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# Rig market review

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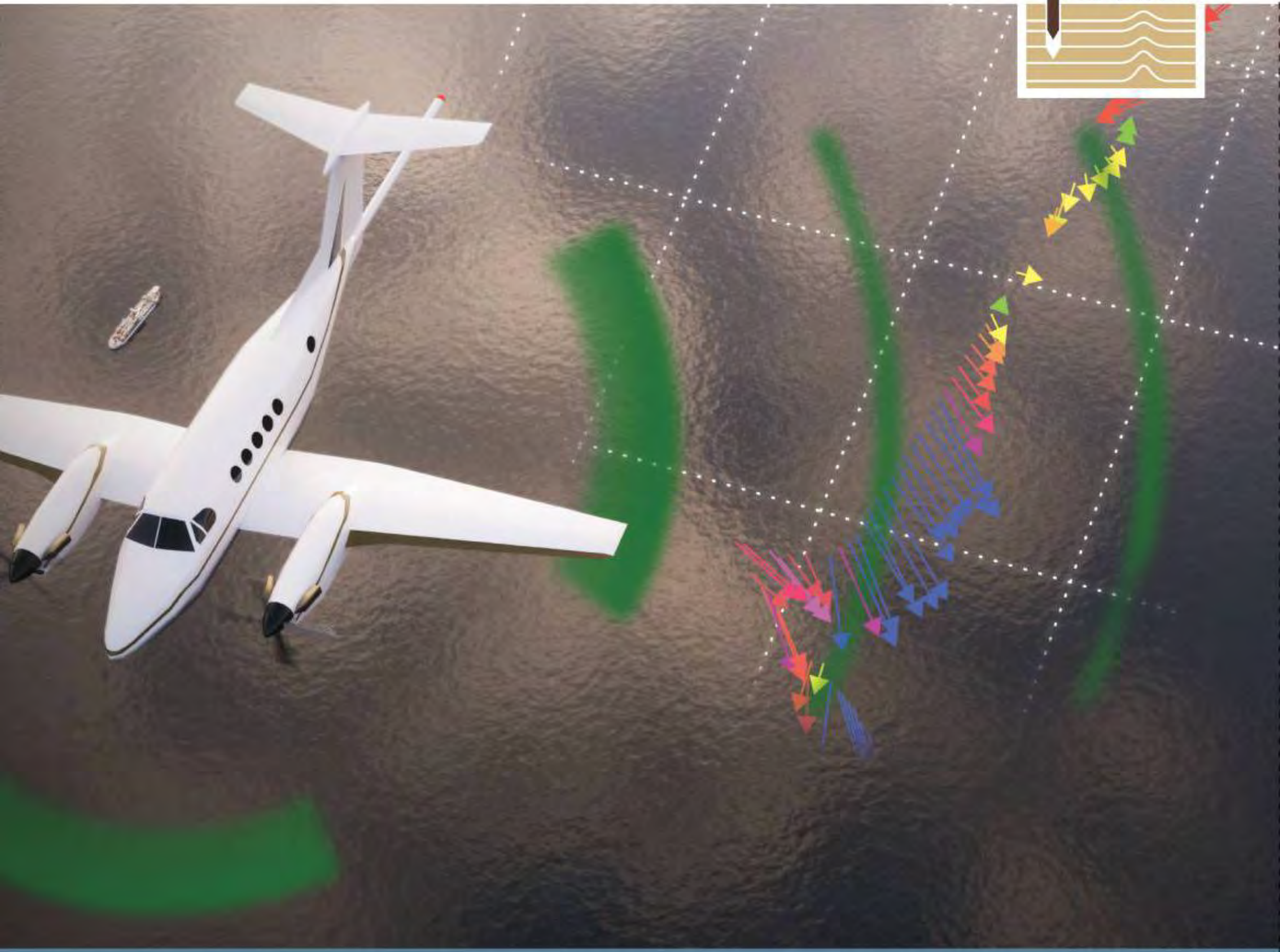
INSIDE: OE highlights Norway's subsea sector and Mexico's budding offshore segment.

Offshore Engineer • March 2016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FEATURE FOCUS

## Rig market review



The *Polar Pioneer* semisub in Seattle. Photo from Shell.

# Features








ON THE COVER

**Big & Bright.** While surveying the offshore rig market may make one depressed, one bright spot is the contract secured by Transocean's new *Deepwater Thalassa* drillship, which graces the cover of this issue. Read more on page 22.
*Photo courtesy of Transocean.*

# Departments & Columns




AtComedia
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**AtComedia**
**1635 W. Alabama**
**Houston, Texas 77006-4101, USA**
**Tel: +1-713-529-1616 | Fax: +1-713-523-2339**
**email: info@atcomedia.com**

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# Online Exclusive

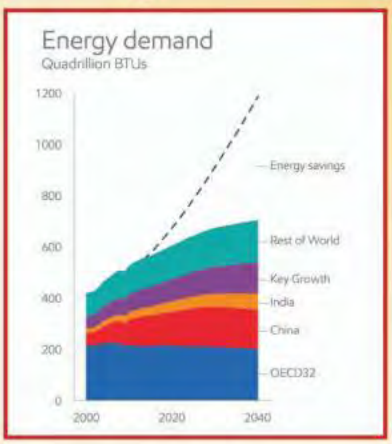
## Mexico under the spotlight

Audrey Leon investigates what is next for Mexico's national oil company Pemex following the appointment of new CEO José Antonio González Anaya.

# What's Trending

## Strong outlook

- ExxonMobil: Energy demand to increase by 25%
- Oil firms still eyeing Arctic exploration
- Shell, BG merger receives final approval




# People

## BP in management shakeup

As BP seeks to restructure its management team, the supermajor elevated upstream executive Lamar McKay to deputy group chief executive, with chief operating officer, production, Bernard Looney, taking McKay's old role.

Lamar McKay

Bernard Looney

# Webinar

## Strategies for Integrated Asset Optimization

The second edition of OE's Asset Integrity Webinar Series brings together experts from Baker Hughes, Sogeti and Dassault Systemes to discuss how technology can be leveraged to hedge against risk and optimize opportunities for power, process manufacturing, chemicals and oil and gas.

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OE OPINION

# Undercurrents

## Rate of change

In early February, Mexican President Enrique Peña Nieto shook things up at the country's oil company, Petróleos Mexicanos (Pemex), replacing CEO Emilio Lozoya Austin with Mexico's director of the Social Security Institute (IMSS) José Antonio González Anaya, a highly respected economist who held positions at the World Bank and at Stanford University in California.

González's new job will not be easy. He is charged with accelerating Pemex's reform, as laid out in the country's new energy framework, and strengthening Pemex's financial and productive health during this period of global low oil prices.

Francisco J. Monaldi, a fellow in Latin American Energy Policy for the Baker Institute at Rice University told *OE* that González was chosen to get the IMSS healthier, and now he's been "chosen to do surgery on Pemex."

"It's an over-bloated company with more than 150,000 employees and declining production," Monaldi says. "And all this was true before the oil price collapsed. They needed the reform because oil production was lagging, and significant, dramatic investment was needed."

**"If Pemex does not reform, then they will have a very difficult time changing the sector and increasing production."**

Pemex hit its production peak of 3.8 MMb/d in 2004, according to the US Energy Information Administration, and hasn't achieved anything close since. According Pemex's own numbers, the company produced 2.2 MMb/d in December 2015.

Monaldi says that reforming Pemex is the biggest piece of the Mexican energy reform. "[Mexico] has only opened very risky or relatively marginal oil fields for private investment and they have kept most of the best areas and proven reserves in the hands of Pemex," he says. "But if Pemex does not reform, then they will have a very difficult time changing the sector and increasing production."

A key to boosting production and the company's financial health will be the long-awaited farm-outs and potential joint venture partnerships, which Lozoya was criticized for not moving fast enough to accomplish.

Monaldi described the situation with Pemex as an "emergency" and Peña Nieto needed to act quickly to replace Lozoya, who had led Pemex since 2012. "I'm sure that he (Lozoya) understood the basic thrust of the need for the reform, it's tremendously difficult because you have a very powerful union," he says. "It's a politically very complex environment in which anything you do might lead the detractors of the reform to use it politically and any major overhaul of the company will face significant backlash, and I think that made Lozoya lose momentum."

And that loss of momentum led to delays, which made the Mexican government lose patience, Monaldi says.

"They are sending an enforcer," he says. "The fact that the president was willing to move one of his most trusted persons to execute this, it means he means business."

Monaldi says the farm-outs should be a priority in the fight to reverse declining oil production.

"These (farm-outs) are the only option where you could have some change within the next five years," he says. "The deep offshore could take 7-10 years to deliver output. This, I think, is a priority, and was a part of the reform that was lagging with respect to what we had expected."

No doubt many will keep watching to see how things play out with Pemex's new leader.

One of those who will continue watching the market is *OE*. In this issue, we have included in-depth analysis on the Mexican market, as well as Latin America, to highlight some of the bright spots in the region as a whole. Find more on pages 67 and 91.

But that's not all. In addition to our Rig Market Review (page 22), *OE* has compiled a special report on Norway's world-class subsea cluster. Check out pages 35-50 to learn more about technologies and subsea trends. **OE**

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**PUBLISHING & MARKETING**

**Chairman/Publisher**
Shaun Wymes
swymes@atcomedia.com

**EDITORIAL**

**Managing Editor**
Audrey Leon
aleon@atcomedia.com

**European Editor**
Elaine Maslin
emaslin@atcomedia.com

**Asia Pacific Editor**
Audrey Raj
araj@atcomedia.com

**Web Editor**
Melissa Sustaita
msustaita@atcomedia.com

**Contributors**
Heather Saucier

**Editorial Assistant**
Jerry Lee

**ART AND PRODUCTION**
Bonnie James
Verzell James

**CONFERENCES & EVENTS**

**Events Coordinator**
Jennifer Granda
jgranda@atcomedia.com

**Exhibition/Sponsorship Sales**
Gisset Capriles
gcapriles@atcomedia.com

**PRINT**
Quad Graphics, West Allis, Wisconsin, USA

**EDITORIAL ADVISORS**
John Chianis, *Houston Offshore Engineering*
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OPINION

# The Barrel

## Mood swings

There is no doubt in my mind that the smartest investor of our generation is the billionaire "Oracle of Omaha" Warren Buffett, who transformed Berkshire Hathaway (a bust textiles company) into a $300 billion investment giant.

Along the way Buffett has imparted many valuable pearls of wisdom, many of which I refer to and use in my own business life. One of these is "a public opinion poll is no substitute for thought."

> **"There is little doubt that the price will continue to swing wildly in the coming weeks as speculators react to the continual bombardment of rhetoric and weekly data, much of which is of questionable precision"**

The first few weeks of 2016 have been very traumatic for anyone involved in the oil and gas industry as oil prices continued their downward slump to levels no one could have envisaged. This decline was driven by the confluence of large crude inventory builds in the US, record production output in Russia/Saudi and the expectation that the lifting of sanctions in Iran will add to the supply glut. Concerns that demand for oil in China is slowing has compounded the misery.

In mid-February, as I write this column, we have seen the crude prices rally above $30 as speculators rushed to close out short bets when Iran voiced its support for a Russia/Saudi-led move to freeze production. This rhetoric is definitely a positive signal but it is a long way from being a definitive commitment to reduce supply. This resulted in traded volumes in US crude futures falling to 500 MMbbl (this still equates to 50 times the number of physical barrels traded) and crude prices rallied by over 10%, demonstrating the extent to which traders are responsible for driving the price volatility.

There is little doubt that the price will continue to swing wildly in the coming weeks as speculators react to the continual bombardment of rhetoric and weekly data, much of which is of questionable precision.

Confidence in the industry will continue to be eroded and, as I've said before in this column, 2016 will be a nightmare year for companies in the oil sector as they are clobbered with the dual misery of falling activity and drained liquidity.

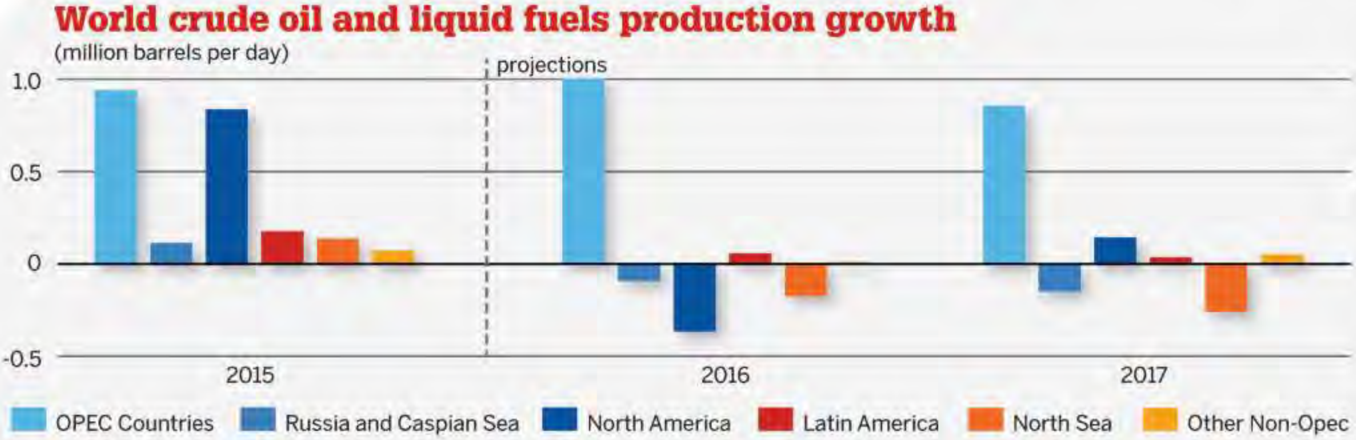
In these times, when sentiment is at its lowest ebb, we need to recall Buffett's advice that "a public opinion poll is no substitute for thought" and remind ourselves of the certainty that all oilfields deplete. Moreover oilfields deplete more quickly if they are starved of investment as is happening at present.

Given that overall demand will continue to rise as the world economy grows (even in the choppy economic conditions of the last three years it grew by approximately 4 MMb/d) it will not be long before the oil market falls back into balance

History tells us that many fortunes have been made from oil sector investments that have been made in the teeth of a downturn and therefore another famous quote by Buffett is relevant here: "Be fearful when others are greedy and greedy when others are fearful." OE

*__Colin Welsh__ joined Simmons & Co. in 1999 to establish the firm's Eastern Hemisphere business. Prior to joining Simmons, in 1987, Welsh established the Aberdeen office of RMD, a newly formed accountancy and corporate finance firm. Previously, he worked in both the London and Aberdeen offices of Touche Ross. Welsh graduated from Aberdeen University having studied economics, accountancy and law. He went on to qualify as a Scottish Chartered Accountant while working at Ernst & Whinney (now Ernst & Young).*

### World crude oil and liquid fuels production growth




Source: Short-Term Energy Outlook, February 2016; US Energy Information Administration.

NEWS

# Global E&P Briefs

## A Chevron drops Buckskin-Moccasin

Chevron cancelled the deepwater Buckskin-Moccasin project in the US Gulf of Mexico, blaming the oil price for the decision to drop the multi-million dollar project. After assessing several alternative developments, including a hub or a tieback, Chevron pulled the plug.

"Right now, the costs in the deepwater haven't come down quite as fast as they have onshore," said Chevron CEO John Watson. "We felt that for the foreseeable future, we've got better places to put our money."

## B Gigante survey halfway done

TGS has acquired 93,000km (50%) of the 186,000km 2D seismic project, Gigante, which covers the entire offshore sector of Mexico and ties into TGS' regional 2D seismic grid covering the entire US Gulf of Mexico.

Interpretation of preliminary data has identified a number of prospective play fairways within a variety of structural provinces. Delivery of fast track products is ongoing with over 57,000km presently available including areas covering the proposed bid rounds in the Campeche, Perdido and Mexican Ridges regions.

In addition, acquisition of the Gigante multibeam data is 12% complete with preliminary results available.

## C Guyana activity increases

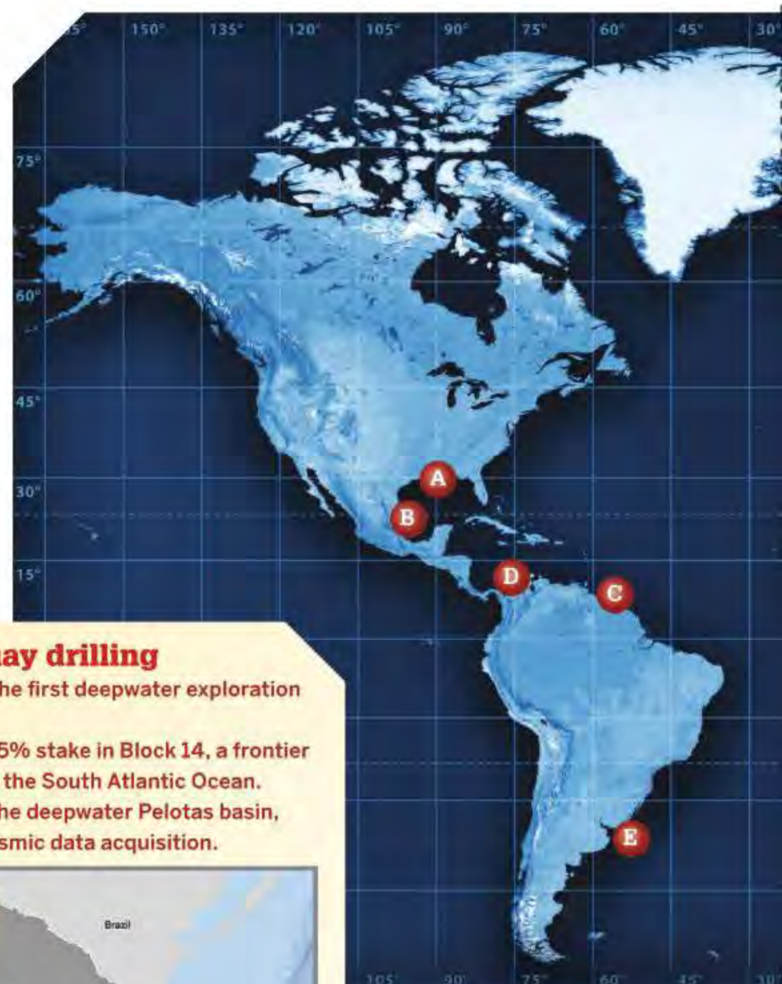
ExxonMobil is moving quickly to spud a well at its Liza discovery where more than 295ft of high quality oil-bearing sandstone reservoirs were encountered at the Liza-1 exploration well last year.

Seismic is nearing completion, and Exxon is working to contract a drillship to appraise Liza, which sits 120mi offshore Guyana, in the 6.6 million acre Stabroek Block.

Tullow (60%, operator) and Eco Atlantic Oil & Gas (40%) entered into a 10-year agreement with Guyana's government to explore the deepwater Orinduik block, in the Suriname Guyana basin, close to the Liza discovery.

## D CGG extends Colombian survey

CGG has been awarded an extension to a major 3D seismic survey completed in 2015 offshore Colombia's Caribbean coast. The new survey follows the original over 16,000sq km survey CGG conducted over portions of the Col-1 and Col-2 blocks.




## E Statoil joins Uruguay drilling

**Statoil will join Total in drilling the first deepwater exploration well offshore Uraguay.**

Statoil has agreed to take a 15% stake in Block 14, a frontier block about 200km offshore, in the South Atlantic Ocean. Block 14 covers 6690sq km in the deepwater Pelotas basin, and has been covered by 3D seismic data acquisition.

The Raya exploration well is due to be drilled in the block using the Maersk Venturer ultra-deepwater drillship in 1H 2016.

Total retains a 50% working interest, with ExxonMobil holding the remaining 35%.


## F Ireland bid round success

Out of the 43 applications submitted in the 2015 Atlantic Margin Licensing Round, 14 two-year licensing options in the Irish offshore has been offered to eight companies: Eni (1), Europa (1), ExxonMobil (2), Nexen (4), Scotia (1), Statoil (4) and Woodside (1) as operators, along with BP who will partner with Eni.

The awards focus on an area in the southern Porcupine basin, where a number of applications included commitments to acquire new seismic surveys later this year.

The second and final phase of awards is planned for mid-May.

## G Total brings Laggan-Tormore online

Total's Laggan and Tormore gas and condensate subsea-to-shore development achieved first gas. The development, in 120-600m water, will produce 90,000 boe/d. It is a four-well subsea tie-back via two, 143km-long 18in export pipelines to the new onshore, 500 Mcf/d Shetland Gas Plant. It will also provide the export infrastructure for two further subsea fields, Glenlivet and Edradour.

## H Qatar Petroleum enters Morocco trio

Qatar Petroleum reached a deal with Chevron to acquire participating interest in three


deepwater offshore leases: Cap Rhir Deep, Cap Cantin Deep and Cap Walidia Deep.

Under the agreement, Qatar Petroleum will acquire 30% interest while Chevron will retain a 45% interest and operatorship. Morocco's Office National Des Hydrocarbures Et Des Mines will continue to have a 25% interest.

The three offshore lease areas are 100-200km west and northwest of Agadir, Morocco, encompassing 29,200sq km with water depths ranging 100-4500m.

## I Kosmos discovers gas in Senegal

Kosmos Energy hit 101m (331ft) of net gas pay in two excellent quality reservoirs at its first exploration well, Guembeul-1 off Senegal.

Guembeul-1 is in the northern part of the St. Louis offshore Profond license area, and about 5km south of the basin-opening Tortue-1 gas discovery in 2700m of water.

The *Atwood Achiever* drilled the Guembuel-1 well to 5245m total depth. The well demonstrated reservoir continuity as well as static pressure communication with the Tortue-1 well, suggesting a single, large gas accumulation. Based on the integration of the Guembeul-1 well results, the Pmean gross resource estimate for the Tortue West structure has increased from 8 Tcf to 11 Tcf.

## K TEN project 85% complete

Tullow Oil's TEN project is now 85% complete and due to start up between July-August 2016.

In January, the project's FPSO set sail from Singapore and should arrive in Ghana in early March. It will be capable of producing 80,000 bo/d and will be tied into subsea infrastructure across the field. Daily output of around 80,000 bbl is expected to be reached by early 2017.

## L Alba B3 installed

Heerema Fabrication Group (HFG) has installed Marathon's Alba B3 topside and jacket offshore Equatorial Guinea. The 2000-ton, four-legged jacket, built at HFG's Vlissingen yard in the Netherlands, supports the 4500-ton B3 compression platform. The topsides were assembled at HFG's Zwijndrecht yard, also in the Netherlands. The Alba field compression project is designed to maintain the production plateau two additional years and extend field life by up to eight years. It is due to be operational by mid-2016.

## M Israeli firms in multi-Tcf find

Two Israeli firms are eyeing a multi-trillion cubic feet deepwater gas field offshore Israel.

According to a resource report by Netherland, Sewell & Associates, the Og field lower sand contains 8.84 Tcf best

## J Repsol to shut down Varg

**Spanish oil and gas explorer Repsol will shut down its Varg field operations offshore Norway, due to low oil prices. Repsol Norge operates Varg, which is 200km west of Stavanger in Block 15/12, with Teekay Offshore contracted to operate the *Petrojarl Varg* floating production storage and offloading unit (FPSO) on a lease basis. At the field, the FPSO and one unmanned platform, Varg A, are linked together with a 1200m production and injection pipeline, and a control umbilical.**

**Repsol operates Varg with 65% stake. Partners include Petoro (30%) and Det norse oljeselskap (5%).**

# Global E&P Briefs

estimate, unrisked gross prospective resources and the Og field upper sand contains 3 Tcf. Both also have some condensate.

The field is in the Daniel East license, operated by Israeli firms Isramco Negev and Modiin Energy, and has been covered by 3D seismic data.

The move comes months after Israel paved the way for Noble Energy and Delek Group to move forward with the Leviathan development and Tamar expansion projects.

### CNOOC fires up South China Sea fields

The Weizhou 12-2 oilfield joint development project and Weizhou 11-4 North oilfield Phase II project have begun production. Both projects are in the Beibu Gulf basin of the South China Sea with average water depths of 36-40m.

The Weizhou 12-2 project has three oilfields in total including the Weizhou 12-2, the Weizhou 12-1 West and the north part of Weizhou 11-2. The main production facilities include three wellhead platforms and 18 producing wells which have all commenced production, producing a total of approximately 16,000 b/d and reaching its ODP designed peak production.

Weizhou 11-4 North project shares the existing adjacent facilities for the development and built two wellhead platforms and 15 producing wells. There is currently one well on production, producing a total of approximately 500 b/d. The project is expected to reach its ODP designed peak production of approximately 8000 b/d within the year.

### Woodside in second Myanmar find

Australia's Woodside Energy has made a second gas discovery offshore Myanmar. The well intersected a 64m gross gas column with 62m of net gas pay at the Thalin-1A exploration well, which sits in 836m water inside Block AD-7 in the Rakhine basin, in the Bay of Bengal.

The well reached 3034m total depth. Woodside's first discovery was made at the Shwe Yee Htun-1 well in Block A-6.

### Lundin begins Maligan drilling

Lundin Malaysia spud the Maligan exploration well in Block SB307/SB308, offshore East Malaysia. The shallow water well will be drilled to 1700m below mean sea level using the West Prospero jackup. Drilling is expected to take 30 days.

Lundin Malaysia (85%) operates Block SB307/SB308, with partner Petronas (15%).

### Chevron makes Wheatstone progress

On the upstream portion of Chevron's Wheatstone project, hookup and commissioning of the offshore platform is progressing, which includes the startup of utility systems.

Offshore umbilicals have also been installed, connecting the platform to the subsea infrastructure. The trunkline is ready for service and the final tie-in work is ongoing. In addition, six of nine wells have been drilled and completed offering sufficient well capacity for the first train.

# Contracts

### McDermott picks up subsea work

Anadarko Petroleum awarded McDermott International a subsea umbilical and flowline installation contract to support Anadarko's Phase II development of the Caesar/Tonga field in the Gulf of Mexico.

The scope of the project covers: project management; engineering, fabrication and installation of two 7700ft-long pipe-in-pipe (PIP) insulated rigid flowlines terminated by pipeline end terminations (PLETS) on either end; installation of one subsea manifold and associated jumpers; installation of a subsea control umbilical approximately 72,000ft long and associated flying leads; and pre-commissioning.

Offshore installation is expected to be completed in late 2016 by the *LV105*, a deepwater rigid reel-lay vessel, and by the *North Ocean 102*, a deepwater flexible lay vessel, which is expected to complete the umbilical installation and subsea construction scope of work.

### Statoil chooses Heerema for Oseberg

Statoil has awarded Heerema Fabrication Group (HFG) an engineering, procurement and construction (EPC) contract for the unmanned wellhead platform at Oseberg Vestflanken 2. Heerema Marine Contractors (HMC) has also been contracted for the transportation and installation of the platform.

Fabrication of the platform will start in June 2016 and the sail away is scheduled for summer 2017, followed by installation with HMC's semisubmersible crane vessel.

Engineering, procurement, and construction of the platform will be executed from the Zwijndrecht yard.

### Fugro picked for Pyrenees install project

BHP Billiton Petroleum chose Fugro for the Pyrenees Phase 3 Installation Project, offshore Western Australia.

Fugro's scope of work includes suspension of existing infrastructure, and installation and pre-commissioning of the new flexibles and flying leads. ROV intervention and well commissioning support will be provided and the scope also includes the supply and fabrication of crossings, stabilization and installation aids, along with mobilization and transportation of equipment to the field.

Commencing in May 2016, all offshore activities will take place from Fugro's modern, multi-role construction vessel, the *Southern Ocean*.

All project management, engineering and associated support functions will also be provided by Fugro.

### Technip bags Deep Gulf Energy work

Technip won a lump sum contract by Deep Gulf Energy III for the development of the deepwater South Santa Cruz and Barataria fields, in 200m water depth in the Mississippi Canyon, Gulf of Mexico.

The contract consists of project management and engineering services, fabrication and installation of about 23km of pipe-in-pipe flowline, design, fabrication and installation of flowline end terminations, fabrication and installation of jumpers, and pre-commissioning for the flowline. Technip's operating center in Houston, Texas, will manage the overall project. The flowline system will be fabricated at the group's spoolbase in Mobile, Alabama. The offshore installation is expected to be performed in 2H 2016 by Technip's vessel *Deep Blue*.

# Taming a Sea Lion

**Since its discovery in 2010, the Sea Lion field offshore the Falkland Islands has been subject to a string of development options. Elaine Maslin looks at Premier Oil's optimized final plan.**

Unlike the penguin logo of the company which discovered it, the Sea Lion field development concept has been something of a shape-shifting beast in recent years.

Rockhopper Exploration's corporate Rockhopper penguin logo has changed shape just once – throwing its little flippers up in the air in delight in 2010, on the discovery of the Sea Lion field.

The shape of the Sea Lion development concept, however, has changed multiple times, going from a leased floating production, storage and offloading (FPSO) vessel, to a bigger FPSO, then a tension leg platform (TLP), then back to an FPSO and finally a scaled-down FPSO, as part of a phased development.

The bumpy ride is no surprise, considering the ups and downs of the oil market over the period from discovery to front-end engineering and design (FEED), the contract for which was issued in January.

The final concept, announced amid US$30/bbl oil prices, is a fit-for-purpose, safety first, functional specification, where savings made have been used to increase – or optimize – the scope.

Phase one of the project will use a converted Suezmax tanker, with 18 wells, costing $1.8 billion up to first oil ($2.2 billion total capex) as part of the two-phase "Sea Lion Complex" project targeting 520 MMboe. Phase two will use a converted very large crude carrier. Phase three, now called "Exploration Upside," will target a further 400 MMboe unrisked, Pmean from the Isobel and Elaine discoveries. Premier is targeting a final investment decision for the Sea Lion Complex in 2H 2017 with first oil due in 2020.

### Sea Lion hunting

Drilling in the Falklands, a self-governing British overseas territory contested by Argentina (which calls the islands the Malvinas), started in 1998, when, at $10/bbl, five discoveries, from a six-well campaign, were declared uncommercial.

Rockhopper Exploration – founded in 2004 – picked up two licenses (PL032 and PL033) in June 2005 and floated on the stock market in August 2005. By 2010, it had started what would become a 10-well, two-year exploration campaign, on the back of the Sea Lion that year, with a total seven successful wells, using Diamond Offshore's *Ocean Guardian* semisubmersible drilling rig.

Sea Lion, 200km north of the Falkland Islands, sits in 450m water depth, on the eastern edge of the North Falkland Basin. In a 2011 capital markets presentation, Rockhopper said the field had 21% porosity and good permeability, at 200 millidarcy, with a water leg useful for pressure support through water injection, and high formation integrity, which would enable high deviation or horizontal wells. After initial concept select screening, Rockhopper was looking at a leased, converted FPSO development with some 24 subsea wells plus water injection wells and one gas injection well. Initial hopes were for first oil as soon as 2016.

### Phase 1a – finally

In 2012, Premier Oil came on board, taking a 60% stake in Rockhopper's North Falkland Basin licenses. At first, Premier Oil followed the FPSO route, considering a larger-scale FPSO. But, in 2014, the game changed to a 30,000-tonne TLP concept, with a $5.2 billion price tag. This would mean taking on another partner, to help fund the project.

However, when the oil price fell, so did the concept. By returning to a FPSO, the partners would avoid the need to bring in another partner required for a costly TLP project. Sea Lion was back to a leased FPSO, with 50-60,000 b/d capacity, as part of a phased development.

**Fiona MacAulay**

Fiona MacAulay, chief operating officer, Rockhopper Exploration, joined the firm in 2010, just after the discovery well, and has led the entire appraisal campaign and then farm out to Premier Oil, now operator, with Rockhopper as subsurface lead.

"We went back to an FPSO and gave ourselves a limit of what we can do for up to $2 billion capex," she says. "We went down the line of an FPSO with 12-14 wells. It was clear at that point we could still get the price down and by the end came out with a revised project at $1.8 billion." This would see Phase 1a tap 160 MMbbl, with peak production at 60,000 b/d and 12-14 wells over a 15-year field life. But even then, the team decided to go further, making more savings, working closely with contractors.

"We have had a great response from our contractors," says David Hartell, senior development manager, Premier Oil. "Often people do not make a choice of contractors until during FEED. We have done something different. We have selected our contractors in the select phase, or pre-FEED. We did partly reimbursable engineering studies and pricing, etc., with contractors in competition with each other, then went to formal tender."

SBM Offshore was selected as the FPSO contractor in January, with an 18-month FEED contract. If all goes well, subject to final investment decision (FID), SBM Offshore also has a frame agreement with Premier to go straight into construction and then lease. Mid-February, Subsea 7 was awarded the subsea umbilicals, risers and flowlines (SURF) FEED contract and National Oilwell Varco the flexibles FEED contract. The subsea production system contract is due to be announced in Q1.

"Picking the four main contractors pre-FEED means they can work together in the FEED phase," Hartell adds, "which is something others don't necessarily do. This will enable efficiencies not just within the companies but also collaborative sharing and looking for value."

The low oil price has also helped reduce costs of course. A large chunk of the project cost is drilling, at $1.2 billion for 18 wells, which is a "significant improvement" in cost compared to a

Ocean Rig's *Ocean Guardian* semisubmersible drilling rig. Image from Ocean Rig.

year ago, Hartell says. After pitting four FPSO contractors against each other, Premier got pricing down some 30-40%, with about the same reduction seen in the subsea installation and subsea equipment costs.

"That's in combination with us trying to specify facilities to functional needs, with not a lot of bells and whistles," Hartell says. "The facilities meet UK safety requirements, but it's very fit for purpose. That's a change for the industry. People got a bit relaxed at $100/bbl, engineers like a lot of features. In a low oil price you can't do that. You need safety first and functionality needs to be fit for purpose. Instead of specifying so many out puts and what it should look like, specify functionality and let the outputs be tested by the business case."

Reducing the costs has also meant being able to increase the scope initially envisioned based on a $2 billion project and add the Northwest flank to the project.

Phase 1a Sea Lion development, will tap 220 MMbbl, compared to 160 MMbbl previously, with peak production at 85,000 b/d, compared to 60,000 b/d, and 18 wells (11 producers, six water injectors and one gas injection/producer) compared to 12-14 wells. The project life has also been extended from 15 to 20 years. Of the 18 wells, 13 are due to be pre-drilled in order to be able to reach plateau production within the first year.

## Waxy

An early concern on the field had been the waxy crude it will produce. But, Hartell says, technology and chemicals development in the past 2-4 years has made the task far simpler. Part of the SURF order is to include heated risers. Sea water, for injection, will also be heated to about 60-70°C on the topsides, to prevent any wax clogging the reservoir. As the field ages, produced water will itself be hot, so less heating will be required. The onboard crude storage tanks will also be heated.

Because of the remoteness of the Falkland Islands, exploration campaigns to date have been managed and supplied out of Aberdeen – some four weeks sailing away. But, while this seems like an unnecessarily long journey, it's more reliable than using other bases and they've had no logistics issues to date, MacAulay says.

However, the cost of manning a production asset this way will be high, which has meant the team has been looking closely at remote monitoring, remote diagnostics and remote control on the vessel, seeing where it is possible to perform work from a central office in, say Aberdeen. "You could easily have a control room in Aberdeen," Hartell says, "monitoring data so you can have a reduced size of staff offshore, and on a longer term scale going through the data looking at trends and performance envelopes, identifying maintenance." You could go further and have your onshore control room looking after multiple assets and maybe have health care contracts with major equipment vendors, such as compressors, who will monitor their equipment.

## Future phases

Premier Oil's latest exploration campaign has proven yet more oil in the North Falkland Basin, which will help feed future phases – including phase three, called "Exploration Upside."

The latest drilling campaign, using Ocean Rig's *Eirik Raude* semisubmersible, made the Zebedee and Isobel/Isobel Deep discoveries.

Zebedee was discovered in March 2015, in the south, followed by the Isobel Deep/Elaine discovery well in May 2015. Due to the succesful Isobel Deep encountering higher than expected reservoir pressures and a reservoir influx, it was cut short but then returned to. Jayne East was spudded, but never drilled, due to being replaced by the Isobel Deep re-drill.

The Isobel Deep re-drill, the most significant of the 2015-16 finds, was 4.2km from the Isobel Deep discovery well. Five F3 reservoir fans were intercepted: Irene, Emily, Elaine South, Isobel and Isobel Deep. 27m of net pay was discovered in Emily, Isobel and Isobel Deep. Reservoir pressure was confirmed to be greater than in Sea Lion, Rockhopper said in its announcement about the find.

Chatham, in the northern area, was due to be the next well to be drilled. It has been deferred following Premier Oil's early termination of the *Eirik Raude* contract over operational issues. Chatham, which is north of Phase 1a, would determine if there is a gas cap on the west flank as well as looking at a deeper horizon beneath Sea Lion, MacAulay says.

"The indications are that area [Isobel] has got enormous amount of potential and could be bigger than Sea Lion. Even in Sea Lion, there are underlying reserves we haven't put in to the development plan," she adds.

Of course, it wouldn't be right not to mention the weather in this British territory. Despite being in a pretty remote location, the metocean and meteorological environment is not harsh. The North Falkland Basin is sheltered to a degree by South America and is further from the South Pacific than the southern Falklands – which means rigs can work year-round. In fact, studies suggest both wave height and wind are lower than in the central North Sea.

"There is a lot of oil in a relatively benign environment. There is instability with Argentina, but in terms of security in other places, this is benign," MacAulay says. **OE**

# Tug of war

**BSEE has proposed a new well control rule that the agency says will make operating in the Gulf of Mexico safer. But, the industry disagrees, and now it has two studies to prove it. Audrey Leon sets out the detail.**

In early February, industry analysts Wood Mackenzie, on behalf of the Gulf Economic Survival Team, released a new study damning the US Bureau of Safety and Environmental Enforcement's (BSEE) proposed well control rule (30 CFR Part 250, Oil and Gas and Sulphur Operations in the Outer Continental Shelf — Blowout Preventer Systems and Well Control). The study's executive summary states the rule "is expected to reduce offshore activity, both development and exploration due to higher incurred costs and technical constraints of implementation."

At the heart of the matter: a blowout preventer. Photo from iStock.

The study, which assumes an US$80 reference oil price, says exploration drilling would decrease by 35-55% - or 10 wells per year. Industry investment, it says, would drop by up to $11 billion per year, on average. Production would decline some 35% by 2030 (>1 MMboe/d), and industry job losses would be in hundreds of thousands (105,000-190,000). Not to mention the adverse effects the rule would have on the country's GDP, which Wood Mackenzie says could decrease $27-45 billion in 2030. Government taxes would drop up to $70 billion through 2030. Rig declines would be 25-50% through the same time frame.

"Because the prospect inventory on currently held leases will likely be condensed and fewer leases will be acquired in upcoming bid rounds, it is anticipated the production gap will continue to widen and could be irreversible post-2030, further limiting jobs, GDP and taxes," the study forecasts.

The study mirrors one prepared by Quest Offshore Resources and Blade Energy Partners for API last July. That study said, "Cumulative direct costs due to the adoption of the proposed rule as currently written are estimated at over $32 billion for the 10 years from 2017 to 2026."

The Quest/Blade study further states, "the proposed rule will likely negatively influence deepwater development the most, especially high pressure, high temperature, and ultra-deep water wells, which may no longer be drillable, and the resources that these wells might have developed may be lost."

Additionally, Quest/Blade believe the rule will lower the oil and gas industry's contribution by $4 billion annually by 2030, from $31 billion in 2015. The 10-year cumulative GDP cost burden of the rule from 2017-2026 is estimated at $28.5 billion, the study said.

### Testimony

BSEE could not be reached for comment as of press time. However, BSEE Director Brian Salerno testified before a US congressional committee on Energy and Natural Resources back in December, defending the rule. Salerno said that the proposed well control rule was born out of investigations and reports that took place after the deadly 2010 *Deepwater Horizon* accident, and incorporates recommendations made regarding blowout preventers (BOPs), well design, cementing, well integrity testing, kick detection and response, real-time monitoring of well operations, and other areas.

"The need for the well control rule is demonstrated by the fact that loss of well control incidents are happening at the same rate five years after the Macondo blowout as they were before," Salerno testified in December, saying that in 2013 and 2014, there were eight and seven loss of well control incidents per year, respectively, and occurring in all water depths. Notably, Salerno recalled the 2013 Walter Oil & Gas blowout at

# In-Depth

## Quick stats

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

### New discoveries announced

| Depth range | 2013 | 2014 | 2015 | 2016 |
|---|---|---|---|---|
| Shallow (<500m) | 73 | 72 | 52 | 2 |
| Deep (500-1500m) | 19 | 29 | 15 | 1 |
| Ultradeep (>1500m) | 35 | 12 | 13 | 2 |
| **Total** | 127 | 113 | 80 | 5 |
| Start of 2016 | 127 | 114 | 72 | - |
| date comparison | - | -1 | 8 | 5 |

*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 | 11,715.00 | 12,893.00 |
| **United States** | | | |
| Shallow | 12 | 66.15 | 144.00 |
| Deep | 20 | 1082.27 | 1048.48 |
| Ultradeep | 25 | 3197.50 | 3100.00 |
| **West Africa** | | | |
| Shallow | 123 | 4,048.45 | 16,801.22 |
| Deep | 37 | 5407.50 | 6350.00 |
| Ultradeep | 17 | 2150.00 | 2610.00 |
| **Total** | 286 | **28,870.87** | **44,541.70** |
| (last month) | ([illegible]) | ([illegible]) | (45,179.10) |

### Greenfield reserves

2015-19

| Water depth | Field numbers | Liquid reserves (mmbbl) | Gas reserves (bcf) |
|---|---|---|---|
| Shallow | 982 | 37,816.14 | 502,542.59 |
| (last month) | (1006) | 36,250.68) | (482,065.76) |
| Deep | 144 | 9676.93 | 118,522.62 |
| (last month) | (147) | (9681.93) | (145,822.62) |
| Ultradeep | 90 | 17,367.90 | 44,700.00 |
| (last month) | (94) | (17,492.90) | (69,900.00) |
| **Total** | 1,216 | 64,860.97 | **665,765.21** |

### Pipelines

(operational and 2015 onwards)

| | (km) | (last month) |
|---|---|---|
| **<8in.** | | |
| Operational/ installed | 42,302 | (42,207) |
| Planned/ possible | 24,495 | (24,553) |
| | **66,797** | (66,760) |
| **8-16in.** | | |
| Operational/ installed | 83,639 | (83,557) |
| Planned/ possible | 49,549 | (49,935) |
| | **133,188** | (133,492) |
| **>16in.** | | |
| Operational/ installed | 94,172 | (94,020) |
| Planned/ possible | 45,081 | (44,671) |
| | **139,253** | (138,691) |

### Production systems worldwide

(operational and 2015 onwards)

| **Floaters** | | (last month) |
|---|---|---|
| Operational | 273 | (274) |
| Construction/ Conversion | 51 | (50) |
| Planned/possible | 313 | (320) |
| | **637** | (644) |
| **Fixed platforms** | | |
| Operational | 9291 | (9278) |
| Construction/ Conversion | 85 | (92) |
| Planned/possible | 1411 | (1406) |
| | **10,787** | (10,776) |
| **Subsea wells** | | |
| Operational | 4880 | (4857) |
| Develop | 424 | (422) |
| Planned/possible | 6451 | (6516) |
| | **11,755** | (11,795) |

### Global offshore reserves (mmboe) onstream by water depth

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|
| Shallow | 14,528 | 20,973.15 | 39,799.62 | 16,690.08 | 16,521.25 | 23,774.11 | 29,719.19 |
| (last month) | (14,531.75) | (28,999.04) | (32,822.31) | (19,608.43) | (14,115.61) | (27,385.17) | (27,401.20) |
| Deep | 4469 | 1085.18 | 5491.04 | 2221.55 | 4592.11 | 6139.51 | 12,168.71 |
| (last month) | (4469.26) | (1091.18) | (5491.04) | (2221.55) | (4592.11) | (6153.51) | (16,972.83) |
| Ultradeep | 2343 | 2037.21 | 3067.88 | 3228.63 | 4893.14 | 6105.41 | 7953.85 |
| (last month) | (2342.81) | (2037.21) | (3067.88) | (3228.63) | (5443.92) | (7477.93) | (10,598.42) |
| **Total** | 21,340.29 | 24,095.54 | 48,358.54 | 22,140.26 | 26,006.50 | 36,019.03 | 49,841.75 |

11 February 2016

**Brian Salerno testifies in front of a congressional hearing on the US Bureau of Environmental Enforcement's proposed well control rule on 1 December 2015.** Image from BSEE's Flickr page.

South Timbalier 200, in shallow waters off Louisiana, resulting in the evacuation of 44 workers, a fire that burned for 72 hours completely destroying the rig, and a financial loss of some $60 million to the company.

According to Salerno, first, the rule implements many of the recommendations related to well control equipment and fills gaps in the regulatory program. It calls for increases in the performance and reliability of well control equipment, with particular focus on BOPs. It improves regulatory oversight of the design, fabrication, maintenance, inspection, and reporting requirements for critical equipment. It also seeks to gain information on leading and lagging indicators of BOP component failures and identify trends in those failures and help prevent accidents. Finally, the rule seeks to ensure that industry uses recognized engineering practices as well as innovative technology and techniques to increase overall safety.

Also in attendance at the December congressional hearing was Erik Milito, group director, Upstream and Industry Operations, at the API, who testified that various provisions of the proposed well control rule could actually serve to increase risk and reduce safety. He urged the committee to, "ensure that it is not implementing prescriptive requirements that will serve to inhibit innovation and technology advancement."

While potential losses in production, jobs, safety and in revenue have been criticisms lobbed at the proposed rule, at one point during the December congressional hearing, Salerno was asked about the possibility of the rule shifting command and control authority from rig to shore, which Salerno refuted, stating that the rule does not shift authority, but that it addresses capability, "so that there would be a second set of eyes, so that you can have extra experts onshore and provide diagnostic expertise in assessing an anomaly."

### Industry reaction

When the new well control rule was proposed in April 2015, BSEE sent a call out for industry comments and, in July groups such as the International Association of Drilling Contractors (IADC) named several areas of concern:

"Specifically with regard to drilling contractors, IADC identified three major areas of concern with the proposed rule. These include its prescriptive requirements that go beyond international standards and will negatively affect the US market for mobile offshore drilling units; the significant costs to drilling contractors to comply with the rule, which were not accounted for in BSEE's impact analysis; and the inspection and more massive BOP equipment requirements, which will negatively impact operations."

US supermajor Chevron weighed in during the public comment period back in July.

"Many of the requirements in this proposed rulemaking do not build on the significant progress made since Macondo and do not take into account the best available, economically feasible technologies for ensuring safety," wrote Chevron North America President Jeff Shellebarger. "Rather, some proposed requirements would decrease safety by increasing risk to our people and our operations. Other proposed requirements are neutral in benefit and would only impose an increased and capricious burden that may make some wells uneconomical, resulting in abandoned or undrilled projects and stranded reserves."

### Base case scenario

Using an $80/bbl base case, Wood Mackenzie shows an average of 19 exploration wells drilled a year, but with the well control rule implemented, that would decrease to somewhere between 9-12 wells per year. Total capex from 2016-2030 under normal scenarios would be $460 billion, but with the well control it would be in the neighborhood of $300-365 billion – a 20-35% reduction.

"Although we expect deepwater Gulf of Mexico to have material activity, value creation relative to other competitive basins could be significantly eroded from the well control rule," Wood Mackenzie says in the well control rule study.

Wood Mackenzie says currently there are 392 exploration wells predicted to be drilled in the Gulf of Mexico thru 2035, but if BSEE's well control rule was implemented, that could fall to 166.

"With 40% higher costs the exploration spend could be cut by 70%," the study says. "Yet-to-find volumes over the period and value creation would follow."

After Wood Mackenzie's study was released, National Ocean Industries Association (NOIA) President Randall Luthi stated that the study was a clear reminder of the consequences of "unnecessarily burdensome regulations."

"While the proposed well control rule purports to improve safety, an overly prescriptive rule may actually decrease safety and increase risk," Luthi said. "A federal regulation of this magnitude must be carefully crafted to actually focus on ways to improve safety and allow companies to adopt its requirements in a safe and practical manner, instead of the current approach which seems to be designed around a political objective and deadline. Getting this rule right is more important than rushing the rule out on an arbitrary deadline. We urge the (Obama) administration to carefully consider the findings of this study before finalizing the rule." OE

## FURTHER **READING**

**To learn more about BSEE's proposed well control rule, find the full 264-page outline here.**
http://1.usa.gov/1PDD2sd

## Rig stats

### Worldwide

| Rig Type | Total Rigs | Contracted | Available | Utilization |
|---|---|---|---|---|
| Drillship | 108 | 81 | 27 | 75% |
| Jackup | 399 | 270 | 129 | 67% |
| Semisub | 148 | 99 | 49 | 66% |
| Tenders | 31 | 21 | 10 | 67% |
| Total | 686 | 471 | 215 | 68% |

### North America

| Rig Type | Total Rigs | Contracted | Available | Utilization |
|---|---|---|---|---|
| Drillship | 37 | 32 | 5 | 86% |
| Jackup | 22 | 5 | 17 | 22% |
| Semisub | 16 | 12 | 4 | 75% |
| Tenders | N/A | N/A | N/A | N/A |
| Total | 75 | 49 | 26 | 65% |

### Asia Pacific

| Rig Type | Total Rigs | Contracted | Available | Utilization |
|---|---|---|---|---|
| Drillship | 13 | 5 | 8 | 38% |
| Jackup | 119 | 72 | 47 | 60% |
| Semisub | 33 | 14 | 19 | 42% |
| Tenders | 21 | 14 | 7 | 66% |
| Total | 186 | 105 | 81 | 56% |

### Latin America

| Rig Type | Total Rigs | Contracted | Available | Utilization |
|---|---|---|---|---|
| Drillship | 29 | 22 | 7 | 75% |
| Jackup | 54 | 39 | 15 | 72% |
| Semisub | 31 | 28 | 3 | 90% |
| Tenders | 2 | 2 | 0 | 100% |
| Total | 116 | 91 | 25 | 78% |

### 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 | 45 | 32 | 13 | 71% |
| Tenders | N/A | N/A | N/A | N/A |
| Total | 93 | 74 | 19 | 79% |

### Middle East & Caspian Sea

| Rig Type | Total Rigs | Contracted | Available | Utilization |
|---|---|---|---|---|
| Drillship | 2 | 0 | 2 | 0% |
| Jackup | 110 | 88 | 22 | 80% |
| 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 | 19 | 3 | 86% |
| Jackup | 23 | 14 | 9 | 60% |
| Semisub | 10 | 7 | 3 | 70% |
| Tenders | 8 | 5 | 3 | 62% |
| Total | 63 | 45 | 18 | 71% |

### Eastern Europe

| Rig Type | Total Rigs | Contracted | Available | Utilization |
|---|---|---|---|---|
| Drillship | N/A | N/A | N/A | N/A |
| Jackup | 2 | 1 | 1 | 50% |
| Semisub | 2 | 1 | 1 | 50% |
| Tenders | N/A | N/A | N/A | N/A |
| Total | 4 | 2 | 2 | 50% |

Source: InfieldRigs 11 February 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 downward spiral

**Most of the news in the rig market is bad, but there are bright spots if you look hard enough. Audrey Leon sets out the details.**

Not much has changed for the positive in the last six months within the floating rig market. Utilization continues to plunge as contracts dry up. But with utilization down, and rates declining, surely that would boost exploration, right? Well, not exactly.

Operators have cut back on exploration budgets, and instead are concerned with cash flow. They are in survival mode.

"Oil and gas companies are postponing or cancelling exploration activity to conserve cash, although declining rig rates mean these wells would generally be much cheaper to drill than they would have been 18 months ago," says Tom Kellock, Head of Offshore Rig Consulting, IHS.

Being in a cash-negative position definitely hinders exploratin efforts. "Offshore exploration success in 2015, in terms of liquids volumes, were the lowest levels the industry has seen in the past 15 years," says Joachim Bjørni, an analyst with Rystad Energy. "Looking at company guidance for 2016, offshore exploration activity is set for a further decline."

A recent report from Clarksons Research paints an even grimmer picture, calling the current offshore rig market "the worst in 30 years," with global utilization dropping from 87% to 73% in 2015.

According to Clarksons' data, global floater working utilization declined from 91% to 77%, down from a high of 97% in 2013, while global jackup working utilization has declined from 86% to 70%, down from a high of 95% in 2013. Average charter rates for high-spec jackups fell 43% y-o-y to $99,000/d, with average ultra-deepwater floater rates dropping by 42% y-o-y to $253,000/d, from a 2014 peak of nearly $600,000/d.

Infield Rigs' data (as of 11 February 2016) shows that there are 686 mobile offshore drilling units (MODUs) worldwide, with only 471 contracted, at a utilization rate of 68%. On 18 November, Infield Rigs reported 690 MODUs worldwide, with only 500 contracted, at a utilization rate of 72% (see page 21 for a breakdown of current rig stats).

Analysts Quest Offshore don't foresee total well demand picking back up to pre-oil price drop levels (2011-2014) of over 600 wells any time soon. Leslie Cook, senior research consultant for drilling, Quest Offshore Resources, said this year the company sees well demand at half of what it used to be, 300-320 wells.

"This volatility in oil prices brings out the conservatism in the industry," Cook says. "It diminishes the pioneering spirit. We're seeing the majors go back to low-risk plays."

However, some supermajors are making commitments to higher risk plays, Cook says, such as Total (Uruguay), ExxonMobil (Guyana), Anadarko (Colombia), and Chevron (Tiber – Lower Tertiary Gulf of Mexico) (see page 90 for more on Uruguay, Guyana and Colombia).

## Regional view

So where are the resilient areas? Cook says the Gulf of Mexico, because it has a mix of supermajors and smaller operators. However, some majors have opted to pull out of the deep water, such as ConocoPhillips and Marathon. Freeport-McMoRan announced late last year they would consider leaving offshore altogether and refocus on the mining segment.

Despite all of its challenges of late, Brazil is another bright spot, Cook says. "Brazil has a lot of good opportunity going forward, they just need to figure out what they are going to do with Petrobras and how to overcome the whole corruption issue," Cook says, "but other than that there's a lot of oil down there."

According to IHS' regional data, as of February 2016, utilization rates range from 38% to 89%, with Australia/New Zealand and South America at the higher end and the US Gulf of Mexico and Southeast Asia below 40%.

## To retire or not retire

Despite low utilization rates, rig owners seemed to have stopped removing older units from their fleet, making matters worse. In early 2015, Norwegian analysts Rystad Energy said as many as 88 units needed to be taken out of the market by 2017. Bjørni told ***OE*** that in order for the market to balance again towards 2020 more retirements are needed, about 40 floaters and 80 jackups must exit before utilization returns to near-historic levels.

"Rig contractors got off to a really good start at the beginning of the year – they took out 30-40 rigs in 1H 2015," Cook says. "48 rigs [were] taken out of service and retired in 2015, but in 2H it tapers off."

Cook says of the 22 contracted newbuilds that were supposed to come out in 2015, only 12 made it out of the yard, and just eight made it into service by year end. Of the 20 uncontracted newbuilds, only five made it out of the yard and are


yet to be used.

There are, however, some rigs still leaving. In February, Noble Corp. retired two offshore drilling units, the jackup Noble Charles Copeland and ex-Shell Arctic drillship *Noble Discoverer*. The retirements bring Noble's full fleet to 30. The *Noble Discoverer* drillship contract was terminated by Shell in December 2015, following the supermajor's announcement that it would suspend its Arctic exploration plans offshore Alaska.

Shell had previously terminated the contract for the other drilling unit in its Alaskan program, Transocean's *Polar Pioneer*, which is now cold-stacked.

According to Transocean's February fleet status report, the company has 21 units stacked and six sit idle. But the news in Q4 wasn't all bad for Transocean.

In February, the newbuild ultra-deepwater drillship *Deepwater Thalassa* started its 10-year contract for Shell at its Stones project in the US Gulf of Mexico on a $519,000 day rate. The rig is designed to operate in up to 12,000ft water depth and drill wells to 40,000ft.

At the end of January, Chevron had moved Transocean's *Deepwater Asgard* drillship to the deepwater Tiber prospect in Keathley Canyon block 102, in the US Gulf of Mexico, according to BSEE data.

The *Deepwater Asgard*, built in 2014, started a two-year contract with Chevron in April 2015 with a $623,000/d dayrate, according to Transocean. Like the Deepwater *Thalassa*, the *Asgard* can work in downt to 12,000ft water depth and drill to 40,000ft deep.

### Jackups

Currently, the jackup market leaves a lot to be desired. Bjørni says Rystad estimates that the global jackup market will continue to drop in 2016, but a market recovery is expected in 2017. In terms of markets expected to fair well out to 2020, Bjørni says the main markets for jackups are the Middle East and Mexico.

However, some rig owners are opting to sell a substantial number of jackups or dump the entire fleet. In Q4, Diamond Offshore said it would sell all of its remaining jackups, except the Ocean Scepter, which is contracted to Pemex until 2017.

Jackup and liftboat owner Hercules Offshore declared bankruptcy late 2015, emerging from it in November following a financial restructuring, then in February announcing it would form a special committee to consider its options, including selling or merging with another company. As of late January, Hercules had 19 jackups stacked out of its 27 units.

Fairing slightly better is Rowan Companies, which only had three jackup rigs stacked (out of 27 jackup units), as of January 2016. A fourth rig, Rowan Louisiana, which was previously stacked, was sold in Q4.

According to its October fleet status report, Ensco, which has a sizeable global jackup fleet, has four units cold stacked in the Gulf of Mexico, one in Bahrain, and one in Malaysia, while another five units do not have contracts. The company also has three jackups under construction, due for delivery during 2016.

Most of Maersk Drilling's jackup fleet is in Europe, primarily Norway. According to the company's February fleet status report, its latest newbuild XL Enhanced 4, under construction at Daewoo Shipbuilding & Marine Engineering's Okpo yard in South Korea, is due for delivery by mid-2016. The XLE series are built for ultra-harsh environments and rated for up to 492ft (150m) water depth and drill depths of 40,000ft (12,000m). Once completed, the jackup will begin a five-year contract, starting in 2017, with BP off Norway. **OE**

## Current contracted utilization

| Manager | Aug-15 Total Util % | Feb-16 Total Util % | Change (% points) |
|---|---|---|---|
| Diamond Offshore | 61.8 | 46.9 | -14.9 |
| Ensco | 62.3 | 60.6 | -1.7 |
| Noble | 90.3 | 77.4 | -12.9 |
| Pacific Drilling | 71.4 | 57.1 | -14.3 |
| Paragon Offshore | 66.7 | 50.0 | -16.7 |
| Rowan | 81.3 | 71.0 | -10.3 |
| Seadrill | 79.5 | 76.9 | -2.6 |
| Shelf Drilling | 83.8 | 81.1 | -2.7 |
| Transocean | 71.9 | 62.5 | -9.4 |
| Vantage Drilling | 85.7 | 57.1 | -28.6 |
| **TOTAL** | **73.3** | **64.9** | **-8.5** |

Data from IHS.

# The final countdown

## The floating rig market is preparing for the most challenging year ahead. Leslie Cook, of Quest Offshore, explains.

In the wake of a prolonged downturn, drilling contractors are looking for ways to secure backlog and reduce costs associated with idle time as they come face-to-face with excessive oversupply, declining demand, and customers with heightened sensitivity for increased value in their drilling programs.

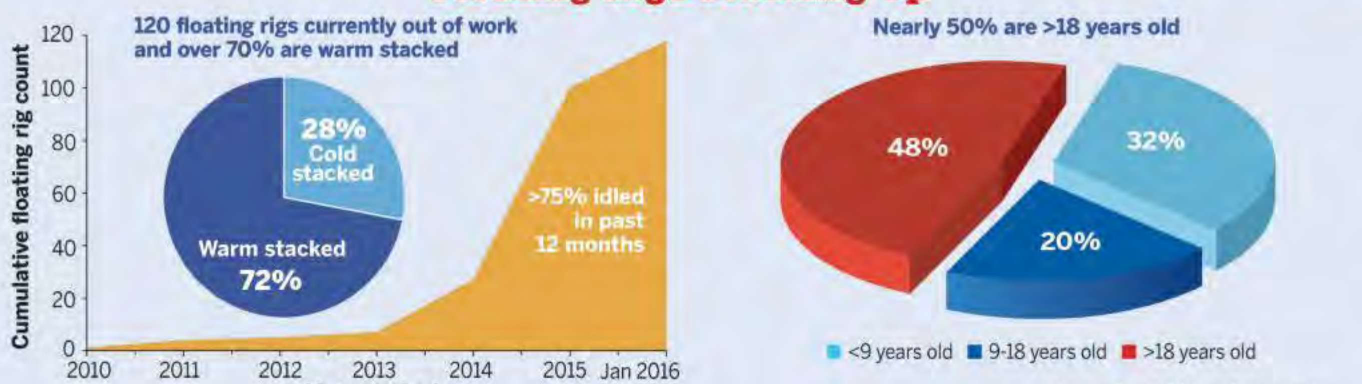
Before oil prices began to collapse in late 2014, the drilling market was in a state of euphoria. Within seven years, 140 new high-specification, sixth generation rigs had been delivered. Marketed utilization in early 2014 was over 90% for all floating rigs with average day rates of US$450,000. New rigs were nearly 100% utilized and average day rates were nearing $550,000.

The sixth generation marvels were designed specifically for the emerging deepwater market and rivaled previous generations in terms of capability, size, and efficiency. Upgrades included water depth capability exceeding 7500ft, advanced instrumentation, expansive deck space, and increased hoisting capacity. All the players were in. Large existing contractors expanded their fleets, new competitors emerged as deepwater purebreds, and contractors with strong positions in the jackup space took the plunge into deepwater. Expansion of the floating rig fleet during the mid-2000s appeared to have all the right ingredients for drilling contractors: reasonable internal rate of return, increased revenue efficiencies, higher operating margins, strong utilization, and increased market share opportunity by offering a new kind of asset needed for new drilling environments. Who could blame them for such aggressive expansion?

### The wake-up call

Overshadowed by the exuberance of a successful sixth generation launch, some alarming signals had begun to emerge by late 2013. Operators were beginning to grumble about the excessively high costs associated with drilling – most notably the ballooning day rates. Reductions in 2014 exploration and production budgets among major operators were considered to be in part a strategic maneuver to put pressure on drilling contractors to reign in some of the excessive pricing that had risen sharply over the previous quarters. On the demand side, exploration drilling from floating rigs was beginning to decrease, leading to fewer wells being drilled in key deepwater regions. By 2014, exploration drilling in West Africa and Brazil had declined

## Floating Rigs Stacking Up




Source: Quest Offshore Resources Inc.

nearly 45%. As part of the Golden Triangle both regions were considered critical to continued demand growth in the deepwater rig market. On the supply side total floating rig supply had grown by 40% and rigs in the ultra-deepwater category grew by 70%. Drilling contractors were adding new rigs, but not removing old rigs. Then came the wake-up call: the fall in oil prices.

**Noble Corp. announced in Q1 it would retire the *Noble Discoverer* drillship after supermajor Shell suspended its Arctic drilling program offshore Alaska.** Image from Shell.

### Fleet retirements

By December 2014, the over-supply situation had become painfully obvious. Despite a drop off in new fabrication awards there were still another 42 new rigs to be delivered in 2015 and only half of those units had secured initial contracts. Operators were once again planning to cut exploration and production spending, which meant further decreases in drilling were inevitable. Rig contractors with large fleets reacted quickly by scrapping or putting up for sale 48 rigs they considered non-core assets. The majority of retirements occurred in 1H 2015 (90%) but then soon tapered off under the hope that oil prices would rebound and stabilize by year end. The two largest contractors, Transocean and Diamond Offshore, were responsible for nearly 70% of the initial rig retirements.

Throughout 2015, rigs were increasingly idled and the pile of warm stacked units grew from 40 to 71 pushing marketed utilization down to 70%. While rig contractors placed heavy emphasis in 2015 on reducing operational and stacking costs, they remained reluctant to retire older rigs, which still accounted for 30% of working supply and 60% of idle supply. Current demand estimates through 2020 suggest that a vast majority of generation 2-4 rigs will not be able to secure work and will continue to age in idle status.

### The final countdown

Currently, there are 120 floating rigs out of work and 75% are classified as warm stacked, which means they are part of marketed supply. Nearly 50% of the unemployed rigs are older generation units that will likely never work again. Another 25 fifth generation rigs are currently stacked with six additional units rolling off contract in 2016. These rigs will be unable to compete against the newer units for at least the next 18-24 months and possibly longer. Every quarter in every region rigs will be reaching the end of their contract terms this year. Forecast demand is expected to drop another 30% as major operators slash exploration and production budgets again for a third straight year in a row. The top five drilling contractors account for 50% of the stacked plus near- term roll-off units while a few smaller drilling contractors will see over 75% of their small stealth fleet sidelined in 2016. Leading edge day rates at the high end have dropped to $350,000 putting them at or near below break-even, and over the next 24 months over 70% of rigs currently working under legacy high rates above $500,000 will roll off contract.

The challenges that drilling contractors face this year cannot be overstated. So far this year, four rigs will either retire or be put up for sale. In reality, there are at least 85 floating rigs in the global fleet that should be considered non-core assets based on vintage alone. Demand recovery will be gradual and it is still unclear when it will even begin. Attrition will play a critical role in the supply demand balance post-2016. Drilling contractors so far have shown the will and ability to cut costs, offer flexibility in contracts, and design new stacking processes for core assets. Re-evaluating what is non-core and reducing global supply must happen this year in order to preserve the long-term vitality of the floating rig market. **OE**

## Supply changes

**>70% of rigs working at >$500,000/day will roll-off contract by the end of 2017** (excluding early terminations)



***Leslie Cook** is a senior research consultant for Quest Offshore Resources responsible for forecasting and analysis of the deep water drilling market. She has a degree in Commerce from the University of Virginia and is currently pursuing her MBA in Energy Management from the Bauer School of Business at the University of Houston.*

# Charting demand

**35 offshore projects and 100 rig years have slipped after the oil price collapse. Oddmund Føre, Analyst, Rystad Energy, explains.**

The market for oilfield services is hurting and offshore drilling is no exception. The global market for mobile offshore drilling units (MODUs) faced a decline of 12% last year. This was twice the decline we saw in 2009 in the same industry, leaving 2015 behind as the most challenging year in the recent past. After booming years in the rig market, we have seen volumes of new rig capacity entering the market. In addition, the oil price has put further pressure on the tight cash flow situation for E&P companies, which has resulted in reduced demand for exploration and development drilling. These drivers combined have led to low utilization and reduced rig rates, and in turn an increased focus on retirements as a consequence.

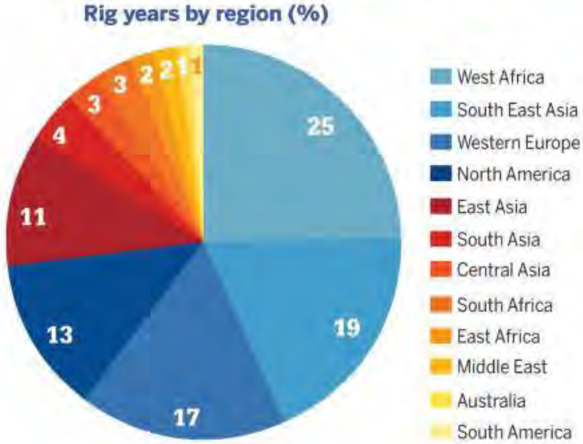
In the world of exploration and production, a change in development schedules is not a rare reality considering factors such as project complexity, infrastructure challenges and governmental regulation. As reduced revenue due to a diminishing oil price has played an important role, budgets have been subject to increased scrutiny upon sanctioning of new development projects. Rystad Energy has taken a closer look at new offshore development projects that have been delayed or cancelled after the oil price plunge of 2014. A project is considered delayed if the original expected sanctioning date falls within two years of the time when news flow indicates a later approval date. The conclusion is that 35 offshore projects have been delayed or canceled as of January 2016.

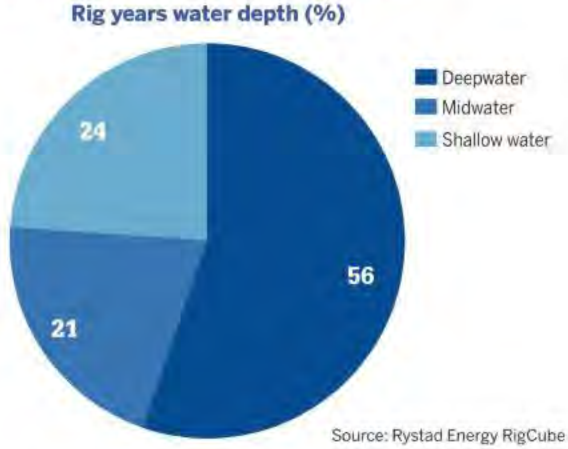
The 35 projects we have identified translate into a demand for floaters and jackups in excess of 100 rig years that consequently have slipped. The left chart shows this rig demand split by region based on the underlying projects. West Africa, Southeast Asia and Western Europe are the three regions affected the most, with the majority of the rig demand subject to rescheduling. The Kasawari project operated by Petronas in Malaysia is just one example of rig demand that was delayed in this period. The Gendalo-Gehem project by Chevron in Indonesia is another. In Western Europe, Statoil has not been able to approve the Johan Castberg field in Norway, leading to further delays of this field as well.

The right chart shows that more than half of the rig demand in question comes from deepwater fields largely made up of elephants such as Bonga Southwest-Aparo in Nigeria and Mad Dog 2 in the Gulf of Mexico. The remainder is split equally between shallow water and midwater.

There is no doubt that 2016 will be a challenging year for the MODU market. Nevertheless, Rystad Energy expects the current year to be the turning point followed by a market recovery in 2017 with a growth rate around 10%. There is a number of projects in the pipeline that will be sanctioned in the upcoming years, which can contribute to a healthier rig market. Gas projects like Zohr in Egypt, Leviathan in Israel and LNG projects in Mozambique are projects that we have to watch out for in the near future. OE

## Rig demand years split by region and water depth




Source: Rystad Energy RigCube

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## Preliminary conference agenda

| Tuesday, April 5 | |
|---|---|
| 0800 – 2030 | Registration Hours |
| 1800 – 2100 | Exhibit Hours |
| 1830 | Opening Ceremony |
| 1915 | Ribbon Cutting |
| 1930 | VIP Tour |
| 1930 | Opening Reception |

| Wednesday, April 6 | |
|---|---|
| 0900 – 2030 | Registration Hours |
| 1100 – 2100 | Exhibit Hours |
| 1100 – 1200 | **Federal Deputy, Georgina Trujillo,** President of the Energy Commission of the LXIII Legislature |
| 1200 – 1300 | **Oscar Roldan**, Head of the National Data Repository for Mexico's National Hydrocarbons Commission (CNH) |
| 1300 – 1400 | Operator Panel |
| 1400 – 1500 | **David Madero**, General Director of the National Center of Natural Gas Control (CENAGAS) |
| 1500 – 1600 | **Lic. David Gustavo Rodriguez Rosario**, Secretary of Economic Development and Tourism, State of Tabasco |
| 1600 – 1800 | General Conference Sessions |
| 1900 – 2200 | Cocktail Reception in Exhibit Hall |

| Thursday, April 7 | |
|---|---|
| 0900 – 2030 | Registration Hours |
| 1100 – 2100 | Exhibit Hall Hours |
| 1100 – 1200 | **Lourdes Melgar, Ph.D.**, Undersecretary of Hydrocarbons at Ministry of Energy |
| 1200 – 1300 | **Ing. Jose Antonio Escalera Alcocer**, Director of Exploration, PEMEX Exploration and Production |
| 1300 – 1400 | **Carlos Morales**, General Director, Petrobal |
| 1400 – 1430 | **Cleantho Leite**, Director of Institutional Relations and Business Development, Braskem Idesa México |
| 1430 – 1800 | General Conference Sessions |
| 1900 – 2100 | Closing Cocktail Reception inside Exhibit Hall |

# Studying hydrate management

**Jerry Lee takes a look at recent work conducted by the Colorado School of Mines and the University of Tulsa (Oklahoma) to mitigate gas hydrate formation.**

**Hydrate formation, deposition, and detection experiments performed for RPSEA in the CSM Hydrate Center in collaboration with Paulsson Inc. (A. Majid, H. Qin, T. Charlton).**
Image courtesy of Colorado School of Mines, Center for Hydrate Research.

Gas hydrate formation is a bane for subsea oil and gas production. Composed of ice-like crystalline solids, these masses can cause flow assurance issues and plug up subsea oil and gas flow lines.

To tackle the problem, the US-based Research Partnership to Secure Energy for America has partnered with Colorado School of Mines (CSM) and University of Tulsa (TU) to study hydrate formation.

"When hydrates form in subsea oil and gas flowlines, they can lead to flowline blockages and loss of production, as well as potential safety and environmental risks," says Carolyn Koh, professor of chemical and biological engineering and director of the Center for Hydrate Research at CSM.

Hydrates form when light hydrocarbons (methane, ethane, and propane), mix with produced water, and are exposed to low temperatures and high pressure, conditions well within the gas hydrate stability zone.

Current mitigation tactics include thermodynamic hydrate inhibitors (e.g. methanol, glycol), which shift the boundaries of the hydrate stability zone to more extreme conditions and prevent the hydrate from forming; low dosage hydrate inhibitors: kinetic hydrate inhibitors, which aim to delay hydrate formation long enough so the fluids can be produced, and anti-agglomerants, which prevent hydrate crystals from grouping together, and keeps the hydrate as a transportable slurry. However, due to water-cut increasing as fields mature, greater inhibitor volumes are required for it to remain effective. This leads to greater costs, making it economically impractical, and increasing environmental concerns. This has led to a shift in ideology from hydrate prevention, to hydrate management.

In order to improve hydrate management strategies, a comprehensive model is needed, which can be used to predict the formation and transportability of hydrates under various oil and gas production scenarios. However, the current models are only for oil continuous (oil dominates with all the water dispersed as droplets) and water/gas systems.

To supplement our understanding of hydrates, the joint study investigates water continuous systems and partially dispersed systems, which lack modeling. Water continuous systems are water dominant with oil dispersed as droplets, and partially dispersed systems, are systems where water is both dispersed in oil and is in a free phase.

Before determining a model, researchers need a fundamental understanding of how hydrates form. For phase one[1] of the two-phase study, the objective was to study partially dispersed and water continuous systems using a large-scale flowloop test, which is closer to field conditions than lab-scale measurements.

"Specifically, to investigate the hydrate formation process as a function of water amount, velocity of the fluid in the pipe, and pressure (subcooling; driving force for hydrate formation). A plugging mechanism and conceptual model for these systems would be investigated from the tests," Koh says. "A first-pass, plugging onset correlation for both partially and fully dispersed systems would then be determined."

Ten experiments were performed using TU's flowloop and mineral oil (Crystal Plus 350T). Each test involved adding calculated amounts of sodium chloride solution (mimicking salt water), pressurizing the flowloop to 1500psig with Tulsa City gas, varying the velocity from 2.3-5.5 ft/s, and cooling the system with a glycol jacket. Incorporating a colored dye into the water, visual observations were made to determine when free water formed, how hydrates grow and plug, and the pressure drop was tracked to determine when hydrates began to form. From these observations it was determined that partially dispersed systems were more problematic than continuous systems.

"The free water enables hydrate growth and accumulation to be far more rapid than when free water is not present, with the water being occluded in the crystallites so the effective volume of solids is much greater," Koh says. "Capillary bridging between hydrate crystals is also facilitated by the free water."

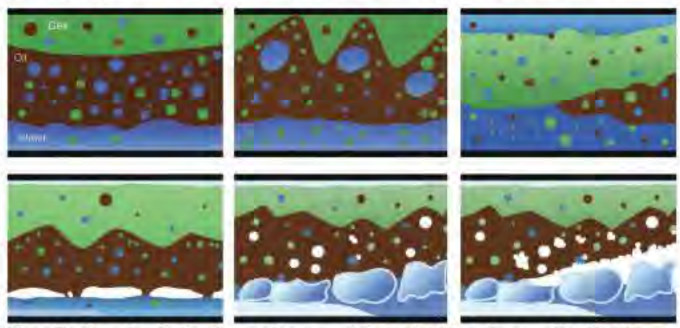
With free water at the bottom of the pipe, the inner pipe surface could be wetted by oil pushing some water to the pipe wall or by a water slug, creating a thin film of water. Once conditions reach the gas hydrate stability zone, hydrate films can form rapidly around the pipe walls. As the oil pushes more water towards the pipe wall, hydrate thickness will increase, eventually forming stationary or moving beds. This combination of water wetting and hydrate bedding is proposed as the mechanistic conceptual model for hydrate formation/plugging for partially dispersed systems.

Expanding on these findings, phase two[2] of the study, currently ongoing, aims to validate and test the conceptual model and correlation developed in phase one with further flowloop tests.

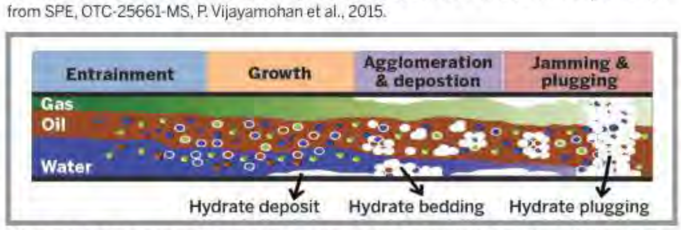
"Flowloop tests were initially performed in phase two to understand the effect of liquid loading and oil properties on hydrate formation and plugging onset," Koh says.

Initial work for phase two began with 18 hydrate formation experiments performed using the TU flowloop. This study investigates the effects of water cut (65% and 80%), mixture velocity (2.3 ft/s and 5.5 ft/s), and liquid loading (50%, 70%, 90%). To determine whether the results are oil-specific, tests were done using three oils (MO 350T, MO 70FG and kerosene): effects on hydrate transportability, plugging tendencies, and the effects of viscosity would also result.

**Hydrate adhesion micromechanical force measurements. (E. Brown)** Image courtesy of Colorado School of Mines, Center for Hydrate Research.



**Top: Before hydrate formation, water wets the pipe walls. Bottom: Hydrates (white) form and accumulate at the interfaces and occlude water.** Source: Rosli, F., Majid, A.A.A., et al, CSM, CHR. Redrawn with permission from SPE, OTC-25661-MS, P. Vijayamohan et al., 2015.




**Partially dispersed systems are more complex and problematic than fully dispersed systems.** Source: A. Majid et al., Colorado School of Mines, Center for Hydrate Research

Experimental procedures similar to those used in phase one were used for phase two.

From these experiments, a new conceptual mechanistic model has been developed. Significant portions of the pipe are wetted by the free water layer (bottom) and pockets of water carried and spread by oil (top). Under hydrate forming condition, hydrates will develop from the thin water layer and at the oil-water interface. These hydrates occlude (soak-up) water. Further water occlusion contributes to hydrate growth and agglomeration, eventually leading to water depletion. The combination of water depletion, pipe roughness and increasing viscosity of the oil phase, due to the hydrates, will lead to stationary or moving hydrate beds forming.

If stationary beds form, the reduced area of flow, increased friction, and greater oil viscosity can contribute to plugging.

The experimental data showed that hydrate transportability is a stronger function of liquid loading and water cut than mixture velocity. However, this is only based on experiments with a single oil (MO-350T). To test the findings, and evaluate the effects of viscosity on hydrate transportability, further experiments with MO-70FG and kerosene were performed.

"Also developed was the plugging onset correlation to indicate when plugging will occur, and the extent of plugging risk for different systems/conditions," Koh says.

The next set of flowloop tests will further develop the plugging onset model and examine methods to mitigate partially dispersed systems, including the use of anti-agglomerants. The study will also consider the effects of advanced robust coating with Oceanit. In support of the study, new fiber optic acoustic sensor technology, provided by Paulsson, will be used to detect and quantify hydrate accumulation.

When the study completes (ca.September 2016), the model will be available to aid production strategies development to reduce hydrate plugging related risks. "The mechanistic models and plugging risk assessment provide new understanding on systems that have been previously underexplored," Koh says. "Such information can provide advanced assessments of the safety risks associated with hydrate formation where free water is present. These assessments can also be used to provide field case studies on partially dispersed systems." **OE**

## Works cited

[1] Vijayamohan, P., Majid, A., Chaudhari, P., Sloan, E. D., Sum, A. K., Koh, C. A., ... Volk, M. (2014, May 5). Hydrate Modeling & Flow Loop Experiments for Water Continuous & Partially Dispersed Systems. Offshore Technology Conference. doi:10.4043/25307-MS

[2] Vijayamohan, P., Majid, A., Chaudhari, P., Sum, A. K., Koh, C. A., Dellacase, E., & Volk, M. (2015, May 4). Understanding Gas Hydrate Growth in Partially Dispersed and Water Continuous Systems from Flowloop Tests. Offshore Technology Conference. doi:10.4043/25661-MS

# Fiscal focus

**Today's flow metering systems for petroleum products must not only precisely monitor production and transfers; they also need to provide robust data to underpin digital intelligence for improved decision-making, says Honeywell Process Solutions' Tim Vogel.**

Custody transfer presents unique challenges for a flowmeter application since substantial sums of money change hands based on its measurements. When metering large volumes of product even a very small measurement uncertainties can cost millions of dollars a year.

Moreover, accurate and reliable fiscal measurement not only defines the point at which ownership changes hands based on regulatory standards, but also helps maximize overall production and movement efficiency.

Until recently, operators used disparate, bespoke systems for these measurements. A fast changing and cost-constrained environment, however, means many are adopting a new approach to metering, replacing old flow computers with new, integrated automation solutions. This provides the benefits of a centralized solution, such as commonality and scalability, with improved monitoring, management and reporting processes that deliver data to the entire operation.

Integrated solutions bring a number of benefits:

- Helping meet regulatory requirements for fiscal reporting of emissions
- Simplifying integration of raw meter data in accounting and reporting systems
- Enhancing performance where control and sequencing-type tasks are critical.

Most field measurement and metering units currently monitor a single process element and present it individually. Intelligent solutions, however, integrate disparate assets throughout the process, so data is fed into a central hub where it can be utilized for highly informed production and business decisions.

In upstream operations, particularly, this data opens opportunities for enhanced operations and increased reliability through condition based monitoring and increased visibility of the downstream supply chain.


**Ultrasonic flowmeters are a preferred technology for demanding fiscal metering applications.** Images from Honeywell Process Solutions.

### Latest metering technology

The flow meter remains the central piece in this intelligent revolution, with accurate measurements essential for safe and efficient operation.

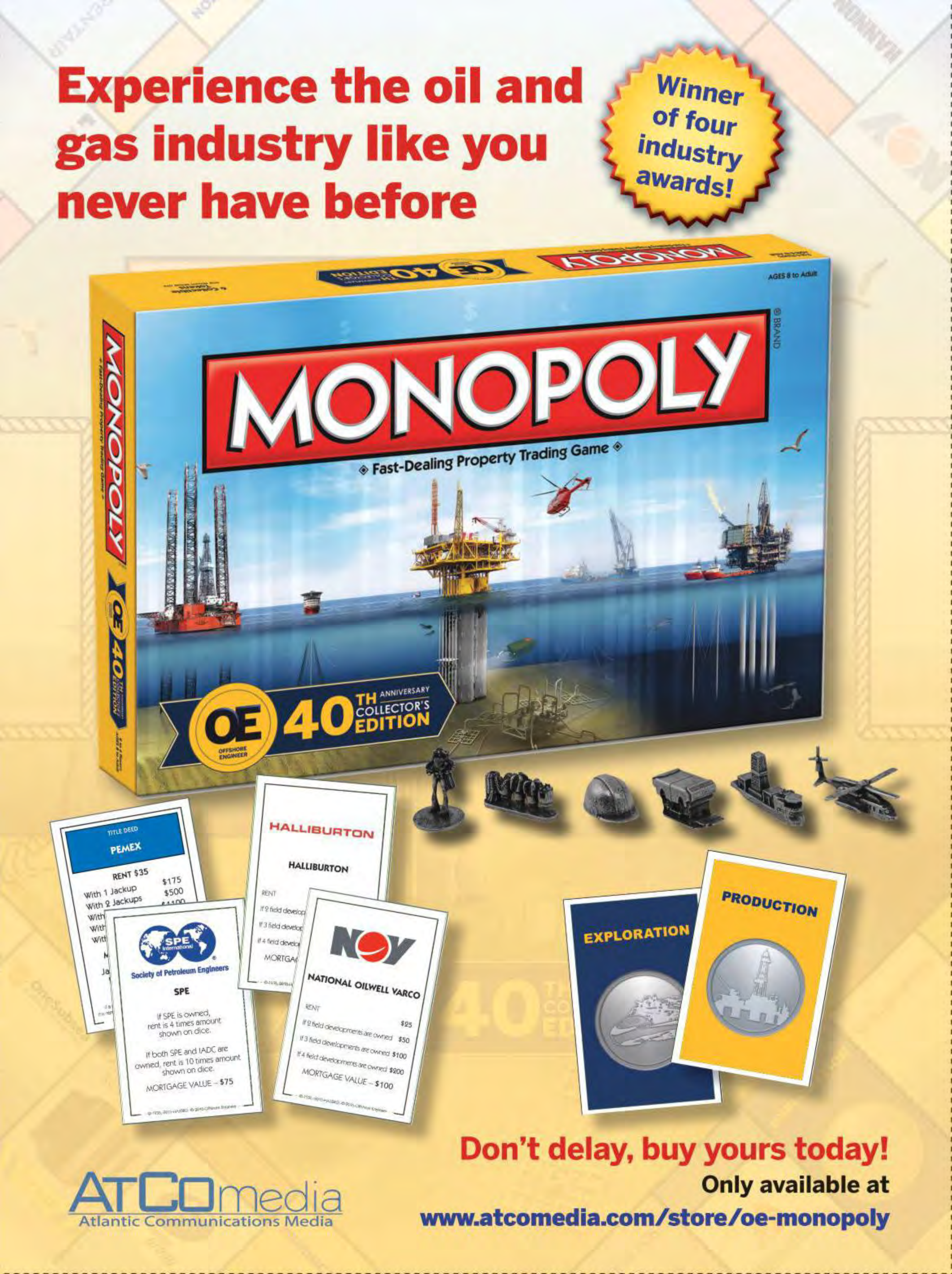
Ultrasonic meters are increasingly a preferred technology for many upstream and offshore operators, being well suited to the dirty gases often encountered. Ultrasonic meters also have negligible pressure drop, have high turndown capability, and can handle a wide range of applications.

A key advantage of ultrasonic meters over other flow measurement solutions is the availability of diagnostic information beyond just delivering pulses or signals proportional to gas volume. New ultrasonic meter designs employ electronics that optimise internal diagnostics, flow velocity calculations, signal processing, data storage, interface to flow computers and supervisory control and data acquisition (SCADA) systems, and field service diagnostics tools.

Again, this diagnostic data is particularly valuable for upstream and offshore operators: The diagnostics help to better understand the process, keeping field maintenance work to a minimum to bring benefits to both efficiency and safety.

The most advanced ultrasonic flow meters today provide stability during flow perturbations due to innovative path designs, utilizing multiple measuring paths on different levels.

Finally, ultrasonic meter designers have developed detection algorithms extending signal amplitude to effectively create a higher signal-to-noise ratio (SNR). For example, by transmitting a predefined burst signal instead of a single pulse the tolerance to signal attenuation is improved. Such innovative detection algorithms enable greater insensitivity to the noise characterizing many upstream installations.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**A key advantage of ultrasonic meters is the availability of robust diagnostic information and condition based monitoring capabilities.**

## The value of integration

Once reliable measurement data is in place, fast, smart business decisions require streamlining the data collection, validation, surveillance, and notification processes from field assets such as the flow meters. An integrated operations platform delivering both operational intelligence and field system and engineering application integration is also required.

Traditional technology assumptions that accurate, safe and reliable measurements required a separate, closed system are no longer valid. Open systems technology now provide this, as well as a wide range of additional benefits. Integrated metering solutions are therefore increasingly replacing separate, higher-cost dedicated systems. A solution that integrates the metering function into the control system architecture provides the basic answer.

Such solutions are much more cost-effective in terms of their installation and configuration, as well as their support and upgradeability over the long-term. Flow computation in petroleum facilities, for example, is traditionally handled by disparate flow computer devices, and recently also by programmable logic controllers (PLCs) and, in non-fiscal applications, "virtual" flow computers. Solutions integrated with distributed control system (DCS) platforms, however, offer significantly greater cost efficiency, extended lifecycle support, improved control and can also be approved for custody transfer making them a real alternative for all applications.

Centralized metering technology enables users to better meet regulatory requirements for fiscal reporting of carbon emissions; simplifies integration of raw meter data in accounting and reporting systems; and improves optimization control of liquid, loading and proving systems where control and sequencing-type tasks are critical. They can also benefit from flexible reporting, Web-based access, and integration with wireless and fieldbus transmitters in the metering function.

With a DCS-embedded metering solution, fiscal and allocation metering functions are integrated in robust and sustainable controls, rather than held in flow computers or dedicated metering supervisory computers. This approach utilizes a redundant process controller as the fiscal point. Additional flow computing calculations are easily configured in software, which links new instrument inputs to results.

With more functions inside the control system there is no external system and custom interface to maintain. This eliminates a separate database, configuration and graphics building effort. Fewer systems to maintain also means less training is needed.

In addition, modern control processors, and therefore the metering solution, support a wide variety of I/O, including analogue, remote, FOUNDATION fieldbus and HART. Finally, users can load ISO, American Gas Association (AGA) and American Petroleum Institute (API) calculations into the controllers and upgrade them to easily keep up with changing business and regulatory requirements.

## Conclusion

By integrating fiscal flow measurements and centralizing the calculations, data becomes more accurate, more manageable, and ultimately more transparent to operators, partners, and regulatory authorities. Integration with the DCS platform also allows for advanced database maintenance, graphics building, trending, management reporting and Web-based intranet access.

Petroleum-based products have always been precious commodities, but today's business outlook makes accurate measurement of production values and product custody transfers all the more critical. For offshore, as for onshore, new ways to use digital intelligence from these fiscal metering systems will become increasingly central to the faster and smarter decisions businesses need to succeed. **OE**

***Tim Vogel** is product marketing manager – gas metering, Honeywell Process Solutions, and has been with Honeywell for nine years. He holds a Master of Science from the Technical University Mittelhessen, Germany, which focused on business process management and a Bachelor of Business Administration and engineering with a major in mechanical engineering.*

## FURTHER **READING**

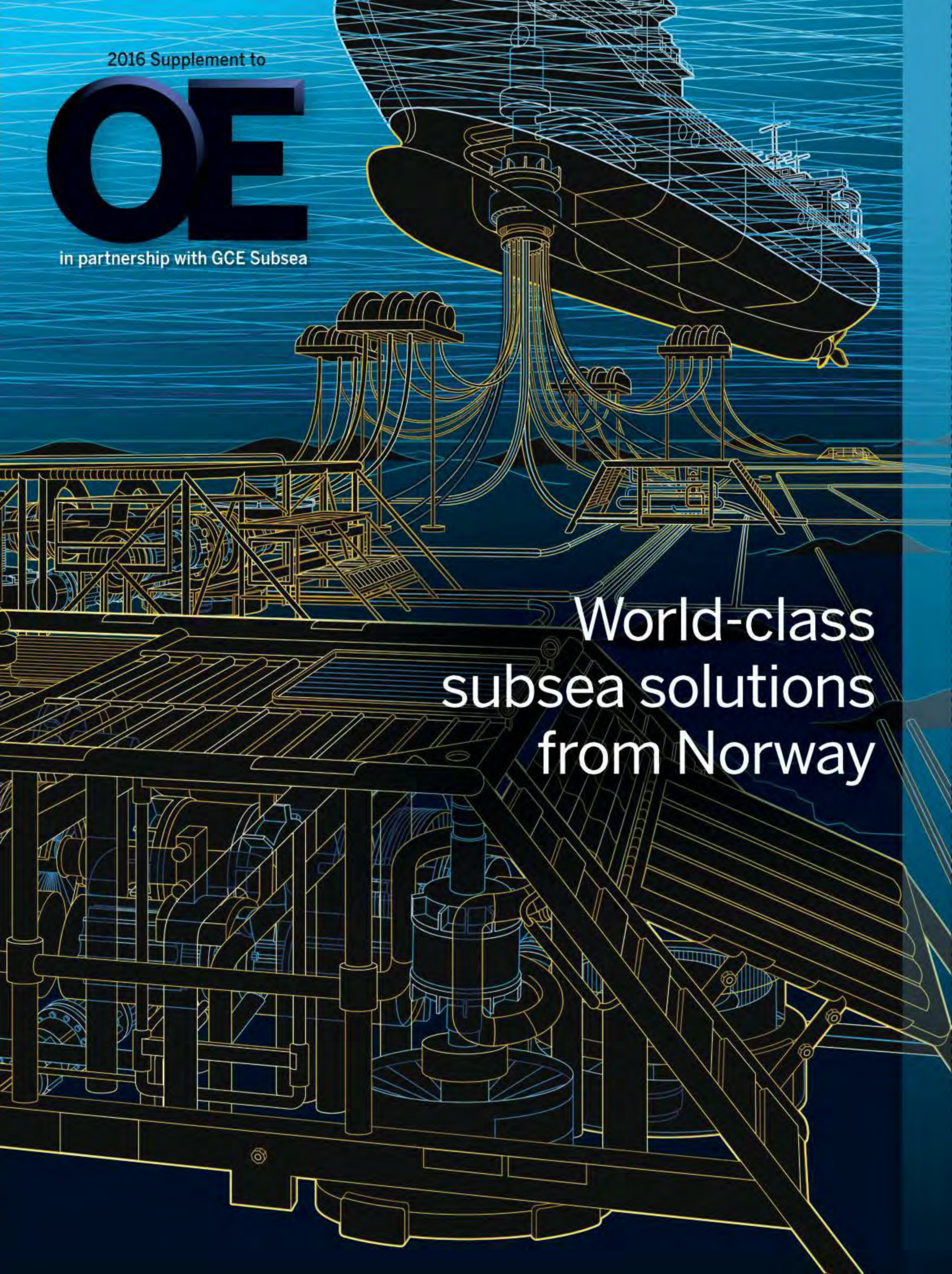
**Oilfield AI** Autonomous inflow control devices are enabling production engineers to manage reservoir uncertainty along the well with better flow assurance and greater oil recovery, says Tendeka's Ismarullizam Mohd Ismail. **www.oedigital.com/subsea/item/11633-oilfield-ai**

2016 Supplement to

OE

in partnership with GCE Subsea

# World-class subsea solutions from Norway



# Inside



*World-class Subsea Solutions from Norway*, is a supplement to *Offshore Engineer*, published by AtComedia.

**Supplement editor**, Elaine Maslin, emaslin@atcomedia.com
**Advertising sales**, Brenda Homewood, brenda@aladltd.co.uk
**Art and production**, Bonnie James
**Reprints**, Jill Kaletha, jillk@fosterprinting.com, +1-219-878-6068

**AtComedia**, 1635 West Alabama, Houston, Texas, 77006-4101, USA.
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# A step forward for Norwegian subsea solutions

**By Tove Ormevik, OIM *Skarv* FPSO, BP Norge, and chairman of the board, GCE Subsea.**

The Norwegian subsea industry has been an adventure, and there is nothing to suggest that it is over. Due to hard work, innovation and collaboration, companies and research and development institutions have developed great expertise and gained market shares.


**Tove Ormevik**

For 10 years, NCE Subsea has contributed to this impressive history and to make this important industry known to the general public, media and decision makers.

In 2015, we took a step forward as we achieved status as Global Centre of Expertise (GCE). Being given a GCE status is a strong acknowledgement of our work and results, and we are now eager to continue our efforts to implement our GCE ambitions and strategy.

GCE Subsea's ambition has always been to function as a unifying organization for the Norwegian subsea industry and reinforce its status as a global knowledge hub. The GCE status gives us the resources we need to achieve these ambitions

Our main objective will be collaboration to strengthen the cluster's competitive advantages in the global market, and realize sustainable growth and value creation.

One GCE Subsea focus area will be international collaboration with neighboring value chains in order to supply the Norwegian subsea industry with new qualifications. This can increase the rate of innovation and competitiveness and open up opportunities in new markets for the use of Norwegian subsea expertise.

We believe that our new GCE status will result in long-term and increased funding for our activities and the industry. This means that we can speed up our long-terms efforts to implement our strategy for the Norwegian subsea industry. As GCE Subsea, we will have the opportunity to assist the industry with the efficiency measures that are necessary in order to increase the competitiveness of the Norwegian industry. The main areas where we will increase our focus are on cost-efficiency, international markets, research and development collaboration and new related markets outside the oil and gas industry.

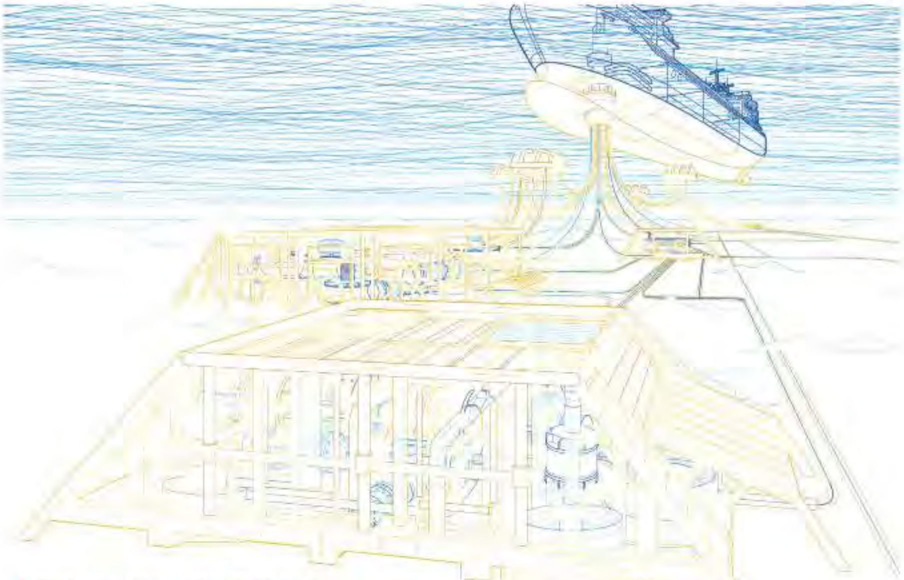


**ABB is working with GCE Subsea partner Statoil on subsea power solutions and provided our 2016 cover.** Image from ABB.

# Compression 2.0

**After completing the world's first wet gas compressor offshore Norway, OneSubsea looks to continue pushing the technology to new limits.**

Mid-October 2015, after more than 24 years' worth of development work, the world's first subsea wet gas compression facility was fired up 130m beneath the waves, 175km west of Bergen, offshore Norway.

The technology will help increase recovery by 22 MMboe, or from 62% to 74% of the field, and extend the production plateau from Statoil's Gullfaks South Brent reservoir – figures that are hard to ignore.

The multiphase compressors on the seafloor at Gullfaks South are two, 5MW, WGC4000 units, with 21 stages each, and 6000 cu m/hr throughput capability. Installed in parallel, they provide a 32 bar initial pressure increase. When in series – achieved by operating two valves – that increases to 64 bar, which may be needed towards end of life.

It's an achievement, but there's more yet to come. Having increased the capabilities and performance of this technology over the past two decades, OneSubsea thinks there's scope to take it even further – a job they're working on already.

"We want to improve the capacity and the differential pressure capability," says Arne B. Olsen, director of sales, OneSubsea. "That's what we are working on. Together with customers, we are targeting at least differential pressure up to 80 bar with one single machine." All while keeping the power requirement low.

OneSubsea's work in subsea compression builds on the work of Framo Engineering, which was bought by Schlumberger in 2011, and subsequently wrapped into its Cameron-Schlumberger jointly owned company – OneSubsea.

The development work on subsea wet gas compression started back in the 1980s. But, at that time, the industry wasn't quite ready for it, Olsen says. The unit capacity was also too small and unable to handle enough volume.

The design principle is based on a set of vertically oriented contra-rotating impellers, one set pointing outwards from an internal shaft, the second on an outer shaft facing inwards, and each driven by its own motor, installed at each end of the unit and supported by axial and radial bearings. Every second row, or stage, of the 21 impellers in the Gullfaks unit, rotates in the opposite direction at a maximum 4500rpm. The motors and power system are based on those OneSubsea uses in subsea booster pumps, which have chalked up more than 2.5 million operating hours.

"What we have developed is a hybrid between a multiphase pump and a compressor," Olsen says. The OneSubsea multiphase compressor doesn't have diffusers, it has two separate shafts of impellers, which contra-rotate, facing inwards towards each other. "This design makes the compressor more compact," Olsen adds.

But while it's taken on some of the characteristics of a compressor, it's more like a multiphase pump in terms of its mechanical robustness, Olsen says. "The hydraulics, i.e. the impellers, are mechanically robust, which means it can handle any combination of gas and liquid and can even be started while filled with liquid."

According to OneSubsea's research, the WGC4000's polytropic efficiency – a measure of compressor efficiency – is 85%. "This matches conventional compressors," Olsen says. Of course this will change according to how much liquid is in the stream.

**Arne B. Olsen, director of sales, OneSubsea**

"It's been a 24-year development project," Olsen says. "The fundamental principles have always been the same. The earlier designs were all horizontal. In 2000, we changed to a vertical orientation, for subsea compactness and retrieveability. Yet the main change has been its performance in terms of capability handling larger volumes. Previously it was a bit too small for some of the bigger gas fields so we worked very hard to improve on that. Now, volume has increased by a factor of five compared to 2000, primarily by changing the geometry of the impellers. The capability today is much closer to what is needed for medium to large gas fields."

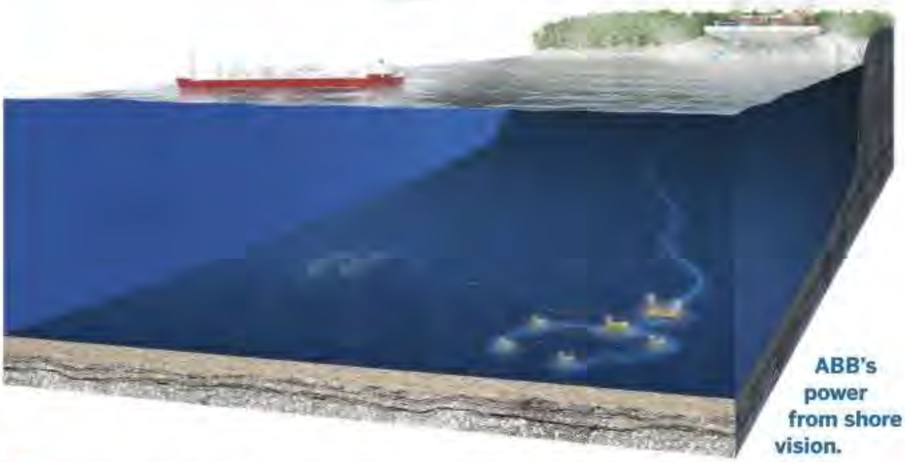
So what next for wet gas compression? Technology-wise, OneSubsea is already working on the next generation multiphase compressor – the WGC6000, with yet more focus on the compressor capacities. Geography-wise, most point to East Africa and Australia.

"There is a big need for this technology in places like Mozambique, Tanzania, and Australia. There will be a big take up of these technologies, I'm quite sure," Olsen says. There could even be scope offshore Norway, according to Kjetil Hove, senior vice president for Statoil's operations west cluster. Speaking of when the Gullfaks multiphase compressor first started up, he said: "We see great opportunities for wet gas compression on the Norwegian continental shelf... for improved recovery on small and medium-sized fields. We are searching for more field opportunities that are suitable." ■

**The multiphase compressor station during installation.** Photos from OneSubsea.

# Powering the deep

**Longer step-outs, harsher environments, deeper waters all point to an increasing need for power on the seafloor. Statoil and its partners are working on solutions. Elaine Maslin reports.**



**ABB's power from shore vision.**

Electrifying the seabed has been a long-term aim for the oil and gas industry. A bid to achieve that goal is getting closer, however, as subsea processing becomes not just a necessary technology, but also a more mature one, which requires ever greater power supply on the seafloor at greater step-outs.

In Norway, Global Center of Expertise (GCS) Subsea partner Statoil is helping to lead efforts to create a subsea power distribution system. In 2013, the oil major inked a US$100 million, five-year joint industry project (JIP) with power and automation giant ABB to qualify a system able to transfer 100MW over up to 300km in up to 3000m water depth. Siemens and GE Oil & Gas are separately working on similar systems.

It's quite a goal, but it's one Statoil thinks the industry needs. "We see this as a key building block for subsea processing in the future, both subsea distribution and long distance power transmission," says Steinar Midttveit, leading advisor, subsea electrical power, Statoil. "The fact that this technology enables the introduction of subsea processing without major topside modification is important. The Åsgard subsea compression development included a 900-tonne topside module on the existing asset, which is a major job to integrate. With this technology [subsea power distribution] we can place the majority of the equipment on the seabed, supplied by one power cable. We can also take power from shore easily, using renewable sources, reducing $CO_2$ emissions and making subsea power processing more independent from where you take the power from."

The past year has seen a lot of progress on the JIP, ABB says. It has passed technology readiness level 2, which means the concept has been selected and key components tested. Concepts for power switching under pressure have been verified and switchgear components have been pressure tested and verified. The next steps are building sub-assemblies and prototypes.

"The next milestone is testing a power cell assembly," says Jan Ø Bugge, vice president and project manager, ABB. "This test is testing the drive-cell under full operation conditions at pressure test facilities in Trondheim."

"Before making final technology decisions, we want to see how it operates in the final environment," says Stian Ingebrigtsen, principal engineer, subsea, ABB. "We will simulate the operation and the power cycling in normal operation. The target is to identify what works well and what needs to be improved for next round of design improvements."

"Showing it is able to handle switching under pressure [in oil filled containers] will be a key milestone," Bugge adds. "The next step after this is to qualify these components to make sure they handle the pressures to 3000 m water depth before building the full prototypes."

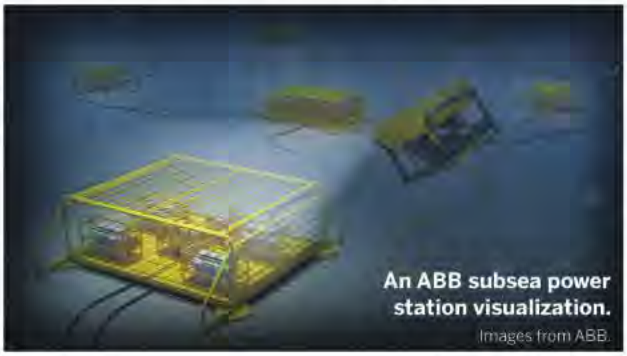
At the same time, ABB is also working on the medium-voltage switch gear, transformer and control systems. All in all, an extraordinary array of components and materials all require testing and verification, to select the optimum arrangement, alongside third party components, especially around connectors and penetrators.

A key challenge will be making sure the equipment will be reliable over the design life of a subsea field, with as little as possible or no maintenance. "Most of this is well known in ABB product development, the new aspect is pressure," Bugge says. "Also, we will have new types of material interfacing with live parts that will see varying temperatures depending on load conditions. A large part of the project is working with material technologies," Ingebrigtsen says.

Then, the next step will be going into a live environment: ABB is looking to start shallow water testing of a complete system towards the end of 2018.

ABB has something of a heritage when it comes to subsea power distribution. In the late 1990s, the firm drove the Subsea Electrical Power Distribution System (SEPDIS) subsea electric power distribution project, resulting in a subsea frequency converter being designed and tested by 2000. At the time, the industry wasn't quite ready for it.

It is hoped the industry will be ready once again, after the JIP completes in 2018 and progresses towards technology readiness levels 5-7 in 2019 onwards.



**An ABB subsea power station visualization.**
Images from ABB.

While Statoil has been postponing projects in response to the reduced oil prices over the past year-18 months, there are a few projects at select phase for such technologies, Midttveit says. "We are working on some projects, but they are in the early phase," he cautions. 2019 might be better timing.

# When the forecasts are flawed

**Subsea processing market projections have consistently overestimated the growth of the market – DNV GL looked into why. Elaine Maslin reports.**

The potential for subsea processing has always seemed clear. Growth in deep water developments, subsea production, and longer steps-outs and the need for production enhancing or boosting technologies, have long been seen drivers for subsea processing technologies – both new and mature.

But, the potential has never quite matched up to forecasts. Why? The good news is that the main reasons are not about the technology itself.

According to a survey of subsea technology professionals devised by Norway-based subsea specialists at DNV GL, a GCE Subsea partner, one-third of participants believe it is a lack of business cases and a further 29% said it was project risk, cost and schedule. Together, those reasons add up to some 62% relating to economics. Meanwhile, just a quarter, cited technology.

"I think it's a sign or symptom that those justifying business cases for specific fields are not the same people as those designing the next generation of equipment," says Bjørn Søgård, Segment Director for Subsea at DNV GL – Oil & Gas. "There's a fundamental disconnect between those communities in a way.

"One of the limiting factors is that there are too many variables involved in a system, so that when it comes to a tender, so many of these have been fixed, limiting options," Søgård says. "There is also not enough interaction with the subsurface team, to really understand what systems are required."

For Tore Irgens Kuhnle, a business development leader, SURF, DNV GL, the ever optimistic forecasts also do not take into account who operates particular fields and how they view subsea processing technologies. "There are many fields that are good candidates, but you look who is operating that field, you known it will never take that [subsea processing] technology into use," he says.

Of the subsea processing technologies, multiphase boosting is the most mature and, according to the survey, also the most attractive, followed by bulk water separation and injection, gas/liquid separation, to which most respondents were "neutral," and then finally gas compression, deemed "unattractive" by most, and which was the only technology not in operation at the time of the survey in 2H 2015.

The attraction to multiphase boosting, considered by 88.2% of the survey respondents to be a proven technology, was its ability to offer higher and faster production, from low pressure wells, deep water and long distance tie-backs. But, while it's the most mature of the technologies, adoption has still not been as great as could be expected, with cost, power, barrier fluids and topsides modifications listed as weaknesses.


Images from DNV GL.

Multiphase boosting has found itself a market. It has an obvious business case and the technology has proven itself with systems proving some eight years without maintenance. But even so, there are just 40 projects are out there and very few players providing this technology on the market, which limits operator's options.

Perhaps the bitterest pill in the survey was the view of how many of each of the subsea processing technologies would be sanctioned over the next five years. It amounted to a total of seven, at the lower estimate, to a maximum 19. These were split as follows: 4-10 multiphase boosting projects, 1-3 bulk water separation, 1-3 gas/liquid separation, and 1-3 gas compression projects.

Given those figures, it was not surprising that 50% of respondents said subsea processing's share of the total subsea market would stay the same. Still, 46% said it would increase, with just 4% predicting a decrease.

"I think the way ahead will be to be more modular, with more compact and smaller units instead of massive central units on the seabed," Søgård says, suggesting cartridge style modular systems with common interfaces. "What we are then losing is overall efficiency, but with lower risk and phased possibilities for investments instead of massive investments."

Other ways to make systems more attractive would be to share power between power users, instead of individually controlling each and every pump. You might have one common speed control and switch pumps in or out when you need them, for example.

But, there will also be a need for new technologies, Søgård says, especially when it comes to powering longer step-outs.

# Outsmarting corrosion

**Detecting corrosion is a huge headache for the offshore industry. CMR is developing a tool to spot it before it takes hold.**

Christian Michelsen Research (CMR) in Bergen has a long track record in developing innovative solutions together with clients.

Today is no different. The institute, whose primary area of expertise is in measurement and computer science, is tackling some of the most current issues in the industry, not least aging infrastructure and the drive towards lifetime extension.

Corrosion under insulation (CUI) is especially challenging, due to the difficulties to detect such degradation.

"CUI can lead to loss of containment, resulting in costly shutdowns, not to mention potentially far-reaching HSE consequences," says Kari Marvik, Vice President CMR Science & Technology. "Furthermore, CUI inspection and maintenance jobs are notoriously time consuming and industry data shows that significant costs could be saved through smarter execution of maintenance programs." Early in 2015, CMR was granted funding from the Research Council of Norway to develop two ideas, one of which was targeting CUI to help change how the industry operates and also result in significant cost savings.

## Getting under the skin

The result has been the development of an Online Distributed Integrity Monitoring System (ODIMS), which will enable operators to perform targeted inspection and preventative maintenance – catching corrosion issues before they become a problem. "ODIMS uses distributed fiber optical sensing technology to detect humidity, water, salinity and temperature," says Peter Thomas, a CMR scientist. The optical fiber is installed under the insulation, and a central electro-optical interrogation unit is measuring continuously to detect any exposure along the installed fiber. It is also possible to add point sensors along the fiber using the system as a communication infrastructure.

"The system is flexible and modular and can be installed on existing installations," Thomas says. "The most cost efficient is to install the system during existing CUI maintenance campaigns. A central application for ODIMS is to serve as a facility-wide early warning system, identifying areas with high humidity and water ingress, which trigger CUI, reducing the risk of production shutdowns and accidents."

However, the technology has the potential to be utilized in other applications too, both in the oil and gas industry and within civil engineering.

Norwegian operator Statoil and oil and gas service firm Beerenberg are participating in the steering committee of the project. They are also due to contribute with test facilities and piloting opportunities. Work done to date has demonstrated the feasibility of the ODIMS solutions with promising results so far.

Larger scale lab-testing started in 2015. Critical components and key features are due to be complete by the end of 2016.

## Kelvin comes to the rescue

However, it's not just corrosion that can cause a problem. The oil and gas industry, as in many industries, depends to a high degree on the quality of the fabrication materials used and the ability to preserve the designed quality and functions of the assembled system or plant. This requires non-intrusive inspection (NII) technologies to ensure that desired quality and specifications are fulfilled during the lifetime of the component and or system.

A particular area of interest are NIIs that could detect hidden faults, from the fabrication process, especially if they could lead to delayed and sudden failures long after fabrication, i.e. fractures due to hydrogen-induced stress cracking (HISC).

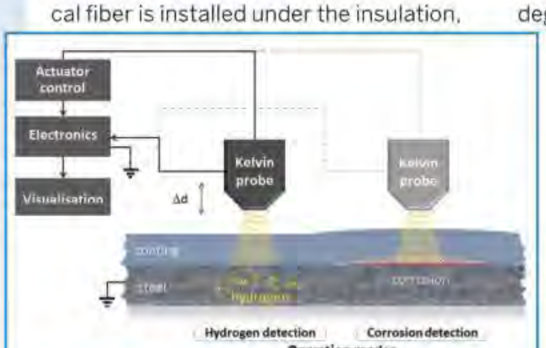
For example, the presence of tiny amounts of freely diffusing hydrogen in steels can, some times, lead to dramatic consequences. "Unlike other detrimental substances, hydrogen can enter the steel right from the processing of the raw material and throughout fabrication, assembly and operation phases," says Michael Rohwerder, Max Planck Institute for Iron Research (MPIE) Germany.

Thomas Peter

To help the industry mitigate the detrimental effect of the hydrogen, scientists at CMR are working with scientists from the MPIE to develop a handheld, automated Field Kelvin Probe (FKP), a contactless technology to enable the detection of minute concentrations of diffusible hydrogen in steel components.

The FKP works by measuring Volta potential differences (i.e. differences of the electric potential resulting from an excess of electric charges) between the steel structure under examination and the Kelvin probe. There is a rather simple relation between this Volta potential and the absolute electrochemical potential of the steel. Moreover, there exists a mathematical relationship between the Volta potential difference and the level of diffusible hydrogen in steel, which could allow qualitative and quantitative detection of hydrogen without any direct contact to the steel. Referring to the working principle, one could say in simple words that the core of the FKP is not more than a variable capacitor.

Currently, CMR is running two projects on the FKP. The Research Council of Norway is funding a four-year project for basic research and development related to the FKP. Additionally, CMR receives industrial funding for more applied FKP applications.




**Schematic representing the measuring principle and possible operation modes of the FKP.**

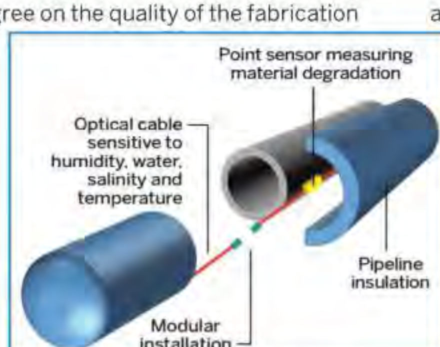



**Illustration of the ODIMS solution.**

Images from Christian Michelsen Research.

# Making Murene

**The need to innovate, collaborate and standardize existed well before the downturn, and not least in Norway. Elaine Maslin sets out how Transmark Subsea has been doing all three.**

Founded in 2009, Transmark Subsea set out three core business strands; cables and connection systems for ocean bottom seismic systems, internal connections on the ROVs, and subsea jumpers.

When the company found that a key component required for the subsea jumpers was only sold by one manufacturer – to two clients – and that new standards were also being drawn up by oil major Statoil for this part, it decided to take matters into its own hands.

Working with a specialist hose manufacturer the firm developed its Murene subsea oil-filled pressure compensated system, a hose and connector system design to be a conduit, barrier and protection for fiber optic and copper cables.

**Tore Diesen**

The system is used on subsea trees and transmits data to/from sensors to the control pods, if it's an electric system. It would also be used on manifolds between subsea structures and as a jumper to the control umbilical.

The Murene system meets Statoil's latest standard for electrical and optical wet mateable jumper assemblies, TR2390 Ver.2, which will be the base of a new international standard.

The clever thing is, the hose uses its own properties to act as a pressure compensator, and it can cope with the temperature and sunlight it would be exposed to on the back deck of a vessel offshore west Africa, as well as arctic temperatures, says Tore Diesen, sales and marketing director, Transmark, based at Rådal, near Bergen."When the new [international] standard comes through, we are one of few, maybe the only one, that is qualified according to this standard," Diesen says.

Transmark's design is based on two layers of special rubber compounds, with an axial layer of aramid fiber in between, to absorb longitudinal pull load during handling, and a cross woven layer of nylon/polyester to provide the pressure compensation qualities of the hose.

"When you go deep subsea, it's important to make sure water cannot penetrate electrical systems," Diesen says. "The way they are doing it is to pressure compensate them – making the internal pressure the same as the external pressure. Murene is manufactured in a way so it acts like a spring, acting like a pressure compensator," he says. The over pressure will be about 2-6 bar, but it will never be more than 10 bar differential pressure inside the hose, or less than 0 at +50°C or -10°C, he says.

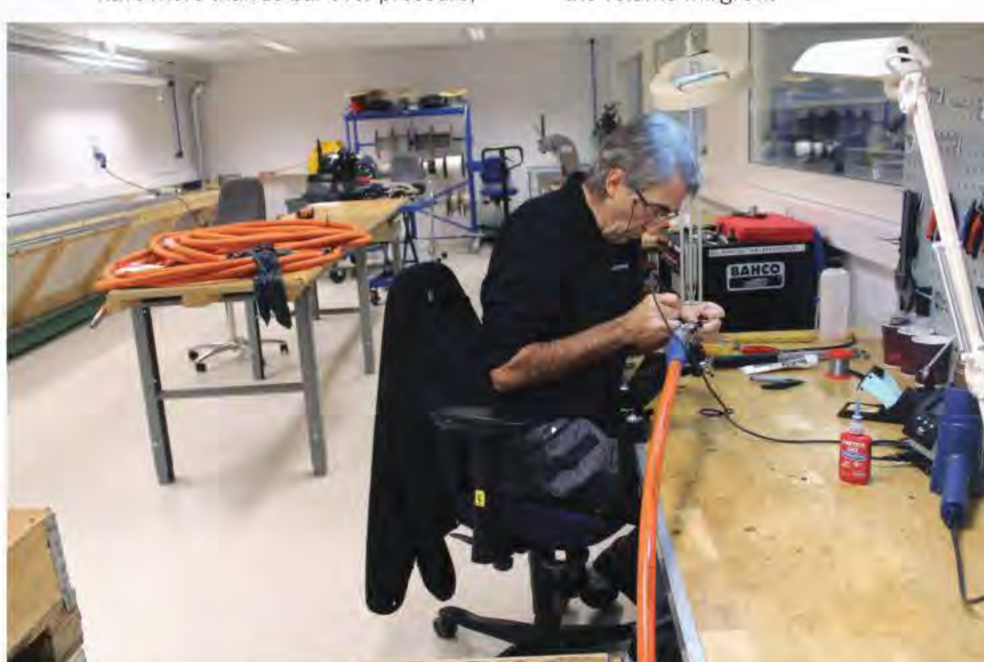
"Not only can it withstand water depth, but also temperature differences, which is even harder to comply with," he says. "The hose was developed to compensate for temperatures and pressure. In the Gulf of Mexico, for example, you will never have more than 10 bar over pressure, and at 3500m you will have slight over pressure of a couple of bars. It also has to tolerate hydrocarbons outside and inside, sea water and sunlight for six months in the likes of West Africa without losing its bright original color and mechanical properties. As it is supposed to be handled by an ROV system – with up to 250hp – it has to be strong as well," Diesen says.

Working with a hose manufacturer, a special "recipe" for a rubber to meet these demands was created (NBR and NVC/SBR). Most use Natural Rubber, Nitrile or chloroprene/Hypalon, Diesen says, depending on the performance criteria needed.

Murene has also been designed so that it has an industry standard Mk2 interface, so it can connect with different types and brands of subsea connectors and different kinds of sensors, as well as being a modular system, comprising "split boxes" with multiple inlets and outlets. All metal components are made in Titanium as standard, other materials on request.

"We have sold several 1000m of Murene since late 2013," Diesen says. "It's good for the industry, now there are multiple suppliers and an upgraded version of this for the industry important product."

Despite the current climate we are in, there's still going to be a growing market, he says. "We are seeing more and more sensors being used to monitor and control what is going on subsea, and for this they [operators] need more hoses, so definitely the volume will grow."




**Work on Murene at Transmark's facility near Bergen.** Images from Transmark Subsea.

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# MEMS the word

**Norwegian universities have a great habit of directing their students towards research that quite often results in a new technology – and new businesses. Elaine Maslin reports on a new business bringing micro-electronic mechanical systems to the subsea business.**

Norwegian Subsea is a great example of how research in Norway can drive industry innovation. The company was founded in 2014, with the help of the Research Council of Norway, by three graduates of the Norwegian University of Science and Technology (NTNU).

One undertook a PhD in inertial navigation, the result of which is the foundation of the company and its first product – MEMS (micro-electromechanical systems) based motion sensors. MEMS technology, which has seen rapid development in other areas in the past decade, could help both increase accuracy, reduce power consumption and weight, according to Norwegian Subsea.

**A MEMS-based subsea motion sensor from Norwegian Subsea.** Photos from Norwegian Subsea.

"We were all at the university, two of us finished master's degrees some years ago and were working in the maritime industry. Then we all came together," says Lars Gaarder Torgersen, CEO at Norwegian Subsea, who studied marine engineering and worked at Marine Cybernetics, since bought by DNV GL, before co-founding Norwegian Subsea.

"We saw that there was a gap in the market for MEMS-based motion sensors with high accuracy and low power consumption. By implementing the latest and best state-of-the-art MEMS sensors and combining them with our own algorithms, we could come up with motion sensors less costly and more accurate than those on the market."

The firm's products include the NORSUB 6000 subsea motion sensor, which offers roll and pitch (both to 0.01°), heading (0.5°), at 0-2000 Hz frequency, in a 1.5kg unit measuring 14.6cm by 7cm. It's been designed for use in water up to 6000m water depth. Existing alternatives include fiber optic gyros, which are expensive, consume more power, and are large and heavy, Torgersen says. Norwegian Subsea also has the NORSUB AHRS 1, for use on small-medium sized ROVs and NORSUB AHRS 2 for auto heading and motion control on ROVs, with both providing measurements without time lag and designed to work down to 6000m. Alternatives used on ROVs include fluxgate compasses.

MEMS are miniaturized mechanical and electro-mechanical elements made using the techniques of microfabrication. The functional elements of MEMS are miniaturized structures, sensors, actuators, and microelectronics, the most notable elements are the microsensors and microactuators, which convert energy from one form to another, i.e. from a measured mechanic signal into an electrical signal.

MEMS were developed for the defense space but for the past 10 years they have been adapted for more commercial uses.

**Lars Gaarder Torgersen**

With a lot of research carried out in to MEMS technology, and subsequent commercialization, production costs have decreased. "The technology has been moving at a very fast pace and becoming quite cheap, smaller and smaller, and more accurate, because the manufacturing techniques have improved. Today, you can buy quite high performance MEMS at affordable prices," Torgersen says.

But, the MEMs is actually not the clever bit. Norwegian Subsea has taken MEMs technology and added its core competence – designing smart, efficient algorithms. "Our algorithms allow us to combine data from many sensors – gyro, accelerometer, etc., – and then fuse them together to increase frequency and therefore accuracy of the calculations, at the same time reducing the amount of power used to do those calculations," Torgersen says. "That allows us to run an algorithm on a microprocessor, which is key to reducing the size and cost of the units."

Other methods, such as Kalman filtering, a type of algorithm which requires a lot of computing power, can be used, but subsea the computing power required is an issue and reduces the frequency of the calculations, Torgersen says.

The motion sensors are intended to be used for asset integrity, measuring BOPs for fatigue, survey work, ROV heading and control, and a myriad of other uses. The young company's first deployments, in late summer 2015, saw the firm initially loaning out a unit in order to get industry feedback, with one or two clients. Sales are expected to start and increase in 2016-17, Torgensen says.

Norwegian Subsea has also moved into marine motion reference units (MRUs), which it thinks could offer a larger market and where costs could be significantly reduced compared to existing solutions. The MRUs use the same technology but it is used on ships in DP or to measure motion compensation on offshore cranes, for example.

The company, which has five staff in Oslo, currently assembles the units, using off-the-shelf MEMS units, with its own programmed algorithms.

# A subsea Inovatum

**Not all projects for clients come to fruition, but the work done along the way can lead to greater things as Norway's Inovatum Lifting is finding out. Elaine Maslin reports.**

For a client in Brazil, turnkey prototype solutions firm Inovatum developed a remotely operated vehicle (ROV) shackle that used sea water instead of hydraulic oil to operate the hot stab, eliminating the risk of any oil leakage.

It was a one-off project. But, once designed the firm realized their product, since named INOshackle could offer a new improved, single stab operation shackle alternative to the market. They have also made further improvements, introducing remote and multiple unit activation with one stab.

**Janny Angvik Aasen**

The INOshackle is a 15-1000-tonne working load limit range of shackles that can be operated with one hot stab operation from a work class ROV, on either the "arm" or the "disarm" stab port. The hot stab uses one hydraulic hose supplied with high pressure water supplied from and ROV standard high-pressure water jetting pack.

"Compared to other shackles, it is faster and easier to use," says Lars Skjold co-founder and general manager at Inovatum, based just north of Bergen. "On others, you maybe do three different things to connect and disconnect and have to move the ROV from one side to another of the shackle. The only thing they have to do with ours is stab it. This is cost and time saving, which is key when it comes to using big support vessels – the time adds up."

The Shackles are manufactured by Brødrene Haukås Mek. Verksted, in Haugesund. Skjold and marketing manager Janny Angvik Aasen set up Inovatum in 2010 to develop turnkey prototypes for ROV tooling. Skjold has worked in the ROV business for more than 20 years, and had become a "go-to" man for problems others couldn't fix.

Since launching INOshackle and a new subsidiary company called Inovatum Lifting in 2013, Inovatum has sold INOshakles to clients including NeoDrill (which was first to use the INOshackle on a suction anchor installation project) and Technip, which used them on the pull in at Eni's Sevan design, Goliat FPSO project in the Barents Sea offshore Norway.

**Lars Skjold**

But Inovatum hasn't stopped there. The firm's latest innovation is enabling multiple shackles to be disarmed from one stab point. On a subsea lifting projects, typically there are multiple shackles. By connecting these to one central lifting shackle (the control hoses are available built into the soft slings) all can be released at the same time by stabbing the central lifting shackle. Inovatum also offers an acoustic release alternative, with a transponder and accumulator to operate the shackle and it is looking to increase the load to 2000-tonne.

Inovatum's new remote release with feedback system will allow several INOshackles to open at the same time from one stab point – subsea or on deck.

**Two 150-tonne INOshackles.** Photos from Inovatum.

# Going global

**2015 was a transformative year for NCE Subsea, gaining GCE Subsea status. Now the world-class subsea cluster has a rock solid base to build on and grow out from.**

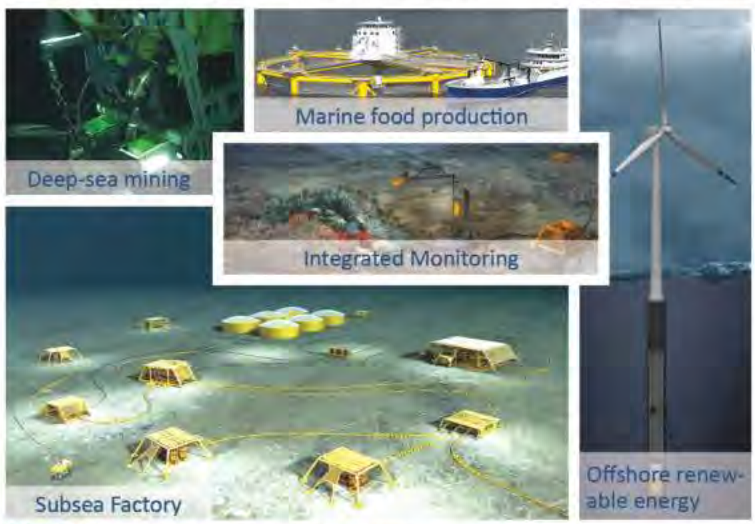
GCE Subsea strengthens innovation and internationalization of the Norwegian Subsea cluster. Its main goal is to increase the cluster's competitive and global market share, to take a leading position in sustainable utilization of ocean resources. The cluster is composed of more than 100 members and partners, with world-class companies and competence, and a notable strength in subsea life of field solutions.

### Becoming GCE Subsea

On 1 January, after a decade as NCE Subsea, under the Norwegian Innovation Clusters program, the organization entered the Global Centres of Expertise (GCE) program, after being awarded the new status in June last year.

The GCE Subsea status recognizes NCE Subsea's achievements, which include:

- Supported more than 60 innovation projects, resulting in NOK600 million external funding
- Support for the Lofoten Vesterålen cabled observatory – developing the future of integrated environmental monitoring
- Members WiSub and ClampOn awarded the Offshore Technology Conference (OTC) Spotlight on New Technology award, based on innovation supported by NCE Subsea
- Contributed to establishing the world's first subsea-specific bachelor program in Bergen, Florø and Kristiansund
- Established the very successful entrepreneurship program "Subsea First Step" and the business development program "Subsea Next Step"



**GCE Subsea overview** Image from GCE Subsea.

### Process under the spotlight

Even more will be able to be achieved under the new GCE Subsea status. GCE status is the highest level in the Norwegian Innovation Clusters program. With it, GCE Subsea will see an increase in public funding from NOK5 million to NOK10 million per year, over 10 years.

"With this increased funding GCE Subsea will strengthen its financial and professional support to facilitate innovation projects. Moreover, we will increase our collaboration with other national and international clusters and continue to offer new competence to our members," says Owe Hagesæther, CEO, GCE Subsea.

"With increased competition and cost efficiency in focus, the challenge for the cluster is to work smarter and collaborate better. We will increase our focus on work processes, targeting standardization, lean management and manufacturing, and life-cycle system engineering," Hagesæther concludes.

### Increased international focus

The export of Norwegian subsea technology has grown considerably and with it GCE Subsea's members international ambitions and engagement. Small and medium-sized enterprises often have limited resources and it is important to learn from each other, and customers, to succeed in new markets. Bigger companies are eager to get Norwegian sub-suppliers to join them internationally. The GCE-status gives us the resources to work closer with our members and help them join forces towards international markets.

More GCE Subsea member companies than ever are participating in the

organization's international activities. The GCE (NCE) Subsea breakfast seminar at last year's OTC in Houston was one of the organization's most visited events last year.

For this year's OTC, GCE Subsea has strengthened the collaboration between other Norwegian clusters in order to help target international markets. As a result, 2016 will be the first year there will be one united Norwegian delegation at OTC. GCE Subsea will also attend Arctic Frontiers, OTC Asia and the Rio Oil & Gas Conference this year.

### Subsea beyond oil and gas

It's not all about oil and gas, however. GCE Subsea will increase cooperation with related ocean industries, to help its members expand into new subsea related markets. Norway has a strong marine and maritime industry, from aquaculture to fishing and ocean exploration, and a competitive advantage within ocean industries. Targeting this potential can give our members access to new national and international markets.

GCE Subsea has already supported companies expanding their businesses into other ocean industries.

"The subsea sector has a very large and strong sub-supplier industry. The timing is perfect to expand our solutions into other applications," says Jon Oddvar Hellevang, Senior Subsea Innovator in GCE Subsea. "A key driver for innovation is mobility of personnel and competence. The seafood industry has the potential to use subsea expertise to develop new solutions that can enable sustainable growth."

NCE Subsea was a huge success and through pro-active measures it succeeded in building a common arena for innovation and knowledge sharing within the cluster, creating a solid foundation on which to build throughout the next 10 years as GCE Subsea.

**From the GCE Subsea award ceremony in Oslo, 12 June 2015, from left; Monica Mæland - Minister of Trade and Industry, Jon O. Hellevang - Senior Subsea Innovator GCE Subsea, Owe Hagesæther - CEO GCE Subsea, Jan Tore Sanner - Minister of Local Government and Modernization.** Photo by Terje Borud, Innovasjon Norge

### Fact 1

The Norwegian Innovation Clusters is a federally funded three level cluster program (Arena, NCE and GCE) that contributes to value creation through sustainable innovation. Each program lasts 10 years.

The program aims to trigger and enhance collaborative development activities in clusters. The goal is to increase the cluster dynamics and attractiveness, as well as individual company's innovativeness and competitiveness. The program is organized by Innovation Norway, and supported by Siva (The Industrial Development Corporation of Norway) and the Norwegian Research Council.

### Fact 2

**GCE Subsea services and benefits**

GCE Subsea strengthens innovation and knowledge collaboration in the subsea cluster. Increased innovation and internationalization is the main goal. All its activities and services will target six focus areas, where we aim to:

- Develop competence and attract talent and investors
- Develop subsea solutions beyond oil and gas
- Stimulate technology development
- Create new entrepreneurs and grow business
- Succeed in the global market
- Improve work and production processes

Go to **www.gcesubsea.no** to read more about GCE Subsea members and membership.

# Upping the Amps

**After making a splash on the market with its pinless, wetmate connector Maelstrom in 2013, Elaine Maslin examines how Bergen's WiSub is upping the game.**

The Torden pinless wet mate connector.

Small, Bergen-based, tech-focused firm WiSub stirred up a storm with its pinless wetmate connectors in 2013, enabling pinless data and power transfer subsea, at up to 100Mbps and 24 Watt, using high-speed, high-frequency microwave electronics (used for through-air communications systems, and low frequency inductive power transfer).

Now, following customer specifications for higher power capacity, the firm has upped the ante and released Torden ("thunder" in Norwegian), a new design pinless wetmate connector able to transfer 1000 W of power across a 0-10mm seawater gap, significantly expanding the envelope of what these wetmate pinless connectors can do.

Key to the technology has been creating stable power regulation, without the use of batteries, which the firm describes as a significant achievement in the oil-filled pressured balanced system product's development. The firm is also set to release a pinless wetmate fiber optic connection, which could be a first for the industry.

The benefit of WiSub's pinless connector is that it is not limited to cycle times and misalignment issues, and has higher performance than low frequency RF, inductive or acoustic technologies, WiSub says.

The increased power rating will give operators the freedom to increase monitoring and controls on subsea BOPs and could be used to power-up resident AUVs. "AUVs could benefit from having a battery charger or underwater docking station, on which they could use our connector," says Olof Nilsson, project manager, WiSub.

But, to create Torden, it wasn't possible to just scale-up Maelstom, Nilsson says. A new design was needed with both the power and data transfer designed together to best satisfy the new specification.

"Dealing with lower powers in pinless connectors means dealing with lower amperages (current) and thus lower-rated components, less adverse consequences to imperfect design, and simpler management of power transfer," says WiSub CEO Mark Bokenfohr. "In our high-power connector (Torden), we transfer a kilowatt at 24v, where a 1% change in efficiency or 'imperfect transfer' can increase heat significantly. Transferring power to the wrong place can also have more dire consequences, such as heating something metal inadvertently – our pinless power transfer designs always have certainty that we are only transferring power from our transmitter to our receiver, and not to something else.

Olof Nilsson, project manager, WiSub

"Not using a battery nor limiting input power to AC volts was also a challenge, especially around power storage for stable power delivery. Our decision to transfer 24v DC in/out, due to customer specification, has also led to high current challenges. Others choose to take in 110v AC to their transmitter, allowing lower amperages (9 Amps) and thus easier circuitry and components. 24v DC, in comparison, results in 42 Amps, providing some interesting challenges around physics."

WiSub's next big step, the pinless fiber optic communications follows a three-year research program. Fiber could run alongside Ethernet to enable flexibility, depending on what is at the other end of the connector, i.e. if you have a video camera far away from connector, Ethernet will only take you about 100m, due to the copper cable length limitations for Ethernet, Nilsson says.

Traditional fiber wet mate connection systems align one optical fiber with another optical fiber through a very complex pressure-balanced, oil-filled assembly that only allows limited wet-mate cycles. In WiSub's connector, the signal travels via light through the optical fiber, or via copper cable, is then converted to an electrical signal, which is passed through the water gap via an MW link, before being converted back to light over fiber optic or to copper on the other side.

Because of its media-independent design, the connector allows the user to interface their systems to either copper or fiber, or both, Bokenfohr says.

WiSub's product is a full-duplex 100 Mbps fiber + copper connector, where you can use either copper or fiber, or you can connect both lines for redundancy, with data rates through either line configurable by the operator.

WiSub's Maelstrom connector.
Photos from WiSub/Kolbrun Retorikk.

To gear up for expansion, the firm recently moved to new fjordside offices in Eidsvag, just north of Bergen. Whilst they're a small company, they lean on the subsea of the subsea cluster, outsourcing manufacturing, performing prototype qualification and testing with project partners. Most development, assembly, and quality control remains in house.

# Simplifying sampling

**Elaine Maslin reports on Norway's NUI newly developed seabed sampler, which will take any type of sediment while using an ROV.**

**The sampler during a test subsea.**

Despite the best efforts by the industry to develop subsea robots capable of doing work traditionally done by divers, they continue to be needed, both on the Norwegian Continental Shelf and across the rest of the globe.

Some 2700 divers (including superintendents, air and saturation divers and support personnel) worked across the industry globally, according to 2012 figures from the International Marine Contractors Association.

While there are continuous efforts to make diving as safe as possible, there are always improvements that can be made and Norway's NUI has come up with the latest. It has developed a solution for taking seabed sediment samples, which could be potentially contaminated from drill cuttings, produced water discharge, crude oil, mercury etc., and isolating them so that any noxious gasses in them cannot get into the diver's quarters. The system will also mean that samples remain fully intact, between collection and the surface laboratory, with no gas leakage, to ensure analysis accurately reflects what is on the seafloor.

"Samples taken by traditional methods lose important information and might be contaminated, we have known that for years," says Rolf Røssland, managing director at NUI, due to the way they have been collected in open samples. "The contamination [usually in the form of gases] from the seabed could seep into the bell or get onto the divers' equipment and into the diving system."

The consequence might be that hydrocarbons and or volatile organic compounds vaporize in the bell atmosphere, creating a narcotic effect, and contamination of atmosphere in the diving chamber system.

"The result of the sampling using traditional methods can also be questionable," Røssland says, "as there are no standard requirements on how to take samples, where to take them, how to handle them, etc. There were also no standards for analysis."

Changes are being made, from the top. Norwegian standards body NORSOK has introduced new standards, which stipulate that if samples are analyzed at the surface, any gases in the sample need to remain in the sample as it is transported from the seabed to the laboratory.

NUI's response has been its seabed sampler, for taking any type of sediment, using an ROV, as well as standard procedures for collecting samples. The seabed sampler is an ROV-transportable rig, with pressure containers into which the samples are taken and, at the site, sealed until they are analyzed without being opened the laboratory.

The system has been through two pilot tests, the first with Statoil and the second with Total, both offshore Norway, using a work class ROV. The project with Total was in May 2015. After that the samplers has been operational and engaged with a client with good success. From lowering the rig, with three canisters, collecting and putting samples into each, using the ROV manipulator arm, which then closes the canister, to bringing the rig back on deck took one hour, Røssland says.

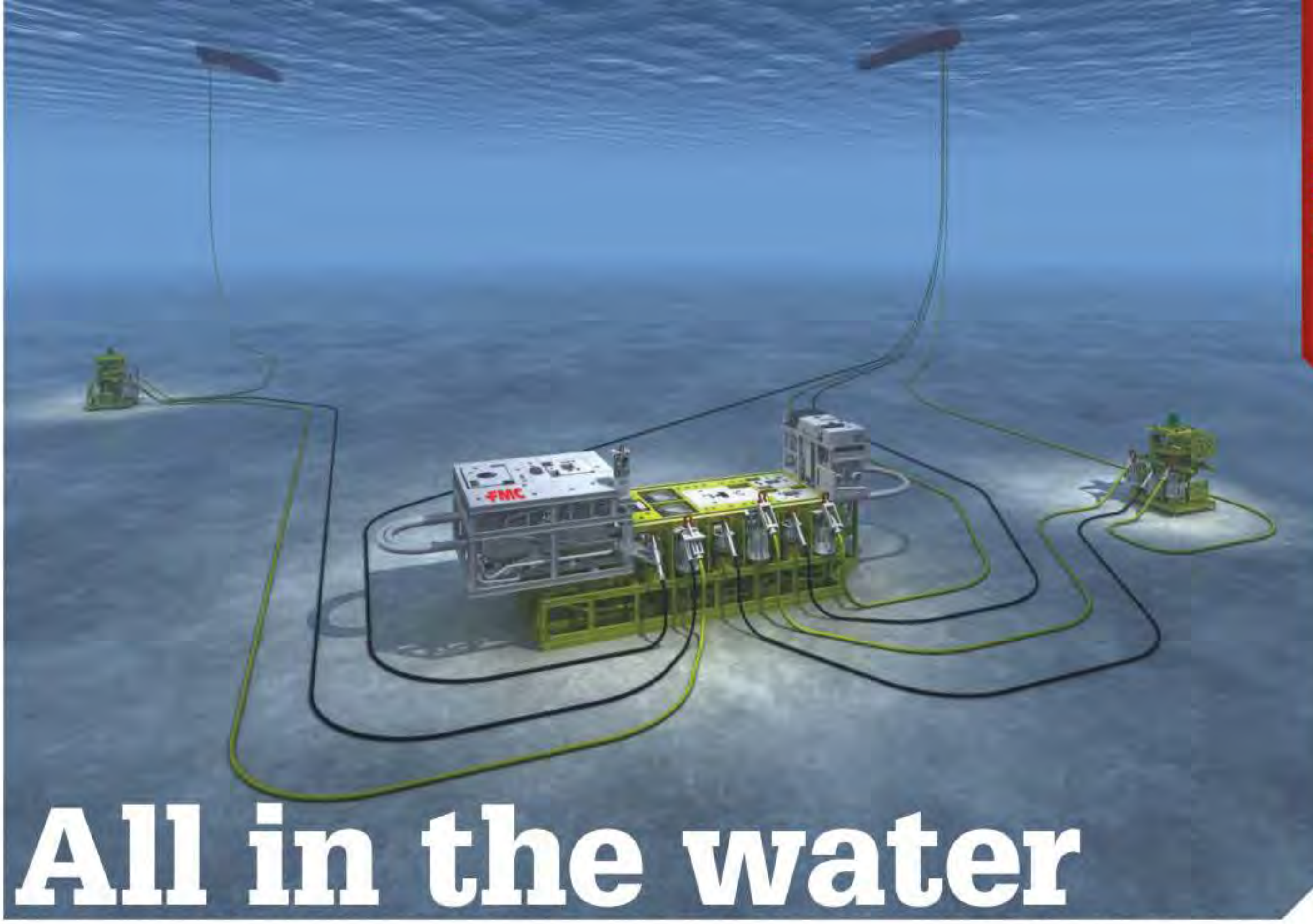
**NUI's subsea sampler.**

Images from NUI.

But, NUI hasn't stopped there. Chamber systems still need to be environmentally monitored to make sure the air quality is correct for the divers. At the moment, samples are taken in 50cm-long pressurized cylinders, which have to be removed from the diver system and transported for analysis. The canisters take up space and weight and offer only a snapshot in time of the chamber atmosphere.

NUI has developed a system using absorbants to monitoring the air quality over long periods of time with testing possible in each chamber and even on individual divers, due to the small size of the carrier for the absorbents, at 11cm by 2cm deep.

NUI is owned by an association, with members including Statoil, Det norske, Repsol, Total, BP, ExxonMobil, and Gassco and has been developing and testing diving and remotely operated equipment from their facilities near Bergen since 1976.



# All in the water

**Marlim Subsea Separation System.**
Image from FMC Technologies.

**For subsea separation and produced water re-injection or discharge to really take hold, technology gaps in subsea water quality measurement must be closed. Progress is being made, says NEL's Ming Yang.**

Subsea separation and produced water re-injection (PWRI) or discharge has long been considered as an enabling technology for developing deep water / ultra-deep water and marginal fields.

It is an integral part of the subsea processing strategy that brings many benefits for the offshore oil and gas industry, including economical, operational and environmental.

However, to successfully implement subsea separation and PWRI or discharge operations, continuous online subsea water quality measurement devices must be in place. Without such devices, one can only use a remotely operated vehicle (ROV) to extract produced water samples and bring them to the surface for offline analysis. Not only is this extremely expensive, it is also detrimental to the effective control of subsea separation and PWRI or discharge operations.

To date, there is only one instrument that has been developed and deployed for a specific subsea separation and PWRI application. Little information is however available in the public domain in terms of how this instrument was developed and qualified, and how it has performed since its deployment subsea.

The problem of a lack of subsea online continuous monitors for produced water quality measurement subsea has been recognized by the industry, and in the recent years, joint industry projects (JIPs) and other projects have been initiated. Consequently, good progress has been made in terms of developing the technical specifications, identifying the potential technologies and conducting performance evaluation tests in a laboratory environment.

### Deep requirements

Unlike surface operations, subsea separation and PWRI or discharge operations will require the online monitors to operate reliably and accurately at a water depth up to 3000m. The devices will also need to withstand a much higher

| Parameter | Re-injection | Separation Process |
|---|---|---|
| Solid concentration (mg/l) | 0-300 | 0-1000 |
| Solid particle size (μm) | 0-200 | 0-200 |
| Oil concentration (mg/l) | 0-5000 | 0-20,000 |
| Oil droplet size (μm) | 1-100 | 10-300 |
| PW temperature (oC) | 4 to 175 | 4 to 175 |
| PW pressure (barg) | 220 upstream of an injection pump or 690 downstream of the pump. | 220 |
| Sea water temperature (oC) | 4 | 4 |
| Water depth (m) | 3000 | 3000 |
| Maximum flow velocity (m/s) | 4.6 | 4.6 |
| Device accuracy (%) | 15 | 15 |
| Response time | 2 minutes for oil content<br>30 minutes for solid particles | |
| Mean Time Between Failures | 5 years as a minimum | |

Testing of subsea sensor at NEL.
Image from NEL.

developing and qualifying a light scattering based oil in water monitor for their Marlim subsea separation system. The system was eventually installed subsea in 2012. The monitor had incorporated a hydrodynamic mechanism to prevent fouling.

For Statoil, whose ambition is to develop a "Subsea Factory" by 2020, development of a subsea oil in water monitor becomes an important part. Three technologies including microscopy, LIF and ultrasonic acoustic, have been selected for a surface field trial before picking up a particular technology for marinization and further development.

Manufacturers including Advanced Sensors, J M Canty, Jorin, and ProAnalysis have all been working with operators and independent organizations like NEL to further advance their technologies.

NEL has carried out three JIPs in the past six years aimed at accelerating the development these devices. Currently, a surface field trial is being pursued to test one of the technologies. NEL is also heavily involved in a US government sponsored project aimed at developing a subsea produced water discharge sensor.

operating temperature and pressure compared to surface.

For various types of operations, there are also differences in terms of technical requirements. For the subsea discharges, the focus will be on the measurement of oil in water – although there is currently no legislation in place specifically developed for the discharge of subsea produced water. While for re-injection operations, the emphasis will be on the measurement of both solid and oil, in terms of concentration as well particle size.

Below is a set of technical specifications developed for devices respectively for subsea PWRI and subsea separation processing operations as part of a JIP conducted early on by NEL. It must be emphasized that technical specifications are still evolving. Those given in the table should only be used only as a reference.

### Potential technologies

There are a number of technologies available on the market that offer the potential to be developed for subsea applications. These include:

- Laser induced fluorescence (LIF)
- Light scattering
- Microscopy image analysis
- Ultrasonic acoustic
- Combination of some of the above

All have the functionality to be used for the measurement of oil in water concentration subsea. However, for the measurement of solid concentration and solid particle size, only the microscopy image analysis and possibly ultrasonic acoustic based technologies may be suitable.

Most of the technologies listed above are optical based (with the exception of ultrasonic acoustic). Fouling of optical window has been identified as one of the main issues that must be addressed. While maintenance is relatively easy for surface applications, maintenance subsea is extremely difficult and expensive.

To mitigate fouling, a number of cleaning technologies have been trialed and incorporated into the devices for surface and subsea operations. These technologies include:

- Jetting spray
- Ultrasonic
- Hydro-dynamic (utilizing a high velocity produced water fluid)

While an ultrasonic-based cleaning mechanism may function well within a low pressure environment, for subsea application, in which high pressure is encountered, it may not work terribly well. Therefore, jetting spray and hydrodynamic arrangements are potentially more suited for subsea applications.

### Research and development efforts

In recent years, a significant amount of research and development efforts have been made by operators, manufacturers and independent organizations like NEL.

Among the operators, ExxonMobil, Petrobras and Statoil have been most active. In the case of ExxonMobil, two PWQM (produced water quality monitoring) prototypes based on using J M Canty's microscopy image analysis were developed and flow loop tested. A jetting spray cleaning mechanism was incorporated into the prototypes. Test results have confirmed the capability of the prototypes developed.

For Petrobras, effort was focused on

### Closing the technology gap

To widely deploy subsea separation and PWRI or discharge systems, technology gaps in subsea water quality measurement must be closed. A significant amount of research and development effort has been made by the industry in developing such instruments. It is anticipated that real progress will be made in the next few years. OE

***Dr. Ming Yang** is the environmental consultancy services manager at NEL, a provider of technical consultancy, research, testing and programme management services. Part of the TÜV SÜD Group, NEL is also a global centre of excellence for flow measurement and fluid flow systems and custodian of the UK's National Flow Measurement Standards.*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**m-pipe in production.** Images from Magma Global.

# Clever composites

**Sometimes, new materials and new manufacturing processes fortuitously emerge, just at the time they are needed. At least Magma Global hopes that's the case. Elaine Maslin reports.**

Magma Global has developed an additive manufacturing process for making bonded thermoplastic pipe, trademarked m-Pipe, using a composite of carbon fiber and PEEK engineering polymer.

It's high-end stuff. The manufacturing process creates a single solid wall, like steel, but due to the additive manufacturing process, dimensional control is possible, which means end fittings can be manufactured as a continuous part of the pipe or flexible riser.

The firm's ultimate target is the flexible riser market, where moves towards depths beyond 3000m, and higher temperature and pressures as well as corrosive fluids have started to challenge existing technologies.

Like the other main firm in this market, Dutch outfit Airborne Oil & Gas (*OE: September 2015*), Magma has started with products more likely to be palatable to the risk-averse oil industry – downlines, jumpers and flowlines.

"Work in the oil and gas sector [at Insensys] alerted us to problems with flexible pipes subsea, from a corrosion and fatigue point of view," says Magma Global co-founder Martin Jones, who founded Insensys, which produced fiber optic measurement tools for monitoring load and integrity on a variety of different structures. "We were also quite involved in carbon fiber and it struck us, where conditions are difficult or challenging, in some instances, carbon fiber is a better bet."

A boost line for Transocean

It's also more expensive, but by using carbon fiber and PEEK, it's lighter than steel by a factor of 10, which could significantly reduce installation spread scopes, it doesn't corrode and can cope with high temperatures, pressures and corrosive fluids, such as $H_2S$, $CO_2$ and also well intervention or remediation chemicals, offering lowering opex costs, Magma says.

Magma Global was founded in 2009 by Jones and a colleague from Insensys. Since then, the firm has been building its credentials in the carbon fiber field, through subsidiary company Magma Structures, which constructed the world's tallest masts – at 300m – for a yacht last August. It now has a 368m mast in production, based on its carbon fiber technology.

But, while the masts are made using carbon fiber and epoxy, Magma Global uses carbon fiber and PEEK. Victrex PEEK is used because it can cope with the higher temperatures in the oil and gas industry, as well as the chemicals and corrosive fluids involved, says Magma. However, this meant Magma the firm had to develop a new manufacturing process, which has leveraged the latest developments in additive manufacturing, also called 3D printing.

Because of Victrex PEEK's high melting temperature [343°C], it's not easy to melt large amounts at a time. As PEEK is difficult to process, PEEK and carbon fibers are first converted into tape. Multiple high powered lasers are then rotated around the pipe to weld this tape onto a mandrel, using a 3D printing process to manufacture the relevant m-pipe size required. The process has been qualified to produce pipe resistant to up to 130°C, with a 200°C resistant pipe having also been produced as a prototype.

Another benefit is that the production equipment is about the

m-pipe production reels in Portsmouth.

size of a 15ft container, making it potentially easy to start-up in country manufacturing. The main space requirements are the spools for the pipe as it passes back and forth through the laser heads. The manufacturing process also enables the oil and gas products to meet higher qualification criteria than they would in the yachting industry, says Jones.

**Martin Jones**

What's more, the additive manufacturing process opens possibilities around dimensional control. "We can thicken the end to create a mechanical lock for the end fitting," Jones says. "This would be perfectly feasible on a riser, to vary the wall thickness through the riser. You might want greater collapse strength and axial strength at the bottom. At the top, where you're worried about supporting the rest of the pipe, it would be built for axial strength. We have not done this yet, but it is feasible."

Magma has been in production since 2012, Jones says, producing items including booster lines for Transocean drilling risers, and it was due to ship out a subsea jumper system as we went to press. Its second and largest production line, able to manufacture 5km of 2in pipe or 2km of 4in pipe, is currently working on a 3km, 3in, 15,000psi, down line designed for the US Gulf of Mexico (*OE: February 2016*). 6in product is also in the pipeline, led by a BP project.

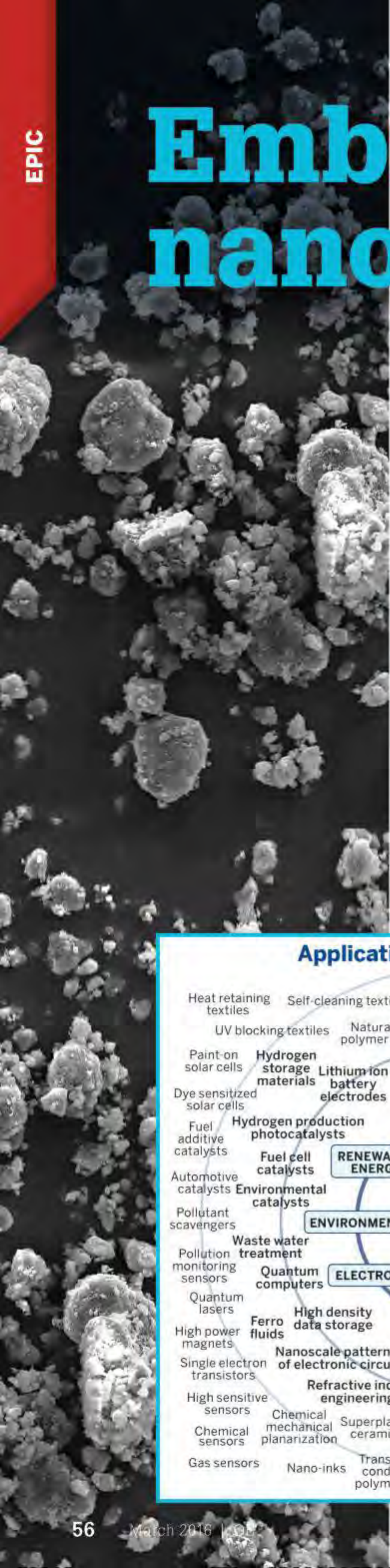
While there has been resistance to composites in the industry, Jones thinks it's changing. "What we are seeing is the development of the technology. Ten years ago you couldn't do what we do today. The manufacturing process wasn't there. It has moved forward thanks in part to the aerospace industry."

Industry is also actively helping to develop the technology. Last April, Magma started a 2.5 year project with BP and Subsea 7, supported by the National Composites Centre and Innovate UK, to qualify 6-12in m-Pipe for risers and jumper systems for deep water environments. Magma is also working with the DeepStar joint industry technology development project group on a 20,000 psi, 4in jumper. "That's something no-one has been able to do and it's really not that difficult with the technology we have got," Jones says. "Existing technology is working hard to keep up with the environment it is in, whereas this technology has room to spare."

**The Deepstar 20,000 psi pipe**

Magma is also working on other components of the riser system as well as other components of sea floor architecture, but that's as much as Jones is willing to divulge right now.

"I think we have a technology that's a step change in performance," he says. "It enables you to re-engineer the cost base for subsea installation capex but also longer term opex." **OE**



# Embracing nanotechnology's potential

**Elaine Maslin examines some of the potential uses for nanoscale manufacturing in the oil and gas industry.**

Nanotechnologies have seen a rapid increase in discovery and development over the past decade. In 2001-2008 there was a 25% increase in the discovery and in the invention of nanotechnology, including the discovery of new classes of materials such as quantum dots and graphene, most of which were passive nanostructures – i.e. not moving atoms to build structures, says Ricardo Melo, production enhancement advisor, at Spanish oil firm Repsol.

More recently, the US and China have been using nanoscale manufacturing, with China leading on an academic front and the US leading in terms of use in industry, he says. But, so far the oil industry is lagging behind adoption of this new technology.

"We are a little bit behind in the exploration and production industry. Renewables and biotechnology have been at this a long time, but [this means] we don't have to start from scratch, we can take it from the point they are at and move in to our world," Melo told the Production Optimization conference in Aberdeen, run by Offshore Network, in December.

However, the potential to apply this technology in the industry is legion, he says. Potential uses include reservoir illumination, by enhancing the resolution for long range imaging, Melo says. This could be through nanosensors in the well bore or using nanoparticles as image contract agents for reservoir mapping.

In drilling and completions, they could be used in drilling fluids or to improve drill bit strength, using nanodiamonds, as well as in cement, using nano-emulsions or additives to enhance mechanical properties, he says. In logging and measuring while drilling, and next generation neutron porosity tools using Li-6 scintillation nanostructured glass ceramic, already being investigated by the likes of Baker Hughes *(OE: October 2015)*.

In completions, high-strength nanostructured material could be used for flow control, frac balls, and plugs, as well as sand control, well bore clean up and more. In production, nanotechnology could be used in sensors, but also in fracking and acidizing work, though viscoelastic fluids, proppants and frac mapping. To remove has hydrates, air suspended self-heating Ni-Fe nanoparticles could be injected, or to prevent scale, production tubing could be lined

## Application of nanoparticles

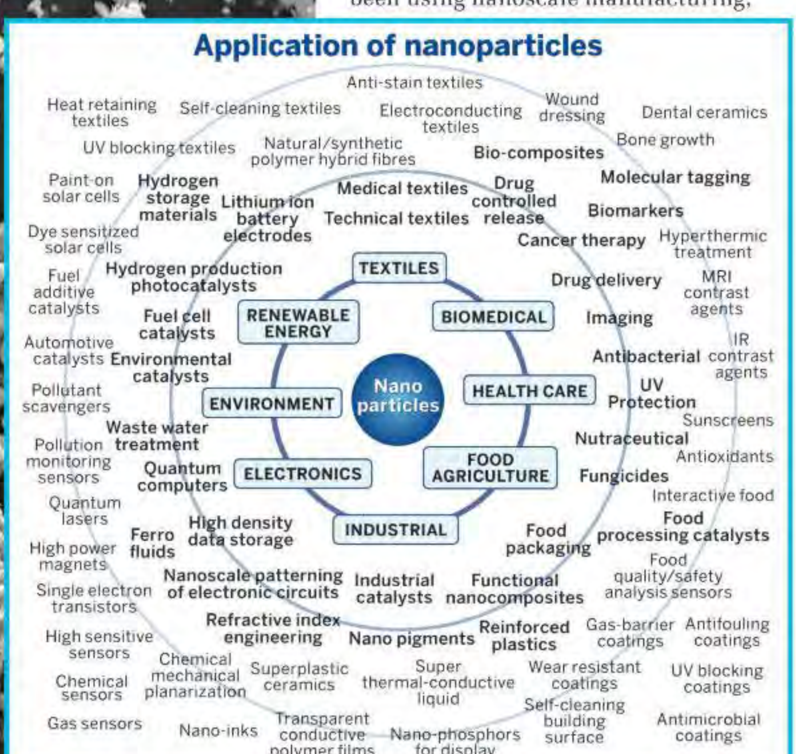



Photo from iStock.

Source: Repsol.

with super hydrophobic surfaces.

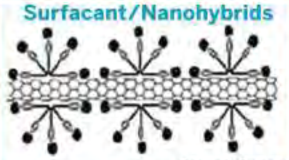
Nanotechnologies could also be used in reservoir characterisation and management, he says, suggesting reservoir flood mapping, oil-microbe detection tools using nano optical fibers, and nano sensors/reporters. There are also applications in enhanced oil recovery. Repsol's interest in nanotechnologies has seen it invest in technology start-up company Graphenea back in 2013.

So, what is holding use of these technologies back in our industry? The challenge in adapting them for the exploration industry, is making them able to withstand downhole pressure conditions, Melo says. "That's the main challenge."

### Reservoir illumination

The cost of developing and using nanotechnologies could also be prohibitive, which led Repsol to join a consortium – the Advanced Energy Consortium, or AEC. Its aim is to find technologies to illuminate reservoirs using micro and nano sensing technology.

Surfacant/Nanohybrids



Source: Repsol.

AEC was founded in 2009, with 10 companies involved at the start. As the downturn has taken its toll, this has dwindled, but still includes Repsol, Statoil, Shell and Total. To date, the group has spent more than US$50 million in research, with some 50 patents filed and 200 publications, Melo says. The Bureau of Economic Geology at the University of Texas at Austin, is managing the organization.

In reservoir illumination, the AEC is looking to bridge the gap between seismic and well logging, or between long-range, low resolution seismic and high-resolution short-range logging. "We want a longer range but higher resolution using different types of sensors and contrast agents," Melo says. To do this, the research needs to aid understanding around the mobility of the nano particles in the reservoir, as well as finding the best contract agent and sensors (nanomaterial and micro-fabricated). There's some way to go yet. Contrast agents, for use in these areas, are 5-10 years away, he says.

Nano-sensor development, for use in reservoirs, is even further away, i.e. up to 20 years, he says. But, work is underway nonetheless. The University of Michigan developed 8mm X 8mm, optically charged and programmed temperature sensors. A second generation reduced the size to 3 x 1 x 2mm, pressure, temperature and ph sensors, containing a solar cell, radio, sensors, decoupling capacitor, batteries, and processor. But, it will still have to be a lot smaller still to be able to go into a reservoir.

In another area of research, the AEC is looking at two areas in enhanced oil recovery, active nano-EOR agents, which are coated with polymers to enhance the reaction, and reactive nano particles, or sensor effectors which could perform water shutoff when exposed to water.

Costs will also need to be addressed, Melo says. However, despite the cost of such materials, in an application such as enhanced oil recovery, by improving material cost effectiveness of surfactants, for examples, by lowering the interfacial tension, creating higher stability and lower adsorption, the amount of surfactant required would be lower, Melo says.

There are plenty more areas where nanotechnologies could be applied, he says. "There's a lot of application for technology. It's a completely new world, but we are not there yet. We are very close," Melo says. **OE**

EPIC

# Popularizing polymers

**Elaine Maslin visited with Nylacast to find out more about engineering polymers and their benefits to the offshore industry.**

Engineering polymers have obvious benefits for the offshore industry – they don't corrode, they can weigh about 1/7th the weight of steel, have a very low friction coefficient and are not affected by $H_2S$ or $CO_2$, so-called sour gases. Engineered polymers also have an enormous plastic range, which means they can absorb impact and retain their shape. But, there are also less well-known properties – Nylacast, for example, has produced antistatic as well as conductive engineered polymers.

In the past, engineering polymers have been held back due to a lack of understanding about their properties and, therefore, potential. Not only that, but when they are being considered, the tendency is to go for PEEK – a higher grade (and cost) polymer, which can price them out of the frame.

"The advantages for engineering polymers can be significant, but they have to be viewed in a different way," says Howard Bradfield, materials engineer, engineered products, oil and offshore, at Nylacast. Just like there are different types and grades of metals, there are many types of polymers offering different properties.

Nylacast has been producing engineering polymers since it was founded in 1967, using Nylon 6. It has made breakthroughs like Nylube, a self-lubricating polymer, now used in components like sheaths and pulleys, removing the need for lubrication and reducing weight significantly. Nylube has been used to replace bronze in marine applications offshore eliminating use of lubricants in splash zone components and on subsea mechanisms, such as clump weight sheaves.

The firm has also recently developed a new high-temperature resistant polymer, CF160, which can withstand up to 160°C and is being used as spacers in pipe-in-pipe applications, including on high-pressure, high-temperature projects, as well as for connectors and calipers.

"For high-temperature applications, CF160 can replace metals as well as higher grade polymers, such as PEEK. CF150 is marginally more expensive than nylon, but considerably less expensive than PEEK," Bradfield says. "PEEK is an order of magnitude 10 times more expensive than Nylon." By replacing metal with plastic in one application, the weight of a structure was reduced from a quarter of a tonne, which meant using a crane to install it, to just 100 kilos, Bradfield says.

"The potential is enormous," Bradfield says, but there's still a way to go in terms of some engineers learning how to use engineering polymers. "The current understanding of polymers is better than it was," Bradfield says. "It is improving. When you look at ROVs 10 years ago, they all had aluminum chassis. Now the majority of the chassis and external protection is made of polymer. This can be replicated elsewhere in the industry."

**Nylacast component being machined.** Images from Nylacast.

**Nylon 6, or polycaprolactum, was an answer to an American firm Dupont's Nylon 6.6 by Germany's IG Farbe. It is a semi-crystalline polyamide, formed by ring-opening polymerization of caprolactum, an oil based product. Caprolactum has six carbons, hence the same Nylon 6, and when heated to about 533 Kelvin (259 degrees C) in an inert atmosphere for about 4-5 hours, the ring breaks and undergoes polymerization, which is then cast into blocks.**

**By varying the conditions of polymerization, and by adding other product, the mechanical properties of cast nylon may be altered, such as self-lubricating plastics, reduced water absorption, and antistatic plastics. There is even a magnetizable nylon, made for the food industry.**

A Nylacast nylon shroud.

Unlike other plastics and polymers, Nylacast's product is, as the company name suggests, cast – not injection molded or extruded. This enables the material to be annealed, which creates improved mechanical, thermal and chemical resistance properties, including higher tensile, compressive and impact strength, as well as improved resistance to creep and heat aging, due to high crystallinity and higher molecular weight, explains Malcolm Fox, head of research and development at Nylacast.

Given the possibility to vary the properties of the polymer through both the manufacturing process and introducing other chemicals into the cast material, Nylacast is also continuously looking at how to take the material further, including for higher temperature applications.

"We are interested in the behavior of material at higher temperatures, particularly creep rates [i.e. deformation]," Fox says. "What we find is design engineers are asking for more detail. So we have started a program to find out more." Nylacast has a graduate working on a program to extend the range of measurements, such as extending the temperature range and type of measurement. For example, if a seal is being pressed against a housing under different temperature regimes, what is the creep rate going to be?

The firm has also been investing in its machining capabilities. Nylacast now has more than 100 machining centers, including five axis milling machines, as well as vintage Bridgeport machines, which still prove their worth, especially under the deft hand of an 80-year-old who has been working them for decades. **OE**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# In your (completion) dreams

**Elaine Maslin reports on Saudi Aramco's work to improve recovery through "smart" completions, thereby simultaneously reducing intervention.**

For some years, Saudi Arabian oil giant Saudi Aramco has been on a mission to improve recovery from its wells, simultaneously reducing intervention, using smart completions.

Core to its mission has been increasing reservoir contact, first through drilling horizontal wells and then through multilaterals.

But, it wants to take matters further. While extended well drilling increases the amount of the reservoir the well bore is exposed to, managing the flow into the well can increase gains even further. It's not a concept lost on Saudi Aramco. The firm has been installing interval control valves, or ICVs, into its wells, creating so-called intelligent completions.

But, that's still not enough, says Dr Mohamed Nabil Noui-Mehidi, petroleum engineer consultant for Saudi Aramco's production technology team. Saudi Aramco wants to take this idea and technology a step further, by gathering live downhole data, which is then transmitted real-time to surface and used to control down hole control valves – also in real time – Initially through wired valves and sensors, but eventually using wireless technologies down hole.

Speaking at the Society of Petroleum Engineer's 2nd Inwell Flow Surveillance and Control Seminar, held in Aberdeen late 2015, Noui-Mehidi said: "We [the industry] call them intelligent wells, or smart wells, etc., but all of them are valves getting information from the wells. They are not [currently] smart, but the way we are driving them has to be smart."

### A smart evolution

Saudi Aramco started drilling horizontal wells in the 1990s. By 2000, it was drilling multilaterals and by 2004, it was looking at intelligent completions, following the launch of a well architecture program called Maximum Reservoir Contact (MRC) wells, Noui-Mehidi says.

The need to develop smart completions was driven by both the complex environments and the up to 37,000ft-long extended reach horizontal wells Saudi Aramco has drilled. This meant using downhole ICVs with downhole temperature and pressure monitoring on individual laterals. This enabled the operator to see what was coming out of each lateral and therefore optimize each lateral's contribution to overall production and mitigate water breakthrough, faster than it would if it had to rely on well intervention operations for logging.

"We can increase recovery and have better sweep of the well by controlling these valves," Noui-Mehidi says. "But, the important thing is that we have gathered all the data from the last 10 years to help us to the next generation of completions."

**Dr Mohamed Nabil Noui-Mehidi speaking at the Society of Petroleum Engineer's 2nd Inwell Flow Surveillance and Control Seminar.**
Photo from SPE/Rory Rait.

The next generation is where all laterals, not just the mother bore, are divided into segments, each with a control device and a monitoring device. "To push the control into the laterals and into compartments will hopefully give us better operability and increasing predictability," Noui-Mehidi says. "And we have started seeing this in new completions we have implemented."

The first project which deployed this type of completion was a wired, full control monitoring project started 5-6 years ago, he says. "We went from classic MRC wells with hydraulic valves and hydraulic lines and gauges and replaced this with a single wire, which controls the valves and gauges," he says. Each section of each lateral has a control unit with a Venturi meter to measure roughly the flow rate, a capacitance water cut meter, to measure the water cut and total production, and an ICV. All are connected to the wire, which transmits the data to surface and controls the valves.

"But, we are not stopping here," Noui-Mehidi says. "We are going from maximizing reservoir contact to extreme MRC... to a non-wired solution in which you have a completion in which you would have a well that has multilaterals and the mother bore completed with segments, each with a control valve and a couple of gauges. They would communicate wirelessly with the heel of the well and then up to the operator."

In a vision presented separately by Saudi Aramco, live data analytics could then help automate the wells using the data gathered down hole.

There are a number of technology hurdles to get over to achieve this aim, Noui-Mehidi says.

**1.** Power is needed to power the sensors, but, while there is potential to generate power in the well, there is a big gap when it comes to storage at temperatures in downhole temperature conditions. "There are no reliable solutions right now, but people have ideas and maybe in 5-10 years we will see solutions," Noui-Mehidi says.

**2.** Everything also relies on this wireless communication. "We are talking about a very salty environment. Brines are 150-200,000 ppm of salt, which is a very high-loss environment for any communication. Waves die very quickly in this," he says.

**3.** One of major challenges is to deliver this system through tiny diameters into bigger diameters – 4½in to 6 1/8in. "To do this we need to think about a new generation of packer that can expand from 4½in to 6 1/8in for example." Noui-Mehidi says. "Also, the sensors and gauges we are putting in there need to be reliable."

There will also need to be work done around sensor technologies, which will need to be able to work in complex, multiphase flow regimes, he says. "Understanding the physical properties of the field we deal with is very important and crucial in the development of the sensors. We have to decide what we are trying to measure before we decide what type of physics we use to get that data to the surface," Noui-Mehidi says.

But, Saudi Aramco thinks the effort will be worth it. "We are doing this because we want to cut down intervention costs," he says. "We want interventionless wells. With the wired solution there is no redundancy, which means if something fails, that's it, you can't do anything about it, except if you want to recover everything. That's why we are going to this wireless solution where we can deploy freely through the 4½in tubing into the laterals or mother bore so if a valve fails we can go and retrieve them and put in another one. This is the dream we have." **OE**

**One year after Mexico launched its Round One, OE asked:**

# Is your company still hopeful about the Mexican market? Why or why not?

An estimated three quarters of Mexico's prospective oil and gas resources are in deep waters or unconventional fields and while the sharp decline in international oil prices may deter spending on some projects, the overall framework is still broadly favorable towards those looking at the region. What's missing is the investment, competition and technical expertise. We believe there is a huge amount of potential for innovative and experienced organizations, whose technical skills and knowledge can help small to medium companies successfully navigate the challenging industry landscape and give them a competitive advantage in the bidding process.

As the only firm involved in assisting a client securing successful awards in the first licensing round, we have seen a lot of interest from companies interested in investing in Mexico. Investors are looking for support in generating development concepts, rationalizing complex investment scenarios and understanding how to deliver commercial benefits through working as an integrated team. Clients are keen to utilize ADIL's experience, gained through delivering commercially challenging projects globally, and apply that to field developments in Mexico.

From an industry perspective, much has been learned from the earlier tenders with regards to the operational requirements. Companies are becoming increasingly aware of the cultural and legacy issues which they too must be prepared to navigate.

Having already utilized the experience of our team to deliver results for one of our clients, and having been welcomed by numerous Mexican clients, newly qualified operators in Mexico and by the authorities, we are confident there is still significant opportunity to build on this in the years ahead.

**Lo Van Wachem, developments manager, ADIL**

The recent historic decline in oil price has had a considerable impact on the liquidity of the major international oil companies and has been even more severely felt by Pemex as a significant part of its revenue goes to support the Mexican government's budget.

This creates both a challenge and an opportunity for the service companies. In the short-term, the majority of contracts to be handed out by Pemex are subject to delays. In a recent meeting with its suppliers Pemex informed everyone to expect payments to be made 180 days after the approval of invoices. The firm also declined to pay for the financing cost. This means that if a service company wants to provide services to Pemex it has to find a way to also fund the project.

On the flip side of this coin, the current situation is motivating the government to continue with the licensing rounds already started. The recent awards in Round 2 and 3 are encouraging and while they may not create any opportunities straight away, they will have a significant and positive impact on Mexico's oil and gas for the service companies that can survive this historic downtown.

Having established a joint venture with our partner Arena Infrastructures which has 25 years' experience in the country's oil and gas sector, Harkand has the advantage of better understanding the technical challenges as well as the local requirements than many of our competitors and ultimately the conviction in the future of the Mexican market.

**Ashit Jain**
**managing director - North America, Harkand**

OE REGION

MEXICO

# Laying the foundation

# OE REVIEW

MEXICO

# Inside



**On the cover** McDermott performs the PB-Litoral-A floatover operation.
Image courtesy of McDermott International.


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**Supplement editor**, Audrey Leon, aleon@atcomedia.com, +1-713-874-2205
**Advertising sales**, John Lauletta, jlauletta@atcomedia.com, +1-713-874-2220
**Art and production**, Bonnie James
**Reprints**, Jill Kaletha, jillk@fosterprinting.com, +1-219-878-6068

**AtComedia**, 1635 West Alabama, Houston, Texas, 77006-4101, USA.
Tel: +1-713-529-1616
Email: info@atcomedia.com | www.oedigital.com


# Assessing Mexico's

**Heather Saucier examines the potential of deepwater plays to be auctioned in Mexico's next offshore round, including the most prized area in the Perdido Fold Belt.**

So far, Mexico's Round One oil auction, which has included shallow offshore blocks in the Gulf of Mexico, has not made a big splash among international investors. In fact, just five of 19 shallow-water blocks have been leased to date, according to the National Commission of Hydrocarbons (CNH) of Mexico.

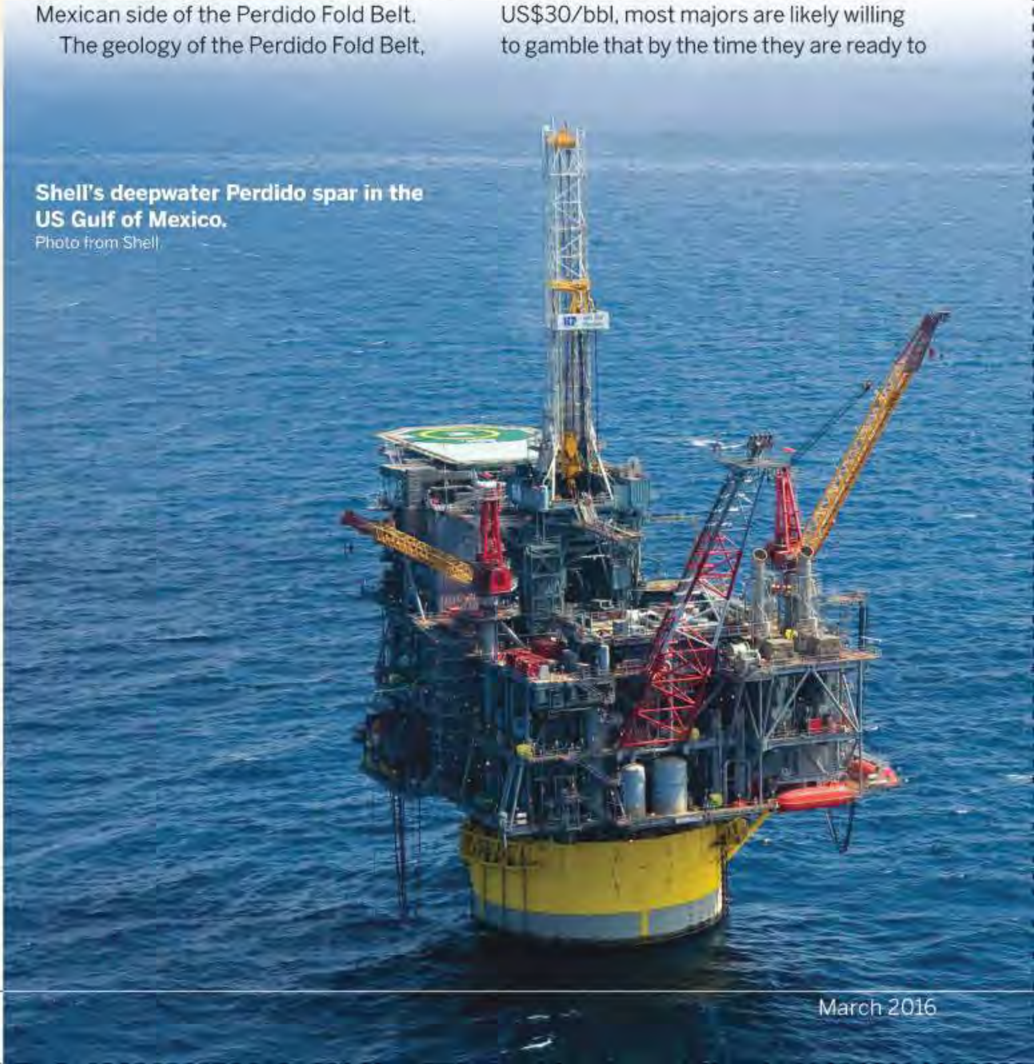
Is this a sign that international operators are skeptical to enter territory that has remained unknown to everyone except for the country's national oil company, Pemex, for the last 77 years?

The short answer is: No. Investors are likely waiting for the Mexican government to open 10 deepwater exploration blocks for bids – a move expected in Q3 2016 – that will include four blocks on the Mexican side of the Perdido Fold Belt.

The geology of the Perdido Fold Belt, which has been partially developed on the US side, is understood in great detail by the majors and super majors that have developed unparalleled deepwater drilling expertise there. A move into the Mexican Perdido Fold Belt is not as risky, geologically speaking.

"It is a mistake to think of the Gulf of Mexico as the same on both the US and Mexican sides once the Gulf opened sufficiently to establish independent petroleum systems. The exception is the Perdido play," says Dan Bendig, a geologist and director of Consulting at IHS in Houston. "This play extends from the US into Mexico. It is a proven play and will be the hot play for Round One."

Even at times when oil hovers around US$30/bbl, most majors are likely willing to gamble that by the time they are ready to



Shell's deepwater Perdido spar in the US Gulf of Mexico.
Photo from Shell

# geological potential

produce from Mexico's deep waters, prices will be on the uptick again. "The price now is irrelevant compared to when the oil comes onstream," Bendig says.

The US government has long said that the Mexican side of the Gulf of Mexico is resource rich. Now that Mexico is opening up its geological vault, it is validating US estimates in many cases.

"The Mexican side of the Gulf of Mexico has the most prolific offshore plays," says Alfredo E. Guzmán, a geologist and director for Exploration and New Ventures, Mexico, for Casa Exploration, a former executive with Pemex, and former commissioner for the CNH. "Comparing the density of exploratory wells in the Northern Gulf and in the Saline Basin in the South to the well density in the Campeche area, it is clear that there are hundreds, if not thousands, of untested opportunities."

### Mexico's offshore geology

Of the seven Mexican geologic basins assessed for conventional and unconventional resources by Pemex, the deepwater Gulf of Mexico basin, which includes the Perdido Fold Belt, contains the greatest amount of undiscovered resources with a mean of 27.1 billion boe.

In fact, Pemex charts no cumulative production in this basin, as it has lacked the capital and technology needed to explore and operate in water depths of 2800m and deeper, Guzmán says.

In this oil-rich basin, "It's going to be interesting to see who's going to grab Perdido," Bendig says. "Anadarko, BP, Statoil, Chevron and Shell – there's not a lot of companies that are able to operate in deepwater."

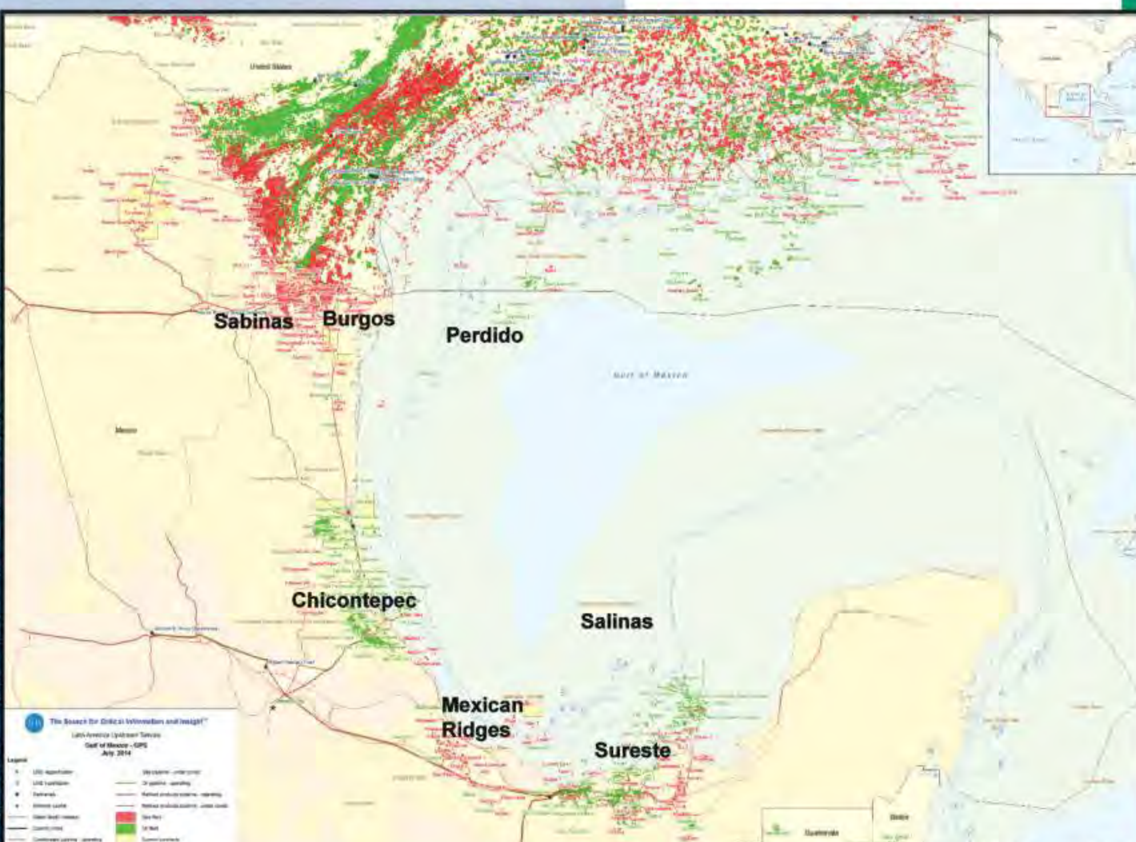
Pemex soon may be able to explore its deep waters as well under Mexico's new energy laws, which were enacted after the country's 2013 constitutional amendment that put an end to the nationalization of oil and gas in the country. "Pemex will be able to partner and/or do farm-outs to reduce risk and exposure," Guzmán says.

The Sureste Basin, which includes the offshore province of Campeche, boasts Mexico's largest and most exploited offshore oilfield – Cantarell – to date. Despite the fact that Pemex has been exploring in this area for more than 50 years, Pemex contends that it still holds a considerable amount of undiscovered resources, with a mean of 16.8 billion boe.

"Pemex has done a good job finding what is there," Bendig says, speaking of the heavily explored areas. "Now, it will be an exercise in extending the field's life. This could be attractive to companies who have the technology needed for EOR (enhanced oil recovery)."

Considering that only a handful of the more than 600 fields – many of them offshore – discovered in Mexico have been subject to EOR, Guzmán says that much room exists for specialized companies to participate in future projects.

The Sureste Basin also includes the Salina del Istmo and Comalcalco provinces, which were part of the Round One bidding process for shallow water exploration blocks. Three of five extraction blocks that contained relatively modest fields were leased to small and mid-sized companies – with the exception of Eni – and are considered to have the lowest engineering risks and production costs, Bendig says.




**Map of US and Mexico producing fields.** Image from IHS.

Installation work at Pemex's Ayatsil.
Photo from Pemex.

Surveying the Ayatsil project, which is near the historic Cantarell field.
Photo from Pemex.

"We will see operators drilling wells there and building platforms," he adds. "It is great fodder for smaller companies. It's cheaper to drill in shallow waters."

Guzmán also points to the Tampico-Misantla Basin as an area with healthy potential. According to Pemex, it contains 2.4 billion boe that should be relatively easy to explore because of its geology.

Rather than pursue this basin, Pemex put its offshore exploration efforts into the Campeche and onshore Sureste basins after the 1970s because the wells were more productive and the return on the investment was better. "As a result, the Tampico-Misantla still holds a lot of potential. There will be important discoveries made there," Guzmán says.

Other areas of interest are in the deeper waters of the Gulf in the Campeche-Sigsbee Salt Basin, an area described as "exciting" by Christopher Schenk, a Denver-based geologist who has overseen the US Geological Survey's (USGS) South American and Caribbean assessments for nearly 20 years.

With an estimated mean of 2.8 billion bo, according to the USGS, this underexplored and relatively unknown basin could be a new highlight on Mexico's unfolding geological map.

"There could be a lot of potential around the salt structures, as they can form ideal traps for oil and gas," Schenk says.

He adds that there also might exist the potential for a sub-salt play.

"Companies are shooting spec seismic there now, so we will have to wait and see," Bendig says. Having already looked at a few 2D seismic lines, Bendig says the geology appears similar to that of north Arkansas and north Louisiana – the northern flank of the Gulf of Mexico Basin.

"A play should exist conceptually," he says. "But production here will be years down the road."

Guzmán says the Campeche area has "little relation" to the United States' producing plays in the Gulf of Mexico, which predominantly come from reservoirs formed in the Mississippi Delta. "But, there is still huge potential in the Saline Basin where the subsalt has not yet been explored," he says.

## Gas, and a future, in the making

"If there is anything that is overlooked in Mexico, it is the offshore gas potential," Schenk says. "And, it's in all the basins."

In fact, Mexico is in the process of building a 45mi pipeline to an onshore gas conditioning plant to transport gas from the Lakach Field – discovered by Pemex in 2007 – in the deepwater offshore of the Veracruz Province. The field, the first deepwater project for Pemex, is estimated to hold proven and probable (2P) reserves of 850 Bcf of gas.

Potential for gas also exists in the Mexican Cordilleras of the Western Central Gulf, Guzmán says.

While some plays are currently being developed, some will no doubt remain on hold until the price of oil looks upward again.

"There aren't that many offshore plays available around the world," Bendig says. "This is one of the few that's there, and that's good. But it's very challenging in this price environment."

When adding up Mexico's offshore potential, the USGS estimates a mean total of 19.3 billion bo. "It's not Saudi Arabia, but it's pretty good." Schenk says. "It's a considerable amount of resource no matter how you look at it."

# Developing Mexico's information industry

**Oscar Roldan, head of the National Data Repository for Mexico's National Hydrocarbons Commission (CNH), discusses the development of Mexico's data libraries.**

After almost 80 years with one operator in the country, Mexico finally opened its oil and gas potential to the private sector; the reform represents a huge challenge in terms of execution capabilities for Mexican institutions.

The new legal framework delegates the responsibility of the creation and managing of the National Data Repository of the country to the National Hydrocarbons Commission (CNH). The first step towards it implies the transfer of all the geological, geophysical, geochemical and petrophysical data generated in the country from Pemex and the Mexican Petroleum Institute to CNH within a period of two years.

The next step is how to grant access to the data for every company that is interested. There are three ways to access the data:

**1. Data packs of the bid rounds.** The first three phases of round one had a data pack that contained all the technical data relevant to present an economic proposal. CNH delivered 132 data packs in total for the first three bids, containing information for more than 1200 wells, 35 seismic 3D surveys and 26 seismic 2D surveys.

As an additional service to the data pack, CNH built a physical data room where companies could come and see all the data integrated in a specialized platform to visualize and analyze the data, within the first three phases of Round One we had 184 visits from companies all over the world.

Finally, companies that pay for the data pack could also access the data through the web via our virtual data room (login and password required), in which they could download all the data, except the seismic data.

**2. License system.** As a way to access the data without being in a tender, CNH launched a regulation to provide access to any company interested to the data through a license system. Companies have to request access to the data by filling out CNH's form and paying the related fees. The whole process takes no longer than two weeks, from the moment that we receive the request to the moment we actually deliver the data.

The data that we have available at the moment is all the data from the deep water Gulf of Mexico: 20 seismic 3D surveys, covering more than 160,000sq km; and 55 exploration wells. Within the first five months since we published the regulation, CNH granted 17 licenses to different oil and gas companies and delivered 23 different sets of data.

**3. MultiClient system.** One of the new elements of the E&P industry are the authorizations for superficial exploration that CNH can grant to the companies interested in the acquisition of new data or reprocessing of existing data. So far, CNH has granted 28, from which 19 are related to the acquisition of new data and nine to the reprocessing of existing data.

There is still a long way to go, but the CNH is convinced that one key element for success is to develop the information industry in the country. The more information outside, the better understanding of the oil and gas resources of the country. ■

Oscar Roldán is the head of the National Data Repository for Mexico's National Hydrocarbons Commission. His career started in 2001 at the Ministry of Finance, where he was part of the team involved on the new fiscal regime for Pemex. In 2007, while in the Ministry of Energy, he participated in the first energy reform and, in 2009, he was part of the founding members of the National Hydrocarbons Commission.

Oscar holds a BA in economics from the Instituto Tecnológico Autónomo de México and a master's degree in statistics and econometrics from University of Essex, in the UK.


**Virtual data display.** Images from CNH.


**One of CNH's data rooms.**

# Bidding for deepwater

**Dallas Parker, Gabriel Salinas and Diego Perez, of law firm Mayer Brown, assess the terms of Mexico's phase four bid round to be held in 2016.**

The Mexican National Hydrocarbons Commission (CNH) published the bidding and contract terms for its next round on 17 December 2015, kicking off the fourth phase of Mexico's Round One.

The contract form selected for this phase is a license contract, which will have 35-year term, extendable for a first additional period of 10 years and a second additional period of five years.

The 10 contract areas offered in the fourth phase are in the deepwater and ultra-deepwater of the Mexican Gulf of Mexico and within the areas of Cinturón Plegado Perdido and Cuenca Salina.

### Bidding process

The phases of the bidding process are as follows:

**a.** Publication of the bidding invitation and terms
**b.** Access to the information data room
**c.** Registration for the bidding round
**d.** Clarification to the bidding terms and contract
**e.** Prequalification of companies
**f.** Delivery and opening of proposals
**g.** Awarding of contract and decision
**h.** Contract execution

### Prequalification

Both operators and non-operators will need to prequalify in order to submit a bid offer. The technical, operational and financial prequalification requirements relating to the deepwater bidding process include:

**1.** Technical and operational experience and qualifications of the operator that will be verified:

**a.** Demonstrate experience as an operator during the period 2011-2015 in at least one exploration and/or extraction in a project with a water depth greater than 1000m;
**b.** Demonstrate aggregate capital investments in exploration and extraction projects of at least US$2 billion;
**c.** Demonstrate experience in industrial safety and environmental protection within the last five years. Must have experience in the implementation and operation of industrial safety management systems, operational security and environmental protection in facilities or exploration and/or extraction projects.

**2.** Financial requirements of the operator that will be verified:

**a.** Demonstrate stockholders' equity of at least US$2 billion; or
**b.** Demonstrate total assets with a value of at least $10 billion and an investment-grade credit rating by one of the following rating services: Fitch Ratings, Moody's Investors Service or Standard & Poors.

**3.** Financial requirements for non-operators:

**a.** Demonstrate stockholders' equity of at least $250 million.

### Forms of participation

A prequalified operator may participate both as an individual bidder and as part of one or more joint bidders with another operator or non-operator. The request for authorization must clearly state the intended form in which the bidder wishes to participate.

Joint bidders may submit a proposal without needing to incorporating a new legal entity, provided that each participating company has obtained CNH authorization and qualification to participate as a joint bidder.

Only one bid offer may be submitted per individual bidder or joint bidder for each contract area through the bidder itself, in the case of individual bidders, or through the designated Operator, in the case of joint bidders. The bidders must take into account minimum national content requirements during the exploration and evaluation periods and the development period.

### Delivery and opening of proposals

Proposals are to be made per contract area. Each proposal must be comprised of two different sealed envelopes, one containing the economic proposal and a cash offer as an additional compensation in the case of a tie, and the other containing the bid bond (*garantía de seriedad*) in favor of the CNH. This guarantee shall be in the form of a standby letter of credit issued or confirmed by a credit institution doing business in Mexico, with a value of US$3 million, valid for 100 calendar days from the date of submission of the proposals.

The opening of proposals will take place in a public act attested by a Mexican notary public that will be streamed on the Internet. The winning and second-place bidders per contract area will be publicly announced in the same act.

### Economic criteria for determination of winning bidder

Before the deadline for publishing the updated version of the bidding terms, the Ministry of Treasury will determine and publicize the minimum values that will be acceptable with respect to each of the variables comprising the economic proposal.

The winning bidder per contract area

will be determined using a formula that takes into account: (i) the additional royalty offered by bidders to the State and (ii) the additional investment commitment that may be offered by bidders in addition to the minimum work program set forth in the bidding guidelines.

In case of a tie, the winning bidder shall be the bidder who, among the tied bidders, offers the highest cash payment to the state. If the tie persists, the bidder will be chosen by a random (insaculación) drawing among the tied bidders.

### Execution of contracts

The CNH may only execute license contracts with Mexican-incorporated commercial entities that meet certain criteria.

Any winning bidder or member of a winning bidding group that is not a Mexican entity must incorporate a Mexican entity for the execution of the contract.

Simultaneously with the execution of a contract, the contractor must deliver: i) a performance guarantee and ii) a corporate guarantee of each of the participating companies. The corporate guarantee must be granted by the ultimate parent of each joint bidder member or, in case the guarantor is not the ultimate parent company, the guarantor must submit to the CNH its duly audited consolidated financial statements that prove minimum stockholders' equity equivalent to the participating interest of the participating company multiplied by US$14 billion. Except for the operator, if the guarantors are unable to meet the requirement of minimum stockholders' equity, they may submit to the CNH their duly audited consolidated financial statements evidencing assets equivalent to five times the requested value of the minimum stockholders' equity. In addition, a document showing an investment grade credit rating issued during 2015 or 2016 by Fitch Ratings, Moody's Investors Service or Standard & Poors must be submitted.

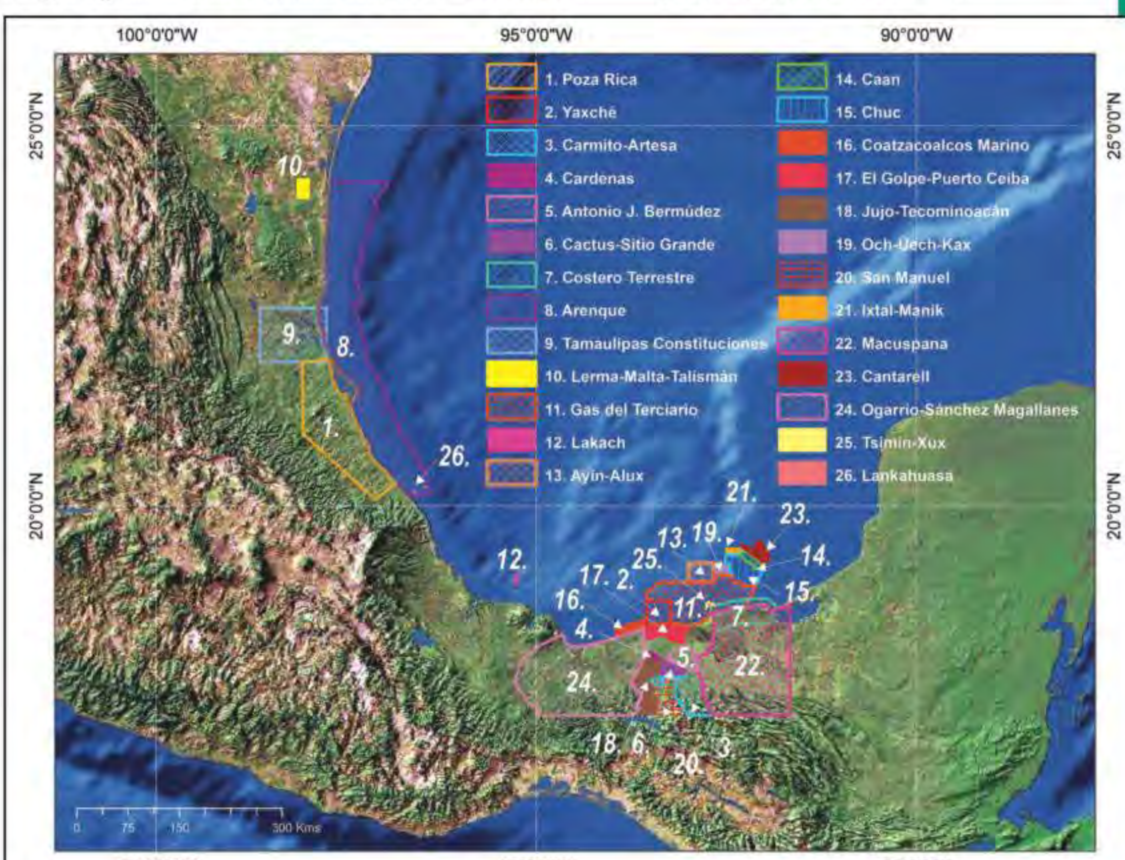
The guarantor's minimum average stockholders' equity or required assets must be maintained until all obligations of the corresponding participating company have been met; otherwise, the guarantee would need to be replaced by a conforming guarantor. If the winning bidder does not execute the contract in a timely fashion for reasons attributable to it, the CNH may award the contract to the second-place bidder and draw the winner bidder's bid bond. ■

**Dallas Parker** is leader of Mayer Brown's Mexico Energy Reform Initiative and serves as leader of the Corporate & Securities practice in the firm's Houston office.

Parker represents clients in a wide range of corporate and securities law matters with a career-long focus on the oil and gas industry. He earned a BA from Vanderbilt University and a JD from The University of Texas School of Law.

**Gabriel Salinas** is a senior associate in Mayer Brown's Global Energy Practice Group. Salinas has experience representing companies in energy projects and transactions throughout Latin America, with particular experience in oil and gas, power generation and infrastructure projects in Mexico. He obtained his LLM from Harvard Law School and JD from Facultad Libre de Derecho de Monterrey in Mexico.

**Diego Perez** is a foreign attorney in Mayer Brown's Global Energy and Corporate & Securities practices in the firm's Houston office. His practice focuses on energy and infrastructure projects, with particular experience in the oil and gas industry. He earned his LLM from Columbia University Law School, and received a JD from the Pontificia Universidad Católica del Perú.




**Exploitation Projects, 2013.** Image from Mexico's National Hydrocarbons Commission (CNH).

# Eyes wide open

**Juan Carlos Luna discusses the risk, compliance and anti-corruption challenges of doing energy deals in Mexico.**

Mexico's energy reform became law on 21 December 2013, representing the most significant overhaul of Mexico's oil, gas, and electric industries of the last seven decades.

This comprehensive new legal and regulatory framework promise huge opportunities for the private sector and increased investment from international firms. However, there are two crucial components when assessing such opportunities. The first is dealing with the economics and financial conditions of the market and the specific contracts, and the second one, dealing the rule of law circumstances and the level of scrutiny and realization of corruption.

Under this second component, US and international companies looking to enter this market will need to consider and stay vigilant of corruption risks, and strategically plan ahead to ensure they implement and maintain adequate governance, risk and compliance structures in order to properly address these scenarios.

Being aware not only of the local but also of the transboundary and international rules, is a key requirement to ensure business is conducted in a way where risks are properly managed, and violations of laws are avoided, since the contractual framework for such opportunities will be subject to a higher degree of scrutiny, not only because the new regulations enacted for such purpose, but because they will also be closely monitored based on both national and international standards.

Given the heightened enforcement of the US Foreign Corrupt Practices Act, particularly in the energy industry, international energy firms need to pay particular attention to their anti-bribery provisions, guidelines and applicable rules when contemplating potential transactions in Mexico. They will also need to be aware of the local rules in this area. Specifically Mexico's Anti-Corruption Law which has important considerations for all parties involved.

A business operating in any capacity outside of their base country will be held accountable to the bribery and corruption laws in another jurisdiction. Even if you are not covered by legislation such as the FCPA or UK Bribery Act, your organization can still be subject to prosecution under international OECD guidelines or other local anti-bribery laws. Increased enforcement will lead to greater risks for companies that do not have adequate anti-bribery and anti-corruption compliance programs in place or companies who have insufficient background information on their suppliers.

Regulators look for evidence that there is a commitment at the executive level to foster a culture in which bribery is not tolerated within an organization. One of the key considerations for any anti-bribery and anti-corruption compliance program is to consider the risk that suppliers and third parties can potentially bring.

## Applicable rules

Mexico has already adopted various legal tools that would potentially be applicable to fight and prevent corruption and abuse of power; amongst the most important are the Constitutional Law suit framework; the criminal code and its specific provisions regarding fraud, the federal law of administrative accountability of public officers.

Despite the existence of a solid framework of laws designed to fight corruption, Mexico still struggles with a negative track record, where lack of transparency, undue political influence, and fraud have created a negative perception and a concern for investors.

In a way, some of these realities are changing into what could represent a more controlled business, political and legal scenarios. An example is the audited methods under which the new energy contracts will be implemented based on the applicable regulatory rules, and the overall expectation for a better legal scenario that the implementation of the energy reform should create.

Regarding the FCPA, the US is the most prolific enforcer of anti-bribery/corruption legislation and its reach is global. There have been a number of recent initiatives that will drive greater enforcement. Subsequently, increased enforcement leads to greater risks for companies that do not have adequate anti-bribery and anti-corruption compliance programs in place or companies that have insufficient background information on their suppliers, partners or alliances.

As international energy companies move into the Mexican market, they must be proactive in assessing the risks involved and the potential legal and economic effects that could derive from the application of the US Foreign Corrupt Practices Act (FCPA), which bars US companies—and their officers, directors, employees and agents—to act with corrupt intent in furtherance of any offer, payment, promise of payment or authorization of payment, money, gifts or anything else of value to any "foreign government official" for the purposes of influencing and gaining a commercial or business advantage. Additionally, US companies (including their foreign subsidiaries) and foreign companies whose shares are publicly traded in the US are also subject to the FCPA's accounting and bookkeeping provisions, which require accurate recording of expenses and internal controls intended to prevent bribes from being paid.

The anti-bribery provisions of the FCPA define a "foreign governmental official" as any officer or employee of a foreign government (or any department, agency or instrumentality or state-owned entity thereof), foreign political party or a public international organization, or any person acting in an official capacity for or on behalf of any such government or public international organization. In the context of the Mexican oil and gas and electricity markets, past FCPA prosecutions in the US involving bribes paid in Mexico have found that corrupt payments to employees of Mexican state-owned companies such as Pemex or CFE (Federal Electricity Commission) constitute prohibited payments to foreign governmental officials under the FCPA.

On the other hand, Mexico has enacted new Federal Anti-Corruption Law for Government Procurement, as part of its efforts to comply with its obligations under the OECD Convention on Combating Bribery of Foreign Public Officials in International Business Transactions; the Inter-American Convention against Corruption; and the United Nations

Convention against Corruption. Mexican laws have traditionally punished authorities charged with corruption, but with the enactment of the Anti-Corruption Law, Mexico is also focusing on punishing the businesses that motivate such illegal behaviors.

This prohibition applies to everyone engaged in federal government contracting in Mexico—Mexican and non-Mexican individuals and companies alike—and includes bidders, participants in tenders, recipients of RFPs, suppliers, contractors, licensees, concessionaires and their shareholders, partners, associates, representatives, principals, agents, attorneys-in-fact, brokers, managers, advisers, consultants, subcontractors or employees. In addition, the law prohibits Mexican individuals and companies from bribing foreign (i.e., non-Mexican) government officials, following the same principle as the FCPA.

The law provides two types of administrative sanctions: (i) financial and (ii) temporary exclusion from future biddings. Sanctions for Individuals could range from approximately US$5,000 to approximately US$240,000, and disqualification from participating in federal government procurement processes for a term of not less than three months and not more than eight years. Sanctions range from approximately US$50,000 to US$10 million, and companies may be excluded from public projects for up to 10 years.

## Being proactive

Any company regularly involved in government contracting processes at the federal level or in international commercial transactions, where foreign public officials are involved, should implement strict compliance policies or revise the existing ones to include clear rules for contracting with governmental entities in Mexico and abroad. Likewise, it is highly advisable to conduct training sessions for those employees within the company who deal with the Mexican federal government or with foreign governments. It is also recommended that companies carry out due diligence on all third parties who may participate as intermediaries in business relationships with the federal government or foreign governments

Given the expedited implementation of the energy reforms, and the increased likelihood of anti-bribery scrutiny by both Mexican and US authorities, it is important for energy firms or any other company doing business in Mexico to take a number of steps to reduce their anti-bribery risk before the contracting process begins.

**1.** Companies should undertake comprehensive risk assessments before entering the market: Who will be your business partners in Mexico? What third parties will you need to engage? And for what functions? With what regulators will the company be interacting, and who on the ground will have contact with government officials or state-owned entities? Do adequate due diligence on any potential local hires, business partners, agents and third parties before engaging them; don't wait until after contracts are won and operations have begun before thinking of potential FCPA/anti-bribery concerns and undertaking the recommended due diligence.

**2.** They should emphasize anti-corruption training for any personnel who will interact with foreign government officials.

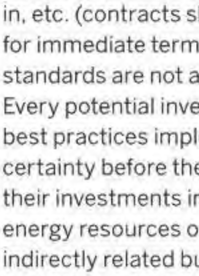
**3.** All red flags should be promptly investigated and remediated. Look for excessive payments or unusual payment terms for consultants or other third parties, or the engagement of a third party that is not well known in the industry or lacks the capacity to do the work for which it is hired.

Establishing an effective third-party ethics and compliance program is strongly advised. Such a program should, at a minimum:

- Survey these third parties as to their ethics and compliance efforts;
- Set standards in a code of conduct for third parties so they understand that integrity is a prerequisite for doing business with your company;
- Closely monitor all payments to and from third parties, such as commercial representatives, agents, and consultants—particularly in high-risk countries;
- Ensure that contracts with third parties include provisions addressing the issue of bribery, such as warranties that no secret commissions have been paid, no competition rules have been violated, no bid rigging or price fixing has been engaged in, etc. (contracts should have provisions for immediate termination if any of the standards are not adhered to).

Every potential investor will want to see best practices implemented and legal certainty before they are willing to make their investments in developing Mexico's energy resources or any other directly or indirectly related business opportunity. Considering that this is a heavily regulated sector, with new regulatory frameworks being developed, and various still fresh legal, political and economic conditions and expectations on the table, this becomes even more important.

Companies looking to enter this attractive market need to stay vigilant and understand all of the moving parts, planning ahead to ensure they have adequate tools to take advantage of the opportunities while controlling and managing risks. ■



**Juan Carlos Luna** is the managing director of Lawgistic. Practicing in the Firm's Houston and Mexico City offices, he assists on transactional projects throughout Mexico and Latin America, as well as advising clients on Governance, Risk and Compliance issues, and strategic legal management consulting.

# Deepwater exploration and production challenges – A regulatory perspective

Photo from DNV GL.

**DNV GL's Santhosh Mony, Eckhard Hinrichsen, and Pedram Fanailoo offer the regulatory perspective on offshore risk management.**

Mexico is recognized as one of the top ten oil producers of the world. To maximize the potential deepwater reserves several significant technical challenges must first be overcome. Understanding the risk associated with these operations and managing the same for unforeseen challenges is important to help optimize performance, safety, in a cost effective way.

### Challenges and measures

During the capital expenditure (CAPEX) phase of deepwater projects there are technological challenges associated with (but not limited to) the environment, water depth, high pressure and temperature, possibly increased fire and explosion loads and hydrocarbon inventories, and reduced accessibility for inspection and maintenance. These contribute to challenges in concept selection and field developments. However, during the operational expenditure (OPEX) phase, the possibility of occurrence of major accidental hazards (MAH) scenarios with severe consequences to people or the environment increase significantly unless appropriate measures are taken. All stake holders (experienced and inexperienced) will need to address:

- Identify and understand the magnitude of the risks involved
- Implement robust barriers to eliminate and mitigate these risks
- Having appropriate codes/standards to maintain the integrity of the barriers
- Create an appropriate governance model for management and the workforce
- Establish well proven and goal driven processes for people and plant
- Verification schemes established by competent third parties to act as an independent verifier complimenting the assurance process

### Proactively manage barriers through shared performance monitoring

Most industrialized countries have well established regulatory regimes with high focus on safety and the environment. These regimes have regulations that define the expectation the stakeholders should assess, understand and mitigate risks in accordance with established requirements (codes, standards, rules, and best practices) which may be prescriptive (as seen in the US sector GoM), goal driven, and performance based (as seen in the UK and Australia) or a hybrid of both (as seen in Norway and Eastern Canada). These regulations also mandate independent verification to a varying degree to ensure that the asset conforms to minimum standards and required performance standards are met.

### Interdependency between various performance elements

As shown in Figure-1; understanding the interdependencies between the 3 cornerstones – Standards & Rules, Risk Management and Operational Philosophies of an asset and the Regulatory regime is important to implement safe and effective regulatory requirements and controls.

As an example any design standards or codes can increase or decrease the risk profile of an asset by the degree to which it increases or decreases the robustness of barriers, an operational philosophy and its focus is directly correlated with the level of safety achieved. A clear understanding of these interdependencies and a holistic and balanced approach will be essential by the Regulators to ensure safe operations in Mexican Deepwater.

### Challenges in Mexican sector of GoM

PEMEX's capability for development and exploration into deepwater has been limited. Leases could be successfully developed with collaboration from experienced deepwater operators. However, more importantly, the regulatory system needs to undergo a radical change, with key agencies and authorities taking roles and responsibilities and establishing appropriate regulations to proactively influence the safety and integrity of the assets and its operation.

With the opening of the offshore upstream arena in Mexico, international companies are coming in as well as new local operators and support industries with limited or no experience. Strong, state-of-the art regulations are now necessary to manage the risk, avoid major accidents, and facilitate efficient production of hydrocarbon reserves.

The pertinent question is how regulatory authorities like ASEA, CNH, and CRE will establish their role and fulfill their mandate.

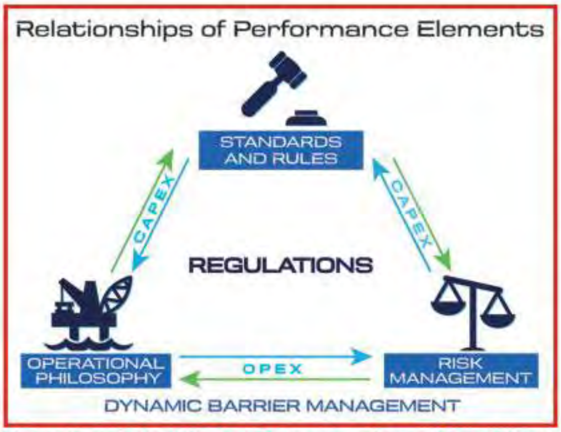



**Figure 1 explains the performance elements and how their relationships mitigate risks associated with deepwater operations.**

What kind of regulatory safety regime will be established? How will it be organized and operated? The involvement of international companies in Mexican waters increases the possibility of learning and sharing of experience from other regulatory regimes.

The increased activity level will impose challenges on maintaining a sufficiently large and competent workforce in both the industry and amongst regulators. This challenge is intensified considering targets for local content requirements.

## Conclusion

It is important that the new players in the industry and regulators learn from the best practices around the world and understand the strengths, pitfalls, and gaps of the various established regulatory schemes. This will ensure a balanced approach to what is most effective and applicable for the specific challenges of the Mexican market. The technical challenges for deepwater operations are some of the most extreme in the oil and gas industry and the ability to overcome these in a cost efficient way adds a further layer of complexity. ■

**Santhosh Mony** is a naval architect with over 25 years' experience in offshore engineering and project management. In his role at DNV GL, Santhosh is responsible for international bidding and execution of many offshore mega projects as well as the Houston Approvals Center for Classification projects and the VCA Verification Hub in Division Americas.

**Eckhard Hinrichse** has nearly three decades experience working within offshore, pressure vessels, and plants and pipelines. Today, Eckhard oversees the development of oil and gas throughout Mexico.

**Pedram Fanailoo** heads DNV GL's Risk Advisory Services in North America. This team focuses on delivering innovation at the core of every solution. His technical practice focuses on managing risk, quantitative and qualitative safety risk, safety barrier systems, environment risk and navigation risk.

# Data analytics for an emerging market

**Henrique Paula, of ABS, explains how data analytics can be used to improve safety, environmental protection, operational efficiency, and profitability in emerging energy markets such as Mexico.**

One of the most promising and legitimate ideas to emerge from the hype around "Big Data" and the "Internet of Things" is data analytics, the science of examining data to inform and improve business and technical decisions. Data analytics has been transforming other industries, and now it is beginning to transform the offshore sector by improving safety, environmental protection, operational efficiency, and profitability, with applications ranging from basic equipment optimization to enterprise-wide fleet and asset performance.

## Defining the terms

Although they are related, data analytics and big data are different. Big data is a broad term for data sets so large or complex that traditional processing applications are inadequate. Gartner, the IT research and advisory company, defines big data as high-volume, high-velocity and high-variety information assets that demand cost-effective, innovative forms of information processing for enhanced insight and decision-making.

Data analytics is the science of examining data with the purpose of drawing conclusions about the information. It is applied in many industries to allow companies to make better business decisions, and it is used in the sciences to verify or disprove existing models or theories.

In a developing region like the Mexican Gulf of Mexico, data analytics has the potential to make an enormous impact.

## Mexico's emerging offshore

According to Clarksons Research, while Mexico is developing only one offshore gas field at present, there are 67 offshore oil fields in development, and there are many more fields with development potential, including nine gas fields and 39 oil fields.

Offshore oil production has seen a steady decline over the last 10 years, standing at slightly more than 1.7 MMb/d at the end of 2015. Analysts predict production will drop by 1% year on year in 2016 due to declining oil supply from maturing fields, including the shallow-water Cantarell Complex. Mexico's gas production also is falling. The country ended 2015 with approximately 4.2 bcf/d of gas production from 51 fields in production.

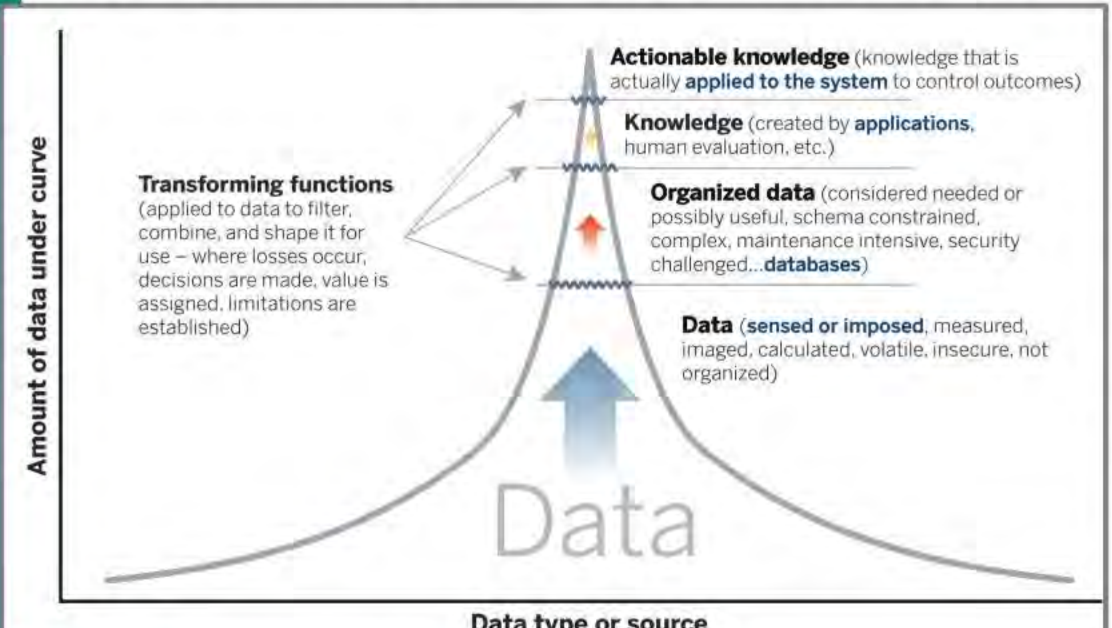
Great efforts have gone into field delineation, and new technologies have been implemented to improve production volumes. In the face of progressively falling output, leveraging data from these assets could provide asset owners with a valuable tool that could be put to use to improve production.

This is particularly important at present because Mexico's 2015 licensing program saw only two blocks awarded in the first stage of bidding in Round 1 in July and five of nine fields awarded in September's second stage. It will be vital for Mexico to get the greatest production from its producing fields until the country is successful in enticing international investors to the region.

## The potential for data analytics

Data analytics is being used through most of the lifecycle of offshore activities. During seismic and reservoir characterization studies, data sources with 3D seismic data, well logs and faults, are integrated and analyzed to support decisions related to achieving key targets in flow assurance, field optimization, drilling performance, well categorization and so forth. Benefits range from attaining optimal reservoir exploitation rate to forecasting the decline of new wells.

For fixed, floating and subsea assets, data analytics starts with collecting data at the asset level, including operating




**Data analytics is a way to move from data to actionable knowledge.** Courtesy of Energective LLC.

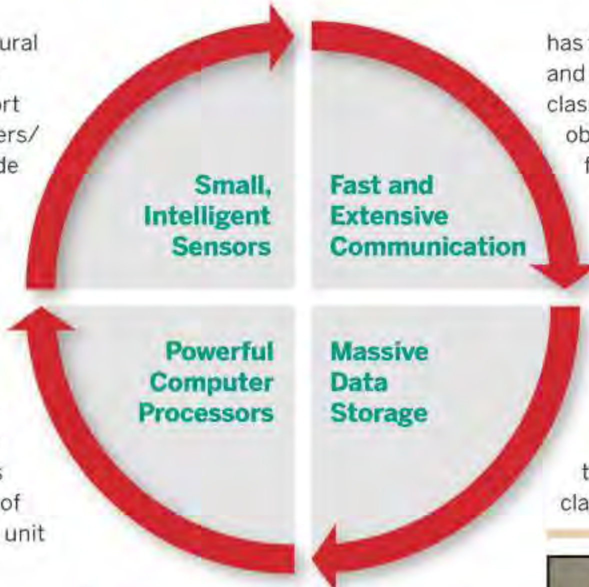
parameters, equipment status, structural stresses and environmental data. For moving assets such as offshore support vessels and dynamic positioning floaters/vessels, data collection can also include location, direction and speed.

These data sets are transmitted securely by satellite to a storage/processing center, which can offer services such as performance optimization, asset tracking and structural integrity monitoring. Significantly more value can be realized by applying data analytics to an entire fleet, where the objective goes beyond optimizing the performance of individual assets to optimizing every unit in the fleet.

Offshore and subsea assets are remote and isolated most of their operating life. Collecting and analyzing more data while an asset is operating can provide more knowledge, improved planning, and reduced maintenance down time – previously unknown conditions generally are more costly and take longer to repair.

In many of these applications, data from disparate, multifarious sources is analyzed to secure new macro-level insights. Typically, an enterprise organizes data across many systems and applications, and data analytics includes techniques for combining different data sources, sometimes significant in volume, and analyzing them in innovative ways to create new insights and knowledge. The key to getting the best value out of data analytics is performing analysis on the "right data" – data appropriate to a particular problem or opportunity – to deliver actionable knowledge or insight.

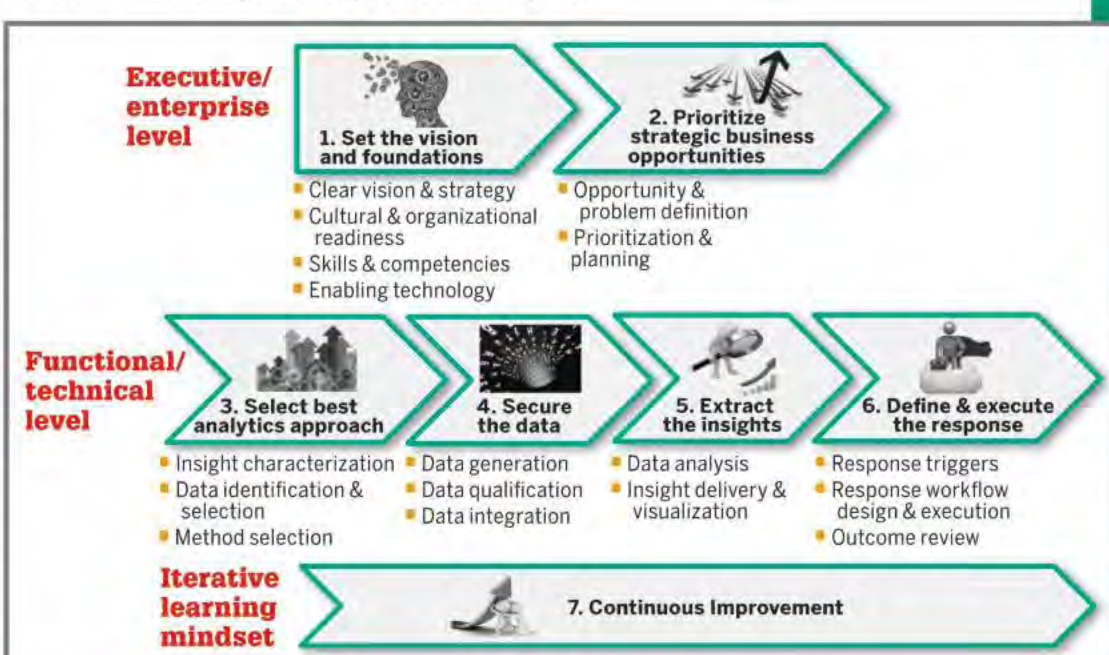
The upsurge of data analytics comes from four contemporaneous trends in sensor, communication, storage and processing capabilities. There has been a proliferation of small, intelligent sensors that measure changes in physical attributes and transmit the resulting data through extensive, easily accessible, and fast wide area communication networks. The data can be stored in massive data centers, and subsequently processed and analyzed by extremely powerful computers and processors to deliver critical insights. Those insights can then be acted upon and facilitated by computer-aided interventions. A key point is that today all this can be done at a relatively low cost.




**The upsurge of data analytics comes from four contemporaneous trends in sensor, communication, storage and processing capabilities.**
Courtesy of Energective LLC.

ABS and its affiliated companies are researching the applications of data analytics and data management to the oil and gas industry. While data analytics has the potential to improve production and profitability, it also can improve the classification process. One of the primary objectives of this research is to find ways for data analytics to be applied to the classification process, allowing it to become continuous, more focused, less intrusive, and more efficient, bringing about a shift from the current calendar-based inspection process to a more condition-based process. Defined as FutureClass, this approach could transform the classification process and change the entire concept of inspection and classification.

**Dr. Henrique Paula** has 37 years of engineering experience with expertise in oil and gas regulatory regimes, integrity management, risk and safety management, process safety management, risk and reliability analyses and project quality management. He has provided consulting and training services in more than 30 countries and authored/co-authored more than 100 documents, including journal articles, conference papers and technical reports. He holds a PhD from the University of Tennessee.




**There are seven steps to follow to achieve successful data analytics.**

# The EPC perspective

**OE's Audrey Leon speaks with Scott Munro, McDermott's Vice President, Americas, Europe and Africa, about recent projects undertaken at the company's Altamira facility.**

**OE: 2015 was a good year for McDermott in Mexico. The company secured contracts for PEMEX's Ayatsil-A, in January, and Ayatsil-C project, in June. Could you discuss each project scope and where things stand currently?**

2015 was a year of significant progress for McDermott in Mexico. The year got off to an excellent start with the transport and installation contract for the Ayatsil A jacket and topsides. This was a fast track project that was completed in Q1 utilizing the *McDermott Intermac 600* (I-600) launch barge and *Derrick Barge* (DB50). These assets bring very specialized capabilities to the market and this, combined with our in-house engineering and project management capability, allowed us to complete the project on time, with an excellent QHSES performance and with a satisfied customer.

The Ayatsil C project adds engineering, procurement and fabrication to the installation skills displayed on the Ayatsil A project. Engineering and procurement are ongoing and the fabrication of the jacket is scheduled to be completed at the Altamira yard in 2016 with installation to follow utilizing the *DB50*.

**OE: What is next for the Altamira yard?**

Our Altamira yard is the most modern of McDermott's wholly owned yards. It has now started to build an enviable reputation for delivery, including its first export project, which was delivered offshore Angola in Q1 2015. The yard continues to support PEMEX with its project needs, but it is also competitive for other markets in the Atlantic basin. We continue to market the yard for these export opportunities.

It is important to also note that we were awarded free trade zone status in 2015, giving McDermott significant cost advantages for the international market. Through 2015 and into early 2016, we have been encouraged by the willingness of our international customers to add Altamira to their lists of approved yards. We also see the opportunity to diversify the client base for the Altamira yard with the arrival of new operators in Mexico due to the recent energy reforms brought in by the country.

**OE: With the downturn heavily affecting 2016 budgets, what is McDermott's take on the entire Gulf of Mexico region? Is there still work to conduct?**

To a large extent, our work depends on our clients and their ability to invest, an ability highly linked to the price of oil. We have long-reaching relationships with all of our clients across the globe, and this is also the case with PEMEX.

At the moment, the industry is experiencing a turbulent environment, which poses many difficulties to market players. Our investment in Mexico was driven by a long-term belief in the Mexico energy market and the ability to compete in a global market from this facility. It is important for companies to realize that this industry requires a long-term focus, and in difficult circumstances, companies must adapt to withstand the challenges.

**OE: Additionally, given the lowered oil prices, are you still hopeful about the Mexican market given the current climate?**

We believe that, in the long term, the Mexican energy market will offer a competitive return for our customers given the resource in place and availability of existing infrastructure. We believe in McDermott's ability to succeed in this market given McDermott's three distinct advantages:

- First, McDermott offers customers a complete solution made up of resources internal to McDermott. We tackle the project from the engineering perspective through to procurement, construction, transportation, and installation with a comprehensive, in-house approach. McDermott is well-established in Mexico and complies with local content requirements. Moreover, the yard is a free trade zone, which is particularly attractive to international companies as material can arrive at our location without having to enter Mexican territory. PEMEX and foreign companies are able to benefit from the absence of import taxes, and have the ability to transform material in our yard under the same circumstances.
- Our second differentiator is our adherence to safety standards. As an example, the Altamira yard has achieved 8.4 million man-hours without a Lost Time Incident to date.
- Lastly, we focus on our clients, building a relationship of trust through development, execution and delivery of projects on time and on budget.

In the short term, we will continue servicing the shallow water sector, including PEMEX. Moreover, we are well-positioned to support new operators as the energy reform releases areas for development throughout the Mexican sector of the Gulf of Mexico.

**PB-Litoral-A topsides floatover operations.**
Photo from McDermott.

**Serimax's Saturnax 09 technology welding root pass.** Image from Serimax.

# The pipeline perspective

**OE's Audrey Leon spoke with Cyril Petit, Serimax's regional manager, Central and North America, about the opening of Mexico's oil and gas industry and what effects it will have on the company and region at large.**

**OE: Serimax works predominately with pipeline welding, can you discuss what the opening of Mexico's industry, particular the pipeline sector means to Serimax?**

**Cyril Petit:** Mexico is currently the third largest supplier of crude oil to the US. For the past 10 years, the consumption of oil in Mexico has been fairly stable while the production has been consistently declining. This situation creates a dip in exports to maintain Mexico's self-sufficiency on oil. In parallel the demand for energy keeps on rising over the same period of time to sustain Mexico's durable development. The gap is closed with an ever increasing consumption of natural gas even though its production has been plateauing over the past seven years calling for more natural gas import from the US.

The increased demand for energy combined with the opening to private investment will create opportunities for Serimax to support the development of the pipeline infrastructure both on- and offshore. Serimax already works with numerous customers in Mexico and we are engaged on various projects as part of the development of the pipeline sector and we look forward to supporting this effort.

**OE: What kinds of projects is Serimax currently involved in, or looking to get involved in?**

**Cyril Petit:** Serimax is involved in multiple offshore oil pipelines projects. The operations are taking place offshore onboard our customers' laying vessels and we are also working with local partners to support welders training and qualifications onshore. We are expanding our reach to the cross country pipelines and we should be involved with the construction of onshore gas pipelines soon.

The opportunities for Serimax are growing in Mexico and we are looking forward to supporting our customers with more technology and engineering. We are offering our customers tailored premium solutions to help them be on the edge and be competitive locally.

**OE: What are some challenges Serimax sees in Mexico in terms of workforce, available materials and equipment?**

**Cyril Petit:** To maintain Mexico's economic growth, the energy sector will have to develop further and grow. As we discussed earlier, the partnership and the possible competitive situation between Pemex and the international companies will help the development of new fields in deeper waters and we might see a shortage of highly qualified resources to support the growth we do anticipate.

Serimax will support the sustainable development of the energy sector in Mexico as it has always done. Our past and current experience shows that the best technology and the best people are wanted. This is where Serimax come into play. Serimax has recognized and certified training programs to teach the theory and provide the required hands on training to the workforce. We can train in our certified centers worldwide or can also train locally at our customers' facility. Our programs are designed to give local resources the skill and competencies required to support the development of the industry in their home country. Serimax has the tools and programs to help its customers grow and train its pool of qualified resources and talents to cope with the challenges that are ahead of us.

**OE: Finally, after the reforms, what is the long-term outlook for Mexico's oil and gas industry from your perspective?**

**Cyril Petit:** In a transition phase, the reforms will help accelerate growth in Mexico. The market attractiveness will grow and will pull investments in from private investors in a sustainable way, maintaining a level of activity for the oil and gas sector providers such as Serimax. The oil fields will go deeper and deeper to uncover new reserves and extract additional resources required to maintain Mexico's growth and its current position of crude oil exporter to the US.

Mexico offers long term opportunities in a dynamic environment calling for more technology and more premium solutions served locally and that is what Serimax strives to deliver to its customers.

The final impacts on the energy sector in Mexico heavily depends on the quality of implementation of the current reforms, but let's not forget that the price of oil on a worldwide basis will also drive some of the success or limitations to these reforms' impact on the long term development plan.

**Cyril Petit** is Serimax's regional manager for Central and North America, a position he has held since 2012. He joined Serimax in 2002 as a research and development welding engineer. He moved to the US in 2004 becoming a project manager, and in 2010, Petit became regional operations manager taking on responsibilities such as all operational activities and supply chain.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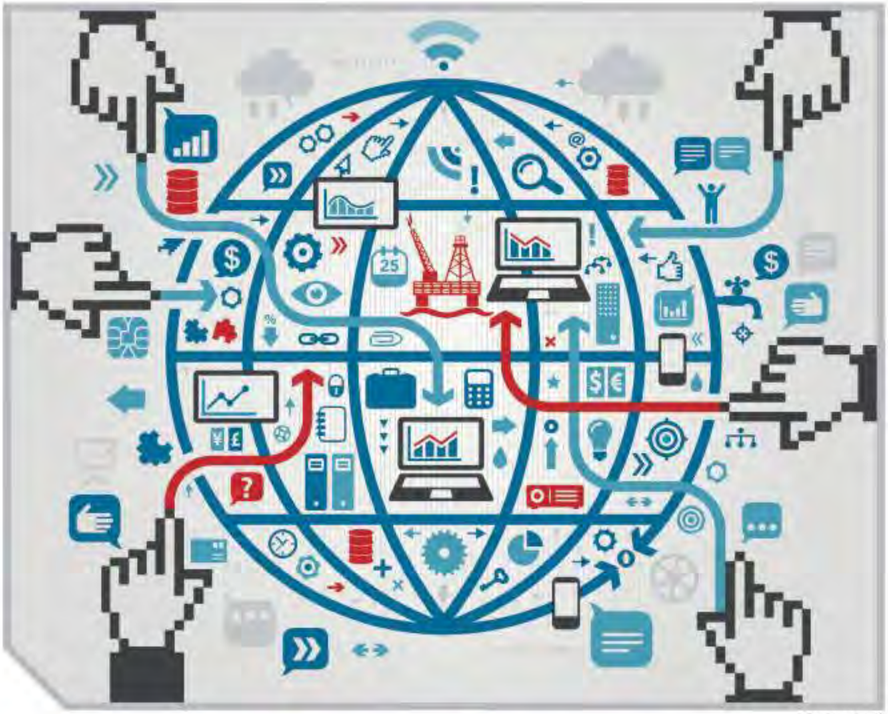

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# Managing data as an asset

By Henrique Paula, ABS

The hype around buzzwords like big data and data analytics has created both believers and skeptics. Wary players in the offshore industry have adopted a wait-and-see approach, hoping clear business solutions will solidify. In dealing with disruptive technology, however, companies must be ready to mobilize if they are to implement game-changing solutions.

**Collecting and analyzing more data while an offshore asset is operating can provide more knowledge, improved planning, and reduced maintenance down time.**

The benefits of data analytics and well-managed data are enormous, potentially as much as billions of dollars each year.

Recognizing the value of what is at stake, ABS is developing guidance for data analytics and data management and is setting standards for best practices.

### Data as an asset

There has been a proliferation of small, intelligent sensors that measure changes in physical attributes and transmit the resulting data through new, fast communication networks. Data can be stored in massive data centers and processed and analyzed by powerful computers and processors. More data, communication, storage and processing ability are becoming available at a relatively low cost, which has led to an exponential rate of data generation.

Data are a valuable asset, but rarely are recognized or managed as one. A typical international oil company invests US$2-3 billion per year in acquiring data. Applying a straight-line depreciation to the value of those data over 10 years results in an asset worth $10-15 billion. How much care and attention should be dedicated to this asset?

For data to deliver value, it is crucial to recognize and equate data analytics and data management to "good investment" instead of a cost of doing business.

### Data processed into efficiency

Offshore assets, including those that are subsea, are a special and complex case. They are remote and isolated most of their operating life, and there are limited pre-scheduled times when repairs and maintenance can be undertaken (e.g., when a unit is dry-docked or when production has been reduced or stopped so the asset can undergo repairs).

Today, operators conduct routine inspections and collect data to determine the condition of the asset as well as specific structures and equipment. Then they develop estimates for remedial work and solicit proposals from repair and maintenance facilities. Sometimes, hidden damage is discovered during repair or maintenance work, which can cause costly delays in returning to operation. Collecting and analyzing more data while an offshore asset is operating can provide more knowledge, improved planning, and reduced maintenance down time. The same applies if deficiencies are uncovered during a statutory inspection or a survey by a classification society – previously unknown conditions generally are more costly and take longer to repair.

The possibility exists today to begin creating data-driven, "self-aware" physical assets, whose performance and state of health is being continually and holistically monitored and predicted. Assets can be designed with sensors and analytic capabilities from the outset. Metrics and sensors can be carefully selected to allow optimization of the asset through predictive data analytics. Sensitive "hot spots," where risks to business and operations objectives are higher, can be proactively identified; so continuous data collection can be used for better decision-making.

Data analytics and data management are still at the early adoption stage in the offshore and subsea industries. ABS is working with industry partners to develop the guidance needed to help the industry realize potentially remarkable benefits.

It is time to start managing data as the asset it is. **OE**

***Dr. Henrique Paula,*** *vice president of global energy initiatives for ABS, has 37 years of engineering experience in management in integrity, risk, safety, reliability and project quality with a focus in the oil and gas, and power sectors. Paula has provided advisory and training services in more than 30 countries and authored/co-authored more than 100 published documents. He holds a PhD from the University of Tennessee.*

# Cyber shy

**Efficiency gains could be made through better use of digital technologies, but the industry is still shy on the uptake. Nada Ahmed, senior consultant, DNV GL - Oil & Gas, looks at the opportunities and risks.**

"Big data" has the potential to radically reshape the oil and gas industry. DNV GL believes that by adopting coordinated, digital processes to analyze and understand the overwhelming amount of data being produced, operational efficiency and productivity could be boosted significantly

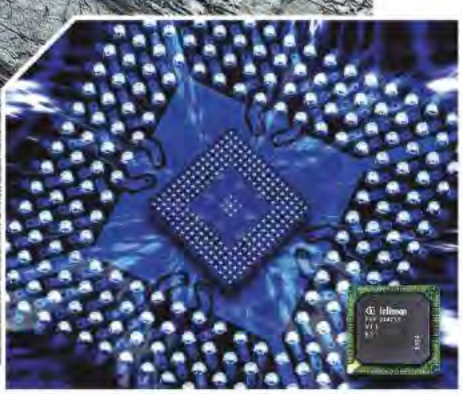
For example, by building advanced digital controls on offshore platforms, combined with improved connectivity, the industry is able to transfer tasks for data processing onshore, reducing manpower and increasing energy efficiency and operational effectiveness. Near real-time condition monitoring is another case in point where the use of data analytics can improve the decision-making process by predicting and mitigating problems at an optimal timing, thus reducing costly downtime.

### Long-term gains

Due to recent years' development in sensor technology and advanced data storage capabilities, the industry is now faced with unprecedented amount of data arriving from all parts of the value chain. However, the ability to connect and analyze these disparate data streams has not kept up with the pace at which the sheer amount and complexity of data has increased.

To catch up, the industry will need to invest in new business models that utilize data in an innovate manner. However, this also presents a dilemma when balancing the books in a volatile economy. As has been seen in other sectors outwith oil and gas, digitalization can deliver financial savings through increased efficiency, reduced risk and streamlined processes, but the results are not immediate as the transition takes time and a new mindset is required.

Skepticism still exists on how quickly advances in digital processes will impact productivity and efficiency in the short term. According to a recent DNV GL survey, *A new reality: The outlook for the oil and gas industry in 2016*, regulators appear to be the most optimistic about the impact of digitalization in the coming year. Nearly a third (29%) of regulators and government authorities believe it has high potential to change operating efficiencies in



Images from DNV GL.

2016, compared to just 10% of operators and 16% of service companies.

One of the key opportunities for companies looking to digitalize operations and services lies in learnings from sectors that are early adopters of digital technologies, such as aviation, retail and logistics.

### Cyber security

A major challenge facing the new digital world is ensuring the protection of highly sensitive and business critical information. Cyber-attacks on the oil and gas industry have grown in stature and sophistication in recent years, making them more difficult to detect and defend against, and costing companies increasing sums of money to recover from.

Recent attacks have included theft of core intellectual property, disruption or destruction of plant and infiltration of confidential communications. Although headline-grabbing cyber security incidents are rare, many lesser attacks go undetected or unreported as many organizations are unaware that someone has hacked the system.

The results of a DNV GL survey of 1100 professionals from businesses in different sectors in Europe, the Americas and Asia found that although companies are actively managing their information security, just over half (58%) have adopted an ad hoc management strategy, with only 27% setting concrete goals.

Lack of cyber security awareness and training among employees is the number one reason for heightened digital vulnerability, according to DNV GL's analysis of Norway's maritime and oil and gas sectors. The study revealed the 10 most pressing cyber security vulnerabilities for companies operating offshore Norway. While it focuses on operations on the Norwegian Continental Shelf, the issues are equally applicable to offshore operations anywhere in the world.

High on the top 10 was increased exposure of critical systems to external networks. This reflects trends towards remote operation and maintenance, and management systems that transport large volumes of process data to the office domain. Due to limited fiber capacity and redundancy, networks are shared, introducing vulnerabilities. Supplying offshore power from onshore facilities introduces risk as electricity grids are digitally vulnerable.

In the coming year, cyber security attack prevention, detection and response and automation are the two IT-related digital technologies that most organizations are expected to invest in (44% and 43% respectively), according to DNV GL's outlook report for 2016. However, investment in cyber security is lagging behind the perceived threat. This difference is most striking in Latin America, where 56% expect cyber security risks to increase in 2016, but only 42% plan to make a significant or moderate investment in this area.

### Security barriers

Companies must go beyond standard protective measures, such as firewalls and passwords, to reduce risk exposure. It is vital that a defense-in-depth strategy is applied which involves predictive and pro-active cyber and data protections, as well as integrated risk analytics. Countermeasures can be established using a barrier management approach, familiar from managing health, safety and environmental risks. By using a bow-tie model, companies can identify threats to operations and plan barriers to prevent incidents and mitigate consequences. This includes procedures to maintain barrier quality documented in performance standards.

Bow-ties and performance standards for security management are just two tools that DNV GL offers to help the industry manage risks and leverage opportunities. The company's software tool, Synergi Life – Risk Management Module is used to establish a live asset and risk registry and enables the assessment of vulnerabilities and threats, as well as mitigation follow-up. The company is also investing in initiatives to develop pan-industry best practice in identifying, preventing and responding to cyber security threats.

The industry recognizes the opportunity for imminent breakthroughs through use of new digital solutions. The exact next steps are not evident, but the pressures to reduce costs, increase efficiency and improve safety will play a dominant role in driving speedy implementation. Through collaboration and investment on innovation, the industry can overcome the challenge of extracting value from complex data streams. Nevertheless, effort is required to ensure data security and reliability. Companies must prepare themselves for a new reality where big data will be a cornerstone of the business and be ready for the risks and ocean of opportunities that follows. **OE**

***Nada Ahmed*** *is senior consultant, DNV GL - Oil & Gas, working with information risk management at DNV GL in Norway. She has six years' experience in risk management and has most recently been working on building the digitalization strategy for the oil and gas business through dialogue and pilot projects with the industry.*


# Dawn of the data engineer?

**Oil and gas has all the resources for a big data revolution – so what's holding us back? Robert Dickson, Director – field development project excellence at io sets out his view.**

Over recent years, in almost every industry, the concept of big data has moved sharply into focus, with Google searches for the term increasing over ten-fold since the beginning of 2011[1].

But what is big data? Perhaps the most helpful way to define it, for the purposes of the oil and gas industry, is the practice of using large data sets to reveal patterns and trends that can be used to optimize performance.

Currently, there are potentially enormous efficiencies that could be generated with the widespread adoption of big data techniques. Today, arguably the most prominent current application of big data is in seismic data interpretation, which has broadly served as the exploration and production industry's introduction to the science of big data and pattern recognition.

Beyond this, a few other new and notable applications of big data are emerging. For example, the use of big data techniques is beginning to be seen in predictive asset maintenance (using advanced statistical techniques to predict the failure of plant equipment); the use of advanced software to implement a statistical approach to production optimization and the use of advanced statistical techniques on health, safety and environment data and other operational data to predict hazardous combinations of activities. Indeed, we at io combined many of these approaches when designing our own "systems thinking" field development approach.

Yet, despite a few positive exceptions, the implementation of big data within the exploration and production industry has to date been slow, and led by those with large enough budgets to conduct pilots and explore tools and techniques. Currently, the oil and gas industry is simply not effectively exploiting the data being collected, and there are a number of reasons why big data techniques do not yet appear to have been widely adopted in exploration and production.

At the core of the issue, there appears to be a reluctance of exploration and production companies to hire data engineers to work with front line engineers and scientists to explore combination of data sets and the value that can be derived from this. Additionally, it seems fair to say that big data requires a more curious or explorative culture based on determining what value can be potentially derived from large and disparate data sets, rather than a more focused approach of solving an identified problem. As such, organizations must consider how they can make sure to hire individuals with such a mind-set, and create a corporate culture that allows them to thrive.

The adoption of big data is not helped by a lack of access to new tools sets created to analyze and handle large data sets. Attempts are being made to address this issue, but so far only select individuals in exploration and production would claim to have access to processing software such as SAS, R platform or IBM Watson. Additionally, the availability structure and quality of data cannot yet be described as "standardized".

Currently, only a small number of exploration and production companies have embraced big data/analytics at an organizational level, establishing centers of excellence to identify analytical techniques and tools and spread their use around the company.

### The 'C' word

More broadly, there is also scope for much greater collaboration within the oil and gas industry. Traditionally, the competitive nature of the industry has meant that companies have gone to great lengths to guard their innovative processes and technologies. Whilst such thinking may lead to a competitive advantage in the short-term, it stifles innovation and leads to significant inefficiencies (the current lack of standardization is a striking example of this).

Instead, the industry would benefit from greater sharing of technology, and where possible should encourage engineers and data specialists to work together to create innovations that benefit the wider industry. For example, extensive work on establishing data standards has been undertaken by joint industry project Energistics as part of the organization's wider objective to

define open standards for the upstream oil and gas industry. The widespread adoption of these standards would allow for greater collaboration within and across organizations, smoothing out many of the road blocks that currently prevent the adoption of big data techniques.

Similarly, other regulated industries, from healthcare to finance, have benefited from the establishment of "Hack Days." Borrowed from Silicon Valley's tech upstarts, the term refers to an event where engineers and developers are encouraged to attend an event and work (collaboratively or competitively) to achieve a specific goal. This concept could be adopted in the offshore industry, and engineers equipped with the necessary data engineering skills could be brought together to collaborate on finding imaginative ways to improve efficiencies within organizations. There is also scope to give individuals with the right skills a wider remit, and involve them in front-line activities to work hand-in-hand with engineers to search for opportunities where big data might add significant value.

While the entire sector is undoubtedly feeling the pain of an uncertain oil price, the current economic environment also presents the oil and gas industry with a unique opportunity. The need to reduce costs to make projects economically viable means that the industry is finally talking about the need to implement widespread change. In this climate, it should now be possible to take the decisions required to implement much greater digitization throughout the industry, and make the world of big data a reality. OE

[1] – google.com/trends – "big data"

***Robert Dickson** is director – field development project excellence at io. He has 24 years' experience in the oil and gas industry, having worked as a petroleum engineer and been in management teams on three major field developments from appraisal to first production. For the past 10 years, he has been a management consultant and E&P adviser covering field development, production and operations efficiency and digital oilfield strategy and implementation.*

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

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*(check one box only)*

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- ❑ 22 Independent Oil & Gas Company
- ❑ 23 National/State Oil Company
- ❑ 24 Drilling, Drilling Contractor
- ❑ 25 EPC (Engineering, Procurement., Construction), Main Contractor
- ❑ 26 Subcontractor
- ❑ 27 Engineering Company
- ❑ 28 Consultant
- ❑ 29 Seismic Company
- ❑ 30 Pipeline/Installation Contractor
- ❑ 31 Ship/Fabrication Yard
- ❑ 32 Marine Support Services
- ❑ 33 Service, Supply, Equipment Manufacturing
- ❑ 34 Finance, Insurance
- ❑ 35 Government,Research, Education, Industry Association
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- ❑ 701 Recommend
- ❑ 702 Approve
- ❑ 703 Purchase

**4. Which of the following best describes your personal area of activity?**
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- ❑ 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
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Latin America

# Great expectations

**Brazil and Mexico are not the only games in town in Latin America. The deepest well ever drilled is lined up for offshore Uruguay and Exxon is set to test Liza offshore Guyana. Elaine Maslin reports.**

International explorationists' eyes will be on South America this year. The region was home to the biggest offshore oil discovery last year – ExxonMobil's Liza discovery offshore Guyana. This year the world's deepest water oil well is set to be drilled by Total offshore Uruguay.

But, while these frontier areas are causing an international stir, for many it will remain just that, a stir, as spending remains under tight reins and frontier exploration an unpopular topic for those setting budgets, says Julie Wilson, upstream analyst at Wood Mackenzie in Houston.

"The main problem these small countries face, and the companies in them, will be getting budget to drill, especially in areas that are high risk. Frontier drilling is out of favor with the people setting the budgets. But, last year it was the frontier wells that caused the biggest excitement."

### Uruguay

You don't get much more frontier than Total's planned Raya (meaning stripe in Spanish) exploration well, offshore Uruguay. It will not only be the first deepwater exploration well offshore Uruguay, but also the deepest ever exploration well, Wilson says. Total is operator with 50% interest. Its partners are ExxonMobil (35%) and Statoil (15%).

Uruguay has three offshore basins: the Punta del Este Basin, in the west, the Pelotas Basin to the east and the Oriental del Plata Basin to the south in ultra-deep waters. The only two offshore wells drilled in the offshore were in the Gaviotin-1 and Lobo-1 wells in the Punta del Este Basin in 40-50m water depth by Chevron in 1976. Both were declared dry.

Total will be testing the Raya exploration prospect using the Maersk Oil's new build *Maersk Venturer* drillship in block 14, which covers 6690sq km in the deep water Pelotas basin, about 200km offshore, in the South Atlantic Ocean.

The block, which was awarded to Total in 2012, and was the only commitment well as part of the second offshore licensing round, is in 1850-3500m water depth. The well will be in 3400m water depth, Wilson says.

"All eyes are on this well because it is very high-risk," she says. "The structure looks enormous, but it is if all the elements are there to make it work."

Uruguay currently has no domestic production according to the International Energy Agency (IEA), but following Uruguay's second licensing round in 2011-12, a string of operators were awarded deepwater blocks. They were: BP (areas 6, 11 and 12), BG Group (areas 8, 9 and 13), Total (area 14), Tullow Oil and Inpex (area 15). However, BP has since been reported to have relinquished its areas, which could reappear in the next round. YPF also operates area 3, where it had been a partner with Shell, which has also pulled out, and GALP. Area 3 was awarded in the 2009 round. Going to press, Statoil, which took a stake in area 14 early February, agreed to acquire a stake in Tullow's area 15.

About 38,500sq km of 3D seismic has been acquired offshore Uruguay between 2012-2014, by PGS, WesternGeco and Polarcus. In addition, 13,000sq km of 3D CSEM has been acquired by EMGS. Uruguay Round 3 is due to be launched this year, offering shallow water areas and some deepwater frontier areas, further offshore than those already awarded.

### Guyana

Attention is also picking up offshore Guyana, where, in 2015, ExxonMobil announced what Wood Mackenzie described as last year's biggest oil find.

Guyana has never had a commercial petroleum discovery, although there are a number of wells that had oil and gas shows both onshore and offshore. "For the past 15 years,


**The newly minted *Maersk Venturer* drillship.**
Photo from Maersk Drilling.

Guyana has been locked up by ExxonMobil," Wilson says. "They have the giant Stabroek block, which is that vast majority of the acreage."

Exploration offshore Guyana along the border with Suriname was also on hold from 2000 to 2008 during a border dispute. Similar issues emerged between Guyana and its other maritime border neighbor Venezuela, resulting in a seismic vessel contracted by Tullow Oil being run-off by the Venezuelan navy. *(OE: January 2014)*.

ExxonMobil's Liza-1 well, in the Stabroek block, encountered more than 295ft of high-quality oil-bearing sandstone reservoirs. It was the first well on the 6.6-million acre Stabroek Block, 120mi offshore Guyana, and drilled to 17,825ft. Wood Mackenzie's estimate for the field's resource is about 400 MMbbl, but it could easily be a lot more than that, Wilson says. Excitement around the find was encouraged by a photo of a well log being leaked. Guyana Minister of Governance Raphael Trotman estimates the reservoir probably holds in excess of 700 MMbbls of oil. "Liza was the biggest oil discovery made last year in the world. The upside is very big," Wilson says. But, it's complicated geology, Wilson says, with overlapping fans.

After waiting 15 years to drill on its Guyana block, ExxonMobil was expecting to start drilling an appraisal well on Liza discovery as we went to press. "It is up against the clock," Wilson says, because its license expires in 2018, when it will need to decide which areas to relinquish. She expected 2-3 appraisal wells on Liza will be drilled with an exploration well elsewhere on the block.

Esso Exploration and Production Guyana (ExxonMobil) holds 45% interest in Stabroek. Hess Guyana Exploration holds 30% and CNOOC Nexen Petroleum Guyana holds 25%.

Others with interest offshore Guyana include: Repsol (Kanuku block, partnered with Tullow), Anadarko (Roraima block), Ratio Oil Exploration (Block B) and CGX Resources (the Demerara and Corentyne blocks and Berbice).

BGP was shooting 3D over 3100sq km for CGX in 2014, with results and prospect identification expected last year. CGX has until July 2016 to drill its first commitment well, expected on Corentyne, but it's yet to be seen if it has the cash.

In January 2016, Tullow Oil signed a Petroleum Agreement for the Orinduik block offshore Guyana. Orinduik covers 1800sq km in shallow water, 170km offshore Guyana in the Suriname Guyana basin, close to the Liza discovery. It is understood that other companies are also negotiating for concessions in the offshore Guyana area.

## Suriname

Neighboring Suriname, south of Guyana, is yet to make its mark, but there are interesting players in the basin who could quietly ramp up their exploration activity, Wilson says. In Suriname, Tullow has blocks 47 and 54, Murphy/Petronas has block 48, Kosmos/Chevron blocks 42 and 45, Petronas/RWE block 52, Inpex/Tullow has block 31 and Apache/CESPA block 53. But, it could depend on cash being available for exploration.

## Colombia

Despite being a large oil exporter, there was only one operating field offshore, the large Chuchupa gas field in the Guajira basin, operated by Chevron, according to a 2014 PWC report.

However, that could change as Anadarko is currently shooting phase II of the largest ever seismic survey off Colombia.

Interest picked up in the country when, in December 2014, Petrobras made the Orca-1 discovery, in the deepwater of

# Latin America

**Fred. Olsen's *Bolette Dolphin* drillship, which is drilling offshore Colombia for US independent Anadarko Petroleum.** Top: Photo from Fred. Olsen; Bottom: Photo from Andarko.

Tayrona block offshore Guajira. It wasn't actually what it had been looking for, which has meant geological models have had to be revisited, which could have delayed follow-up drilling on the find, Wilson says.

Then, last July, Anadarko made the "play-opening" Kronos-1 well discovery, in the Fuerte block, 53km offshore, at 3720m depth, in 1584m water depth, in the south Caribbean area, according to 50% partner Ecopetrol. The well, drilled using the *Bolette Dolphin*, encountered 40-70m net pay thickness of gas bearing sandstones. Wood Mackenzie estimates Kronos-1 to contain some 176 MMboe. Anadarko was also testing a deeper target.

The *Bolette Dolphin* then drilled the Calasu-1 well in the Fuerte Norte Block, 145km north east of Kronos-1. It encountered non-commercial quantities of pay, according to Anadarko.

In Q4 2015, Anadarko completed the Esmerelda survey phase I, in the Colombian Caribbean, covering 16,000sq km over the Col-1 and Col-2 blocks, using CGG's *Oceanic Sirius* and *Oceanic Vega* vessels. Acquisition of Phase II of the Esmeralda 3D survey, approximately 13,000sq km was expected to start this quarter (Q1 2016).

Anadarko operates and has 50% interest in the Fuerte Norte, Furte Sur, Purple Angel, Col 5 and Ura 4 areas, and 100% interest in the Col 1, Col 2, Col 6 and Col 7 areas.

Ecopetrol (Colombia's national oil company), Petrobras, Repsol, Shell, Equion and Statoil are also involved in areas offshore Colombia. Wilson says she expected Repsol to drill in shallow water offshore Colombia this year. In fact, Repsol is also looking at acreage offshore Aruba, an island offshore Venezuela, not far from Orca and with a similar petroleum system to Perla, offshore Venezuela, as well as Suriname, Guyana and Colombia.

Elsewhere in South America, Venezuela has potential but is unlikely to offer much activity offshore, due to current difficulties investing there.

Nicaragua could be of interest, Wilson says. The country, south of Honduras, has been a focus for BG Group. Noble Energy drilled offshore Nicaragua in 2013, and while it was unsuccessful, interest has remained with a number of blocks awarded to Shell, which now owns BG Group, and Statoil, last year. Statoil's four licenses lie off the county's Pacific coast, covering some 16,000sq km in the Sandino Basin.

Deepwater offshore Trinidad could prove an active area, with BHP Billiton eying potential. The company shot the largest ever 3D survey by a non-national oil company at the time offshore Trinidad. While it is a big gas province – BP and BG Group's operations there fuel huge LNG trains – Wilson thinks BHP Billiton, which also has gas production there already, might be looking for oil.

Tullow Oil started a 2D seismic acquisition campaign offshore Jamaica in January, using BGP's *BGP Challenger*. The Bahamas has also been a focus for exploration, but Wilson thinks it is unlikely any time soon.

Of course there is also the Falkland Islands, or Malvinas according to Argentina. Read more about Premier Oil's plans for the Sea Lion discovery on page 16. **OE**

FURTHER **READING**

**Disputed territory.**

**OE** examines the maritime border disputes among several Caribbean countries. http://www.oedigital.com/subsea/item/4680-disputed-territory

Latin America

# FPSOs at forefront

**Despite the ongoing bribery investigations, Petrobras is ploughing ahead with new FPSOs. Pietro Ferreira, of the Energy Industries Council, outlines current contracting activity in Brazil and in Mexico.**

Over the last 12 months, Latin America's offshore segment has been mainly concentrated in Brazil and Mexico. The two countries' national oil companies – Petrobras and Pemex – were responsible for most of the contracting activity during this period, awarding orders in various segments.

### FPSOs

Despite the negative turn of events affecting Petrobras, the company is prioritizing the construction of floating production, storage and offloading vessels (FPSOs). In May 2015, it was announced that the China Offshore Oil Engineering Corp. (COOEC) would carry out the modules integration of the P-67 and P-70 FPSOs, while the construction of 24 compression modules for the six replica FPSOs package (P-66 to P-71) was awarded to a consortium involving Cosco and BJC Heavy Industries.

### Subsea

In the subsea segment, Technip won contracts from Petrobras in March 2015 and October 2015 for flexible lines. The first, worth more than US$543 million, called for the supply of 200km of flexible lines and associated equipment for the Lula Alto field. The second order, worth $110-270 million, included 8in production pipes and 6in service and gas injection pipes for the Libra field. Moving beyond Petrobras, a consortium between GE and McDermott obtained a contract in April 2015 – awarded by independent Queiroz Galvao E&P – for the supply and installation of subsea equipment for the Atlanta field.

Contract Awards in Brazil and Mexico
(Upstream offshore)


### O&M

The operations and maintenance (O&M) segment saw two contracts awarded to Wood Group. The first, awarded in September 2015 by Statoil, is valid for four years and includes services for two wellhead platforms and an FPSO at the Peregrino field. The second contract, awarded in early January 2016, calls for two years of O&M services for PetroRio's Polvo-A fixed platform at the Polvo field.


Pietro Ferreira

### Bidding in Brazil

Looking further into 2016, Brazil's oil and gas market is set to gain momentum with bidding activity for three new production units. Petrobras is scheduled to receive bids for two 180,000 b/d FPSOs on 8 April (one for the Sépia field and the other for the Libra pilot project). Companies invited to bid include BW Offshore, MODEC, SBM Offshore and Teekay. Statoil, meanwhile, is expected to issue a tender in 1H 2016 for a wellhead platform to be installed as part of the second development phase of the Peregrino heavy oil field.

### New activity in Mexico?

Up in Mexico, the bulk of the country's contracting activity took place during 1H 2015. In January 2015, McDermott was awarded a contract by Pemex for the installation of the Ayatsil-A fixed platform, which was followed by a second contract in June 2015 for the construction and installation of the Ayatsil-C replacement jacket.

June 2015 also saw Aker Solutions celebrate its first order for the Mexican Gulf of Mexico, with a contract by Pemex for the Lakach gas field. The company will deliver 73km of electro-hydraulic steel tube umbilicals, to be manufactured in the US.

Lastly, in August 2015, Wood Group was awarded a three-year, $28 million contract by Pemex to provide concept and basic engineering services related to field development planning, topsides facilities, SURF and floating systems. The contract covers eight field development projects such as Ayatsil, Exploratus, Lakach, Tekel and Utsil. OE

# Solutions

## Halliburton releases electrohydraulic subsea safety system

Halliburton has released the Dash 3in subsea safety system, a solution for electrohydraulic control of Halliburton's subsea safety tree. This latest edition uses electrohydraulic actuation for core safety functions, while still providing full direct hydraulic redundant control of all functions. This helps to increase reliability and provide more cost-efficient operation and maintenance.

"The system delivers speed to critical well isolation, pressure containment and emergency disconnect functions," said Abdalla Awara, vice president of Halliburton's testing and subsea business line.

Linking with downhole and surface read-out control systems, the Dash system enables analysis to help drive optimal performance and avoid non-productive time during deepwater dynamic testing.

Recently, the Dash subsea safety system was deployed on a deepwater well in Latin America from a vessel in 7506ft of water with over 400 hours of in-hole operational time. During this deepwater well test, Dash demonstrated a six second downhole safety shut-in followed by an eight second surface shut-in and disconnect. **www.halliburton.com**

### READ, GE launch leak detection solution

READ Cased Hole's new micro-leak detection solution is designed to deliver answers for on the spot well integrity management decisions. The diagnostic solution combines GE Oil & Gas' NTO acoustic noise tool and READ's micro-leak detection service line.

The solution creates a detailed map of downhole acoustic energy, which when combined with measurements from flowmeter and temperature sensors, enables location of leak sites, identification of active flow pathways and determination of the sources of flow energy.

"The information we provide allows operators to plan and prioritize their response to integrity issues, therefore saving time and resources through risk reduction and time loss prevention," said Tobben Tymons, READ's technical director.

READ's micro-leak detection software segregates the acquired acoustic data according to the frequency of the captured sound energy enabling spectral analyses of the data and diagnosis of unwanted flow events associated with well integrity issues.

As an early adopter, READ partnered with GE Oil & Gas on field trials of the NTO technology, accelerating delivery of the micro-leak detection service line that is now being deployed across slickline, electric line, coil tubing and tractor-conveyed well interventions worldwide. **www.readcasedhole.com**

### Magnetrol offers new radar transmitter

Level and flow instrumentation manufacturer Magnetrol International launched the Pulsar Model R96 non-contact radar transmitter for level control in process applications. The two-wire, loop-powered, 6 GHz radar transmitter measures a variety of liquid media in process conditions ranging from calm product surfaces and water-based media to turbulent surfaces and aggressive hydrocarbon media.

The Pulsar Model R96 has a measurement range of 130ft, HART and FOUNDATION Fieldbus digital output, and SIL 2 suitability with a 92.7 Safe Failure Fraction (SFF). It also has diagnostic capabilities with automatic waveform capture and data logging, and a device type manager (DTM) with field configuration and troubleshooting capabilities. **www.magnetrol.com**

## Hawxeye app screens asset lifecycle

Developed by Xodus engineers, HAWXEYE, a cloud-based web app geared to screen assets for vibration, erosion and corrosion related issues, is an alternative to spreadsheets.

Data from monitors and piping and instrumentation diagrams are aggregated in an interface creating accessible and transparent information. Additionally, the app will automatically screen against industry standards and retain data for observation, auditing, asset integrity management, and continuous improvement programs.


HAWXEYE can also highlight poor design in the project and operations phases, and detect the root causes of piping and pipeline failures and monitor reliability, Xodus says.

"HAWXEYE is fully scalable and can be used by any organization facing piping and pipeline condition issues in difficult to reach equipment. Through its simple traffic light system, it highlights likelihood of failures and enables preventative action to be taken," said Graeme Rogerson, operations director at Xodus Group. **www.xodusgroup.com**

## Aker wins Subsea UK's top award

**Aker Solutions won the "Company of the Year" accolade at Subsea UK's annual awards event in late January. The company also walked away with the Innovation & Technology award, at the event, held in Aberdeen during Subsea Expo, for its Vectus Subsea Electronics Module.**

**Other achievements included David Bloom, global business development director for Subsea 7, receiving the Outstanding Achievement award in recognition of his contribution to the subsea sector. Bloom's career spans more than 40 years, having joined the offshore industry in 1975 as financial controller with Oceaneering, where he worked for 20 years.**

**He left Oceaneering in 1995 to take up the role as business development manager for UK and Europe at Jay Ray McDermott, before joining Subsea 7 in 2005.**

**Subsea UK CEO Neil Gordon said: "David is a well-recognized and well-respected figure within the subsea industry. Not only has he contributed significantly to the industry over the course of his career, he has overseen Subsea 7's ambitious expansion plans to great success and has worked hard to position the firm as a global leader in its field."**

**Robert Weeks, lead engineer at JDR Cable Systems scooped the award for Young Emerging Talent.**

**Fathom Systems was crowned the Small Company of the Year and also won the Innovation for Safety award. The Global Exports award went to JDR Cable Systems for its rapid expansion into key international markets with its innovative umbilical systems. OE is principal media sponsor at Subsea Expo.**

**Read our Subsea Expo coverage** www.oedigital.com/component/k2/itemlist/tag/Subsea%20Expo

### Sonomatic breaks ground at new facility

Sonomatic has broken ground at The Core, a new multi-disciplined facility, which will allow the company to cover the entire range of NDT inspections in Aberdeen. The facility will be located north of Aberdeen in Bridge of Don, approximately 4mi from Aberdeen Harbor.

"The Core will immediately feature three radiography bays, two pressure test bays along with the ability to service pipework requiring heat treatment," said Tracy Anderson, Sonomatic UK business development manager. "Our specialized technicians will offer eddy current, magnetic particle inspections, dye-pen and ultrasonic inspections at the base as well as providing them as a mobile service."

Sonomatic's direct investment envisaged at this stage is to be in excess of US$5.7 million (£4 million), including the land, building and fit-out costs.

### Diamond, GE ink performance-based BOP deal

Diamond Offshore Drilling and GE Oil & Gas entered into the offshore drilling industry's first-of-its-kind contractual service agreement that transfers full accountability for blowout preventer (BOP) performance to GE Oil & Gas.

In this "pressure control by the hour model," Diamond Offshore will compensate GE Oil & Gas only when the BOP is available. This 10-year collaborative arrangement for GE's engageDrilling Services showcases a new way of thinking to drive continuous improvement in deepwater drilling.

The arrangement will include GE purchasing the BOP systems aboard Diamond Offshore's four drillships, currently located in the US Gulf of Mexico, for a total of US$210 million.

### Slate of mergers win approvals

BG Group shareholders made the final decision in the US$70 billion mega merger with Shell in an overwhelming 99.53% vote in favor of the deal, making it the biggest merger between two supermajors in more than a decade. With all approvals received, the transaction closed on 15 February 2016. Shell has surpassed Chevron as the world's second-biggest non-state oil company.

Also, Schlumberger received approval from the European Commission (EU) for the US$14.8 billion takeover of Cameron International. The EU concluded that the proposed acquisition would raise no competition concerns. The merger is expected to close in Q1.

### Paragon to file for bankruptcy

Paragon Offshore is the latest company to fall during the downturn, as the company seeks bankruptcy protection to eliminate US$1.1 billion of debt and reduce annual cash interest payments by nearly $60 million.

Paragon shareholders will exchange $984 million in senior unsecured notes for $345 million in cash plus 35% of equity, and they may receive deferred cash payments of up to $50 million based upon 2016 and 2017 consolidated EBITDA results. The company's revolving load, which matures in 2019, will be paid down to $165 million.

Spotlight

Check Mate, which today resides in Stavanger's Norwegian Petroleum Museum. Photos from Vidar Fondevik.

# Wonders of the deep

**Vidar Fondevik's career has spanned challenging the limits of diving to developing remote operated systems. He reflected on his career with Elaine Maslin.**

Vidar Fondvik's career has spanned a fascinating, pioneering era in the subsea industry, from developing the early robotic subsea systems to pushing the boundaries in scientific diving research.

It's an industry easy to be fascinated by, not least in Norway's often forgiving waters. It was here, for example, that the submarine Nautilus was scuttled in a fjord near Bergen after a failed attempt to cross under the North Pole.

"It's not Jules Verne [who wrote about the fictional submarine Nautilus], but it was a big expedition," Fondevik says. "It was just before the [Second] World War, 1931, and then they had to sink it in Norway because the Americans didn't want it to be taken by the Germans."

Finding it, in 350m water depth, some 40 years later, became a mission for Fondevik. The mission was achieved, thanks partly to managing to get a photo of where it where scuttled, but also due to using a specially developed sonar system to find it and then developing one of the industry's first remotely operated vehicles, MAX. It is a story of the Norwegian subsea industry – finding problems and developing solutions – and also a theme close to Fondevik throughout his career.

Fondevik holds an MSc in Underwater Technology and Subsea Engineering from Heriot-Watt University, Scotland, and has bachelor degrees in Naval Architecture and Business Economics.

His underwater career started in 1969, as combat diver in the Navy. He went on to serve as a diving surveyor for DNV in the oil and gas industry and then moved into experimental diving at Norway's NUTEC, and the development of submarine manipulators and tools. He became pilot and manager for the acrylic submarine Check Mate, now displayed at the Norwegian Petroleum Museum, and went on to be general manager for a local company producing hydrophones for military submarines, and a board member for both the Underwater Technology Foundation and the Society of Underwater Technology Norwegian branches.

In the early years, the industry in Norway had wanted to get rid of manned subs and they didn't want men in the water, Fondevik says. "The goal was, by 2000, to totally get rid of the diver. It was never managed. Often they planned fields for ROV operation, but didn't manage to do it with ROVs and so brought the diver back in. Very often that was the case. And it became too expensive to do it. It often took longer with an ROV and it was just much simpler to do with divers, especially when it came to welding."

While replacing the diver wasn't quite fully achieved, many achievements were made in underwater technology, including developing manipulator systems and master controllers, the subject of a 1982 conference paper Fondevik presented at the Underwater Technology Conference thanks to his involvement in it.

But it was projects like Skuld, on the Elf, North East Frigg project offshore Norway, that really helped propel Norway's subsea industry, Fondevik says. "It was the first modular-based, remote controlled production system. Skuld was a test project. It was a full scale test station to test the reliability of the remote control system. They got 20 years of production from that system. It was a very important project."

The industry also continued to push the boundaries of diving. "We did lot of experimental diving in the 1980s, trying to push the limits further and further, diving down to 500-600m," Fondevik says. The world record was won by Comex at 701m. Yet, for safety, today, the usual depth limit on the Norwegian Shelf is 180m for diving. In the UK it is 225m and in Brazil, around 300m.

**Vidar Fondevik, top left, receiving his SUT Fellowship.**

ROVs are also more sophisticated and, as a result of moves into deeper waters, are often the only option. "They know what the ROVs can do and they know what the diver can do and they know the costs," Fondevik says. "They also know the limits of developing a system at 2000m – you have to do it remote. But, if a field is 150m deep, like Johan Sverdrup, divers are an option."

Fondevik will retire 1 March this year, having recently been made a Fellow of the SUT. OE

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# What's next

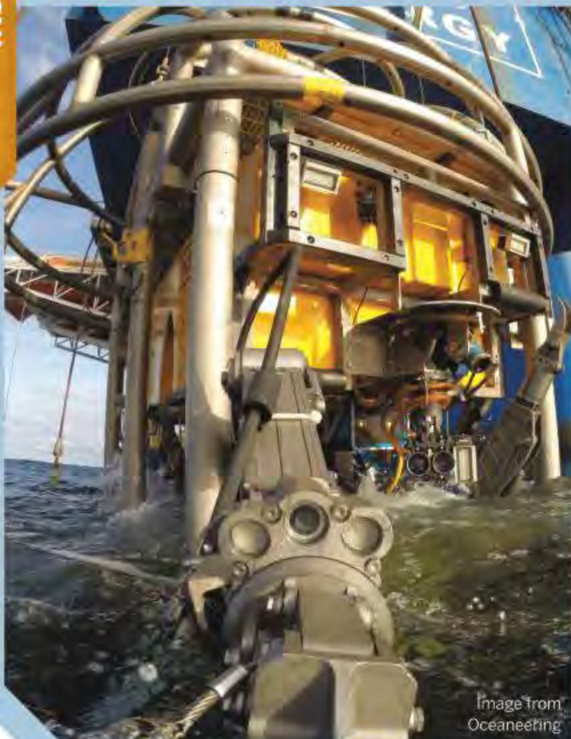

Image from Oceaneering

## Coming up in OE April

### Asset Integrity

- Brownfield Engineering
- Subsea Technologies
- Mature Fields
- Drilling Frontiers
- Drilling Automation
- Regional spotlight: Mediterranean/North Africa

**OTC Preview**

OE Staff will highlight the events, technical sessions, new products and services, and companies to watch out for at this year's Offshore Technology Conference (OTC) held in Houston this 2-5 May 2016, in our April issue.

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Phone: +1 281-758-5733
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**UNITED KINGDOM**
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**chris@aladltd.co.uk**

**SCANDINAVIA, GERMANY AND AUSTRIA**
**Brenda Homewood**, Alad Ltd
Phone: +44 01732 459683
Fax: +44 01732 455837
**brenda@aladltd.co.uk**

**ITALY**
**Fabio Potesta,** Media Point & Communications
Phone: +39 010 570-4948
Fax: +39 010 553-00885
**info@mediapointsrl.it**

**NETHERLANDS**
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Phone: +31 547-275 005
Fax: +31 547-271 831
**arthur@kenter.nl**

**FRANCE/SPAIN**
**Paul Thornhill**, Alad Ltd
Phone: +44 01732 459683
**paul@aladltd.co.uk**