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TechnipFMC Gears Up To Unleash Revolutionary Subsea 2.0

TechnipFMC is aiming to take subsea oil and gas production to the next level by reducing the weight and size of equipment on the seafloor while also simplifying configuration for flowlines and installation.

The Subsea 2.0 tree is about 40% smaller than the previous version. (Source: TechnipFMC analyst day presentation)

Called Subsea 2.0, the company formed nearly a year ago by the merger of Paris' Technip and Houston's FMC Technologies shrinks the average size, weight and part count of the subsea tree, manifold and other subsea infrastructure by about 50%. The company said the change also is capable of cutting lead times, shrinking the manufacturing footprint and reducing manual activities in production.

The subsea system with a streamlined design can be installed in one run, TechnipFMC CEO Doug Pferdehirt said recently during the company's analyst day in Houston. The system integrates the installation of subsea production system (SPS) and subsea umbilicals, risers and flowlines (SURF), while eliminating the need for equipment such as pipeline end terminations and umbilical termination heads that sit between the SPS provider and the SURF provider.

"They don't accelerate production. They don't accelerate first oil. They don't improve the performance of the reservoir. They don't improve the flow rate," Pferdehirt said of the eliminated equipment. "It's the exact opposite. It's greater risk, greater uncertainty and greater challenges over the life of the asset. We are simply removing those."

The Subsea 2.0 design is simpler with the same functionality, explained Paulo Couto, senior vice president of integrated sub-systems for TechnipFMC.

The technology, which TechnipFMC said will be released Dec. 31, could lead to cost savings for part of the industry that has been hit hard by the downturn. Oil and gas companies, which reeled in less profit due to lower commodity prices, slowed offshore activity and cut spending.

"Our strategy is to make things cheaper, faster, accelerate production, resolve integrity issues and make it more serviceable," Couto said. "The goal is to lower the breakeven of the economics, enabling many more subsea fields, making more subsea fields viable."

Despite the potential savings for companies, TechnipFMC may still have some hurdles to overcome as analysts noted.

"Beyond qualification, the greatest hurdle is likely to be cultural," Barclays said in a note. "New concepts take time for acceptance within big organizations, particularly technologically disruptive ones. Despite the cost savings,

WHAT'S INSIDE

the oil and gas industry is notoriously slow to adopt a new concept. But another selling point is a reduction in risk: eliminating interface risk, creating more schedule certainty, dealing with only one team and a single warranty across the entire system."

The Journey

Subsea 2.0 is set to emerge after about three years of R&D work as crews worked to eliminate waste and incorporate more of a manufacturing mind-set. Subsea 2.0 builds upon the company's compact pipeline end manifold and horizontal connection system offering, taking the same concept to subsea trees.

Couto spoke about how the company deconstructed a large manifold down to each of its components, aiming to improve the design by getting rid of unnecessary parts without sacrificing quality or function. The manifold was reconstructed in a way that made it one-quarter of its original size and half the weight with 70% fewer parts.

The compact manifold (right) is about one-quarter of its original size and half the weight with 70% fewer parts. (Source: TechnipFMC analyst day presentation)

"A big enabler for this was the use of subsea robotics. With subsea robotics we are following the trend in other industries to replace hardware with software," Couto said, using the transition from tube TVs to flatscreen TVs as an example. "This replacement of hardware to software was to eliminate hundreds of electromechanical components from the hardware, simplifying the product."

Robotics also had a hand in improving the fabrication process with automated production, taking on cladding and handling more equipment with less human intervention.

The smaller subsea tree, which Couto called the "workhorse of the industry," is about 40% smaller, 50% lighter and has 60% fewer parts. The design process was similar in that the tree's components, which numbered about 10,000 total, was deconstructed and then designed and assembled for functionality.

"But we did not stop there," Couto said.

Using data from subsea wells from across the world TechnipFMC created pre-engineered project architecture, which enabled different configurations of the subsea equipment at the assembly line.

"Engineering will no longer be required after contract award," he said, noting the shift from "engineer-to-order" to "make-to-order."

"We are leveraging the full potential of the integration between flowlines and subsea hardware. … We are writing the future of this industry now," Couto said.

The Response

In an analysts note Barclays described the Subsea 2.0 technology as "an enabler to lower costs."

Pointing out how two-thirds of subsea development costs are related to installation, Barclays singled out the design's reliance on all electric trees and control systems, which eliminates traditional umbilical without the need for hydraulic power. The analysts also noted the system's electric trace heated flexible pipes replace traditional rigid jumpers that connect trees to the manifold and that two, instead of four, lighter construction vessels will be required.

TechnipFMC has carried out test cases with some of its clients. One involved a small field that comprises three wells with a manifold in the middle and a connection system. Couto said the operator was facing difficult economics with the stranded reservoir and struggled to reach a final investment decision. So TechnipFMC took a crack at the challenge with Subsea 2.0, he said.

"We managed to have a reduction of 70% of the weight to be deployed on the seabed from three heavy lifts to one heavy lift," Couto said. "The delivery time of the conventional system was 18 to 20 months."

He said Subsea 2.0 was delivered within 10 months, "so reduction of the delivery time by 50%—from sketch to delivery in 10 months with no previous inventory.

"If you extrapolate this test case to the entire water column you can envisage the magnitude of transformation that you're going to impose to the entire water column," he added.

The first application of the compact manifold and horizontal system connection system with flexible jumpers was part of plans for Phase 1 of Shell Offshore Inc.'s Kaikias deepwater project in the U.S. Gulf of Mexico.

So far, TechnipFMC has sold nine of the new subsea manifolds for developments in various parts of the world, including Brazil, the Gulf of Mexico and Guyana, Pferdehirt said. The first Subsea 2.0 tree sold will be installed in early 2018, he said, adding more will follow. "Our first new generation of control systems will be installed in the North Sea in 2018."

—Velda Addison

DEVELOPMENT

Repsol, VNG Present $2.2 Billion Norwegian Oil, Gas Plans

Spain's Repsol and Germany's VNG presented separate plans on Dec. 19 to develop two Norwegian oil and gas fields for a combined $2.17 billion, the Norwegian Petroleum Directorate (NPD) said.

VNG's Fenja oil and gas field in the Norwegian Sea, a collection of discoveries previously known under the names Pil, Bue and Boomerang, will cost about $1.2 billion ahead of a startup in early 2021, the company said during a press conference.

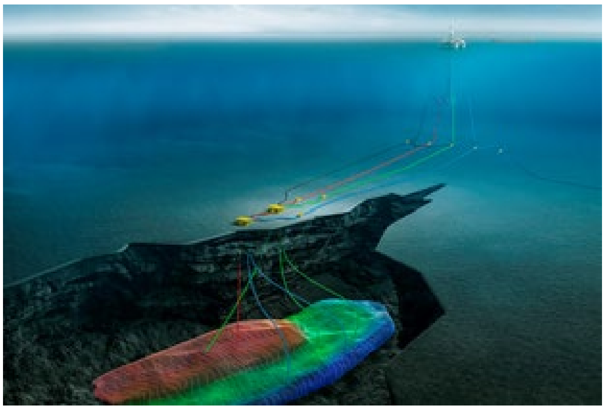
"The planned development solution is a sequential development where Pil is developed and where Bue represents an upside that can be confirmed through the drilling of production wells on Pil before potential production will start," the NPD said.

The plan calls for two seabed templates with production wells and water and gas injection wells.

The discoveries will be produced to the Njord A facility, about 35 km (22 miles) north of Fenja. To mitigate wax and hydrate formation, the production flowline will be heated during production shutdowns. Plans include using an electrically heated pipe-in-pipe solution; however, the NPD noted a "heated pipe-in-pipe over such a distance has not previously been constructed, and technology qualification is therefore needed."

Fenja's recoverable resources were estimated at 100 MMboe. VNG owns 30% of the field, while Point Resources has 45% and Faroe Petroleum 25%.

Repsol's Yme oil field in the North Sea is expected to cost $956 million and will begin production in the first half of 2020, with recoverable resources of 65 MMbbl and peak production seen at 50,000 bbl/d, the operator said.



Fenja will be developed with subsea facilities tied in to the Njord platform. (Source: VNG)

The new plan for development, which involves using existing facilities, comes after structural faults prevented the jackup production facility from being used as originally planned. The facility was removed in 2016, NPD said, without starting production.

The revised plan involves using existing facilities that were installed in 2007. These include a caisson, a subsea oil storage tank, pipelines and a connection between Gamma and Beta, manifold and subsea template with three slots on Beta, subsea loading system for oil from the storage tank, and wells on both Gamma and Beta, according to NPD.

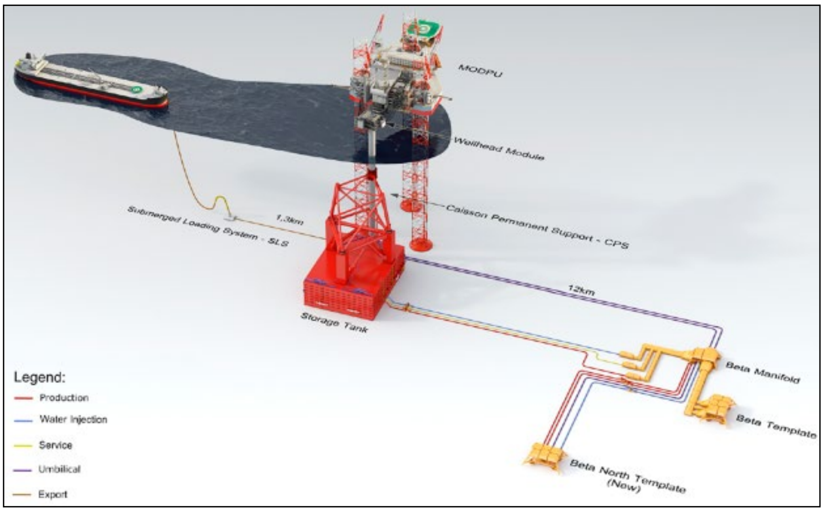
Nine wells will be reused, and there will be six new ones. The Mærsk Inspirer production facility will be used after being modified.

"The strategy is to produce from horizontal wells with pressure support from water injection and water-alternating-gas injection. All produced water and all gas will be re-injected into the reservoir," NPD said.

Repsol owns 55% of Yme, while Lotos Exploration holds 20%, OKEA AS 15% and KUFPEC Norway 10%

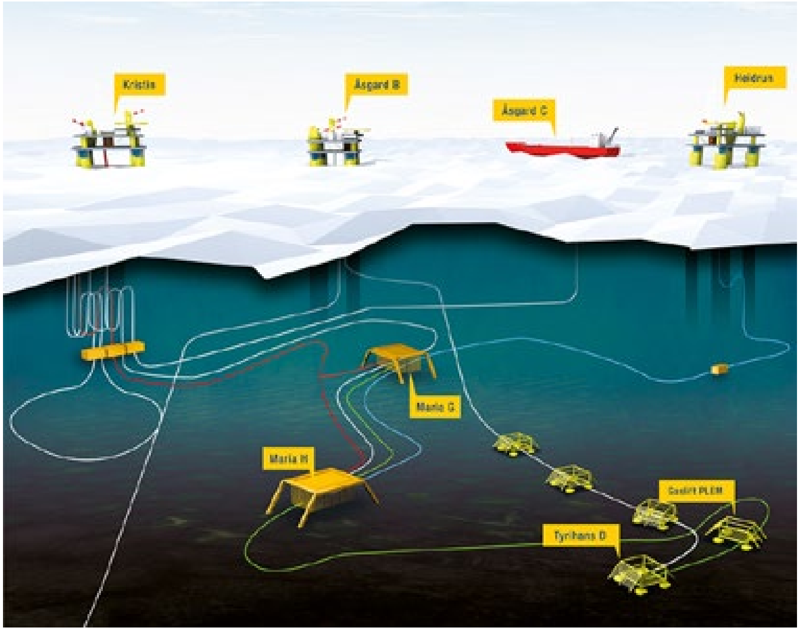
While Yme is expected to produce for 10 years, Fenja's output is seen lasting 16 years, the companies said.

—Reuters & Staff Reports



First oil for the Yme Field in the North Sea is scheduled for 2020. (Source: Repsol)

Wintershall Cranks Up Maria Field A Year Early



Maria is tied back to the Statoil-operated Kristin, Heidrun and Åsgard B platforms. (Source: Wintershall)

Having shaved costs by more than 20%, Wintershall and its partners Petoro and Spirit Energy have started oil production at the Maria subsea development offshore Norway a year earlier than scheduled.

The development came in nearly $360 million below its previous budget of about $1.4 billion, Wintershall said in a news release Dec. 18.

Located in a water depth of 300 m (984 ft) in the Norwegian Sea's Haltenbanken area, Maria is Wintershall's first operated discovery to reach production offshore Norway.

"Delivering a production startup two years and three months after [plan for development and operation] approval by the ministry for such a complex offshore project is a testament to Wintershall's capability to deliver on development projects," Hugo Dijkgraaf, Wintershall Norge's managing director and until recently Maria project director, said in a company statement. "Construction and installation of the subsea equipment and pipelines was completed without any major problems or delays, and this summer we drilled some of the most efficient wells in the history of the Haltenbanken area.

Dijkgraaf added the feat would not have been possible without cooperation from Statoil, operator of the host platforms.

The project itself is considered challenging, taking into account the subsea field is tied back to three platforms—the Statoil-operated Kristin, Heidrun and Åsgard B platforms.

As described by Wintershall, oil is sent via pipeline to the Kristen semisubmersible platform, where it undergoes processing, while water supply for reservoir injection comes from the Heidrun platform. The Åsgard B platform provides the lift gas via the Tyrihans subsea templated.

The processed oil goes to the Åsgard Field for storage. From there, it is offloaded to shuttle tankers, while gas is exported to Kårstø by way of the Åsgard Transport System, the company said.

Production at the field was previously scheduled to start up in fourth-quarter 2018.

"In challenging times, we have kept a clear focus on smart engineering and sharp project management. The fact that we have achieved this so quickly without incidents is a real credit to the whole team that worked so hard to make this happen," Martin Bachmann, Wintershall executive board member for E&P in Europe and Middle East, said in the company statement. "The experience gained in the Maria project will serve as a blueprint, for our Nova development, previously known as Skarfjell, and worldwide."

Wintershall said the field will yield about 180 MMboe over its lifetime of about 25 years.

Wintershall is the operator with a 50% stake alongside Petoro (30%) and Spirit Energy (20%).

—*Velda Addison*

HOEC Readies New Drilling Plan For Cauvery Asset

India's Hindustan Oil Exploration Co. Ltd. (HOEC) is preparing to launch a new drilling campaign in the PY-1 Field, located in the Bay of Bengal's Cauvery Basin, to increase oil and gas production.

"The proposed project entails drilling eight additional development wells and connecting them to the existing unmanned platform and subsea pipeline to offset the decline in production in the PY-1 Field," HOEC said in a pre-feasibility report.

Launched in 2009, the PY-1 Field is producing about 1.6 million standard cubic feet per day (MMscf/d) of gas from three wells. The amount is down from about 20 MMscf/d in 2011 due to accelerated pressure decline and water breakthrough in existing wells.

PY-1 is spread across 75 sq km (29 sq miles) in water depths that range from 40 m to 250 m (131 ft to 820 ft) in the Bay of Bengal, about 18 km (11 miles) from Port Novo on Tamil Nadu coast.

Development Plan

The proposed development plan involves drilling eight development wells in the field up to a target depth of 3,000 m (9,843 ft) in a water depth of 10 m to 75 m (33 ft to 246 ft).

The wells to be drilled will be tied back to the existing offshore platform, subsea pipelines and onshore processing facilities developed during the initial phase of development. Gas produced from the new wells will be transported through 55-km (34-mile), 24-in. subsea pipeline to the onshore processing plant at Pillaiperumalnallur on Tamil Nadu coast.

Drilling will target the proven gas reserves in the "granitic basement structural high" reservoirs located in four hills and ridges (Jupiter, Pluto, Saturn and Venus) of the PY-1 Field.

Gas reserves are contained in the heterogeneous, Precambrian, weathered granite sediments, sealed by Cretaceous to Eocene shales, on the crest of a northeast-southwest basement ridge of the field.

The additional eight wells are expected to increase production from the field to 60 MMscf/d.

The wells drilled in the ridges (Earth and Mercury) during the first phase development encountered pay zones as thick as 61 m (200 ft) at depths of 1,524 m (5,000 ft) to 1,676 m (5,500 ft). The first discovery well, PY-1-1, flowed 13 MMscf/d during testing.

PY-1, originally discovered by ONGC in 1980, has nine hills and each is filled with hydrocarbons, which are estimated to contain gas reserves of 4.1 Bcm (146 Bcf) and 1.16 MMbbl of condensate.

Besides, the operator has a plan to take up reentry drilling in the less-producing PY-1-12 well during the April-June quarter to revive the gas production from the PY-1 Field.

Sharing Infrastructure

HOEC has proposed sharing its PY-1 Field offshore infrastructure with the adjoining PY-3 oil and gas field in the CY-OS-90/1 Block, in which it holds a non-operating stake (21% PI), to optimize operating costs.

"We have submitted an alternative integrated development plan to revive 3,000-plus barrels of oil production from the shut-in well in the PY-3 Block for approval by the stakeholders," the company said.

HOEC, according to the plan, has proposed to transport the gas that comes out along with the oil, which would otherwise be flared, from the PY-3 Field by integrating its existing subsea pipeline of PY-1 through a 6-km (4-mile) pipeline. The plan, estimated to cost about $28 million, includes refurbishing the existing production units along with construction of a pipeline.

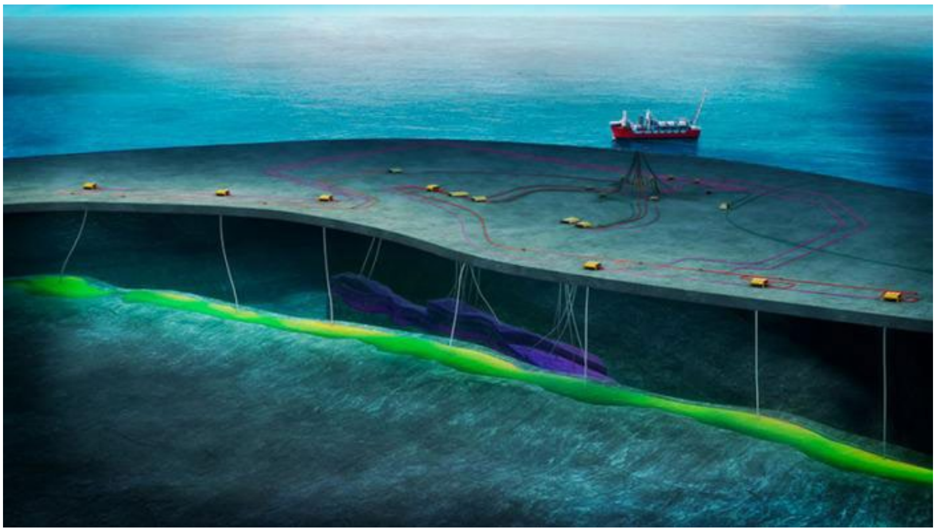
The company has made a provision in the installed subsea pipeline as part of the PY-1 development project to potentially receive associated natural gas from the PY-3 Field operated by Hardy Exploration & Production India Inc.

PY-3 was producing 3,200 bbl/d of crude and 3.5 MMscf/d of gas through a floating production unit before the suspension of operations in 2011 due to a commercial dispute. It is a conventional sandstone reservoir with a potential to produce more than 7,000 bbl/d of high-quality light crude oil with low sulphur content along with the significant quantity of gas.

HOEC has participating interest in nine oil and gas fields in the onshore and offshore basins of Cambay, Cauvery, Assam Arakan and Rajasthan in India.

—Ravi Prasad

AkerBP Delivers Plans For Trio Of Fields Offshore Norway



The Ærfugl Field in the Norwegian Sea will be developed as a subsea tieback to the *Skarv* FPSO unit. (Source: AkerBP)

AkerBP and its joint venture partners plan to spend nearly $1.9 billion to develop a trio of fields on the Norwegian Continental Shelf, showing the industry's commitment to offshore oil and gas development remains as market conditions improve.

The company submitted plans for the Valhall Flank West, Ærfugl and Skogul developments to Norwegian authorities Dec. 15. The move came after the company reduced costs. Combined, the projects are expected to bring in about $12 billion in oil and gas revenue based on a $60 per barrel oil price.

Brent crude futures were trading at more than $63 per barrel the morning of Dec. 15, about $10 per barrel more than it was around this time last year.

"Our ambition is to be recognized as the cost and capital leading offshore E&P company, and I am very proud to announce that the projects have improved significantly in this respect," Aker BP CEO Karl Johnny Hersvik said in a company statement.

Investment for the Ærfugl gas condensate field—formerly called Snadd—fell by about $239 million to an estimated $1 billion, while total investment for the Valhall Flank West development dropped by more than $179 million to an estimated $657 million.

More efficient drilling operations are mainly behind the cost reductions for Ærfugl, according to DEA Norge, which holds a 28.0825% interest in the development. Hans-Hermann Andreae, managing director of DEA Norge, called the submission of the plan for development and operation for the field a milestone.

"The development project also proves that the industry is willing to invest in projects that will extend production from the Skarv area and the Norwegian Sea," Andreae said in a company statement.

Ærfugl: The Ærfugl Field will be developed in two phases as a subsea tieback to the *Skarv* FPSO unit. With production startup set for fourth-quarter 2020, Phase 1 focuses on the southern part of the field and includes three production wells tied into the FPSO unit via a trace heated pipe-in-pipe flowline, AkerBP said.

Plans for Phase 2, which concentrates on the northern part of the field and Snadd Outer, could include three more production wells with startup anticipated in 2023. AkerBP noted that other options will be considered for this phase. The company estimates remaining reserves at about 275 MMboe.

Subsea umbilical riser flowline and subsea production system contracts have already been awarded, respectively, to Subsea 7 and Aker Solutions for Phase 1 with an option for Phase 2.

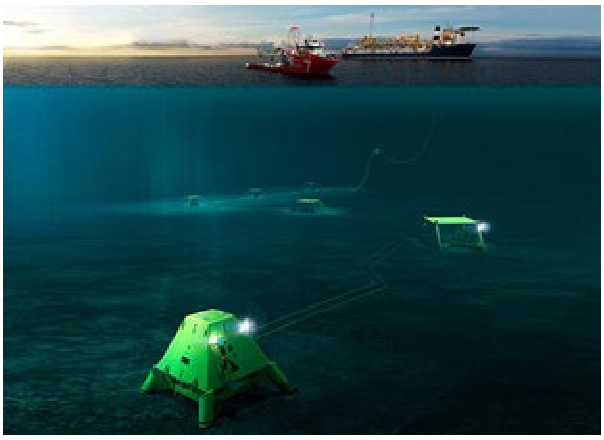
"The Ærfugl development represents a significant opportunity with highly attractive and robust economics," AkerBP said. "In addition, the Ærfugl development will extend the economic field life of the *Skarv* FPSO [unit] and allow for increased recovery from the Skarv Field itself."

Partners in Ærfugl (Skarv Unit) are operator AkerBP (23.835%), Statoil Petroleum (36.165%), DEA Norge (28.0825%) and PGNiG Upstream Norway (11.9175%). Partners in Snadd Outer (PL 212 E) are AkerBP ASA (operator, 30%), Statoil Petroleum (30%), DEA Norge (25%) and PGNiG Upstream Norway (15%).

Valhall Flank West: The operator is eyeing first oil in fourth-quarter 2019 for the Valhall Flank West oil field development. Located in the Norwegian part of the North Sea, the field has estimated recoverable resources of about 60 MMboe. Development plans, which target the Tor Formation, call for a normally unmanned installation tied back to the Valhall field center, where it will be remotely operated, for processing and export, AkerBP said in the release.

The development will have six producers with a fully-electrified wellhead platform. Drainage will be by natural depletion, AkerBP said, but there is an option for future water injection. There is an option to convert two producers into water injectors.

Currently, AkerBP is a 35.95% interest holder in the development. Hess Norge holds the rest. AkerBP is in the process of acquiring Hess Norge, and it is in the process of divesting a 10% stake in the Valhall and Hod fields to Pandion Energy, the release said.



(Source: AkerBP)

Skogul: Formerly called Storklakken, Skogul is the smallest of the three developments and comes with a price tag of about $175 million. The field will be developed as a subsea tieback to the Alvheim FPSO vessel. AkerBP estimates recoverable reserves of the field to be about 10 MMboe.

"The production well at Skogul will be subsea production well No. 35 in the Alvheim area and represents Aker BP's continuous effort to maximize value and extend economical field life to the benefit of the company and its partners," the company said.

Holding a 65% interest, AkerBP is the field's operator. Its sole partner in this development is PGNiG Upstream Norway (35%).

—Velda Addison

DEVELOPMENT BRIEFS

Eni Restarts Arctic Goliat Oil Field, Plans Drilling Campaign

Eni on Dec. 17 resumed production from Norway's Arctic Goliat oil field following an outage of more than two months and now plans to explore for more resources in the area, the company said in a statement Dec. 18.

The Norwegian Petroleum Safety Authority (PSA) on Dec. 8 said Eni could bring back onstream the 100,000-bbl/d field, which had been shut at the agency's order since Oct. 6. The oil field had experienced a series of safety incidents and production shutdowns since its startup in 2016, prompting the PSA to initiate closer scrutiny of operations.

Eni on Dec. 18 said it had carried out extensive planned maintenance and modifications at Goliat as well as work related to the platform's electrical system following the PSA's intervention.

Eni now plans to drill two more production wells at Goliat in 2018 and will drill an appraisal well for a discovery known as Goliat West, and has identified further potential for exploration nearby, it said.

"This will contribute to increased recovery rate, additional resources and further improve profitability of the Goliat Field," Eni said.

Goliat has seen no major incidents or accidents during 2017, and Eni has recorded a strong improvement in the platform's health, safety and environment performance, the company said.

AkerBP Doles Out Contracts For Norwegian Developments

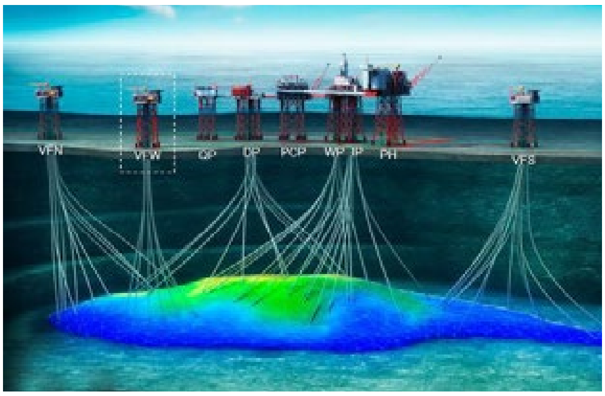
With plans to spend nearly $2 billion on the Valhall Flank West, Ærfugl and Skogul developments on the Norwegian Continental Shelf, AkerBP is lining up companies to help it get work done.

For Valhall Flank West, being developed as a normally unmanned platform, AkerBP has awarded Kvaerner a contract valued at nearly $120 million for delivery of the topside and steel jacket substructure for the development. The award comes as part of the Wellhead Platform Alliance formed between Aker BP, Kvaerner, ABB and Aker Solutions.

Kvaerner said the steel substructure and topside will be ready for delivery and sail-away from its facilities in May 2019 with hook-up and commissioning on the field set for August 2019.

Aker Solutions has also been awarded contracts for work on the fields offshore Norway. The company said it will deliver two subsea manifolds, a controls system and umbilicals for Skogul, which will be tied back to the North Sea Alvheim Field. It will also provide umbilicals and detailed engineering of the topside for the normally unmanned installation for Valhall Flank West.

In addition, Aker Solutions was awarded a contract to deliver the subsea production system for the first phase of the Ærfugl development offshore Norway. The system will include wellheads, vertical subsea trees, a tie-in module and an umbilical riser base. The contract includes an option



First oil for the Valhall Flank West Field project, which will be developed from a new normally unmanned installation, is scheduled for fourth-quarter 2019. (Source: AkerBP) for Ærfugl Phase 2. Work will begin immediately and will involve its facilities in Norway, Malaysia and the U.K.

Subsea 7 is also in on the Ærfugl action. Subsea 7's engineering, procurement, construction and installation (EPCI) contract is a long-distance tieback involving the application of its electrically heat-traced flowline (EHTF) technology for the 21-km (13-mile) tieback to the *Skarv* FPSO unit.

Project management and engineering was set to start immediately at Subsea 7's offices in Stavanger, Norway. Fabrication of the EHTF system will take place at Subsea 7's spoolbase at Vigra, Norway and offshore operations will take place in 2019 and 2020.

Subsea 7 called its contract "substantial," which is defined by the company as having a value between $150 million and $300 million.

Subsea 7 also landed contracts from AkerBP for the Skogul project and the Valhall Flank West project, which collectively are equivalent to a "sizeable" award, according to Subsea 7. The company considers an award sizeable if it's valued at between $50 million and $150 million. The EPCI project for Skogul is a long-distance tieback to *Alvheim* FPSO via Vilje South Field, using pipe-in-pipe technology. Project management and engineering was set to start immediately with offshore operations scheduled in 2019.

The Valhall Flank West EPCI project comprises a 4-km (2-mile) tieback to the Valhall Centre including an umbilical and riser system. Offshore operations will commence in 2018 with completion in 2019.

Energean Lines Up Buyers For Gas From Karish, Tanin Fields

From left to right, Giora Almogi, CEO of OPC; Ovadia Ali, board chairman for ORL; Energean CEO Mathios Rigas; ICL CEO Asher Grinbaum; and ORL CEO Yashar Ben Mordechi are shown. (Source: Energean)

Energean Oil & Gas has added a group that comprises Israel Chemicals, Bazan Oil Refineries and power producer OPC to the list of companies with which it has sealed gas sales and purchase agreements for gas from the Karish and Tanin fields offshore Israel.

The agreements total up to 2.6 Bcm (92 Bcf), Energean said in a news release. This is in addition to up to 0.3 Bcm (11 Bcf) the company has also signed with Rapac Group.

The recently announced agreements boost the total committed purchase volume to more than 4 Bcm (141 Bcf) of gas annual from the two fields. This surpasses the E&P's initial annual target of 3 Bcm (106 Bcf). The progress is moving Energean closer to a final investment decision for the developments. A decision is expected by early 2018.

"We are aiming to progress with FID early in 2018 and our focus now lies in moving ahead on all related project milestones to deliver first gas as planned," Energean CEO Mathios Rigas said.

Development plans for the fields call for use of an FPSO unit. First gas is scheduled for 2021.

Initial Zohr Output Raises Egypt's Natural Gas Production

Output from Egypt's giant offshore Zohr gas field in the Mediterranean will raise Egypt's natural gas production to 156 MMcm/d (5.5 Bcf/d) from 144 MMcm/d (5.1 Bcf/d), Petroleum Minister Tarek El Molla told Reuters on Dec. 17.

The petroleum ministry said on Dec. 16 that the mammoth field has begun an initial production of 10 MMcm/d (350 MMcf/d).

Production from Zohr is set to increase to about 28 MMcm/d (1 Bcf/d) by mid-2018, the Petroleum ministry said earlier this month.

Discovered in 2015 by Italy's Eni, the field contains an estimated 850 Bcm (30 Tcf) of gas.

Egypt's own natural gas output rose to about 144 MMcm/d (5.1 Bcf/d) in 2017 from 125 MMcm/d (4.4 Bcf/d) in 2016 with the start of production from the first phase of BP's North Alexandria project.

The country has been seeking to speed up production from recently discovered fields, with an eye to halting imports by 2019 and achieving self-sufficiency.

Statoil Awards Subsea Contracts On Norwegian Continental Shelf

Statoil said on Dec. 14 it has awarded new subsea maintenance framework agreements to Aker Solutions, TechnipFMC and OneSubsea LLC.

The contracts have a total estimated value of more than $966 million and extend to 2023. In addition, the contracts include options for a total of 20 years. The estimated total value will be about $4.8 billion, should all the options with the assumed scope of work be exercised.

The new agreements apply to Statoil-operated subsea wells on the Norwegian Continental Shelf (NCS) with equipment from the aforementioned suppliers and include maintenance of equipment belonging to more than 500 wells. The figures include planned wells in the field developments of Johan Castberg and Snorre Expansion Project.

The contracts apply to subsea maintenance and additional equipment for the NCS, with work both offshore and onshore. The agreements are effective from March 1, 2018, with a fixed duration of five years and include five four-year options.

Most of the maintenance work will be carried out at the Ågotnes Base outside Bergen in addition to the Polar Base in Hammerfest.

—Staff & Reuters Reports

EXPLORATION

Seismic Work Ahead For Brazil's Presalt Mero Field In Libra Block

A few weeks after being declared commercial, Petrobras' recently named Mero Field—part of the Libra Block—is set for a 3-D seismic survey using ocean-bottom node (OBN) acquisition systems.

OBN systems provide the best seismic data quality and clearest reservoir image to inform E&P strategies throughout the development of the production of the Mero Field, according to Brazilian Geophysical Society Institutional Secretary Ricardo Augusto Rosa Fernandes.

"Seismic surveys of this nature are usually associated with the tracking of the displacement of the oil front with 4-D seismic (time variants)," the geologist said. "In this sense, we understand that the investment in seismic sensors with background sensors indicates that the company and partners plan the use of 4-D seismic to monitor the reservoirs.

Also, the geologist believes that other prolific fields in the Libra presalt block have potential to be declared commercial soon.

"There are exploratory areas recently tendered by the Brazil's oil regulator ANP in this same northern portion of the Santos Basin, which also indicate excellent geological potential," he said. The "Mero Field is located in a retention area defined by Petrobras ['ring fence'] of about 320 sq km [124 sq miles]. The total area of the Libra block is 1,550 sq km [598 sq miles]."

Mero is located in the northwestern part of the Libra Block of the presalt Santos Basin offshore Brazil. The field, which is within Brazil's largest oil area, was deemed commercial in late November after a three-year campaign. The field is located about 180 km (112 miles) off the coast of Rio de Janeiro.

Mero entered production through a long-duration output test carried out by the *Pioneiro Libra* FPSO unit. The field holds roughly 3.3 Bbbl of recoverable oil. According to Petrobras, eight extension wells were drilled in the PAD area during the exploratory and evaluation stage of the Libra block to identify reservoirs with good-quality oil with high commercial value. In fact, the declaration of commerciality of Mero field represents a very important achievement by Petrobras.

"This is our first unit equipped to inject all the gas produced during the tests. To date, 12 wells have been drilled in the Libra Block. Due to its magnitude, production potential, good oil quality and high commercial value, Libra opens up a new business opportunity in the offshore industry," Petrobras said in an official statement. "With an expected duration of one year, the long-duration output test has the goal of evaluating the behavior of the oil reservoir and increasing the knowledge of the characteristics of the deposit."

Libra is Brazil's biggest oil field to date and is expected to produce 1.4 MMbbl/d by 2021, and it holds between 8 Bbbl to 12 Bbbl of recoverable oil, according to ANP. It was the first presalt area that was acquired under the 35-year production-sharing agreement contract by the consortium formed by Petrobras (40%, operator), Shell (20%), Total (20%), CNPC (10%) and CNOOC (10%) in 2013.

—Brunno Braga

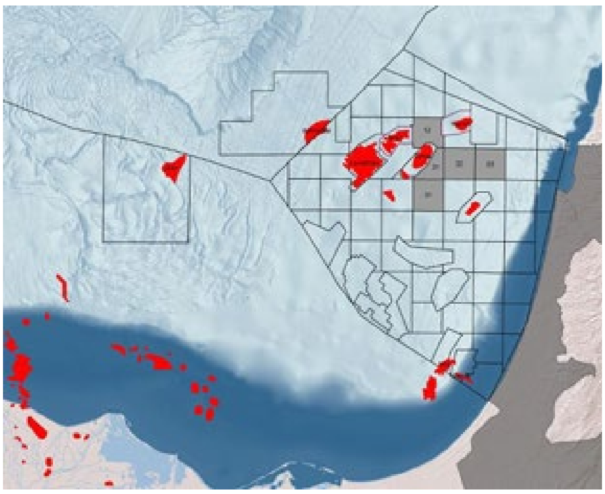
EXPLORATION BRIEFS

Energean Lands Five Exploration Licenses Offshore Israel

The Israeli petroleum commissioner has awarded Energean Israel five offshore exploration licenses within the Israeli Exclusive Economic Zone, Energean Oil & Gas said in a news release.

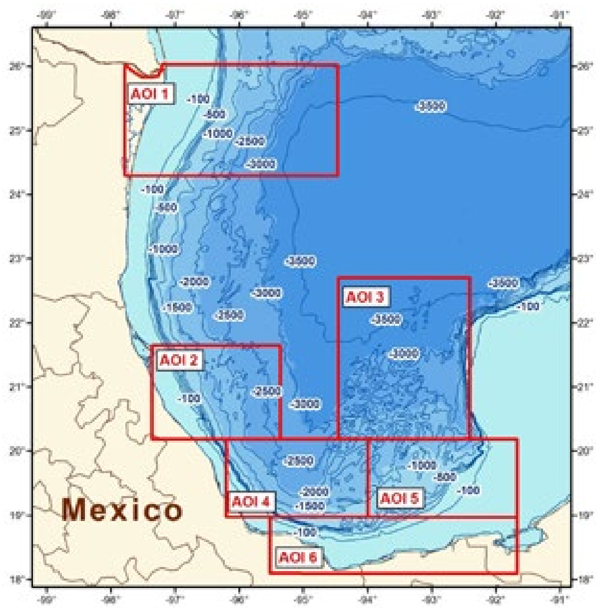
The initial exploration period for each license is three years. The licenses comprise blocks 12, 21, 22, 23 and 31, which were part of Israel's first offshore bid round. The blocks are located near the Karish and Tanin gas fields, which are moving toward development by Energean, the release said.

Energean said it believes the awarded licenses are highly prospective and would benefit, if economic hydrocarbon discoveries are made, from being developed via tiebacks to the FPSO unit that Energean will construct for the Karish and Tanin developments.



(Source: Energean Oil & Gas)

CGG Releases Survey Over Perdido Fold Belt In GoM



The location of AOI 1 and other areas proposed in CGG's multiclient airborne GravMag program offshore Mexico are shown. (Source: CGG)

CGG Multi-Physics has completed acquiring, processing and interpreting a multiclient airborne gravity and magnetic survey covering about 38,000 line km over the Perdido Fold Belt in the Mexican Gulf of Mexico, according to a news release.

The newly acquired Perdido Fold Belt data show a correlation of discoveries along the flanks of basement topography. The data and interpretation will help explorers map crystalline basement, which is not well imaged by seismic, to construct an improved Earth Model, CGG said in the release. The airborne survey also collected data through the "transition zone" from the marine environment to onshore.

A full geophysical interpretation report will provide important insights to exploration and de-risking of prospective areas by oil companies. The report will include mapping of basement, sediment and any intrusives or salt which may be present.

Data acquisition of the AOI 1 area was completed in December 2016. This survey is the first of six areas to be acquired in a wider program totaling 200,000 line km across the Mexican Gulf of Mexico. More acquisition work is planned for 2018.

Lebanon Approves Offshore Oil, Gas Exploration Bid

Lebanon's cabinet approved a bid on Dec. 14 for offshore energy exploration by a consortium made up of Total, Eni and Novatek, in the country's first oil and gas offshore licensing round, a government source told Reuters.

Lebanon sits on the Levant Basin in the eastern Mediterranean where a number of big subsea gas fields have been discovered since 2009, including the Leviathan and Tamar fields located in Israeli waters near the disputed marine border with Lebanon.

Data suggest there are reserves in Lebanon's waters, but so far no exploratory drilling has taken place to estimate reserve size.

The first licensing round for E&P rights was relaunched in January after a three-year delay due to political problems in the country.

Total, Eni and Novatek consortium was the only consortium to submit an offer, bidding for Block 4 and Block 9 of the available five blocks.

Eni Strikes More Pay Offshore Mexico, Raises Estimates

Eni has increased its estimate for hydrocarbon in place to 2.0 Bboe for its discoveries in Mexico's Campeche Bay after a well in the area struck pay.

The Italian major said Dec. 12 the shallow-water Tecoalli 2 well, located in Contractural Area 1, hit about 40 m (131 ft) of net oil pay in the Orca Formation. With a water depth of 33 m (108 ft), the well was drilled to a final depth of 4,420 m (14,501 ft) and then deepened to the Cinco Presidentes Formation exploratory target. There, the well hit another 27 m (89 ft) of net oil pay, Eni said in a news release.

Next steps include conducting a production test followed by temporarily abandoning the well.

"Thanks to the results of this well and the revision of the reservoir models of the Amoca and Miztón fields, the hydrocarbon in place estimate for Area 1 is boosted from 1.4 to 2.0 [Bboe], of which approximately 90% oil and the remaining associated gas," Eni said.

The Tecoalli Field is 24 km (15 miles) from the Amoca Field and 13 km (8 miles) from the Miztón Field.

The company also said it plans to submit the development plan for Area 1 (Eni 100%) to Mexico's Natural Hydrocarbons Commission. When the plan is approved, Eni said it will sanction the development. Production startup is planned for first-half 2019.

Kosmos Energy To Plug Offshore Mauritania Well

Kosmos Energy Ltd. said it would plug its Lamantin-1 exploration well offshore Mauritania after it failed to find significant amount of oil and gas.

Lamantin-1 was drilled to a total depth of 5,150 m (16,896 ft) and was designed to evaluate a untested lower Campanian base of slope fan supplied from the Nouakchott River system, trapped in a combination structural-stratigraphic feature, and charged from underlying, oil-prone Cenomanian/Turonian and Albian source rocks.

Evaluation of logs and samples collected during drilling and wireline operations suggests the Campanian reservoir objective was water-bearing with some residual hydrocarbons, Kosmos said.

"We are still in the early stages of exploring this newly emerging basin and our forward drilling program remains unchanged given the independent nature of the prospects," Andrew Inglis, CEO, said in a statement.

Syria To Start Offshore Energy Exploration In 2019

Syrian offshore gas exploration will begin in early 2019, the country's oil minister said, Syrian newspaper *al-Watan* reported.

Oil and mineral resources Minister Ali Ghanem said contracts for five offshore blocks had been signed with "friendly countries." The report did not say which countries or companies were involved.

He also said Syria has an estimated 1,250 Bcm (44 Tcf) of offshore gas reserves. The report did not say when or how the Syrian government had appraised the reserves.

In 2013, Russian energy firm Soyuzneftegaz signed the first offshore exploration contract with Syria for Block 2. But in 2015, it said it would not go ahead with the project because of Syria's conflict—now in its seventh year.

In comments made to the Syrian parliament on Dec. 12 and reported by *al-Watan* on Dec. 13, Ghanem said Syria aims to produce 19 MMcm/d (671 MMcf/d) of gas by the end of 2018 and 24.5 MMcm/d (865 MMcf/d) by the end of 2019.

He also said Syria aims to produce 70,000 bbl/d of oil by the end of 2018 and 219,000 bbl/d by the end of 2019.

The war in Syria meant the government lost control of the majority of Syria's onshore oil and gas fields, but many have been recaptured as a result of advances made against Islamic State in recent months.

This has enabled the government to produce more power.

—Staff & Reuters Reports

TECHNOLOGY BRIEFS

Terves Builds Dissolvable Alloy For HT Environments

Terves Inc. has released an HT dissolvable alloy that is built for operating temperatures of up to 150 C. (Source: Terves)

Dissolvable materials manufacturer Terves Inc. has released a high-temperature (HT) dissolvable alloy that is built for operating temperatures of up to 150 C (300 F), a news release stated.

The TervAlloy-HT is geared toward HT environments such as in the Gulf of Mexico and is available in various shapes in lengths of up to 48 in.

"All the currently available dissolvable alloys see a 50% to 70% drop in mechanical properties at 300 F compared to their standard operating temperature of 100 F to 150 F [38 C to 65.5 C]; whereas we have been able to engineer our TervAlloy-HT to offer properties similar to industry-leading TervAlloy TAx-100E Alloy at significantly higher operating temperature," Terves CEO Andrew Sherman said in the news release. "This is a significant step toward interventionless tooling being used across any oil and gas operating environment, especially since oil and gas completion and production is witnessing higher operating temperatures every year."

First Wireless Transmission Of Reservoir Pressure Data To Surface

Expro has accomplished proven wireless transmission of reservoir pressure data to surface from a recently abandoned subsea appraisal well, which incorporated a rock-to-rock cement plug, a press release stated.

The system was installed in the North Sea and will be used to improve understanding of the reservoir and to optimize future development planning of the field while ensuring full compliance with local well abandonment regulations. This achievement provides operators with a more cost-effective option for well abandonment design and consideration of wider well barrier techniques while maintaining the ability to monitor the reservoir or plug integrity.

Expro's cableless telemetry system (CaTS) wireless gauges, using electromagnetic technology, were installed in the reservoir of the main bore, and casings were cut below the sidetrack kickoff point to install the cap rock cement plug. CaTS repeaters placed in the sidetrack enabled data transmission across the openhole section and to the seabed transceiver for storage and transmission to an overhead vessel.

The system provided continuous reservoir data, which began immediately after the drillstem test, allowing extended pressure buildup analysis without rig support.

Subsea Rehabilitation System Extends Life Of Pipelines

The IFL technology was recently installed offshore Malaysia. (Source: APS)

After a three-year technology development period from 2011-2013, 10 subsea pipelines running from platform to platform have so far been rehabilitated using APS' InField Liner (IFL) technology, reportedly saving PETRONAS more than $100 million.

The IFL matrix consists of a Solef polyvinylidene fluoride inner layer, a Kevlar core and a thermoplastic *polyurethane* outer layer and is resistant to a wide range of aggressive hydrocarbon mixtures (gas, crude and multiphase) with temperatures up to 110 C (230 F).

The liner can be pulled into existing subsea pipelines over lengths of several kilometers in one single pulling operation, arresting corrosion and substantially increasing the service life of the pipeline. This technology is the world's first fullbore internal subsea pipeline rehabilitation system, enabling a life extension of existing pipelines of more than 30 years.

—Staff Reports

FLOATER & VESSEL NEWS

Libra Consortium Signs Contract For FPSO Unit For Mero Field

Petrobras said on Dec. 18 that it had chartered an FPSO unit to be the first production system of the Mero Field.

The 22-year contract with the Modec Inc., signed on Dec. 14, stipulates that part of the construction to take place in Brazil. The FPSO unit will be deployed at a depth of 2,100 m (6,890 ft) in the northwestern area of the Libra Block in the presalt region of the Santos Basin.

Production is expected to begin in 2021, with this project involving interconnection of as many as 17 wells to the platform. The FPSO unit will have a capacity of up to 180,000 bbl/d of oil, and 12 MMcm/d (424 MMcf/d) of gas.

The FPSO unit will be installed in the Mero Field in the presalt of the Santos Basin.

Libra production began with operations of the first FPSO unit in the block, the *Pioneiro de Libra* FPSO vessel, on Nov. 26. That vessel is dedicated to extended well tests and early production systems. The Libra Consortium—Petrobras, Shell, Total, CNPC and CNOOC Ltd.—declared commerciality of the northwest portion of the block on Nov. 30. Total said Dec. 18 it had made an investment decision on the Libra project.

Aker Solutions To Design Johan Castberg FPSO Accommodation Unit

Aker Solutions landed a contract from Sembcorp Marine in early December to design the living quarters for the Johan Castberg development's FPSO unit.

Aker will engage in detailed design engineering of the living quarters—financial details for the contract were not disclosed—and technical specifications for the equipment and supplies required to build the unit for the Statoil-operated development. Johan Castberg is the largest oil discovery in the Norwegian Barents Sea.

"We will build on our previous work on the development to optimize the design of the living quarters," Knut Sandvik, Aker's executive vice president over the company's projects delivery center, said in a statement.

Aker is already developing the unit at its Oslo, Norway, and Mumbai, India locations. The company expects delivery in second-half 2018.

Sembcorp will build the living quarters at its Singapore shipyard.

Hurricane Is On Track For Lancaster Production In 2019

The *Aoka Mizu* FPSO unit is shown arriving in Dubai. (Source: Hurricane Energy)

Aoka Mizu, Hurricane Energy Plc's FPSO unit that arrived in Dubai in September for an upgrade, will be ready for the company to achieve first production in the Lancaster Field during first-half 2019.

Hurricane assured analysts in early December that the project, west of Shetland in depths of about 160 m (525 ft), was on schedule.

The first phase of upgrades on the FPSO unit has been completed, the company said. These include:

- Removal of a thruster for overhaul;
- Outer hull surveys;
- Replacement of sea valves;
- Installation of new bilge keels;
- Initial tank inspections; and
- Cleaning.

Among the repairs, upgrades and life-extension works to be conducted on *Aoka Mizu,* fabrication work is also planned for an associated buoy to connect to the turret mooring system. The buoy locking ring is in the process of being installed.

Redtech Takes Out 5-Year Charter On Newbuild

Kuala Lampur-based RedTech Offshore has taken out a five-year charter on *Van Gogh*, a diving support construction vessel expected to be ready for delivery in first-quarter 2018, according to reports in Asian news media.

Singapore-Ultra Deep Solutions owns *Van Gogh*, which is under construction at China Merchants Heavy Industry in Shenzhen. The vessel will be Malaysia-flagged.

RedTech handles decommissioning work in the offshore oil and gas industry in Asia. Its executives expressed the hope that it will be awarding more contracts to Ultra Deep Solutions as business continues to pick up.

Van Gogh will be able to accommodate a crew of 120 and operate a 150-ton crane in depths of 3,000 m. (9,843 ft) Its clear deck area is 1,000 sq m (10,764 sq ft)

—Joseph Markman

DECOMMISSIONING

Decommissioning Sector Growth Spurs Activity

On the back of the U.K. government's recent move to allow the transfer of tax history on assets sales, confidence is surging that the industry will experience growth in many areas, such as plugging and abandonment (P&A) work, thus spurring jobs growth and increased spending.

In addition, Aberdeen's Robert Gordon University (RGU) has launched a decommissioning simulator aimed at servicing the growing sector. The simulator and its software will be used to support decommissioning activities in the U.K. and elsewhere, RGU said.

"RGU, in collaboration with funding partners The Oil & Gas Technology Centre (OGTC), KCA Deutag and Drilling Systems, with technical support from Baker Hughes, a GE Company (BHGE), has established the simulator to focus on well plugging and abandonment (P&A)," said RGU. "P&A is an area, which is forecast to cost the U.K. more than US $10.77 billion over the next decade, with around 2,500 wells expected to be decommissioned across the U.K., Danish, Dutch and Norwegian continental shelves."

The simulator can support both oil and gas operators and service companies with the planning and preparation for well P&A, in a similar way pilots get trained and tested on flight simulators.

"With industry driving efficiency improvements which have led to a 16% increase in [U.K. Continental Shelf] production following a decade of decline, the sector is successfully controlling the cost of well plugging and abandonment," said Mike Tholen, upstream policy director of industry body Oil & Gas UK.

At the length of six jumbo jets, the *Pioneering Spirit* lifted the 24,200-tonne platform from Brent Delta in one piece. This operation took place in late April and marks the heaviest marine lift ever undertaken at sea. More than 97% of the Brent Delta platform will be recycled. (Source: Shell)

"The report reveals that the average forecast cost for well P&A has fallen by 5% in the central and northern North Sea and west of Shetland, and by 4% in the southern North Sea and Irish Sea with further cost reductions predicted as the sector ensures decommissioning is carried out as cost-effectively as possible, while maintaining high safety and environmental standards."

Blyth's Decom Focus

Another player showing confidence is the Port of Blyth in Northeast England, which is planning to step into the offshore decommissioning market after a successful application for a decommissioning license from the U.K. Environment Agency (EA).

The port is preparing a site that is suitable for decommissioning at the Battleship Wharf terminal during 2018, the Port of Blyth said, adding that pursuing decommissioning work in the North Sea is a key area for the port's future growth plans.

The designated decommissioning site in the terminal is now licensed to handle up to 50,000 tonnes of offshore energy materials per year. The port will now focus on small to medium sized projects and work of up to 4,000 tonnes.

Jobs Boost, Spending Forecast

"Comparing the number of jobs posted throughout the industry in the year to the end of July versus the same period in 2016, there has been a 2% increase, with jobs from corporates up by 8%," Alex Fourlis, managing director of oilandgasjobsearch.com, noted in reaction to a recent survey that was part of the Oil and Gas Outlook 2017 report.

The forecast upturn could be seen as an indication of the oil market potentially stabilizing, according to Fourlis.

The report signaled a return in confidence since oil prices stabilized from July onward.

Lee Anderson, operations director at NES Global Talent, said that prospects in the North Sea were looking brighter than they had been for several years, including for the upstream sector.

"Confidence is now returning to the market," Anderson said. "Although we are still at the very early stages of the recovery we are now seeing clients look at new development opportunities and further exploration in the North Sea."

Transfer Of Tax History Boost

The U.K. oil and gas industry was generally pleased with the recent U.K. Budget in November, especially as it introduced a means of transferring tax history on assets sales.

This move is forecast "to unlock further investment in the U.K. North Sea by enabling more assets to change hands and allow new owners to provide fresh investment in many mature oil and gas fields," according to industry body Oil & Gas UK.

The measure is planned to be effective by November 2018, U.K. Chancellor Philip Hammond said. Under current legislation, existing owners of oil and gas fields are unable to pass their tax history onto a buyer. This means the buyer can often consider the field to be less attractive commercially, partly because they are unlikely to be able to access the same level of tax relief than the current owner when entering the decommissioning phase.

"Enabling the transfer of tax history allows the purchaser to value the asset on a similar basis to the vendor and removes a significant barrier to asset trading," according to Oil & Gas UK. "Transferable tax history will not permit the purchaser to gain greater tax relief than the vendor and will be at no net cost to the Exchequer."

Deirdre Michie, chief executive of Oil & Gas UK, called the action "a vital step that can bring in new investment to increase recovery from existing fields and fund fresh investment." She added that it will also "help extend the lives of many mature fields and postpone decommissioning."

—Steve Hamlen

BUSINESS

Statoil Buys Stake In Roncador Offshore Brazil For Up To $2.9 Billion

Statoil will triple its output off the coast of Brazil after agreeing to buy a 25% stake in Roncador, one of the country's largest oil fields, from national oil company Petrobras for up to $2.9 billion.

The deal announced Dec. 18 fits Statoil's strategy of bolstering its presence in Brazil as it seeks to add new barrels which are becoming more difficult to obtain closer to home on the Norwegian continental shelf.

"This transaction adds material and attractive long-term production to our international portfolio, further strengthening the position of Brazil as a core area for Statoil," Statoil CEO Eldar Saetre said.

The *P-54* FPSO unit is shown on the Roncador Field. (Source: Geraldo Falcão/Statoil)

The agreement consists of an initial payment of $2.35 billion plus "additional contingent payments" of up to $550 million, Statoil said in a statement.

Its structure showed Statoil was betting on the increased recovery from the mature field, Sparebank 1 Markets analyst Teodor Sveen-Nilsen said in a note.

"With Statoil's very strong track record on the Norwegian continental shelf for increasing recovery rates, we believe the outlook for increasing recovery rate for Roncador is good," he added.

Roncador, Petrobras' third-largest producing field in the Campos Basin offshore Brazil, is estimated to contain about 10 Bboe in place and more than 1 Bboe in expected remaining recoverable volumes, Statoil said.

The Norwegian company said its ambition was to increase the recovery factor by at least 5 percentage points, bringing the field's total remaining recoverable volumes to more than 1.5 Bboe.

The production from the field, which started in 1999, stood at about 240,000 bbl/d in November.

After the transaction, Statoil's output off Brazil will increase to 110,000 boe/d from about 40,000 boe/d, the company said.

Petrobras will continue to operate the field and will hold a 75% stake.

Analyst Anders Holte at Danske Bank said the implied transaction's valuation stood at $9.4 per barrel, compared with valuations of recent transaction off Norway at average $11 per barrel.

Sparebank's Sveen-Nilsen said the deal showed Statoil had used an opportunity to make a deal outside Norway as the Norwegian continental shelf assets market was getting "pretty crowded."

The transaction over Roncador will take effect from Jan. 1. The deal is subject to approval from Brazilian authorities.

—Reuters

BUSINESS BRIEFS

BASF Plans To Merge Its Oil Unit Wintershall With DEA

Chemical giant BASF agreed to merge its oil and gas unit Wintershall with DEA to create one of the largest independent oil and gas firms in Europe, the companies said.

By folding DEA into Wintershall and creating Germany's first oil champion, growth opportunities could await in large Western markets.

For BASF it represents a second chance to diversify outside Russia where it is heavily present via ventures with gas monopoly Gazprom.

The new company will produce about 590,000 bbl/d from fields mainly in the North Sea, Africa and Russia and have combined proven reserves of 2.1 billion barrels of oil equivalent.

BASF will control 67% of the new firm while LetterOne will own the remaining 33%

BASF could increase its stake in the company at a later stage by folding into it its pipeline business, which was left outside the initial merger.

The new group would consider an IPO upon completion of the merger, which is expected in second-half 2018.

Subsea 7 Makes Changes To Executive Management Team

Øyvind Mikaelsen will step down from the position of executive vice president, commercial, for Subsea 7 with plans to depart in second-quarter 2018, the company said in a news release. He has worked with the company for more than 25 years.

He will be succeeded on Jan. 1 by Stuart Fitzgerald, vice president for strategy and technology, will be appointed as executive vice president, strategy and commercial. In his new role, Fitzgerald will be responsible for the commercial activities of the SURF and Conventional Business Unit as well as asset development, sales and marketing, strategy and technology, and the alliances, according to the release.

Elliott Seeks To Remove CEO John Hess Of Hess Corp

Activist investor Elliott Management Corp. is readying for a new fight with U.S. oil and gas producer Hess Corp. hoping it can remove its CEO John Hess, or push him to sell all or part of the company, *The Wall Street Journal* reported on Dec. 14.

New-York based Elliott, which owns 6.7% of Hess, is seeking changes including a dividend cut in "favor of stock buybacks", the *Journal* reported, citing people familiar with the matter.

A Hess spokeswoman was not immediately available to comment.

Elliott Management had earlier called for the breakup of the company and said it may nominate directors to its board.

Delmar, MDL Team Up To Establish Flex-lay Base In US

Delmar Systems, a global mooring specialist, has entered a partnership with pipelay equipment provider Maritime Developments (MDL), to set up a flex-lay base in the USA, a news release said.

The agreement will see a suite of MDL's equipment move into Delmar's yard in Port Fourchon, Louisiana, where it will have access for work in the Gulf of Mexico and other parts of the world.

The facility encompasses 11 acres of shore space, 600 feet of dockside access and a 300-ton extended reach crane. Using the MDL flex-lay equipment, the partnership will offer a wide range of cost-saving services to energy businesses in the region, reducing mobilization costs and mission times safely and efficiently.

Subsea UK Unveils New Board For 2018-2019

The industry body that represents more than 300 member companies involved in Britain's subsea sector has named its new board.

Bill Edgar serves as the organization's chairman, while Neil Gordon serves as chief executive.

Board members are David Rennie, Scottish Enterprise; Bill Cattanach, the Oil & Gas Authority; Mark Richardson, Apache North Sea; David Sheret, Archer Knight Ltd.; Nicky Etherson, Bibby Offshore; and Zander Bruce, BP North Sea.

The remaining board seats will be held by Geoff Lyons, BPP-TECH; Peter Blake, Chevron Energy Technology; Tim Sheehan, Oceaneering; Cameron Mitchell, Shell UK; and Phil Simons, Subsea 7.

ExxonMobil Completes LNG Acquisition In Mozambique's Area 4

A transaction by ExxonMobil Development Africa B.V. to acquire a 25% indirect interest in Mozambique's gas-rich Area 4 block from Eni and assume responsibility for midstream operations has been completed, ExxonMobil Corp. said.

ExxonMobil will lead the construction and operation of all future natural gas liquefaction and related facilities, while Eni will continue to lead the Coral floating LNG project and all upstream operations. The operating model will enable the use of best practices and skills with each company focusing on distinct and clearly defined scopes while preserving the benefits of an integrated project.

The deepwater Area 4 block contains an estimated 2.4 Tcm (85 Tcf) of natural gas in place.

ExxonMobil now owns a 35.7% interest in Eni East Africa S.p.A. (to be renamed Mozambique Rovuma Venture S.p.A.), which holds a 70% interest in Area 4, and is co-owned with Eni (35.7%) and CNPC (28.6%). The remaining interests in Area 4 are held by Empresa Nacional de Hidrocarbonetos E.P. (10%), Kogas (10%) and Galp Energia (10%).

Mozambique President Replaces Energy, Foreign Ministers

Mozambican President Filipe Nyusi has sacked four ministers, including those with the foreign affairs and energy portfolios, his office said, without giving a reason.

Energy is a key portfolio in Mozambique, which has vast untapped offshore gas reserves that are being developed by oil majors such as Italy's Eni.

Nyusi's office said Ernesto Max Elias Tonela had replaced Leticia da Silva Klemens as minister of energy and mineral resources and Jose Condugua Antonio Pacheco was the new foreign minister, replacing Oldemiro Baloi.

The president also replaced the ministers of industry and trade and of agriculture and food security.

Tonela, the new energy minister, previously served as commerce minister. An economist by training, Tonela has also worked on the board of the Hidroelectrica de Cahora Bassa SA company responsible for Mozambique's 2,000 megawatt hydroelectric dam.

Kuwait Names New Oil, Finance Ministers In Cabinet Reshuffle

Kuwait replaced its oil, finance and defense ministers in a cabinet reshuffle on Dec. 11, state news agency KUNA reported.

Bakhit al-Rashidi was appointed the new oil minister of the OPEC member state and Nayef Falah al-Hajraf was named the new finance minister, KUNA said, citing a royal decree.

Sheikh Nasser Sabah Al-Ahmad, son of the ruling Emir Sheikh Sabah Al-Ahmad Al-Jaber Al-Sabah, was appointed the new minister of defense.

The previous cabinet resigned Oct. 30 when its information minister was questioned by parliament and faced a no-confidence vote over alleged violations of budgetary and legislative rules. Mohammed Nasser Al-Jabri was named the new minister.

The major oil producer has the oldest legislature among the Gulf Arab states and experiences frequent cabinet reshuffles. The previous government was formed in February.

Rashidi, who replaced Essam al-Marzouq as oil minister, is CEO of Kuwait Petroleum International Ltd. (KPI), the international downstream subsidiary of state-run Kuwait Petroleum Corp. There was no immediate announcement about his KPI post.

Hajraf replaced Anas al-Saleh, who had been finance minister since early 2014. Hajraf was previously chairman of the board of commissioners of the Capital Markets Authority, the securities regulator.

Saleh was named deputy prime minister and state minister for cabinet affairs.

Premier Oil Awards Operations, Maintenance Contract To Sparrows

Sparrows Offshore Group Ltd. said on Dec. 7 it has secured a new five-year contract with Premier Oil for the provision of crane operations and maintenance across two of its North Sea assets.

The scope of work, awarded to Sparrows for the first time, will see the company provide offshore crane operations and maintenance, including major component change out and overhaul, to the *Balmoral* floating production vessel and the Solan installation.

The contract encompasses all cranes and associated mechanical, electrical, hydraulic and instrumentation on the fields. Sparrows will also be responsible for all inspection, condition monitoring, management of maintenance strategies and full engineering scopes. Onshore support and repairs will be conducted from Sparrows global headquarters in Aberdeen.

The Solan Field, located 96 km (59 miles) northwest of the Orkney Islands, achieved first oil in April 2016 and can store up to 300,000 bbl of crude oil. *Balmoral* is positioned 200 km (124 miles) northeast of Aberdeen at a water depth of 143 m (469 ft).

The contract comes just weeks after Sparrows said that it had been awarded a three-year year crane management services contract with Chrysaor Holdings Ltd. for the three operating assets it took ownership of from Royal Dutch Shell in November.

Sonangol Settles Dispute With Cobalt International Energy

Angola's state oil company Sonangol said on Dec. 19 it had settled all disputes with Houston-based Cobalt International Energy and would pay the U.S. oil firm $500 million for its stakes in two offshore oil blocks.

Cobalt had filed arbitration requests in May seeking in excess of $2 billion due to the impact of failed extension talks on its attempts to sell offshore blocks 20 and 21 in Angola.

Sonangol said it would pay $150 million by Feb. 23 and a further $350 million by July 1.

"Sonangol will continue the development of strategies and actions with all stakeholders to relaunch the stability and attractiveness of the hydrocarbons industry in Angola," Sonangol CEO Carlos Saturnino said in a news release.

Cobalt CEO Timothy Cutt wished them "all the best" in developing the assets, saying the resolution was in the best interest of stakeholders.

The settlement is subject to approval by the U.S. Bankruptcy Court for the Southern District of Texas.

SBM Wraps Up $720 Million Financing Of *Liza* FPSO Unit

SBM Offshore has completed the project financing of the *Liza* FPSO unit for $720 million, having secured financing by a consortium of 12 international banks, the company said Dec. 20.

The company said it expects to draw the loan in full, phased over the construction period of the FPSO unit, which is owned and will be operated by SBM. The financing will become non-recourse once the FPSO unit is completed and pre-completion guarantees have been released, according to the release.

The unit is a converted very large crude carrier capable of producing up to 120,000 bbl/d of oil with an associated gas treatment capacity of about 4.8 MMcm/d (170 MMcf/d)and water injection capacity of about 200,000 bbl/d. It will be spread moored at the Esso Exploration and Production Guyana-operated Liza Field offshore Guyana. Esso is an affiliate of ExxonMobil, holding a 45% interest in the Stabroek Block where the field is located. Partners are Hess Guyana Exploration Ltd. (30%) and CNOOC Nexen Petroleum Guyana Ltd. (25%).

UPCOMING

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