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UK Tolmount, Blythe Projects Gather Pace

Tolmount was drilled by the ENSCO 92 rig. (Source: Ensco)

Two gas development projects offshore the U.K. are gaining momentum. Premier Oil's Tolmount Field is gearing up for tendering, while Independent Oil & Gas (IOG) is looking to start construction work on its Blythe Hub project by mid-2018, meaning it will also go to the market with tenders.

U.K. player Premier plans to make a final investment decision for Tolmount in the U.K. North Sea in first-half 2018, with tendering for "major project scopes" imminent.

FEED work for the onshore and offshore parts of the Tolmount development is ongoing, said Premier, which operates the field in the Southern Gas Basin.

"Tendering of the major project scopes will commence shortly. We are targeting project sanction in the first half of 2018," Premier told *SEN*, adding the estimated capex for the project is about $550 million gross.

Premier added that it is "discussing alternative funding options for Premier's share of this cost with infrastructure funds."

Tolmount is "a relatively straightforward development," Premier said, noting the company needs a standalone normally unmanned platform using four wells and a 48-km (30-mile) subsea gas export tie-in pipeline. There are existing processing facilities onshore that Premier said it will use.

Tolmount was discovered by E.ON in 2011. It was drilled by the ENSCO 92 rig. The field was handed over to Premier when the company acquired E.ON's U.K. North Sea assets in early 2016 for $120 million.

Subsurface studies on Tolmount East and Tolmount Far East are continuing before any appraisal drilling will be undertaken.

Premier estimated the Tolmount development holds gross resources of between 5.67 Bcm and 28.33 Bcm (200 Bcf and 1 Tcf).

The company plans to target the Tolmount main structure and recover 15.30 Bcm (540 Bcf) of gas from the planned four production wells.

Premier operates Tolmount with a 50% stake but previously said it would consider farming out a 20% stake.

WHAT'S INSIDE

IOG Turns In Blythe Hub FDP

IOG has submitted the field development plan (FDP) to the U.K. Oil and Gas Authority (OGA) for the Blythe Hub, which comprises the Blythe and Elgood fields in the U.K. Southern North Sea.

The Blythe and Elgood gas fields are 100% owned and operated by IOG and located near existing infrastructure and other IOG-owned licenses, which hold the Vulcan Satellites Hub and the Harvey prospect. Both are tieback options to the Thames Pipeline System that IOG is recommissioning to develop its Southern North Sea projects.

Blythe contains 2P reserves of 971.7 MMcm (34.3 Bcf), equivalent to 6.1 MMboe, while Elgood has 623.3 MMcm (22 Bcf) of 2C resources (4.3 MMboe), the company said in a news release.

According to IOG's FDP, Blythe will require an unmanned production platform, while Elgood will use a subsea tieback.

IOG has a target breakeven price for the Blythe Hub of less than £0.25/therm, equivalent to about $20/boe. Total gas recovery is expected to be about 1.84 Bcm (65 Bcf).

Reservoir modeling has already been completed, while well design work is underway as IOG prepares an Environmental Impact Assessment.

Contracting and funding processes are being combined with the Vulcan Satellites Hub to benefit from synergies, IOG noted.

A May report by analysts Arden Partners stated, "IOG is pursuing a hub strategy, aimed at tying smaller fields together to make up economic developments. Its Blythe/Elgood and Vulcan Satellites clusters follow this principle, with shared infrastructure and a shallow-water location helping to keep costs down and boost returns."

With regard to IOG's Southern North Sea costs, Arden added, "This is a shallow-water region, with no field at greater water depth than 30 m [98 ft]. This is expected to allow development using unmanned fixed platforms, helping reduce both upfront capex and ongoing opex. We estimate total capex for the Blythe/Elgood and Vulcan Satellites developments of $385.6 million (£296m), or $6/boe. This compares favorably to capex elsewhere in the North Sea."

IOG is pursuing an aggressive development schedule that targets first gas from the Vulcan South, Vulcan Northwest and Blythe fields in second-quarter 2019. The other fields, meaning Elgood for the Blythe Hub, would go online in the following months. Hopes are for every field in the Vulcan and Blythe hubs to be onstream by fourth-quarter 2019.

"We are very pleased to have delivered the Blythe Hub FDP for approval to the OGA, thanks to the team's extensive development work. This is a major step forward from the single-field draft submission in December 2016. The Blythe Hub is of great strategic value to IOG alongside the larger Vulcan Satellites Hub," IOG CEO Mark Routh said.

"There are significant synergies with the 100%-owned Vulcan Satellites Hub, containing independently verified 2C resources of 9.09 Bcm (321 Bcf), or 55.45 MMboe, which is also intended to be exported via the Thames Pipeline," he added. "IOG is also 100% owner of the Harvey discovery, which lies between the Blythe and Vulcan Satellites hubs. Harvey needs further appraisal and is currently estimated to have P50 recoverable resources of 3.2 Bcm (113 Bcf), or 19.5 MMboe."

—Steve Hamlen

DEVELOPMENT

Asia-Pacific Developments Forge Ahead

Two development projects in the Asia-Pacific region are making solid progress with a development plan submitted for an Australian project, while calls for bids have been issued for a field offshore Vietnam.

U.S. player ConocoPhillips has handed in a development plan for its Barossa Area project in the Timor Sea off Australia. The Barossa Area covers the Barossa and Caldita fields in the Bonaparte Basin. The project is located 300 km (186 miles) north of Darwin, Northern Territory.

ConocoPhillips said the project is estimated to produce LNG at a rate of 3.7 million tonnes a year and condensate at 1.5 MMbbl per year. First gas is expected in 2023. The project is forecast to have a life span of about 20 years.

The development concept includes a permanently moored FPSO vessel, subsea production system and a subsea gas export pipeline.

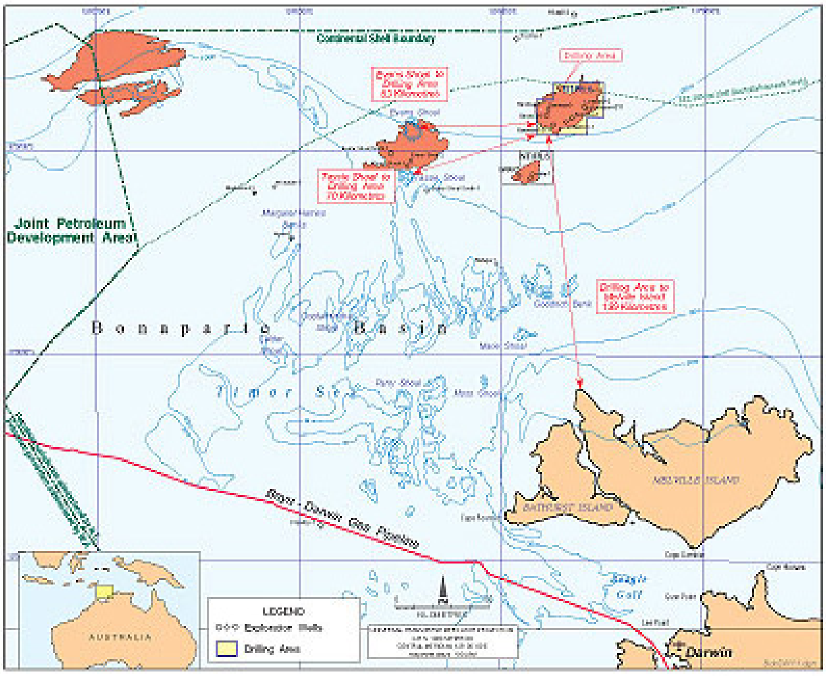
The FPSO facility will separate natural gas and condensate extracted from the field, and the condensate will be exported directly from the FPSO facility to offtake tankers in the Barossa offshore development area. The dry gas will be transported via a subsea gas export pipeline for onshore processing.

The development plan is to connect the new subsea gas export pipeline to the existing Bayu-Undan infrastructure that will transport production to the Darwin gas export pipeline, which feeds the onshore Darwin LNG facility at Wickham Point. This would enable the transport of dry gas from the Barossa Field to Darwin for liquefaction and export.

Gas from the Barossa Field would replace the existing supply from the Bayu-Undan Field once it is depleted, which is forecast for 2022.

Pre-FEED work for the project is ongoing and will be followed by FEED in 2018. The final investment decision for the project is expected in 2019.

"The FPSO facility concept will deliver gas supply continuity for the already existing Darwin LNG facility, which not only greatly reduces development costs but importantly also has a significant socioeconomic benefit and social investment flow-on effects such as creation of local jobs and supplier opportunities to the Darwin community," ConocoPhillips said.



(Source: ConocoPhillips)

Tender Invitations Near For Vietnam Platform

State-owned PetroVietnam is gearing up to issue invitations to tender (ITTs) for a production platform at the Block B gas development project offshore Vietnam.

The move toward tendering follows the previous prequalification of up to five interested contractors that are eager to bid on the project. With many projects shelved or delayed due to the oil and gas industry's downturn, this workload would be a prized contract to win.

PetroVietnam's subsidiary Phu Quoc Petroleum Operating Co. is preparing to launch the bidding process to construct the main platform linked to the Block B development.

Five construction big hitters entered the prequalification stage earlier this year. The hopefuls were Samsung Heavy Industries, Daewoo Shipbuilding & Marine Engineering, SembCorp Marine, Hyundai Heavy Industries and McDermott, according to reports.

However, it is not yet clear how many got through the prequalification phase. So ITTs could be completed by all five or fewer.

Wheatstone Startup Imminent

Woodside Energy reports that the startup of the giant Wheatstone LNG development offshore Western Australia "is imminent."

Originally, startup of the Chevron-operated Wheatstone project was scheduled for year-end 2016, but in February 2016 the project was delayed until mid-2017.

Woodside said the final commissioning of the Wheatstone LNG Train 1 is nearing completion.

The Australian player added that the offshore platform hookup and commissioning required for LNG Train 1 startup was complete and trunkline pressurized, ready to supply gas onshore.

At the time of the installation in 2015, the Wheatstone platform was the largest offshore gas processing platform ever installed off Australia, with a topsides weight of about 37,000 metric tons.

The project will develop the Wheatstone, Iago, Julimar and Brunello gas fields. The Wheatstone and nearby Iago natural fields lie about 200 km (124 miles) north of Onslow off the Pilbara coast. The Julimar and Brunello fields will be tied back to the central processing platform.

Woodside did not give an exact date for Wheatstone startup. LNG Train 2 startup is expected between six and eight months after LNG Train 1 startup, Woodside said.

ExxonMobil Goes Cool On East Natuna

U.S. major ExxonMobil "no longer wishes to continue further discussions or activity" involving the East Natuna natural gas block offshore Indonesia, which is estimated to hold one of the world's largest reserves of undeveloped gas, according to a Reuters report.

Erwin Maryoto, vice president of public and government affairs for ExxonMobil Indonesia, said the decision was taken after completing a "technology and market review."

ExxonMobil's exit likely means further delays in developing a field that was discovered in the 1970s. Problems with the field have included contract disputes and the remoteness of the block, which is on the southern edge of the South China Sea, Reuters reported.

The East Natuna Field holds about 1.3 Tcm (46 Tcf) of recoverable gas resources, according to ExxonMobil, although it comes with a CO_2 content of more than 70%, which increases the production costs.

State-owned Pertamina had expected to sign a production-sharing contract with ExxonMobil and Thailand's state player PTTEP for the project in 2016, but more delays set this back.

Indonesia's government has received a letter from ExxonMobil on its decision to pull out of the gas block, Wiratmaja Puja, director general of oil and gas at the Energy Ministry, told reporters.

"Surely Pertamina wouldn't be able to develop the block alone, we need a partner," Syamsu Alam, Pertamina's upstream director, told Reuters.

—Steve Hamlen

Aker BP Works On PDO For Three Fields Offshore Norway

Aker BP said it is preparing to submit to Norwegian authorities plans for development and operation (PDO) for the Valhall West Flank, Snadd and Storklakken fields by year-end 2017.

Speaking on field developments during the company's second-quarter earnings presentation, Aker BP CEO Karl Johnny Hersvik said the company is on track with its operated projects and partner Statoil is doing an "excellent job" on Johan Sverdrup.

"Even though these are smaller projects compared to Johan Sverdrup they are attractive investments with breakeven prices well below $45 per barrel," Hersvik said during the presentation. He noted that the company was on track with its operated projects.

Valhall West Flank: Located in the Norwegian North Sea, the field would be developed as an unmanned installation with 12 well slots tied back to the Valhall field center. Aker BP has said the goal is to submit the PDO in second-half 2017. Production startup is expected in 2020.

Snadd: The development, which includes six subsea wells tied back to the *Skarv* FPSO unit, is progressing. Aker BP anticipates submitting a PDO for the development in fourth-quarter 2017. First gas is expected in 2020.

Storklakken: The subsea development ties back to the *Alvheim* FPSO unit via Vilje. Startup is expected in 2020.

While Aker BP serves as operator for the Valhall West Flank, Snadd and Storklakken fields, it is a partner in the Statoil-operated Johan Sverdrup development, holding an 11.6% interest. Hersvik said Phase 1 facility's construction was about 60% complete by the end of the second quarter. Most major contracts have been awarded, platform construction is ongoing and the first steel jacket is completed, he added. Meanwhile, headway is being made on drilling 10 water injectors. This follows completion of eight producers and four pilot wells. The companies are targeting second-half 2018 to deliver the PDO for Phase 2 of the project.

Turning to the area north of Alvheim and Krafla/Askja, Hersvik said "This could potentially become our next major development project. Gross resources in the area are estimated to be in excess of 400 million barrels of oil equivalent but spread across a number of discoveries."

In June the licensees—Aker BP, Statoil and LOTOS—agreed to evaluate joint area development for the north of Alvheim area. One solution is for a field hub, led by Aker BP, with a processing platform in the middle of the area. The other option is for two unmanned processing platforms—one each in the Krafla/Askja, operated by BP, and the North of Alvheim area, operated by Aker BP.

A concept selection is targeted for first-quarter 2018, he said.

—Velda Addison

DEVELOPMENT BRIEFS

Maersk Oil Wraps Up Culzean Jacket Installation

Maersk Oil has finished installing the three jackets for its HP/HT Culzean development in the U.K. North Sea.

The milestone was reached July 20 when installation of the central processing facilities and the utilities and living quarters jackets was completed. The wellhead platform jacket was installed in 2016. The company said Heerema built all three jackets and installed them with the Thialf crane vessel.

Combined, the jackets weigh more than 22,000 tonnes, which is the equivalent of about 30 jumbo jets per jacket, according to Martin Urquhart, project director for Culzean.

Located at a water depth of about 88 m (289 ft) with a pressure of about 13,500 psi and a temperature at about

Maersk Oil CEO Gretchen Watkins is shown at the final installation of the third Culzean jacket in the U.K. North Sea. (Source: Maersk Oil)

175 C (347 F), the Culzean Field is estimated to produce between 60,000 boe/d and 90,000 boe/d.

"Culzean was sanctioned less than two years ago and already we've progressed the project over the halfway mark," said Maersk Oil CEO Gretchen Watkins. "We're continuing to hit our milestones on time, and this progress means we're on track to deliver first gas in 2019."

The field was discovered in 2008.

Saudi Aramco Awards WorleyParsons FEED Work For Marjan Oil Field

Saudi Aramco has selected WorleyParsons to provide project management and FEED services for its Marjan Oil Field Development Program, the Australia-based engineering firm said in a news release.

The firm's work will cover the offshore oil and gas facilities and the onshore upstream and downstream parts of the project. WorleyParsons said it will execute its services from its office in Al-Khobar in the Kingdom of Saudi Arabia with support from other WorleyParsons offices.

The Marjan oil field is located offshore Saudi Arabia's east coast. Saudi Aramco is expanding the oil field to meet increased domestic gas demand.

TAQA Taps Schlumberger For Otter Field EPCIC Work In North Sea

OneSubsea and Subsea 7 are working together on what is expected to result in the longest subsea multiphase boosting tieback in the U.K. North Sea.

TAQA has awarded OneSubsea, a Schlumberger company, an engineering, procurement, construction, installation and commissioning (EPCIC) contract for the subsea multiphase boosting system for the Otter Field in the U.K. North Sea, according to a news release.

Working with Subsea 7, its subsea integration alliance partner, OneSubsea will supply and install a subsea multiphase boosting system, which includes topside and subsea controls as well as associated life-of-field services, Schlumberger said in a news release.

The project will result in a 30-km (19-mile) subsea tieback to the TAQA-operated North Cormorant platform, making it the longest subsea multiphase boosting tieback in the U.K. North Sea, according to Schlumberger. OneSubsea and Subsea 7 will deliver the turnkey integrated project from design through supply, installation and commissioning.

Brazil Approves Long-term Tests At Petrobras Libra Platform

Brazil's environmental agency Ibama has issued an operating license for long-term tests at the Pioneiro de Libra floating platform operated by Petrobras, according to a statement on the agency's website.

The license was issued on the condition that the operators of the platform in the Libra Field, located on the

Santos Basin, monitor marine life and develop a plan to control pollution in the area.

Panoro Reaches Final Investment Decision For Dussafu Oil Fields

Panoro Energy subsidiary Pan Petroleum Gabon and partner BW Offshore have made a final investment decision regarding development of the Dussafu oil fields offshore Gabon.

Panoro said it has approved BW Offshore's proposed work program, which includes two initial horizontal wells at Tortue in the Gamba and Dentale reservoirs. The wells will be tied back to a leased FPSO unit. Plans also call for drilling an appraisal sidetrack in the northwest section of the Tortue Field, according to a news release.

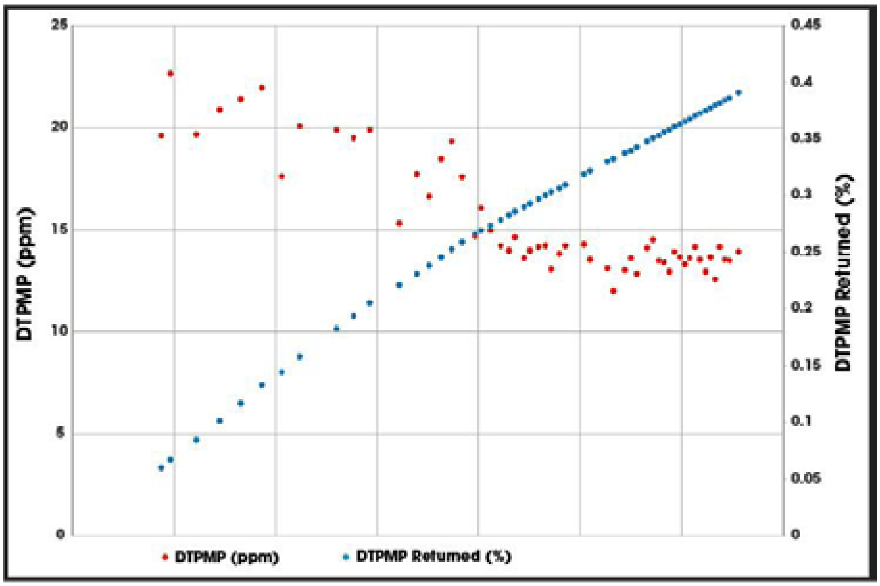
In addition, the partners are working to update resource estimates, working with Netherland Sewell and Associates.

The companies hope to "move forward at full speed." First oil is anticipated in second-half 2018.

—Staff & Reuters Reports

TECHNOLOGY

New Proppant Technologies Deliver Cost Savings In The GoM



Performance of SCALEGUARD was monitored to confirm that the inhibitor release rate maintained control to reach the projected treatment duration target. (Source: CARBO)

The Lower Tertiary of the Gulf of Mexico (GoM) hosts ultradeepwater oil and gas fields that have long required advanced technologies to maximize their economic returns. One of the most significant challenges in this environment is the sheer depth at which the reservoirs are located—typically below more than 1.6 km (1 mile) of water and in excess of an additional 6,096 m (20,000 ft) of rock. At this depth, extreme downhole pressures during the drilling and completion phases have mandated the development of completely new equipment and products designed specifically for these extreme environments.

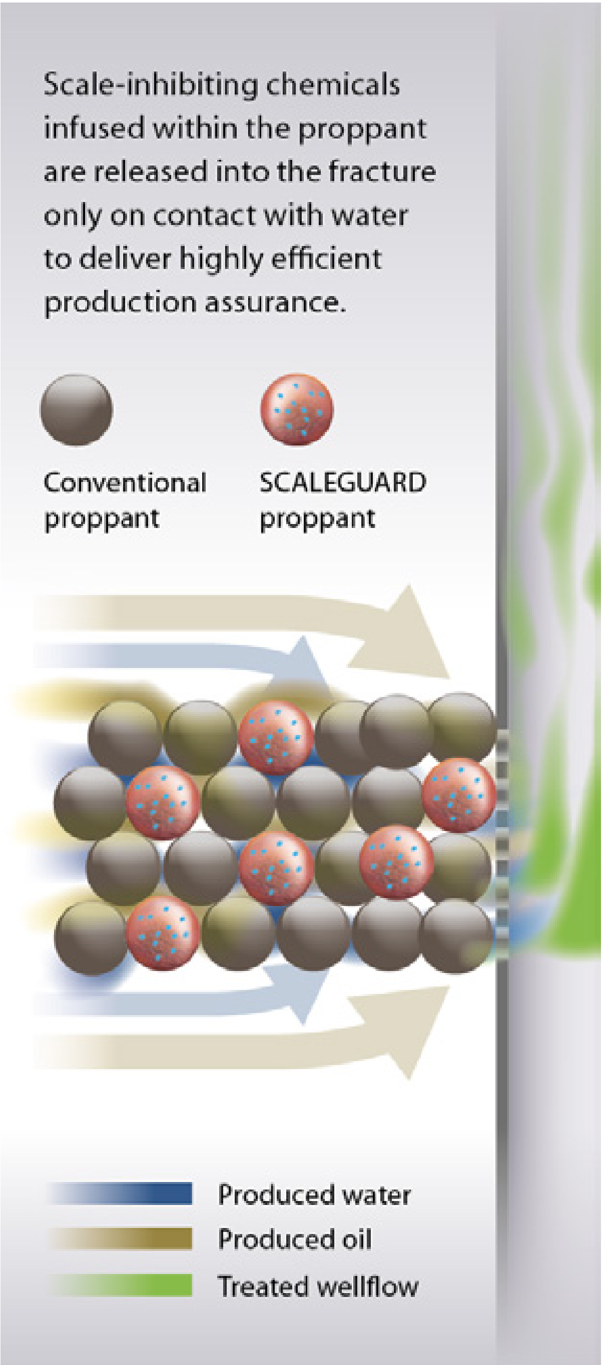
Stress-resistant Proppant

After years of research into materials that would perform well in ultradeepwater high-pressure (HP) environments, CARBO developed a proppant at the request of a major oil and gas operator in the deepwater GoM.

KRYPTOSPHERE HD is an ultraconductive high-density ceramic proppant technology designed to withstand the elevated closure pressures at these tremendous depths and extreme cyclic loading conditions for the life of the well. While its manufacturing process still employs typical ceramic steps—pelletizing and sintering—the new process modifies the manner in which the pellets are made. It aims to enable operators to attain higher flow rates at the highest closure stresses and features precision-engineered strong round single-mesh-sized and smooth proppant grains along with an advanced internal microstructure. The sphericity and smoothness of the grains reduces erosive effects and creates a fracture with more space for hydrocarbon flow.

As a result of the improved technology features, significantly higher baseline conductivity at stresses above 10,000 psi compared to typical bauxite-based high-strength proppant were observed, with KRYPTOSPHERE HD maintaining the highest flow rates and levels of conductivity for the productive life of the fracture. The higher flow rates and increased proppant durability increases recovery and return on investment, which lowers finding and development costs per barrel of oil equivalent.

The use of the newly developed proppant technology in the GoM's Lower Tertiary was in conjunction with a major operator's first development in this reservoir. Seeking to maximize the productivity of its wells, the operator performed fracture and reservoir modeling to



(Source: CARBO)

justify the use of this new advanced proppant. To date, IP results have proved better than expected from the wells, and they also have exhibited a higher negative skin than anticipated. As a result, all wells in Phase 1 of development have used or are scheduled to use the new proppant technology.

The operator also desired to minimize the impact of barium sulfate and calcium carbonate scale in its Lower Tertiary completions. When scale formation occurs, it can present itself in the fracture, perforations, downhole screens and inside the wellbore. Standard technology allows inhibition in the wellbore, but remediation and inhibition in the downhole completion, screen, perforations and fracture can be expensive and often difficult to accomplish. To solve this problem, proppant technology was successfully married with SCALEGUARD to address scaling tendencies for the operator.

A Unique Infusion

SCALEGUARD technology is a production enhancement technology in which scale inhibiting chemicals are infused directly into ceramic proppant. The technology uses a proprietary process to install interconnected internal porosity in a ceramic proppant grain, infuse that porosity with scale inhibitor and coat the grain with a semipermeable coating. These infused proppant grains are then substituted for a designed amount of the standard proppant and pumped into the fracture during normal fracturing operations. This technology provides a controlled release of the scale inhibitor, resulting in long-term protection against the formation of oilfield scales, and it has provided years of scale inhibition on hundreds of wells.

The technology is designed to safeguard the entire production network—from the fracture through the wellbore to the subsea/surface processing equipment—without compromising fracture conductivity, thereby protecting the operator's entire asset.

Each treatment can be engineered to last for the effective life of the well based on anticipated production profiles, reducing production maintenance requirements and costs, avoiding workovers and eliminating the potential for production system failures.

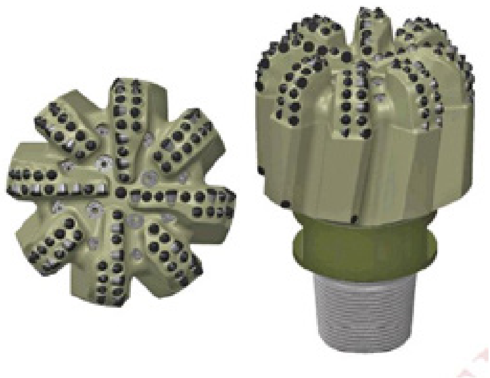
The same operator wished to deploy the same technology in its Lower Tertiary GoM wells. Due to the HP environment, SCALEGUARD technology was deployed into KRYPTOSPHERE grains, yielding to the ability to replace up to 20% of the standard KRYPTOSPHERE proppant with SCALEGUARD-based KRYPTOSPHERE without compromising fracture conductivity. This technology also has been deployed in all first-phase wells for this particular operator.

Scale residual results indicate that the scale inhibitor met the operator's dual objectives of maintaining high conductivity while preventing scale formation and eliminating the need for costly remedial treatments. Furthermore, it is projected that millions of barrels of water will be inhibited in each well.

To simultaneously prevent the formation of scale while maintaining high conductivity in Lower Tertiary GoM completions, the combination of proppant-delivered scale-inhibiting technology and ultraconductive ceramic proppant is recommended. Together, they continue to gain market acceptance as technologies that are proven to deliver higher production wells and reduce the impact of scale, both of which are positively contributing to reduced finding and development costs per barrel for operators throughout the GoM. The success already documented in the completions using these technologies is encouraging the deployment of KRYPTOSPHERE in additional deepwater wells for other operators.

—Terry Palisch, CARBO

Drilling Technology Helps Petrobras Crack Presalt, Boost Production



Credit is being given to a drillbit with conical diamond element technology for presalt production gains offshore Brazil. (Source: Petrobras)

In June Petrobras reached a record high oil and gas output of 2.81 MMboe/d, up 0.6% compared to the previous month. The figures released by Brazil's state-owned oil company also indicate Petrobras and its partners in the presalt layer hit two new oil output highs: the monthly rate reached an average 1.35 MMbbl of oil and the single-day production hit 1.42 MMbbl on June 19.

The success in the presalt is being driven by large investments in research and technology, aiming to produce oil at a lower cost.

The presalt covers about 350,000 sq km (135,135 sq miles) in water depths up to 3,000 m (9,843 ft) off the southern coast of Brazil. In early 2012 Petrobras and Schlumberger initiated a multidisciplinary R&D project to reduce presalt drilling costs.

As a result of this project, three drilling systems were designed—from the project phase to field testing using conical diamond element technology. Two factors were key to the success of this project: the application of a system engineering methodology and collaboration between research groups, and engineering and operations teams at Schlumberger and Petrobras.

High well construction cost in this environment motivated the search for a drilling solution that would bring a step change in drilling performance. Such an effort would be very expensive and time-consuming if using a trial-and-error approach in deep water. This led Petrobras and Schlumberger to sign a joint research project to develop a system engineering approach to identify the causes of low performance when drilling complex presalt carbonates with a goal of developing a fit-for-purpose solution.

Known as the "Drilling Optimization in the Presalt" project, this approach aimed to tackle several challenges ahead for operators such as analyzing the low ROP and premature bit damage to design fit-for-purpose drilling systems and maximizing the amount of laboratory testing, particularly screening drillbits in a real scale drilling simulator. Petrobras invests about $476 million in R&D and innovation with a major focus in the E&P segment, which accounts for 75% of the budget.

"This value is higher than last year and will continue to grow in the coming years due to the increase in our production curve," said Paulo Barreiros, technology management manager for CENPES, Petrobras' R&D Center. "Our major focus on developing technology is to produce more at a lower cost."

Among the strategies implemented was the design of a drillbit.

Named StingBlade, Model ER26769, this new drill design was developed through a technological cooperation agreement between Petrobras and Schlumberger, which was started in November 2011 and completed in November 2015.

According to CENPES, the drillbit was developed in 48 months. The first test was performed with an 8½ diameter drillbit. The other three tests were performed with a 12¼-in. drillbit. This technology greatly increased the presalt carbonate drilling yield, surpassing previous benchmarks and reducing the cost by between 15% and 20% in field-tested prototypes. The expected reduction in capex can reach the equivalent of the daily cost of drilling a well.

This drillbit was developed specifically for the presalt carbonate rock, which was not as well known by Petrobras beforehand. In the laboratory tests the characteristics of the test specimens (rocks), mainly hardness and heterogeneity, were adjusted to simulate the rocks found in the presalt carbonate.

Petrobras set a new presalt production monthly record of 1.35 MMbbl/d in June. (Source: Petrobras)

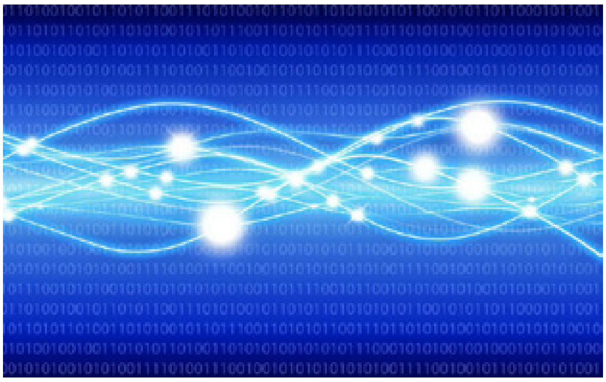
In the last field test performed by Petrobras, use of this drillbit increased ROP by 11.5% and the drilled gap by 25%. The benchmarking values used were: 219 m (719 ft) of perforated interval with a penetration rate of 2.6 m/hr. "The technological difference of this type of drillbit is its cutter, which has shown potential to greatly increase the drilling efficiency of the presalt reservoir carbonate rocks. The methodology used in this development was considered as an example for future technological developments," Petrobras said in a statement.

There is no depth limit for this type of drillbit since it has no moving parts, and depth does not pose limitations on its use. The type of tapered diamond cutter sets it apart from other drillbits used in the post-salt and presalt. This technology allowed the development of a cutter with greater resistance to impact and abrasion when compared to traditional cutters.

The StingBlade conical diamond element bits were launched in 2014 by Smith Bits, a Schlumberger company.

—Brunno Braga

Oil, Gas Sector Rides Digital Technology Wave



The move to incorporate more digital technologies into projects comes as the oil and gas industry copes with lower commodity prices. (Source: Shutterstock.com)

Challenges and opportunities are plentiful in the digital oil field. Data are scattered across different places, a multitude of software is being used and money is tight. However, data are abundant, and technologies exist to put it to use.

Not being able to clearly identify returns on investment for digital technologies, among other reasons, have left some companies in the oil and gas field paralyzed—buried in paperwork, trapped with legacy systems and slowed by the search for data needed to get work done.

But some companies have dived into the digital transformation, and the plunge appears to be paying off.

"Some have seen as much as a dollar or more per barrel being gained in the capital projects area," Greg Mitchell, managing director for Deloitte Consulting, said during a recent webinar on digital capital projects. "So it can be dramatic and significant, and a lot of those values are being delivered now."

The move to incorporate more digital technologies into projects comes as the oil and gas industry copes with lower commodity prices and works to gain efficiency. Capital projects groups are starting to attach themselves to the digital transformation wave by digitizing assets and processes, according to Deloitte.

Their actions have ranged from what could be considered baby steps to major leaps.

"Some companies have declared success because they now have all of their drawings in a PDF and have a SharePoint library, or some other document repository, and now people can try to search and find them," Mitchell said. "That's really a fundamental step, but there is so much more that can be done in the capital projects area."

Wearable Technology: Instead of accessing hardcopy documentation or looking for documents on a laptop or tablet, smart hardhats or smart glasses could be used to give real-time access to documents and improve communication among staff, according to Mitchell. Further benefits include having access to hands-free handbook information and remote assistance.

Drones: The use of drones has already taken off in parts of the oil and gas industry such as inspections and land seismic operations. Drones also can be used to not only inspect hazardous situations but also to conduct health and safety assessments before work crews arrive.

Blockchain: As defined by IBM, blockchain is a "shared ledger for recording the history of transactions that cannot be altered." Mitchell said Deloitte believes blockchain will have a dramatic impact on capital projects, especially considering a project can involve many contractors. Being able to see what each other is doing and quickly reconciling transactions are among the benefits. Blockchain, he said, can enable validation on the financial side as well as change orders, transmittals or design drawings—putting everyone on the same page quicker and more efficiently.

Live Fabrication: This area involves companies thinking of themselves more as manufacturers in which they can "rinse and repeat and drill the next hole and the next hole," he said. Live fabrication could provide more visibility to operations, allowing tracking of processes, products and raw materials. Potential benefits include "increased visibility into the fabrication process while reducing rework, warranty costs, component inventory and prime product inventory."

RFID/Tracking and Traceability: Live fabrication complements radio frequency identification (RFID) technology. As explained by Deloitte, the process of identifying materials typically involves manually entering information into a warehouse inventory system. However, RFID technology can read tags faster and include more information. Other potential benefits include reducing the number of tock-outs and repurchases.

Digital Asset Management: An emerging concept is looking at assets holistically, Mitchell said. It involves breaking down silos and connecting, for example, those responsible for geological and seismic work to those doing workovers or building assets or equipment. "Intelligent asset management capabilities can monitor the life cycle of asset management."

McDermott is among the companies that is digitizing its processes. The offshore engineering and construction company, working with Dassault Systèmes' 3D Experience platform, is piloting Project Lifecycle Management technology. McDermott aims to simplify work processes into one integrated, agnostic engineering platform with the software. Data from the Project Lifecycle Management are combined with 3-D modeling software, creating a digital twin.

"The real power and value is not about individual technologies," Mitchell said. "It's about bringing those technologies together in a cohesive way to impact the business process, deliver value and improve things that are happening."

—Velda Addison

TECHNOLOGY BRIEFS

Trendsetter Completes Live Well Operations Of 15K-psi Subsea System

Trendsetter said the campaign was the first carried out with a hydraulic well intervention system certified by a U.S. Bureau of Safety and Environmental Enforcement approved independent third party. (Source: Trendsetter)

Houston-based Trendsetter Engineering has finished live well operations with its new 15,000-psi subsea hydraulic intervention system known as STIM, the company said in a news release.

The campaign, which was conducted from February through March, consisted of acid stimulation on three wells with water depths as deep as 2,195 m (7,200 ft), pressures up to 12,500 psi and sustained pump rates of 10 bbls per minute.

"The successful operations of our 15,000-psi hydraulic intervention system (STIM) on a live well signals the official entry of Trendsetter into the subsea well servicing market," Mike Cargol, vice president of rentals and services for Trendsetter Engineering, said in the release. "Working with our Offshore Services Alliance partners C-Innovation and Halliburton, we are excited about what the future holds for both our company and this innovative team."

Delmar Releases System To Help Avoid Storms, Improve Efficiency

Delmar Systems has released its new RAR Plus and MOOR-Max releasable mooring system. The RAR Plus is the next generation of rig anchor release (RAR) systems, building on proven acoustic release technology by adding key features such as a manual backup release method and increasing the ultimate and release load ratings, a press release stated.

The RAR Plus transmits both direct and indirect line tension measurements from internal sensors for real-time display onboard the rig in a user-friendly graphical user interface. The RAR Plus is a key component in the MOOR-Max releasable mooring system. The MOOR-Max system provides a mooring system for mobile offshore drilling units to avoid storms or improve rig move efficiency. It is the only mooring system that combines proven acoustic mooring release technology with efficient proprietary methods.

(Source: Delmar Systems)

"Not only does the MOOR-Max system allow rigs to significantly mitigate risk by evading cyclonic storms or ice floes, but it also reduces critical path time when disconnecting rigs for transit to the next location," said John Shelton, Delmar Systems vice president of engineering.

GE Offers Integrated Service For Offshore Oil, Gas Water Treatment

GE Water & Process Technologies has released its new OnBoard service offering, a customizable, total integrated water treatment solution and service plan for offshore oil and gas producers, a press release stated.

OnBoard incorporates digital technologies, remote monitoring and diagnostic software, membranes, chemicals, sulfate removal technology, and offshore field and process expertise. The service helps producers improve operations, performance and profitability at offshore water treatment facilities. By choosing the OnBoard program parameters that match their unique needs, offshore oil and gas producers and operators have the potential to decrease clean-in-place time, improve recovery rates and lower maintenance costs.

The program is also designed to increase sulfate removal unit recovery by up to 5% and decrease clean-in-place hours and same-day troubleshooting.

New Salinity System Aims To Increase Flow Assurance

Emerson Automation Solutions has released the Roxar Salinity Measurement System for the sensitive, accurate and real-time measurement of saline water in gas production wellstreams, a press release stated.

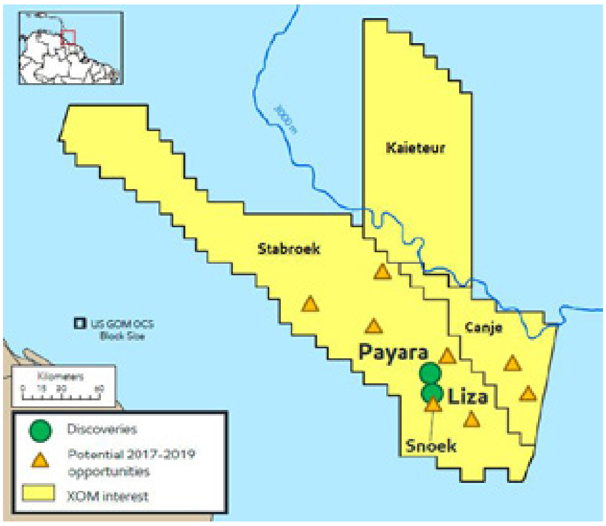
Through the new system operators can instantly identify changes in the flowstream and the smallest amounts of saline water at never previously achieved levels of sensitivity. This enables the operator to take immediate remedial action to prevent threats to production such as scaling, hydrate formation and corrosion. The onset of formation water and its salinity, if not controlled, can lead to well shutdowns and cost producers millions in unplanned shutdown time.

The system is a key element of the Roxar Subsea Wetgas Meter and is based on microwave resonance technology. It provides quantitative and qualitative real-time salinity measurements in many types of field conditions but particularly in the high gas volume fraction/wet gas flows that characterize wet gas fields.

—Staff Reports

EXPLORATION

ExxonMobil Strikes More Oil Offshore Guyana



The Payara-2 discovery boosts the Payara resource estimates to about 500 MMboe. (Source: ExxonMobil)

ExxonMobil Corp. has chalked up another win offshore Guyana where its latest Payara well has hit oil, bringing the estimated gross recoverable resources for the Stabroek Block up to as much as 2.75 Bboe.

"Payara-2 confirms the second giant field discovered in Guyana," Steve Greenlee, president of ExxonMobil Exploration Co., said in a July 25 company statement. "Payara, Liza and the adjacent satellite discoveries at Snoek and Liza Deep will provide the foundation for world class oil developments and deliver substantial benefits to Guyana. We are committed to continue to evaluate the full potential of the Stabroek Block."

The success story unfolding offshore Guyana has been a positive for oil and gas exploration—an area that saw deep spending cuts in recent years as the downturn bit into profits and prompted companies to pause high-dollar drilling plans. But projects believed to have the greatest potential survived, and the effort is paying off for ExxonMobil and its partners offshore Guyana.

Drilled to a depth of 5,812 m (19,068 ft) in about 2,135 m (7,000 ft) of water, the Payara-2 well hit 18 m (59 ft) of oil-bearing sandstone described by ExxonMobil as being high quality. The well was drilled by Esso Exploration and Production Guyana Ltd., an ExxonMobil affiliate.

The discovery boosts the Payara resource estimates to about 500 MMboe, while increasing the estimated gross recoverable resource for the 26,800-sq-km Stabroek Block—where the offshore Guyana discoveries are located—to between 2.25 Bboe and 2.75 Bboe. The latest well is located 20 km (12 miles) northwest of Phase 1 of the play-opening Liza oil discovery.

The Payara-2 discovery comes just over a month after ExxonMobil made a final investment decision to proceed with the Liza oil discovery, which is expected to initially produce up to 120,000 bbl/d. Production is expected to start by 2020.

As part of the more than $4.4 billion Phase 1 project, the company said it will use a subsea production system and an FPSO vessel to develop about 450 MMbbl of oil. SBM Offshore landed the contract to construct, install, lease and operate the converted very large crude carrier FPSO unit that will be spread moored in a water depth of 1,525 m (5,003 ft). Development plans also include four drill centers with eight production wells, six water injection wells and three gas injection wells.

Esso E&P Guyana Ltd. is the operator with a 45% interest in the block. Hess Guyana Exploration Ltd. holds a 30% interest, while CNOOC Nexen Petroleum Guyana Ltd. has 25%.

—Velda Addison

EXPLORATION BRIEFS

CGG Wins Data Processing Contract Offshore Brazil

Petrobras has chosen CGG to process seismic data from a 3-D ocean-bottom node (OBN) survey covering 2,180 sq km (842 sq miles) in Brazil's deepwater Santos Basin, a news release said.

CGG said this survey will be the largest node survey ever acquired and processed in the industry.

The survey will be acquired by Seabed Geosolutions, CGG's joint venture with Fugro. The dataset will be processed in CGG's Rio de Janeiro Subsurface Imaging Center, the release said.

"CGG is a natural choice for this high-profile OBN processing contract given our in-depth geological knowledge of the Santos Basin and our recognized track record and proven advanced technologies for OBN processing," CGG CEO Jean-Georges Malcor said. "OBN surveys are one option at present for acquiring full-azimuth data offshore Brazil, and we will work closely with Seabed Geosolutions to deliver the best images of the subsurface in the highly prospective Santos Basin."

Brazil Publishes Contract Model For 14th Round Oil-rights Auction

On July 19 Brazil's oil watchdog ANP published the model contract for its 14th round auction of oil and natural gas exploration rights scheduled for Sept. 27.

On offer are 287 blocks in the offshore basins of Sergipe-Alagoas, Espírito Santo, Campos, Santos, Pelotas and onshore basins in Parnaíba, Paraná, Potiguar, Recôncavo, Sergipe-Alagoas and Espírito Santo.

If all blocks are assigned, the government will earn a minimum of about $537 million.

ANP Director Decio Oddone said on July 18 he expects more bids this round thanks to a contract model that will be more attractive to investors.

Among the changes, the 14th round eliminates local content as criteria in the bidding process, heeding a long-standing demand of oil majors, and introduces lowers royalties for less explored areas and mature basins, which pose greater risks.

Statoil Says Norwegian Arctic Gas Find Disappoints

Statoil made a smaller-than-expected gas find in the Barents Sea near its Snoehvit gas field, the company said July 17.

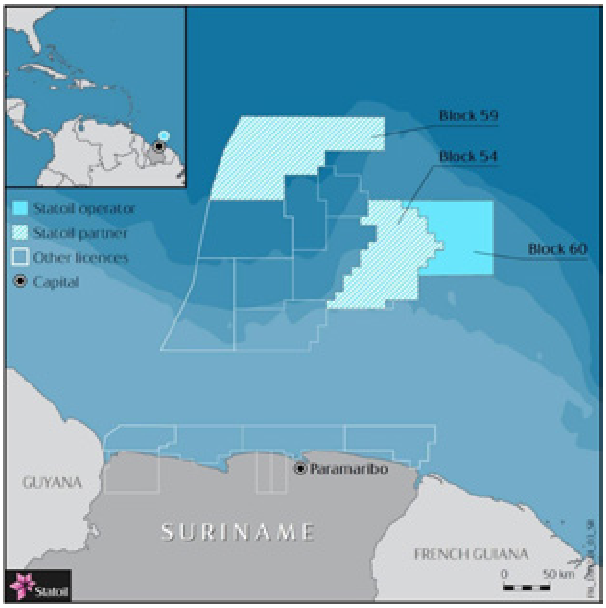
The find at the Blaamann well is estimated to hold up to 3 billion standard cubic meters of recoverable gas. No oil was found.

"We were exploring for oil and this is not the result we were hoping for," Jez Averty, Statoil's head for exploration in Norway and Britain, said in the statement.

Statoil has a 50% stake in the license, called PL 849, with partners Eni (30%) and Norway's Petoro (20%).

Statoil will exploit the gas via existing infrastructure for the Snoehvit Field.

Suriname Signs Offshore Oil Deals With ExxonMobil, Hess, Statoil



Statoil has won rights to develop Block 60 offshore Suriname. (Source: Statoil)

Suriname's state oil company Staatsolie said it signed production-sharing contracts involving ExxonMobil Corp., Hess Corp. and Statoil ASA for two blocks off the coast of the South American nation.

The 30-year E&P agreements involve the areas known as Block 59, to be developed by a consortium consisting of ExxonMobil and Hess, and Block 60, to be developed by Statoil.

The area off the shoulder of South America has generated interest from oil companies after Hess and ExxonMobil discovered crude off the coast of nearby Guyana.

Hess and Statoil already own stakes in Suriname oil projects.

Staatsolie will be able to take up to a 10% stake during the development and production phases.

Staatsolie has said 2016 was one of the most difficult years in its 36-year history due to low oil prices, though the company managed to reach a gross profit of $13 million.

UK Offers 12 Licenses For Offshore Acreage

The UK's Oil and Gas Authority (OGA) has offered 12 licenses to 11 operators under the 2016 Supplementary Offshore Licensing Round.

Originally, 14 blocks were offered in the round, which was launched in response to industry nominations of areas outside of those covered by the 2016 frontier 29th Licensing Round. Bidding closed in March 2017.

The blocks on offer have locations across the U.K. Continental Shelf from the southern North Sea to East of Shetland.

"The round offered blocks under flexible terms, enabling applicants to define a license duration and phasing that will allow them to execute their optimal work program," the OGA said.

The OGA received 15 applications covering 11 blocks. The OGA said it is ready to offer 12 licenses covering these 11 blocks.

—Staff Reports

FLOATER BRIEFS

Prelude Floating LNG Vessel Arrives In Australia

The *Prelude* FLNG facility is towed to Australian waters. (Source: Shell)

Shell's 488-m (1,601-ft) long *Prelude* floating LNG (FLNG) vessel has arrived offshore Australia at the Prelude Field, where next steps include hookup and commissioning after the vessel is secured with 16 prepositioned mooring chains, the company said.

Four anchor piles, constructed by West Australian-based CIVMEC, will hold each mooring chain to the seafloor.

The arrival marks a milestone for Shell's first deployment of its FLNG technology. The facility will produce 3.6 mtpa of LNG, 1.3 mtpa of condensate and 0.4 mpta of LPG from the Prelude Field, located about 475 km (295 miles) offshore Western Australia.

"Seven production wells will feed gas and condensate from the reservoirs via four flexible risers into the facility. All subsea connections join the facility via the turret. The turret's swivel design enables the facility to pivot according to wind and sea conditions while it remains fixed to the sea floor," Shell said on its website. "The *Prelude* FLNG facility has thrusters to ensure it remains steady during production and offloading, but it is a fixed facility, with no means of propulsion. The management of subsea wells and manifolds is carried out via umbilicals connected through the turret to the control room on the facility."

In a news release, Shell Australia Chairman Zoe Yujnovich described the arrival of *Prelude* as a new era for the Australian LNG export industry. "*Prelude's* arrival is a clear demonstration of Shell's longstanding commitment to investment and development in Australia—delivering significant economic benefits to the nation," Yujnovich said.

The *Prelude* project will employ 260 local workers onboard the facility during operations and create more than 1,500 jobs during the project's hookup and commissioning phase of the project, the release said. Shell said it expects to see cash flow from the project in 2018.

Ichthys Venturer Sets Sail En Route To Browse Basin

The Inpex-operated Ichthys LNG Project's FPSO unit sails away from near its construction site in South Korea. (Source: Inpex video)

Ichthys Venturer, the FPSO facility for the Inpex-operated Ichthys LNG project, has started its estimated one-month journey to Australia's Browse Basin after sailing away from waters near its South Korean construction site.

After traveling 5,600 km (3,480 miles) to its destination offshore Western Australia, Inpex said the facility will be permanently moored in 250-m (820-ft) deep water. There, it will undergo hookup and commissioning with the *Ichthys Explorer* central processing facility (CPF), located 3.5 km (2.2 miles) away. The FPSO facility will process and store condensate delivered from the CPF before periodically offloading it for export via carrier vessels.

"The *Ichthys Venturer* has been designed to withstand cyclonic conditions and is one of the largest and most advanced offshore facilities of its kind in the world," said Louis Bon, managing director for the project. "*Ichthys Venturer* has a storage capacity of 1.12 million barrels of condensate and will have a continuous operating life of 40 years, setting new benchmarks for durability."

SOFEC Wins Coral South Turret Mooring System Supply Contract

SOFEC Inc., a MODEC Group company, has scooped up the turret mooring system supply contract for the Eni-operated Coral South floating LNG (FLNG) project offshore Mozambique, according to a news release.

Under the contract, the mooring solutions specialist will be responsible for all engineering, procurement and construction activities for the internal turret mooring system and its ancillary components. The project is led by the joint venture of TechnipFMC and JGC Corp.

SOFEC also will assist in turret integration and offshore commissioning activities in Mozambique, the release said. Project delivery includes the turret mooring systems—which comprise the mooring legs, mechanical connectors and anchor piles—and fluid transfer systems, which include piping, swivels, safety and controls.

Designed to produce 3.4 million tonnes per annum of LNG, the Coral South FLNG facility will be moored in a water depth of 2,000 m (6,562 ft) in Mozambique's Area 4.

—Staff Reports

VESSEL BRIEFS

Mermaid Lands Contracts Offshore Indonesia, Middle East

Mermaid Maritime Public Co. Ltd. said it was recently awarded two subsea contracts with a combined estimated value of $4.6 million.

Work for the one contract, which was awarded by an engineering, procurement, construction, installation and commissioning contractor in the Middle East, involves a short ROV campaign for pipeline touchdown monitoring. The job is set to begin in third-quarter 2017.

The other contract will begin in fourth-quarter 2017. The work entails use of a diving vessel with work class ROV carrying out a subsea services project offshore East Kalimantan, Indonesia, for a global upstream oil and gas company.

Petrobras Sticks With Subsea 7 For Pipelay Support Vessels

Subsea 7 has secured contract extensions, valued at about $250 million total, for three pipelay support vessels on long-term day-rate contracts offshore Brazil, the company said in a news release.

The firm contract periods for the *Seven Waves*, *Seven Rio* and *Seven Sun* will end, respectively, in second-quarter 2021, third-quarter 2021 and second-quarter 2022. The day rates and commercial terms are the same as stipulated in the original contracts, Subsea 7 said.

—Staff Reports

POLICY BRIEFS

Brazil Mulls Easing Local Content Rules In Older Oil Contracts

Brazil's oil regulator may allow companies to apply more flexible local content rules to preexisting E&P contracts, the agency chief said on July 18, in a bid to revive projects put on hold due to costly requirements.

Decio Oddone, director of oil regulator ANP, said the agency would open a 30-day comment period on the proposal, followed by a hearing and publication of the rule in September. Contracts signed since 2005 but before more flexible rules went into effect this year would be eligible.

"We believe this new option will unlock investments, attracting capital and generating new hires, jobs and revenue," Oddone said at a press conference in Rio de Janeiro.

Many crude projects have been put on ice in Brazil, including exploration of the Libra oil field in the subsalt region of the Santos Basin, thought to be Brazil's largest oil reserve, due in part to steep costs stemming from tough local content rules.

Oddone said the ANP had received more than 230 requests for exemptions from the rules by companies with preexisting contracts, including one by state-controlled oil firm Petrobras, which has partnered with Total, Shell and others to develop Libra.

In February ANP sharply reduced local content requirements in future oil E&P contracts in a boon to oil companies but a major setback for local suppliers. If approved as proposed, the plan announced July 18 would extend the more flexible rules to older contracts.

Machine and equipment makers association ABIMAQ said it opposed the proposal, describing local content requirements as "low" and the decision as unilateral. The oil companies "have not only failed to comply with local content rules in the past ... they are now trying to get rid of those obligations," ABIMAQ Vice President Cesar Prata said.

The new resolution would also hammer out the rules for waiver requests and transfers of surplus local content, which have been pending for more than a decade.

Mexico Sets Date For Next Deepwater Oil, Gas Tenders

Mexico's oil regulator, the National Hydrocarbons Commission, set Jan. 31 as the date for the next round of auctions for deepwater oil and gas tenders in the Gulf of Mexico.

The so-called 2.4 auctions will offer 30 areas, of which 10 are in the Cordilleras Mexicanas deepwater basin, 10 others in the Salina Basin, nine in the Perdido Fold Belt off the U.S.-Mexico maritime border and one more in the Yucatan platform.

The Cordilleras Mexicanas deepwater basin is home to national oil company Pemex's Lakach natural gas project and located east of the Gulf Coast port of Veracruz.

Cordilleras Mexicanas is viewed by the oil and gas industry as having extensive untapped potential.

The auction will be the first time the basin has been made available to international oil majors, which for decades have profitably developed other fields in U.S. waters nearby.

Mexico's first deepwater oil auction in December 2016 included blocks from the Perdido Fold Belt straddling the U.S.-Mexico maritime border and the Salina Basin farther to the south.

A 2013 constitutional energy reform ended Pemex's decades-long E&P monopoly, paving the way for seven oil auctions since then.

—Reuters

BUSINESS

Tullow Oil Stays In Red As Weak Oil Prices Drag Down Asset Values

The *Prof. John Evans Atta Mills* FPSO vessel is shown at the Tweneboa, Enyenra, Ntomme (TEN) fields offshore Ghana. (Source: Tullow Oil)

Tullow Oil reported a deeper-than-expected operating loss for the first half as lower oil price expectations forced it to book hefty impairment charges, but the market welcomed news it had raised a cost-saving target by $150 million.

London-listed Tullow, whose main operations are in Africa, stayed in the red in first-half 2017 with an operating loss of $395 million, steeper than the $350 million loss expected by analysts. This was mainly due to a $572 million charge on its Ghanaian TEN oil fields, which it brought onstream last year. This extends Tullow's loss-making streak after it reported a third straight annual loss for 2016 in February.

But the firm, which appointed a new CEO and CFO in the past three months, is starting to turn a corner after it was hit hard by falling oil prices when it was spending heavily on new projects.

Tullow was free cash flow positive in the first half of the year at $205 million and managed to reduce debt to $3.8 billion, down from $4.8 billion at the end of 2016, mainly due to using the proceeds from a surprise rights issue. On July 26, Tullow also announced a fresh internal cost reduction target of $650 million by mid-2018 from a mid-2015 base.

"We believe the company has turned a corner. Tullow has the ability to generate free cash flow and further improve its balance sheet, whilst also continuing to offer high-impact exploration potential," analysts at BMO Capital Markets said.

The firm is gearing up to drill for oil offshore Suriname in an area close to where U.S. oil major ExxonMobil Corp. announced a new oil discovery and raised its resource estimate on July 25.

But shareholders expecting a reinstatement of the dividend will have to remain patient. CEO Paul McDade told Reuters the company was unlikely to do this before the end of next year.

"We see the dividend as a potential part of that overall shareholder return at the right time," he said, adding that bringing production from the TEN oil fields to full capacity over the coming 18 months would be one of the parameters to meet.

—Reuters

Saipem Could Land Work On Novatek's Arctic LNG 2 Project

Italy's Saipem is likely to get a subcontractor role in a new project to produce LNG in the Arctic by Russia's Novatek, one of Novatek's partners said.

Novatek, Russia's largest non-state LNG producer, is aiming to produce as much LNG as the world's biggest exporter Qatar and is drawing up plans to build a second plant, known as Arctic LNG 2, on the Gydan Peninsula that juts into the Kara Sea. Production is due to start in 2022-2023.

Four sources told Reuters earlier this month that Saipem was expected to be chosen to build offshore platforms for the facility.

"It is planned that Saipem will take part as a subcontractor to design the gravity-based units. That's where they have expertise and experience," said Boris Lim, head of NIPIGAZ, an engineering firm on the project and a Novatek partner.

The gravity-based units will sit on the seabed some 40 km (24.85 miles) from the onshore gas deposit and will produce and ship LNG, Novatek CEO Leonid Mikhelson said.

Mikhelson said Novatek was also in talks with Saipem to possibly give the Italian firm a partner role in managing the company that will oversee the shipyard which is to be built on the Kola Peninsula in north-west Russia. He said more foreign firms might also participate.

Novatek started building the wharf—expected to cost between $1.3 billion and $1.5 billion—in June. The first dock is expected to be ready in 2019.

Mikhelson, Russia's richest businessman according to *Forbes* magazine, said Arctic LNG 2 would have three lines with a capacity of around 6 million tonnes per year each.

The Utrenneye gas field will be the resource base for Arctic LNG 2. "We have defined production capacity at just over 30 billion cubic meters [1 Tcf] per year... which is enough to compensate for the project's costs," Mikhelson said of the gas field.

For now, Russia has just one operational LNG facility, run by Gazprom on the Pacific island of Sakhalin.

Novatek is due to start producing LNG at its Yamal LNG project in the fourth quarter. That project will eventually produce around 16.5 million tonnes of LNG per year.

Mikhelson said Novatek was in talks with a number of companies to join Arctic LNG 2, including his current partners in Yamal LNG which is co-owned by France's Total, and China's CNPC and the Silk Road Fund.

Novatek is under U.S. sanctions over Moscow's role in the Ukraine crisis, which limits the company's ability to deal with U.S. financial entities. Novatek raised financing for Yamal from China, Russia and some European lenders.

—Reuters

BUSINESS BRIEFS

TechnipFMC Shares Slide After Company Says It Overstated Earnings

A TechnipFMC ROV is deployed to provide subsea services. (Source: TechnipFMC)

TechnipFMC's shares slid on July 25, a day after the oil services company said it had overstated its first-quarter net income by $209.5 million.

The company said late on July 24 that the overstatement stemmed from accounting errors related to its auditing of foreign exchange movements after examining the matter with its management and PricewaterhouseCoopers.

TechnipFMC's accounting error added to negative sentiment hitting the oil services sector, with Italian rival Saipem—controlled by oil major Eni—also issuing a profit warning on July 25.

TechnipFMC shares were down by about 4% in New York and in Paris, where the company has a secondary stock market listing, while Saipem shares were down 1.5%.

Oil service companies have been struggling to fill order books as oil majors defer projects and cut billions of dollars in costs to offset low crude prices.

"We are steering clear of these stocks for now, due to the tough market conditions facing them," said Keren Finance fund manager Benoit de Broissia.

Delek Completes Spinoff Of 9.25% Stake In Tamar

Delek Drilling said it has completed spinning off a 9.25% stake in Israel's Tamar natural gas field into a new company, Tamar Petroleum , which was scheduled to begin trading in Tel Aviv on July 24.

The Israel-headquartered company has said it expects to get $980 million from selling the stake—about $837 million in cash and the rest in Tamar Petroleum shares, which it will begin selling off in about six months.

Tamar Petroleum in June raised $650 million in a Tel Aviv debt offering and another $330 million in a share offering.

Delek Drilling, a unit of conglomerate Delek Group, said in a statement to the bourse that it had received the necessary regulatory approvals to complete the transaction. It still has a 22% stake in Tamar.

Anadarko Shrinks Quarterly Loss, Slashes Capex For Rest Of 2017

U.S. oil producer Anadarko Petroleum Corp. on July 24 said its quarterly loss shrank and that it would cut its 2017 capital budget by $300 million because of depressed oil prices.

The company posted a loss of $415 million, or 76 cents per share, compared to $692 million, or $1.36 per share, in the year-ago period.

Average daily sales volumes, the physical amount of crude and natural gas sold, fell 20% to 631,000 boe/d.

The U.S. Gulf of Mexico (GoM), where Anadarko has 10 operated assets, remains one of Anadarko's core focus areas. Anadarko reported GoM average sales volumes for second-quarter 2017 were 140,000 boe/d, which was down 12% compared to first-quarter 2017. "The reduction in volume was largely a result of planned maintenance and upgrades on multiple facilities during the quarter," the company said in its operations report.

The Woodlands, Texas-headquartered company also has assets in the U.S. onshore and Algeria as well as offshore Brazil, Colombia, Côte d'Ivoire, Ghana, Kenya, Mozambique and New Zealand.

Paragon Completes Restructuring Plan, Emerges From Chapter 11

(Source: Shutterstock.com)

Paragon Offshore Ltd., the Cayman Islands successor company to Paragon Offshore Plc, said the group has completed its corporate and financial reorganization.

The plan of reorganization under Chapter 11 of the U.S. Bankruptcy Code eliminated about $2.3 billion of secured and unsecured debt for the company. The new Paragon emerges with eight rigs currently operating plus a ninth rig expected to begin operations in August 2017, about $165 million of available cash on its balance sheet and $85 million of new debt, according to a news release.

"With a clean balance sheet and good liquidity, we emerge from bankruptcy as a stronger company—more focused on our core operating areas in the North Sea, Middle East, and India and better positioned to compete in the recovering, but still very challenging, offshore drilling industry," said Dean E. Taylor, the company's CEO and interim president.

In addition, the company has named a new board of directors. James Swent, a director of Energy XXI Gulf Coast Inc. and retired executive vice president and CFO of ENSCO, is the chairman. Other board members are:

- Mark G. Barberio, a director of Life Storage Inc., Exide Technologies and principal and founder of Markapital;
- Michael Clark, a director of Halcón Resources Corp. and a former partner and portfolio manager at SIR Capital Management;
- Paul P. Huffard IV, a director of Vubiq Networks and a former senior managing director in Blackstone's restructuring and reorganization advisory group;
- George Sandison, a director of Aspire Holdings and retired senior vice president of global E&P services for Hess Corp; and
- Zaki Selim, a director of Parker Drilling and GlassPoint Solar Inc. and retired president of Schlumberger Oilfield Services, Middle East and Asia.

A search, led by Korn Ferry, is also in progress to find a CEO for the company.

Centrica, Bayerngas Agree To Merge North Sea Oil Businesses

Centrica has agreed with Bayerngas Norge AS to merge the companies' North Sea assets, creating the region's largest non-major oil and gas producer and allowing Centrica access to younger fields and to lower its decommissioning liabilities.

The joint venture (JV), to be led by Centrica's head of E&P, will produce 50 MMbbl to 55 MMbbl in 2017 and have access to 625 MMbbl of proved and probable oil and gas reserves.

Centrica will own 69% of the new entity and raise its interests in younger fields, including the Cygnus gas field which started producing in December, as well as dilute its decommissioning costs and reduce its capital expenditure needs.

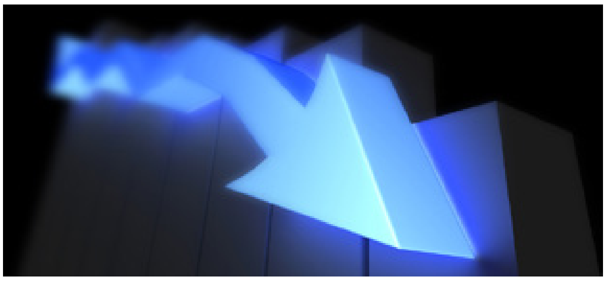
Bayerngas Norge, in return, gets access to a profitable business, further expertise and a bigger balance sheet.

"This joint venture creates a larger, more sustainable and more capable European E&P business," Centrica CEO Iain Conn said in a statement.

The British utility has been trying to reduce reliance on its oil and gas business following its decision to focus more on providing services in the energy retail market.

Hess Posts Bigger Loss As Oil Production Dips

Oil producer Hess Corp. reported a bigger loss in the second quarter as the company produced fewer barrels of oil due to a cutback in drilling.



(Source: Shutterstock.com)

The company said losses in the E&P unit—its biggest—climbed to $354 million in the second quarter ended June 30, from $328 million a year earlier.

Net production, excluding Libya, fell to 294,000 boe/d from 313,000 boe/d.

Hess cut its 2017 E&P capex to $2.15 billion from its previous guidance of $2.25 billion.

Like many of its peers, Hess is struggling to adapt to the dip in oil prices this year, which was not expected when 2017 capital budgets were crafted. Earlier this week, rival Anadarko Petroleum Corp cut its 2017 capital budget because of depressed oil prices.

Hess's total revenue fell to $1.23 billion from $1.27 billion. Net loss attributable to the company was $449 million, or $1.46 per share, in the reported quarter, compared with a loss of $392 million, or $1.29 per share, a year earlier. Hess said its corporate and interest expenses rose to $111 million from $75 million.

Seadrill Warns Again Of Chapter 11 As Debt Talks Continue

Offshore drilling contractor Seadrill again delayed restructuring its $14 billion in debt and liabilities on July 26 and reiterated that Chapter 11 bankruptcy was likely.

Once the biggest offshore rig firm by market value and the crown jewel in the business empire of Norwegian billionaire John Fredriksen Seadrill shares have fallen 99% from a September 2013 peak. The company's business has struggled as energy firms have slashed investment due to a more than 50% fall in the price of crude oil since 2014.

"(Seadrill) has reached an agreement with its bank group to extend the comprehensive restructuring plan negotiating period until Sept. 12," the firm said in a statement, pushing back a previous July 31 deadline and the latest of several delays.

The company is negotiating with more than 40 banks, including Norway's DNB, Sweden's Nordea and Denmark's Danske Bank as well as with bondholders and several rig-building yards.

In April, Seadrill warned its shares would lose almost all of their value and its bonds would be hit as it was preparing for potential bankruptcy proceedings.

African Petroleum Lets Blocks Sale Exclusivity Clause Lapse

African Petroleum has agreed to let an exclusive agreement lapse in talks to sell oil licenses in Gambia and Senegal, the company said.

African Petroleum had been in negotiations to sell a 70% stake in blocks A1 and A4 offshore Gambia to an unnamed third party along with another license in neighboring Senegal. The blocks, which could contain more than 3 Bbbl of oil, are adjacent to ones in Senegal where large discoveries have been made.

"The parties have mutually agreed to not extend the exclusivity agreement which expired today," African Petroleum said in a statement. "The company has been approached by other industry players that are interested to join the company in the A1 and A4 licenses when the situation with the Gambian government is resolved.

(Source: Shutterstock.com)

The oil ministry told Reuters that African Petroleum had failed a number of times to meet its commitments. The company has acknowledged that it did not meet a requirement to drill a well within the timeframe of the agreement.

African Petroleum CEO Jens Pace met with Gambian President Adama Barrow on July 13 to discuss the state of the exploration licenses and resolve the situation.

"The company expects formal feedback from the Gambian government in early August," it said, adding it had reiterated its position over its legal rights over the licenses.

Uncertainty over the status of some the most promising licenses in West Africa provoked a sharp drop in Oslo-listed African Petroleum's shares earlier this month.

Tele-Fonika Kable To Purchase JDR Cable Systems

JDR Cable Systems (Holdings) Ltd., a subsea umbilicals and power cables supplier, will be acquired by Tele-Fonika Kable (TFKable), a Poland-headquartered wires and cables producer.

The transaction, which is subject to regulatory approval and other customary closing conditions, is expected to close in third-quarter 2017.

Plans are for JDR, which is based in the U.K., to continue operating in its current locations.

The two companies are building on their long-term relationship.

"Both companies have a long history of collaboration, with TFKable being JDR's important business partner providing water blocked power cores for its cable and umbilical systems JDR's highly technical subsea systems, used in the global offshore oil, gas and renewable industries, allow its customers to power and control their offshore operations, and will enhance the range of cable solutions TFKable can provide to its customers," JDR said in a news release.

SBM Offshore, Repsol To Get $247 Million in Yme Insurance Settlement

Dutch oil industry services group SBM Offshore and Spanish energy firm Repsol will share an insurance payment of $247 million, less legal costs, related to a troubled Norwegian offshore project, SBM said.

SBM said it had reached an agreement in principle with nearly three quarters of the insurers who provided $500 million of primary cover for the Yme project with a final agreement expected to be wrapped up in the coming weeks.

SBM will receive a cash payment of around $247 million in full and final settlement with these insurers. After legal fees and other expenses have been paid, the proceeds will be shared equally with Repsol in line with a 2013 agreement, the company said.

The group said it continues to pursue its claim against all remaining insurers. The total claim presented by SBM Offshore to its insurers in 2014 in relation to the Yme platform was for $1.28 billion.

"The news is positive because it wipes out a big scar from the past," KBC analyst Tom Simonts said.

SBM built the Yme oil platform for Canadian oil company Talisman Energy and its partners but faced technical difficulties completing the project, which was evacuated in the summer of 2012 due to safety concerns. Talisman was later bought by Repsol.

Simonts also said the focus for SBM now shifts to Brazil, where the company is looking to settle a corruption probe that has prevented it from bidding for work in a major market.

Aker BP Ups 2017 Output View, Lowers Cost Outlook

Oil firm Aker BP, the second-largest operator of oil and gas platforms off Norway, raised its 2017 output guidance and lowered its production cost outlook as it posted second-quarter earnings roughly in line on July 14.

The company is the result of a merger between the Norwegian business of oil major BP and the Norwegian oil company Det norske controlled by billionaire Kjell Inge Roekke.

Aker BP said its output guidance for 2017 would be raised to a range of 135,000 bbl/d and 140,000 bbl/d of oil, against an earlier view of between 128,000 bbl/d and 135,000 bbl/d, while its production cost would be lowered by one dollar to $10/boe.

Its earnings before interest, tax, depreciation and amortization came in at $395 million, while a Reuters poll of analysts had expected $403 million, up from $175 million at the same time a year ago.

Aker BP offered a dividend of $0.185 per share, in line with expectations and at the same level as the dividend it offered in the last quarter.

—Staff & Reuters Reports

UPCOMING

The next issue of *Subsea Engineering News* will be distributed Aug. 10. Until then, visit *epmag.com*.

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