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SUBSEA ENGINEERING NEWS

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# Neodrill Shines Focus On Top-hole Construction

When the issue of subsea wells is broached all too often the top-hole construction is a neglected area. But if Norwegian-based Neodrill get its way that will soon change.

Neodrill's Conductor Anchor Node (CAN) system uses high load carrying capacity suction anchors to secure seafloor mooring points via a large diameter, relatively short cylinder. Unlike traditional methods, no cement is required, negating the risk of conductor problems due to cementing failure. It also provides a well foundation to be drilled or jetted through, or with a preinstalled short conductor. It already has been proven in 17 installations to date with 14 runs in Norway and one on the U.K. Continental Shelf (UKCS).

Neodrill said its Conductor Anchor Node system can save time and costs. (Source: Neodrill)

However, outside Norway there appears to be a reluctance to adopt what appears to be a valuable tool to reduce costs and speed time to first oil. The technology is at the heart of a new joint industry project (JIP) by the Industry Technology Facilitator (ITF) in collaboration with Maersk Oil, Nexen, Shell, Siccar Point Energy, TechnipFMC and the Oil and Gas Technology Centre. The role of the JIP is to investigate an alternative well foundation technology for subsea E&P wells. The aim is to examine the versatility and robustness of CAN technology as an alternative well foundation for most seabed soils.

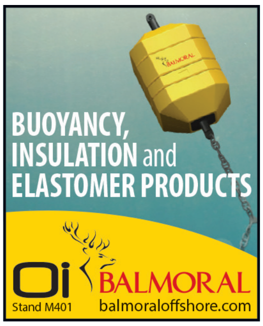
## Breaking From Tradition

The traditional approach in the U.K. sector is to drill a 36-in. to 42-in. hole, down to about 92 m to 107 m (300 ft to 350 ft), then run a CAN-ductor string into that, and then cement that string. The process requires large equipment, rigs and several days of rig time to get this first operation underway. "It's a really crucial operation, especially if the well's going to be a producer," said Ben Foreman, technology manager for ITF. "You need to get that CAN-ductor in vertically, and you need a good cement job to ensure that you've got sufficient load-bearing capacity for your well architecture. Every operation you do afterward is dependent on having a good CAN-ductor cemented in place."

The verticality is important and must be within 1 to 1.5 degrees, facilitating easy landing of the BOP and christmas trees on top without issues such as latching and unlatching. The other big challenge is the cement itself, especially in most areas in the North Sea where seabed conditions are soft.

WHAT'S INSIDE





Ben Foreman

### Saving Cost, Time

The first major benefit of the new CAN technology is that a rig is not required for installation, simply a suitable supplier intervention vessel with a crane.

"You just lift it and you drop it onto the seabed. The first penetration is just through the weight of the CAN-ductor itself," Foreman explained. "The CAN-ductor is like an upturned bucket, and it's very similar to what has been used in this industry for years to anchor FPSO [units]. After the initial penetration there's a suction cap on the top, and an ROV sets a pump onto the top and starts to pump the seawater out of the CAN-ductor. This pressure difference sucks it down farther into the seabed. There is no drilling required beforehand."

Foreman estimated that because this is carried out offline with an intervention vessel or a larger supply vessel without a drilling rig there, it is only the tenth of the traditional cost.

"The other really nice thing about the technology is these CAN-ductors are reusable," he added. "That's a big potential cost saving there, because typically when we cut and abandon wells, we don't reuse the CAN-ductor or the well housing—well not without a serious, serious refurbishment anyway."

### Addressing Industry Concerns

The sector traditionally constructs wells the same way it has since the 1920s. Although the CAN technology has been utilized a lot in the clay soils on the Norwegian Continental Shelf it has yet to be tested on the sandy soil on the UKCS seabed and locations that contain a mixture of soils. Foreman believes companies involved in the JIP would have separately investigated the technology with their own research and simulations.

"With a joint industry project and everyone pulling together data, they can all learn from each other," he said.

Another area of concern that is holding back adoption of the technology is drilling the next smaller hole size from below the CAN-ductor. "A typical conductor string is about 80 m [262 ft] long, whereas a CAN-ductor is much shorter at 10 m to 15 m [33 ft to 49 ft] long," Foreman said. "There's a lot of unconsolidated soil that typically we would have cased off and cemented off. There is some concern that, when using a CAN-ductor, when you drill out from underneath it, whether the soil there is just going to wash out and cause stability issues. The other half of this JIP is technical experts looking at the geotechnical and geomechanical data to give guidance on drilling procedures and giving operators confidence that, when they drill the next section, they're going to maintain well integrity."

For Neodrill, the JIP is a milestone in bringing CAN technology to a wider user group within the UKCS.

"Building on the knowledge we have obtained from previous runs, we can assess its suitability for other substances including sand," added Neodrill CEO Jostein Aleksandersen. "Compared to the conventional conductor, we already know that CAN demonstrates many advantages, including the ability to save rigs time and well costs as a smaller and more cost-efficient vessel is used for CAN/conductor installation ahead of the drilling unit arrival.

"The JIP aims to demonstrate further cost efficiencies as well as robust and versatile solutions for subsea exploration and production wells," Aleksandersen added.

***—Mark Venables***

## DEVELOPMENT

# BW Offshore Pushes Toward Dussafu First Oil By 2H 2018

BW Offshore aims to achieve first oil at the Dussafu development, which targets the Gamba and Dentale sandstones offshore Gabon, by second-half 2018, the company said during an update.

The project will initially develop the Tortue discovery; however, there are several other smaller discoveries and more than a dozen prospects nearby that could add upside to this Atlantic Margin presalt play.

Tortue Phase 1, which secured approval from Gabonese authorities in December 2017, includes two subsea horizontal production wells with a provision for gas lift and sand control. One well will target the Gamba reservoir, while the other will target the deeper Dentale. The water depth is 115 m (377 ft), which company executives said makes the project easier to develop.

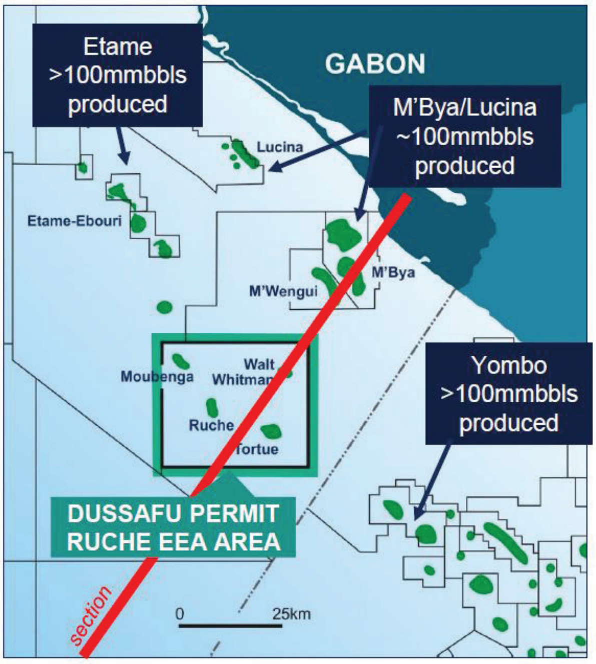
The company also plans to drill one appraisal well, which will be located on the west side of the field, in hopes of finding additional resources.

"It's a good time to be doing an oil and gas development," Lin Espey, managing director for BW Energy, said during the presentation.

He pointed out that all of the major goods and services for the development have been tendered, with costs coming in below previous estimates.

Costs for subsea equipment and drilling rigs came in between about 40% and 50% below previous estimates, while support vessels were between 50% and 60% lower and flexibles were between 20% and 30% lower than previous quotes, according to BW Offshore.

The Borr Norve jackup arrived in Gabon on Jan. 5 and began loading equipment, and the rig is expected



(Source: BW Offshore)

to reach its drilling destination by the end of January to begin drilling activity, Espey said, adding subsea trees and equipment also have arrived.

In addition, the FPSO mooring equipment was preinstalled in December 2017 and the contract for the FPSO *BW Adolo* is being finalized with expected mobilization to Gabon by first-half 2018 followed by subsea tieback installation. Given the typical waxy quality of crude offshore Gabon, the FPSO unit will have excess processing and heating capacity, Espey said.

Gross capital investment for the initial two-well Phase 1 is between $160 million and $170 million, BW Offshore said. Estimated peak production will be between 10,000 bbl/d and 15,000 bbl/d for Phase 1, which targets more than 15 MMbbl of gross resources.

Eyeing up to 45 MMbbl of incremental gross Tortue upside reserves, Phase 2 would involve two more wells per drilling phase starting in 2019, the company said.

Recently released results from an assessment conducted by Netherland, Sewell & Associates show the Gamba and Dentale D6 formations have about 15.9 MMbbl of proved reserves, 23.5 MMbbl of proved and probable reserves and 31.4 MMbbl of proved, probable and possible reserves, the company said. The assessment covered only Phase 1 and Phase 2.

Further upside is evident from nearby existing discoveries, namely in the Ruche Exclusive Exploitation Authorization (EEA). The 850-sq-km (328-sq-mile) EEA also contains the Ruche, Walt Whitman and Moubenga presalt oil discoveries, he said.

"We like the exploration prospectivity the Ruche EEA contains," Espey said. "We have a lot of prospects that have been identified. We're going through a process of reevaluating and high-grading them."

The target formations are the same—Gamba and Dentil—at a target reservoir depth between 2,500 m and 3,500 m (8,202 ft and 11,483 ft), he said, adding that many of the prospects are adjacent to existing discoveries, which should aid in development, tying them back and putting them online.

All are in water depths of less than 100 m (328 ft).

BW Offshore acquired the Dussafu production-sharing contract after completing a deal with Harvest Natural Resources in April 2017.

Dussafu is operated by BW Energy, a joint venture between BW Group and BW Offshore. Partners are Panoro Energy and Gabon Oil Co. (transaction pending).

***—Velda Addison***

## DEVELOPMENT BRIEFS

### Premier, Partners Reach First Oil At Catcher Area Development

First oil has been achieved at the Premier Oil-operated Catcher area development in the U.K. North Sea, the company said in a news release.

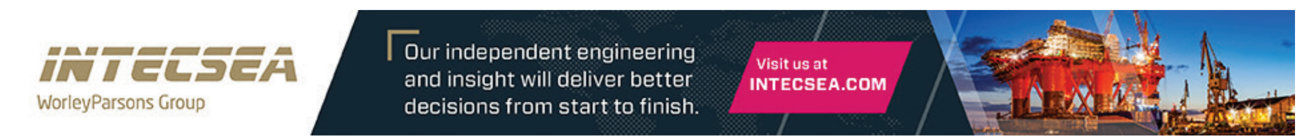
The development consists of the Catcher, Varadero and Burgman fields. Plans are for the Carnaby discovery, which also is located in the area, to serve as a future tieback.

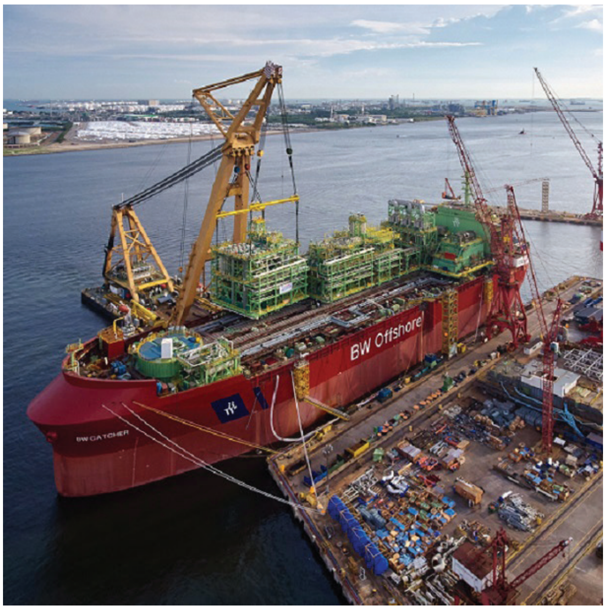
The project was delivered on time and nearly 30% below budget, according to Premier Oil CEO Tony Durrant.

"Catcher is an example of Premier Oil's capability to deliver full-cycle FPSO projects from exploration through to production," Durrant said in late December. "As production ramps up in the first half of 2018, the increased cash flows will play an important role in Premier's plans for debt reduction."

The company anticipated an initial stabilized production of about 10,000 bbl/d from the Catcher Field, with plans to ramp up production from the Varadero Field followed by the Burgman Field.

"The phased approach allows for management of the well stock [while] commissioning of the gas processing






The *BW Catcher* FPSO vessel is used to produce oil from the Catcher Field in the North Sea. (Source: BW Offshore)

modules and full water injection systems on the FPSO [unit] are completed," Premier said in the release.

In all, production in the Catcher Area will increase to about 60,000 bbl/d during first-half 2018, which will add 30,000 bbl/d (net) to Premier's production, the company said.

The sanctioned development includes 20 subsea wells on the Catcher, Varadero and Burgman fields, all of which will be tied back to a leased FPSO unit. Oil will be offloaded by tankers, while gas will be exported through the SEGAL facilities.

Premier's partners in the Catcher area development are Cairn, MOL and Dyas.

## UTEC Receives Greater Enfield Project Contract From TechnipFMC

UTEC, a survey company in subsea services group Acteon, has been awarded a contract by Technip Oceania Pty Ltd. to provide survey and positioning services for the Greater Enfield project offshore Western Australia.

The work scope includes prelay surveys; onshore dimensional control; survey and positioning associated with installation of rigid and flexible flowlines, umbilicals, jumpers, flying leads and subsea structures; and as-laid surveys, as-built surveys and final reporting.

The project will develop the Laverda Canyon, Norton over Laverda and Cimatti oil accumulations. These reserves will be tied back to the Ngujima-Yin FPSO facility.

To execute the work scope UTEC has set up a project management team in Perth and Singapore with additional personnel based in Kuala Lumpur. Preparation already is underway with offshore activity due to begin early in 2018.

## Saipem Lands More Engineering, Construction Work

Saipem has signed a contract with Eni regarding the West Hub development project in Angola, the company said. The contract incorporates work orders made in 2016 and 2017 and the scope of work for the development of the Vandumbu Field in Block 15/06.

The additional activities will be carried out by Saipem's Offshore Engineering and Construction division and encompass the engineering, procurement, construction and installation required for the development of the Vandumbu subsea field at water depths ranging from 1,300 m to 1,500 m (4,265 ft to 4,921 ft).

The project includes two production pipelines and the laying of umbilicals and service lines.

In addition, Saipem has been awarded a new contract in the Gulf of Mexico involving transportation and installation of the compression platform CA-KU-A1 on behalf of Dragados Offshore SA. Operations will be carried out by the *Saipem 7000* semisubmersible vessel.

Saipem also has been awarded new contracts in offshore drilling in two areas of primary interest for the company. A/S Norske Shell tapped the company to drill one well, with an optional well offshore Norway. Drilling work will be carried out by the sixth-generation semisubmersible *Scarabeo 8*, beginning in second-quarter 2018 and lasting two months.

In the Arabian Gulf, Saipem will carry out drilling activities for the National Drilling Co. using the high-specification jackup Perro Negro 8 for 10 months.

Saipem also obtained onshore drilling contracts in Kazakhstan, Romania, Argentina and Bolivia.

The combined value of the contracts is about $380 million.

## McDermott Wins EPCC Contract For Maersk's Tyra Redevelopment Project

The redevelopment plan includes a new processing platform and a new accommodation platform for Tyra East (shown here) and Tyra West. (Source: Maersk Oil)

McDermott International Inc. has landed engineering, procurement, construction and commissioning (EPCC) services work for Maersk Oil's Tyra redevelopment project in the Danish sector of the North Sea, a news release said.

The contract win, valued at between $500 million and $700 million, marks McDermott's return to the North Sea to carry out such work, the company said. McDermott said it will provide its full suite of EPCC services for seven topside structures, six connecting bridges and six jacket extensions.

The work will be carried out as part of two separate work packages.

One work package consists of Tyra East G platform's gas processing topside of about 18,188 tons and includes two 100-m (328-ft) connecting bridges of 468 and 771 tons, respectively, and a 137-m-long (449-ft-long) flare, according to the release.

The other work package consists of two wellhead topsides for Tyra East B and Tyra East C at 1,763 and 1,366 tons, respectively; a 2,480-ton riser topside at Tyra East E; two wellhead topsides for Tyra West B and Tyra West C at 1,421 and 1,488 tons, respectively; and a riser topside at 335 tons at Tyra West E. Four connecting bridges ranging from 60 to 1,102 tons are also part of the package.

McDermott said it also will fabricate six module support frames totaling 1,289 tons to raise the existing platforms 13 m (42 ft) to account for seabed subsidence. The existing four wellheads and two riser topsides along with the old bridges will be removed by others while retaining the original jackets to accept the new topsides with their module support frames, the release said.

Work on the contract is expected to start in early 2018 with the lump sum contract reflected in McDermott's fourth-quarter 2017 backlog. McDermott said it is scheduled to complete its work packages for sail-away by Feb. 1, 2020, and Feb. 1, 2021, respectively.

## L&T Hydrocarbon Engineering Secures Order

India's Oil & Natural Gas Corp. has chosen Larsen & Toubro subsidiary L&T Hydrocarbon Engineering Ltd. to provide engineering, procurement, construction, installation and commissioning services for its Bassein Development 3 Well Platform and Pipeline project offshore India.

The contract, valued at about $229 million, includes three new wellhead platforms, a 23-km (14-mile) subsea pipeline, composite subsea power cable, clamp-on works on an existing platform and modification work on nine existing platforms in the western offshore basin in India, according to a news release.

The project is part of ONGC's efforts to jointly develop the B-147, BSE-11 and NBP-E fields. The project is scheduled for completion by May 2019.

## Songa Enabler Rig To Drill Wells At Goliat Field

Eni will use the Songa Enabler semisubmersible rig to drill two infill wells at its Arctic Goliat Field in 2018, the Norwegian Petroleum Safety Authority said.

Drilling is scheduled to begin in late January and is expected to last for 116 days, the safety watchdog, whose consent was required to use the rig, added in a statement.

The Songa Enabler, owned by Songa Offshore, is on a long-term contract with Statoil and was on sublets to Aker BP and Bayerngas in December.

Statoil has a 35% stake in the Goliat Field, while operator Eni holds the rest.

## DeepOcean Scoops Up Contract For Snorre Expansion Project

DeepOcean has won a contract for performing marine operation scope on the Statoil-operated Snorre Expansion Project in the North Sea.

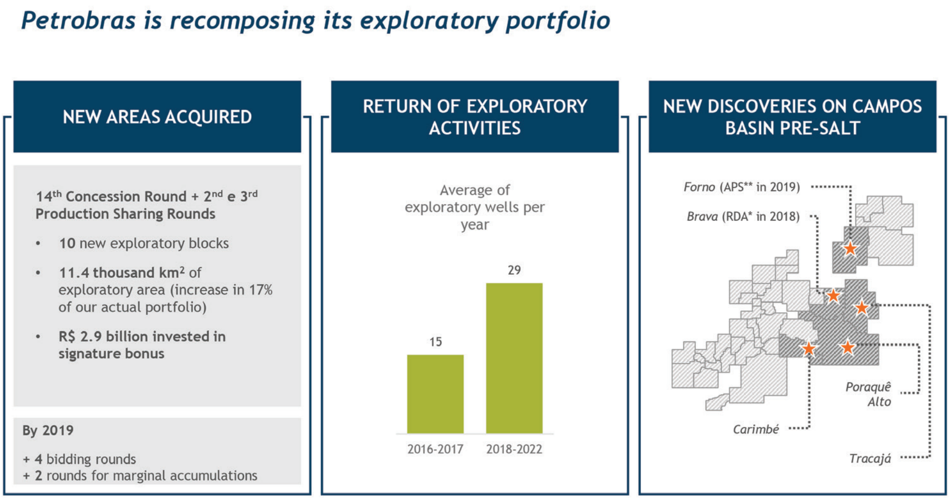
The award covers project management, engineering, procurement of anchors for risers and umbilicals, and offshore installation activities, according to a news release. The company also will be charged with installation of six integrated subsea template structures and manifolds, plus installation of riser systems and umbilical systems on the Snorre A production platform.

DeepOcean plans to use its *Edda Freya* construction vessel to carry out offshore work in 2019 and 2020.

*—Staff & Reuters Reports*

## EXPLORATION

# Petrobras Intends To Increase Offshore Drilling Activities In Coming Years



(Source: Petrobras)

Petrobras plans to increase its exploratory activities over the next four years, according to its Business and Management Plan 2018-2020 launched in late December 2017.

The Brazilian major intends to drill an average of 29 exploratory wells annually by 2020, nearly double the average number of wells drilled in 2016 and 2017.

Petrobras was among the companies that gained offshore E&P rights in the latest actions in Brazil. Pedro Parente, the company's CEO, admitted that more drilling rigs must be contracted to carry out exploratory activities.

"We will have to look for new rig contracts" for the company's exploratory program, Parente said.

The company finds itself in a precarious situation, with 15 of its current rig contracts set to expire in 2018.

Petrobras ended 2017 with 30 drilling rigs under contract, practically double that of BP (14), Shell (13), Chevron (12) and Total (12), according to a survey from the Bassoe Offshore consulting firm. Petrobras steadily grew its contracted fleet until 2013. But global E&P activities began to slow as oil prices started to plummet a year later.

According to Bassoe's survey, the fleet of drilling rigs and other subsea vessels contracted by Petrobras in 2013 included 70 units. This number dropped to about 50 in 2015 and fell to 35 in 2016.

"In order to reduce the idleness, Petrobras' rigs perform various tasks in addition to drilling, with the duration of each activity between weeks and months, such as completions, maintenance in wells in operation and abandonment of already closed wells," a source from Petrobras said.

In 2017 Petrobras only used 13 drilling rigs—half of the fleet. According to Petrobras, more than 60 interventions were made in 2017.

Without other major E&P projects, Petrobras has focused on drilling activity—mostly production work—in the Libra Field.

Now Petrobras works to adjust its fleet, which is considered swollen by the market, to tame drillship idleness. Petrobras already ended contracts for seven rigs (P-3, P-10, P-16, P-17, P-23, P-59 and P-60).

But this comes as the company gears up for more exploratory drilling work.

Currently, three rigs are involved in lawsuits related to contract terminations made by Petrobras. A fourth drilling rig was moved overseas, and the contract for a fifth, the Alpha Star (QGOG), ended.

Good news is that at least one of the rigs involved in lawsuits has moved toward settlement. Diamond Offshore Drilling Inc. said the company and Petrobras have agreed to settle the suit and amend the *Ocean Valor* drilling contract.

According to the agreement, the rig will be in an extended standby period retroactively from July 2017 to the end of September 2018 at a rate of $190,000 per day. The rig will then continue under contract with Petrobras through to the end of September 2020 at a rate of $289,000 per day. Diamond said it would book a one-off charge of $20 million in its fourth-quarter 2017 results to account for the adjusted standby rate.

Claudio Makarovsky, head of ABESPetro, Brazil's oil service company association, is "cautiously optimistic" that Petrobras will sign new contracts by year-end 2018. However, he said the industry must be cautious.

"We had the auctions, which are already beginning to create a demand for drilling rigs. It's going to be a busy year," Makarovsky told *Valor Econömico*, a Brazilian newspaper.

On the other hand, José Firmo, head of Brazilian Petroleum, Gas and Biofuel Institute, is not so optimistic about the current drilling rig climate in Brazil. For him, 2018 will not be so good for Brazil.

"I think 2018 may be the year with the lowest drilling activity in Brazil in 30 years," Firmo said. "Oil activity depends on the drilling ships and wells."

***—Brunno Braga***

## EXPLORATION BRIEFS

### ExxonMobil Makes Sixth Oil Discovery Offshore Guyana

ExxonMobil affiliate Esso Exploration and Production Guyana Ltd. has struck oil at its Ranger-1 exploration well, marking the company's sixth oil discovery offshore Guyana since 2015.

The Ranger-1 well discovery adds to previous discoveries at Liza, Payara, Snoek, Liza Deep and Turbot, which are estimated to total more than 3.2 Bboe.

Esso began drilling the Ranger-1 well on Nov. 5, 2017, and encountered about 70 m (230 ft) of high-quality, oil-bearing carbonate reservoir. The well was drilled to 6,450 m (21,161 ft) depth in 2,735 m (8,973 ft) of water.

"This latest success operating in Guyana's significant water depths illustrates our ultradeepwater and carbonate exploration capabilities," said Steve Greenlee, president of ExxonMobil Exploration Co. "This discovery proves a new play concept for the 6.6-million-acre Stabroek Block and adds further value to our growing Guyana portfolio."

Following completion of the Ranger-1 well, the *Stena Carron* drillship will move to the Pacora prospect, 6 km (4 miles) from the Payara discovery. More exploration drilling is planned on the Stabroek Block for 2018. This will possibly include appraisal drilling at the Ranger discovery.

With a 45% interest in the Stabroek Block, Esso Exploration and Production Guyana Ltd. is operator. Partners are Hess Guyana Exploration Ltd. (30%) and CNOOC Nexen Petroleum Guyana Ltd. (25%).

### Delek Group Partners In Gulf of Mexico Drilling

Israel's Delek Group said on Jan. 8 it has signed a deal with GulfSlope Energy and Texas South Energy to explore 12 concessions in the Gulf of Mexico.

Delek, through a foreign subsidiary, agreed to cover 90% of the costs for the first two drillsites—up to $50 million—in exchange for 75% of the rights in those prospective drilling sites at the first stage.

In addition, Delek said it will use its own funds for the project and will have the option to buy rights in the other concessions as well.

A third-party resource report showed a first stage best estimate of 99 MMbbl of oil and 5 Bcm (177 Bcf) of natural gas, Delek said.

### BP, Kosmos Partner On Five Ivory Coast Offshore Oil Blocks

Ivory Coast has awarded partners BP and Kosmos Energy five new offshore oil blocks under an agreement with state oil company Petroci, government spokesman Bruno Kone said in late December.

Petroci will maintain a 10% stake in blocks CI-526, CI-602, CI-603, CI-707 and CI-708. Kone did not give a breakdown of Kosmos' or BP's stakes.

Elsewhere in West Africa, BP and New York-listed Kosmos are partners on oil and gas blocks off the coast of Senegal and Mauritania. Natural gas discoveries there contain sufficient reserves to warrant two LNG projects, they said.

Ivory Coast, located in the center of Africa's oil- and gas-rich Gulf of Guinea, has granted a number of licenses following a road show in October 2017 in Cape Town, South Africa.

Africa-focused Tullow Oil has picked up six blocks in recent weeks. SECI, a local unit of French industrial group Bouygues, has signed contracts for two blocks.

In September 2017 an international tribunal ruled in favor of Ghana in a dispute with Ivory Coast over the two countries' maritime boundary that had slowed exploration.

***—Staff & Reuters Reports***

## TECHNOLOGY

### Interpreting Data From The Depths Of The Seas

A colleague recently described subsea operations as "trying to hit someone in the head with a baseball bat while it dangles from an airplane." Drillbits that are only a few inches wide must travel thousands of feet under water and then drill tens of thousands of feet farther in order to reach the desired target. Although there are advantages to subsea production, like protection from natural elements and reduced load on floating platforms, it is difficult work.

At underwater depths of several thousand feet there is no visual on corrosions or leaks as there would be with onshore wells. The monitoring of operations is not as simple as sending a worker in a truck to check it out. If a potential problem arises, investigation involves specially trained teams of divers, ROVs and more, typically resulting in lost production time for an already staggeringly expensive venture (in the realm of millions of dollars per day).

In addition to conducting this precise work with little visibility as to how it's going, there is essentially no room for error. *The Deepwater Horizon* blowout in 2010 demonstrated the vital differentiator of subsea operations. While all well failures are big and expensive hassles, subsea failures can be catastrophic. With such severe consequences reliable operational insights are of the utmost importance.

Recently, companies have been turning to artificial intelligence (AI) to provide visibility into how operations are progressing and to protect against disaster. AI

Companies are turning to AI to better monitor and respond to offshore operational challenges. (Source: SparkCognition)

has already been employed across several industries, saving millions of dollars in energy production thanks to failure prediction, providing more intelligent maintenance in aerospace and increasing viable production in manufacturing. AI technology holds particular promise for subsea fields in the form of predictive maintenance uses, the ability to streamline operations, and reduced safety and environmental cost implications.

## Science Of AI

At its core the use case for AI is relatively simple. It can analyze large amounts of historical data from various sensor sources (temperature and pressure gauges, flow rate, etc.) during previous behaviors (including normal operations and during failures) to find patterns. Because AI is capable of considering so many variables, it can find connections and indicators of failure that may otherwise go undetected.

Previously, subject matter experts would leverage their understanding of an asset to create a physics-based or statistical-based model that predicts a desired outcome; essentially it would be the data plus the program to determine the output (data+program=output).

Now, with machine learning, algorithms can derive a predictive model by simply learning from a combination of historical data and examples of the outcomes that one would want to predict; essentially it is the data plus the outcomes to determine the program (data+ outcome=program).

There are two main areas of AI that can be utilized to help the oil and gas industry.

Supervised learning can be used to build predictive models when there are sufficient examples of the outcome to predict. These algorithms derive the pattern of information that precedes the desired outcome.

Unsupervised learning can be used to find anomalies when there are insufficient examples of the desired prediction. In these cases, the model does not look for the desired outcome but instead can be trained to determine what is "normal." Then the software can alert users to any issues that are "not normal" or anomalous.

Finding anomalies indicative of a deviation from normal or making a direct prediction of a desired outcome can have significant implications for an oil and gas company in terms of improving efficiency, production and safety.

## Aiding Decision-making In Drilling Process

Efficiency has always been a focus for oil and gas companies, particularly in recent years. This is especially true for subsea operations due to high cost and has driven operators to look for efficiencies whenever possible.

Subsea drilling is completely human-driven from the ocean surface: One operator ensures the drill follows the path predetermined by a computer while another controls the drill.

However, AI can aid subsea processes by finding the most efficient path to drill to a reservoir. As a drill goes through different formations, the technology could regulate weight on bit in terms of speed, torque or other variables during lengths of hard or soft rock to avoid diverting from the drilling path while maintaining the correct angle. This kind of real-time feedback helps to avoid human error while optimizing the drill path for maximum energy efficiency.

## Optimizing Pump Configuration, Predicting Failures

Production also can benefit from AI's ability to analyze large amounts of data and build models from the information. Based on historical data, production models can be developed for each well and reservoir. The advanced analytics of AI can produce a much clearer picture of production at each well, and this information can be used to decide what types of pumps should be used and how many should go in each well.

Predicting failures also leads directly to increased production. For example, Fereidoun Abbassian of BP recently mentioned that the company has completely eliminated stuck-pipe instances since implementing Well Advisor, an advanced analytics platform. With each instance costing $10 million to $50 million, BP estimates this implementation is saving the company $100 million/year.

## Forewarning To Avert Disaster

Another major opportunity for AI is in the detection of incidents like well kicks. From an environmental and safety perspective, the unwanted entry of fluids into a reservoir can be disastrous as it can spill flammable material on the rig and into the ocean. With less sophisticated methods of detection a kick is only evident when these fluids actually reach the rig. From there the time line to resolve the incident before disaster occurs is limited, meaning more drastic measures like blowout prevention (which will wipe out all progress on the well and result in hundreds of millions of dollars in lost production) might be necessary.

AI technology can provide failure prediction further in advance than traditional methods of monitoring. It can monitor downhole sensors and inform the surface-level crew if conditions indicate a well kick. This allows the crew to make remedial decisions more intelligently since they have more information and more time to solve the problem. In addition to preventing downtime, the increased forewarning could save lives.

## A More Intelligent Future

Although not all of these applications are flawlessly in use today, they represent the future direction of the industry. Early successes have reinforced faith in the abilities of AI, and as the field expands, more use cases are being explored. AI is defining its place in oil and gas, and the unique considerations of subsea operations are allowing for the possibility of progressive changes in the field.

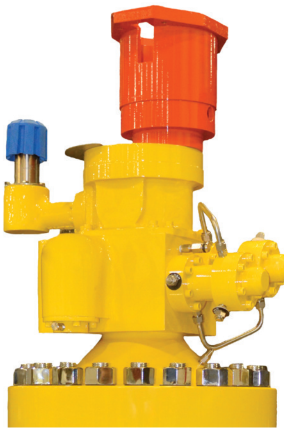
*—Philippe Herve, SparkCognition*

# TECHNOLOGY BRIEFS

## High-resolution Subsea Actuator Enables Increased Production

Master Flo Valve Inc. has released a new high-resolution subsea actuator that enables operators to increase production utilizing its existing subsea infrastructure.

Based on the hydraulic stepping actuator design that has been proven in subsea applications for more than 20 years, the SL3 provides three times the number of opening set points of previous actuators, a press release stated. When bringing new production online, this combination of reliability and higher resolution delivers the precision required to reduce the downhole pressure drop and surge experienced at each step, and thereby decreases the likelihood of reservoir damage, sand production and debris.



Master Flo's new high-resolution subsea actuator is designed to help increase production while utilizing existing subsea hydraulic architecture. (Source: Master Flo Valve Inc.)

On existing wells, the SL3 can open subsea chokes to the sand breakthrough point in smaller steps to safely increase production. The SL3 is backward compatible with existing subsea chokes and utilizes the installed electrohydraulic infrastructure. According to the company, this makes it a more cost-effective option than switching to electric actuators, which typically require modifications such as implementing battery power banks or additional power umbilicals.

## Teledyne Launches HydroPACT 660 Pipe Tracker

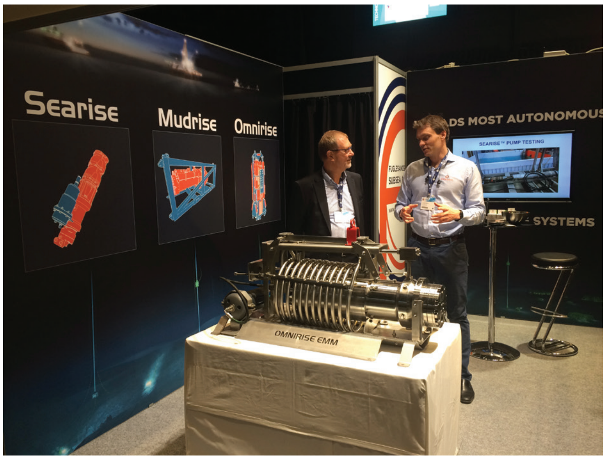
Teledyne TSS, a division of Teledyne Marine, has grown its portfolio of subsea pipe and cable detection and tracking products with the launch of a new smaller HydroPACT 660 pipe tracking system.

As explained by Teledyne, the 660 has been designed to help reduce the cost of subsea pipe surveys by allowing the use of smaller classes of underwater ROVs. Capable of operated to 3,000 m (9,842.5 ft) depth, the compact HydroPACT 660 has a single small form factor coil array with an operating range greater than 85% of the larger HydroPACT 440 system.

The HydroPACT 660 pipe tracking system is suitable for use on smaller classes of underwater ROVs. (Source: Teledyne)

In addition, TSS has expanded the capabilities of the HydroPACT 440 pipe tracking system with a new 24VDC upgrade kit. The company has introduced a 24VDC power supply pod for the HydroPACT440 system that aims to help increase the flexibility and use of the system on vehicles that only support DC power capability, the release said.

## Statoil Joins JIP Focused On Subsea Boosting Pumps




The JIP aims to bring the Omnirise single-phase booster to market by early 2019. (Source: Fuglesangs Subsea)

Statoil has joined the Fuglesangs Subsea-led joint industry project (JIP) that aims to revolutionize subsea boosting pumps, according to a news release.

Other members of the DEMO2000 JIP are Aker BP, Lundin and National Oilwell Varco. The JIP is working to deliver a lower cost, lighter and more reliable subsea boosting pump solution—the Fuglesangs Subsea Omnirise single-phase booster—to market by early 2019.

"We think we've cracked the code," Fuglesangs Subsea CEO Alexander Fuglesang said in a news release. "This project has the potential to deliver improvements in all three areas: cost, weight and reliability."

After eliminating the biggest problem with subsea pumps—the mechanical shaft seal—everything else fell into place, Fuglesang said.

"Dynamic shaft seals not only fail all too frequently, they also require a constant flow of so-called barrier fluid, supplied by topside hydraulic equipment and delivered through umbilical lines that can stretch over many kilometers. Traditional variable speed drives also add considerable weight and volume topside, with projected subsea versions looking equally as bulky," a news release said. "The Omnirise system gets rid of all these elements by employing a patented Hydromag Drive Unit, essentially a combination of a fixed low-speed subsea electric motor, a variable-speed torque converter and high-performance magnetic coupling."

Rystad Energy has estimated that Omnirise can provide savings of about $18.6 million on a single-well boosting installation, compared to conventional boosting systems, the company said.

***—Staff Reports***

## FLOATERS

### Dispute Threatens Egina Project As FPSO Unit Nears Arrival

A dispute over towing services could jeopardize Total's Egina project offshore Nigeria with a government agency threatening to prohibit the FPSO unit from entering its waters.

The Nigerian Ports Authority (NPA) insists that the country's law gives it sole authority over towing and piloting, which conflicts with a multimillion-dollar contract that Total has signed. The company's *Egina* FPSO vessel left its shipyard in South Korea on Oct. 31 and was expected to arrive in Nigerian waters during the second week of January.

The ship is scheduled for integration of its six topsides at Tarkwa Bay in Lagos, Nigeria. Failing to reach an agreement with the NPA would reduce Nigerian content in the project and erode confidence about its viability.

Total, operator of the Egina Field, and FPSO contractors Ladol/Samsung are reportedly negotiating with and lobbying the government.

"All hands are on deck to ensure that the matter is resolved before the FPSO arrives," a representative of Ladol/Samsung told *The Guardian* newspaper.

The *Egina* FPSO vessel has a storage capacity of 2.2 MMbbl of crude oil and a production capacity of 108,000 bbl/d. It can accommodate a crew of 200.

The field is expected to add 200,000 bbl/d to Nigeria's output and is scheduled to come onstream in 2018 although the dispute could delay first oil.

Abdullahi Goje, NPA's general manager for corporate and strategic communications, told *The Guardian* that he was optimistic for a solution but would not back down if one cannot be found.

"Notice has already been given to promoters of the FPSO [unit] to the effect that the vessel would not be granted access to Nigeria's waterways," he said. "The NPA would pursue legal remedies in its determination to ensure that no organization impedes on the mandate of the NPA as provided in Part II of the Port Act."

***—Joseph Markman***

## FLOATER BRIEFS

### BMT, MSI Land Joint FSRU Terminal Project Contract Offshore Greece

BMT Group Ltd. and Metocean Services International (MSI) have been jointly awarded a contract by Gastrade, the companies said Jan. 9. The contract will allow the companies to deploy an environmental monitoring system and develop metocean criteria to be used for the design of an offshore moored floating storage and regasification unit (FSRU) and the subsea pipeline to shore.

The Alexandroupolis FSRU will be located offshore Greece in the northern Aegean Sea in about 40 m (131 ft) water depth and will connect to shore via a 24-km (14-mile) subsea pipeline.

The FSRU is part of the Alexandroupolis Independent Natural Gas System, which aims to create a new natural gas gateway to central and southeastern Europe.

MSI will provide a site-specific measurement program to record metocean parameters including waves, currents, water levels and temperature offshore as well as meteorological parameters onshore for 12 months.

BMT will deliver the metocean criteria study to support the engineering design phase and will use its in-house, long-term wave hindcast and hydrodynamic modeling software TUFLOW-FV to simulate local sea states and hydrodynamic conditions. TUFLOW-FV is a 2-D/3-D finite volume numerical model that simulates hydrodynamic, sediment transport and water quality processes.

### North Sea's First FPSO Unit Heads To Brazil

*Petrojarl I*, the North Sea's first FPSO vessel, is on its way to Brazil's Atlanta Field after work in Aibel's Haugesund, Norway shipyard.

Teekay's TenTech 685-design vessel will be stationed 185 km (115 miles) offshore in depths of 1,535 m (5,003 ft), the deepest in which *Petrojarl I* has operated. The post-salt Atlanta Field, located in the Santos Basin, marks the 14th field in which the FPSO vessel has operated. It will begin a five-year charter contract in first-quarter 2018 with a consortium led by Queiroz Galvão Exploração e Produção SA.

The FPSO vessel required 450,000 engineering hours from Damen Shiprepair Rotterdam to complete the redeployment overhaul. Most of the vessel's process equipment had to be removed and replaced with new and additional equipment to handle heavy crude.

*Petrojarl I* will operate as an early production system in the heavy-crude field, which has estimated reserves of 190 MMboe and an expected production life of about 15 years. The FPSO vessel will undergo field installation and testing before it begins a five-year charter contract.

### Maersk Drilling Wins Contract Offshore Ghana

Tullow Ghana Ltd. has awarded Maersk Drilling a four-year contract for the *Maersk Venturer* deepwater drillship, according to a news release.

Signed in December 2017, the contract is expected to start in February 2018 and cover development drilling on the Jubilee and TEN fields offshore Ghana. The contract is Maersk's first with Tullow Ghana.

Maersk said on Jan. 2 that the drillship is in transit for the job offshore Ghana.

Maersk Rigworld Ghana, Maersk Drilling's joint venture with Rigworld International Services, will provide local services for the operation, the release stated.

### Mitsui, Others Join MODEC-led FPSO Charter Project Offshore Brazil

Mitsui & Co. Ltd., Mitsui O.S.K. Lines Ltd. (MOL), Marubeni Corp. and Mitsui Engineering & Shipbuilding Co. Ltd. (MES) have agreed to invest in a long-term charter business promoted by MODEC Inc. to provide an FPSO unit for use in the Sepia area offshore Brazil, a news release stated.

The five companies entered related agreements on Jan. 9.

Based on these agreements, Mitsui, MOL, Marubeni and MES will invest in Sepia MV30 BV, a Dutch company established by MODEC, and the companies will proceed with the project jointly.

MV30 has entered a long-term charter agreement to deploy the FPSO unit with Petrobras.

The FPSO unit will be chartered for 21 years under the agreement.

### BW Offshore In *Polvo* Win Extension

BW Offshore has reached an agreement with Brazil's Petrorio to extend the contract for the *Polvo* FPSO vessel for one year.

The contract has been extended to third-quarter 2019 from third-quarter 2018, with options to extend to third-quarter 2022.

The vessel is being used at the Polvo Field, where it produces about 8,000 bbl/d in the Campos Basin offshore Brazil, according to Petrorio. The *Polvo* FPSO has a fluid processing capacity of an average 100,000 bbl/d and storage capacity of up to 1 MMbbl.

—*Staff Reports*

## VESSELS

# Vessel-sharing Scheme Launched In Central, Northern North Sea

Four partners are seeking to maximize efficiencies through standardized processes with a new vessel-sharing scheme in the central and northern North Sea.

Peterson, joined by Maersk Oil North Sea UK Ltd., Petrofac and Dana Petroleum Ltd., launched the scheme in July 2017 but did not announce it until the first week of January 2018. The vessels operate from Peterson's Waterloo Quay facility in Aberdeen, Scotland.

The two weekly sailings serve four assets:

- Maersk Oil's *Gryphon* and *Global Producer III* FPSO units;
- Dana's *Triton* FPSO unit; and
- The *FPF-1*, of which Petrofac is duty holder.

Peterson, which has managed vessels in the southern North Sea for more than 20 years, acts as an independent facilitator as well as vessel charterer. Representatives from each partner compose the partnership's steering group. An operations committee handles routine activities.

So far, the partners have achieved success through combining volumes, distance and capacity, increased schedule flexi-

Peterson is managing the ships operating in the North Sea vessel-sharing scheme. (Source: Peterson) bility, reduced environmental risk and cost savings. The standardized safety processes derived from the uniform approach inherent in vessel sharing could set a new industry standard.

"We are delighted to be working with like-minded, visionary companies who see the value in sharing resources and are pleased to be acting as pool facilitators and enabling the principle of a CNNs [Convolutional Neural Networks] pool to come to reality," said Chris Coull, regional director for Peterson, in a statement. "Other companies are watching the progress of this initiative with great interest, and we trust we will welcome more forward-thinking organizations onboard in the future."

Les Mills, corporate logistics superintendent for Petrofac, added that the collaboration was cutting the cost of North Sea operations.

"Reducing the number of vessel voyages has many advantages," he said. "Fewer vessel movements minimize safety risks, reduce emissions and lower costs for the vessel charterer and share partners. As established and new entrant operators seek to extend field life in the North Sea, logistics sharing provides an effective way to meet operating requirements, while reducing costs when compared to dedicated resources."

***—Joseph Markman***

## VESSEL BRIEFS

### Infusion Of Fund Allows ROVOP To Bolster ROV Fleet By 50%

Aberdeen, Scotland-based Rovop Ltd. is using $88.15 million in funding to bolster its fleet by 50%, the company said in late December 2017.

The company also announced that its co-founder and chairman, Mark Vorenkamp, would retire from the 6-year-old company.

The cash infusion comes from Blue Water Energy and BGF and will be used to support growth plans spurred by ongoing customer demand. As many as 80 jobs could be created in the execution of the plans.

Rovop's fleet grew from 16 to 24 with the purchase of assets from Tidewater in Houston.

"The past few years have seen customers recognize the difference in our quality of service," Rovop CEO and co-founder Steven Gray. "This latest investment allows us to continue to deliver this service to more customers, especially in the U.S. where much of the new fleet is being acquired from Tidewater. The combination of the latest ROVs with our current assets means that we will have the highest quality ROV fleet globally."

Along with the immediate step change for the company, the funding primes the company for the future, Gray said.

BGF's first investment in Rovop was about $14.4 million in 2015. It has pumped in funding twice since then to grow the company's fleet.

"BGF's strategy is to continue to invest in our most successful businesses, and we are delighted to welcome the Blue Water team onboard," said BGF's Mike Sibson.

### Petrobras Awards DOF Subsea ROV Contracts

DOF Subsea has been awarded two new ROV contracts by Petrobras, DOF said in a news release.

The ROVs will be installed onboard *Skandi Angra* and *Skandi Paraty*.

The new contracts start in April 2018 and end in September and November 2020, respectively.

In addition, DOF said Petrobras has extended two contracts for the ROVs onboard *Skandi Iguacu* and *Skandi Urca* until year-end 2018.

The new contracts and contract extensions give 1,630 days of ROV services for DOF Subsea and increase the backlog by about $24.7 million, DOF said.

### Kreuz Subsea Wins Contract To Support Larsen & Toubro, ONGC

Kreuz Subsea said on Jan. 9 it has been awarded its most financially significant contract in the company's history. The independent firm will mobilize five vessels to deliver subsea completion works for Indian multinational conglomerate Larsen & Toubro Ltd. (LT).

The contract, which is worth an undisclosed eight-figure sum, will see Kreuz Subsea supporting LT to install all riser clamps, risers, crossing works, tie-ins, subsea trenching and hydrotesting of pipelines, which are part of the Oil & Natural Gas Corp.'s (ONGC) pipeline replacement project and Daman Field development projects off the west coast of India.

The five vessels to be used throughout the campaign in the Mumbai High and Daman fields, located in the Mumbai Offshore region, include *Kreuz Installer*, the DP2 purpose-built subsea umbilicals, risers and flowlines vessel, and *Kreuz Supporter,* the diving support and construction work barge.

In other news, Kreuz Subsea said the company bolstered its senior management team in November 2017 with the appointment of Phil Bradbury as HSEQ director.

Bradbury has more than 27 years' experience in the oil and gas industry and has held HSEQ-related management roles at DSND, ISS, Harkand and most recently, Rocksalt Subsea Ltd.

***—Staff Reports***

## POLICY BRIEFS

### US Proposes Easing Offshore Oil Drilling Safety Regulations

The U.S. Interior Department has proposed eliminating some safety regulations for offshore oil and gas drilling that the Obama administration put in place after BP's massive Gulf of Mexico (GoM) oil spill, a move it said would reduce "unnecessary burdens" on the industry.

The Interior Department's Bureau of Safety and Environmental Enforcement (BSEE), which regulates offshore drilling, said its proposal to scale back some of the Obama-era requirements was in line with the Trump administration's goal of "encouraging increased domestic oil and gas production by removing regulatory hurdles."

The regulation, called the Production Safety Systems Rule, addresses safety and pollution prevention equipment, subsea safety devices and safety device testing for oil and gas production on the U.S. Outer Continental Shelf. BSEE said its initial regulatory impact analysis estimates that the proposed amendments would reduce industry compliance burdens by at least $228 million over 10 years.

One of the safety provisions BSEE plans to remove is a requirement for operators to get a third party to certify that safety devices work under extreme conditions.

During the BP spill, one of these devices, a BOP, failed to work. The 2010 *Deepwater Horizon* rig explosion in the GoM resulted in the deaths of 11 workers and led to the largest oil spill in the history of U.S. marine oil drilling operations. BP paid out about $60 billion in fines and cleanup costs in the wake of the disaster.

The proposal also would revise some oil production safety system design requirements.

Industry groups welcomed the opportunity to give more input into how offshore drilling is regulated.

Randall Luthi of the National Ocean Industries Association said the proposal presented an "opportunity for further dialogue, discussion and debate."

However, environmental groups warned that the proposal puts the U.S. at risk of another major offshore oil spill.

"By tossing aside the lessons from the *Deepwater Horizon* oil spill, Trump is putting our coasts and wildlife at risk of more deadly oil spills. Reversing offshore safety rules isn't just deregulation, it's willful ignorance," said Miyoko Sakashita director of the oceans program at the Center for Biological Diversity.

The comment period for the proposal, which was published in the Federal Register on Dec. 29, ends Jan. 29.

### Brazil Authorizes State Company PPSA To Sell Presalt Oil, Gas

Brazil has set out provisional rules for Pre-sal Petroleo SA (PPSA), the state company managing contracts, to develop the coveted offshore presalt layer to market the government's share of oil and gas.

Development of presalt, where oil is trapped under a layer of salt beneath the ocean floor, is governed by production-sharing contracts that require companies to give so-called profit oil to the government for sale by PPSA.

But before Dec. 22, no rules had been set to dictate how PPSA sells that output, which is the percentage pledged to the government after factoring in costs.

The decree published Dec. 22 allows PPSA to conclude contracts on behalf of the government with trading agents or sell the oil directly, preferably by auction.

The rules take effect immediately but require congressional approval to become permanent.

***—Reuters***

## BUSINESS

### Analysts Forecast 2018 Comeback For Deepwater GoM

The deepwater U.S. Gulf of Mexico (GoM) is poised for a comeback in 2018 with production set to hit a record high as breakevens and costs fall and efficiency rises.

This is according to analysis from Wood Mackenzie, which forecasts deepwater oil and gas production in the GoM will hit about 1.9 MMboe/d, eclipsing the previous record set in 2009 by about 10%.

The anticipated growth comes after some challenging years for offshore operators that faced lower commodity prices during the downturn.

Some projects that are taking shape in the GoM have benefitted from "capturing the bottom of the cycle in the supply chain and through the dip we've had since 2014," resulting in lower breakevens, William Turner, senior research analyst for Wood Mackenzie, told Hart Energy. He noted these include the Shell-operated Vito development and the BP-operated Mad Dog.

The breakevens for deepwater GoM projects vary, depending on the type of development. For tiebacks, which don't require significant infrastructure to be installed, the typical breakeven can be as low as the mid-$20/bbl, Turner said, while developments requiring new platforms could carry breakevens ranging from the mid-$50s/bbl to mid-$60s/bbl.

"One example is the Hess Stampede project," he said. "We expect first oil from that any day now. That one should come online with about a mid-$50 breakeven. So they'll come online in the money."

Alison Wolters, an upstream research analyst for Wood Mackenzie, added, "The projects that are pushing the lim-

(Source: Shutterstock.com)

its on technology, like any field that would produce from the inboard Lower Tertiary, would be at the higher range of breakevens."

Subsea tiebacks are playing an integral role in the recent growth trend and keeping costs down.

Five subsea tieback developments—one from Anadarko and four from LLOG—are expected to start production in 2018. All of these are due to come online with a turnaround from discovery to production in less than three years and in one instance 2½ years, Turner said.

"But still when you're comparing to the cycle time of onshore, which is six months, 2½ years is still a considerably different investment consideration," Turner said.

Turner also pointed out that the current production growth is not sustainable with conventional deepwater fields, so more exploration and development targeting HP/HT environments is needed. Policy incentives could aid in this regard.

Some groups are already advocating for targeted incentives for high-pressure development, Turner said. Examples could include extending a lease term longer than 10 years once a reservoir has been established as having a high pressure or relaxing the royalty rate for such developments.

"Those targeted incentives will help to justify funding of the research and development programs in the companies that are required to push this technology along because the technology is not there yet," Turner said.

Analysts believe that technology will still have a hand in improving efficiencies offshore.

Among the technologies expected to play a greater role as adoption and demand picks up are managed-pressure drilling, which Wood Mackenzie said improves the "competitiveness of ultrahigh-pressure developments by increasing drilling efficiency and safety through automation" as well as the use of supercomputers, Big Data and analytics to improve resolution and processing time for seismic data. Such technologies can enable better well placement and design.

"The potential for advanced digital capabilities to improve deepwater competitiveness and productivity are monumental," Turner said in a statement. "In 2018 the industry will finally begin to widely embrace and implement buzzwords like Internet of Things, automation and Big Data to achieve new and sustainable efficiencies and optimizations that decrease unplanned downtime, improve maintenance processes, extend asset and equipment life, and reduce costs."

***—Velda Addison***

## BUSINESS BRIEFS

Christina Verchere

### BP Asia President Quits For OMV Petrom CEO Job

BP's Asia-Pacific President Christina Verchere is leaving to become head of Austrian energy group OMV AG's Romanian unit Petrom, ending a 20-year career at the British oil major.

She will take up her new position by May 21 at the latest, OMV said in a statement on Jan. 9.

Verchere, 46, will replace Mariana Gheorghe, who will leave after 12 years at Petrom and before her contract was due to end in April next year.

Verchere worked for BP in Britain and North America with a focus on E&P. She is currently based in Jakarta.

### Subsea NE Appoints Heppenstall To Serve As New Chairman

Subsea North East has named Bruce Heppenstall as its new chairman, replacing Andrew Hodgson.

Bruce Heppenstall

Heppenstall, who serves as CEO of BEL Valves and is the former general manager for the GE Oil & Gas' Wellstream division, will be responsible for promoting the northeast sector globally while working with Subsea UK, according to a news release.

Hodgson, who has been chairman of Subsea North East since 2010, will continue serving as chairman of the North East Local Enterprise Partnership.

### Maria Hanssen Takes Over As CEO Of DEA Deutsche Erdoel

DEA Deutsche Erdoel AG has named Maria Moraeus Hanssen as its CEO and chair of the board of management, the company said.

Hanssen succeeds Thomas Rappuhn, who served over 12 years on the executive board and eight years as CEO of DEA.

According to DEA, Maria Moraeus Hanssen has extensive experience in the oil and gas industry. Prior to joining DEA, Hanssen was entrusted with the entire international E&P business of Engie SA.

## Helix Appoints Executive Vice President, Chief Commercial Officer

Helix Energy Solutions Group Inc. has named Geoffrey Wagner as executive vice president and chief commercial officer, the company said.

Wagner has more than 15 years of experience in the energy industry. Prior to joining Helix, Wagner spent several years in executive leadership with Atwood Oceanics Inc. as vice president of strategic planning, technical services and supply chain, and of marketing and business development.

Wagner joined Atwood from Transocean Ltd., where he spent five years in various management positions with increasing responsibility, and prior to that, he worked with SeaRiver Maritime Inc., a subsidiary of ExxonMobil Corp.

## Tanzania's Swala Oil Plans To Buy Stake In Orca's PAE

Tanzania's Swala Oil and Gas will buy up to a 40% stake in Orca Exploration Group's PAE PanAfrican Energy Corp. for $130 million, Swala said.

When completed, the deal will give Swala part ownership of PAE's Tanzanian subsidiary, which holds E&P rights for natural gas in the Songo Songo Block, in partnership with the Tanzania Petroleum Development Corp.

Swala said the transaction will involve the issue of 16.3 million preferred shares, worth $16.3 million, to Orca, if shareholders approve. It also will take on PAE Tanzania's debts worth another $24 million, Swala said. Funding for the deal was arranged by Exotix Capital, a London-based specialist frontier markets investment bank.

## Subsea UK Unveils Finalists For 2018 Awards

Industry body Subsea UK has announced finalists for its 2018 business awards, which recognize innovation and success in the Britain's subsea sector.

The awards dinner is set for Feb. 8 at the Aberdeen Exhibition and Conference Centre during the Subsea Expo exhibition and conference.

Finalists for each category are

- Company of the Year: Caley Ocean Systems, Tekmar Energy and JDR Cables;
- Innovation & Technology Award: Hydratight, Swagelining and Maritime Developments;
- New Enterprise Award: 1CSI Ltd., Rovco and Triton Marine & Engineering Consultants;
- Best Small Company: AgileTek, Namaka and DiveSource;
- Innovation for Safety: The Underwater Centre, Secc Oil & Gas and Maritime Developments;
- Global Exports: Tekmar Energy, STATS Group and Maritime Developments; and
- Young Emerging Talent: Arnold Grundy, Oceaneering; Robert Marshall, Shell UK; and Jingyi Wan, JDR Cable Systems.

The individual who has made the most outstanding contribution to the subsea sector will be announced during the awards dinner.

*—Staff & Reuters Reports*

## UPCOMING

**The next issue of *Subsea Engineering News* will be distributed Jan. 25. Until then, visit *epmag.com*.**

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