)	(6139.51)	(12,168.71)
Ultradeep	2342.81	1928.92	3173.17	3231.63	4893.14	5880.73	7888.56
(last month)	(2342.81)	(2037.21)	(3067.88)	(3228.63)	(4893.14)	(6195.41)	(7953.85)
Total	21,341.04	23,963.82	48,475.54	21,825.59	25,302.70	34,892.62	45,407.21

09 March 2016

***Pioneering Spirit* with *the Lorelay*, one of Allseas' first vessels.**

Allseas has also worked through a number of component level design flaws, such as a gear sprocket, used to move the beams forwards and back, which had to be removed and a new stronger sprocket designed.

"We did not plan the commissioning of the beams sufficiently accurately," Heerema says. "If you take all the cables you have to pull, the terminations, cylinders, valves, control systems, etc., multiplied by 16 beams... it gradually became clear that 2015 couldn't be achieved."

But, he says: "We have had no fundamental problems. We are totally confident in the system, we are just going through the work and it is just slow. There were a few design flaws but none were insurmountable. There are so many control systems, everything has a backup, redundancy." The delay has also given the yards preparing to receive this facilities more time to get ready, Heerema says.

To date, 12 of the 16 beams have been installed and Allseas is focused on completing these, ready for the Yme job, for which only 12 are needed.

The system that allows for the cooperation of all the beams together was tested a long time ago, Heerema says. Each beam's ability to move up and down, sideways and in and out has also been tested. The next step is testing them working in a real operation, which will be via a test lift in Dutch waters using a 5500-tonne dummy topsides, built for Allseas, sitting on the now decommissioned North West Hutton modular support frame, installed on suction piles.

Scheduled for some time in May, this will be a key – and for Edward Heerema exciting – test of the system, as it will verify the cooperation of the beams working together. "The point isn't how much the system lifts," he says. "It is how it lifts." Just as cranes have to be tested to 10% above their capacity, each beam will also be tested to 10% over its 3000-tonne capacity, by hanging a cargo barge from it.

The huge unit's massive ballasting capabilities are already being tested as work is carried out. *Pioneering Spirit* is currently ballasted low enough to allow work on the lifting beams from the purpose-built *Iron Lady* barge, positioned between the twin hull slot. The ballast capacity ranges from a draft of 10m to 27m. This involves pumping 37,000cu m of water per hour.

Once testing is complete, the vessel will sail out to Yme, often called "why me," after the facility had to be scrapped

The test platform under construction.

before going into production due to issues with its substructure. Its topsides will be lifted and then taken to the Lutelandet yard in Norway, transferred by the *Iron Lady*, to be decommissioned by Veolia. Allseas' work will then focus on adding the final four beams, including two that have been extended 5m, ready for a targeted May 2017 Brent Delta topsides removal, with disposal, again via the *Iron Lady*, to Able's yard in northeast England.

The vessel's 170m long stinger, completing the 2000-tonne tension capacity S-Lay pipelay package, is ready to be installed when it's required, and sitting in storage in Vlissingen, Netherlands. Meanwhile, the jacket lift system, a tilting system, which has been fully designed with some equipment and steel purchased, is still on hold – it's not currently required until 2019, for the one Brent steel jacket (the rest are concrete gravity based structures).

However, while *Pioneering Spirit* remains without its jacket lift system, Allseas is planning to add a 5000-tonne long reach crane to the rear of the vessel, where the jacket lift system is due to also go later on. Allseas hasn't been afraid of making changes to the *Pioneering Spirit*, including, mid-build in 2013, deciding to increase the slot size for wider platforms. The latest addition, as well as numerous other optimizations and tweaks since construction started back in 2010, is the result of numerous feasibility studies for clients, Heerema says.

"We have been going around telling the industry for 25 years about this and initially clients said it's nice, but didn't take it seriously," he says. "Since construction started in 2010, and it's for real, we are getting orders from clients who let us do paid studies of exactly how we lift their platforms. Then, we had to go into every detail of how to do it. Some things had to be more optimized or done in a smarter way. That's given us a lot of additional knowledge.

"As an example, we are going to add a 5000-tonne crane on

Rig stats

Worldwide

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	104	77	27	74%
Jackup	399	267	132	66%
Semisub	144	97	47	67%
Tenders	31	22	9	70%
Total	678	463	215	68%

North America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	35	30	5	85%
Jackup	23	6	17	26%
Semisub	16	11	5	68%
Tenders	N/A	N/A	N/A	N/A
Total	74	47	27	63%

Asia Pacific

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	12	4	8	33%
Jackup	118	69	49	58%
Semisub	33	16	17	48%
Tenders	21	15	6	71%
Total	184	104	80	56%

Latin America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	29	22	7	75%
Jackup	54	38	16	70%
Semisub	31	27	4	87%
Tenders	2	2	0	100%
Total	116	89	27	76%

Northwest European Continental Shelf

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	N/A	N/A	N/A	N/A
Jackup	48	42	6	87%
Semisub	43	31	12	72%
Tenders	N/A	N/A	N/A	N/A
Total	91	73	18	80%

Middle East & Caspian Sea

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	0	1	0%
Jackup	111	88	23	79%
Semisub	4	3	1	75%
Tenders	N/A	N/A	N/A	N/A
Total	116	91	25	78%

Sub-Saharan Africa

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	22	18	4	81%
Jackup	22	14	8	63%
Semisub	9	7	2	77%
Tenders	8	5	3	62%
Total	61	44	17	72%

Eastern Europe

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	N/A	N/A	N/A	N/A
Jackup	2	1	1	50%
Semisub	1	0	1	0%
Tenders	N/A	N/A	N/A	N/A
Total	3	1	2	33%

Source: InfieldRigs 11 March 2016

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

the ship as well as the jacket lift system. The jacket lift system is wonderful for jacket lifting, but it is not quick or versatile. If we want to do quick small lifts, there is pressure to have a fast traditional crane with a long boom." More details are to be decided.

The *Pioneering Spirit*, developed over three decades, enters a market in one of its toughest down cycles, with few expecting a return to a boom any time soon. Allseas, which also operates pipe layers including the *Solitaire* and *Audacia*, and other vessels, is holding its own, Heerema says, even if that means waiting on investing in the *Pioneering Spirit's* jacket lifting system.

The current market conditions also means work on *Amazing Grace*, a new heavy lifter which would dwarf *Pioneering Spirit* with a 72,000-tonne topside lifting capacity (*OE: August 2014*), has slowed. "We are still equally enthusiastic, but the speed has been reduced and delivery date shifted forward two plus years from what we had been saying before," which was 2021, Heerema says.

"My feeling is that the business will stay depressed this year and next, and 2018 will start to pick up for a few reasons," Heerema says. "New wells will have to be drilled because insufficient work is being done at the moment, and fields will deplete. Also, the oil producing nations will have to come together to talk to Saudi Arabia to limit production of oil, so the price goes up. I guess one day or another this will take place. "This time it is very politically driven," he adds, "with antagonism between several countries, so it is difficult to predict. The situation makes our cash flow low, but there is work which covers all our dues. But it is not enough to make large new investments."

As a decommissioning vessel, the hastening of field cessations caused by the low crude prices, should, in theory, result in more work for the *Pioneering Spirit*. Yet, operators are holding back, wanting to save their cash, Heerema says.

"They are doing preparations for decommissioning but not spending money on it because they need the cash," he says. "There is no urge for them to do it," despite the costs of keeping a platform idle and indeed the current lower rates of drilling rigs and subsea construction vessels, which could be used for plugging and abandonment campaigns or removing subsea infrastructure.

The time will come when they have to bite the bullet and one of the tools that could help them looks finally set to prove itself this year. **OE**

OE has been following the progress of the *Pioneering Spirit*, for many years named the *Pieter Schelte*, after Edward Heerema's father. Last year, we also got a tour of the gargantuan vessel.
Gallery: http://ow.ly/ZJyOT

Let's get

If topsides asset integrity management is a bane, imagine looking after subsea assets. Elaine Maslin reports on the challenges associated with keeping up with both older equipment and newer, more complex equipment.

A subsea field layout. Image from Aker Solutions.

Subsea asset integrity was a popular topic at February's Subsea Expo, from operator-contractor collaboration on predictive maintenance to university research into sensors and modeling.

Subsea asset integrity is a key topic for the North Sea, as it moves into what industry body Oil & Gas UK recently called a "super mature" era. Asset integrity has been under the spotlight of the UK's Health & Safety Executive (HSE) and Subsea UK has a Subsea Asset Stewardship workgroup, run in collaboration with the Oil and Gas Authority, the UK industry's new regulator, and led by Aker Solutions' Matt Corbin, head of subsea product management.

"We are one of the most mature basins in the world," said Gordon Drummond, project director at the National Subsea Research Initiative (NSRI), who led Subsea Expo sessions with an asset integrity focus. "Because, we have such extensive architecture in place, there are challenges facing us. There is a need for new inspection technologies, especially for flexibles and composites."

Internal corrosion also remains a number one threat, he said. "Many companies make money looking from the outside in, but this is flawed," Drummond said. "Pigging might be difficult [in some circumstances]. [For] life extension projects, how do you justify reliability and performance of subsea architecture once it is in place?

"There is also a need for data analytics and condition monitoring. Even more so with the advent of reciprocating and rotating equipment in the [subsea] field. We maybe have struggled with static plant [subsea]. When it comes to the active plant, it's a real challenge."

predictable

Yet, Drummond said, data monitoring, trending and analysis haven't seemed to really take off in field. Indeed, the HSE's KP4 report on aging and life extension (*OE*: September 2014) said data trending was not being used enough by the industry. It might finally be time to redress that situation, both to correctly assess the state of existing infrastructure, but also as the industry continues its move towards the total subsea factory, as Statoil calls it.

In control

Some are trying to do just that. Aker Solutions and Shell presented work, at Subsea Expo, that they are doing around subsea controls integrity management, or predictive services. The two firms started working together about 18 months ago after Aker asked operators what they wanted in terms of subsea controls system integrity management, shortly after the HSE's KP4 report highlighted subsea controls as an area requiring focus, due to how it is linked to safety and environmental systems on the seabed.

"We know about the system and have information – that people don't use – about how it works, said Roy Stenhouse, subsea integrity business manager, Aker Solutions, a subsea control system supplier. "The control system carries a lot of capability that can help to manage the integrity of the systems it is connected to. Through the data in the control system we can infer information about the subsea tree, such as degradation in a spring in an actuator."

Having the data, or information, about the status of the system, enables operators to develop better ways to maintain systems. However, it's not quite as simple as data mining. An understanding of the operating envelope of the system is needed, and in some cases it is not fully understood, said co-presenter Tom Moore, principal subsea engineer, Shell, at Subsea Expo.

Giving Aker Solutions access to data from the subsea control systems in a particular field meant Aker was able to identify faults and then predict when these might happen in the future. In one instance, the firm was able to show that one of Shell's subsea control systems was not working to its optimum, because it was trying to communicate with a production well that hadn't actually been drilled, wasting its energy, Stenhouse said. By telling it to no longer seek information from the non-existent well – which involves looking for information from 50-60 non-existent data points – the system was able to operate more efficiently. Shell also learned it had inbuilt capacity to connect up another well with little work, if it needed to.

In addition to enabling a more preventive operating regime, this system allows for life extension work, due to having the understanding of the status of the facility and also the ability to predict the condition of the system. "How can we extend the life [of equipment of facilities] if we don't know how they have been performing and the failure mechanisms? It is understanding real root causes, and how we turn the data we have into information we can use is really important," Stenhouse said.

Knowing more about the status of equipment and sharing that information with the equipment vendor also means that vendor can improve the product, Stenhouse highlighted. What's more, he said, by knowing the condition of the system you're more likely to be able to sell it on as spares when it's no longer required.

The offshore industry needs to catch up, Stenhouse said, not

V-integration

Technology firms, such as Viper Subsea, are providing some of the tools needed to help monitor subsea infrastructure. The firm, part owned by Oceaneering, which already launched V-LIM, a topside monitor of insulation resistance and electrical integrity of subsea electrical umbilicals, has now also created V-SLIM, a subsea electronics node that measures a range of electrical integrity data and transmits it back to the surface.

Together, V-LIM and V-SLIM will form V-IR to offer an integrated system that provides a complete subsea distribution system electrical integrity map. V-SLIM is rated to 3000m water depth and the complete system started a three-month shallow-water trial including use of a 2km-long subsea cable early this year. ■

Viper Subsea's V-IR concept. Image from Viper Subsea.

GE Oil & Gas' unified operations dashboard. Photo from GE Oil & Gas.

least when it comes to achieving the subsea factory, which, in order to be successful, needs this level of ongoing predictive maintenance. "A lot of other industries have moved into much more predictive models, aerospace and automotive, for example, and they are in a much better position. We should move away from being reactive and be more prepared."

As a result of the KP4 report and its work with Shell in this area, Aker Solution's has now also put forward a new guidance document to the UK's Energy Institute, and which, once approved, will be available to the entire industry.

Fundamental research

Meanwhile, universities are looking at some more fundamental research. Srinivas Sriramula is working at the Centre for Safety and Reliability Engineering at the University of Aberdeen covering two research areas: developing reliable modeling techniques for condition monitoring and applying the information or data produced to understand the reliability of actual systems.

Laser light

In a short period of time, subsea laser scanning has sprung up as a new viable option for subsea imaging and measurement. Elaine Maslin takes a look.

A number of firms appeared, around the late 2000s, offering subsea laser scanning technologies, already used topside, including Cathx *(OE:* August 2015*)* and 2G Robotics.

The attraction of laser scanning is that it can offer greater detail – mm-level detail – point clouds, from which detailed measurements can be taken, of subsea structures or equipment, and assessment of asset integrity issues, such as corrosion or other damage.

The technology works by using the "time of flight" principle or triangulation-scanning techniques. The results can be turned into images in real time, on dynamic surveys, and exported to CAD packages.

Because it's using optical light, while it struggles to see through silt, for example, it is more accurate than sonar, by a level of magnitude, as sound waves attenuate in the water.

Jason Gillham, founder and CEO of Canadian measurement solutions firm 2G Robotics, started to look into subsea laser technologies in 2008, when a project they were working on, relating to requirements for a near-range, high-precision localization and mapping sensor for underwater robotics, needed this type of technology.

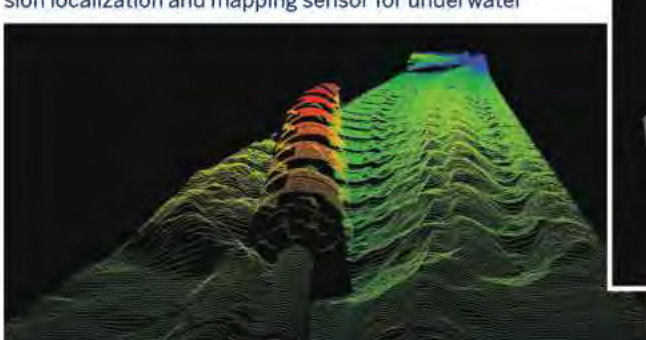
"There was nothing commercially available so we started developing our own," he says. "Acoustics is the most prevalent and most common technology used for mapping. But it didn't have the level of detail we were looking for. By 2010, we had developed our own technology."

To date the firm's ULS-500 laser has performed more than 2500km of pipeline and seabed scanning from AUVs, travelling at 4+ knots, and survey and work class ROVs worldwide. One was also used to scan the hull of the ill-fated Italian cruise ship, *Costa Concordia*, in 2013.

2G Robotics' system works by sending a laser line to the target surface. An optical sensor (which moves to collect 3D data) then captures the return signals, which are then calculated into a 3D point cloud. 2G has developed the system so this can be carried out from a moving object (ROV/AUV etc.) with the imaging processed real-time. This has proved an interesting prospect for firms wishing to perform pipeline scans. Post processing can also be performed for further assessment work.

Pipeline damage and free span assessment are two of the more popular areas for use of the tool, he says, alongside anode assessment. Subsea metrology is also a key area, where an operator or contractor wants increased dimension certainty. "With the current downturn, there's a real benefit from the efficiency stand point, from dynamic surveys," he says, "to quickly capture details you cannot get traditionally."

But there's still a place for sonar, Gillham adds. "Laser scanners aren't for finding something new [an object for example], it's great for measuring something you have already found." Sonar is the tool for finding the object in the first place. ▪



Buoyancy collar. Images from 2G Robotics.

A wellhead connector, shown from data a subsea laser scan.

"On the reliability side, we are looking at tools to improve reliability of riser systems," Sriramula said at Subsea Expo. This includes sensor systems, new models, and establishing protocols for exchange of information. "The next area is a model for corrosion using probabilistic modeling. If we have data looking at wall loss, we can look at inspection frequencies and how to manage inspection schemes," for example, he said. The university is also looking at aging infrastructure, such as fixed jackets that are over 25 years old, which means having to know uncertainties, loads, degradation and damage mechanisms – i.e., they need the data.

This is the way to go, agreed Matthew Franchek, a professor and director of the subsea engineering program at the University of Houston, who presented on the Institute of Subsea Operational Integrity Management. But, all of this work, real-time monitoring, making sense of data, will require a new type of worker, he said. "Real-time monitoring is going to be very important in coming years," Franchek told Subea Expo. "It means better monitoring of equipment, not tests every two weeks – you can change the frequency of testing." But, he said, the work force you need in the industry to do this work is going to be different.

Cradle to grave

Federico Noera, senior vice president subsea engineering at GE Oil & Gas, told ***OE***: "The real opportunity is making sure the right people with the right data are available at the right time."

But, for Noera, it's not just about asset integrity. Building a model of the asset, from design through to decommissioning, including performance, structural, environmental data, etc., would improve understanding of the asset, result in optimized field configurations and equipment, aid standardization and reduce costs/add value. He calls it a "digital thread." "That's where GE is playing a role with Predix," a cloud based application built for big data and analytics for industry, including oil and gas, he says.

It is already happening in other industries, from aerospace to offshore wind, Noera says, echoing Stenhouse. There, problems are identified before they happen so they can be fixed proactively. "The good news is we can learn from other industries, power and automation, for example, and wind. Its evolutionary steps." **OE**

FURTHER **READING**

Protecting assets through better data trending
www.oedigital.com/component/k2/item/6665-protecting-assets-through-better-data-trending

Expro is collecting real-time data to support production optimization from brownfield wells using a non-intrusive wellhead surveillance technology. www.oedigital.com/component/k2/item/11942-non-intrusive-surveillance

Show me the data

Two components are failing ten times more than they should in the subsea space, says Sture Angelsen, business development manager for certification and risk advisory firm DNV GL; mooring lines and flexible risers and umbilicals, particularly flexible lines under higher pressure.


Sture Angelsen

To help understand the issues around both, DNV GL is considering something it has being using in the maritime shipping segment called a digital twin, a model that measures the movement of the rig or semisubmersible, etc., plus all manner of other data, including the weather and operating conditions (pressure, temperature, etc.), then models the stress and strain in the equipment.

"That's one way to see the condition prior to a failure and then look for any sign of that in the future," Angelsen says.

DNV GL has also looked into wellhead fatigue analysis, resulting in recommended practice 0142. Part of the work here was about increasing the amount of monitoring, to provide data which could reduce uncertainty in the modeling. "This could enable better timing of recertification," Angelsen says, as well as reduce the number of failures, which appeared to be higher once a system had been removed and opened up for recertification.

The latest subsea processing technologies are coming with monitoring technologies included, including Statoil's Asgard subsea compression station, offshore Norway. But, Angelsen asks, can we monitor corrosion inside the Xmas tree? "There are some corrosion probes, but the technology isn't that widely used," he says.

It's even harder for subsea trees, etc., installed 20+ years ago that don't have today's monitoring systems and are increasingly suffering failures. With high retrieval costs, this could mean loss of safety barriers and or early shut-in of wells. System obsolescence is also an issue, Angelsen says.

Ultimately, monitoring, data analysis and modeling go hand in hand. Monitoring is fine, but you need to make sure what you're monitoring has value and that the data is accurate, Angelsen says. Then, you need staff with operational understanding who can interpret the data and if you're using machine learning failures need to be fed into the system. "Data in itself isn't necessarily the Holy Grail," he says. "Machine learning only works if you can feed a failure in to it."

It's also important to focus on implementation, he says. In a trial looking at reliability, condition monitoring equipment was installed on a floating production unit. Some years later, the operating staff were asked if they had used the information. They hadn't, for a number of reasons, including trust, bad information, the sensors not being properly installed, etc. •

– Elaine Maslin

Cracking the code

Scot McNeill and Kenneth Bhalla, of Stress Engineering Services, show how measured data coupled with engineering analysis can increase asset utilization.

To date, the oil and gas industry has struggled to employ structural monitoring data in meaningful way. The missing link has been the ability to extract and interpret useful information from the data and apply it in a manner that has a significant impact on productivity and utilization.

To design and install successful monitoring systems, engineers with knowledge and experience in signal processing and data acquisition, as well as the mechanics of offshore systems, are needed throughout the entire program.

Some approaches to incorporating measured data into an engineering assessment are highlighted by using an S-N based fatigue analysis as an example. In this type of analysis, fatigue damage is determined using an empirical stress (S) vs. number of cycles (N) relationship. A typical fatigue analysis consists of modeled environmental loads, the structural model that takes in applied loads and outputs stresses, and the fatigue assessment, which computes fatigue damage from structural stresses.

The process for S-N fatigue of offshore structures is:

1. Develop environmental loads from limited offshore measured data, using statistical models;

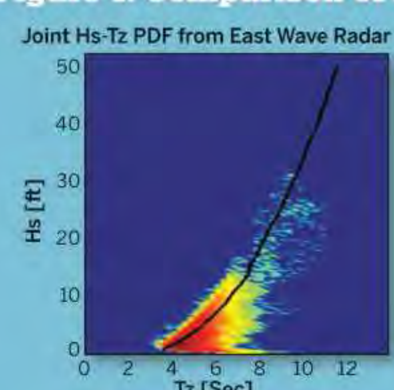
2. Apply the environmental loads to a structural model to determine stresses;

3. Perform fatigue analysis at critical locations using the calculated stress.

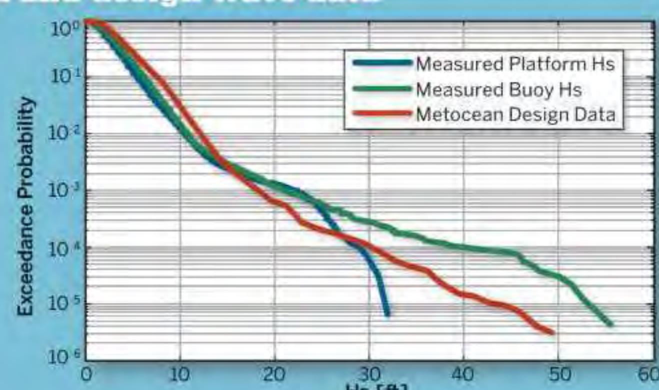
Uncertainty in each of the above is typically dealt with in a conservative manner by engineers, leading to uncertainty stack-up in the fatigue life estimate. The uncertainty is magnified even further by applying large factors of safety (e.g. 10) to the fatigue life estimate, prior to comparing to allowable values. In this way, uncertainty in the environmental load, for example, propagates in a multiplicative manner to the factored fatigue life estimate.

Uncertainty can be reduced in a fatigue assessment by

Figure 1: Comparison of measured and design wave data



Joint Hs-Tz distribution.



Hs exeedance probability. Images from Stress Engineering Services.

introducing measured data. The data may take the form of environmental loads (waves, wind, current), structural response (motions, vibrations, stresses). Depending on the type of measurements made, the data can be incorporated in a fatigue assessment in different ways, representing different levels of assessment:

1. Driven by indirect environmental data – Apply measured environmental data to structural models to determine stresses.
2. Driven by indirect motion data – Apply measured structural vibration/motion data to structural transfer functions to determine stresses.
3. Direct – Use measured stress/strain data directly in S-N fatigue assessment.

Modeling requirements are highest for level 1 and decrease going down the list, while data requirements (accuracy, completeness and relevance) are highest for level 3. If a level 2 assessment is performed, the uncertainty associated with environmental loads is eliminated, as well as some of the uncertainty associated with the structural model (the portion associated with calculating motions from applied loads), for example. The approach is illustrated in the following examples.

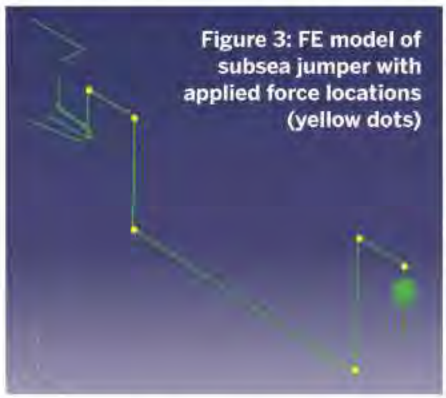


Figure 3: FE model of subsea jumper with applied force locations (yellow dots)

TLP tendon fatigue demand

With continuous metocean and floating production system (FPS) response monitoring the design environment and structural response can be assessed. To maximize the impact of the data measurement program, knowledge of the environment and FPS response with proper data cleansing and analysis techniques need to be integrated. In this example, measured waves and tendon tensions at a tension leg platform (TLP) in the Gulf of Mexico (GOM) were compared with design data to determine the level of conservatism in design. Results were fed into a continued service assessment.

The wave time series data and tendon tensions on the TLP were measured over a five-year period, 2006-2011. Figure 1 (left) compares the design wave and measured wave data. In this case, the design wave is very consistent with the measured data at the site. Figure 1 (right) compares measured significant wave height exceedance probability (from five years of FPS data and 14 years of wave buoy data) to metocean design data. Though the wave size in large, low-probability seastates is slightly under predicted in the design data, due to several large hurricanes in the GOM during that period of time, the high probability seastates that are the primary contributors to fatigue are conservative (larger at a given probability level) in the design data.

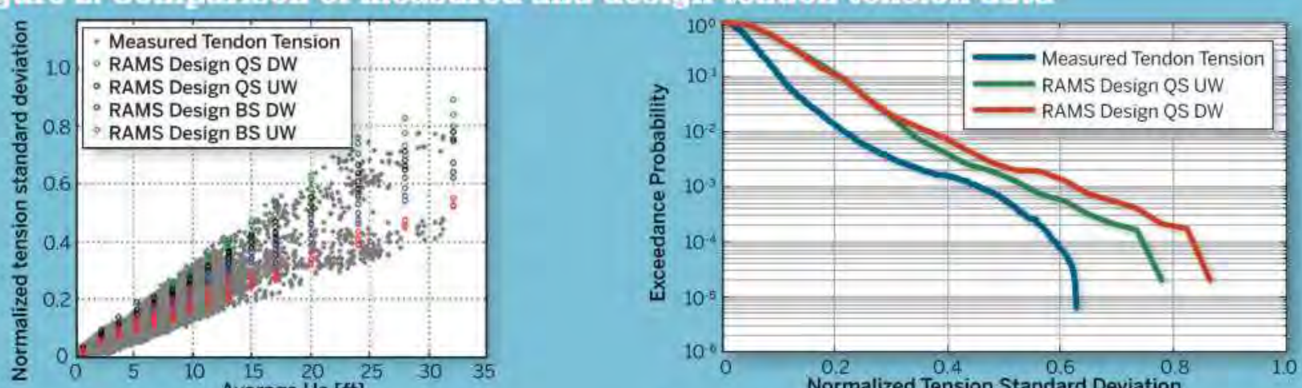
Figure 2 (left) shows the relationship of normalized tendon tension standard deviation to significant wave height over the five-year period, along with analytical RAMS coupled analysis software [1] predictions from the design scatter diagram. It can be seen that the analytical predictions show the same relationship between tendon dynamic response and wave height as the measured data. The scatter in the relationship is primarily due to the wave heading, quartering seas or beam seas, compared to the tendon location, up or down wave. Figure 2 (right) shows (normalized) measured TLP tendon tension standard deviation exceedance probability, along with tensions resulting from the design scatter diagram. In this case, it is clear that the dynamic tendon tension values used in design are conservative compared to the measured values. This is not particularly surprising, considering that conservative assumptions are often made in design. Such a result paves the way for life extension efforts.

Many operators have realized the importance of continuously monitoring metocean conditions and the FPS response to support design verification efforts, evaluate future expansion capacity, and extend the service life of the asset. The value of data from existing monitoring systems can be fully realized when the measurements are integrated into engineering analysis.

Subsea jumper vibration

Flow induced vibration (FIV) of piping systems is generated by flow restrictions such as elbows, tees and partially closed valves. Vibrations can be severe enough to cause restrictions on production rates. Predictive analysis of subsea piping is limited, due to lack of empirical data for common geometries and flow conditions. An alternative analysis approach, combining in-field

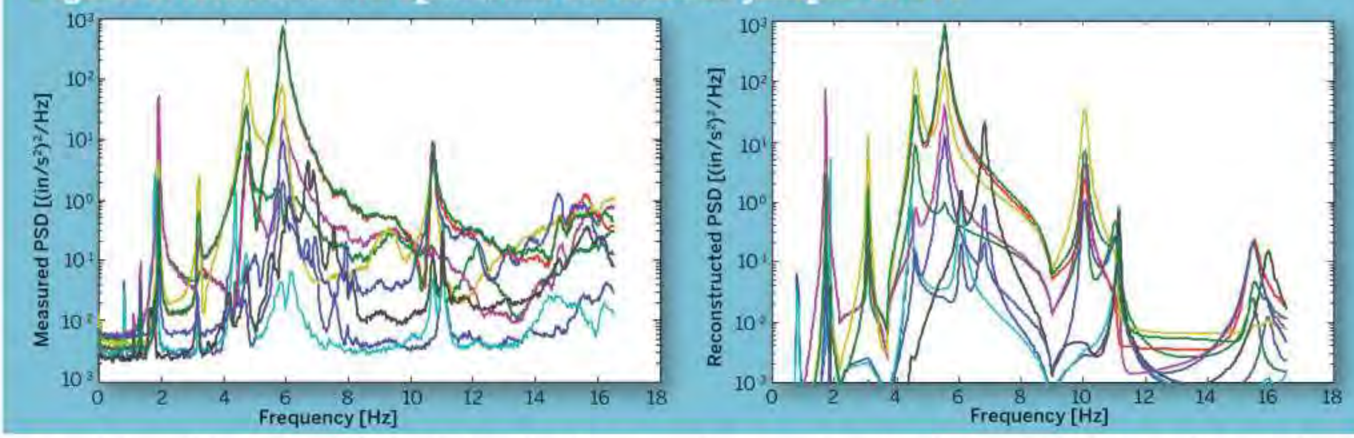
Figure 2: Comparison of measured and design tendon tension data



Hs-tension scatter plot.

Tension standard deviation exeedance probability.

Figure 4: Acceleration spectrum for subsea jumper in FIV



measured data and finite element (FE) models can be taken to assess stress and fatigue damage. To obtain accurate results, understanding the nature of random response and applying appropriate data analysis methods are imperative.

Many of the analytical tools and techniques developed for random vibration induced fatigue assume that the dynamic stresses are stationary, narrow-banded and normally distributed. These assumptions must be validated before application of such methods. Measured acceleration power spectral density (PSD) data from a well jumper at a subsea installation is shown in Figure 4 (left). Three vertical, three horizontal in-plane and three horizontal out-of-plane channels were recorded. The data revealed that the dominant direction of vibration was vertical (green, red and yellow lines). Though many modes were excited, only two modes contributed significantly to vertical acceleration (4.5 Hz and 6 Hz modes). Computation of the statistics, including bandwidth parameter, skewness and kurtosis confirmed that the vibration is classified as narrow banded and normally distributed.

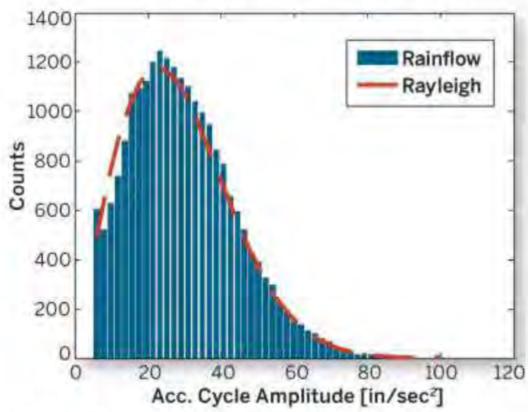


Figure 5: Measured (rainflow) acceleration cycles with theoretical Rayleigh distribution.

Under the assumptions, the peaks or cycles in the vibration time history should follow the Rayleigh distribution. This is confirmed by comparing the measured acceleration cycles to the theoretical Rayleigh distribution in Figure 5.

After verifying the nature of the random vibration and building the FE model (Figure 3), the forcing function was determined such that the predicted acceleration PSD matches the measured acceleration PSD for all peaks (vibration modes) and all sensors. In the process, the true natural frequencies and mode shapes are identified from the measured data, using operational modal analysis techniques.

The FE model is then refined such that the FE natural frequencies and mode shapes are in close agreement with the measured values. The predicted acceleration PSD, from FE analysis, is shown in Figure 4 (right). The resulting analytical stress PSD is then re-examined to ensure that it is narrow-banded before applying the classical spectral fatigue damage calculations. By merging the measured subsea vibration data into the fatigue assessment, FIV effects on subsea piping can be accurately assessed. More information on the method and applications can be found in the paper co-authored by BP [2], including discussion on handling nonstationary and non-Gaussian vibration.

Conclusion

The industry has started to take advantage of measured data for analysis of offshore structures. The case for incorporating measured data will strengthen over time, as the benefits of doing so are continually demonstrated. Enterprising companies will be quick to embrace the heightened safety and efficiencies gained by utilizing measured data, rather than waiting for competitive pressures or regulatory decree to provide the impetus. **OE**

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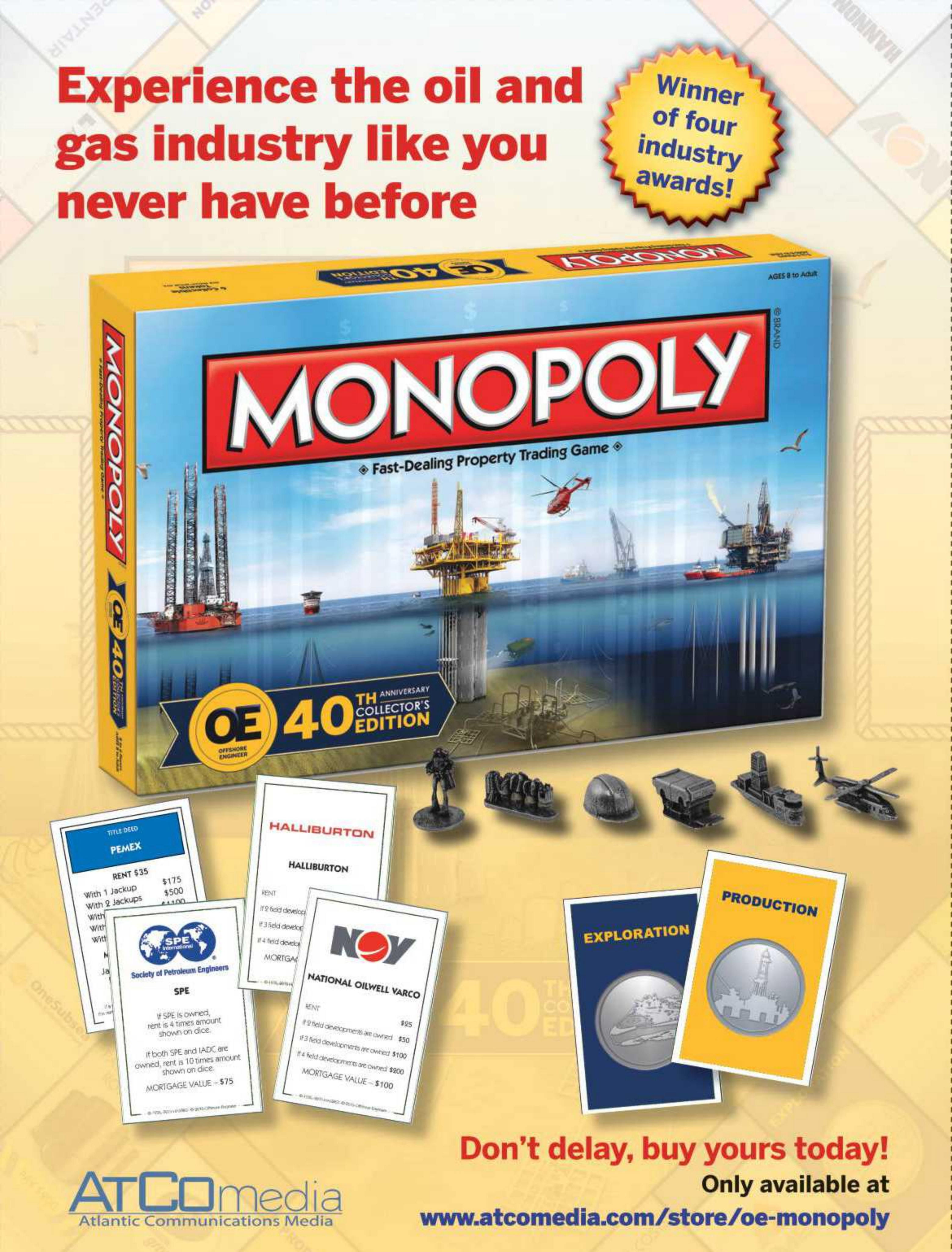
***Scot McNeill** is a principal at Stress Engineering Services. He specializes in dynamics, vibrations, signal processing, dynamics and random processes and has been working on structural monitoring systems. McNeill holds BS and MS degrees in engineering mechanics from the University of Wisconsin at Madison and a PhD in mechanical engineering from the University of Houston.*



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Life goes on

Divers installing the conductor guide frame. Photos from Boskalis.

Elaine Maslin takes a look at the Dan Bravo complex offshore Denmark, which, at 44 years old, has a new lease on life thanks to some serious steel reinforcement.

When the Dan Bravo Complex came on stream in 1972, the facility – Denmark's first producing offshore oil field – was expected to produce for only 25 years. Forty-four years later, it is still going.

Following a multi-year subsea structural reinforcement campaign, involving the installation of 136 tonnes of new steel, over more than 200 diving days, the life complex's wellhead platform, Dan A, has had its life expectancy extended to a total 70 years.

The DSV *Constructor* working on site.

The structural overhaul of the Dan A platform's jacket, undertaken by Dutch offshore contractor Boskalis was akin to a 3D, subsea puzzle, involving a large subsea photogrammetry campaign, site clean-up, preparation work and the installation of temporary cranes on vertical platform members to help maneuver the new steel into place at 10-41m water depth – all while the platform was in production.

Boskalis, which was contracted for the installation, as well as fabrication, procurement, equipment testing and structural examinations, was also tasked with installing a new boat landing ladder on Dan B, and removing obsolete equipment from the Dan A and B platforms as part of the Dan Bravo Rationalization (DABRAT) program.

"This had not been done before – fortifying underwater structures in this way on this scale," says Bert Kamsteeg, contract manager, Maersk DABRAT, Boskalis. Had nothing been done, the platform's life would have been shortened, says Jakob Knudsen, DABRAT project manager, Maersk Oil.

The Dan field was discovered in 1971, about 125mi west of Esbjerg, Denmark. Dan A and C are wellhead platforms and Dan B is the process platform of the Dan Bravo Complex. The Dan Bravo complex

Divers working on a clamp.

had in fact been ordered from the US for the Kraka field, but it was installed on Dan when Dan was found to be larger.

Boskalis' main scope was to reinforce Dan A's jacket, using 10 clamps, called K-node clamps, and to install a new conductor guide level – both of which would require maneuvering 15 pieces of <4-5-tonne sections of fabricated steel through slots in the platform's structure, guided by divers.

First, the existing structure was assessed using existing inspection data and new data acquired during July-September 2013, through a photogrammetry exercise – Boskalis believes the largest of its type – with some 20,000 high-definition, overlapping photographs taken. These were then converted, using computer software, into a geometric 3D model, from which the conductor level guide could be designed.

Inspection, surface cleaning and preparation followed, including underwater grit-blasting and measuring member wall thickness, prior to installation work. Steel fabrication started in winter 2013-14 in Denmark, alongside planning work.

In order to perform the offshore operations, including transferring the new steel from the ship to the position it needed to be in, beneath the water, larger capacity cranes needed to be installed on the Dan A platform.

"The platform had a small 2.3-tonne capacity crane, but the steel weighed in subsea conditions in some cases 4-5-tonnes," Kamsteeg says. "One of the solutions, and actually the only sensible solution, was to build up two temporary cranes, 12m above sea level, on to the vertical members of the platform, something which has not been done before."

First, a clamp with a pedestal was installed on to the vertical member, and a conventional knuckle boom crane was built on to it. Two cranes Boskalis already had on its vessels were used and modified so they could be remote controlled from the dive support vessel (DSV).

Installing the temporary cranes meant steel could be lowered from one of the two DSVs being used, then connected to the temporary platform crane's hoist wire, before being disconnected from the DSV's hook by divers and maneuvered into place, assisted by divers and rope access personnel at the platform.

The K-clamps were created to reinforce areas of the jacket structure where a horizontal member is intersected by cross members. Each clamp comprised of two sections to create a steel-to-steel friction clamp, which is held fast using steel bolts, weighing 10 kilos a piece. To install the 10 clamps, some 2000 bolts were used, each having to be handled and set by the divers using specially-built hydraulic tensioning gear and a specially designed tool basket was used for handling the bolts and nuts subsea.

Next, the new conductor guide level, measuring 3m-wide and 8m-long, had to be lowered, tilted, and slotted through the platform members before being brought back on to the horizontal and lifted into position, between the six existing conductors, then bolted in place using further sections of steel.

With the new conductor guide level installed, the old levels were removed. As part of its scope, Boskalis also replaced a number of anode bracelets, which also involved significant inspection, cleaning and preparation work, including removing marine growth, grit-blasting, and taking measurements.

The final part of the 2014 offshore campaign was removing the temporary cranes before the winter season.

"The impact on Dan A, achieving a lifetime extension to 70 years in total, is quite an achievement," Knudsen says. "The planning and preparation was key. We did as much as we could onshore. Once you go offshore there's a high cost involved, every minute is a lot of dollars. We have had more than 200 diving days over the last two years." OE

FlatFish during shallow water seatrials.
Photos from BG Group.

Getting fishy

The race is on to create an autonomous, resident underwater vehicle capable of long-term inspection operations and eventually a level of intervention. Elaine Maslin takes a look at BG Group's version.

Late last year, a select few were given a preview of a technology many would like to get their hands on – a resident subsea autonomous inspection vehicle.

The industry has an ever increasing amount of infrastructure on the seafloor, in ever deeper depths. Getting at it, for inspection and intervention, means hiring remotely operated vehicles (ROVs) and paying the day rates for the vessels that support them. The deeper ROVs have to go, the bigger they tend to get, and the costlier the support.

Operators are looking for a new tool for the job, and the Holy Grail is a form of autonomous underwater vehicle (AUV) that can get up close and personal, hovering on station without a tether to the surface, or indeed a support vessel. The aim is for a machine that can be left on the seafloor and sent on missions, autonomously collecting data and information, and actively replanning its route according to what it finds, such as a hydrocarbon leak or an unknown object.

Creating such a vehicle has been a goal for the industry for some time. Eni has been working on its own AUV technology, Clean Sea, which the firm says is conceptually similar to a drone, but in the marine environment. *OE* has also covered Subsea 7's autonomous inspection vehicle (AIV) development and Total's inspection AUV project in the past year (*OE:* October 2014). Late last year, Shell announced a US$7 million prize, the Shell Ocean Discovery XPrize, to "accelerate breakthroughs for rapid and unmanned ocean exploration."

Shell could already have what it wants under its nose via BG Group, which it officially acquired in February. Over the past two years, BG Group has been developing the FlatFish – a lightweight, subsea resident autonomous vehicle, which it eventually hopes to deploy from floating production units, platforms or from a subsea docking station. The first prototype was built and tested in Germany, and last year BG Group tested a second, tethered prototype, in shallow waters offshore Bahia state, Brazil.

The first FlatFish is a 275kg unit rated to 300m water depth and measuring 220cm-long and 105cm-wide. It's been designed to be able to run for 16-24 hours, covering up to 20km, including a return journey. It runs on Lithium-Ion batteries, and has six hubless ring thrusters. It has lighting, a laser line projector, sonar, four cameras, depth sensor, altitude and heading and inertial heading (INS) referencing systems, Doppler velocity log (DVL) and multiple communications systems. The navigation system and payload system will be separate, but connected, via Ethernet.

While two years might not seem like a long time to develop this unit, BG Group chose the Brazilian Institute of Robotics in Salvador as a partner, and has been working with the Robotics Innovation Centre, DFKI, Bremen, Germany, which has a 3.5 million liter seawater test tank, and the Robotics Group, at the

University of Bremen, which has meant it can build on at least a decade worth of work into artificial intelligence and robotics, says Adam Hillier, BG Group's chief technology officer.

He says getting a resident AUV is an industry goal. "It is one of the technologies the industry is crying out for and we see a need for it. There is a big relevance to our assets in Brazil and on other fields around the world where this could be of interest."

FlatFish on display in Brazil.

What sets FlatFish apart, he says, is the level of intelligence built into the software on the machine. "It is the software that drives the navigation controls and the ability to interpret and optimize route plans during a mission, as well as processing technology for 3D, high-precision images. It's difficult to judge, [in comparison to] others, but certainly FlatFish is exciting. It's the ability to be down there almost permanently and move away from the need for a specialist crew and a vessel. ROVs exist and are quite mature, but they have limitations."


Adam Hillier

Normal ROVs or AUVs either position themselves acoustically, using a mother vessel as a reference or using its INS or DVL with dead-reckoning, which can accumulate an error over time. FlatFish uses a combination of INS/DVL, ultrashort baseline (USBL) acoustic, identification of pipelines and umbilicals, and optical-acoustic feature detection to navigate. In fact, it's this navigational technology that has held back previous efforts to create such a unit, according to a paper presented at Oceans '15 in Washington in October.

The software architecture has been designed so that components are integrated and coordinated, but have a single purpose, so fault finding is easier. It also uses Syskit, a model-based approach which allows the different configurations of the systems component networks to be combined into more complex systems, with different subsystems able to be switched on and off, according to the Oceans '15 paper.

"The software is essentially the brains of the AUV, which controls navigation, real-time plan optimization and the high precision 3D image reconstruction and interpretation," Hillier says. The ability to hover is also key, enabling closer and clearer structure inspection as well as, high definition images to be captured, he adds.

The various AUV offerings on the market differ in size and shape, with few looking like a traditional AUV. FlatFish is no different in that sense. "We have been going through tank testing and everything is looking good in that space. It's a combination of being able to get the right hydrodynamic characteristics against being able to package the sensors in the right space."

The second FlatFish prototype was demonstrated at the Senai CIMATEC University campus in Bahia, Brazil, in December. The current testing, offshore Bahia, is putting the FlatFish to work looking at a number of ship wrecks, to test controls, imaging and image processing, and creating 3D images of the wrecks.

"The next stage is building on the experience of Phase 1 and extending it in to slightly deeper water and starting to think about the docking station," Hiller says. "The docking station isn't everything. FlatFish could be useful without being permanently resident. There's also a driver to get FlatFish in the field as soon as possible. That could happen before the docking station is finalized. All of this is due to be determined in the next year."

Some of the other resident AUV concepts have looked at deployment in a cage or having it dock on infrastructure in place. Another option could be setting it off in shallow waters to its deeper water destination. "The docking station is the ultimate goal, but it is key to get the interfaces right, for power and data, with existing subsea infrastructure," Hiller says. "Certainly, if we are going to retrofit it, there are going to be quite a few challenges. Green field would be a bit different."

At the moment, the plan is for data collected from the AUV to be downloaded when it returns from a mission, either via docking or by being retrieved back to a vessel. But, Hiller says: "There's potential for data to be transferred during the mission, which might be a future development."

To be able to intervene on infrastructure is also a longer term goal for FlatFish, as it is for Subsea 7's AIV. Subsea 7 has set out a four-step vision for its technology, to "sense, see, touch, and do." "It's not part of the initial version of FlatFish, but it's part of future versions," Hiller says. "We share that vision. I don't think we see the next version as doing any significant intervention, but daughters of FlatFish will be going there."

For long-term deployment, there will also be practical considerations to consider, such as bio-fouling, degradation of seals and the blockage of moving parts, according to the Oceans '15 paper.

The wider operator community is interested in BG's work, Hiller says. But the next step will be working out a commercialization strategy. "We know we might need another partner, maybe more, but we want to move quickly," Hiller says. "We think we are on the cusp of something special." OE

XPrize

The Shell Ocean Discovery XPrize is a three-year global competition challenging teams to advance ocean technologies for rapid and unmanned ocean exploration. An additional US$1 million bonus prize is being put forward by the National Oceanic and Atmospheric Administration (NOAA) for teams that demonstrate their technology can "sniff out" a specified object in the ocean trough biological and chemical signals.

Announced in December 2015, the three years incorporates nine months for team registration, 12 months for initial solution development, and 18 months for complete two rounds of testing and judging. Tasks will include making a bathymetric map, producing high-resolution images, and identifying archaeological, biological or geological features. Reliability and durability will also be assessed down to 4000m water depth.

Robots in disguise

The NEXXUS ROV working in the Gulf of Mexico off the *Olympic Intervention IV* vessel. Photos from Oceaneering International.

Elaine Maslin speaks with Oceaneering about its latest underwater technologies and its thoughts on the future of the ROV and AUV industry.

By pure numbers, Oceaneering International is the biggest player in the global offshore oil and gas market, with more than 300 remotely operated vehicles (ROVs).

It's looking to stay that way, developing automated, intelligent ROV operations and navigation systems, for an electrified subsea world where ROVs and autonomous underwater vehicle (AUV) technology look set to merge.

In 2015, Oceaneering bought C&C Technologies, a leader in AUV technology, complete with its own control software, which can control and monitor missions. Oceaneering then went on to demonstrate remote piloting of one of its NEXXUS ROVs in the US Gulf of Mexico, from an onshore control room, via a satellite link to the *Olympic Intervention IV* vessel. Oceaneering was also able to do this using a command-based system involving automated steps, rather than "hands-on" control using a joystick.

Next month [May], the company will display one of two new electric work class ROVs, the eNovus, built for Statoil, under a long-term contract, at the Offshore Technology Conference (OTC) in Houston, and a suite of electric tools is under development.

21st century ROV

Recent developments in machine vision technology, notably used by the Google car and in other areas in the automotive and other sectors, alongside real-time video processing software, have opened up opportunities for underwater robotics control – which remains notoriously hard despite advances in tooling and manipulators.

It might finally be time for the all-electric work class ROV (there are already established all-electric non work class ROVs) or even remotely operated autonomous vehicles (ROAV). Why? Deepwater exploration demands, which have resulted in heavier electric-hydraulic ROVs and umbilicals, combined with a desire to have a resident robotics for inspection and intervention, as well as moves into more sensitive environments, have created a need.

Electric

Oceaneering developed its first electric work class vehicle in 1999-2000: the E-Magnum, or eMag. One was deployed on the *Deepwater Horizon* semisubmersible drilling rig for nine successful years.

Now, under contract to Norwegian oil major, Statoil, Oceaneering developed the newest kid on the block, the eNovus, a version of the eMag. Two units were ordered, to work on Statoil's two new Cat J rigs, due to be delivered this year and next. As well as offering a cleaner technology, for exploration in environmentally sensitive areas, electric vehicles are attractive because they are more efficient than hydraulic vehicles, says Kevin Kerins, senior vice president, underwater vehicle technologies, Oceaneering. "Electric to hydraulic is

ROV market view

The short-term outlook for the remotely operated vehicle (ROV) market is set to look sluggish. The ROV market relies to a large extend on drilling operations, accounting for between 55% and 71% of global fleet utilization, depending on who you believe, with the majority of the rest related to offshore construction.

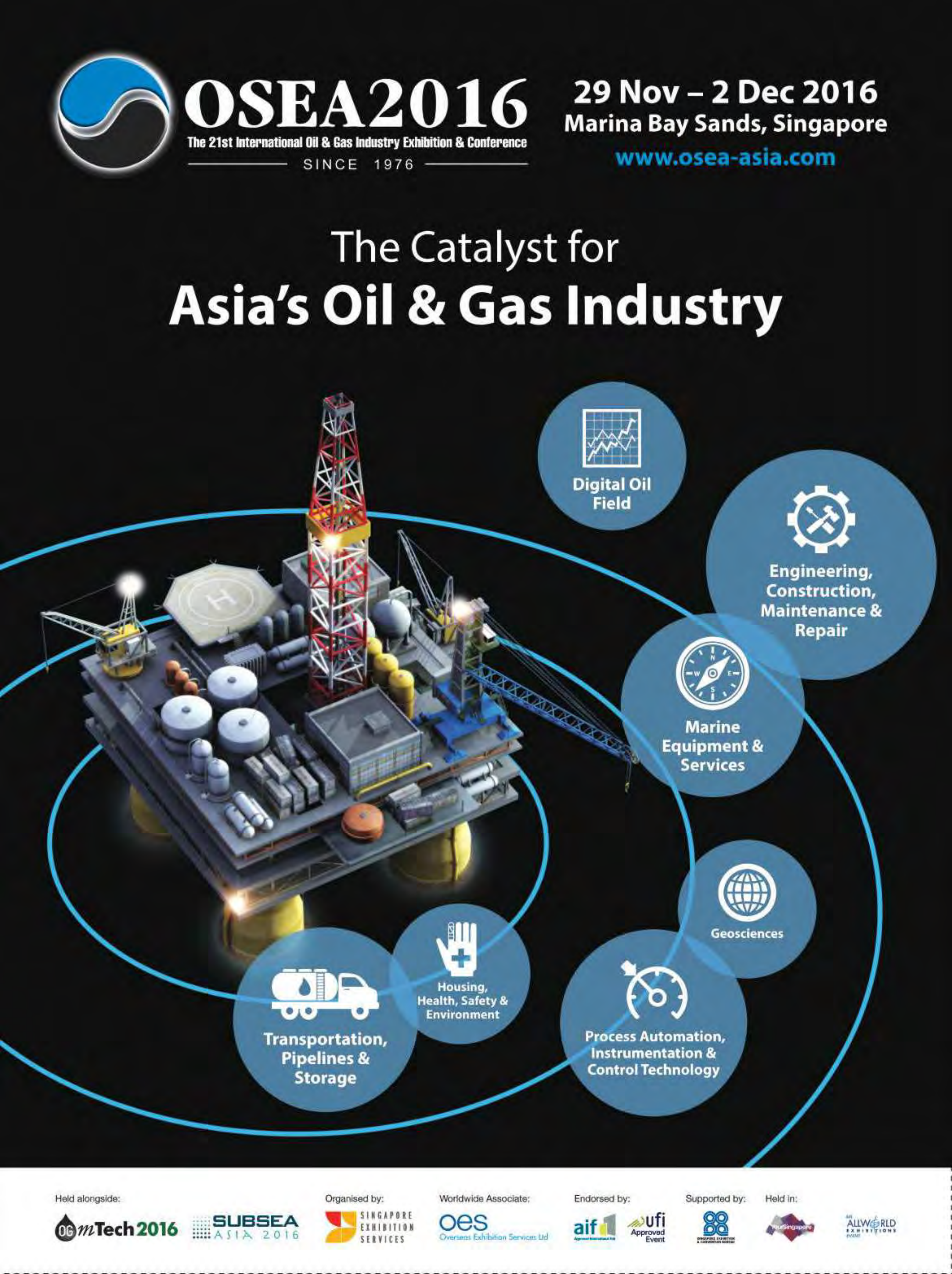
With drilling operations taking a hit thanks to oil majors cutting their budgets across the board, as they seek to mitigate the US$30/bbl oil prices, work is not as easy to get as it was and there are more work class ROVs in the market than ever.

Work class ROV new buildings hit a high of nearly 154 in 2008, compared to 62 in 2005, according to Infield Systems' Kieran O'Brien. While the newbuild rate fell in 2009-10, it rose again in 2011-2013, averaging 121 systems per year, with Oceaneering leading the pack, followed by Forum Energy Technologies and FMC Technologies Schilling Robotics. However, the rate plummeted in 2015.

For Oceaneering, ROV income dropped 32% year on year in 2015, on 24% less income, due to lower demand for drilling support services and an 11% reduction in average day rates.

Total ROV days on hire dropped by nearly 14,500, or 15%, to about 83,800 days for the day, according the firm's 2015 annual results. During 2016, some 16 new ROVs were put into service, 36 were retired, leaving 315 vehicles in the fleet.

O'Brien predicts demand will remain sluggish into 2017, when it will plateau before a slow recovery later in the decade. ▪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Oceaneering's eNovus ROV.
Photo from Oceaneering.

50% efficient. Electric power to electric thruster is over 90% efficient," he says. "The umbilical can be smaller or you can have more power for other things. An electric ROV can also be an extension cord for other electric power subsea; when you're not flying, you can divert power to subsea pumps, dredgers, etc., because of the higher efficiency."

Kevin Kerins

He continues: "What the first eMag lacked, being an electric vehicle, was that it had a hybrid power pack for small tools, but it lacked electric tools. We are now developing a set of electric tools." But, it will still have hybrid capability, for hydraulic intervention, if it's needed.

However, it's not just about electrifying the work class ROV. The future work class vehicle will be a merger between ROV and AUV technology, Kerins says.

Convergence

ROVs will become more like AUVs, in terms of their ability to behave autonomously. But, AUVs will also be more like ROVs in terms of functionality, he says.

Autonomous functionality means automating all the tasks the ROV does and allowing the ROV to perform the task using machine vision technology software, which communicates with the ROV's thrusters to accurately position the ROV relative to subsea infrastructure. At the moment, this means procedures, from maneuvers to stabbing operations, have to be broken down into pre-programmed units the pilot can select, i.e. "move ahead 6in," "grab hand hold on left," "go back to the cage," as performed on the NEXXUS ROV from the *Olympic Intervention IV*.

The future will be further autonomy, using intelligent navigation systems developed for AUVs for tasks such as pipeline tracking and being able to see – and react to – unexpected obstacles on a given route or task. Indeed, Oceaneering is working on obstacle avoidance. Oceaneering is also working on a vehicle that also can track pipelines visually, using technology similar to facial recognition technology, but recognizing an anode, debris, and even damage to the pipeline or leaks.

"We keep saying ROV and AUV and maybe we will always call them all ROV, but eventually we want to take out the "remotely operated" part," says Jami Cheramie, director of technology and special projects, Oceaneering. "It will become a true autonomous vehicle, moving from the human being as supervisor, to the vehicle being truly autonomous. The reality will be a programmed one, with enough intelligence to do what is needed, from servicing a chemical line to just observation."

Jamie Cheramie

Merging ROV and AUV technology could pave the way for concepts such as an ROAV – an ROV which travels between subsea clusters, behaving like an AUV during transit, and an ROV onsite. This could then pave the way for the Holy Grail – not requiring a support vessel.

To a large degree, the technology is in place to achieve this, Kerins says. The problems are access to infield power and communications, as well as battery technologies.

Chicken and egg

Power is a problem. On the battery yield front, prospects are improving, with the likes of Tesla developing electric cars, battery yield has improved some 60% in the last three years, Cheramie says.

But, to have a vehicle in the field, working autonomously, for weeks at a time, you are going to need local power supply power, Kerins says. "It could be provided through an existing subsea control umbilical or we could lay down our own an umbilical. We have researched the possibility of laying our own umbilical, 20-30mi out from an existing platform and at the end putting the ROV in a cage on the sea bed. Using a conventional tether at 3000ft-long, extending in any direction, you could cover 1mi diameter area." Such a system could be also be used as a charging station for an AUV, but, if you want to see what the AUV is seeing in real time, and modify its mission, you still need an umbilical as acoustic data transmission that has limited bandwidth and the only viable alternative for larger through water bandwidth communication for the likes of video is light transmission, which is limited by the distance it can travel through water, Kerins says.

Kerins thinks having power and communication umbilicals in place would be cheaper long-term than vessel day rates. In fact, in the Gulf of Mexico there is already a fiber optic trunk line installed by BP where some 13 platforms and rigs tie into and still more could, he says. "All you then need is power, but you could tie back to one of those platforms or rigs, which have plenty of power."

However, that means getting permission from the rig or platform operator as well as a contract. And until those agreements can be achieved, it's hard to justify the cost of building on spec a resident system and the level of testing a fully autonomous work class ROV would require before being deployed for up to one year. In other words, it's a chicken and egg situation.

A similar situation exists for the

A Millenium ROV being launched.

potential to have a small resident ROV installed on a BOP during deepwater drilling campaigns. "In 10,000ft water depth, it is a long trip down for an ROV to the BOP and if there is weather or loop currents, it may not be possible to launch the ROV," Kerins says. "A resident ROV on the BOP acts as the eyes to see what is going on in real time. Add a simple paddle valve actuator and you can extend the capability." It's an idea that's been around since the 1990s, but, operators weren't keen and BOP designs are not ROV friendly enough to allow connection of such a system.

There are signs this could change, however. Kerins notes API 53, which says ROVs can be a secondary control for BOP functionality, such as supplying fluids for closing shear rams in under 45 seconds. "The precedent now exists for the ROV to do more," Kerins says.

Fleet evolution

Oceaneering continues to expand its fleet. The company's main ROVs are the Millennium and Magnum, both built with open software architecture to enable easy fast fleet upgrades. Oceaneering has also been developing the next generation eNovus, based on the E-Magnum, reconfigured to take on bigger packages, and driven by a 172kVA electric propulsion system, with a dedicated hydraulic circuit for traditional tools.

Replacing the Millennium would be the Evolution, a larger electric work class ROV. However, work slowed on the Evolution while the eNovus was being developed. Evolution would be a multipurpose, configurable work class vehicle, with a configurable bottom half able to be used for anything from hydrate remediation to other work packages.

However, with the ROV market in something of a slump, along with the rest of the industry, fewer new builds will come out this year, with focus on reconfiguring existing assets and delivering existing orders, Kerins says.

ROVs are not Oceaneering's only robotics tricks, however. The company also has an entertainment arm, delivering theme park rides, is also working on a new IWOCS system, with built-in intelligence and "more like an ROV than what you would think an IWOCs system is," Kerins hints. Oceaneering's asset integrity team is also building sensors to monitor the subsea factory and subsea systems.

And, while there is convergence, in terms of ROV and AUV technologies, there will still be work class ROVs and inspection and survey AUVs on the market, doing their jobs. What will be created will be a new type of vehicle – a hybrid – joining the fleet, Cheramie says. OE

Keeping it simple

Sometimes it's not all about throwing the latest bells and whistles at a production facility – its best to keep it simple. Elaine Maslin looks at how an eductor has kept a gas field going.

Maintaining production from mature assets will always be an interesting challenge. Not least when external influences – a ban in the use of Freon as a refrigerant – causes you to re-route gas to a different terminal, resulting in an increase in back pressure above which one of your fields will no longer flow.

That was the challenge facing Centrica Energy on its North Morecambe Bay field, in the Irish Sea, off the east coast of England. The firm had to re-route gas from the giant South Morecambe field, which had been going to its South Morecambe Terminal, where Freon had been used to cool import gas, via a new underground 1.1km, 36in-diameter trunkline to its North Morecambe Terminal, where a new type of coolant is to be used. This meant back pressure was reduced and production from the North Morecambe field would need compression, or some other way to reduce back pressure for it to flow down the export line to the North Morecambe terminal.

The facility producing the North Morecambe field is the North Morecambe or DPPA platform, a 10-well normally unmanned facility, which started production in 1985, and on which it was preferable not to have machinery that would require regular maintenance, such as a compressor. Centrica decided to install an eductor (which go by other names, *see panel*) on DPPA.

Eductors are relatively simple devices that use a high pressure stream to boost a low pressure stream. The Rhyl field, brought on stream in 2013, via DPPA, needed to have its production pressure reduced for export, so it made an ideal high pressure source for an eductor on DPPA.

Rhyl sits at 35 bar g, North Morecambe at 5-6 bar g. Using the high pressure Rhyl flow, the North Morecambe well streams can be increased to above the 8.5 bar g downstream pressure, in the process taking out about 9-10 bar g from

Eductor and Cantilever Sections 4&5.

Eductor installed.

Seajacks' Kraken working at the DPPA. Images from Centrica.

the Rhyl stream.

"In the process [at North Morecambe] the pipeline pressure from the North Morecambe wells is increased to 8.5 bar g," says Ronak Patel, project manager. The North Morecambe wells wouldn't flow downstream otherwise, so this is helping to produce 8.8 Bcf we wouldn't realize the value of without the eductor."

Centrica had tried to use an eductor twice previously, but the conditions hadn't been right. "Eductors have been used elsewhere, but they've not necessarily had a 100% record in some applications we've used them in," says Myrtle Dawes, director of projects & decommissioning, Centrica.

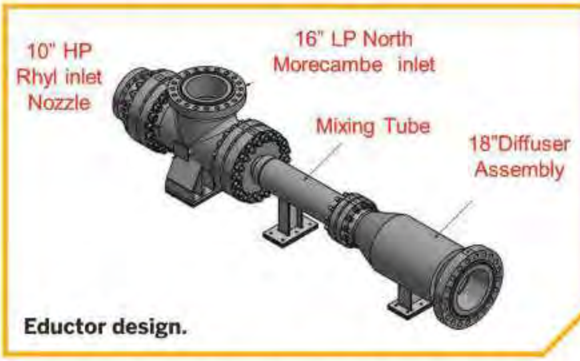
Patel says in the past the issue has been not enough understanding around the pressure-flow (P-Q) relationship on new fields, i.e. not knowing enough about how a new field will perform, or uncertainty around the data, so that flow isn't what was predicted, so the eductor has not been designed correctly.

"In this case, we knew the P-Q relationship on Rhyl and North Morecambe," which meant the eductor was designed fit for purpose, Patel says. As part of the design, Centrica will also be able to change out the nozzle on the eductor, relatively easily, as the P-Q relationship changes, to match the new regime. This is likely to happen every 2-3 years, Patel says.

Introducing the eductor involved Centrica's subsurface team and the process team working closely. Just to make life interesting, at that time, Hysys, a process simulation software, didn't contain a module for modeling eductors, which meant Centrica had to do the modeling itself.

Then, the 3-tonne eductor package, including nozzle pack, diffuser, and silencers at both ends, on a 17m-long new cantilever structure had to be designed to fit onto a small already busy platform, with pipework for the existing well streams, including Rhyl, also having to be adapted accordingly. In total some 35 spool pieces were installed, as well as a new metering package, at the request of the UK regulator, the Oil and Gas Authority.

The brownfield work made use of a 3D laser scan on the platform, which was used to create a 3D pipeline model, with particular attention paid to key tie-in spools. An animation produced by contractor Amec Foster Wheeler also became a useful tool to show the installation process, from start to finish, through the process.



Eductor design.

The project had been approved in February last year, offshore work started in July, using marine contractor Seajack's Kraken mobile jackup unit. First gas was achieved on 20 September.

And, so far, Centrica is happy with the results. "It is not the most efficient device, but it's free and it's efficient enough," Dawes says. "A few years ago, if we had a bigger flow, we would have put a compressor out there. But, we've gone back to basics, getting the same effect, but without the requirements for staff offshore." **OE**

Overlooked and undervalued

Ejectors are also known as eductors, injectors, and surface jet pumps. It's a technology that has been around since the mid-1800s, says David Ainge, managing director at UK-based Transvac Systems. But it's been somewhat overlooked and can do more than you might think.

The first US patent for an "oil ejector" was registered in 1866. Since then, ejectors have been commonly used in industries using steam to create a vacuum or liquid for pumping applications.

Transvac Systems has been designing and manufacturing ejectors since it was founded in 1973, mostly for steam and vacuum applications, or liquid ejectors for dosing and mixing. In the 1990s the firm moved into oil and gas, offering a way to boost production on low pressure wells, using otherwise waste energy, including on the southern North Sea Sean field for Shell in 1997. It's since been offering the technology as part of the sand separation process and has more recently qualified it for subsea applications.

The benefits of ejectors are that they don't need power and don't have running costs or maintenance requirements, says Peter Ainge, Transvac's business development director. They're also low-weight and compact, he says, making them suitable for brownfield deployment, and make use of an otherwise "waste" product.

Transvac has been designing ejectors for flare gas recovery, since the early 2000s, safely and economically compressing waste and surplus gas back into the production process and reducing emissions.

Since around the same time Transvac ejectors have also been used for pumping sand slurry as part of topside sand separation systems, for clients such as NOV Merpro, Chevron, Maersk Oil Qatar, Total, and BP.

Ainge says take-up hasn't been as great as it could because of a lack of education about them among those who could them. Transvac is trying to redress that. "Ejector based solutions are a simple, low-cost solutions with CAPEX payback often in a few days," he says. "However, they are not regarded as the 'traditional' solution, so they are not always considered."

The tide might be turning. "We are seeing an increase in the use of ejectors in two main areas offshore; production boosting/enhanced oil recovery (EOR) and flare gas recovery," says Gary Short, Transvac's projects director. "Using ejectors for production boosting provides a low cost method for significantly increasing asset output, typically 20% overall," he says.

Transvac has also now achieved a fully qualified technology readiness level 7 for subsea ejectors, after providing FMC Technologies and Petrobras each with a fully submersible ejector currently working in depths up to 870m.

More recently, liquid/gas ejectors have been developed for microbubble generation for oil in water separation on compact flotation units. ▪

– Elaine Maslin

Keeping a stiff upper lip

There's a lot of doom and gloom in the North Sea as operators battle to make operating costs profitable. Yet, it's not all bad on the UKCS. Meg Chesshyre reports.

A measure of optimism about the future of the North Sea, despite the current low for longer oil price scenario, was expressed by speakers from both Maersk and Total at the IP Week in London this spring.

"We're very optimistic about the North Sea and doing business there," said Maersk Oil CFO Graham Talbot. "We believe we have a very good understanding of how to operate effectively in the North Sea and we are planning to continue to invest there." He said that Maersk Oil "has an appetite for long-term resilient countercyclical investment in energy." It is currently developing the high-pressure, high-temperature (HPHT) Culzean gas condensate field in the UK *(OE:* December 2015*)* and is a partner in the major Statoil-operated Johan Sverdrup project in the Norwegian sector.

"We're building into the design of our Culzean project the means to control our operating costs by developing a truly 21st century smart platform," he says. "The upfront investment in facilities, such as pre-wiring fiber optic cables linked to a robust and secure Wi-Fi network, allows us to track manpower, materials, equipment in almost real time and thereby optimize production efficiency, and run a safer, more reliable facility.

"Critical equipment on the Culzean platform will have ID tags attached. These tags will scan using handheld devices, such as tablets, and provide the operator with all the information associated with that bit of equipment in

The Culzean facilities.
Image from KBR.

real-time. The information will include manufacturing data and certificates, drawings, video simulation and maintenance and operational activities, maintenance history and so on."

He said that the full potential was still being mapped out, but simply making sure that the right equipment was available at the right time, and ensuring uptime of facilities had a material impact on the cash flow, was going to be absolutely critical in the North Sea going forward. Applying these enhancements to Culzean is currently forecast to result in savings in excess of US$10 million per annum. "The tablet is now joining the wrench and the screwdriver as a standard piece of equipment in North Sea developments of the future."

"The tablet is now joining the wrench and the screwdriver as a standard piece of equipment in North Sea developments of the future."

– Maersk Oil CFO Graham Talbot

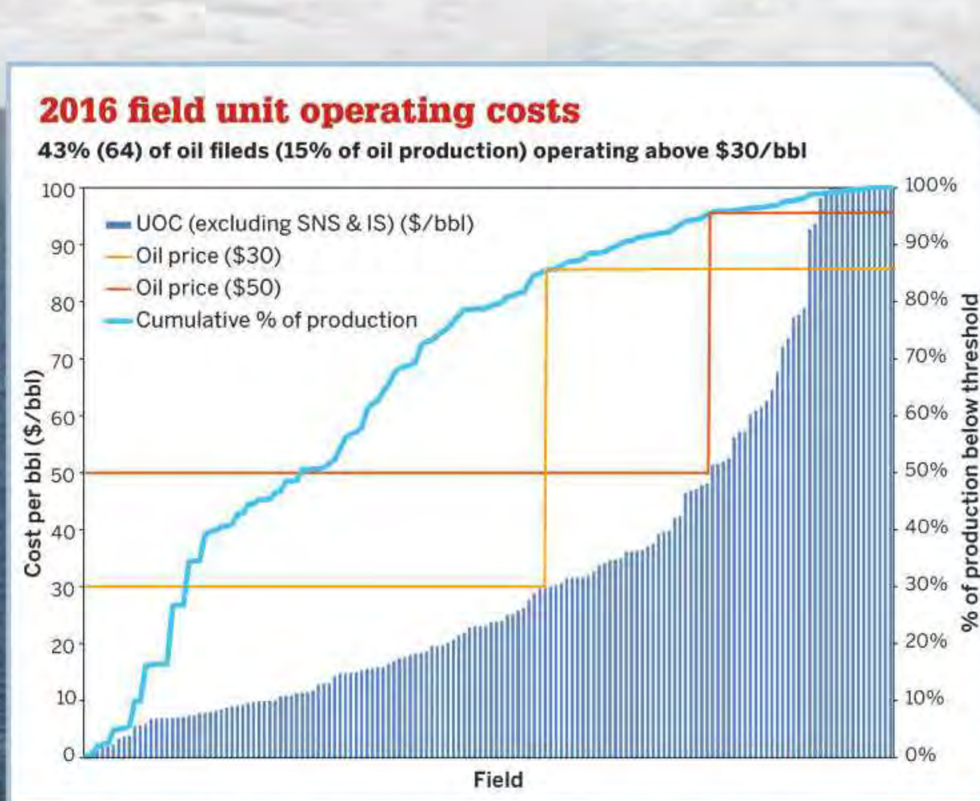
Staying efficient

Total E&P UK's Managing Director Elisabeth Proust quoted UK Prime Minister David Cameron as saying, on a recent visit to Total in the UK, that "this industry is the jewel in the crown of the British economy, not was." Proust continued, saying that Total remains very interested in being here. "We know that there are resources," she said. "The prospectivity is still there.

"We know that there is need for change. We know that the change is going to be difficult, because we are reducing the number of actors, but it is necessary." Proust said that there was "a strong need effectively to identify what are the fields, what are the problems of production, asset by asset, where we can be economic." She pointed out that about 70% of UK Continental Shelf fields are above the $30/bbl barrier in operating costs (*see graph*). "This is why the landscape is going to be very different and very soon."

The Total E&P Group launched a cost efficiency project in 2014, with Total E&P UK as the pilot, with a three-year implementation phase from 2015-2017. All aspects of company activity were included in the scope with full workforce engagement. This program delivered 20% savings in opex, capex and exploration costs in 2015, compared with a 2013 baseline, and is targeting a 30% reduction by year's end. It aims to simplify the organization. The final objective is a cost culture fully embedded in the company and its shareholders.

Total is one of the top three operators in the UK in terms of production and reserves, and recently brought on stream the Laggan-Tormore gas and condensate fields. The Laggan-Tormore development consists of a 140km tie-back of four subsea wells to a new onshore gas plant on Shetland. The fields will produce 90,000 boe/d. The UK subsidiary contributed almost 10% of the Total's daily production in 2015, and anticipates an expenditure of £6 billion ($8.6 billion) over the next five years. **OE**



UK Continental Shelf unit operating costs, excluding southern North Sea and Irish Sea, presented by Total. Source: Energy Institute IP Week presentation.

Technician examines HEX electronics in Songkhla. Photos from Weatherford.

Team work

Weatherford and Chevron teamed up to develop a LWD service capable of running in high temperature environments, such as the Gulf of Thailand. Jerry Lee reports on how the project came together.

Logging-while-drilling (LWD) tools are robust and built to withstand the stresses of oilfield conditions, but even they can succumb to the demands of high temperature environments.

Operations can become challenging, making data acquisition difficult. Dealing with such a situation, Chevron Thailand partnered with Weatherford to develop a LWD tool capable of running in high-temperature environments, to reduce non-productive time (NPT).

In the Gulf of Thailand, an area which sees some of the world's highest bottom hole temperatures, standard LWD tools are typically not up to the challenge; with temperatures reaching over 200°C (or as high as 3.2°F/100ft), standard LWD tools are only rated to 175°C. Lacking a hardier tool, drillers adapted by using temperature mitigation techniques; e.g. stop drilling, pull up to a cooler zone, and circulate mud to cool the tool. This mitigation process works well enough as a short-term solution, however, it must be done each time the tool needs cooling. If the process does not work, the tool will likely fail and will need replacement; in both cases, NPT and high rig costs will accumulate.

Chevron Thailand was familiar with LWD-related NPT, however, the operator still needed to drill safely and has a specific requirement to eliminate or minimize wireline logging in all wells.

"For our operation, we want to drill at maximum speed without any interruptions," says Douglas Ellis, drilling rngineer and joint development project manager, Chevron Thailand Exploration and Production. "Logging the well and taking surveys needs to be done concurrently with the normal routine drilling operation to maximize efficiency.

"In addition, the directional driller uses the survey data to calculate and make adjustments to the well trajectory and the earth scientists use the petrophysical data to determine the rock and reservoir properties. All of this is done during the drilling operation," he says.

With NPT costs mounting, Chevron knew it needed a better solution: a triple combo high-temperature LWD (HT LWD) tool capable of acquiring porosity, density, and resistivity data. This fell in line with Chevron's capital efficiency strategy and the Offline Data Acquisition Project, the aim of which is to develop concepts and technologies to optimize rig-time; e.g. acquiring the petrophysical and reservoir data while drilling. As a result, Chevron asked Weatherford to accelerate the development of HT LWD tools.

Weatherford dedicated its research and development resources to fast track the development of 200°C capable tools, with Chevron investing US$1.575 million for development cost.

Feeling the heat

For phase 1 of Weatherford's proposal, prototypes were developed utilizing high-temperature mud pulse telemetry, directional sensors, as well as neutron porosity, gamma ray, and pressure-while-drilling logging tools.

At fields with temperatures exceeding 175°C, the electronics in standard LWD tools start to break down and fail. For areas like the Gulf of Thailand, electronic components that can survive in these temperatures long enough to get the logging job done are needed.

"We completely redesigned the electronics packages within the tool to withstand 200 hours of operation in 200°C and four hours of survival in 210°C," says Richard Barton, product champion – new technologies, Weatherford. "At 210°C the tools are designed to shut down and preserve themselves so they can be tripped out of hole and reused again."

The HeatWave Extreme LWD service leverages technologies used in Weatherford's HEL system but improves the temperature rating. The new service also includes optional bore and annular pressure as well as gamma and neutron porosity measurements.

Innovation in electronics was required for the tool to work at these high temperatures. "The biggest hurdles, and time cost, in the development part of the project was the selection of the electronic components that could operate at that temperature," Barton says. "We took components off the shelf, heated them up, and they failed. We had to use different components organized in different ways to find a solution, and each time we had to rewrite the firmware to use those components. Then, we designed a completely new PCB (printed circuit board), populated the PCB with the selected components, and qualified them at 200°C for 200 hours and 210°C for four hours."

In addition to the PCB and components, the HT-LWD tool required new elastomer seals and a new type of battery insert that has the ability to function at high temperatures.

With the ability to operate at high temperatures, engineers can focus on drilling, logging, and working towards optimizing the cost of the well. Mitigation tactics to cool the tool are avoided, as well as the need to trip in and out to replace the tool if it fails.

"If you stop temperature mitigation procedures then you could be saving up to 11 hours per well," Barton says. "And if you prevent one trip per well, then you're saving at least 12-15 hours of rig time."

Case study

Five HT-LWD prototypes were completed and qualified and then taken to the Gulf of Thailand in January 2015 for field testing. The HeatWave Extreme (HEX) project, as it was called, involved utilizing the HT LWD tools (HEX tools) for a 22-well campaign. During this campaign, Chevron experienced zero

HEX Tools ready for deployment in Thailand.

tool failures, blind runs, safety incidents, or NPT in 25 runs and 1218 hours of drilling. Without having to perform cooling trips, Chevron saved around 223 hours of rig time and decreased the average time to drill and log the well to 6.2 days per well.

To date, 27 wells and 186,250ft (56,769m) have been drilled, with no failures or service interruptions in 2175 operating hours. The HEX tools also set multiple drilling records for Chevron Thailand: deepest 3-string production well: 11,566ft TVD; first well greater than 10,500ft TVD drilled in less than four days: 10,552ft TVD in 3.88 days; fastest well deeper than 11,000ft TVD: 11,316ft TVD in 5.31 days.

The HEX tools experienced extreme temperatures, including a maximum circulating temperature while drilling of 198°C, and recorded a maximum temperature of 213°C. During the 213°C run, the tool was run to bottom however circulation was not initiated until it was near the bottom and transmitted a temperature reading of 212°C. All of the sensors and batteries were operational except for the neutron sensor, which had thermally shut-down at 212°C. After being cooled, the neutron sensor functioned normally.

"This is something that's unprecedented," Ellis says. "Normally, we would never see wellbore temperatures that high and circulation would be initiated occasionally while running in the hole. I doubt this will ever happen again in our operation."

As a result of their success, the HeatWave Extreme project won the 2015 SPE E&P award on 26 Feb 2016 in Bangkok, Thailand.

"This was Chevron Thailand's first joint development project, and Weatherford's R&D did an awesome job designing, testing and building the tools," Ellis says. "Winning the award would not have been possible without the operational team in the office and on the rig. It was the personnel in the field that pushed the tools to the absolute limit and proved the reliability of the tools."

Next phase

Despite the success of the HEX tool, Weatherford is not yet finished with the project.

"At the moment we've completed phase 1 of the project with Chevron," Barton says. "Phase 2, we're going to be developing resistivity and density measurements to go along with it as well."

Phase 2, endorsed by Chevron in January 2015, will complete the suite of high temperature triple combo tools.

"The big savings will come when the HT triple combo tools are deployed," Ellis says. "These tools can be run on all wells with the potential to exceed 175°C without the downside of having to spend time running wireline logs. One question that I have always been asked [by operations personnel] during the field trials was, 'when will the HT triple-combo tools be here?' My answer is Q3 2016." OE

Winners of the 2015 Thailand SPE E&P Award. [Left to right] Steve McBride, Weatherford Country Manager, and Doug Ellis, Senior Drilling Engineer, Chevron Thailand.

X-ray vision

When people think about X-rays, they most likely think about hospitals or maybe even pipeline inspection. Elaine Maslin examines how X-rays could be deployed in a wellbore near you.

X-ray technology is being taken downhole to help visualize what is happening in the well, such as stuck or faulty downhole equipment or damaged casing and maybe even formation evaluation.

Existing techniques for seeing what's happening downhole include dropping lead to create an impression of equipment in the hole, ultrasonic imaging, which relies on knowing the specifications of the well fluid at the investigation depth, and using cameras in transparent well fluid or gas filled wells, which can mean spending time cleaning and preparing the well.

Malta, Stavanger and Houston-based Visuray hopes its VR90 tool, incorporating a thermionic X-ray tube, will supersede those methods by providing 2D and 3D images from inside the well, without the need to condition well fluids or to have detailed knowledge of the inside geometry and physical properties of the materials inside the well.

But, because X-ray imaging traditionally involves access to both sides of the object being X-rayed, Visuray has had to develop a new technique – fluid-based surface imaging. It has the X-ray source and detector positioned on the same side of the object. But, because steel or metal objects absorb the photons emitted, it is mostly radiation reflected by the fluid that will be picked up by the detector.

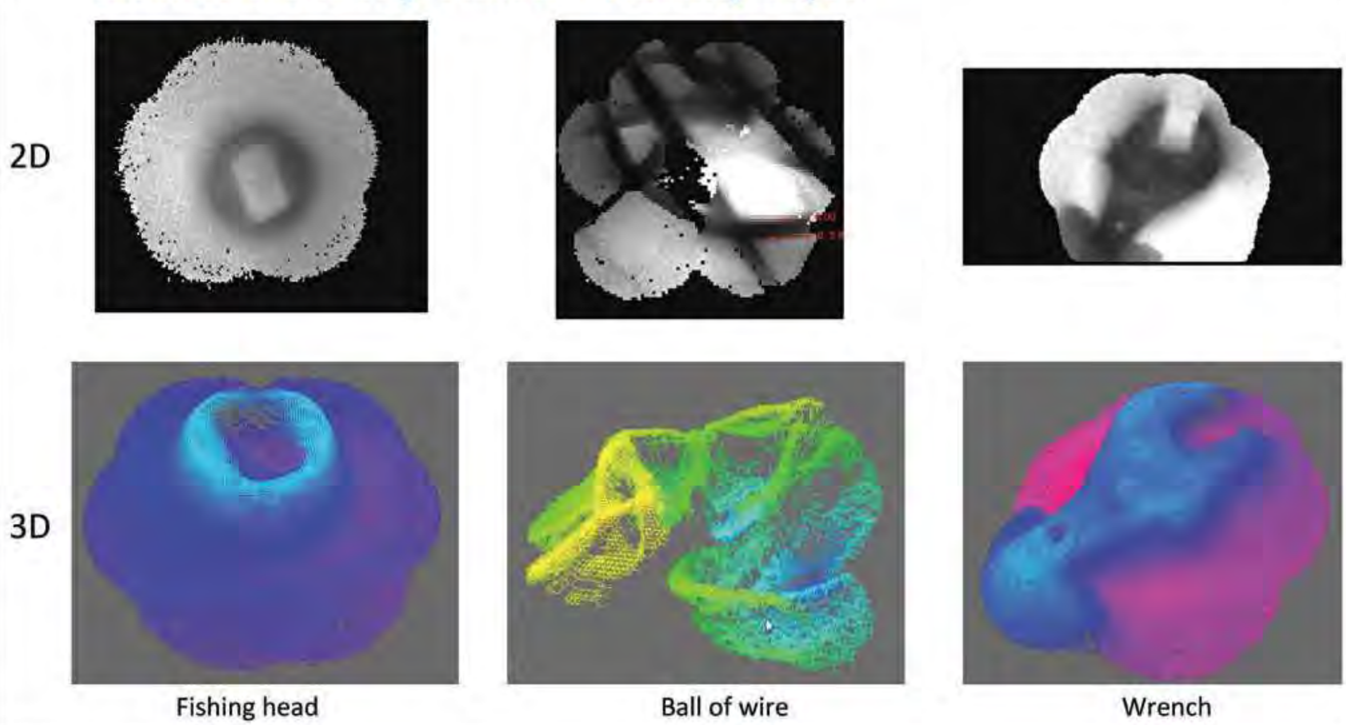
To deal with this, Visuray's fluid-based surface imaging converts the "noise" created by the fluid backscatter into a reconstruction of the surface of the object in it, based on the amount of scattering arising from the fluid between the source/detector and the object.

The firm's tool stems from work by Phil Teague, a graduate in Physics and Astrophysics from the University of York, England, who started the company in 2004.

"The physics are quite novel," says Jack Johns, field test coordinator at Visuray, told last year's Production Optimisation conference in Aberdeen. "Normally you transmit X-rays from the source to detector [passing through the target]. As we're in a well, you can't get the detector behind the source, so need to use the backscatter [off the target].

"We illuminate the area in front of the tool in the well. Backscatter goes through pin holes in front of the detector and projects an image on to detector," he continues. "In essence, you create a 3D representation of the fluid in

Downhole X-ray vision - Visuray style



Test images. Images from Visuray.

front of tool or well architecture. So you know what is there – it could be a safety valve, collapsed casing – by reconstructing and inverting the image."

To produce X-rays, the tool has been developed to produce whatever high-voltage power is required, from power passed downhole through the wireline. This also meant an active downhole cooling system had to be developed. The company is keeping a tight lip about both technologies. "As far we know it is the first down hole actively cooled tool," Johns says.

Visuray says that there's no residual radiation to humans, because the tool is always switched off near or at the surface.

The firm initially worked with support from Statoil, BP and Shell, proving the technology. In 2005, the first successful laboratory image was taken through mud. In 2007, a 4m-long, 9in-diameter prototype was built and run downhole at the Ullrigg test well just outside Stavanger.

In 2014, the first working, field operating tool was created and in early 2015, after seven years and about US$90 million investment, a 3 5/8in commercial version of the same tool –the VR90 – was successfully tested in a well in Germany.

The tool measures 8.38m-long, with three sections (telemetry, cooling and high voltage section) and 9.2cm-diameter and is compatible with tractors, strokers and coiled tubing, capped at the end by a 2cm-thick Beryllium window (Beryllium has high transparency). It operates at ambient temperatures up to 150°C or 300°F and pressures up to 20,000 psi.

It includes a custom-built, shielded thermionic X-ray tube, operating at 180 kV and an electron beam current of 1 mA. The electronic detector has six individual detector tiles, each divided into 128x128 pixels, with pixel size at 100 µm by 100 µm. Each detector tile has its own 350-µm diameter pinhole to direct backscattered X-rays onto the tile.

Data from all six tiles are combined to create a single composite image spanning the entire field of view. The composite image may be displayed as a 2D depth map image or rendered as a 3D surface reconstruction.

During the tests in Germany, 11 separate runs were made to conduct tests and create images at depths of up to 2100m (6890 ft) and temperatures of up to 100°C (212°F).

The first commercial operation was run late 2015 for TAQA in an onshore gas storage well. Two complete tool strings sent to the wellsite have performed a total of 13 runs with a maximum temperature of 85°C up to a depth of 2100m. The tool successfully imaged the top of a coiled tubing disconnect with millimeter accuracy and helped TAQA to plan fishing operations in the well. With the 3D images created, firms could then design a fishing tool.

During lab testing in different fluids, from water to brine and then oil, showed that similar images could be produced of the object, at up to 10cm in a variety of stand well fluids, with 1mm resolution. How the tool performed at different distances from the object has also been tested, including sand, which still worked at up to 5cm.

Visuray is also working on other projects using its X-ray technology, including cement evaluation (VR360) and formation evaluation. **OE**

PDA on the drillfloor

The lack of automation in the oil and gas industry is a puzzle to Brian Evans from Curtin University, Australia. Elaine Maslin learned how he hopes to redress the situation.

Brian Evans is not your traditional academic – he worked offshore in the North Sea in the 1970s, working on various vessels and production platforms, so he has an understanding of the challenges.

Professor Brian Evans. Photo from University of Aberdeen.

His more recent work has involved predictive data analytics (PDA) and it's something he feels should be applied to offshore drilling.

"The concept is to take any form of drilling rig and retrofit by adding sensors and automation, which could detect and transmit changes in pressure, vibration, temperature and location to a local relay station, for onward transmission to a command control room," he told Subsea Expo, in Aberdeen, earlier this year. "This data would then reduce manning levels and allow remote control with limited autonomous operations."

But, to do PDA properly, all equipment data, historic and current is needed, including service history, component parts, and over lays of 2D and 3D displays of manufacture and installation. To these, business planning tools are added, plus engineering alternatives and data visualization tools, as well as economics and supply chain information with predicted money market movements providing an analytics tool for what Evans calls "tomorrow's smart remote control room operator."

Sounds simple? Maybe not, and Evans admits it wouldn't be easy. To achieve the goal would require a sensor on every valve – when in some plant there are more than 10,000 valves onboard, which would need retrofitting, Evans says. "It also requires a fundamental belief in security and sustainability of autonomous systems that are fail safe," he adds.

To date, moves towards automation haven't been as strong as in other industries. For the North Sea, it amounts to unmanned monotower gas facilities. "It is pretty pathetic, this is how automated we have got in the North Sea," Evans says.

Slightly more is being done offshore Australia. Woodside's Angel unmanned platform, the operator's first unmanned facility, produces 50,000 b/d. It has been unmanned for 15 years, but it does require maintenance for 2-3 days in every 45 days with temporary board accommodation.

Woodside wants to do more, however. Woodside's CEO Peter Coleman has said all offshore facilities will ideally be automated within 10 years, Evans says. The company has over 80 analysts trying to do the basic work to make a start to fit-out platforms, on the North West Shelf alone.

It's a big job and would be an even bigger job applied to existing drilling rigs, Evans says. What's more, the people required to man the retrofitted equipment would need to be different, "not the blue collar worker of today, but someone who understands data, computers, and sensors, and can understand the economics and business consequences of making a decision on the fly."

Instead, "a new paradigm is required," he says. Evans proposes reducing the number of components requiring sensors by reducing the wellbore size. "If the rig is for exploration only, this reduction can be dramatic. Reduced rig size minimizes footprint." Taking it a step further, the drilling rig could be moved to the seafloor, controlled from surface using umbilicals.

Evans further proposes using small bore, composite coiled tube drilling, with a 2in-diameter borehole, drilling using a downhole turbine. Remote operated vehicles would be used for blowout preventer placement and removal and the entire unit would be mounted on a tracked vehicle for movement on the seabed. The composite tubing would contain integrated circuit (IC) chips for logging while drilling. Reverse circulation drilling would allow closed loop for drilling muds with real-time sensing and display of cuttings during drilling.

Carbon fiber drill rod is about 35% weight of conventional steel, he points out. The data from the chips could be transmitted by light through fiber or Wi-Fi when onshore.

It might sound far-fetched, but over AU$56 million (US$42.4 million) is being spent on a current long-term project with a view to its being used in onshore exploration and mine site drilling. A coiled tube rig has been built and has been working at mine sites in Australia by the world's largest mining research project known as the Deep Exploration Technology Cooperative Research Centre (DET CRC), alongside specialist lab facilities at Curtin University in Western Australia for drilling and flow loop experiments, coiled tubing material testing and cuttings return and borehole stability studies. Composite rod development has also been underway, with the aim to someday develop built in sensors which take many more bending cycles with 24 Mpa (3500psi) water pressure than is conventionally possible.

Composite condition monitoring sensors are being researched to place on the equipment for monitoring and transmission to the control unit, in order to provide data on location, excessive vibration, stress, pressure, and temperature changes using ICs.

The coiled tubing drill rig prototype modified for use with flexible H-Coil, a potentially more durable, alternative to steel tubing, last year. Photo from Deep Exploration Technologies CRC.

"We look forward to the DET CRC launch of a new prototype land-based rig (with two operators controlling it) in November this year, complete with a mud circulation, cleaning and automated sampling system," Evans says. "Then Curtin hopes to fully automate it for operational control through the use of data analytics and the Curtin remote control room."

The next steps then would be to take it subsea, which Bergen University College hopes to achieve, by adapting the fully automated Curtin University drilling system. In such a system, the rig would walk around the seabed, controlled by umbilicals from a single vessel on the surface. This would allow drilling to continue whether a storm is occurring on the surface or when drilling under ice.

Even just taking it offshore, replacing expensive semisubmersible exploration rigs, would have multiple benefits not just financial, but health, safety and the environment also, Evans says. Using coiled tubing would reduce the amount of pipe stored on board the rig deck, allowing a reduction in rig floor size and the dramatic reduction in number of personnel needed on the rig. But, the trick is also to use sensors embedded in the composite coiled tube, including electronic chips, which could operate during drilling, with on board real-time automated cuttings, separation and sampling.

"You have to start from the bottom and build up," Evans says. Or indeed start from the surface and work towards the seafloor. We are someway from that at present. **OE**

Automating drilling fluid analysis

Clint Galliano and André Rand of Halliburton and Steve Sparling and Pat Watson of Anadarko Petroleum discuss how automated, real-time measurement of fluid density and rheology can enhance drilling operations.

Offshore workers.
Photos from Halliburton.

Managing drilling fluid properties at the rig site is a critical step to delivering every well successfully. Fluctuations in these properties are inevitable, and even minor deviations in the drilling fluid can have dramatic impacts on wellbore stability, hole cleaning, equivalent circulating density (ECD), and overall drilling performance. Hydraulic simulations are an essential part of planning the drilling program, and real-time data can offer greater opportunities to improve overall operations.

The ability to model fluid characteristics and drilling activity across a range of variables can help operators identify the best potential path to drill and complete a well safely and efficiently. Physics-based simulations are often seen as industry-leading tools, since no calibration is required. Cuttings transport, surge and swab, sweep designs, and ECD simulations are all heavily dependent on fluid properties and formation composition. Even the best physics-based simulations can benefit from improvements in fluid data points.

Operators depend on accurate drilling fluid data to determine appropriate action plans for the success of their drilling programs. The drilling fluids representative at the rig site has multiple responsibilities and may not have the opportunity or time to conduct repeated, consecutive tests on the fluid. Data can potentially be up to 24 hours old and may not accurately reflect current fluid conditions in the wellbore. Automating routine fluid property tests provides access to precise and dependable drilling fluid properties in real-time data points that are vital when crucial decisions are necessary.

Halliburton Baroid has developed a new solution to help automate the process of fluids data capture and analysis. The BaraLogix Density and Rheology Unit (DRU) is a single, modular device that allows real-time measurements of fluid density and rheology, combined with trending analysis that is autonomous and highly visible to the well construction team. The BaraLogix DRU can help reduce risk, increase efficiency, and communicate performance of drilling projects.

Automated density and rheology measurements

The BaraLogix DRU can provide functionality and features that have historically required multiple instruments and manual interactions. Engineered to compliment the onsite or remote fluid specialists, each BaraLogix DRU incorporates a densitometer and rheometer into a single device, to automatically measure density as frequently as every minute, and rheology as frequently as every 15 minutes. A patent-pending fluid delivery system with self-generating nitrogen purge capability was created to help ensure that fluid is supplied to the unit in a reliable and efficient manner. The unit is capable of 14 days of continuous autonomous operation prior to maintenance servicing. Data accuracy has been proven for 6-speed rheology within 1.5 dial readings of a FANN 35 rheometer, with rheology numbers reported in Herschel Bulkley parameters (n, k, tau0). Density accuracy is within 0.1 lb/gal of pressure-while-drilling (PWD) tools. The Halliburton InSite Anywhere software included in every BaraLogix application can provide additional convenience by allowing a central point of data access for all decision team members, and the constant stream of data can also be provided in multiple industry-standard formats.

The BaraLogix DRU was designed with a small footprint, and components are modular to allow quick and easy maintenance. Slide-out trays aid serviceability with efficient access to critical components. Configured for ATEX and IECEx Certification, the unit is skid-mounted and can be placed near the mud tanks.

The BaraLogix unit can be used in a variety of configurations. A single unit can allow real-time and remote monitoring of fluids data on a single project. Units can also be placed on multiple rigs, allowing monitoring of fluids data for multiple projects though a single InSite Anywhere information portal. For the most complex projects, data from multiple rigs can be filtered through Baroid applied fluids optimization (AFO) specialists who constantly monitor the data, help identify potential problems before they occur, and provide expert recommendations based on proven workflows to help improve operations.

Gulf of Mexico application

Anadarko Petroleum had experienced a stuck pipe during the salt exit stage of a deepwater well in the Gulf of Mexico. The drilling team was looking for new ways to mitigate risk and reduce non-productive time for a new well in the same field. Specific focus was placed on hole cleaning effectiveness and the ability to more efficiently manage fluid properties throughout the project, with the salt exit phase identified as high priority.

The Baroid team deployed a two-part solution incorporating the BaraLogix DRU and AFO services. The complex nature of the well and previous stuck pipe required strict management of fluid properties to maintain target ECD levels and consistent hole cleaning. Constant visibility of fluids data across the drilling team was preferred to maintain proper oversight for the project, and the data stream from the BaraLogix units and real-time monitoring from the AFO team helped satisfy these requirements.

Two BaraLogix DRUs were installed on the rig. The first unit was installed near the mud pit, while the second was installed near the shakers so Anadarko could capture fluids data at both the suction and the return points while drilling throughout the salt exit stage of the project. The data was passed through Halliburton's Insite Anywhere platform to provide real-time visibility to all members of the drilling team. The fluid engineers were able to monitor the constant stream of data from the DRU and used the readings to help minimize fluid dilution rates and improve fluid efficiency throughout the project.

Additionally, AFO engineers were able to fully leverage the real-time data from the BaraLogix DRUs and PWD tools throughout multiple stages of the well. The AFO team used Drilling Fluids Graphics Real-Time (DFG-RT) software to help monitor and predict downhole hydraulics behavior based on the real-time data. This capability allowed the AFO engineers to identify an unexpected delta between surface mud weight and downhole mud weight during an early stage of the well. The AFO team re- ported the delta, which was confirmed to be the result of pipe movement. Proactive identification of this issue helped avoid a potential formation influx scenario. During the salt stage, a spike in PWD, which could potentially lead to a pack off situation, was identified. Adjustments were made in accordance with documented workflows to avoid further issues. Anadarko was able to drill to total depth successfully with no NPT related to fluids management.

The integrated BaraLogix DRU and AFO solution helped Anadarko avoid a potential stuck pipe similar to what had been encountered on the previous well. By actively monitoring fluid density and rheology in real time, the fluid engineers were able to maintain proper fluid formulation while minimizing base oil additions in the salt exit interval. The reduced dilution helped Anadarko save approximately 143 bbl of base oil compared to the same interval in the previous well, for a net cost savings of approximately US$22,868. The AFO team was also able to predict maximum rate of penetration and trip speeds to help improve drilling efficiencies. The end result was an effective implementation of new technology and service integration to help Anadarko successfully drill through a challenging formation in a deepwater well. **OE**

A Baroid unit.

Clint Galliano *is operations manager for digital solutions at Halliburton Baroid, handling automation and optimization services. Galliano's background includes working offshore as a mud engineer in the Gulf of Mexico and technology development of automation and optimization services in the Gulf of Mexico, North Sea and Caspian Sea.*

André E. Rand *is a technical advisor at Halliburton Baroid, responsible for deepwater drilling operations and completions fluids in the Gulf of Mexico. Rand has 20 years' experience in various positions including as a field professional in the Gulf of Mexico, Trinidad and Venezuela, as well as a technical professional and operations leader in the Gulf of Mexico.*

Steve Sparling *is a senior drilling engineer with Anadarko Petroleum.*

Pat Watson *is a drilling and completions operations manager with Anadarko Petroleum.*

Mediterranean & N Africa

Sea of opportunity

Heather Saucier examines the geology of the Mediterranean and North African region, and assesses where more discoveries could be made.

Eni's recent discovery of the supergiant, deep water Zohr gas field *(See page 16)* roughly 100mi off the coast of Egypt – believed to contain up to 30 Tcf of natural gas in place – marks what could be the largest gas find in the Mediterranean Sea and one of the largest in the world in recent years.

In fact, after its full development, Eni CEO Claudio Descalzi said the field will be able to satisfy Egypt's natural gas demand for decades.

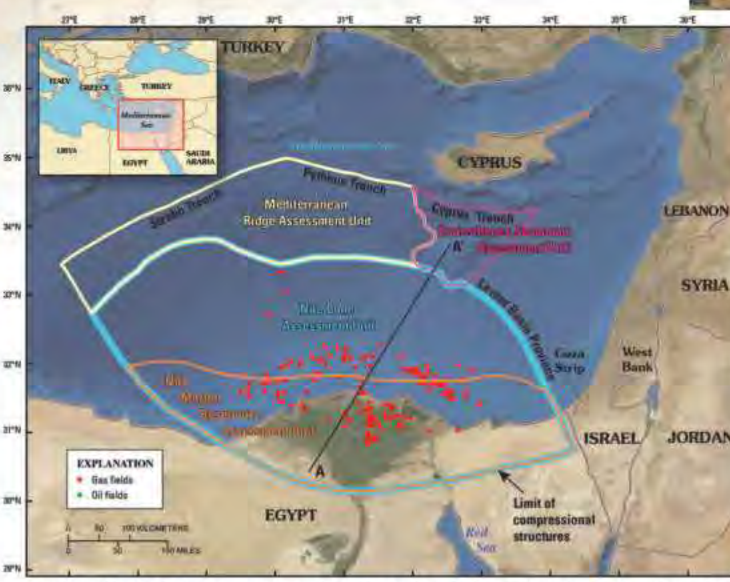
While the discovery has caused some political stirrings regarding overlapping maritime borders and energy export deals, it also serves as an important reminder of the vast number of opportunities that still exist in one of the Earth's most prosperous geological gas havens.

When assessments of mean undiscovered resources by the US Geological Survey (USGS) in the Nile Delta Basin and the Levant Basin are combined, the Eastern Mediterranean becomes the No. 2 spot in the world – just behind Western Siberia – for gas resources. Together, the basins have an estimated mean of 345 Tcf, says Christopher Schenk, a Denver-based geologist who has overseen the USGS' oil and gas assessments for nearly 20 years.

The secret lies in the salt. Named after the salt marches in the Italian town of Messina, the Messinian salt that remained after the Mediterranean Sea dried up during the Miocene Period, measured as thick as hundreds, even thousands of feet, Schenk says.

"It's one of the most amazing geological phenomena ever," he says of the Messinian salt event. "If you look at the 2D seismic data for this area, you can just see these beautiful, large structures. It's a very nice system. You can imagine oil and gas coming up from below and being trapped in structures. The salt seal has been quite effective for the Levant and for the Nile."

Noble Energy was the first to piece together the geology of the Eastern Mediterranean – drilling 11 successful wells



The location of four assesment units in the Nile Delta Basin Province in the Eastern Mediterranean. (Map not definitive for political boundaries.)
Map from USGS.

and discovering 40 Tcf of recoverable natural gas resources in the Levant Basin, since entering the region in 1998. The company's finds include the Leviathan field, which has been appraised to hold 22 Tcf of recoverable resources and was the largest discovery in the world in 2010.

Yet, other operators including Eni, BG Group, Shell and BP, have begun making their own discoveries – bringing sighs of relief to countries in need of natural gas.

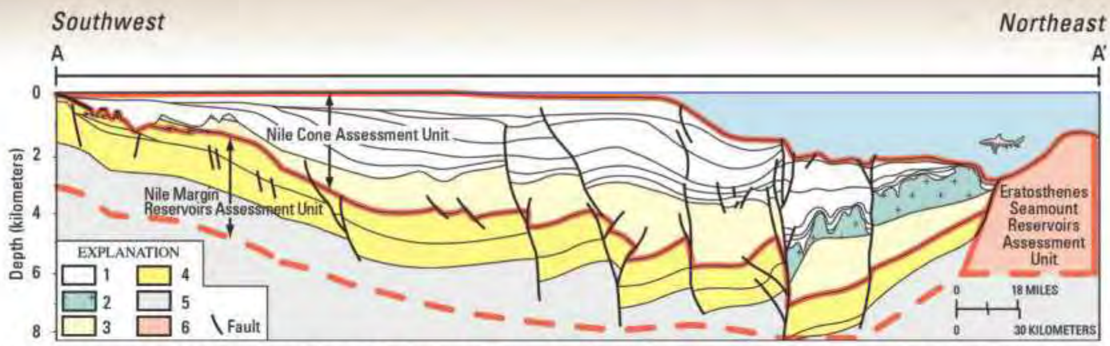
As large as the Zohr field discovery may be, an abundance of resources await to be discovered in areas where drilling is currently taking place, and in substantially underexplored areas ripe with potential.

Nile Delta and Levant basins

By their very geological components, deltas are ideal places to explore, as they contain source rocks, reservoir rocks and traps. In the Nile Delta Basin, an area that has been explored for quite some time, channel sandstones, sheet sands and basin floor fan sands make up the meat of that particular play, Schenk says.

With an estimated mean of 223 Tcf of natural gas, the world's largest delta remains plentiful despite discoveries that

Part of the ancient Roman aqueduct at Caesarea Maritima about half way between Haifa and Tel Aviv on the Mediterranean coast. Photo by Chris Schenk. Courtesy of the USGS.



Schematic geologic cross section of the Nile Delta Basin Province illustrating the geologic definition of three of the four assessment units (AU) in this study (dotted red lines): Nile Margin Reservoir AU, Nile Cone AU, and Eratosthenes Seamount AU. The forth AU, Mediterranean Ridge, is out of the plane of the cross section. Key: 1 – Miocene (post-Messinian and Pliocene-Quaternary; 2 – Messinian Salt; 3 – Miocene (pre-Messinian); 4 – Paleogene-Cretaceous; 5 – hypothesized pre-Cretaceous; 6 – Eratosthenes Seamount. Source: USGS.

total roughly 75 Tcf of natural gas to date, Schenk says. The basin's most prospective area is the Nile Cone, with an estimated mean of 217 Tcf. The basin also has an estimated mean of 1.8 billion bbl of oil.

"A petroleum charge is confirmed by more than 100 producing fields, numerous oil seeps, mud volcanoes and gas chimneys imaged on seismic profiles," reports the USGS.

Although a far cry from the enormous Zohr prospect, a discovery of 5 Tcf in the Nile Delta Basin was also made last year by BP Egypt from its Atoll-1 deepwater exploration well. "Success in Atoll further increases our confidence in the quality of the Nile Delta as a world class gas basin," said Bob Dudley, BP Group chief executive, in a statement to the press.

Just east of the Nile Delta Basin, the Levant Basin has an estimated mean of 122 Tcf of natural gas, with its most promising plays located in its subsalt areas, which have an estimated mean of 81 Tcf, Schenk says. Its oil prospects have an estimated mean of 1.7 billion bbl.

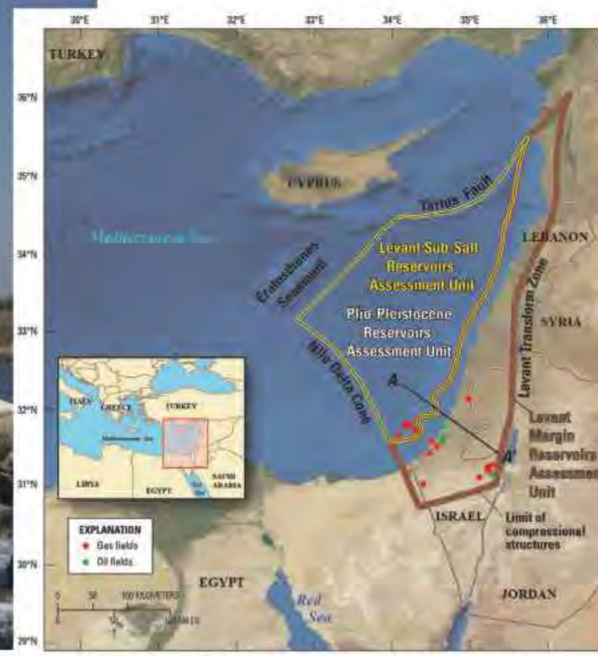
Geologic features including nearshore marine sandstones and deepwater slope and fan sandstones help make the Levant Basin a prospective play. Noble Energy relied on seismic data, spot-on interpretations and proficient project execution to achieve production in the Mari-B field in 2004, and the Tamar field, which boasts 10 Tcf of recoverable resources, in 2013. Today, Tamar supplies more than 50% of the energy resources Israel uses to generate electricity.

"Interpretation of seismic was key. We saw hints that suggested the possibility of a really porous sandstone reservoir in a reasonably simple structure with a salt seal," says Susan Cunningham, executive vice president of Exploration, New Ventures, Geoscience, EHSR and Business Innovation at Noble Energy. "We also saw the possibility of a flat spot on the seismic – an indicator of hydrocarbons."

When determining which blocks to lease in the Levant Basin, Noble Energy obtained available 2D seismic and underwent a basin-wide study to determine where structures similar to Tamar could be found. "We could see the running room in the basin and applied for the perspective acreage offshore Israel and Cyprus," Cunningham says.

The company discovered the Aphrodite gas field with an estimated 4 Tcf in Cyprus' maritime Exclusive Economic Zone in 2011. It has been reported that the resources in offshore Cyprus are more than the country could consume in a century.

Chalk cliffs near Rosh Hanikra western Galilee region coastal Israel.
Photo by Chris Schenk. Courtesy of the USGS.



Location of the three assessment units (AU) in the Levant Basin Province in the Eastern Mediterranean. The boundaries of the Levant Sub-Salt AU and Plio-Pleistocene Reservoirs AU are coincident. Map from USGS.

Subsequent discoveries by other operators in the Levant Basin and the recent Zohr discovery will help countries such as Israel, Egypt, Jordan and Cyprus meet their needs for power, but could also enable them to become exporters to Europe and other parts of the world. In fact, reports of competition have already begun hitting mainstream media outlets.

Venturing out

While many operators are exploring in the Nile Delta and Levant basins, a long list of prospects exist in areas that remain more obscure on the oil and gas map.

Perhaps most notable is the Essaouira Basin off the west coast of Morocco with an estimated mean of 45 Tcf of natural gas and 7 billion bbl of oil, according to the USGS. Unlike the Nile Delta and Levant basins, the salt present in the Essaouira originated during the initial rifting of the Atlantic Ocean, Schenk says.

"I think this is a very exciting place in the offshore basin," he says. "Although not many wells have been drilled here, the area has potential for source rocks, reservoirs, traps and seals. It has all the elements of a system that could really work."

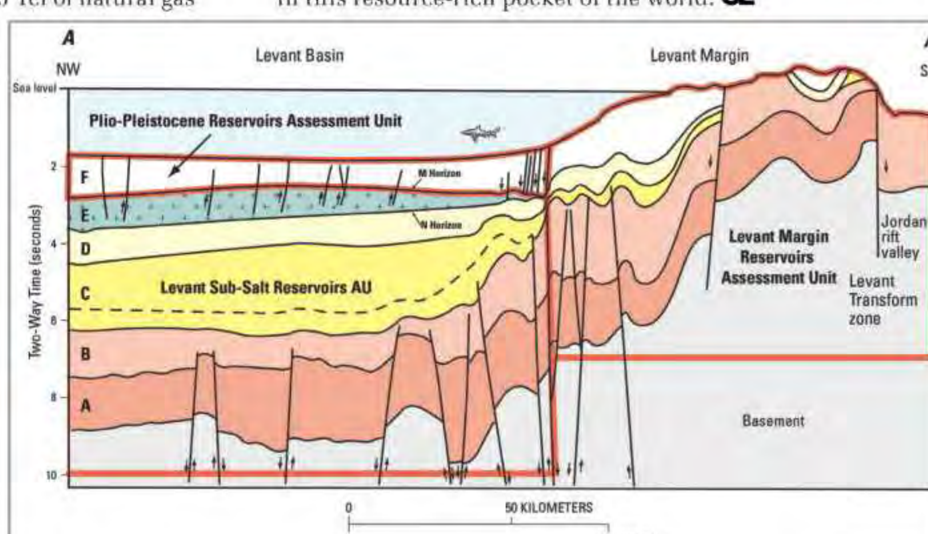
While some of the potential play is located in deep water, shallow prospects also exist, Schenk says.

Offshore Greece also holds potential, according to a 2012 study taken by Athens-based Flow Energy. The study estimates that south of Crete, an impressive 123 Tcf of natural gas and 1.5 billion bbl of oil are awaiting discovery.

Another underexplored gas prospect, the Provence Basin, is located just south of France. While no wells have been drilled in this area, the known presence of Messinian salt removes a bit of risk from this play, Schenk said. In fact, in terms of undiscovered resources, the USGS estimates a mean of 13 Tcf of natural gas and 500 MMbbl of oil in this basin.

As new technology and more 2D and 3D seismic data become available, discoveries in the Mediterranean will become less risky. Using 2D and 3D seismic is "absolutely routine" now, Schenk says. "That forms the basis for all of these new discoveries in the Levant Basin for sure," he adds.

Such technology will likely pave the way for others as well in this resource-rich pocket of the world. **OE**



Geologic cross section southern part of the Levant Basin Province illustrating the definition of the three assessment units (AU) in this study. The areas of the Levant Sub-Salt Reservoirs AU and the Plio-Pleistocene Reservoirs AU are coincident, and neither AU overlaps with the Levant Margin Reservoirs AU. Dashed line separates Cenozoic (above) from pre-Cenozoic rocks. Messinian-age salt (between the M and N seismic horizons) is shown in green. Key: A – Permian to Aalenian age; B – Bajocian to Turonian age; C – Senonian to Early Oligocene age; D – Oligocene to Late Miocene Age; E – Late Miocene (Messinian) age; F – Plio-Pleistocene age rocks. Source: USGS.

Bucking the trend

Chad Barnes reports that contrary to current industry norms, contracting activity in the Eastern Mediterranean and North Africa region is on the rise.

The last year has witnessed an overall decline in offshore activity in many parts of the world, due to low oil prices. However, activity in the Eastern Mediterranean has actually increased and the area offers potential future opportunities for offshore companies. The activity is fuelled by several recent major gas discoveries in Israel, Cyprus and Egypt that have the potential to not only serve domestic gas demand, but to act as a hub that could supply the European gas market.

Early in 2015, after years of delays, BP's US$12 billion West Nile Delta Development in Egypt, the biggest project in the region, also finally received the green light. BP said that the project will be fast-tracked to meet Egypt's gas shortages, with first gas planned for 2017.

Likewise, Eni's 30 Tcf deep water Zohr discovery offshore Egypt is also a game changer in the region, with the potential to convert Egypt from a net importer back to the LNG exporter that it was 10 years ago. The two-phased, fast-tracked project is targeting first gas in 2017 by drilling six wells this year and tying them into existing nearby infrastructure.

The recent success of Egyptian exploration has hindered developments of Israel's Leviathan field and Cyprus's Aphrodite field. Egypt was due to be a major gas customer from these fields. However, that has changed since Zohr has the potential to cover a significant part of Egypt's domestic gas demand.

The $7 billion FPSO development of the Leviathan field has recently been scrapped in favor of a revised, cheaper fixed platform solution. According to the new plan, half of the 21 Bcm of gas per annum is destined for Israel and neighboring countries while an additional platform exit point will be made for potential export opportunities to new markets. A final investment decision by Noble Energy is due to be made in late 2016. However, the Aphrodite partners are in advanced gas sale negotiations with the Egyptian market for potential exports in 2022. BG Group's recent Aphrodite field farm-in suggests that gas from the field is likely to go to BG Group's Egyptian refinery or potentially to their Idku LNG export facility.

With Egypt not expected to require gas imports from 2022 for its domestic needs, exporting to Greece or Turkey may be a more attractive option for Cyprus and Israel. A pre-FEED study is due to be completed in March 2016 (as *OE* went to press) for a subsea pipeline to Greece, which could influence the development decisions of the Eastern Mediterranean fields. However, considering the Zohr, Aphrodite and Leviathan fields all lie within close proximity to each other, there is the potential to allow a coordinated development of the fields, using the existing idle LNG export facilities in Egypt. Provided that there is better cooperation between the countries and improved political stability, the next decade could see the region emerge as a major gas exporter to meet Europe's growing gas demand. **OE**

The Eastern Mediterranean gas landscape and a focus on Egypt

Source: Middle East Economic Survey.

***Chad Barnes** is an analyst at the EIC for the upstream sector, and covers this remit globally. He has a degree in geology from the University of Leeds and a Master's degree in integrated petroleum geoscience from the University of Aberdeen. Chad has also gained experience working with a North Sea operator, Ithaca Energy.*

OTC: adapting to new realities

Photos from OTC.

The Offshore Technology Conference (OTC) returns to Houston with strategies for adapting to the new normal.

by Melissa Sustaita

In its 48th run, the 2016 Offshore Technology Conference (OTC) will once again bring together energy leaders and professionals from all over the world to Houston to tackle the oil and gas industry's current low oil price environment, with ideas and strategies on how to adapt and move forward.

The mega conference is placing focus on adapting to today's "new environment," and coping with lower oil prices, overcapacity, sluggish economic growth, and price volatility, in addition to opportunities, and solutions.

On Tuesday, 3 May, two panels filled with heavy hitters such as Mexico's Minister of Energy Pedro Joaquin Coldwell, Pemex's new CEO José Antonio González Anaya, Mexico's National Hydrocarbons Commission (CNH), Statoil, and more, will discuss Mexico's historic energy reform. One panel will take an in-depth look at new deepwater plays offshore Mexico that have been identified in new multi-client exploration data.

Technical highlights will include presentations of floating LNG projects and developments, extending the life of aging fields, as well as a look at Statoil's Asgard and Gullfaks projects, the world's first two subsea compression stations.

New this year, OTC is introducing several training courses that will be hosted by several sponsoring societies, and will take place on 30 April and 1 May at the George R. Brown Convention Center in downtown Houston. Some course topics include: ASME code design for HPHT wellhead components, deepwater riser engineering, modern well design, recognizing catastrophic incident warning signs, subsea production and technologies, deepwater drilling and production technology, and petroleum geology for engineers.

To switch things up this year, OTC will replace its Annual OTC Dinner, by hosting the Distinguished Achievement

OTC 2015 by the numbers:

94,700 – The number of attendees OTC attracted

130 – The number of countries OTC attendees represented

2682 – The number of companies that exhibited

695,005sq ft – The amount of sold-out exhibit space in OTC history

300 – The number of technical papers presented

11 – The number of panel sessions

29 – The number of executive keynote speakers

17 – The number of technologies recognized for innovation

Awards Luncheon on Tuesday, 3 May, at NRG Center. The 2016 beneficiary of the OTC Distinguished Achievement Awards Luncheon will be presented to the Junior Achievement (JA) of Southeast Texas for its strong focus on students whose families have been directly affected by the industry downturn. The luncheon will raise funds for scholarships to students pursuing degrees and certifications needed for, and careers in, the offshore industry. Priority will be granted to those students whose family has been impacted by layoffs related to the economic downturn. Resources will be used to support the growth of JA Inspire, Junior Achievement's work readiness program aimed at eighth grade students, informing them of the opportunities in the offshore oil and gas industry.

After the successful debut of d5 last year, the forward-thinking event will return in 2016 as global innovators speak and lead group discussions aimed to spark creativity and identify the next big step for the energy industry through technology, leadership practices, and competitive advantages. There will be presentations available, along with the chance to participate in discussions set to inspire ideas, innovation, and to leave a lasting impact.

This year's d5 event will be held at Rice University on Friday, 6 May.

Sponsoring organizations for OTC 2016 include: American Institute of Chemical Engineers (AIChE), American Association of Petroleum Geologists (AAPG), American Institute of Mining, Metallurgical, and Petroleum Engineers (AIME), American Society of Civil Engineers (ASCE), American Society of Mechanical Engineers (ASME), Institute of Electrical and Electronics Engineers Oceanic Engineering Society (IEEE-OES), Marine Technology Society (MTS), Society of Exploration Geophysicists (SEG), Society for Mining, Metallurgy, and Exploration Inc. (SME), Society of Naval Architects and Marine Engineers (SNAME), Society of Petroleum Engineers (SPE), and The Minerals, Metals, and Materials Society (TMS).

Supporting organizations include: American Association of Drilling Engineers (AADE), American Petroleum Institute (API), Association of Energy Service Companies (AESC), ASTM International, Center for Offshore Safety, Independent Petroleum Association of America (IPAA), Institute of Marine Engineering, Science, and Technology (IMarEST), International Marine Contractors Association (IMCA), International Society of Automation (ISA), National Ocean Industries Association (NOIA), and Research Partnership to Secure Energy for America (RPSEA). **OE**

OTC takes place 2-6 May 2016 at Houston's NRG Park complex. For more information on OTC, including the full conference and events, visit 2016.otcnet.org.

Solutions

Technology advances highlighted during OTC Spotlight Awards

This year's OTC Spotlight on New Technology winners showcase innovation in drilling, completions, production, and subsea operations. Congratulations to all the 2016 winners.

The OTC Spotlight on Technology Awards will be presented in the NRG Center Rotunda Lobby on 2 May. The recipients were selected based on four criteria: New and Innovative: less than two years old; original and groundbreaking; proven: through full-scale application or successful prototype testing; Broad Interest: broad appeal for the industry; and significant Impact: provides significant benefits beyond existing technologies. For a second year, OTC recognizes innovations developed by small businesses. This year's recipient of the Spotlight on Small Business Award went to Barge Master.

AFGlobal Corp., Riser Gas Handling (RGH) System

AFGlobal's Riser Gas Handling (RGH) system mitigates gas for dynamically positioned/moored rigs. The RGH system handles retrofits and new builds using specialty riser joints and equipment, which are transparent to rig processes.
www.dynafab.com

Baker Hughes, Integrity eXplorer cement evaluation service

The Integrity eXplorer cement evaluation service directly measures the cement strength across a range of weights, utilizing electromagnetic-acoustic transducer sensor technology.
www.bakerhughes.com

FMC Technologies, producer of InLine ElectroCoalescer (IEC)

FMC Technologies' InLine ElectroCoalescer is a pipe-based technology which uses a high-frequency, alternating current with high voltage to polarize, coalesce and enlarge water droplets to improve oil/water separation and helps maximize deepwater production of medium and heavy oil.
www.fmctechnologies.com

GE Oil and Gas, SeaPrime I Subsea MUX BOP Control System

GE's SeaPrime I Subsea MUX BOP Control System allows drilling contractors to continue drilling if components of one POD fail. This new design simplifies access to critical components, utilizes only two pods, and re-routes failed functions within a POD.
www.geoilandgas.com

Halliburton, BaraLogix Density and Rheology Unit (DRU)

The BaraLogix Density and Rheology Unit (DRU) is an autonomous, automated device that allows real-time measurements of fluid density and rheology, combined with trending analysis visible to the well construction team. The BaraLogix is modular in design and ATEX and Zone 1 certified. *(See page 50 to read how the system was deployed in the US Gulf of Mexico.)*
www.halliburton.com

Lankhorst Ropes, LankoDeep – Soft Rope Systems

The Soft Rope System is comprised of Lankhorst Ropes' LankoDeep rope, DSM Dyneema, and an Active Heave Compensation (AHC) drum winch system from Deep Tek. It is capable of handling heavy loads at over 3000m water depth and makes use of a rope condition management system.
www.lankhorstropes.com

Oceaneering International, Remote Piloting and Automated Control Technology

Oceaneering's Remote Piloting and Automated Control Technology (RPACT) allows SMEs or ROV pilots to establish ROV control through a satellite or wireless network link to support operations at a remote work site.
www.oceaneering.com

OES Oilfield Services Group, DOPP

Dropped Objects Prevention Programme (DOPP) is a tablet based four stage program that evaluates each rig site's ability to control, implement and mitigate Dropped Objects. A tablet populated with the data gathered from

a dropped objects survey is given to the rig crew, which allows the rig to keep control over dropped object prevention and maintenance.
www.oesgroup.com

OneSubsea, AquaWatcher Water Analysis Sensor and HyFleX Subsea Tree System

Two OneSubsea technologies have been recognized.

The AquaWatcher Water Analysis Sensor detects and characterizes water in multiphase and wet gas flows, plus determines water salinity and the injected chemicals to water ratio. This ratio also allows accurate determination of chemical dosage requirements for injection management.

The HyFleX Subsea Tree System design configures the tubing head spool, tubing hanger and tree independently of each other, allowing installation like a conventional horizontal or vertical tree. This provides operators with the functional flexibility in installation sequence and workover operations.
www.onesubsea.com

SkoFlo Industries, Subsea Back Pressure Regulator Valve

SkoFlo Subsea Back Pressure Regulators (BPRs) maintains a predetermined fluid column pressure at the injection point to prevent siphoning and uncontrolled delivery of chemicals into production wells. The device activates when well pressure falls below a set limit, regulating and controlling the overall line pressure.
www.skoflo.com

Teledyne Oil & Gas, Electrical Optical Flying Lead (EOFL)

The Electrical Optical Flying Lead features a Nautilus Rolling Seal Hybrid

connector on one side, and a Nautilus electrical connector on the other, with a qualified electrical/optical converter integrated into the pressure balanced, oil-filled hose. Additionally, the EOFL's modular power converter allows the use of different power inputs to provide flexibility to project requirements.
www.teledyne.com

Barge Master, producer of Barge Master T40

The BM-T40 is designed to compensate for sea induced motions while lifting from a moving vessel to an offshore installation. The vessel's heave, roll and pitch motions at the base of the crane are compensated by three vertically mounted hydraulic cylinders.
www.barge-master.com

COMPANIES

Activity

Raising the bar

Investing at a time when the oil industry is facing one of its hardest downturns may not be the easiest decision for many. Balmoral Offshore Engineering isn't holding back, however. Elaine Maslin reports.

Artist's impression of the Balmoral Subsea Test Centre. Image from Balmoral Offshore Engineering.

Aberdeen-based buoyancy, insulation and elastomer product firm Balmoral Offshore is investing around £20 million (US$29 millon) in a new subsea test center. Once complete, later this year, it will be one of the largest hyperbaric testing facilities in Europe, both for the firm's own in-house work but also for third party testing.

Creating the center has meant blasting a 13m hole into Aberdeenshire granite to build a pit large enough to house what will be the facility's largest pressure vessel. At 10m-long and 1.8m in diameter, the vessel will be able to test pressures up to 6890psi (475 bar), or the equivalent of being in 4750m (15,583ft) water depth. The vessel, being produced in Italy and due to arrive in the UK in April/May, has been designed to accommodate drill riser buoyancy modules and other large pieces of equipment. It will be one of 14 vessels, with the pressure tests possible up to 10,000psi (700 bar).

A new 9m-diameter by 4.5m-deep, 286,000 liter test for large scale displacement testing is also being built, which will also serve as a water tank for the pressure vessels. The new 12m high center, covering 800sq m, at Balmoral Offshore's premises, will also have three cranes, including a 40-tonne capacity gantry crane.

The idea is to be able to increase the facilities available for testing everything from huge drill riser buoyancy modules and ROVs to smaller pieces of subsea equipment, such as valves and controls, says Jim Milne, Balmoral's founder and managing director.

"It could be in-house testing of buoyancy or elastomer products or it could be unusual materials from half way around the world," he says. "The equipment we have is unique in its application and we carry out work across many sectors."

Fraser Milne, engineering and projects director, says there's demand for these facilities. "We are continually testing at our current center and we are finding we cannot support the [third party testing] market because of our own work, so we are having to pass some external customer out of the test center."

Part of the increase in testing demand has been an increase in testing requirements, especially longer-term testing, he says, from 12-hour tests to 168-hour tests, which takes vessels out of other use. As the industry has moved into ever deeper waters, the scale of capability of test facilities has also had to increase.

There are other hyperbaric test facilities, including the National Hyperbaric Centre in Aberdeen, and the Newcastle University/Bel Valves new facility in Newcastle. Newcastle's larger chamber is 2.5m-diameter, but it's limited to 4500m depth equivalent testing. The National Hyperbaric Centre can test up to 8000m depth equivalent, but has smaller facilities. "We offer a full service with full materials testing," Milne says.

The new test facility, which will sit alongside the firm's science laboratory and elastomer facility – an 18m high facility to accommodate a 14m-high oven – will offer facilities for hyperbaric, mechanical and laboratory trials, including the buoyancy and polyurethane materials and product testing.

Balmoral has also created its own software to allow full test traceability and real-time observation from anywhere in the world, which it believes is a first for the industry and can also reduce downtime.

Standard hyperbaric tests range from water ingress and hydrostatic collapse to bulk modulus and buckle arrestment performance.

The hyperbaric vessels use air driven liquid pumps and can accommodate electric, hydraulic and instrumentation connections. Each vessel can be fitted with chart recorders, pressure and temperature data loggers that provide highly detailed results for analysis.

For mechanical testing, a multipurpose load rig can also perform a range of tests from axial and lateral slip loads to compression and shear testing on companion cylinders. ▪

Offshore achievements recognized

Well-SENSE Technology's technology director Dan Purkis has been singled out for his efforts in the offshore oil and gas industry with the award of the Society of Petroleum Engineer's (SPE) Aberdeen section Significant Contribution accolade.

Purkis' career spans some 20 years, but his interest in engineering started much earlier. An inventor at heart, Purkis has led world-class design teams, pioneered the world's first intelligent completion and played a critical role in developing intellectual property for some of the world's best-known oil and gas service companies.

The award was presented at the SPE's 30th Offshore Achievement Awards, of which *OE* is media sponsor, held in Aberdeen in March.

After collecting his award, he said: "Enthusiasm, passion, and always questioning if there's a better way are the keys to successful innovation. In a low oil price environment there has never been a better time to introduce new technology. It does however require the right industry support and an acceptance that no significant changes can be made if a risk averse attitude prevails."

Trevor Garlick, who was presented with a special recognition award from SPE Aberdeen. Photo from Offshore Achievement Awards.

Companies picking up awards included Tendeka, Well-Centric, Interventek Subsea Engineering, Darcy, N-Sea, CETCO Energy Services, TWMA, Peterson and Aker Solutions.

A special award was presented to BP's former North Sea region president Trevor Garlick, in recognition of his long term support of SPE.

Alan Dick, of award organisers SPE Aberdeen, said: "This year's Offshore Achievement Awards have been a much-needed injection of energy for the industry, reminding all of us that by continuing to innovate, collaborate and communicate, we can remain confident in the long term future of North Sea oil and gas." **OE**

The 2016 Offshore Achievement Award winners in each category are:

Emerging Technology Awards
- WINNER – Interventek Subsea Engineering

Innovator Award
- WINNER – Darcy

Safety Innovations Award
- WINNER – N-Sea

Environmental Innovation Award
- WINNER – CETCO Energy Services

Export Achievement Award
- WINNER – TWMA

Collaboration Award
- WINNER – Peterson

Outstanding Skills Development Program Award
- WINNER – Aker Solutions

Young Professional Award
- WINNER – Hayleigh Pearson, Costain

Above & Beyond Award
- WINNER – Allan Smillie, TAQA

Great Small Company Award
- WINNER – Well-Centric

Great Large Company Award
- WINNER – Tendeka

PEOPLE

Spotlight

Welding to West of Shetland

The North Sea is facing some tough challenges. Elaine Maslin spoke with Brenda Wyllie, who aims to confront those challenges as part of the industry's new regulator, as well as chairman of the DEVEX conference.

Poacher turned gamekeeper is always an interesting step to take and it is one Brenda Wyllie never foresaw taking. However, she's not one to worry about breaking molds. Wyllie started out as an apprentice welder, graduated with an MSc in petroleum engineering, and went on to work for service companies and both large and smaller operators.

Now, after a stint at trade body Oil & Gas UK, she's Northern North Sea and West of Shetland Area Manager at the newly formed UK North Sea regulator, the Oil and Gas Authority (OGA), and also heading up this year's DEVEX conference, headlined as "Delivering positive change to maximize value."

Recognizing that it's not an easy time to be in the North Sea, the organizers – the Society of Petroleum Engineers, Petroleum Exploration Society of Great Britain and Aberdeen Formation Evaluation Society –have made the Aberdeen conference free, to help those perhaps not in work remain networked and up to speed.

Indeed, the basin, much of which is not profitable at US$30/bbl, faces some hard work in coming months and years and most of it will be about focusing on getting more out of what is already there. "In a $30/bbl world, we cannot get a shiny new asset, we have to look at what we have got and maximize production, drive costs down," Wyllie says. "It's looking at what we have currently available and how you can really squeeze it. We need to chase every barrel, every day."

Wyllie's career started in 1987, when, just out of school, she joined Halliburton in her home town Arbroath, Scotland, as an apprentice welder. She'd seen the service provider's equipment proudly paraded through the town before its onward journey, often overseas, and was inspired.

"People like me didn't go to university, it wasn't an option," Wyllie says, who was the only female at the site. "I remember that first day thinking 'I've made it.' I would have a skill and a job forever." But, "back then, the oil price was $20/bbl," she recalls. "It was a collapsing industry."

Thanks to coaching from a boss at the time, Jack Stockdale, at the end of the five-year apprenticeship, Wyllie went to university, studying at Robert Gordon University in Aberdeen and then at the University of Stavanger on an exchange program, gaining an MSc as a petroleum engineer.

Brenda Wyllie

Her mission was to work for Schlumberger as a wireline engineer, which she achieved, working in Shetland servicing the Brents, Ninian, Cormorant and other fields before leaving to have three children. When she returned in 2006, it was to work for operators, including Hess, from 2006-2009, in Malaysia, then BP, in the North Sea, working on the Schiehallion and Loyal fields, and finally Canadian Natural Resources as UK production manager, up to March 2014.

Moving to work for operators, and different scale operators, set Wyllie up well for her latest roles, at Oil & Gas UK, then the OGA, the UK's newly formed regulator, at a time when the industry is facing some major introspection. The UK North Sea was suffering from falling production, low exploration rates, and ever higher costs, even before the oil price collapse, resulting in the UK Government commissioning the Wood Review, an outcome of which was the formation of the OGA.

"My time at BP taught me some really good petroleum engineering work flows - they have got the field basics," she says. "Working with the smaller companies, you can make some decisions quicker, but they're not always the right decisions because they don't have those work flows.

"I never thought I would be working for the regulator, but, reading the Wood Review and seeing all the work leading to the OGA, it became obvious. Working at CNR, I thought I had a helicopter view [looking after multiple assets]. At Oil & Gas UK, I then had a sense of seeing the industry from 35,000ft. It was an obvious step up to the OGA."

DEVEX, running 18-19 May at Aberdeen Exhibition and Conference Centre, has a number of themes this year, including advanced recovery mechanisms, maximizing production, solutions to defer cessation of production, tight gas, best in class field development options, and near field exploration.

Wyllie is making it a mission to make sure there are core samples on show, and there will also be a field trip as part of the event. One of the focus areas is water flood. But it's not just about looking to apply these technologies, it's understanding what will work best where. "If you can add something in to your injection water it helps clean the rock," Wyllie says. "But if you don't have the basics right you will not get the best out." OE

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What's next

Coming up in OE May

Global Deepwater Review
- Platforms
- Subsea Processing
- Risers & Umbilicals
- Topsides
- Deepwater Drilling
- Automation Safety
- Regional spotlight: Gulf of Mexico

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- ❑ 01 Executive & Senior Mgmt (CEO,CFO, COO,Chairman, President, Owner, VP, Director, Managing Dir., etc)
- ❑ 02 Engineering or Engineering Mgmt.
- ❑ 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)

- ❑ 21 Integrated Oil/Gas Company
- ❑ 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
- ❑ 31 Ship/Fabrication Yard
- ❑ 32 Marine Support Services
- ❑ 33 Service, Supply, Equipment Manufacturing
- ❑ 34 Finance, Insurance
- ❑ 35 Government,Research, Education, Industry Association
- ❑ 99 Other *(please specify)* ____________

3. Do you recommend or approve the purchase of equipment or services?
(check all that apply)

- ❑ 700 Specify
- ❑ 701 Recommend
- ❑ 702 Approve
- ❑ 703 Purchase

4. Which of the following best describes your personal area of activity?
(check all that apply)

- ❑ 101 Exploration survey
- ❑ 102 Drilling
- ❑ 103 Sub-sea production, construction (including pipelines)
- ❑ 104 Topsides, jacket design, fabrication, hook-up and commissioning
- ❑ 105 Inspection, repair, maintenance
- ❑ 106 Production, process control instrumentation, power generation, etc.
- ❑ 107 Support services, supply boats, transport, support ships, etc
- ❑ 108 Equipment supply
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- ❑ 110 Production
- ❑ 111 Reservoir
- ❑ 99 Other (please specify)

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