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# The FLNG Issue

page 24

Offshore Engineer - June 2016




# Features




**ON THE COVER**

**New beginnings.** In May, Petronas' first FLNG facility, *PFLNG SATU*, set sail for the Kanowit gas field, offshore Sarawak, making a 2120nm journey from DSME's Okpo, South Korea yard to Malaysia.

Read more FLNG coverage on page 24 of this issue. *Cover image courtesy of Petronas.*


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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


Photo courtesy of OIS Ltd.

## Collaborating on subsea decommissioning

**Endeavor Management's Keith Caulfield details how the firm's subsea decommissioning joint industry project strives to find industry solutions for subsea decommissioning.**

# Activity

## FMC, Technip to merge

**French engineering house Technip and US-based underwater technologies firm FMC Technologies are to combine, creating a new US$13 billion business to be called TechnipFMC. The combined firm would have more than 49,000 employees operating in over 45 countries. Together, in 2015, Technip and FMC generated combined revenue of about $20 billion. As of March 31, 2016, the two companies together had consolidated backlog of approximately $20 billion.**


Photo from Technip.

# People

## FMC names Pferdehirt CEO


Photo from FMC Technologies.

**Before the merger with Technip, Douglas J. Pferdehirt was appointed president and CEO of FMC Technologies, effective 1 September 2016, succeeding current Chairman and CEO John T. Gremp. Under the structure of the new company, Pferdehirt will serve as CEO of TechnipFMC, while Technip Chairman and CEO Thierry Pilenko will serve as executive chairman.**

# Undercurrents

## Waiting for the decom dam to burst

It's like the trickle of water that appears before the flood gates burst open. It's not certain when the gates will burst or how much water will rush through. For the North Sea's decommissioning market, the problem is even worse. It doesn't appear that it will be a nice consistent flow of work. And worryingly, estimates given by industry bodies are accurate to +/-100%.

Here's what we know: a large chunk of the North Sea's infrastructure is nearing the end of its life. Decommissioning work to date has cost more than estimated, and annual forecasts continue to rise.

Even if you take Oil & Gas UK's estimates (based on the annual Insight Report survey) with a pinch of salt, there's still plenty of work: Over the next 10 years, an estimated 1500 wells on the Norwegian and UK Continental Shelves, 6000km of pipeline, 491 modules on 91 platforms, and 510 on 93 platforms to be made safe and prepared for removal, respectively, and an eye-popping nearly 800,000-tonne of material to come onshore for disposal. The work is coming: the number of fields going into cessation of production has been higher than what had been estimated, some, but not all, due to the oil price.

How will this mountain of work be handled? There are concerns the UK, which bears the brunt of offshore facilities to be decommissioned, is not ready for this work. The supply chain wants to get on with it, but it needs more detail about what exactly needs to be done – and when.

The technology offerings need to be turbocharged, a sentiment expressed at Decom North Sea's Decom Offshore conference in Aberdeen in May. A different mindset coupled with more transparency, openness, and new players, is needed we're told.

The good news: some of this is happening. Oil & Gas UK's next Insight Report will look at decommissioning actuals, with metrics from projects that have actually taken place, as well as some estimates from the Dutch and Danish sectors (Norway was added last year).

Operators are also sharing their experience and pinpointing where they need more help, such as ConocoPhillips, with its 130-well southern North Sea abandonment campaign (see page 34).

We're also hearing more on Shell's multi-year mega-challenge to assess attic oil and sediment in its Brent Delta concrete storage cells – a step it has to take before it can decide how exactly to handle the decommissioning of these immense structures. It has taken a NASA-like focus on technology development to achieve and ***OE*** looks forward to sharing the story with our readers.

There are also companies, such as GA Drilling and Well-Sense (both featured in this issue), developing technologies to meet the call to turbocharge. As always, the efforts of these firms need the support of operators so that new technologies can be trialed, tested and commercially deployed. While there's talk of bringing in new entrants, the industry could make strides by dropping some of the "not invented here" mentality.

With a vessel like Allseas' *Pioneering Spirit* set to offer a step-change (see page 32), focus should be on every piece of the puzzle, right down to pipeline cleaning, and even regulation, which is sometimes based on rules drawn up when less was known about how marine life reacts to oil and gas infrastructure.

Yet, in an industry that lives and dies by its reputation, it should present how its actions (such as leaving pipelines or drilling mud piles in situ) will be better for the environment than removing them. BP has outlined how leaving North West Hutton drill cuttings pile on the seabed has meant less potential disturbance to the seabed and shown how marine life has returned to the area faster than expected (see page 36).

While the flow seems uncertain now, one thing is: ***OE*** will be there to showcase new methods and technologies. **OE**

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**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**
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araj@atcomedia.com
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msustaita@atcomedia.com
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**CONFERENCES & EVENTS**
**Events Coordinator**
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jgranda@atcomedia.com
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Gisset Capriles
gcapriles@atcomedia.com

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

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# The Barrel

## Painting a rosy picture

Good news at last! In recent months, I have endeavored to counter some of the gloom that has pervaded the oil business for the last eight quarters by highlighting fundamentals such as the consistency of long-term demand growth and the reality of larger-than-normal production declines arising from the slump in oilfield spending.

This month, I am delighted to report that evidence of these long-term realities is beginning to emerge, with recent data and events combining to create a rosier outlook.

On the supply side, shale oil production declines are accelerating such that it is reasonable to expect year-on-year production to decline by approximately 1 MMb/d by year's end. With spending on conventional production at minimal levels, it is also reasonable to expect production declines there of more than 3 MMb/d. We have also had a reminder of how unforeseen events can affect supply, with wildfires in Canada restricting supplies by 1 MMb/d and Nigerian supply outages of approximately 500,000 b/d. On the other hand, it was a surprise that Iran managed to increase its production by 300,000 b/d.

> **"As we have never been in this position before, it's impossible to predict what will happen. But, I hope and expect the industry will get a chance to recover..."**

Demand looks solid, with China roaring past the US to become the world's largest car market. New car sales increased 10% in Q1 2016, over the previous year, and sales of sports utility vehicles rose by a stunning 45%. In India, gasoline demand is setting records. The size of India's vehicle fleet doubled between 2007 and 2015, making it the world's sixth largest vehicle market. In a move reminiscent of the explosion in Chinese oil consumption growth in the early 2000s, Q1 demand grew by 400,000 b/d over the previous year.

The level of short bets on crude has reduced dramatically, lifting the oil price to the mid US$40/bbl levels. With analysts, the EIA and the IEA now anticipating a tightening of the supply/demand balance, it's likely that crude prices will continue to march upwards. Many experts anticipate $60 crude by year end.

With this in mind, it was interesting to attend this year's Offshore Technology Conference where there was much discussion about what happens next, assuming crude prices do firm significantly. How will shale oil operators respond? Can we expect a rapid reversal in the rig count slump and a consequent ramp up in production that will depress the recovery and prevent prices from rising further?

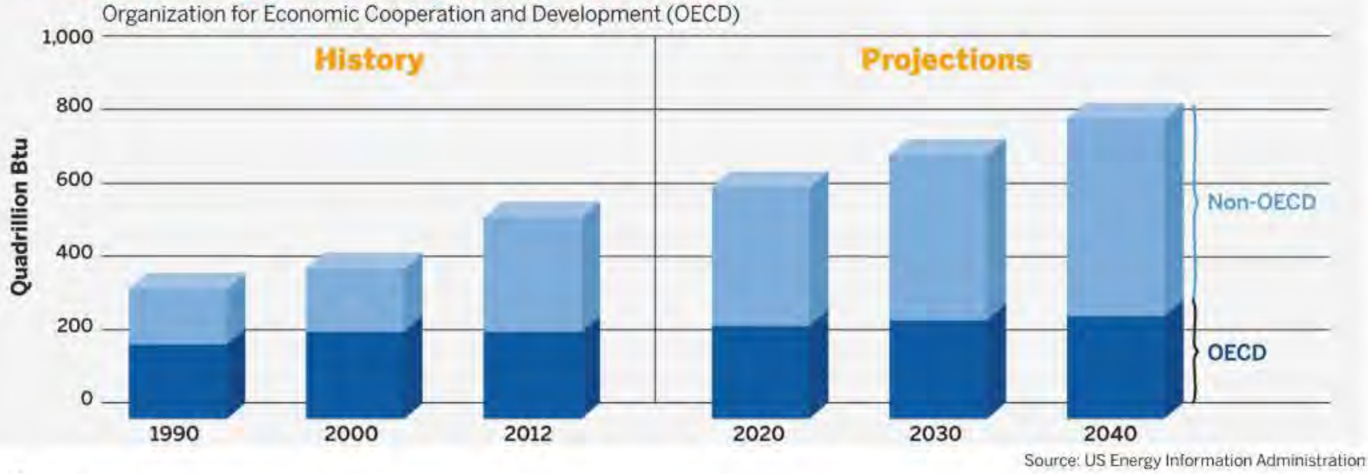
The good news is that there seems to be a consensus among experts that higher crude prices will need to endure for a considerable period of time so that balance sheets can be repaired before rigs will be put back to work in meaningful numbers. I don't doubt that is true for the majority of shale producers. However, I suspect that we will see the very best shale operators – who have been working hard during the downturn to develop drilling and completion efficiencies, while driving down costs, and whose balance sheets remain strong – putting rigs back to work before too long.

As we have never been in this position before, it's impossible to predict what will happen. But, I hope and expect that the industry will get a chance to recover and stabilize before more damage is done. **OE**

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

**World Energy Consumption, 1990-2040**

Organization for Economic Cooperation and Development (OECD)




Source: US Energy Information Administration

# Global E&P Briefs


## A TGS expands 3D shoot

TGS is expanding its multi-client library offshore Eastern Canada, with plans to acquire about 2000sq km of 3D seismic data, in partnership with PGS. The survey will be acquired utilizing the PGS GeoStreamer technology. Data acquisition will commence during the summer season 2016. Pre-processing of the initial GeoStreamer signal will be performed by PGS following which TGS will perform data processing with final data available to client in Q3 2017.

## B BP starts Thunder Horse EOR

BP has started a water injection project at its Thunder Horse platform in the Gulf of Mexico. The project will extend the facility's production life and boost recovery of oil and natural gas from one of the Thunder Horse field's three main reservoirs.

The move follow a three-year refurbishment project plus the drilling of two new water injection wells. The improvements are expected to yield an additional 65 MMboe, BP says.

Thunder Horse is about 150mi southeast of New Orleans, in the Mississippi Canyon at 6050ft water depth.

## C Petronas, Hess set sights on Suriname

Operators are setting sights on Suriname in South America. The country, which is east of Guyana where the major Liza-1 discovery was made, could be poised to make its own mark.

Malaysia's Petronas began drilling operations on the Roselle-I well last month (May). The well, in Block 52, will be drilled using Rowan's Ralph Coffman jackup, which is under contract with Petronas until August 2016. The program is expected to take approximately three months. Block 52 covers 4749sq km and is 130km offshore, north of the city of Paramaribo, in water depths ranging 50-200m.

Nearby, Hess farmed into a one-third stake of Kosmos Energy's offshore Block 42 contract area. In return, Hess will fully fund the cost of a 6500sq km 3D seismic survey, expected to start in Q3, and a portion of the first exploration well.

## D Exxon starts up Julia

**ExxonMobil began oil production at its US$4 billion Julia oil field in the Gulf of Mexico with the first producing well currently online, and a second well set to start production in the coming weeks. Exxon's initial development phase for Julia uses subsea tiebacks to the Chevron-operated Jack/St. Malo production facility located 15mi away, which reduces the need for additional infrastructure and enhancing capital efficiency. The company is also utilizing subsea pumps that have one of the deepest applications and highest design pressures in the industry to date, Exxon said.**

**Julia is approximately 265mi southwest of New Orleans in the ultra-deepwater Walker Ridge area in more than 7000ft water depth. It is thought to contain some 6 billion bbl of resources in place.**

## E Petrobras wins Campos extension

Brazil's National Petroleum Agency (ANP) granted a 27-year extension to Petrobras for the Marlim and Voador fields in the Campos Basin offshore Brazil. Originally scheduled to end in 2025, the concession contracts will now continue until 2052.

According to Petrobras, the extensions will ensure the maximum utilization of the existing reserves which will be done through revitalization projects in the two fields. The projects will include two new platforms, with expanded water injection and fluid processing capacity, and the drilling of 10 new wells.

## F Faroe spuds Brasse

Faroe Petroleum began drilling on the Brasse exploration well in the Norwegian North Sea. The well, 31/7-1, is immediately south of the producing Brage oil field (Faroe 14.3%) and, if successful, could be tied back to the Brage facilities or alternatively to other nearby installations. The well will target the Jurassic aged sandstones in a four-way dip-closed structure with a total vertical depth of approximately 2750m in the Early Jurassic Statfjord Formation. The water depth at the site is 118m and the well will be drilled using the semisubmersible *Transocean Arctic* drilling rig. The co-venturer in the PL740 license is Core Energy (50%).

## G Laggan Tormore reaches full production

Total's Laggan-Tormore subsea to shore development West of Shetland has now ramped up to full production at 90,000 boe/d. The French oil giant held an official inauguration ceremony at the Shetland Gas


Plant, built to receive the production, in mid-May. Laggan-Tormore production started 7 February. The project taps two fields, Laggan and Tormore, in 600m water depth, via a 140km, four-well tieback to the new onshore gas plant.

### H Woodside to start Irish 3D

Woodside and partner Petrel Resources have received environmental approvals from the Department of Communications, Climate Change, & Natural Resources to begin 3D seismic surveys this summer in the Irish Atlantic.

Woodside awarded both Granuaile and Bréanann 3D marine seismic surveys to PGS on 6 May. Technical, safety and environmental induction and final preparations were successfully completed on 16 May. The *Ramform Vanguard* survey vessel and its support vessels sailed from Killybegs on 17 May. The vessels are now mobilizing to the Granuaile survey area in the Southern Porcupine Basin, about 150km southwest off the Co. Cork coast. It is anticipated that the Bréanann 3D seismic survey covering, inter alia, Woodside-operated Frontier Exploration License 3/14 (Petrel has a 15% carried interest) will start in about 40 days, in the ideal weather window, Petrel said.

### J Anadarko hits off Ivory Coast

Houston's Anadarko Petroleum successfully drilled its first horizontal deepwater well offshore the Ivory Coast, encountering 100ft net of true vertical thickness pay on the Paon-5A well using *Bolette Dolphin* drillship.

Anadarko is now drilling the Paon-3A horizontal sidetrack, to be followed by a drillstem and interference test. Positive results should advance the project toward commerciality. Two exploration wells, Pelican and Rossignol, are planned following Paon.

### K Kosmos gets fifth consecutive hit

Texas-based Kosmos Energy has drilled its fifth consecutive successful exploration and appraisal well in the Mauritania-Senegal fairway, taking the firm's total discovered resources to 25 Tcf gross Pmean, with a 50 Tcf potential to be tapped, the company says. The firm describes the play as having world-class resource potential.

The Teranga-1 deepwater exploration well, drilled using the *Atwood Achiever* ultra-deepwater drillship, hit 31m (102ft) of net gas pay in good quality in the Cayar Offshore Profond block, offshore Senegal, in nearly 1800m water depth.

### L Pure Vida looks to drill Madagascar

Pura Vida Energy has taken over operatorship (100%) in the Ambilobe block, offshore Madagascar, East Africa,

### I Anadarko to explore Purple Angel

**Anadarko plans to drill an exploration well during 2H 2016 in the Purple Angel block offshore northwest Colombia, in the southern Caribbean Sea. The area is adjacent to the Kronos discovery in nearby Fuerte Sur. Kronos, discovered in July 2015, encountered 130-230ft (40-70m) of net natural gas pay in the upper objective.**

**Anadarko has also started Phase II acquisition of the Esmeralda 3D survey, which will cover 13,000sq km of blocks Col-6, and Col-7 in the Grand Col area. Phase II will add to the approximately 16,300sq km of 3D seismic acquired in Phase I for blocks Col-1 and Col-2.**

# Global E&P Briefs

following the withdrawal of Sterling Energy from the license.

Pura Vida also renegotiated the terms of the work commitments under the production sharing contract (PSC). The PSC is in Phase 2, which has been extended to January 2017, although all work commitments have been completed.

Pura Vida has been assessing newly acquired 3D seismic data and says it is moving towards a drilling phase on the block, for which it is seeking a partner.

## M Leviathan back on track

Work on Israel's giant deepwater Leviathan field could be back on track after a new agreement on the country's oil and gas terms.

Noble Energy, which operates the field, had put forward its revised Leviathan development plan earlier this year. Part of the development plan terms was a 10-year stability clause, which stated that the Israeli government couldn't impose regulatory changes, such as breaking up monopolies, on the Leviathan partners for a 10-year period.

However, a ruling by Israel's Supreme Court in March, which affirmed Israel's natural gas regulatory framework, didn't include the stability clause, putting the brakes on the Leviathan project.

Now, the cabinet has agreed new terms which seek to offer stability for Noble and its partners, while giving the state more leeway to change oil and gas policy should it see fit.

## O Eni ups Nooros production

Just 10 months after the discovery at the Nooros field offshore Egypt, Italy's Eni has increased production at the field to some 65,000 boe/d. Nooros is in the Abu Madi West concession in the Nile Delta, about 120km northeast of Alexandria. Production at Nooros consists of approximately 10 MMcm/d of gas, and 5000 b/d of condensates. Eni said its next target is to increase production up to 140,000 boe/d by the end of 2016, through the drilling of additional wells and facility optimization.

## P Dolphin nets Black Sea seismic

Dolphin Geophysical has entered into an agreement for seismic acquisition and processing services offshore the Romanian coast of the Black Sea. The agreement includes the delivery of a fast track 3D volume, for Black Sea Oil & Gas and its co-venture partners. The job will use the 16 streamer vessel *Polar Marquis*, towing a high resolution multistreamer configuration.

## Q India launches bid round

India's government has launched its Discovered Small Field Bidding Round 2016, offering 67 discovered small fields in 46 contract areas spread over nine sedimentary basins in onshore, shallow water and deepwater areas.

It says the areas up for bidding have known hydrocarbon discoveries of more than 85 million tonne of in-place reserves. A revised business model will be offered under revenue sharing contracts that will involve international competitive bidding with no mandatory domestic participation.

## R Santos starts Indonesia appraisal well

Santos began drilling the AAL-4X appraisal well off Indonesia using the PT Apexindo's Raniworo jackup. AAL-4X is in the West Natuna basin and sits in 72m water depth. Santos is drilling the well at 200m total vertical depth subsea in a 24in hole, and will be drilled to a total depth of 1232m, which is expected to take 48 days to complete.

## S Mubadala's Sri Trang-1 fails

Mubadala Petroleum has failed to find commercial quantities of oil at its Sri Trang-1 exploration well in the northern Gulf of Thailand. Sri Trang-1 is in the G1/48 concession, 18km north-northeast of the Manora oil development. The well was spudded on 17 May in 40m of water by the Atwood Orca jackup and was drilled to an extended final total depth of 2814m. Although the oil is not in commercial quantities, Mubadala said, the Sri Trang-1 discovery has validated the hydrocarbon prospectivity of the Northern Kra Basin.

## T Woodside weighs Myanmar development

Woodside is considering development options on its two discoveries, Shwe Yee Htun-1 and Thalin-1a, offshore Myanmar. A campaign totaling 4-7 wells is expected to start in Q1 2017, with an active drilling program also planned for 2018. The two discoveries have increased the company's best estimate contingent resource (2C) offshore Myanmar by 83 MMboe to 4481 MMboe.

## U Rosneft starts Sakhalin drilling

Rosneft began drilling on the Lebedinskoye oil and gas condensate field, which sits under the Sea of Okhotsk, in Sakhalin region, Russia.

It will drill a 5.3km-long horizontal extended-reach well off Sakhalin Island, using contractor RN-Burenie for RN-Sakhalinmorneftegaz. Three horizontal production wells, approximately 5000-7000m deep, are to be drilled. First oil is expected this year using the RN-Sakhalinmorneftegaz infrastructure.

## N Ichthys pre-lay completed

**Inpex completed the offshore pre-lay of the 77km chain and cable mooring system for its Ichthys LNG project in the Browse Basin, off the northern coast of Western Australia.**

**As part of the mooring system, 49 chains were laid on the seabed in water depths of up to 250m and anchored to 5.5m-diameter and 63m-long foundation piles.**

**The mooring system will secure the project's two massive offshore facilities—the central processing facility (CPF) and a floating production, storage and offloading (FPSO) facility—in the Ichthys Field seabed for at least 40 years of continuous operation.**

**The CPF will export gas and some condensate through an 890km subsea gas export pipeline to onshore processing facilities in the Northern Territory. Most condensate will be processed through the FPSO and shipped directly to market.**

# Contracts

## Statoil picks Technip for Oseberg

Statoil picked Technip to supply the umbilical to the Oseberg Vestflanken 2 field offshore Norway. The contract covers project management, engineering and the manufacturing of over 9km of static steel tube umbilical. The umbilical includes a large bore integrated service line and multiple power cables. Technip Umbilicals' facility in Newcastle, UK, will manufacture the project, which is scheduled to be completed during 1H 2017.

## Wood Group wins Caspian work

Wood Group won a five-year contract with BP, valued at US$500 million, to deliver services to eight facilities offshore Azerbaijan. Wood Group PSN will provide engineering, procurement and construction management services, which has the option of two, two-year extensions. The firm will support the following platforms: Chirag, Central Azeri – production drilling quarters, Central Azeri – compression and water processing, East Azeri production drilling quarters, West Azeri – production drilling quarters, Deep Water Gunashli – drilling and utility quarters, Deep Water Gunashli – pressure compression and water utilities and Shah Deniz Stage 1.

## Siemens gets Beatrice wind order

Siemens will supply, install, and commission 84 wind turbines, each with a 154m rotor diameter designed to generate 7MW of power, for the Beatrice project. Furthermore, the scope of supply comprises the offshore grid connection to the mainland in consortium with Nexans, which will supply the connecting export cables. Siemens will deliver the onshore and offshore substations consisting of two offshore transformer modules, which are smaller in weight and size.

## JDR inks Vashishta subsea work off India

GE Oil & Gas chose UK-based JDR to engineer, design and manufacture 12 steel tube flying leads and associated hardware for ONGC's Vashishta and S1 project offshore India. The flying leads will be manufactured at JDR's manufacturing facility in Hartlepool, UK. The Vashishta and S1 fields are in the KG Basin, 30-35km off the east coast of India, at water depths of 250-700m.

## Actemium inks BP Angola FPSOs

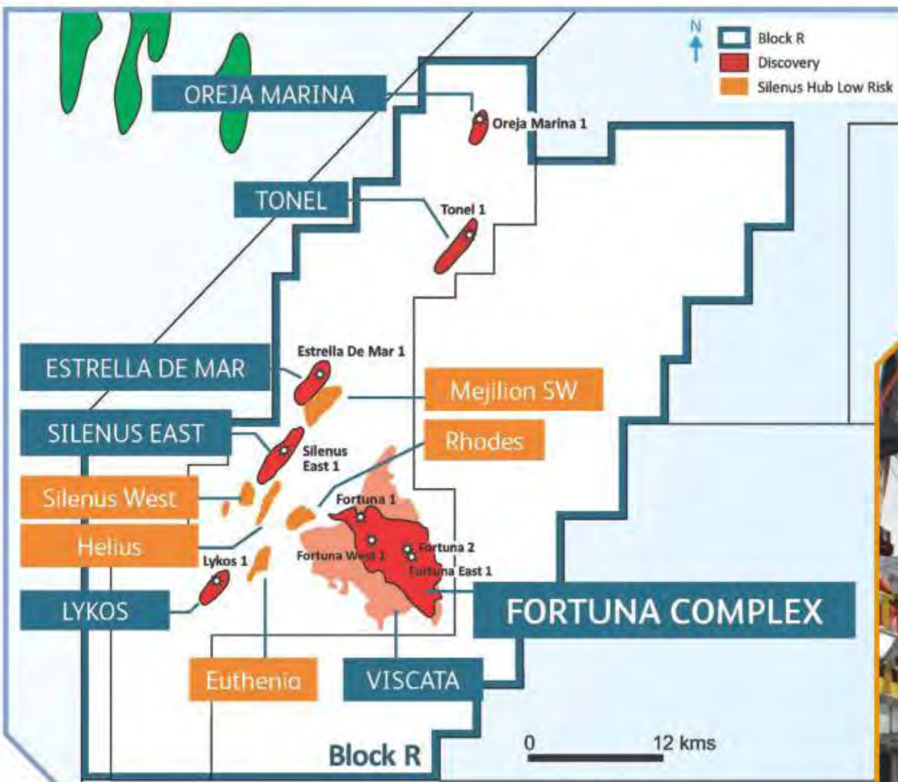
Actemium has won a multimillion dollar contract with BP Angola. The "two-asset" agreement, the first of its kind for BP's Angolan operations, will see Actemium become the key topsides maintenance provider for BP's two floating production storage and offloading units in Angola: Greater Plutonio (Block 18) and PSVM (Block 31).

Under the five-year contract, Actemium will deliver onshore and offshore maintenance support services to the two assets, with scope for additional ad-hoc services to support the operations.

The work will be executed through Actemium's Angolan offices and the Paris Maintenance Center of Expertise. ▪

# A small Fortuna

**Floating LNG – it's a big business, taking decades to develop and involving the world's largest vessels and cutting edge technology. Or is it? Elaine Maslin explains how operator Ophir Energy is taking a different tack off West Africa.**




**Block R, offshore Equatorial Guinea.** Images from Ophir.

When it comes onstream in 2019, Ophir Energy's Fortuna floating LNG development offshore Equatorial Guinea will be Africa's first deepwater floating LNG project.

Unlike its larger counterparts, such as Shell's *Prelude* and Petronas' *PFLNG1* project, it's rather modest in scale. This is thanks to shallow reservoirs, dry biogenic 99.7% methane gas and benign metocean conditions, which lend themselves to a small-scale, low-cost and low-risk FLNG concept.

**Oliver Quinn**

It was also partly about good timing, says Oliver Quinn, Ophir's director of Africa and Global New Ventures. As Ophir was looking through development concepts for Fortuna, Golar LNG, an LNG carrier firm, was branching out into smaller scale floating LNG projects.

Indeed, Golar LNG is already working on its first FLNG project, using the *Golar Hilli* unit, currently undergoing conversion, for Perenco's Sanaga Sud and Ebome fields offshore Cameroon. This is due to be delivered in 2017 – timing that means Golar will be able to implement lessons learned from *Hilli* on Fortuna.

"What is interesting is the simplicity," Quinn says. "When you come to FLNG, the first thing in your mind is 'big, complex and expensive.' But, actually, when you break it [Fortuna FLNG] down, it is none of those things. It is a good example of where simple engineering and logical engineering can unlock something. In 10 years, this could be quite a mainstream development concept."

The Fortuna project entered front-end engineering and design (FEED) in July 2015 and is on schedule for final investment decision (FID) in mid-2016 and first gas in 2019. Production is expected to be around 330 MMscf/d with a plateau of 30 years.

### Discovery

Fortuna sits in Block R, some 140km west of Bioko Island, in the southeastern Niger Delta complex. Ophir took on the license in 2006 and two years later discovered Fortuna, in 1680-1850m water depth, and 800m reservoir depth.

In 2009, Ophir hit at the Lykos-1 well. Appraisal wells were drilled in 2012 (Fortuna East-1, Fortuna West-1 and Tonel-1) and then 2014, when it ran a drill stem test (DST) (Fortuna-2 and also the Silenus East-1 well).

The main Fortuna field, which has 35-40% porosity and 1000-1300mD, is estimated to contain some 3.7 Tcf recoverable resource, or 4 Tcf if compression is used, which Ophir plans to.

Ophir, currently 80% interest holder in Block R, had considered a subsea development with pipeline to shore, some 140km away, where there are existing LNG facilities on Bioko Island. But, thanks to the modest topsides processing equipment required for the dry gas, FLNG was the clear winner, using a leased FLNG unit to reduce capex outlay for Ophir.

"As we looked at it, it was clear that small-scale LNG was coming along," Quinn says. "Golar is maturing the technology and that solution is much better for this gas. Although it is deepwater, it is a very benign marine environment and simple reservoir conditions. Because we have dry gas, you can use a small vessel and do side-by-side loading. You could look at a TLP or remote facilities, but very quickly you get to a point where it is very inefficient, so it was either a tieback or FLNG. As we went along the exploration curve and drilling wells, [small-scale] FLNG emerged in parallel, with different providers, not just the majors, doing it. If we hadn't had line of sight on LNG, it might have looked different."

## Learnings

Bringing in Golar gives upstream focused Ophir midstream capabilities, as well as freeing it from capital spending, due to using a leased vessel, and an ability to learn directly from Perenco's experience with the *Golar Hilli* offshore Cameroon.

Perenco is looking to tap 500 Bcf of natural gas in shallow water, off Kribi, Cameroon, with lean associated feed gas. It is expected to have 2-3 trains and an eight-year production life at production of 1.2 MTPA. Vessel delivery is due in early 2017 with startup scheduled for Q2 2017.

The Fortuna Golar LNG solution, a four-train 2.6-2.8 MTPA nameplate system, will use a converted Moss LNG carrier, the *Gandria*, to be owned, operated and maintained by Golar LNG. It will have an NOV external turret and mooring. Keppel Shipyard is performing the vessel conversion, with Black & Veatch as the liquefaction process supplier.

The project is expected to have a 20-year life with 17 wells in four phases. Earlier this year, Ophir had expected to spend US$600 million in upstream capex to first gas, with about $1.5 billion being spend on midstream capex by Golar, mostly relating to the vessel. But, after receiving the EPCIC tenders, that has been reduced to $450-500 million from FID to first gas spending for Ophir.

Phase one will see just four pre-drilled development wells, three on Fortuna, and one on Viscata, but only two are expected to be required to achieve 2.2 MTPA plateau, with standard subsea infrastructure.

Ophir had planned more wells, but the Fortuna-2 DST in 2014 flowed gas to surface at a constrained rate of 60 MMscf/d, exceeding expectations. The implied unconstrained rate was greater than 180 MMscf/d, meant the number of development wells required could be reduced.

**Drilling operations on the Fortuna field.**

Drilling operations on the Fortuna field.

The wells will have gravel pack completions, 5in horizontal Xmas trees, rated for 5-15,000 psi, and a standardized well design. MEG will be injected via cores in steel tube umbilicals. The project will also have dual 12in flowlines and risers.

### A simple system

"From the sand face to the vessel, it is a very straight forward system because we don't have that liquid component," Quinn says. "Later in field life offshore compression will be required, but that's just managing the pressure decline in the reservoir as normal. Subsea compression is a possibility. We are planning for the assumption at some point we will need compression on the deck."

Phase two will see five wells drilled in 2024, three on the Silenus East discovery, one at Estrella de Mar, and one at Tonel, to elevate plateau to 4.4 MTPA using second vessel, *Fortuna 2*.

Phase 3 would see a further eight wells drilled in a 2027-2030 drilling phase (three on Viscata as the phase 3, tied into *Fortuna 1* vessel). The same drilling phase would also see one well on the Lykos discover and four on the Silenus hub prospective resources, also tied into *Fortuna 2*, under a phase 4. Drilling will be executed by Ophir's drilling team in London.

The second vessel FID date is expected mid-2022, with first production in mid-2025, however, this could be brought forward, depending on the success of both the *Golar Hilli* offshore Cameroon and the first Fortuna FLNG unit. The second vessel is likely to be a similar size to the first, Quinn says.

"By 2019, the *Hilli* will have a number of years production experience and Golar will understand how it is working," he says. "If we are in good shape, it allows us the possibility to bring forward the second *Fortuna* vessel date."

Some early engineering work was performed by a consortium of Crondall Energy, Aker Solutions and Subsea 7. This was to provide technical support to the competitive upstream FEED. Two other tendering consortia, comprising McDermott and GE, alongside GE Oil & Gas and Aker Solutions, have competed for the subsea system engineering, procurement, installation and commissioning (EPIC) contract, which is due to be awarded once FID is reached.

## LNG market

**Oilfield services giant Schlumberger had originally taken an increased interest in the Fortuna project, signing an agreement with Ophir Energy that could have seen the firm pick up a 40% stake.**

**However, Ophir and Schlumberger did not reach agreement on the non-binding heads of terms, and talks soon ended.**

**While Ophir and Schlumberger could not agree, the service giant said its memorandum of understanding with Golar LNG – to cooperate on the global development of greenfield, brownfield, and stranded gas reserves – remains unaffected.**

**According to industry analysts Wood Mackenzie, with 50% growth predicted between 2015 -2020, the global LNG market is one of the fastest growing in the world. Yet, the current commodity price slump is creating a challenging market for LNG projects, with reduced demand from Asia coupling with expected oversupply from the likes of Australia, where a string of LNG megaprojects have been under way.** ▪

### Explorer turned operator

As an exploration firm, with limited production operation experience, on a project where the third party vessel and equipment supplier has a key role, how the project is managed is yet to be fully defined.

Worley Parsons is Ophir's "owner's engineer," and Ophir will manage the subsurface and drilling, as well as having supervisors on board the *Fortuna* FLNG vessel.

"Not many FLNG projects have been completed," Quinn says. "One of the things we are working through is the best operating model between ourselves and Golar. Combing the two as an operations group will be important."

Working out a good operating model could be prudent to aid future projects using this technology. Both Golar LNG and Ophir think there are opportunities.

"With proof of concept at Fortuna, it will mean smaller than traditional volumes of gas could be taken out elsewhere in Africa or any other remote location [based on the conditions at each location]. There are 2-3 other places around Africa we think this could work very well. Once we are through FID we will look to pursue other options." OE

# In-Depth

# Coping with the new normal

**There's no disputing the somber mood of this year's Offshore Technology Conference in Houston, but industry leaders attempted to stay upbeat. Melissa Sustaita reports.**



**Wael Sawan executive vice president, deepwater, Shell, speaks at the "Coping with Lower Oil Prices: Perspectives from Industry Leaders" panel at OTC.** Photos from OTC/Todd Buchanan 2016.

The downturn in oil prices has had far reaching implications throughout the industry. This year's Offshore Technology Conference (OTC) in Houston forced the industry to share just how they plan to adjust in these difficult times.

One panel entitled "Coping with Lower Oil Prices: Perspectives from Industry Leaders" featured representatives from Shell, Transocean, and GE Oil & Gas to discuss how their companies are adapting.

According to Lars Eirik Nicolaisen, partner at Rystad Energy, we need to be above US$80/bbl to make this industry work going forward, and to feed the ever-growing demand for oil, towards 100 MMb/d. Deepwater is at the end of the marginal cost curve and will struggle, he said during the panel.

"We think that offshore is able to compete with shale in the future," Nicolaisen said. "We remain optimistic on behalf of the offshore sector."

However, Wael Sawan, executive vice president, deepwater, Shell, said that Nicolaisen's view on deepwater is too simplistic, since it can span from anywhere from sub $30/bbl break-evens, to north of $100 break-evens in certain cases.

"The issue with a company like ours is to not simply say that we play in deepwater, but it is in our nature that we play in the lowest end of the cost curve to be sure we stay relevant and prove to be resilient when oil prices do go through the natural cycles that they do go through," Sawan said.

Shell's recent mega-merger with BG Group has the company playing in deepwater in several Brazilian projects, in addition to its other big projects, such as Malaysia's Maliki and the Stones project in the US Gulf of Mexico.

"We believe that competitive growth is a must-have in this business," he said. "Unfortunately, over the years of excesses with $100/bbl oil, we have not truly built the full potential of this business."

Shell, just like other oil and gas companies, says it is coping with the low oil prices. Three of its coping strategies, Sawan said, include safety, people, and zero-based maintenance.

With zero-based maintenance, Shell is looking at what the company fundamentally needs in order to be able to conduct its work, which has come to be safety and reliability, in addition to competitive scoping.

"Competitive scoping has changed the mindset of many of our engineers as we've looked at our projects and yielded significant savings," Sawan said. "Our Stones wells are a great example of how some of those savings were achieved, where we actually went to our new conventional business to learn what they do, and we eventually saved US$1 billion in capex."

At Transocean, the focus is on four aspects; geographic reach, technology, financial flexibility, and management focus, said Merrill A. "Pete" Miller, Jr., Transocean's director and chairman of the board.

"These four things will help us change to make sure that we're viable, that we're doing things for this industry that are going to allow us to be able to fill the voids that you see out there," he said.

Discussing geographic reach, Miller said that, as a company, you have to be able to provide a customer with the same quality of operations, the same type of personnel, wherever you may be in the world.

"Is it expensive? Certainly. But, it's a lot more expensive trying to take a rig out of the Gulf of Mexico and moving it to Australia," he said.

"We think that we're scratching the surface, but the goal is that we have to be able to drill in this industry at $30/bbl. Are we there yet? Nope. Will we get there? I think, absolutely, yes."

GE Oil & Gas President and CEO Lorenzo Simonelli said that partnership and collaboration in the industry are critical to accelerate commercial and technological advancement. In that regard, GE and Diamond Offshore recently teamed up on a first-of-its-kind contractual service agreement that transfers full accountability for blowout preventer (BOP) performance to GE Oil & Gas.

"We've got to look at our standards. We've got to look at our documentation, our requirements. A fit for purpose," Simonelli said. "That means people have to be willing to accept standardized specs. It means that we move towards modularization."

"Let's simplify. Let's take out the redundancies. Let's take out inappropriate bureaucracy that we have during processes, and work together towards more clarity of what we're trying to achieve," Simonelli said. "I think we'll get there even faster if we continue to collaborate."

### 'Safety, productivity, and collaboration are key'

Elsewhere at OTC, Bernard Looney, BP chief executive of upstream, shared his thoughts on the dramatic change the industry has undergone.

"In the past we've adjusted, reduced our costs, and tightened our belts," he said. "Some businesses didn't make it through and some came back stronger. Let me be clear, at BP, we don't think that it's lower forever. The long-term demand picture is strong – very strong."

Looney said that there are many moving parts and that it is hard to tell where this will all play out.

He suggested that improving productivity might be the best insurance for the future, as global energy demand will continue to grow.

"Our own forecast at BP says that world energy demand will most likely be about a third higher in 2035 than it is today. That's like adding another US, EU and Japan combined," Looney said.

Looney also believes that collaboration and being open to new ideas and suggestions from partners will help the industry weather through the low oil price storm.

"Here in the Gulf of Mexico we have been collaborating with our suppliers on costs and it has allowed us to rethink our Mad Dog Phase 2 project," Looney said. "This was a $20 billion project and we've brought it down to under $10 billion, with the expected returns improved despite a lower oil price."

**Bernard Looney, BP chief executive of upstream, speaks at OTC.** Photo from OTC/Rusty Costanza 2016.

He said that there is also real value to be had, if the industry opens itself up to learn from, and with, other companies and other sectors.

"In 2015 we saw the potential in training rig teams together ahead of drilling in the field," Looney said. "So we gathered BP employees and contractors from our Egypt region to train in one of the most advanced drilling simulators in the world – Maersk's immersive state of the art drilling simulation facilities."

Looney stressed that the industry cannot afford to be complacent and slip back into old habits, however.

"Waiting for the oil price to rise again is not sufficient – nor is short-term cost cutting. We need to be able to compete, on a global scale, with other energy and transport sectors. It will require innovation and continuous improvement – getting a little better in everything we do, every single day," he said.

## 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 | 53 | 3 |
| Deep (500-1500m) | 19 | 29 | 17 | 2 |
| Ultradeep (>1500m) | 34 | 13 | 12 | 3 |
| **Total** | 126 | 114 | 82 | 8 |
| Start of 2016 | 127 | 114 | 72 | - |
| date comparison | -1 | - | 10 | 8 |

*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 | 8 | 30.75 | 333.28 |
| Deep | 13 | 1316.00 | 1695.00 |
| Ultradeep | 42 | 11,601.00 | 12,833.00 |
| **United States** | | | |
| Shallow | 9 | 66.6 | 152 |
| Deep | 19 | 915.36 | 1231.57 |
| Ultradeep | 22 | 2960.50 | 3050.00 |
| **West Africa** | | | |
| Shallow | 114 | 3,780.50 | 15,422.56 |
| Deep | 34 | 3,742.50 | 5,350.00 |
| Ultradeep | 14 | 1,600.00 | 1,210.00 |
| **Total** | 267 | 25,982.46 | 40,944.13 |
| (last month) | (262) | (27,475.22) | (43,099.70) |

### Greenfield reserves

2015-19

| Water depth | Field numbers | Liquid reserves (mmbbl) | Gas reserves (bcf) |
|---|---|---|---|
| Shallow | 901 | 34,353.47 | 466,591.73 |
| (last month) | (924) | 34,953.49) | (476,110.34) |
| Deep | 140 | 7871.52 | 89,755.71 |
| (last month) | (143) | (9038.93) | (90,507.62) |
| Ultradeep | 84 | 16,448.90 | 42,190.00 |
| (last month) | (85) | (16,466.90) | (43,190.00) |
| **Total** | 1,125 | 58,673.89 | 598,537.44 |

### Pipelines

(operational and 2015 onwards)

| | (km) | (last month) |
|---|---|---|
| **<8in.** | | |
| Operational/ installed | 41,554 | (41,633) |
| Planned/ possible | 24,334 | (24,406) |
| | **65,888** | (66,039) |
| **8-16in.** | | |
| Operational/ installed | 83,101 | (83,053) |
| Planned/ possible | 48,219 | (48,473) |
| | **131,320** | (131,526) |
| **>16in.** | | |
| Operational/ installed | 95,079 | (95,109) |
| Planned/ possible | 44,423 | (44,547) |
| | **139,502** | (139,656) |

### Production systems worldwide

(operational and 2015 onwards)

| **Floaters** | | (last month) |
|---|---|---|
| Operational | 269 | (270) |
| Construction/ Conversion | 50 | (51) |
| Planned/possible | 299 | (299) |
| | **618** | (620) |
| **Fixed platforms** | | |
| Operational | 9189 | (9190) |
| Construction/ Conversion | 75 | (76) |
| Planned/possible | 1363 | (1370) |
| | **10,627** | (10,636) |
| **Subsea wells** | | |
| Operational | 4888 | (4888) |
| Develop | 382 | (369) |
| Planned/possible | 6318 | (6323) |
| | **11,588** | (11,580) |

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

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|
| Shallow | 14,559 | 20,484.04 | 37,569.64 | 15,791.01 | 15,666.57 | 22,746.47 | 24,934.07 |
| (last month) | (14,558.63) | (20,483.81) | (39,103.43) | (15,994.92) | (15,560.30) | (22,747.67) | (25,578.97) |
| Deep | 4474.00 | 955.55 | 5167.33 | 2685.57 | 3925.03 | 6173.22 | 5741.23 |
| (last month) | (4469.26) | (955.55) | (5433.92) | (2408.30) | (3925.03) | (6175.47) | (7093.04) |
| Ultradeep | 2343.00 | 1922.92 | 3167.92 | 3190.03 | 4443.63 | 5440.92 | 7644.87 |
| (last month) | (2343.00) | (1922.92) | (3167.92) | (3190.03) | (4503.63) | (5575.22) | (7644.87) |
| **Total** | 21,375.78 | 23,362.51 | 45,904.89 | 21,666.61 | 24,035.23 | 34,360.61 | 38,320.17 |

10 May 2016

# Rig stats

## Worldwide

| Rig Type | Total Rigs | Contracted | Available | Utilization |
|---|---|---|---|---|
| Drillship | 105 | 73 | 32 | 69% |
| Jackup | 398 | 263 | 135 | 66% |
| Semisub | 134 | 90 | 44 | 67% |
| Tenders | 31 | 21 | 10 | 67% |
| Total | 668 | 447 | 221 | 66% |

## North America

| Rig Type | Total Rigs | Contracted | Available | Utilization |
|---|---|---|---|---|
| Drillship | 35 | 27 | 8 | 77% |
| Jackup | 22 | 6 | 16 | 27% |
| Semisub | 15 | 10 | 5 | 66% |
| Tenders | N/A | N/A | N/A | N/A |
| Total | 72 | 43 | 29 | 59% |

## Asia Pacific

| Rig Type | Total Rigs | Contracted | Available | Utilization |
|---|---|---|---|---|
| Drillship | 11 | 3 | 8 | 27% |
| Jackup | 119 | 70 | 49 | 58% |
| Semisub | 29 | 16 | 13 | 55% |
| Tenders | 21 | 14 | 7 | 66% |
| Total | 180 | 103 | 77 | 57% |

## Latin America

| Rig Type | Total Rigs | Contracted | Available | Utilization |
|---|---|---|---|---|
| Drillship | 29 | 22 | 7 | 75% |
| Jackup | 54 | 36 | 18 | 66% |
| Semisub | 27 | 24 | 3 | 88% |
| Tenders | 2 | 2 | 0 | 100% |
| Total | 112 | 84 | 28 | 75% |

## Northwest European Continental Shelf

| Rig Type | Total Rigs | Contracted | Available | Utilization |
|---|---|---|---|---|
| Drillship | N/A | N/A | N/A | N/A |
| Jackup | 47 | 41 | 6 | 87% |
| Semisub | 41 | 32 | 9 | 78% |
| Tenders | N/A | N/A | N/A | N/A |
| Total | 88 | 73 | 15 | 82% |

## Middle East & Caspian Sea

| Rig Type | Total Rigs | Contracted | Available | Utilization |
|---|---|---|---|---|
| Drillship | 1 | 0 | 1 | 0% |
| Jackup | 111 | 87 | 24 | 78% |
| Semisub | 4 | 3 | 1 | 75% |
| Tenders | N/A | N/A | N/A | N/A |
| Total | 116 | 90 | 26 | 77% |

## Sub-Saharan Africa

| Rig Type | Total Rigs | Contracted | Available | Utilization |
|---|---|---|---|---|
| Drillship | 22 | 18 | 4 | 81% |
| Jackup | 22 | 12 | 10 | 54% |
| Semisub | 6 | 2 | 4 | 33% |
| Tenders | 8 | 5 | 3 | 62% |
| Total | 58 | 37 | 21 | 63% |

## Eastern Europe

| Rig Type | Total Rigs | Contracted | Available | Utilization |
|---|---|---|---|---|
| Drillship | 1 | 1 | 0 | 100% |
| Jackup | 2 | 1 | 1 | 50% |
| Semisub | 2 | 1 | 1 | 50% |
| Tenders | N/A | N/A | N/A | N/A |
| Total | 5 | 3 | 2 | 60% |

Source: InfieldRigs 25 May 2016

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

**Lourdes Melgar, Mexico's undersecretary of hydrocarbons, speaks at OTC.** Photo from OTC/Rusty Costanza 2016

### Battles to ensue over Mexico's new play areas

Competition is fierce for the yearend battle to win the right to explore Mexico's deepwater acreage, a group of panelists said at OTC.

Mexico's highly anticipated deepwater bid round, due in December, already has 14 companies lining up to prequalify.

Lourdes Melgar, Mexico's undersecretary of hydrocarbons, told the crowd that there have been some 30 interested companies, with 14 requesting to pre-qualify for the round that encompasses 10 blocks, four in the Perdido Fold Belt and six in the Salina Del Istmo basin.

According to CNH's website, as of 13 May, some 31 companies have now shown interest and 16 companies have begun the prequalification process. Those included in the prequalification process are: Atlantic Rim Mexico, BHP Billiton, BP, Chevron, China National Offshore Oil Corp. (CNOOC), Exxon, Hess, Inpex, NBL Mexico, PC Carigali, Pemex, Ophir, Shell, Sierra, Statoil, and Total.

The Gulf of Mexico is mostly divided between Mexican and US territory, with 54% in the Mexican jurisdiction, 44% in the US jurisdiction, and the remaining 2% with Cuba, Mexico's Hydrocarbons Commission (CNH) president Juan Carlos Zepeda Molina explained.

When looking at the US side, some 80% of the deepwater area is under exploration. On the Mexican side, there is currently zero exploration in deepwater, he said. The disparity is due to the industry not being allowed to invest in Mexico. That is expected to change with the deepwater bid round on 5 December.

CNH released an updated version of the deepwater license contract in May, and will follow with a list of final bidders and the final contract on 24 August.

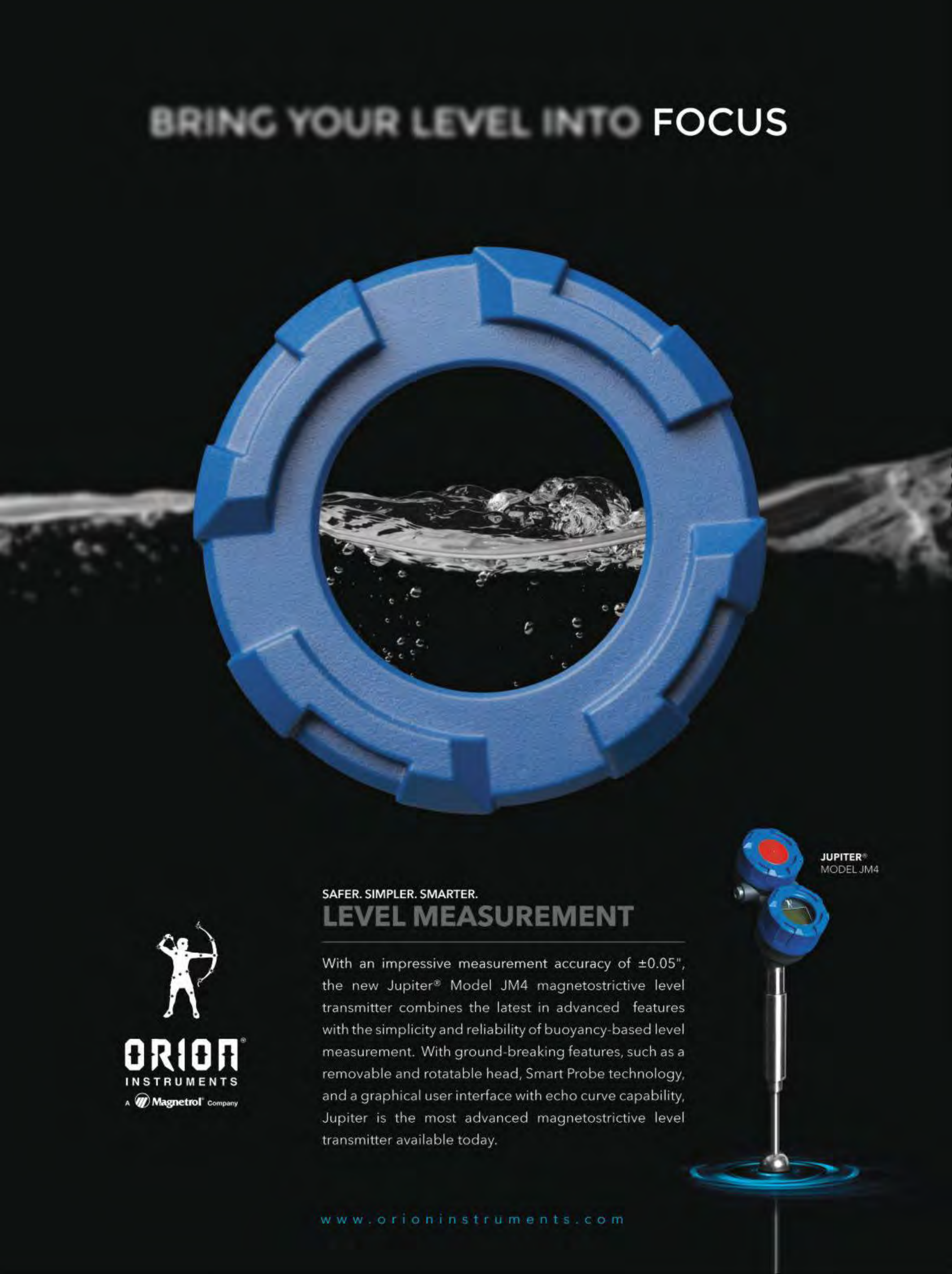
According to Melgar, Round 2.1, which includes shallow water blocks will be announced in June 2016, along with a call for bids. OE


FURTHER READING

**Assessing Mexico's geological potential**
www.oedigital.com/component/k2/item/11834-assessing-mexico-s-geological-potential

**Mexico lowers local content rule for deepwater**
www.oedigital.com/component/k2/item/12030-mexico-lowers-local-content-rule-for-deepwater

**Mexico's deepwater round set for December** www.oedigital.com/component/k2/item/11722-mexico-deepwater-round-set-for-december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**Laurentino Rangel, a consultant with Poten & Partners, provides an overview of current floating LNG projects around the globe.**

# Floating prospects

A floating LNG (FLNG) facility paves the way for opportunities to monetize gas resources from remote, marginal and stranded fields, which would otherwise be uneconomical to develop via conventional means. FLNG has advantages in areas with small gas reserves, expensive onshore port facilities, and/or constrained engineering, procurement and construction resources. It can also offer simplified approval processes while avoiding domestic gas commitments and unfavorable taxation.

Projects in Australia, Malaysia, Cameroon and Equatorial Guinea have chosen FLNG solutions to monetize fields, with projects under construction and first production due between 2016-2018.

However, current global oversupply is leading to tough times for all new developments. Over the past 18 months, projects with 150 MTPA of new onshore and floating liquefaction capacity have been shelved, due to a LNG market that is expected to remain oversupplied until well into the next decade, threatening a new cycle of tightness in the following years. In Q1 2016 alone, 60 MTPA of new capacity was canceled or delayed as oil and LNG prices continue to trade close to historic lows, with companies adjusting to the oversupply.

Shell proposed the world's first FLNG development and is now building *Prelude*, 125mi off Australia's northwest coast, and due to start up in 2017. Prelude will produce 3.6 MTPA of LNG, 0.4 MTPA of liquefied petroleum gas (LPG) and 1.3 MTPA of condensate, using one quarter of the size of an equivalent plant on land at a cost of US$12 billion.

*Prelude's* hull and topsides are under construction at Geoje, South Korea, at the Samsung Heavy Industries (SHI) shipyard, which has one of the few dry docks in the world big enough to construct a facility of this size.

Petronas' smaller *PFLNG 1*, to be based on the remote and otherwise stranded Kanowit field, offshore Sarawak, Malaysia, will be a major milestone as the world's first operating FLNG unit once it starts production this year. The *PFLNG SATU* vessel was delivered from Daewoo Shipbuilding and Marine Engineering in Okpo, South Korea. It is designed for an operating capacity of 1.2 MTPA,


***Prelude.*** Photo from Shell.

**Golar *Hilli*.** Photo from Keppel shipyard.

***PFLNG SATU.*** Photo from Petronas.

measuring 365m-long and will have a crew of 145 onboard.

In 2014, Petronas also moved forward with *PFLNG 2* for the Sabah development in Malaysia. In November 2015, the project reached a milestone with the keel laying ceremony at SHI, South Korea. Petronas originally scheduled it for delivery in 2018, but recently extended the delivery date to an unspecified time, with the potential that the 1.5 MTPA project may be mothballed, due to the current economic climate.

In November 2015, Perenco and partner Societe Nationale des Hydrocarbures made a final investment decision (FID) on developing its Kribi fields offshore Cameroon using its GoFLNG technology. Golar LNG is converting the Moss-type LNG carrier *Hilli* to an FLNG unit at the Singapore Keppel Shipyard for the project. Golar will provide the floating LNG assets and technology, while oil and gas contractor Schlumberger will contribute upstream development services and capital. Golar LNG says the focus is on increasing it to a three-train operation over a longer-term charter.

Golar had options to convert two more vessels, the *Gimi* and *Gandria* LNG carriers, into FLNG facilities and exercised the options in 2015. Both vessels have secured contracts for Ophir's 2.2 MTPA Fortuna project in Equatorial Guinea, with delivery expected in 2018 and 2019, respectfully. (See page 16 for an in-depth look at Ophir's Fortuna FLNG project.) Golar plans to have five or more GoFLNG vessels operating by the end of the decade.

Hoegh LNG made a surprise announcement in February 2016, saying it would leave the FLNG sector to concentrate on floating storage and regasification units (FSRUs). Since 2007, the Norwegian company had been working to position itself as an FLNG player and took a $37- million writedown on its Q4 2015 earnings as result of its decision to abandon FLNG.

At the end of March 2016, Australia's Woodside said it would indefinitely delay its 10.8 MTPA Browse FLNG project, which was expected to use three FLNG units. The company blamed an economic environment unsuitable for a major LNG investment. The announcement came a week after supermajor


***Prelude*'s massive turret sets sail for South Korea.**
Photo from Shell.

Shell and Japan's Inpex said they would delay any investment decision on the 7.5 MTPA Abadi FLNG project in Indonesia until at least 2020. The decision came as the Indonesian government said it wanted the plant to be built onshore, which the project partners consider a more expensive option.

FLNG schemes account for four of Australia's six shelved projects, with potential volumes totaling about 24 MTPA compared with about 13 MTPA for Australia's canceled onshore capacity. It mirrors similar problems around the world, with half of all export developments — both onshore and FLNG — being canceled or delayed. Canceled FLNG projects amount to some 40 MTPA of capacity, dealing a significant blow to the progress of the nascent sector.

## Some bright spots

Hope still remains for floating liquefaction, and such is the case with Iran. Iranian officials are negotiating with international companies to sign a contract with Iranian Offshore Oil Co. and Nogam Oil and Gas Co., a subsidiary of Bank Mellat, to build an FLNG and tap the associated gas capacity of the Forouzan oil field in southern Iran. So far, that gas has been burned off through flaring at a rate of 200 MMcf/d of gas.

In February of this year, Italy's Eni reported that its plan to develop the 16 Tcf Coral gas discovery off Mozambique, in Area 4 of the prolific Rovuma basin, had been approved by Mozambique's Council of Ministers. Eni called the plan's approval a fundamental step toward FID. The plan for phase 1 development includes drilling and completing six subsea wells and building and installing a 3.4 MTPA FLNG facility. Eni aims to sell LNG from the facility to supermajor BP.

## Conclusion

Both onshore and offshore liquefaction projects in Australia, Canada and the US, among others, have been scrapped, delayed or just quietly forgotten as developers shift priorities, cut development budgets, and cancel or delay FIDs as they try to weather the downturn in the commodity cycle at the expense of sanctioning new LNG developments, while maintaining dividends.

Together, Shell, Golar LNG, and Petronas have ordered seven FLNG vessels that can process a total of up to 13 MTPA. Exmar, which holds two FLNG options expiring at year-end at China's Wison shipyard, must find a new home for its FLNG project. It was originally destined for Colombia but since Colombia's gas outlook shifted to a need to import LNG by 2017, the FLNG unit is now homeless. The slowdown in making such long-term decisions based on relatively short-term factors could ultimately result in an excessively tight market within five years or so, with supply again trying to catch up with demand once existing production and that which is under construction is absorbed by consumers. **OE**

***Laurentino Rangel** is a Houston-based LNG and shipping analyst for Poten & Partners. He joined Poten in 2014, and has been involved in a number of LNG shipping studies, country specific natural gas balances for Latin American countries, and EPC monitoring of a Gulf Coast export facility on behalf of the lenders.*

# Making **room**

**Choosing the right FLNG topsides equipment can be a complex process. Audrey Leon reports on some of the solutions presented by Black & Veatch at this year's Offshore Technology Conference.**

**Top – The Carribean FLNG unit.** Photos from Exmar.
**Bottom – The unit was previously built for Pacific Exploration & Production to operate offshore Colombia.**

Operators are looking to floating liquefied natural gas (FLNG) solutions to help bring uneconomic gas reserves to market. In a paper presented at this year's Offshore Technology Conference (OTC) in Houston, Javid H. Talib, of Black & Veatch, discussed some of the challenges faced during FLNG topsides equipment selection before presenting some solutions.

There are many challenges associated with offshore production facilities. Deck space is often limited and then there are weight considerations, not to mention the severe weather and motions in open sea conditions floating systems are often subjected to.

FLNG facilities also need to have some level of complexity (which also comes with more expense) to process raw gas, unless they're lucky enough for it to be very dry. Therefore, Talib told an OTC audience, FLNG topsides equipment needs to be more flexible and should have a smaller footprint. "Everything goes back to weight and cost," he said.

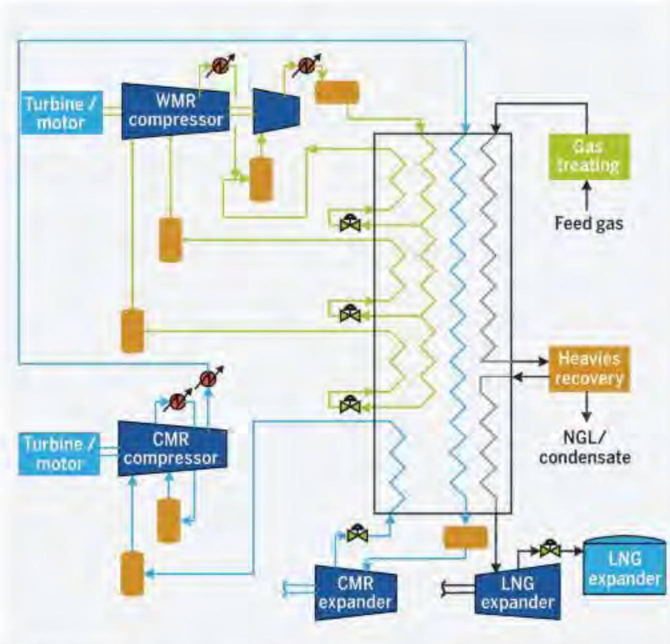
The size and scale of liquefaction facilities depends on the reservoir size and also the LNG export (volume) strategy, Talib and his co-author Bob Germinder, wrote in their OTC paper, "Game-changing floating LNG solutions" (OTC-27182-MS). They wrote that, in general, a 1 Tcf gas reservoir will supply gas for producing LNG at about 1 MTPA for 20 years. Reservoirs containing 1-4 Tcf reservoirs are considered small, requiring small-to-midscale range (0.5-4 MTPA) liquefaction production capacities.

To make FLNG viable, the liquefaction technology should be proven, reliable, space-efficient, and simple to operate, Talib says. He compared two technologies: single mixed refrigerant (SMR) and dual mixed refrigerant (DMR). He said that the SMR process is the best fit for small-to-midscale offshore liquefaction operations, while DMR can provide the option of higher LNG production in a single larger train for midscale applications, according to the OTC paper.

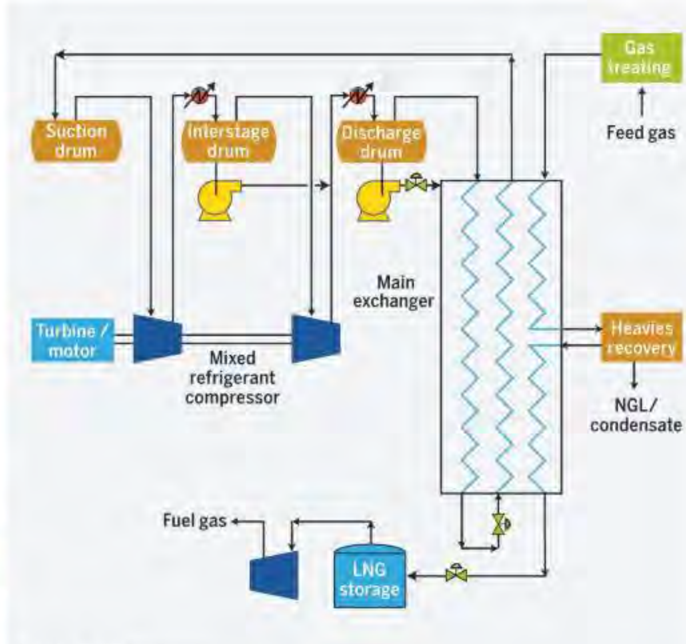
Black & Veatch has its own SMR and DMR options under the PRICO product line.

### Advantages of PRICO-SMR

- Single refrigeration system; no series systems
- Reduced equipment count
- Compact layout
- Single module for entire liquefaction train
- Simplified operation
- Modular philosophy and process concerning available drivers
- Small refrigerant inventory
- No venting of refrigerant during shutdown
- Application across a broad range of plant sizes
- Efficiency competitive with baseload systems
- Use of a single body compressor
- High turndown ratio
- Economies of scale
- Quick startup after shutdown
- Lower capex and opex




**PRICO-DMR process.** Illustrations courtesy of Black & Veatch.




**PRICO-SMR proces.**

PRICO-DMR, according to Talib, has the same functionality as SMR, with two mixed refrigeration circuits and four brazed aluminum heat exchanger zones contained in either one or two cold boxes. Equipment would include a warm mixed refrigerant compressor, a cold mixed refrigerant compressor, refrigerant expander and a LNG expander.

Talib said that DMR, paired with a compact layout, is an optimal solution for single, larger train FLNG applications because the brazed aluminum heat exchangers minimize motion concerns, while requiring fewer components to be stored for refrigerant makeup.

According to Talib and Germinder's paper, the exchange works by pressure feeding the vapor refrigerant to multiple cores through a header, while the liquid refrigerant is pumped into the cores and independently controlled. The pressurized refrigerant flows through passages in the core unaffected by the position or motion of the core. This process, the two authors said, eliminates the possibility of any maldistribution of refrigerant fed to multiple cores.

While comparing the two options for midscale FLNG, Talib noted that larger trains can offer economies of scale (thereby reducing capex) and a reduced footprint, but less operational flexibility. Talib told the OTC audience that choices around equipment will be limited with longer delivery periods, which could potentially affect the economies of scale.

The smaller trains, while having fewer economies of scale, offer their own benefits. "Smaller trains offer operational flexibility, easier startup, and when one shuts for maintenance the others keep producing," he said, which means annual maintenance can be staggered. He also noted that with multiple smaller trains, you have a wider selection of fabrication yards and suppliers.

## Projects underway

Black & Veatch has a number of projects underway, including Exmar's Caribbean FLNG, which consists of a simple barge with five-day LNG storage that is supplemented with a separate floating storage unit. The vessel's main features include one, 0.5 MTPA PRICO liquefaction train, a GE LM2500+ gas turbine driver, refrigerant compressor with interstage cooling using seawater, a brazed aluminum heat exchanger for the main refrigerant exchanger, gas treatment and dehydration modules to remove $CO_2$ and water, and a boil off gas handling module. The vessel's hull is 140m-long with 16,500cu m storage.

However, the Caribbean FLNG project is currently in turmoil. Earlier this year, Exmar terminated an agreement with Pacific Exploration & Production after the company delayed project startup in early 2015. Back in 2012, Exmar was contracted to build, operate, and maintain the unit, which was meant to serve the La Creciente field in Colombia's lower Magdalena Valley basin. Wison Offshore and Marine's fabrication yard in Nantong, China, was chosen to construct the vessel. Exmar is looking for other employment opportunities.

Black & Veatch is also involved with the Golar GoFLNG conversion of the *Hilli Moss* LNG carrier, for Perenco's Cameroon FLNG project. The vessel, delivery planned by Q1 2017, features four 0.5-0.6 MTPA PRICO trains, pre-treatment, liquefaction, boil-of-gas, and heat recovery steam generator, a GE LM2500+ G4 turbine/compressor, brazed aluminum heat exchanger, and seawater interstage cooling. Other projects in the pipeline include Golar's *Gimi* and *Gandria* GoFLNG conversions planned for mid-2018 and Q1 2019, respectively. **OE**

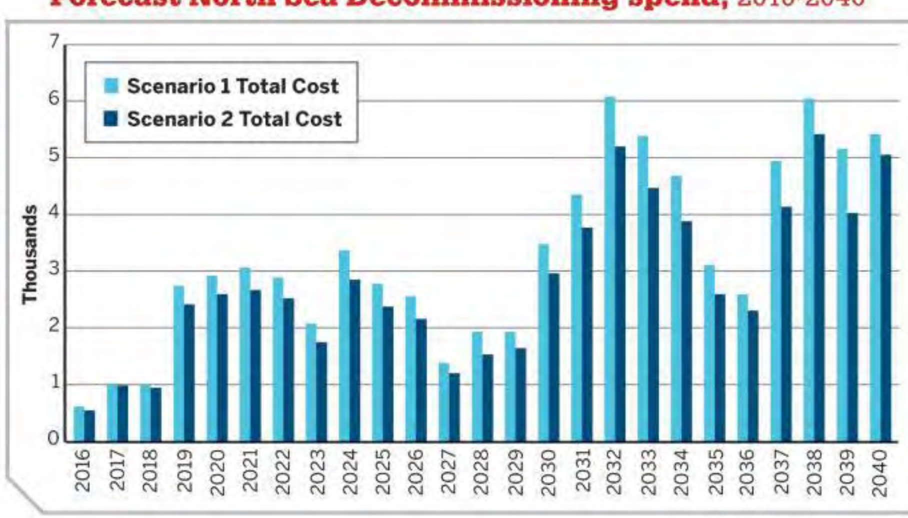
## FURTHER **READING**

**Ophir's Fortuna FLNG project** on page 16.

# North Sea opportunity knocks

**The UK North Sea is expected to dominate the decommissioning market from 2016-2040. How much it will cost depends on the success of vessels such as Allseas' *Pioneering Spirit*, says Douglas-Westwood's Ben Wilby.**

**Forecast North Sea Decommissioning spend,** 2016-2040




Graph from Douglas-Westwod.

The oil price downturn has substantially impacted companies across the oil and gas sector. Often firms have been affected negatively, but there are many who stand to benefit from the downturn – particularly those with exposure to potential decommissioning work in the North Sea.

Large-scale decommissioning in the North Sea has been expected for a long time, yet, in recent years, activity has been minimal. The current climate has accelerated decommissioning timeframes and long-term drivers are unlikely to change soon.

For abandonment and decommissioning, it is not that oil prices are low, but how long they are forecasted to stay low that will drive large-scale decommissioning. Once projects are operational, operators take a long-term view of the market, as fields will be producing for a number of years. Therefore, when there is a sustained period of low prices, operators will assess operating costs and their impact on future projects, often making abandonment and decommissioning preferable.

This is especially true in the North Sea where much of the infrastructure is dated and production is in decline. Operators have to pay for costly


The *Pioneering Spirit* at D-quay at Daewoo Shipbuilding and Marine Engineering's Korean yard. Photo from Allseas.


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

maintenance and enhanced recovery techniques that simply do not make sense at low oil prices.

A recent example is the Athena field in the UK, utilizing a leased floating production, storage and offloading (FPSO) vessel. The field was considered non-commercial in 2015, when Brent was around US$50-60/bbl. Despite a contract renegotiation to lower the vessel's dayrate, when prices dropped to below $30/bbl in early 2016, the operator decided on early field abandonment. This situation is expected to become increasingly common over the next few years, particularly in the North Sea.

Douglas-Westwood's recently released North Sea Decommissioning Market Forecast 2016-2040 considers the potential market for decommissioning in the UK, Norway, Denmark and Germany. The costs for decommissioning have been forecast in two different scenarios.

Scenario 1 is a "business as usual" forecast and assumes that current methods for platform removal remain in use. Scenario 2 however, considers the potential impact that single lift vessels (SLVs), such as Allsea's *Pioneering Spirit*, could have on the removal of extra-large platforms, which are platforms over 10,000-tonne. It should be noted that scenario 2 is indicative of the cost savings SLVs could represent rather than our expectation of the market.

Over the period 2016–2040, Douglas-Westwood expects spend on decommissioning in the aforementioned countries to be worth $82 billion in scenario 1 and $70 billion in scenario 2 – demonstrating the savings that SLVs could represent.

The UK will see the largest proportion of this spend, accounting for $50 billion in scenario 1, and $44 billion in scenario 2. This is due to the large amount of installed infrastructure as well as the age of platforms, with many past their design life (typically 15-25 years). Norway will account for the majority of the rest of spend – $27 billion in scenario 1, and $23 billion in scenario 2.

## Setting the standard

The Allseas vessel *Pioneering Spirit* is able to remove topsides up to 48,000-tonne and jackets up to 20,000-tonne in a single lift – making it ideal for some of the large platforms in the North Sea. It will be the first SLV in operation when it begins work, beginning with the Yme platform off Norway later this year. The entire platform, which weighs 12,400-tonne will be removed in a single lift. This will be followed by the removal of the Brent field topsides, which weigh over 20,000-tonne each. This project is expected to be key in demonstrating the capabilities of the vessel to other operators.

A large amount of preparation has gone into readying the topsides for removal, with additional steel installed to ensure that the topsides maintain structural integrity during the lift. As a result, we do not expect the vessel to be awarded any further contracts until this project has been successfully completed. Even then, it will require a high rate of reliability and a low, competitive dayrate to even be considered as an option for further decommissioning work.

Allseas is confident in the technology and is already planning to build another vessel with an even greater lift capacity. The vessel, currently known as *Amazing Grace*, is still in the planning phase, but could enter the fleet in the early part of the next decade. If this vessel is commissioned, Allseas is likely to corner much of the potential market for SLVs, as there are a limited number of platforms that are appropriate for the single lift approach.

## Well decommissioning

Well plugging and abandonment (P&A) work will represent the majority of decommissioning expenditure. We forecast about $48 billion in spending – making up over half the total cost in both scenarios.

Expenditure will be split between surface and subsea wells. Surface wells represent 74% of the wells to be P&A'd, with a cost of $21 billion. Subsea wells, despite being only 26% of all wells, will see comparatively higher expenditure at $27 billion. This difference is a result of the additional number of days required on subsea wells as well as the specialized vessels and equipment that is unique to them.

The subsea market is expected to be a major opportunity for subsea P&A companies. If these firms can establish a strong reputation in the early round of decommissioning, there is likely to be sustained demand throughout the coming decades. Douglas-Westwood expects a total of 7800 wells to be removed by 2040 – almost 2000 of which, will be subsea. **OE**

***Ben Wilby** is an analyst at Douglas-Westwood and the author of the North Sea Decommissioning Market Forecast. In addition he has authored Douglas-Westwood's' Subsea Hardware, FLNG and FPS reports. He holds a BA in history from the University of Chichester.*

# Put a plug in it

**ConocoPhillips is working to plug and abandon 130 wells in the southern North Sea, reducing the number of days it takes as it works through the program. But, it wants to improve further, Elaine Maslin reports.**

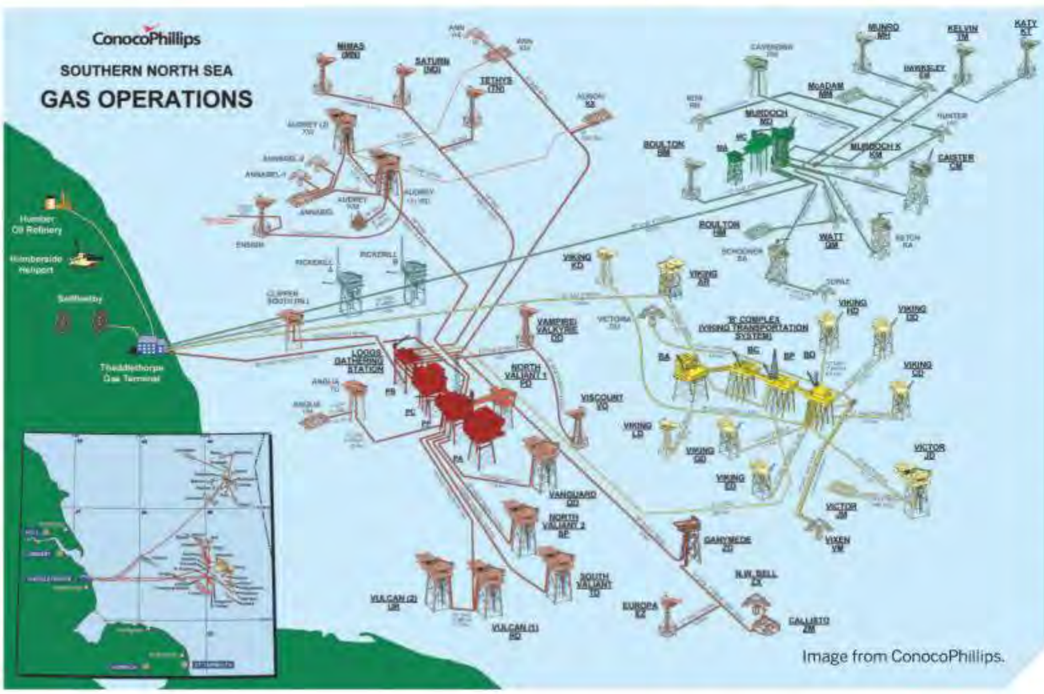



Image from ConocoPhillips.

ConocoPhillips has been learning by doing as it gets through some 130 well plugging and abandonment (P&A) operations in the southern North Sea.

The firm has been making incremental improvements as it works through the Viking area and the Lincolnshire Offshore Gas Gathering System (LOGGS) field wells, some dating back to the 1960s.

Over 18 months it has abandoned 24 wells. In that time it has reduced the average number of days per abandonment from up to 32 on the first three wells, to a 22 day average across all 24 wells, by learning from each operation and applying those lessons to the next. But, it wants to make further gains and reduce the average time to under 10 days. "To do this, we will need more than incremental improvements – we will need transformational technologies," said Andrew Hutchison, well abandonment technology team lead for ConocoPhillips UK, at the ITF Energy Showcase in Aberdeen earlier this year.

ConocoPhillips has a large portfolio of mostly unmanned satellite platforms in the southern North Sea, off the east coast of England. The company's P&A campaign in the area started in June-July 2014 in the Viking area, which comprises of late 1960s through to 1980s wells, including production, exploration and appraisal wells from seven normally unmanned platforms plus one manned complex. The first Viking field was discovered in 1968, with first production in 1969. Typically, they are dry gas wells, with 9-5/8in casing with 7in liner, with completion string 5½ x 4½in.

Today, ConocoPhillips' P&A operations are ongoing in the LOGGS area, with wells dating from the 1980s, and once they are completed, the company will move on to the Caister Murdoch System (CMS) area.

An initial problem on satellite platforms is that deck space for equipment is limited and it is hard to P&A wells without using a jackup drilling rig. This means the focus has to be on how many days it will take to P&A a well, thus reducing the number of the days the drilling rig is needed.

"To complete an abandonment, and prevent fluids coming to surface, there needs to be permanent barriers from "rock to rock" across the full cross-section of the wellbore," Hutchison says. "Just pumping cement down the tubing isn't deemed adequate because you cannot guarantee a good cement bond all the way around the tubing, which could create a potential leak path up the 'A' annulus."

ConocoPhillips has been punching the tubing and bull heading the "A" annulus and tubing content into the reservoir, then setting temporary tubing barriers. This allows the Xmas tree to be removed, the blowout preventer (BOP) set and the completion to be pulled from the well. Once the completion is out, a logging string is run inside the casing to analyze the quality and quantity of the "B" annulus cement.

"At the moment, this cannot be done without first recovering the tubing," he says. If adequate cement is found, a permanent barrier can be set by using a mechanical plug and placing a large cement plug on top of it, adjacent to the reservoir cap rock. But, if the annulus isn't adequately isolated, i.e.

to 100ft in length as per guidelines, a 100ft window has to be section milled to remove 100ft of casing adjacent to the cap rock. This allows poor cement and the inadequate isolation to be repaired by exposing the formation and setting a cement plug from "rock to rock."

"To mill a 100ft window in 9-5/8in casing you are not going much more than 3-3.5ft/hr if you are lucky," he adds. "So you are 30 hours on the bottom and that doesn't include swarf management. Typically, you are looking at 4-5 days to mill each window." It's a problem that the industry is seeking a solution for (*See story on page 38 about plasma milling*).

ConocoPhillips has substantially reduced the amount of time taken to perform these operations. The company has gone from 26-27 days per well on the first, three-well satellite, which was abandoned, to an average of 42 days per well on the second three-well satellite. There was one troublesome outlier that ended up pushing the average up much higher However, the rate then steadily improved to 15 days per well on the last satellite, setting an average of 22 days per well overall, including conductor recovery and pulling the tubing.

But, they want to reduce this time per well even further. "We can continue to apply lessons learned, and we are doing that well, but a transformational technology would radically change the way that wells are abandoned," Hutchison says.

One transformational technology the company is searching for would allow analysis of the "B" annulus cement, while leaving the tubing and tree in-situ.

"Some companies are looking at a solution to the 'A' annulus problem, by cementing the tubing inside the casing without leaving a channel, but we still don't have a product to see through two tubing strings to see if we have isolation in the 'B' annulus," Hutchison says. "Even if we did, if we logged before the rig arrived and found it to be poor, we would still have to mill the window," an operation which involves rigging-up into the well with intervention equipment, removing the tree, installing the BOP, etc.

"If we could find a solution that would allow us to keep the tree in place until we have to cut the conductors beneath the mud-line, this would be a game changer for the industry." OE

**The GMS Endurance jackup.**
Photos from GMS.

# Mud, glorious mud

**The day grab used in the 2013 survey.**
Photos from Gardline.

**How to deal with drill cuttings piles as part of the decommissioning process has been a subject of study for some years. Meg Chesshyre examines how North West Hutton may show the way forward.**

Complete seabed recovery of the surface sediments from within 100m of North West (NW) Hutton drill cuttings pile could be possible by 2028, if recovery continues at the current rate, says Marion Collin, senior environmental report writer with survey firm Gardline Environmental.

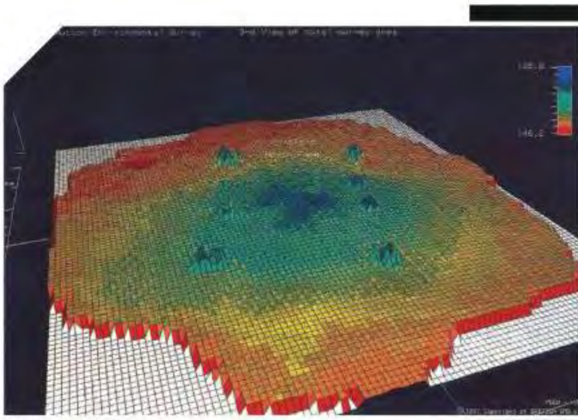
The NW Hutton platform, in block 211/27 in the East Shetland basin, was decommissioned between 2008 and 2010.

A total of 53 wells had been drilled on NW Hutton, operated by BP, using oil-based drilling fluids (OBM), including diesel OBM until 1984; then lower-toxicity kerosene OBM until 1991. Before 1992, all drill cuttings were disposed of at the seabed, resulting in a cuttings pile about 31,000cu m in volume (200m x 150m x 5.5m).

BP's most recent seabed survey was carried out in 2013 from 30 stations using a 0.1sq m day grab, following surveys in 1992, 1997, 1999, and 2002. The objectives of the latest survey included gathering a baseline of the environment post decommissioning activity to fulfill the commitments within the decommissioning plan, to assess the natural recovery of the seabed over time and the reducing footprint of BP's operation, and to assist regulatory discussions on the close out of BP activity at the site and to determine the future plans for longer term monitoring.

Collin, speaking at the Oceanology International conference in London this spring, said the 2013 survey had a "smart, efficient, intelligent, survey design." In addition to tracking declining hydrocarbon and barium concentrations over time, she described samples involving two fauna indicator species collected at all stations along the northern transect – Capitella capitata, a polychaete worm, hydrocarbon tolerant, highly opportunistic with high abundances often found in and close to cuttings piles, and Owenia fusiformis, another polychaete worm, which is hydrocarbon intolerant.

Capitella capitata, the hydrocarbon-loving worm, was found in very high abundance 500m from the platform in 1992, but by 2013, was only present in quite low numbers only 100m from the platform site. By contrast, Owenia fusiformis, the hydrocarbon intolerant worm, was only visible in fairly low abundance 800m from the platform



**The mud pile.** Image from Gardline.

**A Capitella capitata worm.** Image from MESL.

in 1992, but was in 2013 in much higher abundance from 200m from the platform.

Collin concluded that recovery of seabed surface sediments can happen in decades, not thousands of years, and that this can see a return of macrofaunal communities. Long-term monitoring to aid decommissioning strategies should thus be seen as having value. Also, by leaving parts of the seabed infrastructure and cuttings in place, further disturbance to the environment could be eliminated and allow for faster recovery.

Moving forward, Collin said that collaboration on surveys or survey cruises would save cost/time and make results and data more consistent across operators. It would also permit regional surveys, which would give an idea of the background environment. "If we don't know what the environment is supposed to be like, how do we know if it is contaminated or if is recovering," she asked. **OE**

# Plasma power

**Elaine Maslin reports how Slovakian company GA Drilling hopes to make short shrift of section milling using a plasma-based downhole tool technology.**

**Assembly of a plasma testing prototype.** Photos from GA Drilling.

Section milling is a time-consuming operation often required as part of plugging and abandonment (P&A) operations. Section milling often has to be carried out when there is uncertainty over the annular cement in the well, which has the potential to cause flows, cross flows, or seepage of water, gas or oil.

To avoid such risks, section milling is used to remove casing and cement to allow placement of new isolations, as part of the P&A process. A 50m section could take more than 10 days to mill, GA Drilling says.

Standard milling operations currently involve removing the wellhead and the Xmas tree, then pulling the production tubing, before deploying a section milling tool, often requiring a sizeable and costly rig. GA Drilling says its solution, Plasmabit, will be able to mill out sections of tubing or casing, without having to remove wellheads, Xmas trees or production tubing.

"You can mill away the part of the production tubing you want milled," says Tomas Krištofič, CTO, GA Drilling. "The advantage is that you do not need a rig. Using a coiled tubing type approach is another advantage because you don't need to pull the production tubing out of the well."

The tool, which could be deployed using a light well intervention vessel, uses a non-mechanical rotating electrical arc, with up to 800 revolutions per second, to create a plasma which will fragment steel, cement, rock or other material, in the well.

The plasma arc is created by passing electricity through a plasma forming media, typically water, which is heated to 3000-6000°C. Hydrodynamic and magnetic forces are then used to either radially or axially direct the plasma arc, for either milling or drilling operations, respectively. The impact and speed of disintegration is computer controlled.

During tests on simple and

**Casing and cement string after plasma milling testing.**

multi-string casing samples in brine environments, a 3½in tool was able to mill a range of casing sizes including 4½in, 5½in and 7in. Rate of penetration was achieved at similar rates to traditional section milling techniques, but because one tool can mill various casing dimensions, tripping time is reduced. Testing also found the tool could mill carbon steel as well as steel alloys without significant difficulty.

The operation generates a finer powder, compared to the swarf created in traditional milling, he says. Fluid management is integrated within the Plasmabit device, which also has a movement and anchoring sub-assembly, which can also enable milling of wider diameters.

"We are also able to deliver and generate the energy needed continuously, which is different to the thermite reaction solutions currently offered by others," Krištofič says. In the next two years, GA Drilling intends to trial the technology onshore before running offshore field tests in early 2018, with offshore operational deployment planned for 2019.

"We are structurally changing the whole process," says Igor Kočiš, CEO. GA Drilling was founded by Krištofič and Kočiš, who worked together in embedded systems and IT system security. After selling their previous company, they looked for a new challenge, setting up GA Drilling in 2008, which initially focused on the geothermal energy sector.

Geothermal energy has had a big impact in places like Iceland and Slovakia. But, because you have to drill very deep to get the temperatures needed, it can be costly. GA assessed various technologies, including laser drilling and water jetting, but chose plasma, opting to build laboratories and testing facilities to develop and commercialize the technology. At the end of 2012, after four years' testing, it presented its first working prototype.

At that point, GA Drilling realized the technology could have other applications, Kočiš says. In 2013, the firm launched a joint industry project with a number of operators and service companies. By 2014-15, the first priority application for the technology was identified – section milling for P&A operations.

Work is ongoing. GA Drilling is looking at two different conduits to take the tool to the work site – either coiled tubing or a hybrid cable, which could perform in downhole conditions. The hybrid cable would contain a fluid line and electrical and fiber optic elements for power and data transmission.

In March, GA Drilling opened an office in Aberdeen, as it looks to grow its P&A services. In 2015, the firm created an advisory board including Nigel Jenkins, previously CEO of industry body Decom North Sea, as its decommissioning, commercialization, strategy and growth adviser; Mikhail Gelfgat, a wells and drilling expert previously with Weatherford, and former Shell senior well abandonment and intervention engineer Iain Pittman. Longer term, the firm anticipates the technology will be a solution for geothermal well drilling. But, it has also been looking at options for well stimulation and even temporary wellbore stability enhancement. OE

## WATCH

**GA Drilling presents this video clip demonstrating how the Plasmabit tool works, watch it on OEDigital.com:**

http://ow.ly/RKow300JzHP

# Cement goes digital

**A Brazilian combo is hoping to make evaluating cement through tubing less of a headache with its new software.**

**Samuel Tocalino (left) and Gustavo Longhin.**

Trying to assess the integrity of cement behind casing is an ever and increasingly present challenge for the industry, especially as it looks to determine which sections in wells have enough integrity to enable plugging and abandonment operations.

Brazilian firms Adest and SimWorx, based in São Paulo state, have been working together to develop CementFinder software, which could help make this challenge a whole lot easier.

Adest's founder, Samuel Tocalino, presented the technology, which the partners hope will reach a market readiness level in three years, at the ITF Technology Showcase in Aberdeen earlier this year.

"Until recently, it was common practice to run cement evaluation logs only in the final production casing or liner. Intermediate or surface casing cement isolation was measured by much less precise methods such as pressure indications," he says.

"To meet modern environmental and safety regulations, the operator of wells to be permanently plugged and abandoned must ensure authorities that all cement isolations are competent, from the hydrocarbon-bearing reservoir to surface aquifers, an indication only possible with dedicated log runs," Tocalino says. To do this could mean having to remove the production tubing to expose the casing, an operation that requires a rig and the resulting day rates costs. "In wells to be decommissioned, the old production tubing can be corroded or stuck adding more time, cost and hazards to the operation," adds Tocalino, who worked at Schlumberger for 14 years before founding Adest.

CementFinder is being designed to allow for precise interpretation, in real-time, of data produced from traditional acoustic logs, both in the sonic (cement bond and variable density Logs) and ultrasonic (rotating or radial pad tools) ranges during through-tubing runs.

"In traditional through-casing runs, acoustic wireline tools emit sonic waves and capture the casing returns. Attenuated returns indicate good cement-to-casing bond while strong responses indicate micro-annuli, channelling or absence of cement, i.e., poor hydraulic isolation between different zones," Tocalino says.

"In through-tubing log runs, the initial and stronger returns are from the free production string reflections followed by noise, a multitude of reflections on multiple surfaces (casing, formation, etc.), still lacking the dedicated examination to be provided by CementFinder."

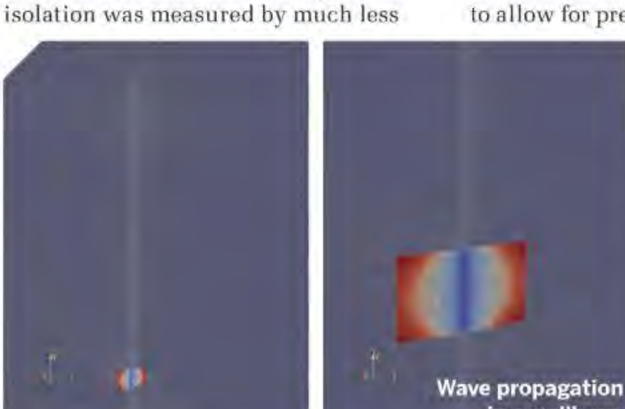
CementFinder interprets through-tubing cement log data sets to identify casing reflections within the recorded noise and their attenuation levels indicating the presence of cement and well integrity giving operators and authorities the needed insurance.

"Its development starts with recreating typical wellbore configurations in a computer simulator incorporating variables like acoustic wave properties, multiple tubular strings, eccentricities, cement and fluid densities, background noise, allowing for the precise definition of the casing returns and cement quality indicators in a through-tubing cement log run, i.e., what to look for among the noise," explains Gustavo Longhin, a co-founder and projects director of SimWorx Engineering Research and Development.

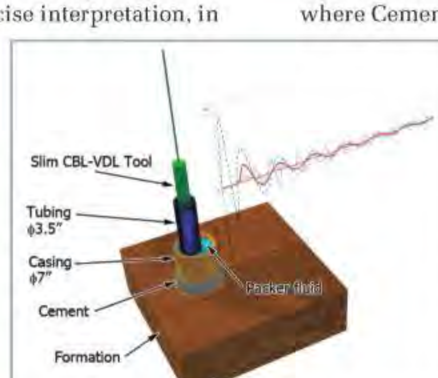
Then powerful noise filters and pattern-search (data mining, association and clustering) algorithms are applied to the log data to identify the expected casing returns and attenuation levels corresponding to adequate isolation or not.

"This approach will lead the way to rigless decommissioning campaigns where CementFinder confirms a good primary cement job and restricts expensive rig operations to the cases where repairs are advised," Tocalino says.

CementFinder can also be used to measure the cement's final compressive strength, by combining ultrasonic log data sets with traditional pulsed echo technology. **OE**



**Wave propagation in a wellbore.**




**CementFinder illustrated.** Images from Adest.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# Propelling subsea innovation

**Jerry Lee takes a look at Bastion Technologies' PYRO-Accumulator, which could potentially help meet requirements laid out in BSEE's new well control rules.**

Two 7gal, 10,000psi rate PYRO-Accumulators
Photos from Bastion Technologies.

Gas charged accumulators are widely used as the hydraulic power source for subsea blowout preventers (BOPs). To compliment these conventional accumulators, Bastion Technologies has developed a PYRO-Accumulator, which uses a solid fuel source, like the booster rockets used to send vehicles into space, instead of gas.

Conventional accumulators use pressurized gas to deliver the hydraulic power used to actuate a BOP. Bastion's technology burns a solid propellant charge made of fuel and an oxidizer, PYRO, to produce a gas that provides hydraulic power.

The PYRO-Accumulator is composed of a gas generator (pyrotechnic section), a piston, and a hydraulic section. The propellant charge and igniter are housed in the pyrotechnic section, and a discharge port is located at the end of the hydraulic section opposite the piston. To provide hydraulic power, the igniter initiates a controlled burn of the propellant. As the propellant burns, hot gas is rapidly produced, which drives the piston and compresses the hydraulic fluid held in the hydraulic section. The fluid is exhausted through the discharge port, which is connected to the BOP, to actuate the BOP.

PYRO-Accumulators are capable of producing over 10,000psi of pressure, and over 100 gal/min flow rates. The propellant charge can be reloaded, has a service life of 10 years, and if greater pressure is required, more propellant can be loaded. In addition, the critical systems, including the electronic control unit, are dual string, which can achieve a reliability of 99.99% and a Safety Integrity Level of 4 (1 being lowest). Higher reliability can be achieved as more strings are added.

The technology can be used in failsafe subsea or land applications as a power-source for BOPs or operating valves.

### Conventional vs PYRO

For decades, nitrogen accumulators have sufficiently functioned as a subsea hydraulic power source. However, as operators develop fields in deeper waters, the efficiency of conventional accumulators decrease; they are capable of delivering less of its hydraulic fluid capacity. As depth increases, the subsea pressure the rams need to overcome increases, and the temperature decreases.

"Since conventionals are charged with gas on the surface, where temperatures may be over 100°F, when the accumulators are lowered to seabed, where temperatures can be 32°F or even lower (due to pressure of seawater), the gas cools, reducing the gas pressure available for use by as much as 20% or more," says Nazareth Bedrossian, Bastion Technologies' director for oil and gas. "Also, because BOP's must be closed quickly, conventionals undergo a rapid adiabatic discharge that reduces its temperature, and the pressure of the gas available to pressurize the hydraulic fluid. In deepwater, it is not uncommon for a 15gal capacity conventional accumulator to only provide 0.5gal of usable fluid."

In addition, because the pressure is stored in a gas, they need a hydraulic capacity that is multiple times the usable fluid volume they can deliver subsea. In order to deliver the hydraulic fluid required by the BOP, more accumulators need to be added, which increases the weight of the BOP stack.

PYRO-Accumulators, on the other

hand, are designed to always deliver 100% of their hydraulic capacity regardless of depth. Because of the 100% efficiency, the PYRO-Accumulator weighs 70% less and has a smaller footprint than comparable conventional accumulators, Bedrossian says. As energy is stored in a chemical reaction it can generate 200% or more hydraulic pressure. It also provides built-in water depth compensation.

Conventional accumulators also require topside equipment to operate. Not only does this take up valuable space on the rig, but a technician is required to operate it.

The PYRO-Accumulator does not require surface equipment, umbilicals, or a subsea support system. This, and the capability for direct connection to the shear rams, removes two sources of hydraulic losses, which allows the rams to shear pipe 50% faster, Bedrossian says. Additionally, the power source is self-contained and on-demand, and only requires a 25V subsea battery to remain operable. The system can be activated by acoustic signaling, a pre-programmed pressure switch, or an electronic command for fail-safe applications or when intermittent power is needed.

### RPSEA

In 2014, Bastion presented the technology to the Research Partnership to Secure Energy for America, (RPSEA), of which it is a member, for funding and was rated highly by the ultra-deepwater program advisory committee.

"Shear ram BOPs are the toughest to work, and require a lot of energy. Having the energy source at the wellhead instead of coming from the surface was something we were very interested in," says Bill Head, ultra-deepwater program manager, RPSEA. "And, if the PYRO-Accumulator was not being used as an energy source, it could be used as a safety release for possible casing gas buildup. This thing is a safety device that needs to be developed," he says. "It's smaller, stronger, and can be autonomous."

Bastion continued the development of this technology, going to Seattle, Washington, for testing earlier this year. Using two 7gal PYRO-Accumulators to actuate a 13.625in blind shear ram with 3000psi working pressure, the objective was to shear a 20.8lb/ft pipe with a 5.56in outer diameter, and .375in thickness. Within 9 seconds, the PYRO was ignited, sheared the pipe, and the rams were at 100% stroke. The test was also witnessed by three BSEE representatives.

"Now we know it will work, so we (Bastion and RPSEA) are trying to do research to make it better, more autonomous, stronger, and safer," Head says. "We're developing a JIP (joint industry project) with Bastion to try to get the prototype testing funded."


Cut pipe from the February demonstration.


Propellant section being loaded.

### Offshore applications

Many BOPs are older and have been in operation for years (although they have to be inspected once every five years per API 53). For operators interested in redundancy or automation, the PYRO-Accumulator is focused on providing enough energy for the shear rams when it is needed.

"With some modifications, it could be put on everybody's equipment," Head says.

Earlier this year, the BSEE released its new well control rules, three of which apply to accumulators. The long-awaited post-Macondo revisions now require a dedicated subsea accumulator with the capacity for autoshear and deadman. The PYRO-Accumulator meets these requirements because it does not require a control system, and it can be connected directly to the shear rams.

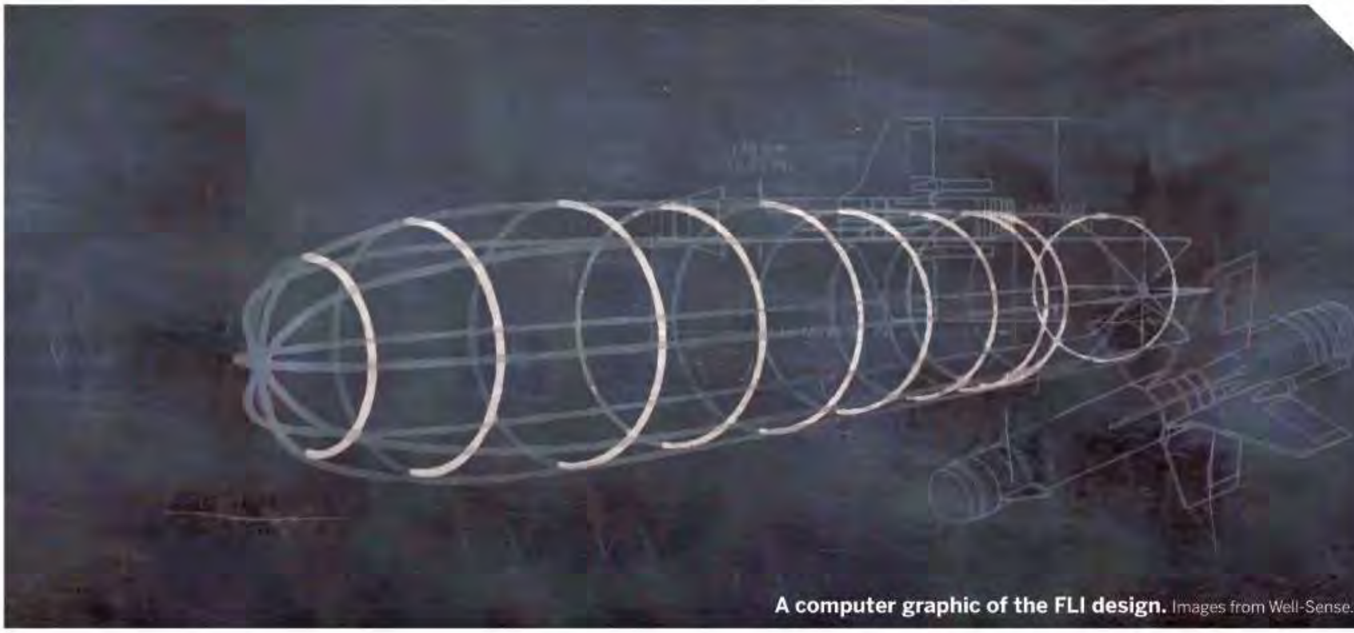
Within five years, BSEE will require the use of dual shear rams in subsea BOPs to shear currently unshearable elements, such as a tool joint. However, with the capacity to generate pressures in excess of 10,000psi, PYRO-Accumulators could address the issue of unshearable elements.

Also within five years, BSEE requires greater accumulator volumes to enable the well control system to close and hold, unassisted, against the maximum anticipated surface pressure while remaining a minimum of 200psi above the pre-charge pressure in the bottle.

"Given the inefficiencies of the conventional accumulators, meeting the new rules with conventionals would be costly both from weight and footprint perspective due to space limitations on BOPs, crane capacity, BOP and rig structural integrity," Bedrossian says. "The efficiency of PYRO-Accumulator to supply 100% of its hydraulic capacity results in BSEE's requirements being met, while providing a cost effective solution as it reduces weight and footprint by 70%."

With one technology, all three rules pertaining to accumulators in BSEE's new rules are met. The PYRO-Accumulator is one of BSEE's STAR technologies; STAR No. 28.

"This technology is on the road to becoming a failsafe device we can rely on as an additional tool, not a substitute," Head says. "We need more testing, and we need to get the industry to see that this is an innovative alternative, which can provide an increased safety margin and a whole lot more reliability." **OE**



A computer graphic of the FLI design. Images from Well-Sense.

# Downhole disintegration

**A new concept in well tools could see one-off tools built, run and left down hole to disintegrate. Elaine Maslin reports.**

Disintegrating downhole tools have been making an impact on the US-onshore business, starting with disintegrating frac balls and more recently completion tools, such as frac plugs and bridge plugs.

The technology follows a trend observed in plastics and in metal in the medical space where implants could be designed to dissolve. The idea is that materials, from plastic bags to high strength metals, on contact with a fluid, such as brine/acid and heat, can dissolve, disintegrate or corrode such that they're not going to cause an impedance in the wellbore, rubbish dump or even the human body.

In the medical space, the concept is being developed using magnesium and iron that is 3D printed into parts, which can be used as scaffold for healing bones, in place of screws, pins, rods or plates currently used.

A newly launched UK-based oil services firm, Well-Sense, is looking to use this technology into the well intervention space, alongside fiber optics, to create a new discipline, says its founder Dan Purkis.

Dan Purkis

The ex-Petroleum Engineering Services and Petrowell inventor's method is called FiberLine Intervention, or FLI, involving a gravity deployed tool which spools out fiber optic cable, linked to surface for real-time data transmission, including video, like some wire-guided technologies outside the industry. Once it has done its job, the tool will disintegrate downhole.

The benefit of a tool that disintegrates downhole is you no longer need topside intervention equipment, such as a coiled tubing, wireline or electric line unit, making it suitable for use on installations with no free deck space or structures that are unable to take extra weight. Components within the tool can also be "off the shelf," as the tool no longer need to withstand long periods of exposure to downhole conditions or be required to be used again.

"If you don't have to take the tool out you don't need anything at the surface," Purkis says. "Leaving tools downhole is seen as a problem. But if it dissolves you could leave it in the well." With a fiber connection to surface, raw data can be transmitted, with no processing required on the tool, minimizing what is required on the tool and meaning very little power is needed.

"All we need is the sensor itself, i.e. a camera or casing collar locator, straight to the optical transmitter," Purkis says. "You could have eight cameras on the tool, two looking down and six on the sides, running on a small battery."

The technology will use magnesium and other light metals, which disintegrate when exposed to certain environments, such as liquids or heat, due to transfer of ions from the magnesium breaking it down. Well-Sense is looking at using magnesium and aluminum.

The "off the shelf" components inside the tool will be protected using a heat shield for as long as they need to be – around 30 minutes to an hour – to let the tool do its job and send the information required to the surface. The heat shield the firm is looking to use will be based on a sacrificial material, a phase change material, which remains a certain temperature as the temperature increases, it erodes as it absorbs the heat energy, like ice in water.

Using fiber means being able to draw on recent distributed acoustic sensing (DAS) and distributed temperature sensing (DTS) technologies, which let you monitor along the full length of the fiber. This could be used to detect leaks or assess sand production down the length of the wellbore and also range-find the device down the wellbore. This would also be cheaper than permanent fiber installation, but also fiber deployed on carbon fiber rods, or fiber in wire, Purkis says.

In fact, DAS work looks set to be the first trial of Well-Sense's technology, with an operator probably in Houston or maybe Alaska, sometime this year, Purkis says.

Of course, there are limitations. Being gravity deployed, there will be wells with an angle at which it will not be suitable – Purkis is developing a new type of tractor to overcome this. And there are some things that won't dissolve – the electronics and the batteries. But, these will leave just small amounts of debris, Purkis says.

He says anything that runs on electric line could be configured to run using this method. And he has plenty of other ideas for its use, such as helping to determine with greater accuracy where wells actually are, which would help plan wells areas where they have been drilled in high density and there's a risk infill wells could connect with older wells. This would be by using an inertial navigation system – which could be bought for $200 off the shelf and is as big as your thumb, Purkis says.

As another example, he suggests using explosives in the tool for well re-perforation. "It's not a tool, it's a new discipline," Purkis says. "We want people to develop their own tools to go on this method."

The technology has been assessed by the Aberdeen-based Oil & Gas Innovation Centre, which then put out a call for expressions of interest to the academic and research community, resulting in Robert Gordon University, Aberdeen, being selected to work with the company on developing the concept. OE

# Payment on results

**TNW is taking a brave step as it launches its new intervention service line. Elaine Maslin reports on the company's new business model – payment on results.**

TNW, set up a few months ago, has launched a subsidiary StimLite to offer well intervention services combining some relatively new technologies, including a green cleaning fluid, radial jetting, and downhole fiber optics, into a 'no results-no fee' package, with joint venture partner Well Services Group.

StimLite will look at manned and unmanned platforms, most likely where there is already a coiled tubing unit on deck. Operations will involve a minicoil, or 5 1/8in coil, with a small footprint, which will apply a green well cleaning fluid, Biosul, to remove to wax deposits.

**Paul Landers**

Biosul is a mix of 13 ingredients from plant fibers, which together dissolve wax from the wellbore and leaves a coating to prevent future wax build up for a few months, TNW CEO Paul Landers says. "Biosul is a fairly new approach to this, rather than using acid," he says. "It has been around a few years in South America in various wells and can be used to clean crude oil tanks."

**Mini-coil installations.** Photos from TNW.

Then radial jetting can be used. As a concept this has been around since the 1980s, but only started to be looked at more in the 2000s. It involves using high-pressure fluid being expelled through a high-pressure hose and a nozzle to drill, in StimLite's case, 100m into the formation. In cased holes, a cutter, or milling tool, is used first to penetrate the casing and cement. Using this technique can both stimulate the well and access missed pay zones, Landers says.

Then, a fiber optic cable, to be provided by a England-based downhole acoustic survey (DAS) company, will be installed downhole to enable monitoring, with the idea to make sure production is increased for at least 12 months. Dutch firm Well Services Group is providing the technicians, minicoil and radial jetting equipment. StimLite has acquired the international rights for Biosul, produced in Brazil and used by Petrobras, according to Landers.

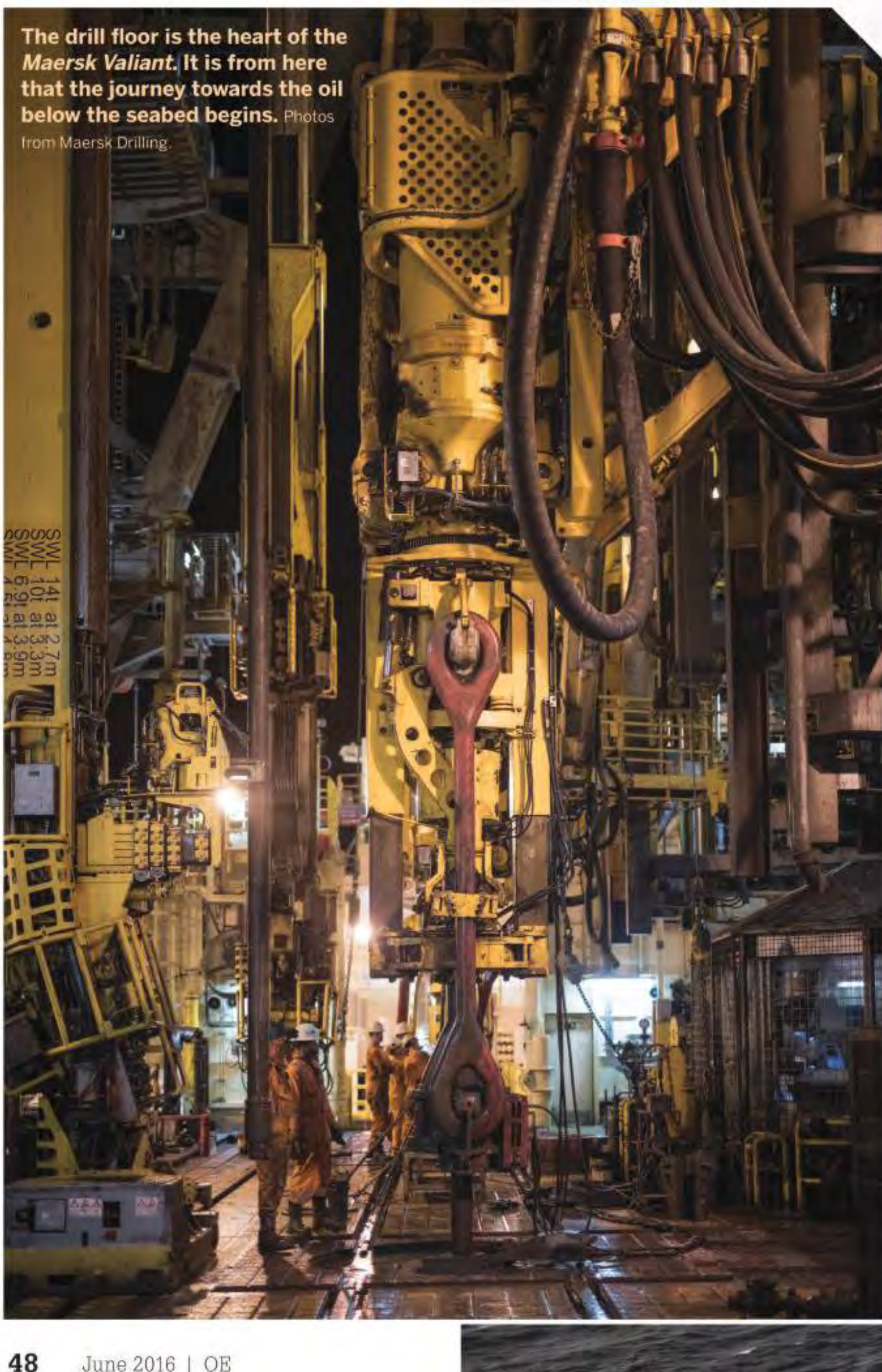
Of course, based on a no production increase, no pay basis, TNW won't want to just take whatever wells the operator throws at it. There would be screening first and wells would be stimulated on a campaign basis, Landers says.

"If we can use new technology to increase production significantly, that's great," says Landers, who has some 30 years' experience in the oil and gas business, primarily in the service sector, but also advising operators and national governments. "But, they [operators] don't have money to spend, so we put together an approach where you come in and intervene in wells, stimulate with green chemical, use radial jetting, and put down fiber optics for ongoing monitoring – and do it for free. If it doesn't increase production, we take the cost. But we're sure the vast majority of wells will increase and we will take a share of the profits."

Across Europe, StimLite will be targeting some 250 onshore wells and more than 700 offshore wells it thinks will be suitable, at a rate of four wells per week onshore and 12 wells a month offshore. It expects to take a share of the extra oil and gas production from a well it has worked for the first year. **OE**

# A 'Valiant' effort

**Jerry Lee discovers how Marathon and ConocoPhillips teamed up to drill difficult deepwater wells in the Gulf of Mexico using a custom MPD system onboard the *Maersk Valliant* drillship.**



**The drill floor is the heart of the *Maersk Valiant*. It is from here that the journey towards the oil below the seabed begins.** Photos from Maersk Drilling.

Managed pressure drilling (MPD) has been an enabling technology around the world, but its presence in the US Gulf of Mexico (GOM) has been lacking. Strict regulatory requirements and unfamiliarity with MPD could contribute to the resistance to its adoption; however, a recent campaign by Marathon Oil and ConocoPhillips (COP) could change attitudes in the GOM.

Dennis Moore, Marathon's senior technical consultant, presented the partnership's challenges and successes at the 2016 SPE/IADC Managed Pressure Drilling & Underbalanced Operations Conference & Exhibition in Galveston.

COP and Marathon partnered on a six-well campaign in the GOM, which saw two deepwater wells drilled in 2015-2016 using an integrated MPD system on the *Maersk Valliant* drillship. However,

**Delivered in 2013, the state-of-the-art drillship measures a total of 228m (748ft).**

the drillship, which was under a three-year contract, did not have MPD capabilities, leading the partnership to invest in upgrading the system.

## Equipment selection

MPD kits for offshore operations are not new. However, the options for MPD equipment on a DP drillship are limited to old technology, and full systems, available through MPD service providers, did not provide the functionality and performance the partnership required. As a result, the decision was made to "cherry pick" all the required equipment and integrate it as much as possible into the existing drilling equipment environment already available on the *Maersk Valiant*.

**Choke Control and SafeVision Monitoring Station installed in front of the driller.** Photo from SafeKick.

There are several advantages to owning the system and choosing the components, according to several companies involved with the project.

"Say one MPD company provides the entire system, they may have the best RCD (rotating control device), but not the best chokes and choke controls," says Helio Santos, president of SafeKick. "So deciding to buy the different components from various sources gives the operator the flexibility to buy the best components to optimize their system."

Owning the system also allows operators to use the system any way they wish, or upgrade components without having to worry about breaching a contract.

"The installation and subsequent operations has provided the *Maersk Valiant* crew with a lot of learning opportunities and raised the knowledge level on both the MPD equipment and the managed pressure drilling process," says Lars Ostergaard, unit director, *Maersk Valiant*. "A fully integrated system, also makes it easier and more cost effective to prepare for drilling operations where MPD is required as there is no rigging up or down of equipment."

Furthermore, there were several shortcomings in existing MPD systems, all of them based on technologies that were typically more than 10 years old. With the narrow fracture margins the operators were expecting to encounter, they required higher precision and control of the choke. With large cuttings, high cutting volumes, and high and low flow rates expected, the available flow control equipment at that time commonly found in the market was sized too small for the job.

During equipment selection, most readily available chokes were 3in max orifice, creating a very high native back pressure induced by the MPD system. As the goal was to use MPD on all phases after the BOP has been installed, with flow rates in excess of 1500 GPM, the use of 3in chokes and small pipe

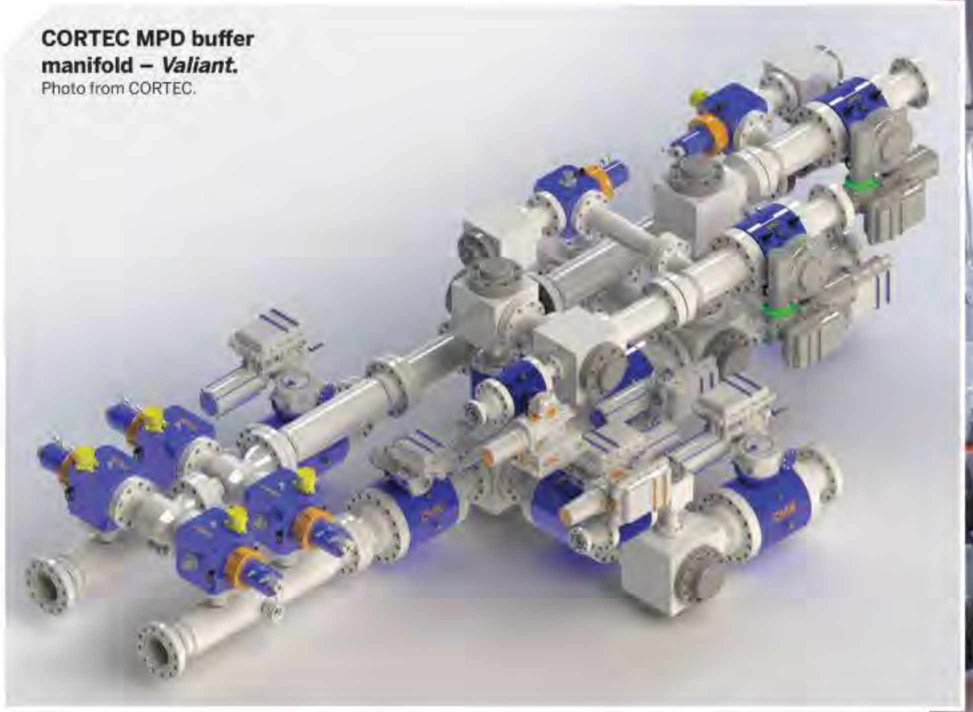
diameter became technically unfeasible. A decision was then made to pursue the development of a 6in choke. "The problem lays in the native back pressure generated by the MPD equipment," Santos says. "Using 3in chokes, even if the chokes were fully open, there would still be high back pressure as a result of the smaller cross-sectional area. And this high back pressure 'eats' the safe mud weight window available, which is usually not big."

Finding a solution to the issue, CORTEC developed a 6in orifice drilling choke capable of interfacing with the SafeKick Intelli-choke control system, which already had a very good accuracy in position and pressure control. Both the 3in and the new 6in Intelli-Choke achieved the precision required.

"CORTEC worked with the *Valiant* project group to design a 6in orifice drilling choke as well as 3in and 4in orifice pressure relief valves that were capable of providing the control necessary to flow at desired conditions," says Stephen Corte, vice president marketing and business development, CORTEC.

To handle the larger equipment and minimize frictional losses, the system also required larger 8in nominal piping with 7.0625in bore isolation valves. To this end, CORTEC supplied the buffer, choke, and metering manifolds, but space on a drillship is limited.

"This creates an ideal scenario for 'compact' manifolds," Corte says. "Our compact valve division, CORTEC Manifold Systems, specializes in the design of compact ball valves and manifolds, which optimize weight and space savings while maintaining or exceeding API standards. Utilizing compact ball valve and manifold technology allowed this entire large bore system to fit within a space that is 7ft tall and 11ft wide, running along the rail of the vessel's moon pool."



**CORTEC MPD buffer manifold – *Valiant.***
Photo from CORTEC.

Issues were also identified when selecting an RCD system, which was made more difficult by a host of challenges around sizing compatibility and market availability.

Weatherford, which has a history of successful deepwater rig integrations and experience accommodating the existing riser equipment on the *Maersk Valiant*, provided a unique RCD system that incorporated an Elite RCD body and latch assembly along with a customized SeaShield model 7875 RCD bearing assembly.

"A sizing modification was required to drift the rig's upper riser package," said Neal Richard, MPD project manager, Weatherford. "The RCD's existing bearing assembly design was modified to accommodate a smaller outer diameter (OD)."

"Marathon and COP ended up deploying the Weatherford field-proven model 7875 RCD bearing assembly in a specially developed Elite riser-based body and latch system to allow for a reduced bearing assembly OD of 18.88in," says Brian Grayson, director of secure drilling services pressure control, Weatherford.

Bringing all the components together, a control system was required, but the systems with which the operators previously had experience did not offer the sensitivities that this campaign required.

A proportional integral derivative (PID) control system would not work with the dynamic processes of MPD. The hydraulics software lacked accuracy, and the control for hydraulic choke position lacked the necessary precision. The input and output volumes also required greater accuracy, and fluid density information needed to be fed directly into the hydraulics models.

In 2013, Marathon and COP selected SafeKick to provide the control system. The SafeKick control system is comprised of their SafeVision and Intelli-choke technology. SafeVision provides monitoring

## Case Study

**With the system integrated, crew trained, ABS-CDS certification, and BSEE approval to take the mudweight below pore pressure, Marathon spudded the Solomon exploration well on Walker Ridge Block 225, in mid-May 2015. The first well of the six well campaign, Soloman was successfully drilled to over 34,600ft, into the lower tertiary target interval, but the well came up dry.**

**After the well was plugged and abandoned, the *Maersk Valiant* was transferred to COP, and the second well, Melmar, was spudded in December 2015, in Alaminos Canyon Block 475. The well was successfully drilled to over 29,000ft, into the lower tertiary Wilcox target, however, non-commercial quantities of oil were encountered, and the well was also plugged and abandoned. At the end of April this year, COP opted not to finish their remaining two wells, Horus and Socorro. The *Maersk Valiant* has since been hot-stacked.**

**Although, both wells came up dry, the *Maersk Valiant* was able to drill well sections overbalanced, with mudweight below pore pressure, detect influx in less than 1 bbl, mitigate wellbore breathing effects, trip with no losses or gains when the operating window was minimal, and conduct dynamic wellbore integrity tests during drilling operation.**

**"ConocoPhillips, Marathon and Maersk Drilling has proven that MPD can be used in US GOM to drill wells that are difficult to drill with conventional methods," Ostergaard says. "MPD was new to most onboard the *Valiant*. The crews adapted well and the drillers have done an excellent job. Now time has come to take all the learnings and make some more formalized training programs with Maersk Training and the structure of this is currently being discussed."** ▪

Coriolis meter manifold.
Photo from CORTEC.

the market, which can enable operators to drills wells with a tight drilling window or drill more conventional wells safer and more efficiently."

Without involving a third party, there is also less uncertainty. One of the issues hindering more general acceptance of MPD are the differing standards and policies between the operator, the drilling contractor, and the MPD service provider. Before a campaign can begin, the standards and policies of the three entities must be bridge, but some conventional policies are challenged by MPD operations. In the case of the *Maersk Valiant*, however, this is a non-issue: the MPD provider is the drilling contractor.

and real-time hydraulic modeling, and Intelli-choke controls the choke position. The MPD system would be controlled through SafeKick software and equipment, so they worked with the vendors to develop new equipment to improve the systems performance. Using Coriolis meters on all pumps, and manifolds, and connecting the data into the system, the control system could, in real-time, accurately track fluid density, rate, and model the hydraulics in a very accurate way, not seen to date on MPD jobs. For choke control, the system used intelligent predictive control (IPC) instead of PID.

"The system is able to control the choke to an accuracy of 0.003%, or about 5psi," says Erdem Catak, vice president of operations, SafeKick. "The system is also incredibly easy to use. A crew member could learn how to use it in a couple of minutes."

Throughout the process of equipment selection and development, the operators, and vendors worked with the US Bureau of Safety and Environmental Enforcement (BSEE).

"We kept our processes transparent, which is important, it shows that we have nothing to hide," Santos says. "This made the permitting process easier."

## Integration

Traditionally, to use MPD on a well, the driller would need to relinquish control of the well to the MPD service provider. With responsibility of the well still laying on the driller, resistance to using MPD more readily is not surprising.

"How would you feel if you are responsible for the well, and someone else is controlling the pressure in the well," Santos says. "With the traditional MPD systems, if pressure is increased, the driller is not in control of it."

The MPD system on the *Maersk Valiant*, however, is different.

"The MPD system is integrated into the *Valiant's* driller's cabin, so it works directly with the driller, whose responsibility is to apply or reduce the pressure being applied by the MPD chokes," Catak says. "The driller is taught how the MPD system works and how to use it, and the rig crews are taught MPD as normal operations. So now the control of the MPD system is in the hand of the drilling contractor."

By integrating the MPD system into the *Maersk Valiant*'s rig, the driller no longer has to worry about handing over control of the well to a third party; when MPD is required, the driller initiates it.

Moreover, the integrated MPD system became part of the rig's maintenance system.

"With learnings gained over time, high system uptime was achieved through effective operations, maintenance and spares availability," Ostergaard says. "Finally, having an integrated MPD system proven in operations make *Maersk Valiant* a very attractive drilling unit in

## Training

With the MPD system integrated into the drilling system, the crews from Marathon, COP, and the *Maersk Valiant* needed to learn how to use it.

Brought on early in the project development for their MPD experience, Signa Engineering Corp. was familiar with all phases of the operation, and were chosen to facilitate the training program.

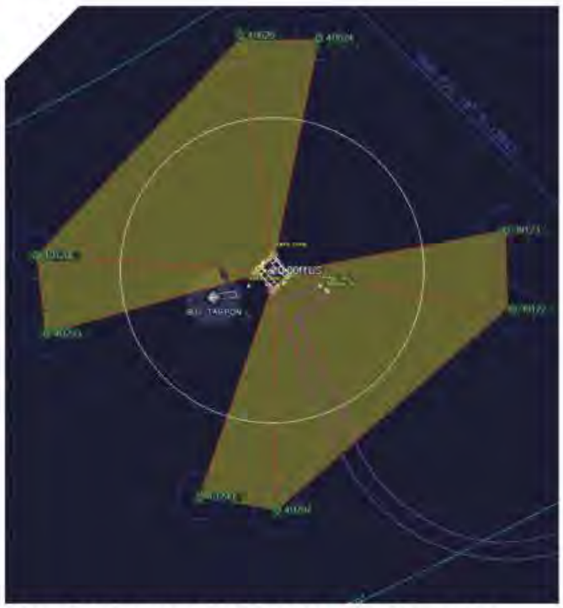
Although SafeKick provided training for software control and operations, a Signa project team, and Marathon and COP MPD experts, developed all of the training curriculum: MPD operations, hydraulic modeling, simulated and hands-on choke operations, and drilling connections.

"The primary objective was to develop a training program that facilitates efficient and safe MPD operations, while meeting or exceeding all regulatory requirements," said Bob Goodwin, senior operations engineer at Signa.

"The vast majority of the training was performed using the actual MPD equipment spread on the *Maersk Valiant*," Goodwin says. "This included simulated operations and contingences, as well as the mentor-supervised on-the-job training (OJT). The initial [rig-based] training was performed in multiple 2-4 hour sessions, but continuous OJT was performed throughout the drilling programs." OE

# Sounding the alarm

**Michael Cole, Fugro's manager of survey prospects, explains how dynamic alarms coupled with office assisted remote services, can help provide better early warnings and navigation for end users.**



**Vessel alert zones (depicted in yellow) from the Stone Energy project.** Images from Fugro.


**Dynamic avoidance zones are modeled in real time from the rig fairleads.**

Offshore driller Ensco had recently modified the *ENSCO 8503* semisubmersible rig by adding four additional mooring lines to enable moored operations in the Gulf of Mexico's shallow waters, where DP (dynamic positioning) operations no longer provide sufficient watch circles.

With the *ENSCO 8503* under contract to Lafayette, Louisiana-based Stone Energy at a shallow water location in Mississippi Canyon Block 26, a high-temperature, high-pressure (HPHT) subsea completion was to be installed as part of the firm's Amethyst project.

An eight-point taut mooring system with OMNI-Max anchors was designed by Delmar Systems to provide the most robust station keeping capability due to subsea infrastructure, to minimize offsets relative to the subsea tree during completion activities, and with ability for the rig to evade potential hurricanes. However, the taut mooring system resulted in shallow mooring lines near the rig, which support vessels could cross over and come into contact with, creating a potential hazard.

One solution investigated involved divers setting buoys on the mooring lines to give vessels a visual approach; however, this was not considered a viable option due to the desired quick response times for evading storms, and vessels would not be warned when approaching potential danger zones. As a result, Stone Energy contacted Fugro to explore a variant of the Starfix.Moor mooring position software, which had been developed by Fugro, along with mooring specialist Delmar Systems, some years before.

Starfix.Moor can compute a straight line 3D profile of each mooring leg and also provides 2D profiles of each mooring leg along with the ability to create audible and visual alarms when predetermined minimum clearances are reached. When integrated with Fugro positioning software, it provides a computation engine and visualization environment, utilizing the industry proven Delmar Systems DelCat catenary algorithms, and providing real-time in situ positioning and monitoring of the rig, anchor handling vessels (AHVs), and 3D visualizations of the mooring lines in relation to the seafloor and those assets that reside on it.

## The solution

Stone Energy required a method to monitor and alarm when vessels entered into potential danger zones, and to ensure operations were not interrupted.

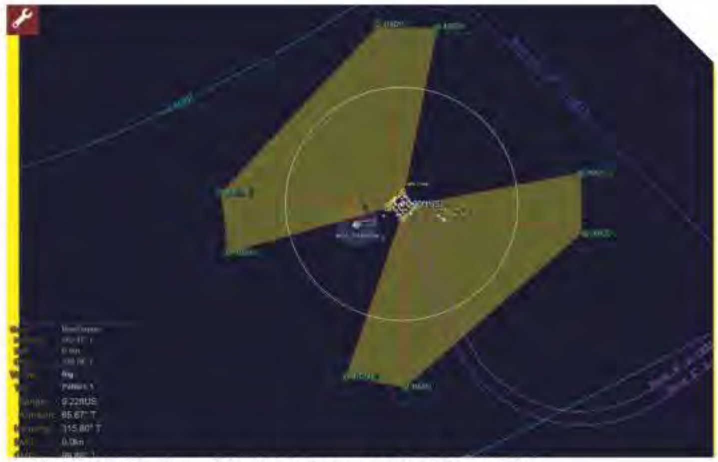
They also recognized this was the first eight-point mooring system designed and installed in hurricane season post-Ivan, Katrina and Rita (IKR). Further, federal regulators (The US Bureau of Environmental and Safety Enforcement, and the US Coast Guard) would be very interested in the performance and management of the system.

After meeting with Stone Energy, Fugro's OARS (Office Assisted Remote Services) support team, the research and development group, and senior management, came together to see if a diverless solution could be implemented within the tight 30-day deadline set by Stone Energy for development and testing.

Fugro's OARS system, on which a patent is pending, had originally been developed to reduce costs, but it also means the surveyor is located in a command center, rather than aboard a vessel offshore.

The OARS Command Center (there

are currently two, one in Lafayette, Louisiana, and the other in Aberdeen, UK, with more planned) is like an air traffic control center, with multiple vessels being displayed and tracked simultaneously, each with an individual project scope, and without an actual personnel presence on the vessel. The onboard system consists of computer servers, Fugro's Starfix GNSS positioning receivers and GNSS-based heading solutions in a single unit; it also includes a phone and headsets for direct communication with the OARS Command Center.



**Full OARS display with alert zones and rig's position.**

Staff in the Command Center can assist in maneuvering, mooring and positioning, as well as monitoring and planning survey work, as if they were on board.

For Stone Energy, flexibility was key in the search for a solution. Within a few days, a plan was in place to modify the new Fugro global survey platform (Starfix.NG) and the OARS solution. The proposed updates included dynamic avoidance zones, advanced automated information system (AIS) integration and alarm notifications.

Local systems testing and integration efforts by the OARS team were run in parallel with the development of the system, enabling real-time feedback as issues arose.

Stone Energy approved the system and Fugro's global research and development group set to meet, and met, the 30-day deadline. The system was mobilized in Q3 2015. Since installation there has been no survey downtime on the project and the feedback from Stone Energy has been very positive.

"Recognizing the hazard is good," says Craig Castille, director of deepwater drilling & completions, Stone Energy. "However, putting a system in place that provides early warnings to vessels better protects Stone, Ensco and vessel owners, and raises awareness amongst vessel captains and provides a record of vessel movements for reference in case of an event occurring.

"Controlling work with integrated systems better enables real-time visual operations," he says. "During winter, with a rig that has always worked in DP mode, and thus having only two approach zones, this enabled vessels to better navigate to and from the rig in a safe manner."

The *ENSCO 8503* was the first drilling rig to use the new dynamic alarms feature that is utilized with Fugro's OARS system. Now current systems in the field on dive vessels (where the market quickly saw the benefits, including reduced costs, more bunk space, improved food and transportation logistics, as well as fewer delays for job start-up), derrick barges and dynamically positioned vessels, are being updated with the new features, and there has been a high volume of interest from across the industry. **OE**

***Michael Cole*** *joined Fugro in 2004, starting as an offshore field surveyor. In 2009, he became a project manager. During the Deepwater Horizon incident, Cole was deployed to the BP command centers in Mobile, Alabama, and New Orleans. He also served as Fugro's dedicated project manager for Shell's Arctic drilling operations. In late 2014, he became Manager of Survey Projects. He has a bachelor's degree from the University of Louisiana at Lafayette.*

**OARS operations are monitored 24/7 by the command center.**

# Wireless wonder

**Automating data collection reduces operator exposure to offshore hazards, as well as making it easier, says Emerson Process Management's Craig Abbott.**

Flammable materials, transport, chronic exposure to chemicals and even the natural environment are common hazards for offshore workers. Operators are constantly looking for opportunities to improve safety, however, all project costs are now under intense scrutiny. Initiatives that have improved offshore safety and increased production are shining lights in the currently gloomy market.

At the core of successful projects lie solutions to common challenges; installed cost, infrastructure requirements, weight and installation time. The key strategy that overcomes all of these challenges is wireless instrumentation.

In terms of production, improved measurement leads to improved management. A broad range of sensors that are quick and easy to install would enable better wellhead management, leading to improved production. Indeed, WirelessHART, which includes devices that are compliant to the IEC62591 standard, has the broad, industry leading, range required. Instruments to measure pressure, temperature, level, flow, valve state, hydrocarbon leak detection, corrosion and vibration are just some of those available.

When discussing safety it is important to understand the hierarchy of risk control measures that are rigorously applied to reduce risk to as low as reasonably practicable. The hierarchy, in order of effectiveness is:

- Elimination of the hazard
- Substitution to a lesser danger source or reduced exposure
- Isolation of people from the source of harm, by time or distance
- Engineering to prevent access to harm
- Procedural controls
- Personal protective equipment
- Warnings and signage to assist vigilance

Wireless instrumentation strategies underpin the most effective risk control measures. Eliminate the task, reduce exposure or isolate staff from the hazard.

### Reducing exposure

In the North Sea, any time workers step outside of the cabin, they are at risk; however, inspecting pressure gauges for casing leaks and checking flow rates for blockages are an important part of minimizing environmental risk and maintaining production.

**The success of these projects was reinforced in 2015, by the addition of 150 light-weight, wireless, pressure transmitters to each of the three Gullfaks platforms.**

Statoil installed WirelessHART transmitters on a number of platforms to monitor wellhead conditions from the control room. This has significantly increased the information available to allow operators to recognize adverse conditions sooner and respond faster. Workers are also safer, checking values from the control room, rather than moving around an exposed deck.

Obtaining the wellhead data could have been achieved using wired instruments, but WirelessHART made it easier. What's more, these typically take around two hours to install compared with up to two days for a conventional wired unit, says Geir Leon Vadheim, Instrument Lead, Grane platform, Statoil.

The success of these projects was reinforced in 2015, by the addition of 150 of the light-weight, wireless, pressure transmitters to each of the three Gullfaks platforms.

### Pneumatic platforms

An operator in the Gulf of Mexico, recognized that their aging pneumatic platforms posed several risks. There was the risk of environmental issues occurring before they could be detected and prevented. Process optimization, to improve production, required regular helicopter flights, a recognized safety risk. Workers risked arriving at a platform and being exposed to a hazardous atmosphere without any warning.

After reviewing several options, a WirelessHART solution was selected, resulting in reduced travel requirements and a greater awareness of facility conditions. With regular updates of the platform conditions available remotely, the operator has realized US$2 million/yr in increased production, reduced helicopter travel costs by $1.3 million/yr and significantly reduced operator exposure to hazards.

**Statoil's Gullfaks' B platform.**
Photo from Statoil.

Wireless was selected as it was 700kg lighter and approximately $3 million cheaper to install than comparable solutions.

A standard pressure transmitter, manufactured from stainless steel, weighs approximately 5kg and requires the addition of cables, cable trays and junction boxes. The latest Rosemount wireless pressure gauge, manufactured from a corrosion resistant polymer and suitable for replacing gauges currently installed on offshore wellheads, weighs only 820g and requires none of the cabling infrastructure. It also replaces mechanical bourdon tubes with a digital sensor, reducing the risk of mechanical failure, another safety improvement.

Another global operator performed a similar upgrade of their pneumatic platform, off the Indonesian coast. Designed to be unmanned, the platform required daily trips by four personnel to collect process data. Pressures were read manually, and when issues were identified, an operations team also traveled to site, resulting in up to 24 hours of reduced production. Automation was clearly required to improve production and reduce the risk associated with staffing a platform that was never designed to be manned.

A combination of 10 wired and 77 WirelessHART transmitters were installed on the platform, across two decks and operating at greater than 99.9% reliability. This allowed operators to collect the process data remotely and investigate issues without travelling to site. A post project review concluded that compared to an equivalent, fully wired solution, the system saved 22% of the budgeted costs and 82% of the budgeted time.

## Shut-in wells

The low oil price has created the need to shut-in wells and demobilize low producing platforms. Even when not producing, control systems must remain operational to monitor well integrity and mitigate environmental and safety risks. These systems are often powered by diesel or fuel gas generators. Diesel eventually runs out and fuel gas systems require regular maintenance, both requiring travel and ship or helicopter to platform transfers, which are identified safety risks.

To overcome this issue, Emerson Process Management is working with an operator in Australia to deliver a self-contained monitoring solution that includes WirelessHART pressure transmitters for monitoring casing pressure, gas and flame detectors, a radio, RTU, IP camera and navigational equipment. The solution includes an autonomous power system, utilizing solar panels, and can be craned onto a very small footprint. This independently operating solution will permit real-time monitoring, whilst mothballing all other infrastructure and practically eliminating travel to site.

Automating the collection of data reduces the exposure of operators to offshore hazards that could include explosive atmospheres, the environment and transport risks. A WirelessHART network that is lightweight, compact and requires minimal infrastructure makes it the ideal solution for quickly and easily adding instrumentation offshore and improving overall field safety. **OE**

*Craig Abbott is wireless specialist, Emerson Process Management. He graduated from the University of Western Australia with a BSc (hons) in Computer Science and Information Technology and stepped straight into a career in Process Control and SCADA as a systems programmer.*

SE Asia

# Stop competing, start collaborating

## We have the saying "digital oilfield" within the industry, but does it exist in reality? Audrey Raj reports.

**Technip CEO Thierry Pilenko.**
Images from OTC Asia.

With offshore projects in Asia Pacific targeting increasingly complex reservoirs and deepwater environments, execution risk is clearly increasing, not to mention costs overruns. Other industries have had the successes with repeatable models to drive down costs and ensure that standardization occurs at every part of the value chain. However, despite many years of effort, the oil and gas industry remains somewhat elusive.

While we have seen operators and the supply chain working together to develop fit for purpose designs to bring back expenditures, we need more of this in today's low oil price environment. As technology and manufacturing developments can be unpredictable, sharing the risk as well as the rewards could just be a win-win strategy for all.

Although, essentials like collaboration, standardization and innovation have become more important than ever, so has the need for behavioral change across the board. This was echoed by industry experts at the 2016 Offshore Technology Conference Asia (OTC Asia) held in Kuala Lumpur, Malaysia; and the 18th International Conference & Exhibition on Liquefied Natural Gas (LNG 18) held in Perth, Australia.

### Behavioral change is key

If the industry is leading on to find cost cure, it must look at things that are sustainable. In the very short term, all operators are doing what they have to do, which is trying to extract cost savings as quickly as they can.

"But in many cases those savings are absolutely not sustainable," warned Technip CEO Thierry Pilenko. "Cost reduction is not happening throughout the industry because people are still behaving the old way, which is to reduce cost of individual elements instead of rethinking the entire system. This is where working on the behavior is going to be as important as actually trying to react in a very short-term," he suggested.

In terms of innovation, there are areas in which Asia is at the edge and at the same time lags, such as fluids and subsea valves, to name a few. The region is also a fast growing research and development hub for many service companies.

Looking on a global scale, Pilenko said there is no monopoly of innovation in the world anymore. For example, if we look at the efficiency and innovation, and the technology integration deployment that exists in Brazil today, its way beyond most of the developments seen in the Gulf of Mexico.

"In terms of standardization, simplification and innovation, it is to the point that some of the things we are now developing in Brazil like flexible pipe technologies, can be now deployed in the rest of the world," he said

"And this is what is happening in Asia. We should not forget that Asia is the place where the first two floating LNGs are being constructed today. Big in Malaysia is the *PFLNG SATU*, and the next one very soon in Australia is a much larger unit. So, I think there is no single place in the world that can say there is a monopoly of technology innovation," Pilenko said.

Voicing concern about standardization, Petronas' CEO for upstream Datuk Mohd Anuar Taib said that while standardization is already taking place in the sector, more can be achieved only if the supply chain lets go of the "yes, I agree to standardization, but on my standards" thinking, which is sometimes against standardization.

Although, this is true to some level, the supply chain doesn't feel empowered to challenge its own standards, Pilenko countered. He said this is where we have to measure behavioral change, so that not only oil companies feel that they can allow the entire supply chain to challenge the way they work, but supply chain members feel empowered to do that as well.

GE Oil & Gas CEO Lorenzo Simonelli.

"This is not the way this is happening for two reasons," Pilenko said. "First, is because we have put in place processes across the supply chain that has been there for 20 years. The second thing is we are passing down the supply chain very contradicting messages and I need to talk about that.

"We cannot say that we are here, we all love each other and we are going to have a new way to work. And at the same time, the first groups that you see are lawyers and contract managers saying these are the new terms and conditions, which by the way you have to abide to, otherwise you are immediately excluded. And those terms and conditions are the worst that we have seen in 30 years," he said.

Another area to look into is over the years we have also broken up the value chain and this has increased the management costs of the contracts itself, added SapuraKencana CEO Tan Sri Shahril Shamsuddin.

"For example, if you have 10 contracts, you have 10 lawyers, and if you have a 1000 contracts, we have a 1000 lawyers saying that we have to take on the return that we need and safety margins along the way," he said.

"And here is where we have to examine how much of that access costs we have seen since 2004. These are opportunities that if we come together and say lets do blocks of management together; we would actually achieve the savings that we need," he suggested.

## Digitalization

If we examine how technology priorities are changing in the oil and gas industry, we see the industry working with the service sector and thinking largely of three things - standardization, cost optimization and the importance of big data automation.

The oil and gas industry is potentially behind some of the other sectors. When you look at the aviation or power sector, the usage of big data is much more pronounced.

"We have the saying of a digital oilfield within the industry, but has that really proved out to be the case," asked Lorenzo Simonelli, CEO of GE Oil & Gas. "Others are ahead of us and we have got an opportunity to go forward and start to take on best practices from other industries," he said.

"We have operational islands that are being created. When you think about the way in which this industry works, you got individual consortiums that are running fields, offshore or onshore. These are micro ecosystems that are very independent in nature.

"And we have got to find a way in which we can bring those together and have the ecosystems talk to each other, so as to better predict and have a better outcome at the end of the day. Therefore, we have to break the operational islands that exist within our industry, and big data enables us to do that," he explained.

For example, on a weekly basis an offshore well would generate millions in revenue. Should that well go offline, it's a very significant impact on the bottom-line of an operator. However, if there is consistency in monitoring the well, reducing the time of which it goes offline is achievable. Currently, there is over a 100,000 pieces of rotating equipment in the industry and two million miles of pipelines. OE


SapuraKencana CEO Tan Sri Shahril Shamsuddin.

# SE Asia


# FEEDing recovery in Asia Pacific

**Dockwise loading out the SHWE platform.** Photo from Dockwise.

**The downturn is forcing operators to go back to the drawing board in order to advance projects. EIC Analyst Angeline Elias provides an overview of activity in Asia Pacific.**

As oil prices continue to languish, many offshore projects have been delayed or canceled in the Asia Pacific region. This has pushed many operators to pursue alternative activities in order to stay buoyant during the economic turmoil, and be well placed once the market recovers.

During this bumpy industry cycle, it is evident that many operators have taken the opportunity to continue to progress development concepts and initial engineering on stalled projects. Operators such as Chevron, CNOOC, Petronas, Shell and Woodside, to name a few, have gone back to the drawing board, to redesign offshore structures for better economies of scale while also ensuring effective operational productivity and cost optimization through technological innovations.

## Going back to the drawing board

Chevron has taken this approach with the Ubon gas field development in the Gulf of Thailand, undertaking a design re-evaluation of its proposed central processing platform, and is expected to return with a much downsized project. At the same time, the operator has also put engineers to work on optimal conceptual design of a large deepwater semisubmersible that is expected to provide gas compression at the Jansz gas field, offshore Australia. While Aker Solutions is working on the conceptual design for the semisubmersible hull, Chevron is also considering an alternative design concept for the spar platform design. The front-end engineering design (FEED) contract is expected to kick in by 1H 2017.

Notably, CNOOC is working on its FEED to develop the Liuhua 16-2 oil complex, in the South China Sea, which involves multiple tension leg platforms as well as an alternative design concept based on a circular semisubmersible unit, with a decision on the final design concept expected by 2H 2016. Meanwhile, Petronas has revitalized its plan to proceed with the development of a central processing platform for the Bokor Phase III field development involving the application of water-alternate-gas enhanced oil recovery with a final investment decision expected by Q3 2016.

Other key projects in the region in potential conceptual design and FEED stage are listed in the table.

## Key regional projects

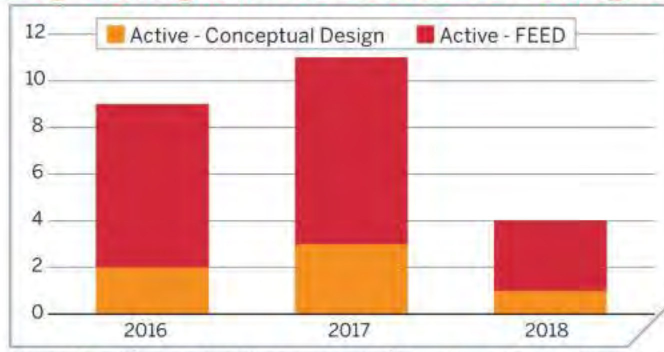
| Project name | Country | Project stage |
|---|---|---|
| Penglai 19-3 phase 3 expansion | China | Conceptual design |
| Shwe gas field phase 2 | Myanmar | Conceptual design |
| K5 gas field | Malaysia | FEED |
| Samarang redevelopment gas field | Malaysia | FEED |
| Sole gas field | Australia | FEED |

Source: the EIC's project tracking database, EICDataStream.

### Learning from past market recoveries

As seen during past market recoveries, lead times for delivery decrease and oil prices typically increase as activity picks up.

## Engineering activities in Asia Pacific region




Being the "first in line" as a result of implementing a strategy to continue with conceptual design and FEED work through the current down cycle may be crucial to maximizing the net present value operators are able to achieve from future field developments.

While activity is set to increase in 2016 and 2017 for some projects, 2018 seems rather bleak at the moment with the market still facing many uncertainties, not least of which is the "wait and see" approach currently being adopted by the industry. OE

*Angeline Elias is regional analyst for Asia Pacific at the EIC. She previously worked for Southeast Asian major oil and gas fabricator Malaysia Marine and Heavy Engineering.*

# Solutions

## As seen at OTC 2016

**OE Staff highlights some products and services viewed at this year's Offshore Technology Conference in Houston.**

### GE Oil & Gas showcases SeaPrime

GE Oil & Gas' SeaPrime I Subsea MUX BOP Control System was unveiled and awarded a Spotlight on New Technology Award at this year's Offshore Technology Conference in Houston.

The subsea BOP control system allows the surface operator to communicate with the BOP by translating electronic commands to hydraulic, which are used to actuate the BOP. Without this communication tool, the operator would need to rely on a ROV to operate the BOP.

GE's SeaPrime I system's dual pod system provides redundancy should a component fail, allowing the operator to continue operations. However, the SeaPrime design is also capable of rerouting functions from a failed component to a working component.

"For example, if you have an issue with outlet 61, you isolate the hydraulic supply to de-energize the primary path used to get to that function on the BOP," said Chuck Chauviere, drilling systems president, GE Oil & Gas. "Then, in the software architecture, another outlet on the pod is repurposed as 61, rerouting the function to the new outlet. On the BOP control system itself, an ROV plugs a flying lead to the repurposed outlet and connects it to the BOP function using a three-way shuttle valve: on the ROV override, on the blue pod, or on the yellow pod. Once the flying lead is installed, the system is up and running."

With the capability to reroute functions, about 75% of the SeaPrime system's functions can tolerate a failure, increasing availability by three times. The redundancy and rerouting capabilities can keep the system in operation, rather than requiring drilling operations be stopped to pull the unit for surface repairs, which can be an expensive task with high offshore rig rates. The fault-tolerant system also takes over some of the workload traditionally done by ROVs, another source or time and cost savings.

In addition, the SeaPrime system is designed so that sub-plate-mounted (SPM) valves, which are susceptible to failure, can be replaced without having to dismantle the equipment. Once the system is brought up for repairs, the failed SPM valve can be replaced by removing four front facing screws that secure the valve in place, allowing the component to be removed. The replacement SPM valve is then inserted, the four screws secure the component, and the valve is ready for operation. Previous designs would require a technician to go behind the valve to unscrew the failed component, which increases the time and risk of the repair operation.

The design of the new system also eliminated 100% of pilot tubing. Due to the inherent risk of any offshore operations performed in limited deck space, eliminating repair operations reduces the risk involved with drilling a well. **www.geoilandgas.com**

*–Jerry Lee*

### Riser extends operator reach

Flexible riser technology, capable of handling dynamic environmental conditions, has enabled the widespread use of floating production systems. Now, with operators needing to optimize spending and looking to produce from more remote and deeper fields, floating production systems look increasingly attractive.

GE Oil & Gas unveiled its composite flexible pipe, which can save 20% on total installed cost, GE says, improving the economics behind using floating production systems.

GE's new riser utilizes a composite bonded liner made of a non-metallic carbon-fiber thermoplastic that is as strong as steel. The bonded liner replaces the metallic (steel) pressure armor layer of conventional flexible risers, making it 30% lighter. With a lighter riser, not only is less raw material needed, but more pipe can be transported per spool, and less equipment (buoyancy modules, clamps, and tethers) is required to support the riser configuration in the water.

The new risers are resistant to $CO_2$ and the presence of $H_2S$, and are capable of handling operations at 3000m and beyond, so extending the reach of operators into deeper waters. GE's composite pipe will be offered in sizes ranging from 2-16in.
**www.geoilandgas.com**

*–Jerry Lee*

## Viral protection

Most people outside oil and gas know Red Wing for their namesake product, shoes, but Red Wing has been providing personal protective equipment (PPE), including high-grade work boots – for several decades. The company had their VectorGuard uniform on display at OTC this year, which the company says offers industrial-grade mosquito resistant technology which can combat transmission of Zika and other diseases.

According to Red Wing, VectorGuard binds permethrin – the only pesticide approved for this application by the US Environmental Protection Agency – to flame resistant and non-flame resistant garments. The gear is effective through 50 washes. The company says independent testing has shown that VectorGuard can reduce mosquito bites to the skin.

Red Wing also offers other PPE for different environments, including extreme conditions such as the Arctic, where suits need thermal protection. Tito Warren, vice president of global sales and distribution, Red Wing, told *OE* that all of the company's products are engineered, wear-tested and designed for the worker. "We don't want it to just look well," he said.

On coping with challenges caused by the drop in oil prices, Warren told *OE* that companies cannot forget about safety. "Safety is not a cost, it is an investment," he said. "You have to invest in protecting people. You don't want to reduce safety."

**www.redwingsafety.com**

***–Audrey Leon***

## NOV presents updated workstation

Service giant NOV aimed to make their whole booth more interactive this year, but there was one exhibit that truly stole the show: the Amphion/Cyberbase Rise workstation. The station is a fully integrated, networked rig control system that allows for the management and monitoring of rig floor equipment. The system is designed for the comfort of the operator who must sit there for long shifts. The chair will stand the operator up or sit the operator down. The Amphion/Cyberbase Rise workstation also comes with interactive touch screens and a redundant joystick for further control of drilling-related functions. You can see the workstation on display at OTC via this video:

http://ow.ly/dNqo300GJ0u

### Trident unveiled

In addition to the workstation, NOV also introduced the Trident crane, a knuckle boom crane that is purpose-built for fiber rope, which the company says, can deploy heavier loads to greater depths. The company says unlimited depths are no longer an issue because the crane allows the hook-capacity to stay the same, no matter the water depth; for example, a 400-ton capacity NOV Trident crane will allow the user to bring an actual 400-ton load to a specified chosen depth.


The hoisting system includes the "winch on king" concept and a spooling system designed for fiber rope, but can also handle hybrid rope or steel-wire. It utilizes a rope protection system, ensuring that the rope temperature is condition and protects the rope from environmental exposure.

The crane's key features are a lower weight, reduced installation and commissioning – compared with below deck winch systems, and it can be electrically and/or hydraulically operated.

**www.nov.com**

***–Audrey Leon***

# Activity

## Baker Hughes outlines future after failed merger

**After Halliburton and Baker Hughes terminated their multi-billion dollar merger last month, Baker Hughes has outlined its path forward.**

**Baker Hughes, which had been held back from making cost saving decisions during the merger talks, said it will now seek to reduce costs, simplify its business, improve its commercial strategy, and optimize its capital structure, as it looks to reshape the business "during the ongoing industry challenges of today" as well as to meet the "additional opportunities" it expects to be available when the market recovers.**

**Baker Hughes has also consolidated its previous regional operations structure into one global organization. Belgacem Chariag, who was most recently the company's vice president and chief integration officer, will serve as president, global operations. Art Soucy, previously president, Europe, Africa and Russia Caspian (EARC) region at Baker Hughes, will serve as president, products and technology. Derek Mathieson will serve as chief commercial officer of the newly formed commercial strategy organization. Richard Williams, formerly the president of the company's North America region, will play a critical role in the organizational transitions outlined above. Serving as senior advisor to the company's executive leadership team, Williams will use his extensive operational experience to assist the company in implementing these changes without disruption to operational performance or customer commitments, Baker Hughes said.**

**The merger with Halliburton was proposed in November 2014, and was met with much resistance from both US and European regulators. Once the merger dissolved, Baker Hughes received US$3.5 billion from Halliburton for the termination of the agreement. Baker Hughes said it plans to use the payment to fund a $1.5 billion share buyback and $1 billion debt buyback, alongside a $2.5 billion refinancing planned for later this year when an existing credit facility runs out.**

### Majors join forces in engineering JIP

Fifteen offshore companies, including Shell and Chevron, have signed a memorandum of understanding (MOU) to establish engineering industry standards known as the Standardization Unified Joint Industry Project (JIP).

The one-year agreement sets out the terms and conditions upon which the signing parties shall establish industry standards for offshore engineering. The objective is to reduce cost and increase predictability without compromising safety in international offshore oil and gas engineering, procurement and construction (EPC) topside projects by using standardized bulk materials and equipment, construction and qualification procedures, and documentation requirements.

A signing ceremony at the 2016 Offshore Technology Conference in Houston included officials from offshore engineering companies: Wood Group Mustang, McDermott International, DNV Korea, Technip, Samsung Heavy Industries Co. (SHI), Daewoo Shipbuilding and Marine Engineering Co., (DSME), Hyundai Heavy Industries Co. (HHI), Royal Dutch Shell, Chevron and MODEC International.

Classification societies signing the agreement included: ABS, Bureau Veritas, Korea Offshore & Shipbuilding Association (KOSHIPA), Korea Marine Equipment Research Institute (KOMERI) and Lloyd's Register.

### Cyberhawk establishes Houston base

Cyberhawk Innovations, an aerial inspection and survey provider, is set to establish a Houston office.

The new Houston office will focus predominantly on the onshore and offshore oil and gas industry. Cyberhawk has already undertaken oil and gas inspection work in North America, for operators in Canada, and has a number of projects lined up with oil and gas supermajors in the US over the coming months.

Cyberhawk's operations director, Chris Fleming, has spent the last three months in the US undertaking market research and will relocate to Houston permanently, to become general manager for America.

### Aker opens Brazilian subsea facility

Aker Solutions has opened its new subsea plant in Curitiba, Brazil. The facility will employ about 850 people and is dedicated to machining, welding, surface treatment, assembly and testing of X-mas trees and other subsea equipment. It will provide subsea control systems manufacturing capabilities, and enable delivery of complete well systems that are placed on the seafloor.

The plant, located in the city of São José dos Pinhais, will double the company's production capacity in the country. It is part of a global delivery model with subsea execution hubs in the Americas, Asia Pacific and Europe and will support customers both in and outside of Brazil. Aker Solutions is also upgrading its subsea services unit in Rio das Ostras to better meet customer demand.

Spotlight

# Up to the challenge

**Jerry Lee speaks with Thomas K. Holley about his 30-year career and challenges he faced as interim chair at the University of Houston's petroleum engineering department.**

**Thomas K. Holley**

After nearly 30 years with Shell, Thomas K. Holley, left the supermajor to start up a petroleum engineering program in a large university system. Holley's choice may be perplexing to some, but it's an unsurprising decision for someone who does not shy away from challenging problems that have a large impact.

After over three decades of absence, the undergraduate petroleum engineering program at University of Houston (UH) returned in 2009. Lacking accreditation, and competing for faculty and space, Holley was recruited in 2010 and tasked with developing a nationally competitive petroleum engineering department.

Holley's experience with higher education began at University of Missouri-Rolla, where he received a Bachelor of Science in physics and applied mathematics in 1975. This was followed by a master's and a doctorate in physics from University of Wisconsin in 1976 and 1982, respectively. However, his passion for education began much earlier.

"As with most children, my parents were my strongest influence," Holley says. "One of my father's pieces of advice was 'Never miss an opportunity because of insufficient education.'"

After receiving his doctorate, Holley joined Shell in 1982. Drawn by the challenging nature of geophysics and the impact it has on the industry, he spent the next 28 years as a geophysicist at the supermajor.

"Most of my career was in the research organization," Holley says. "I was involved with most aspects of seismic exploration, from survey design to data processing to interpretation to software development."

Holley wrote Shell's first interactive 3D seismic data survey design software, 3DSIGN, as well as patented a method on how to design and process 3D seismic surveys on land, which led to changes in survey design and processing. In addition, for 10 years, Holley led the development of an in-house seismic data interpretation system, which gave Shell the ability to quickly implement new processing and interpretation methods, a competitive advantage before robust vendor systems existed.

Attracted to the challenge of building a new undergraduate program, Holley retired from Shell on 31 March 2010. The next day he began his mission to start up the UH undergraduate petroleum engineering program.

"I loved my work and the people at Shell; I still do," Holley says. "I only left because of the exciting challenge to lead the petroleum engineering program (now department) at University of Houston. It is exciting to build a new program and to influence the careers of the next generation of petroleum engineers."

As the new program director, Holley began his task with clear objectives. First, his goals were to achieve ABET accreditation while growing the undergraduate program. Second, for the master's program, he set out to double its size, while maintaining quality. Third, he aimed to get approval from the State of Texas to begin a doctorate program. Lastly, for the petroleum program as a whole, he set out to evolve the program into its own department, with world-class faculty and facilities.

Beginning with few students and fewer teachers, Holley filled in the gaps, teaching, and sometimes building, nearly half the classes that were needed to grow and maintain the program.

In six short years, Holley completed all of the objectives he was tasked with: the undergraduate program received ABET accreditation, the master's program doubled in size, a doctorate program was started, and the program attainted department status. Holley achieved all this while becoming the largest department in the engineering college, boasting over 1000 students.

"I had a huge amount of help from our faculty, staff, dean, and Petroleum Engineering Advisory Board, [and] we have met all the milestones set out when I was hired," Holley says.

With the startup phase of UH's petroleum engineering department complete, Holley plans to retire this September.

"It is time for new leadership for the next growth phase," Holley says. "I expect the next chair of the department of petroleum engineering to propel the department into the top tier of petroleum engineering programs in the US."

As retirement approaches, Holley remains quiet about his plans. However, one thing is for certain, his plans will continue to focus on challenge and impact. **OE**

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# What's next

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