SEN
SUBSEA ENGINEERING NEWS

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New Flying Lead Technology Emerges

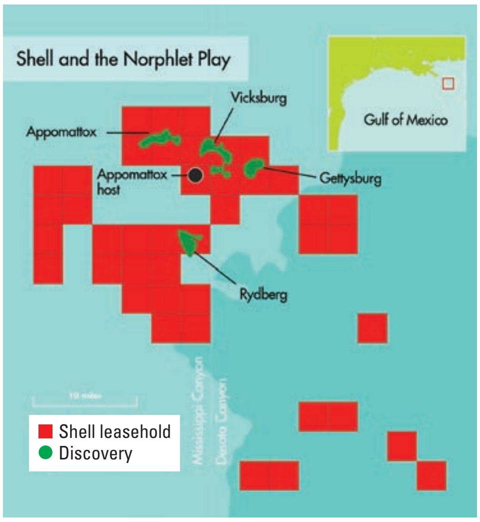
HOUSTON—Tough times for the oil and gas industry have led offshore operators to subsea technology to help cut costs as many lean toward standardization and simplified yet innovative concepts.

Use of new electrical optical flying lead technology is among the design changes helping trim costs for the Royal Dutch Shell-operated Appomattox development in the U.S. Gulf of Mexico's Norphlet geologic trend. Unlike some of its fellow deepwater counterparts, Appomattox is progressing through the downturn, making it past the final investment decision stage in July 2015 with project costs down 20%.

Teledyne Marine is "participating strongly" in the Appomattox development with its electrical active flying lead and corrosion monitoring, Teledyne Marine President Mike Read said during the company's Technology Focus Day this week in Houston.

"Many of you are coming to us for new ideas on how to take costs out of the next-generation system. …We've been driving standardization factories that are more automated," Read said. "We're using tools such as product configuration to really simplify and standardize," making customers jobs easier and more cost-efficient.

Shell has attributed cost savings at Appomattox to supply chain savings, lowering the number of wells needs for the development and design improvements. New data transmission technology from Teledyne led to one of the design changes, according to Teledyne.



Shell's Appomattox development is located in the Gulf of Mexico's Norphlet trend. (Source: Shell)

The flying leads, or electrical and fiber-optic connections, include wet mate connectors that are joined by subsea hose, providing a link from the topside facilities to subsea control modules on the seabed, Teledyne explained on its website. Such connections are needed for each well to power subsea equipment and transit data.

"New flying lead technology now has the ability to embed electrical-to-optical conversion equipment into the hose itself, removing the need for some of the routing modules on the seabed," Teledyne said. "A new product with this technology, an Electrical Optical Flying Lead (EOFL), will provide a direct link from topside to a subsea control module to transmit data regarding pressure, temperature, flow rates, equipment health and a host of other functions, while at the same time streamlining the field architecture into a simple, cost-effective layout."

Teledyne Marine will provide more than 40 EOFLs needed for the development, which calls for a semisubmersible unit, four-column production host platform and a subsea system with six drill centers along with 15 producing wells and five water injection wells. The development, in which Shell has 79% interest with partner Nexen Petroleum Offshore USA holding 21%, is located at a water depth of 2,195 m (7,200 ft) in the Mississippi Canyon and Desoto Canyon areas.

WHAT'S INSIDE

Teledyne's electrical optical flying lead embeds electrical-to-optical conversion equipment into the subsea hose. (Source: Teledyne)

The EOFL technology is one of many ways Teledyne is putting R&D efforts to work.

The company is bringing in record R&D dollars despite market conditions, Read said, noting the figure peaked at $13 million in 2015.

"We're increasing our global presence, we're deepening our customer partnerships [and] we're focused on factory consolidation centers of excellence. We will be the cost leader," Read said. He challenges the Teledyne team to "think bigger, be bolder and speed it up. … At Teledyne Marine, we're moving from defense to offense."

Looking Forward

Another division of the company, Teledyne Scientific & Imaging, also is making strides in areas that could benefit the subsea oil and gas sector.

The company is applying machine learning technology to its sensors. The goal is to embed learning capabilities in sensors, said Berinder Brar, president of Teledyne Scientific & Imaging.

One of Teledyne's sensor companies also has taken visible infrared imagery and fused it, making it possible to get infrared information in the context of a typically recognizable image, Brar said.

"Algorithms are getting more sophisticated, and this is going to change the way the world will be in the future," he said. "As an industry we have to learn to utilize these sensors better as well as be able to take information out of the sensors and make more efficient and lower cost alternatives."

Teledyne Scientific also has worked with the Defense Advanced Research Projects Agency (DARPA), part of the U.S. Department of Defense, and North Carolina State on drone technology, developing an unmanned aerial vehicle that can fly out of water and land in water.

In addition, there is a new material coming out—also funded by DARPA—called Gallium nitride (GaN), a semiconductor material with a large band gap that is capable of operating in high temperatures, Brar said.

"New materials like gallium nitride can be very, very important for the future of oil and gas," he added. GaN can not only operate at high temperatures but also at high frequencies and handle high voltages. "It allows you to take power supplies and compact them significantly. We're doing work on gallium nitride at Teledyne as well," he said.

—Velda Addison

DEVELOPMENT

Statoil Favors Subsea Option For Snorre Expansion

Statoil and its partners will make a decision before year-end 2016 to proceed with the expansion of the $3 billion to $3.3 billion Snorre Field in the Norwegian Sea.

Statoil said the partners would make the "Decision Gate 2" (DG2) within this time frame, with the preferred option being "a significant subsea tie-back" to the Snorre A platform.

The Snorre expansion program is targeting 200 MMbbl to 300 MMbbl of oil in the Norwegian Sea. (Source: Statoil)

Once this decision is made, the partners can move swiftly onto the FEED stage.

"A contract for FEED work can be awarded quickly after a positive DG2 is reached," Statoil told SEN.

The operator added that Wood Group is "a part of the total Snorre Expansion Program (SEP)," which suggests that the contractor has a good chance of success once the FEED contract comes up for grabs. Indeed, Wood Group has an option for the FEED and an option for construction of the riser base.

"All the work we are performing within the project helps the decision. Specs for subsea requirements will be worked out during the FEED phase," Statoil said.

Tendering for engineering and construction work is expected to be launched after final project sanction in 2017. A plan for development and operation for the SEP is expected to be submitted by year-end 2017.

Statoil said the SEP is due onstream "during 2021, but we do not have any more specific timing at this stage."

For some years, the Snorre partners have been struggling to agree on the best concept to develop the estimated additional 200 MMbbl to 300 MMbbl of oil that the SEP is targeting. In February they agreed to study a subsea development as a possible concept for the SEP, with this solution now the preferred option.

Norway's Petoro has frequently expressed its concerns that as production depletes the Snorre Field every year, reservoir pressure falls and fewer barrels can be recovered. Now the ball seems to be rolling again on the SEP after these delays.

Early engineering work has been carried out to look at the potential subsea field layout, design of pipelines, system engineering and design of subsea pipeline structures.

The Snorre Field covers blocks 34/4 and 34/7 in the Tampen Area of the Norwegian North Sea. The field has been producing oil and gas since August 1992. The Snorre development embraces two platforms, A and B.

Snorre A is an integrated production, drilling and quarters (PDQ) unit. This tension-leg platform is moored to the seabed by steel tethers.

Partly stabilized oil and gas from Snorre A is transported via a subsea pipeline to the nearby Statfjord A platform for final processing.

The oil is then loaded into shuttle tankers, while the gas is transported to continental Europe through the Statpipe system and to St Fergus, Scotland, through the Tampen link.

The Snorre B platform came onstream in June 2001. This semisubmersible PDQ floater lies around 7 km (4 miles) north of the A platform. Oil from Snorre B is piped for 45 km (28 miles) to Statfjord B for storage and export.

Part of the gas is injected back into the reservoir, while the rest is transported by pipeline via Snorre A to continental Europe through the Statpipe system and to St. Fergus, Scotland, through the Tampen link pipeline.

Pil & Bue Concept Chosen

Faroe Petroleum reported that the partners in the Pil and Bue discoveries in production license 586 (PL 586) have chosen a subsea development solution tied back to the Njord platform in the Norwegian Sea as the preferred concept for the discoveries.

Three competing concepts were considered in the evaluation process: subsea tiebacks to either the Njord or Draugen platforms as well as an FPSO vessel as a standalone development.

The FPSO option was estimated to cost about $1.59 billion but lost out in favor of the tieback concept to Njord. The tieback had an initial cost of about $1.83 billion, but it is believed significant reductions have since been made that gave this option the edge over the FPSO solution.

"Going forward, the development solution will be matured through the front end engineering design stage toward a formal field development plan," Faroe said.

The Njord production facility is currently in Kvaerner's Stord facility in Norway undergoing extensive modifications to increase materially its operating life and accommodate a number of new satellite field tieback developments, including Pil and Bue.

"I am very pleased to announce that the Njord facilities have been chosen for the development of the material Pil and Bue discoveries," said Faroe CEO Graham Stewart. "This is a significant step in the maturation of these high-quality discoveries, and the fact that they will be tied back to infrastructure we know well, and are joint venture partners in, further consolidates one of our core areas in Norway."

Operator VGN estimates that recoverable reserves at Pil and Bue are between 80 MMboe and 200 MMboe.

The partners in PL 586 are VGN (30%), Spike Exploration (30%), Faroe (25%) and Pure E&P (15%).

—Steve Hamlen

Nexen Rethinks UK Buzzard Phase 2 Concept

Nexen Petroleum is moving ahead with a new look concept for the Buzzard Phase 2 development in the U.K. North Sea following a reevaluation of the project earlier this year.

The original concept under consideration was a bridge-linked platform but Nexen wanted to find a cheaper option. The rethink has resulted in the new concept of an infill drilling program and subsea tieback solution to produce from the northern part of the Buzzard Field.

The *Ocean Nomad* drilled the Buzzard discovery well in the North Sea. (Source: Dana Petroleum)

At the recent annual Share Fair in Aberdeen, held by trade body UK Oil & Gas, delegates heard that the new concept is being taken into FEED imminently and tenders for the FEED work are being evaluated.

The Buzzard Phase 2 plan of infill drilling and a subsea tieback still needs formal approval, but if the plan is given the green light then more work can be started this quarter.

Buzzard is located in the Outer Moray Firth in blocks 19/10, 20/6, 19/5a and 20/1S, about 96 km (59.6 miles) northeast of Aberdeen. It has a water depth of about 96 m (315 ft).

Nexen said Buzzard is the largest U.K. North Sea oil discovery in the past 20 years. Oil from Buzzard is exported via the Forties pipeline to the Kinneil Terminal in Scotland. Natural gas is exported via the FUKA pipeline system (Frigg UK Pipeline) to the St. Fergus Gas Terminal in northeast Scotland.

Nexen, a wholly owned subsidiary of China's state-owned CNOOC Ltd, operates Buzzard with a 43.21% stake. The other partners are Suncor Energy (29.89%), BG (21.73%), Dyas EOG (4.70%) and Oranje-Nassau Energy Petroleum (0.47%).

The Buzzard Field was discovered in June 2001 using the semisubmersible rig Ocean Nomad, which initially encountered a 122-m (400-ft) gross oil column.

The oil column tested at 6,547 bbl/d. A subsequent sidetrack extended the oil-bearing sands 1.3 km (less than 1 mile) to the east and increased the gross oil column to 229 m (750 ft).

The Buzzard Field's total recoverable reserves are estimated at more than 550 MMbbl of oil.

—Steve Hamlen

Total Returns To Iran With South Pars Agreement

Total SA has signed on to develop another piece of the world's largest natural gas field, Iran's South Pars in the Persian Gulf, as part of a two-phase development, working with CNPC and Petropars.

With a price tag of an estimated $2 billion, Phase 1 of the project includes plans for 30 wells and two wellhead platforms connected by two subsea pipelines to existing treatment facilities onshore, according to Total, which will serve as operator of the South Pars Phase 11 (SP11) project. Phase 2 will include construction of offshore compression facilities.

The Paris-based company's heads of agreement (HOA) with the National Iranian Oil Co. (NIOC), announced Nov. 8, comes as the Middle Eastern country works to renew its energy sector following the lifting of sanctions earlier this year when global leaders reached a deal concerning Iran's nuclear program. The country also is looking to meet its growing domestic gas needs while also increasing exports.

SP11 is expected to have production capacity of 50.9 MMcm/d (1.8 Bcf/d) starting in 2020, with produced resources moving into Iran's gas network.

Total is no stranger to South Pars. The company developed phases two and three of the field, which partly lie in Qatari territory, before the U.N. imposed sanctions in 2006 that forced it to leave Iran. According to the agreement, project partners will work to finalize the 20-year deal under terms established by the recently approved Iranian Petroleum Contract, which replaces buybacks as well as technical and economic terms reached in the HOA.

"Total will develop the project in strict compliance with national and international laws and looks forward to working alongside the Chinese state-owned company CNPC in this additional international partnership," Total CEO Patrick Pouyanné said in a statement. "This project fits with the group's strategy of expanding its presence in the Middle East, where the origins of the group lies, and growing its gas portfolio by adding low unit cost, long plateau gas assets."

Pars Oil and Gas Co., the NIOC subsidiary charged with developing the South Pars and North Pars gas fields, said the contract is expected to be finalized in early 2017, with SP11 gas production starting within 40 months.

"This would be the first plan from among the South Pars common field plans in which the pressure boosting system is used in order to prevent the reservoir pressure decline," the company said. "It would subsequently be used as the design pattern for the pressure boosting system in other locations of the common reservoir."

About 3,700 sq km (1,428.5 sq miles) of the 9,700-sq km (3,745-sq mile) gas field lies in Iranian waters and holds an estimated 14 Tcm (494 Tcf) of gas reserves along with 18 Bbbl of gas condensates, according to Pars. The field is being developed in 24 phases—about half of which are complete.

The U.S. Energy Information Administration estimates additional phases of the South Pars natural gas field will help boost Iran's noncrude liquids production by 150,000 bbl/d by year-end 2016 and by another 100,000 bbl/d by year-end 2017.

Iranian news agency Shana reported that SP11 will add 56 MMcm (1.9 Bcf) of gas to Iran's gas extraction capacity.

Partners in the Total-led consortium include CNPC (30%) and Petropars (19.9%). Total holds the remaining 50.1% interest.

—Velda Addison

DEVELOPMENT BRIEFS

Aker BP Brings Viper, Kobra Online

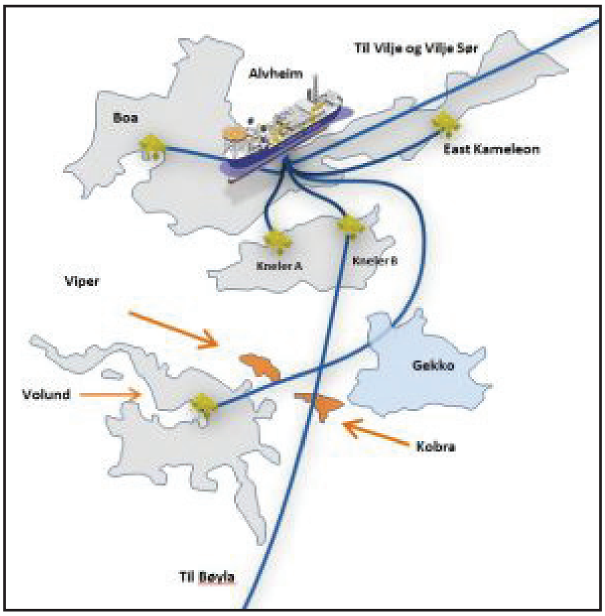
Accomplishing the task on time and within budget, Aker BP has started production from the Viper-Kobra development in the Alvheim area offshore Norway.

The initial output from the two wells is expected to be an estimated 15,000 boe/d. Each of the reserves is estimated to hold about 4 MMbbl of recoverable oil with total recoverable reserves estimated at 9 MMboe, including gas, Aker BP said in a news release.

With development costs at about NOK 1.8 billion (US$211.6 million), work included the drilling of two wells, subsea installations, pipelines and hookup. The development, which consists of the Viper and Kobra discoveries but is considered part of the Alvheim Field, is tied back to the Alvheim FPSO vessel.

"The development comprises a new subsea installation with a pipeline tied into the Volund manifold," Aker BP said in the release. "The four well slots are designated for one well from Viper and one from Kobra, in addition to two well slots intended for potential future wells in the area."

Geir Solli, senior vice president of operations for Aker BP, called the project a small but important one for the company.



The greater Alvheim area is developed with an FPSO vessel and subsea wells. (Source: Aker BP)

"Viper-Kobra leverages on the existing infrastructure in the Alvheim area, thus ensuring maximum utilization of the adjacent resources and will contribute to maintain the Alvheim production at a high level," Solli said.

Alvheim license operator Aker BP has a 65% interest with partners ConocoPhillips (20%) and Lundin Norway (15%).

Danos Fabricates Boarding Valve Skids For Appomattox

Louisiana-based Danos said it has completed the fabrication of three boarding valve skids and one service line skid for Shell's deepwater Appomattox facility.

Requiring about 12 months to complete, the project engaged four Danos service lines, including project management, fabrication, coatings, and automation, the company said in a news release.

"Delivery of this project marks Danos' entry into the module fabrication market," Mark Danos, vice president of project services, said in the statement. The project was delivered on budget.

The skids, weighing in at approximately 160 tons each, were fabricated at Danos' facility in Amelia, La. Key design elements of the modules included 12,200 psi design pressure and 350°F operating temperature requirements. The API 15K psi piping system consisted of 4130 material overlaid with Inconel 625, according to the release.

Xodus Secures FEED Contract For Midia Gas Development

Black Sea Oil & Gas SRL and partners have awarded the FEED contract for the offshore and onshore facilities for the development of Ana and Doina gas discoveries on the XV Midia Shallow Block, offshore Romania, to Xodus Group, according to a news release.

FEED services to be provided by Xodus include engineering and design for the development that consists of a wellhead platform (jacket) receiving and supporting production from a subsea tieback from Doina subsea well controlled through umbilical; an infield pipeline from the Doina subsea well to the Ana wellhead platform and an offshore export pipeline from the Ana platform to shore.

Services will also cover an onshore pipeline to a gas treatment plant and the gas treatment plant itself, the release said.

Mexico Finalizes Terms For First Deepwater Project

Mexico's oil regulator approved on Nov. 4 a final set of business-friendly tweaks to bid rules for a highly anticipated upcoming auction that will pick a partner for state oil company Pemex to develop its first-ever deepwater project.

The joint venture (JV) covers Pemex's Trion Field and marks a major step in the opening up of Mexico's oil industry, a process enabled by a landmark energy reform in 2013 that permits Pemex to enter E&P JVs for the first time.

Trion is located at a depth of 2,500 m (8,202 ft) in the Gulf's Perdido Fold Belt just south of Mexico's maritime border with the U.S. The field is believed to contain some 480 MMboe.

Among the final changes to the bid terms, the oil regulator, known as the CNH, voted to eliminate a provision in the joint operating agreement that would have given Pemex the power to unilaterally remove the oil company chosen to operate the project.

The CNH also voted to eliminate a cash bond that was included in the joint operating agreement, leaving just a bond set out in the license contract as well as specifying that the operator will have the "decisive vote" in the event of any work program disagreements.

The CNH previously voted to lower Pemex's minimum stake in the project from 45% to 40%.

The license contract, similar to a concession, will be awarded on Dec. 5, the same day that the regulator also will auction 10 separate deepwater fields, including four that surround Trion.

Pemex has estimated the Trion project will require a total investment of about $11 billion.

Stella Coasts Into Final Stages

Ithaca Energy reported that its Greater Stella Area development is progressing as the FPF-1 floating production facility has been towed to the field and moored on location with dynamic risers and umbilical connecting the subsea infrastructure to the vessel installed.

An update on the development, located in the Central Graben area of the North Sea, was given during the company's third-quarter 2016 earnings report.

Technip has finished the subsea commissioning program for the development, and all infield flowlines have been flushed and are ready for production to begin, the company said.

"Connection and operational trials for the 'single anchor loading' system also have been completed for the fleet of shuttle tankers that are available for oil exports from the FPF-1," Ithaca said in a news release. "The FPF-1 offshore commissioning program is ongoing, involving preparation of the topsides processing and utility systems for the introduction of hydrocarbons."

Among the essential remaining work is the manufacture and installation of pipeline export pumps on the FPF-1 facility and final subsea connections needed prior to the switchover, the company said.

First hydrocarbons from the development are expected near the end of November 2016.

Technip Wins Umbilical Supply Contract In US GoM

Technip SA said Nov. 10 its wholly owned subsidiary Technip Umbilicals Inc. was awarded a contract to supply a subsea control umbilical in the U.S. Gulf of Mexico (GoM).

The contract was with an undisclosed major operator, according to the press release.

The contract includes the project management and manufacture of several kilometers of a static and dynamic unarmored steel tube umbilical.

Technip Umbilicals facility in Houston will manufacture the project for the high-pressure field, which is scheduled to be completed in 2017.

Aker BP Taps Altus Intervention For Services At Alvheim

Aker BP has awarded Altus Intervention a frame agreement contract for well intervention services consisting of cased-hole wireline, slickline and tractor services on three production wells and one exploration well on the Alvheim Field, the company said in a news release.

The agreement, which runs for three years, has options that could extend the agreement to a total of nine years.

Startup of the field, located in the central part of the North Sea, is scheduled for mid-December 2016.

Sonangol Begins Operations At Mafumeira Project

Sonangol EP and its Block Zero partners have begun Early Production System (EPS) operations at the South Wellhead Platform of the Mafumeira Sul project offshore Angola's Cabinda province, according to a news release.

EPS will operate with a maximum production capacity of 10,000 bbl/d, marking an important step in efforts to increase domestic oil production, the company said. Mafumeira Sul is located in a water depth of about 60 m (200 ft).

Partners involved in the project are Cabinda Gulf Oil Co. Ltd., Total E&P Angola and Eni Angola.

Petrobras: Consortium Completes First Libra Block Well

The Libra Consortium has completed the first well in the Libra oil field, located in Brazil's Santos Basin, Petrobras said in a news release.

Drilled by the *West Carina* rig, the 3-RJS-739A well—also called NW3—is now ready to produce oil and natural gas. The well lies in the northwestern section of the block in a water depth of 1,951 m (6,401 ft).

"The NW3 has been fitted with an intelligent dual-zone system to facilitate real-time control and production monitoring," Petrobras said. "It will start production in 2017, connected to *Pioneiro de Libra* FPSO [vessel], during the first Libra extended well test."

The Libra Consortium is formed by operator Petrobras (40%), Shell (20%), Total (20%), CNPC (10%) and

CNOOC (10%). The production-sharing contract will be managed by state-owned Pré-Sal Petróleo S.A.

Saipem Lands $1 Billion In EPIC Contracts

Saudi Aramco has awarded Saipem two engineering, procurement, construction and installation (EPCI) contracts for activities relating to the development of the Marjan, Zuluf and Safaniya fields in the Arabian Gulf, according to a news release.

Saipem said new contracts and change orders awarded to the company total about $1 billion.

The contracts, which are part of a long-term agreement in force and renewed in 2015 until 2021, cover the design, EPCI and implementation of subsea systems in addition to the laying of pipelines, subsea cables and umbilicals, platform decks and jackets, Saipem said in the release.

The company added that the two contracts also will include additional maintenance and dismantling works on the existing platforms already operating in the fields.

Chevron Begins Production At UK Alder Field

Chevron North Sea Ltd. has started production at the HP/HT Alder gas condensate field in the Central North Sea.

Alder is a single subsea well tied back via a 28-km (17-mile) pipeline to the existing ConocoPhillips-operated Britannia Platform, in which Chevron holds a 32.38% nonoperated working interest. The project has a planned design capacity of 3.1 MMcm (110 MMcf) of natural gas and 14,000 bbl of condensate per day. Production from the Alder Field is expected to ramp up over the coming months.

More than 70% of the Alder development work was executed by U.K.-based companies, providing significant investment to the U.K. supply chain. The contracts supported several hundred jobs across a range of U.K. locations including Aberdeen, Invergordon, Leeds and Newcastle.

Discovered in 1975, the development has been enabled through the application of innovative subsea technologies designed to meet the temperature and pressure challenges of Alder. Key technologies have included a number of firsts for Chevron in the North Sea, including a vertical mono-bore subsea tree system; a subsea high-integrity pressure protection system; and a specially designed corrosion monitoring system to measure the real-time condition of the production pipeline.

Alder is operated by Chevron North Sea Ltd. (73.7%) with ConocoPhillips (U.K.) Ltd. (26.3%).

FMC, Technip, Aker Land Contracts For Trestakk Development

FMC Technologies and Technip have been selected to jointly deliver engineering, procurement, construction and installation (EPCI) services for the Statoil-operated Trestakk development in the Norwegian Sea.

The EPCI contract covers subsea, umbilicals, risers, flowlines—including subsea template, manifold, subsea trees, completion system, wellheads, pipelines, risers, control systems, control cable and marine operations, Statoil said in a news release Nov. 4.

Statoil also awarded a contract to Aker Solutions for Åsgard topside work for the development. The Åsgard A production vessel will be modified to receive oil and gas from the Trestakk Field, Statoil said. Work involves piping to connect the wellstream to the vessel and upgrading of the metering systems.

Statoil is the operator of the license with a 59.1% stake with partners Exxon Mobil Exploration and Production Norway (33%) and Eni (7.9%).

—Staff, Reuters & Business Wire Reports

FLOATERS

EMA Report Expects Improvement In Awards Next Year After Anemic 2016

Energy Maritime Associates (EMA) confirms in its fourth-quarter 2016 Floating Production Systems Report that the industry has experienced a rough year.

"Unless there is a sudden surge of awards in the next two months, 2016 will be the worst year ever for the floating production market," EMA's Managing Director David Boggs said in a statement. "We expect improvement next year as companies are reassured by more stable oil prices and take advantage of lower costs."

Boggs said record low drilling rates could create a window of opportunity for deepwater and marginal fields, along with the reuse of available assets that can enable cost-efficient production.

"However, this situation will not last forever," he added. "Companies that take FID [final investment decisions] sooner will benefit from availability and reduced costs throughout the supply chain."

EMA's review of third-quarter 2016 included:

- *Two more floating storage regasification unit (FSRU) awards:* These two bring the total for the year to four—all FSRUs. Three were for speculative newbuilt units, and the other was deployment of the LNG Regas Vessel Excelerate for FSRU service in Abu Dhabi;
- *$230 million floating, storage and offloading (FSO) contract awarded by Chevron:* MISC will convert an FSO unit to replace the Benchamas Explorer, which has been operating in Thailand since 1999; and
- *Three units delivered:* Petrofac's *FPF-1* semisubmersible unit, Bumi Armada's LNG *Mediterrana* LNG FSO unit and Uzma's *Marsya* mobile offshore production unit (MOPU).

Two issues led EMA to ponder whether a floating production and storage vessel (FPS) market recovery was in the offing:

1. Petrobras has resumed FPSO orders, with seven awards planned by 2018. After a two-year pause, Petrobras plans to lease large FPSO units for the Libra Pilot and Sepia (tenders underway), Buzios V, Marlim Revitalization I and II, Libra 2, and Parque das Baleias developments; and
2. EMA has identified 10 possible awards that could still be granted in 2016. However, most will be deferred into 2017 as oil companies continue to push back spending. The most likely upcoming awards have a combined capex of $6.35 billion: Coral FLNG (Mozambique), *Ophir* FPSO (Malaysia), *Yombo* FPSO (Congo), and *Ca Rong Do* FPSO and tension-leg platform (Vietnam).

EMA also turned its attention to idle units and the possibilities for their redeployment. Forty-six FPS units are available: 24 FPSO units, 10 production semisubmersible units, six FSO units, five MOPUs and one floating LNG. This is up from 26 at the beginning of the year.

Plus, finding new employment is not easy. While some of these assets will be put back in service, the majority will likely be recycled, like the FPSO *Falcon*. This FPSO unit was first of three "generic" West African FPSO units ordered by Exxon, which were designed for a wide range of field properties, weather conditions and water depths. Despite these features, the FPSO Falcon was never redeployed.

Details of EMA's research are included in the 275-page *Q4 2016 Floating Production Report*. The upcoming *Floating Production Market Outlook Report 2017-2021* provides a complete assessment and forecast for each type of FPS. This report will be released in early January.

Turkey Looks To FSRUs To Bolster Gas System

The BOTAŞ Pipeline Corp. aims to use FSRUs as part of its plan to expand Turkey's energy supplies and diversify its gas sources, the *Hurriyet Daily* News reported.

The newspaper identified two FSRU projects in the eastern Mediterranean Sea—one on the southern coast of Turkey and one in the Gulf of Saros off the Gallipoli Peninsula in northwestern Turkey. Construction on those projects is expected to be completed in 2019 and result in total capacity of about 40 Mcm/d.

The FSRUs are part of BOTAŞ' greater goal of increasing daily capacity of Turkey's natural gas system from the current 200 MMcm/d to 350 MMcm/d (7 Bcf/d to 12.3 Bcf/d), according to data released by the government. Figures reveal that the company currently imports 42 MMcm/d (1.4 Bcf/d) from Russia's West Line and 47.3 MMcm/d (1.6 Bcf/d) via the Blue Stream from Russia. The country also buys 19 MMcm/d (670 MMcf/d) of gas from Azerbaijan and 28.5 MMcm/d (1 Bcf/d) from Iran. Turkey has made clear its goal to reduce its dependence on energy imports and increase its reliance on domestic resources. The country's energy imports through September 2016 totaled $19.5 billion, according to the Turkish Statistical Institute (Turkstat). Last year, with low oil prices, Turkey's energy import bill totaled $38 billion compared to $55 billion in 2014.

—Joseph Markman

VESSELS

Technip Introduces DSV *Deep Explorer*

Four Technip vessels are under construction, including *Deep Explorer*. The company operates an 18-vessel fleet. (Source: Technip)

Technip's Deep Explorer diving support vessel (DSV) has been named and is undergoing equipment outfitting and commissioning in preparation for its work in North Sea Canada.

Naming for the DP3-class DSV was held Nov. 12 at shipbuilder VARD's Langsten shipyard, with Heidi Brovoll-Bø, wife of Technip North Sea Canada President Knut Bø, serving as vessel godmother.

Deep Explorer's hull was built by Vard Tulcea shipyard in Romania and then towed to Vard Langsten. The vessel features JFD's 24-man twin bell saturated dive system rated to 350 m (1,148 ft).

The new vessel boasts the latest techn ology diving control system, 400 Te box boom crane, large deck area, working moonpool and work-class ROVs, making it the most modern and versatile DSV on the market. It is capable of working globally on diving and subsea construction projects, even in extreme weather conditions, and is expected to begin operations in 2017. "This event marks an important milestone in this three-year project to design, build and deliver this impressive, fantastic new ship," said Bruno Faure, Technip's senior vice president for subsea projects and operations. "We are proud to welcome the *Deep Explorer*, an impressive key asset for the Technip fleet and for our clients. My sincere thanks to all those in Technip and our partner companies who have contributed to this successful project."

VARD's team also was excited to participate.

"It has been a great honor for us in VARD to be a part of this exciting project," said at Vard Langsten Yard Director and Senior Vice President Dag Vikestrand. Technip operates 18 vessels (with another four under construction) specializing in pipeline installation and subsea construction.

Demand for OSVs Will Drop 10% Through 2017, IHS Markit Says

Global demand for oil and gas offshore supply vessels (OSV) will continue its 10% annual decline through 2017, IHS Markit reported in a new analysis.

"Despite a significant decline in operator demand for offshore supply vessels, such as platform supply vessels (PSV) and anchor-handling tug supply (AHTS) vessels, the global OSV fleet continues to grow," said Erik Simonsen, the company's senior manager of energy costs and technology and lead author of "IHS Energy: When Will the AHTS and PSV Market Recover?"

"This growth comes as a result of excessive new OSV orders placed during several years of growth before the oil and gas industry went into decline. As a result, we expect overall utilization for these vessels will stay below 60% through 2020, which is extremely low." Global demand began its annual 10% falloff in 2014.

PSVs are specially designed to supply offshore oil and gas platforms. The primary function for most of these vessels is logistic support and transportation of goods, tools, equipment and personnel to and from offshore structures. AHTS vessels mainly handle anchors for oil rigs so the rigs can be towed to their location, anchor them and occasionally serve as an emergency response and rescue vessel. These vessels also transport supplies to and from offshore rigs, especially in the North Sea. Although demand for OSVs, which includes PSVs and AHTS vessels, is expected to increase beginning in 2018, the market, along with day rates, will not recover until after 2020, Simonsen said. The OSV market has more than 400 managers, IHS Markit said, and is overripe for consolidation.

However, the report said consolidation alone will not solve the capacity problem. "While some OSV managers may consider cold-stacking vessels as a means of buying time while they wait for a better future market, we believe that to bring the market back into balance for both day rates and fleet utilization requires a massive scrapping plan that eliminates older vessels at levels previously not seen in the industry," Simonsen said.

Vessels built before 2000 will struggle to achieve term contracts, while spot rates in an oversupplied market will most likely only equal daily operational expenses for these older vessels, IHS said. Utilization in the spot market remains below 50% of the fleet, meaning that EBITDA will remain negative.

"These older vessels will not survive until the next up cycle," Simonsen said. "The scrapping of these vessels, along with our IHS Markit expectation that many vessels currently under construction or those on order will not be delivered, could reduce the current fleet significantly. We believe as many as 1,000 vessels need to be scrapped or permanently removed from the fleet, including vessels under construction or on order, to achieve market balance by 2020."

What that translates to is the scrapping of as many as 200 vessels per year for the next five years compared with the average scrapping of 25 vessels per year in recent years. Cold stacking of vessels is not the solution, IHS Markit said, because it will actually delay industry recovery and balance.

"The question remains whether the industry, with such a fragmented ownership structure, will be willing to scrap older vessels to address overcapacity in the market, which may benefit other managers with more modern fleets," Simonsen said. "However, most oil and gas companies are not willing to enter term contracts with vessels older than 15 to 20 years, so those vessels will have to compete on the spot market and that will prove increasingly difficult for those vessels when newer vessels are available at attractive rates."

—Joseph Markman

VESSEL BRIEFS

Bibby Scoops Up Another Subsea Inspection Contract With Shell

Bibby Offshore has been awarded two contracts this year from Shell to provide inspection services on assets in the Corrib natural gas field in the North Atlantic Ocean, according to a news release.

As part of the first contract Bibby Offshore's construction support vessel *Olympic Ares*, which is equipped with Quantum Work Class and SeaEye Cougar Inspection Class ROVs, performed subsea inspections offshore Ireland in water depths of about 360 m (1,181 ft). The 40-day campaign, completed in June, involved pipeline survey inspection work on a 83-km-long (51.5-mile-long), 20-in. gas pipeline as well as internal wellhead and manifold fault diagnostics, structural inspection and cathodic protection measurements to ensure optimum levels of productivity were achieved, Bibby said.

Shell awarded Bibby a second contract for work, which began in July, at the operator's West Ireland assets. This project also involved use of Bibby's *Olympic Ares*. Expected to be complete by year-end 2016, the company said it will install an electrical distribution unit and several replacement control jumpers. The company also will perform inspection, repair and maintenance services in water depths of 400 m (1,312 ft).

Gulf Marine Confirms Contract For New Large Vessel

U.K.-based Gulf Marine Services Plc confirmed on Nov. 15 a contract to build a large-class vessel to support maintenance work in the European oil and gas sector.

"This new contract is testament to our leading industry expertise and strong track record of successful operations in European waters," said Duncan Anderson, the company's CEO, in a statement. "GMS is very well-positioned to capitalize on our clients' desire for less expensive and yet more capable offshore support solutions, as our self-propelled vessels are significantly more economical and time-efficient than conventional support vessels without self-propulsion."

—Staff Reports

EXPLORATION

Offshore Oil Prospects Offer Mixed Blessing For Somalia

Somalia looks more likely to strike oil than gas in its long pursuit of offshore riches, making it easier for the African state to exploit any windfall but also potentially upsetting the fragile recovery led by its Western-backed government.

The waters off Somalia, best known for years of piracy, may harbor hydrocarbons at a depth where crude is usually found, seismic services company Spectrum said last week based on its research. This is unlike the seas farther south along the African coastline where gas is abundant.

That would be good news for Somalia, which would likely find pumping out oil onto tankers easier than securing the multibillion-dollar investment needed to liquefy gas for export.

Oil revenues could transform Somalia's economy, where many people rely on subsistence livestock farming. However, it could prove a challenge for a government trying to rebuild a nation battered by clan rivalries and Islamist insurgents after it descended into war in 1991.

"Disagreements between the member states and the federal government could fuel violence and corruption in a country that is still very much trying to build and extend governance," said Ahmed Soliman, an expert at British think-tank Chatham House.

Some fear oil rigs also could become a new target for pirates, who were the scourge of commercial shipping on nearby trade routes until naval protection and costly security on ships drove them away. The last major hijacking was reported in 2012.

"Somalia is still extremely fragile and hence the risk of the piracy resurfacing is a concern," said Cyrus Mody, assistant director in the ICC International Maritime Bureau.

Seas Of Black Gold

Onshore exploration in Somalia took place in the 1950s, but the collapse of the government and ensuing conflict 25 years ago kept oil firms away. Much of the geophysical data that had been gathered by the state were lost or destroyed.

But explorers have been spurred on by finds of offshore gas in Tanzania and Mozambique and onshore oil in Kenya and Uganda, although exploiting those reserves has been hamstrung by the slide in oil prices and retrenchment by oil firms.

"It is very prospective," Neil Hodgson, vice president for geoscience at Spectrum, told Reuters, adding that Somalia's source rock was similar to that found in Mozambique and Tanzania but the deposits were not as deep, suggesting oil over gas.

Spectrum has acquired 20,000 km (12,427 miles) of 2-D data from the government and shot 20,000 km itself as part of its research.

The so-called "gas window" for gas reserves occurs at depths of 3 km to 6 km (1.8 miles to 3.7 miles) and extremely high temperatures. Oil is usually found at lower temperatures, between 2 km and 4 km (1.24 miles and 2.48 miles).

Round One Begins

Somalia is pressing on with its exploration plans. Last week, officials announced its first offshore hydrocarbon licensing round at a conference in Cape Town.

The initial round will cover areas off central and southern Somalia and will exclude shallow-water block concessions signed in 1988 with Shell and Exxon Mobil.

Abdulkadir Hussein, technical director-general for Somalia's Petroleum Ministry, said a new majority-state owned national oil company and regulatory body should be operational next year.

Initially, the state oil firm would get a free 10% stake in all hydrocarbon ventures.

"Later, when the company becomes established it will participate with its own money, up to a limit of 30%," he told Reuters.

Jamal Mursal, the Somali Oil Ministry's permanent secretary, said Somalia was working to build capacity to handle the new industry. "We have more to do but are getting there," he said.

But investors also will need more reassurance about doing business with a government that has had to fend off past criticism from donors about corruption and poor management. The country also needs to put in place legislation.

"There's still uncertainty about the exact implementation of the petroleum law at all levels of government," said Ed Hobey, an analyst with Africa Risk Consulting.

—Reuters

TECHNOLOGY BRIEFS

BP, SMG Focus On Borehole Microgravity Logging Technology

BP Ventures, the corporate venture division of BP Plc and Silicon Microgravity Ltd. (SMG), have formed an advisory board to explore future cooperation around borehole microgravity logging technology for use in oil and gas exploration, SMG said in a news release.

The advisory board comprises BP's Luis Alcoser and Robin Wye along with Paul Vickery and Francis Neill, both from SMG.

A spinout of the University of Cambridge, SMG developed novel sensor technology that is used by oil companies to enhance oil recovery.

"We believe our new proprietary, patented borehole microgravity logging technology, based on a unique approach, will present a disruptive approach to the measurement of waterflood fronts in major conventional reservoirs," SMG CEO Paul Vickery said in a news release. The technology could help operators:

- Improve sweep efficiency and recovery through better EOR management such as flood front prediction, coning and sanding risk;
- Better thin bed detection in resource assessment; and
- Enable superior bypassed pay identification, he added.

BP Ventures sees "the SMG borehole gravity technology as a key enabling technology with potential applications across the BP global portfolio," Alcoser said. "The BP support is intended to enable SMG to develop a greater understanding of operator requirements and also the ability to deploy the technology in a range of applications.

GE, Maersk Drilling Team Up For Digital Pilot Project

Aiming to cut maintenance costs by up to 20% and increase the productivity of vessels, GE and Maersk Drilling have agreed to work together on a data analytic-driven pilot project.

The two companies have collaborated to deploy SeaStream Insight, GE's latest innovation in marine asset performance management, powered by Predix, according to a news release. The pilot project will be carried out on one of Maersk Drilling's XLE rigs and will last for 12 months. Data already have been collected from a rig and are being processed and analyzed.

"Operational sensor data from critical equipment are connected to a historian, a specialized server that stores the data needed to model the blueprint of the drilling operation," the release said. "By building this 'digital twin,' the digital software can then help compare assets to assets and provide access to vessel performance against the ideal state. Big data also are translated into clear dashboards with a holistic view of a vessel, which can help operators make more informed decisions."

Advanced algorithms also will enable SeaStream Insight to predict the future state of critical asset health, identifying inefficiencies or detecting potential failure earlier, up to weeks ahead. In addition to enhanced productivity, SeaStream Insight also will allow operators to maintain equipment in a more efficient manner, according to the release.

BP, GE Launch POA Offshore Digital Technology

BP Plc and GE started up the plant operations advisor (POA) offshore digital technology that will improve the efficiency, reliability and safety of BP's oil and gas production operations.

The POA already is helping BP manage the performance of one of its platforms in the U.S. Gulf of Mexico and, subject to a successful pilot, it will be deployed next year to other BP facilities around the world, according to a Nov. 15 press release.

The POA, built on GE's Predix operating system, was created as part of a development partnership the two companies announced in January. The tool combines Big Data, cloud hosting and analytics.

The POA delivers notifications and analytical reports to engineers using real-time data, helping engineering teams prevent unplanned downtime and improve facility reliability.

Lorenzo Simonelli, president and CEO of GE Oil & Gas, said the product was created over the past year.

Firms Pitch Subsea Technology In Aberdeen

U.K. companies planned to pitch their subsea technologies to a panel of operators and Tier 1 contractors—including Apache, Bibby Offshore, Chevron, Nexen and Technip—on Nov. 17 at Subsea UK's second Springboard event.

In partnership with the National Subsea Research Initiative, the event encouraged companies to present their processes and systems that they believe have the potential to reduce operational costs and boost efficiencies, Subsea UK said.

Presenting companies lined up for the event included AISUS Offshore, Caley Ocean Systems, SECC Oil & Gas, J2 Subsea, Systems Engineering & Assessment, Aquatec Group, Tracero and SETS. Representatives were asked to deliver a short presentation, showcasing their technologies that could help lower operational costs, improve integrity management, extend field life, reduce risks and maximize data collection.

Subsea Springboard events take place every three months.

"The event aims to help connect subsea companies with potential clients, highlighting the products and services currently available to them," said Neil Gordon, CEO of Subsea UK. "By bringing the supply chain together with operators and Tier 1 companies, we hope to further encourage the uptake of current, cost-effective technologies, which can improve efficiencies and speed up project delivery times."

—Staff Reports

BUSINESS

Lower For Longer Means Going Back To Basics For BP

HOUSTON—Can deepwater oil and gas survive in a $50/bbl environment?

That's a question operators such as BP Plc are challenged with, according to Ryan Malone, projects general manager for BP's Gulf of Mexico (GoM) operations. The rise and fall of commodity prices, which reached the $50/bbl mark in recent months only to slip to about $45/bbl amid the world's bounty of oil, have made some skittish on deepwater profitability as the lower-for-longer price environment prompts players to change the paradigm.

When oil prices began to fall about two years ago, "We took the stance that we were going to make all of our businesses viable and commercial at $50 per barrel," Malone said Nov. 15 while giving the state of the industry keynote during Teledyne's Technology Focus Day.

The task required a shift in strategy, but the company's confidence was boosted by its profit-returning track record in places such as the GoM and offshore Angola and Egypt, where subsea and deepwater technologies are present, he added.

But like its peers combating the profit-gobbling force—also known as the oversupply-driven downturn—it has been challenging. BP's underlying replacement cost profit, or net income, dropped to $933 million during third-quarter 2016 compared with $1.8 billion a year earlier. However, the supermajor continued to cut costs, with capex expected to fall to about $16 billion in 2016; guidance shared earlier this year was $1 billion to $2 billion higher.

The challenge, Malone said, is to not only get back to being competitive at $50/bbl oil but to "test the boundaries" by targeting $25/bbl breakeven prices at some deepwater developments—"irrespective of the revenue stream and prices."

The BP-operated Na Kika K3 project, which included subsea infrastructure tied back to the existing Na Kika Platform in the U.S. Gulf of Mexico, went from discovery to first oil in 11 months. (Source: BP)

Yet there are more obstacles today. After pointing out smaller pool size, lower exploration success rates, difficult political environments in some parts of the world and harder-to-find rock, Malone encouraged the industry to return to the basics and aim to be cheaper, faster and more reliable. He's convinced that BP has the right structure to return profits to desired levels.

BP's approach focuses on fast-cycle projects and targets multiple fields and reservoirs. The company has a bias toward subsea infrastructure, and it aims for smaller and simpler developments. Also key to its strategy is following proven designs and standard components, leveraging supply-led solutions, focusing on select new technology and using cross-functional expertise, according to his presentation.

Favoring Subsea

Malone highlighted the BP-operated Na Kika K3 project in the U.S. GoM as an example. The development, which included subsea infrastructure tied back to the existing Na Kika platform, went from discovery to first oil in 11 months. The company used what Malone called a "reverse engineering methodology" to do the work that would have taken between 24 and 36 months at a 30% cost saving.

"We utilized a lot of inventory. We liquidated a lot that we had built up around the region. We also looked within the industry for what was available. … It wasn't going through 10,000-page specifications and figuring out how to build the biggest, baddest, most gold-plated piece of component or kit on the seafloor," Malone continued. "It was taking what you had, realizing the environment that you were operating in and engineering to it."

The single-well tieback development, which started up Oct. 3, has a flexible flowline, umbilical and ancillary controls, a subsea tree, flow assurance module and metering module.

Keys to success for a larger infield expansion project—an unnamed three- to four-well tieback development with two static flowlines, a subsea chemical metering system and three subsea trees and production manifolds in a complex brownfield environment—included true front-end loading and advanced computer modeling and simulation. The project is within days or weeks of startup and is expected to come in under cost by 30%.

"These are some of the most prolific wells that we have in our entire portfolio. To be able to bring this on at a time when we need cash, when the industry wants to see that cash turned back into reinvestment. This is a big achievement for us."

BP also is progressing with plans for its Mad Dog Phase 2 project in the U.S. GoM, having cut costs for the planned development from $20 billion to less than $10 billion. The company has also cut about three years off the previously forecast first oil, "giving increased confidence that we're on the right track," Malone said.

"We're feeling very confident about not only doing the small subsea tiebacks, bigger subsea tiebacks, but also new host facilities that may be more competitive."

The BP Way

BP's approach in today's lower commodity price environment mirrors that of many other operators, Malone said, "We've got to be cheaper, faster and more reliable across the functional disciplines we deploy to execute our projects."

For better efficiency, for example, BP's global wells organization is managing a global fleet, looking for the best rates, while its global projects team, specifically deep water, is measuring efficiency from a technical development cost and subsea cost per well perspective.

"What we're finding is subsea cost per well is largely indicative of your overall facility concept or structure," Malone said. Costs concern more than dollars shelled out for equipment. It's about how the field is being developed and the completion plan, he said.

Execution is essential when "building quality through choice" across its portfolio, and opportunities are plentiful and not limited to deep water, according to Malone.

BP is working to build a global subsea execution organization, which will work with engineering, procurement, construction contracts to consistently develop projects. The company also is looking at equipment costs and delivery schedules differently for subsea equipment: ditching the old way of fully buildout BP specifications to going with what the company could live with to what it ends up with, what BP calls the "supplier-led solution." As Malone explained, that's essentially modifying the core offering from the supplier to meet the specific needs of a particular project.

"We've almost trained the supply chain to wait for the next step on what the operator wants: interpretation of codes, our own bespoke wellhead interfaces having to do with trees, the number of pressure and temperature sensors," he added, but noted a gap still exists.

Overcoming the gap takes those in the supply chain working closer with operators to understand needs and challenges, Lance continued. "We think the gap can be addressed at a lower cost and at a better schedule than what we're getting right now."

It'll take collaboration and the conversation is ongoing, he added.

—Velda Addison

Cost Optimization Keys Abu Dhabi Consolidations

Want to make of a series of high-profile consolidations in Abu Dhabi this year? The Abu Dhabi National Oil Co. (ADNOC) is the latest entity to enact structural changes—all in an effort to drive down costs and increase efficiency.

In early October the state-owned oil firm announced the consolidation of two of its largest offshore subsidiaries: the Abu Dhabi Marine Operating Co. (ADMA-OPCO) and the Zakum Development Co. (ZADCO). This one consolidated organization will eventually manage all of the associated offshore oil concessions.

The announcement is in sync with ADNOC's emphasis on optimizing costs and streamlining operations across the firm's 19 subsidiaries and joint ventures (JV). This process was initiated at the beginning of 2016.

ZADCO operates three offshore fields. Its most important field, Upper Zakum, covers 1,200 sq km (463 sq miles) and has about 50 Bbbl of oil in reserves. Oil is processed at a facility on nearby Zirku Island, along with oil from ZADCO's Umm Al Dalkh and Satah fields.

ADMA-OPCO produces oil from two primary fields, Umm Shaif and Lower Zakum, with crude transported to the company's Das Island facilities for processing, storage and export.

ADNOC looks to boost production levels—current output is 3.1 MMbbl/d, with a target of 3.5 MMbbl by 2018.

Offshore development remains a key focus of the company. ADNOC's offshore fields contribute a combined 1.2 MMbbl, with production expected to reach 1.7 MMbbl next year, thanks to output at the Satah Al Rasboot, Nasr and both Umm fields as well as completion of the UZ750 project.

The $10 billion UZ750 development, which consists of the construction of four artificial islands, aims to increase daily production at the Upper Zakum field from 640,000 bbl/d to 750,000 bbl/d by next year. With Abu Dhabi's offshore fields pointing to promising yields, the firm's capex spend has remained in line with past years to meet the company's 2018 target.

Meanwhile, international spending on E&P is expected to decline by 21% year-on-year in 2016, according to Barclays' revised forecast released in March.

While offshore fields are more technologically challenging, and thus more expensive to develop, recovery techniques such as dredging and the incorporation of artificial islands are helping to bring down the long-term costs of these ventures.

According to CEO of ADNOC Sultan Al Jaber, the consolidation of the two entities represents a logical next step in achieving the company's objectives around people, efficiency, performance and profitability.

"It will unite our offshore experience, streamline governance and decision making, and give management a better line of sight through the company's operations," he said.

The operating costs of ADMA-OPCO's Satah Al Rasboot Field, for example, already were set to be reduced with a move to link services with Zirku Island, itself belonging to ZADCO.

Additionally, the combined Upper and Lower Zakum fields previously divided between ADMA-OPCO and ZADCO, respectively, constitute the largest single offshore field in the world in terms of reserves.

ADNOC's international partners are working with the firm throughout this whole integration process.

Currently, ADNOC holds a majority share of ADMA-OPCO at 60%, with the remaining shares owned by BP (14.67%), Total (13.33%) and the Japan Oil Development Co. (JODCO, 12%). Likewise, ZADCO is a partnership between ADNOC (60%), Exxon Mobil (28%) and JODCO (12%).

In the near term, a steering committee has been appointed by ADNOC and its JV partners to oversee the integration, with the consolidation process to be completed by early-2018.

"The existing concession rights of our partners in the concessions currently operated by ADMA-OPCO and ZADCO will not be affected by the consolidation," Al Jaber said in early October.

However, international firms are positioning themselves for the expiration of ADMA-OPCO concessions in 2018; ZADCO's concessions do not expire until 2041.

ADNOC's consolidation is the latest in a series of moves in the emirate.

In August Abu Dhabi-based investment and development company Mubadala Development Co., which owns Mubadala Petroleum, merged with the International Petroleum Investment Co., with $125 billion of combined assets. This consolidation brings together two of the emirate's most important investment companies, offering a range of domestic and international energy portfolios.

—Gordon Feller

BUSINESS BRIEFS

Oceaneering Appoints Senior VP Of Business Development

Oceaneering International Inc. has named Stephen P. Barrett as senior vice president of business development, according to a news release.

In this role, Barrett will oversee Oceaneering's global business development efforts.

With more than 35 years of experience in the oil and gas industry, Barrett joined Oceaneering in 2015 as senior vice president of subsea products. Prior to joining Oceaneering, Barrett was with FMC Technologies Inc., where he held various leadership positions including global subsea services director, the release said.

Barrett earned a Bachelor of Science degree in mechanical engineering from Texas A&M University and a Masters of Business degree in finance and entrepreneurship from Rice University.

Knut Eriksen, who joined Oceaneering in 2010, currently holds this position and will support Barrett during the transition period while continuing to build customer relationships at the executive level, the release said.

North Sea Gets $200 Million Investment Boost

Private-equity player Energy Ventures has earmarked a budget of $200 million to help "boost North Sea businesses during challenging times."

Energy Ventures plans to invest in companies that need finance for stabilization or continued growth.

"Energy Ventures is one of the few oil and gas private-equity funds investing at this time. In the past 20 months we have made three platform investments in the North Sea and a total of 11 investments including add-ons in the same period," said Tomas Hvamb, Energy Ventures' Aberdeen-based investment director. "The additional funding of $200 million, which we have set aside, is testament to the commitment we have to the area.

"We believe in the North Sea and the opportunities it continues to offer for domestic and international growth. We look to partner with talented management teams in service and technology companies with high growth potential and seek to invest between $10 million and $40 million in each company. With them, we can help them move forward positively, while investing in their future."

Greg Herrera, one of the company's partners, said, "The additional funding that we are currently making available is there to help businesses in the North Sea who may be finding trading conditions particularly challenging just now due to the low oil price. We are keen to partner with them to help them through this period and beyond."

Weir Lands $12 Million Wellhead Contract In Middle East

Weir Oil & Gas Dubai has been selected to provide Kuwait Oil Co. (KOC) 295 seaboard wellheads valued at about $12 million, according to a news release.

The agreement was reached through Khuff Trading and Contracting.

As part of the deal, Weir will provide KOC with 11 different wellhead configurations ranging from 3,000 psi to 10,000 psi, the release said. The products include conventional wellheads along with HH-cladded trees and solid block dual completion trees. Equipment designs will accommodate casing and tubing sizes ranging from 24 in. to 3½ in. in the various wellhead configurations supplied to KOC.

Dril-Quip Completes TIW Acquisition

Dril-Quip Inc. has completed its previously announced acquisition of TIW Corp., according to a news release. Houston-based TIW is a global provider of liner hanger systems and related equipment and services.

Dril-Quip, also based in Houston, announced on Oct. 17 that it would acquire the company for $143 million. The deal marks the first acquisition in Drip-Quip's history.

"In addition to expanding our offshore and onshore market opportunities, this transaction allows us to significantly expand our product offerings to our customers," Dril-Quip CEO Blake DeBerry said in the release.

Sonardyne Gets New Marine Robotic Systems Global Business Manager

Subsea technology company Sonardyne International Ltd. UK appointed Ioseba (Joe) Tena as its new global business manager for marine robotic systems, effective immediately.

Tena has worked for more than 20 years with marine robotic systems, most recently at SeeByte, Sonardyne said Nov. 15.

Tena worked with marine robots as a research associate at Heriot-Watt University early in his career and completed a Ph.D. in 2001. He was an original founder of SeeByte, and in 2008 he became sales manager there, also leading recruitment and management of SeeByte's sales and marketing team.

Weatherford CEO Bernard Duroc-Danner Leaves

Weatherford International Plc said on Nov. 9 that CEO Bernard Duroc-Danner has left the company. The oilfield services company named CFO Krishna Shivram its interim CEO.

The company's shares, which were halted for news pending, surged 33.2% in late trading and closed up at $5.06.

Shivram will continue as CFO until that position is filled, Weatherford said.

Weatherford's unit, Weatherford International LLC, agreed in September to pay a $140 million penalty to settle charges that it inflated earnings between 2007 and 2012 by using deceptive income tax accounting.

The U.S. Securities and Exchange Commission said in October that Ernst & Young will pay $11.8 million to settle charges over "failed audits" of Weatherford International Plc.

Frank's International Names New President, CEO

Douglas Stephens will become president and CEO of Frank's International NV, effective Nov. 15, the company said.

Stephens will succeed Gary Luquette, who has been president and CEO since January 2015.

Luquette will remain at Frank's to assist with the transition until Dec. 31 and will continue as a supervisory director until the May 2017 annual meeting of shareholders, at which time Stephens will be recommended for election to the supervisory board.

Most recently, Stephens was president of global pressure pumping at Baker Hughes Inc. Prior to working at Baker Hughes, he worked for Schlumberger Ltd. for more than 20 years, working in the U.S., the U.K., Oman, Italy and Egypt.

OMV Sells UK Business In Retreat From Costly Exploration

OMV is selling its U.K. business to Siccar Point Energy for up to $1 billion, putting an end to the Austrian oil and gas group's exploration activities in Britain as it seeks to escape high costs in areas such as the North Sea.

The firm's CEO Rainer Seele is unwinding a strategy set by his predecessor, who bought North Sea assets in 2013 for $2.65 billion, by shifting OMV's focus from output growth to cutting costs and cash generation.

The Nov. 8 deal is expected to close in first-quarter 2017 but would be effective from Jan. 1, 2016.

The transaction, which is pending regulatory approval, would at current exchange rates shave 350 million euros (US$386 million) off OMV's overall earnings before interest and tax to reflect lost revenues in 2016, OMV said.

OMV was due to report third-quarter results on Wednesday, Nov. 9, but it was unclear when the impairment would be booked.

Under the terms of the deal, Britain's Siccar will pay OMV $750 million in cash and a further $125 million once a long-awaited final investment decision is made on the Chevron-operated Rosebank Field.

It will also get a further $125 million for investments it already has paid for in Britain this year if the deal goes through.

As part of Seele's strategy shift, OMV is placing its bets on swapping a stake in its Norwegian unit with Russia's Gazprom for a stake in a low-cost Siberian gas field, although the deal is taking longer than expected. ($1 = 0.9073 euros)

Nilsson Takes On Statoil's Executive VP, COO Role

Jannicke Nilsson was appointed as executive vice president and COO of Statoil, replacing Anders Opedal, who will lead operations in Brazil as the new country manager, the company said Nov. 4.

Nilsson's new role becomes effective Dec. 1, while Opedal will assume his responsibilities Jan. 15, 2017.

—*Staff & Reuters Reports*

UPCOMING

The next issue of Subsea Engineering News will be distributed Dec. 2. Until then, visit *epmag.com*.

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