SEN
SUBSEA ENGINEERING NEWS

HARTENERGY

vol. 33 - no. 13 September 23, 2016

Subsea Compression Technology Takes Shape

The Åsgard subsea compressor is installed at the K-lab test facility in Kårstø north of Stavanger. (Source: Statoil)

Having successfully completed testing of the world's first subsea gas compression system on the Ormen Lange Pilot project offshore Norway, Anglo Dutch major Shell and its partners are now gearing up to kick start the process of simplifying the total system that is seen as the next step for the technology, GE Oil & Gas said.

The Ormen Lange Pilot has been undertaken by Shell and its partners Petoro, Statoil, Dong and Exxon Mobil since 2011 at Shell's test facility at Nyhamna in Norway where gas from the Ormen Lange Field reaches shore.

Alisdair McDonald, head of GE Oil & Gas' Subsea Power & Processing business, talked to *SEN* about the next step for the key technology following the testing stage.

"Subsea compression technology is ready for subsea use. The drive in the industry is now to simplify the total subsea compression system, and making the compressor more robust and tolerant to liquids is a key part of this," McDonald said. "GE is currently qualifying a liquid tolerant compressor, which will be an important step in this direction."

In terms of how much the system costs and how applicable it is for use on development projects on the Norwegian Continental Shelf (NCS) and across the world, McDonald said, "The cost will be very dependent on field size and requirements (number of compressors, step-out, etc.). Subsea compression may also be economic for smaller developments given that the power system infrastructure around is beneficial and the reservoir properties are suitable.

"The main benefit of subsea compression systems is increased recovery. For many fields the challenge is that the wellstream does not have enough pressure to push through the pipeline, especially when reservoir pressure declines," he said. "The compressor basically helps the gas stream flow, allowing the well to produce more easily."

When asked about the future for subsea compression systems, McDonald noted, "Subsea compression is definitely an important part of the subsea puzzle in the future, but not for all fields. It will depend on the reservoir and on the infrastructure in the area. As the systems become less complex and the technology is adapted in the market, we will see more subsea compression developments in the future."

GE Oil & Gas was heavily involved in the program and said the test produced "a full subsea power supply, transmission and distribution system that further advances the development of hydrocarbon processing on the seabed."

"The Ormen Lange Pilot was a first of its kind and was designed to test a full-scale integrated subsea compression system in submerged conditions with real hydrocarbons," GE said.

The system allows operators to conduct gas compression on the seabed, reducing the need to introduce additional power generation on nearby offshore facilities.

Statoil Startups

Prior to the end of the pilot, Norway's Statoil saw the potential of the technology and became the first company

WHAT'S INSIDE

to apply subsea gas compression with two project startups in late 2015.

In October 2015, Statoil and partners Petoro and OMV started the world's first wet gas compression on the seabed of the Gullfaks South Field off Norway.

The use of this technology will increase recovery by 22 MMboe and extend plateau production by about two years from the Gullfaks South Brent reservoir, Statoil said.

"Subsea processing and gas compression represent the next generation of oil and gas recovery, taking us a big step forward," said Margareth Øvrum, executive vice president for technology, projects and drilling at Statoil.

Gullfaks South is a satellite field linked to the Gullfaks C platform. Gas is compressed in 135 m (443 ft) of water, raising pressure in the pipelines and accelerating gas flow to the platform.

The Gullfaks system provides a multiphase compression model for smaller fields, where simplicity and relatively low-boost pressure drive investment decisions.

In field-life extension efforts on Gullfaks, Statoil worked with OneSubsea and other suppliers to qualify a helico-axial multiphase compressor technology. Following successful onshore compressor testing in 2011, Statoil and its partners selected subsea compression as the preferred concept—a giant leap forward for the technology.

The main components include inlet coolers, a multiphase mixer unit and two multiphase compressors. Three additional flowline hubs are available to tie-in future Gullfaks satellite fields.

In September 2015, Statoil also started the Åsgard subsea gas compression.

During 2013, the Åsgard system involved one subsea template containing two parallel compressor trains installed in 300 m (984 ft) of water. As of September 2016, Train 1 had been in operation for one year and Train 2 for nearly eight months.

The more sophisticated Åsgard model is best suited for large fields or wells with a great step-out distance requiring a larger pressure boost. Åsgard's subsea system involves gas-scrubbing equipment upstream of centrifugal dry gas compressors.

At Åsgard, gas needs to be boosted from the Mikkel and Midgard satellite fields to the Åsgard B platform to maintain stable production rates and avoid accumulation of mono-ethylene glycol in the flowline.

Gas production from the Midgard and Mikkel reservoirs is about 40% higher than before subsea compression started. Field life was extended by many years, Statoil added.

Placing a compressor closer to the well helps maximize production rates and energy efficiency. Subsea compression also requires relatively little supporting steel and operating personnel, giving it a low physical footprint compared with compression done on a platform. Statoil is considering the use of this technology on its other properties, both in Norway and elsewhere.

"The two projects are the first of their kind worldwide, and represent two different technologies for maintaining production when the reservoir pressure drops after a certain time," Statoil noted.

"Subsea compression has a stronger impact than conventional platform-based compression. It is furthermore an advantage that the platform avoids increased weight and the extra space needed on the platform for a compression module."

—Steve Hamlen

DEVELOPMENT

GSPC Seeks Partner For 'Difficult' HP/HT Field

India's Gujarat State Petroleum Corp. Ltd. (GSPC) is looking for a strategic partner to solve problems the company is facing in developing the Deen Dayal West (DDW) Field in the shallow-water KG-OSN-2001/3 Block, off Bay of Bengal.

HP/HT conditions and low permeability have stifled development at the field for the last two years, making it difficult for GSPC to produce commercial volumes of gas.

The company has approached a couple of global firms, including state-run ONGC Ltd., to discuss offering a majority share of its 80% participating interest in field in return for hydraulic fracturing expertise and funding to develop the oil and gas prospects.

ONGC Chairman and Managing Director D K Sarraf said the company has been in talks with GSPC and appointed consultant Ryder Scott to evaluate gas properties in the deepwater block and independently certify the reserves quantities.

"We did some technical study on the field and post that we thought that it would be better to appoint a consultant because it is quite a difficult field," Sarraf said.

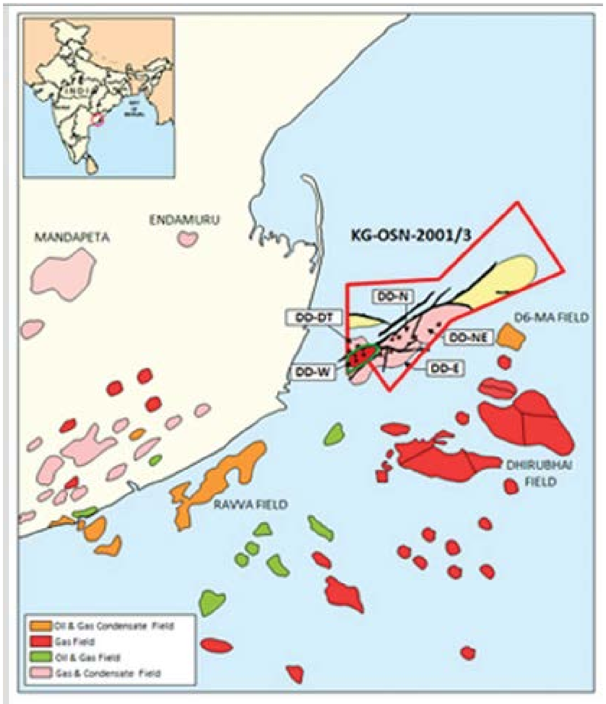
ONGC is weighing the benefits of sharing infrastructure, considering the block is next to some of its prospects in the KG-D5 Block.

Cost overruns and failure to produce gas from developed wells in the field forced GSPC to seek a strategic investor.

So far, GSPC has invested more than $2.5 billion in exploration and development of infrastructure around the field but has achieved little success in addressing low permeability problems.

The operator carried out hydraulic fracturing in one of the four wells (DDW D3) in an attempt to solve the low permeability problems but failed to produce any result. A study on the job indicated that the main reason for failure could have been the use of an inappropriate fracturing fluid. Two wells (DDW D1 and D2) were developed later without hydraulic fracturing. The results of the fourth well are yet to be disclosed.

A report prepared by the Comptroller and Auditor General of India said the operator had not developed suitable drilling technology during the exploration phase



Four development wells have been drilled in the Deen Dayal West Field. (Source: Jubilant Energy)

and data gathered during the exploration stage was inadequate, which created problems in the development phase.

"The successive changes in approach for resolving the issue of low permeability and their outcome indicate that the company is still not clear on how to obtain the proposed production rate from the wells," the report stated.

Four development wells have been drilled so far, compared with the target of 15 wells envisaged in the field development plan.

Trial production from the field began in August 2014, and production remains about 19 MMscf/d. The production target from the 15 wells was set at about 200 MMscf/d.

The operator acknowledged the failures and lessons learned during exploration and development well drilling, pointing out the need to make changes in well design, specifications for casings and chemicals, and completion strategy to boost production. The operator also said hydraulic fracturing and drilling multiple wells would be better options to increase the production.

During the exploration stage, GSPC drilled 13 exploratory and five appraisal wells in the KG Block. Some of these wells were drilled to up to 6,000 m (19,685 ft) depth. Nine discoveries were made in the southern part of the block. Of these, three were in the DDW and six were in other areas.

The field development plan (FDP) for the DDW discoveries was launched with a plan to drill 11 development wells, convert four exploratory wells already drilled to development wells, and build offshore and onshore processing facilities, including a wellhead platform, an offshore process-cum-living quarter platform, a subsea pipeline and an onshore gas terminal.

The operator has so far drilled four of the proposed 15 development wells but has constructed all the offshore and onshore facilities, spending about \$2.57 billion—including exploration costs—as of March 31, 2015. The amount is much higher than the \$1.7 billion cost for the entire DDW development plan approved in 2009.

The DDW Field, according to the FDP, has estimated oil and gas in place reserves of about 55.2 Bcm (1.95 Tcf) with a projected cumulative production of 30 Bcm (1.06 Tcf) at a recovery rate of 54.3%.

The KG-OSN-2001/3 Block, which is spread across an area of 1,850 sq km (714 sq miles), is estimated to have in-place reserves of 396 Bcm (14 Tcf) with about 215 Bcm (7.6 Tcf) recoverable, according to Gaffney, Cline and Associates.

Jubilant Offshore Drilling Ltd. and GeoGlobal Resources each hold a 10% participating interest in the block.

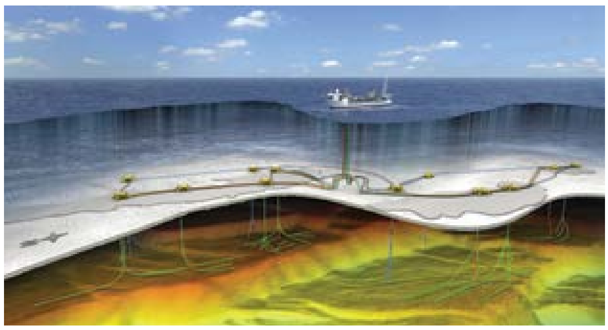
—Ravi Prasad

Statoil Selects Gas Turbines To Power Johan Castberg

High costs and the technical challenges posed by powering a long-distance subsea development from land have led Statoil and its partners to offshore gas turbines to power the Johan Castberg development.

Statoil recently shared news of the recommended power solution after extensive analysis on possible alternatives were carried out by Aker Solutions, Aibel, ABB, Unitech, Pöyry and Thema Consulting. Investment costs for full or partial electrification could range from more than NOK 4 billion (US\$481 million) to just above NOK 12 billion (US\$1.4 billion), Statoil said, noting the high cost makes the option a risk to the project's timeline and feasibility.

The company and its partners plan to submit a final development plan for the field, deemed to be the largest awaiting development on the Norwegian Continental Shelf (NCS), in 2017. The proposed impact assessment program, which only covers the offshore development part of the project, was set to be delivered Sept. 13 to Norwegian authorities.



Statoil plans to submit a final development plan for the Johan Castberg project in 2017. (Source: Statoil)

"We have developed a highly energy-efficient solution involving use of gas turbines for power generation on Johan Castberg. By use of heat recovery we achieve a turbine power efficiency of 64%, which is an outstanding result from use of gas turbines on offshore platforms," Margareth Øvrum, executive vice president for technology, projects and drilling for Statoil, said in a statement. "The license partners consider gas-fired power to be the most suitable and socio-economic solution for the development."

With use of gas turbines, emissions from the development would be 0.27 million tonnes of CO_2 per year, which equates to about 2% of current annual emissions from the NCS, Statoil said.

"Johan Castberg will be prepared for future electrification by use of alternating current technology in case this becomes an efficient and feasible solution in the future," Statoil said in the release.

The Johan Castberg development, previously called Skrugard, is located about 100 km (62 miles) north of the Snøhvit Field in the Barents Sea. Johan Castberg, which will develop the Skrugard, Havis and Drivis oil discoveries, is believed to hold proven resources of between 450 MMbbl and 650 MMbbl of oil.

The work of project partners—which include operator Statoil, 50%; Eni Norge, 30%; and Petoro, 20%—to development the fields comes as the oil and gas industry continues to rebound from one of the worst downturns in history. Lower commodity prices, the result of a supply and demand imbalance, have prompted many companies to seek out cost savings.

Statoil's efforts have included work toward lowering development breakeven costs. The company said such costs for Johan Castberg have fallen from about $80 per barrel to below $25/bbl.

Statoil said "considerable Johan Castberg spin-offs" also exists.

"During our improvement work we have created new opportunities for the Johan Castberg Field in the far north. We have changed the concept and found new solutions that allow us to realize the project," Øvrum said. "But we are still vulnerable to increasing costs and a continued low oil price."

Statoil said investment for the project is estimated at between NOK 50 billion and 60 billion (US$6 billion and 7.2 billion) which makes up a large chunk of NCS investments expected between 2018 and 2022. However, the company warned that low oil prices may impact plans.

"The Johan Castberg Field will be producing for more than 30 years, and the major project spin-offs will be created in the long-lasting production phase," Arne Sigve Nylund, Statoil's executive vice president for development and production Norway, said in the release. "Castberg will trigger much activity for suppliers in North Norway and have ripple effects throughout Norway, both in the development phase and the operating phase."

—Velda Addison

DEVELOPMENT BRIEFS

EnQuest, Delek Group End Kraken Stake Sale Talks

Israeli conglomerate Delek Group Ltd. and EnQuest have ended discussions about a potential sale of interest in the Kraken oil field development in the North Sea.

The news was delivered less than two months after the companies said they were in talks for Delek to buy a 20% interest in the field. Reuters reported the deal could have been worth $162 million.

EnQuest said the two were unable to reach a deal; however, the development continues to move forward.

Kraken is on track to reach first oil in first-half 2017 as the operator continues to reduce costs for the project. Gross full cycle project capex for the project is now about $2.6 billion after the operator added about $150 million in cost reductions to the approximately $425 million in reductions that were unveiled since the project was sanctioned, EnQuest said in its half-year 2016 report.

Sail away of the Kraken FPSO vessel, which has an 80,000-bbl/d production capacity, is expected sometime before year-end 2016.

If Kraken comes onstream in April 2017 as envisioned, it could bring about $100 million in operating cash flow with $45/bbl oil representing the forward curve, according to James Smith, CFO of project partner Cairn Energy. Plateau production will be about 50,000 boe/d.

Aker Solutions Lands Troll B Modifications Contract

Aker Solutions has picked up more work in the North Sea after securing a NOK 370 million (US$44.5 million) contract from Statoil and partners for Troll B engineering, procurement, construction and installation (EPCI) work.

The contract is an option in a FEED agreement awarded to Aker Solutions in January, the company said. The EPCI work aims to boost the gas treatment capacity at Troll B to increase oil recovery.

"The gas module is an important contribution to reaching the licensees' IOR ambition for the Troll Field. It will raise production capacity on Troll B and help us recover as much as possible of remaining resources during tale end production," Eric Normann Ulland, project director for Statoil, said in a news release. "From the module startsup in the autumn of 2018 until Troll B is shut down in 2025 it will increase recovery by around 4.7 million barrels of oil."

Knut Sandvik, head of Aker Solutions' maintenance, modifications and operations business, said "this project has targeted key cost savings to create the sustainability the industry depends on and is looking for during these challenging times."

Aker plans to carry out engineering work at in Bergen and begin module construction in Egersund next year. The module, which weighs more than 500 tonnes, will be delivered in third-quarter 2018.

Subsea 7, Det Norske, Aker Form Subsea Development Pact

Aker Solutions, Det norske oljeselskap and Subsea 7 have formed a partnership to find cost-effective solutions for developing Det norske's Norwegian subsea portfolio.

The companies' combined expertise in front-end engineering, E&P, brownfield modifications and subsea systems for the partnership, which will enable them to work as one integrated team.

Senior management members from each company will handle the overall management of the partnership, according to a news release. The project management team will be led by a manager from Det norske.

The companies' agreement to form this partnership comes after Det norske announced a four-year framework agreement with Aker Solutions to provide subsea production systems and services for Aker's oil and gas developments in Norway and with Subsea 7 for subsea umbilicals, risers and flowlines in June.

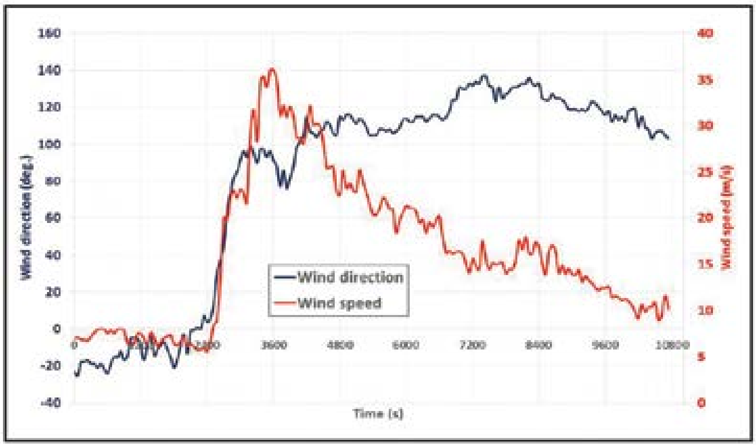
The scope of these framework contracts has a total potential value of about NOK 2.8 billion (US$337 million), of which about NOK 800 million (US$96.3 million) is Aker Solutions' share and NOK 2 billion (US$240 million) is Subsea 7's. These values may change depending on how much work the operator calls for under the contracts, and Aker Solutions will book individual orders under the contract as they come in, the release stated.

Previously, field developments were typically managed on a project-by-project basis that curtailed the reuse of technology and solutions.

—Staff Reports

FLOATERS

Taking On Turret-mooring Challenges



A time history of the squall illustrates how rapidly wind speed and direction changed in the course of the simulation. (Source: ABS)

Turret-mooring systems are being used today in a broad range of operating environments from Atlantic Canada, Brazil and Australia to the South China Sea. These systems are subjected to environmental forces that affect their motions and, in some instances, their stability.

The primary components of a turret-mooring system are the turret system, which is integrated inside or outside the vessel, and a mooring system that anchors the turret column to the seabed. The value of this type of system is that it contains a bearing system that allows the vessel to swivel around the fixed part of the turret so that it experiences the least resistance from waves, wind and currents. The ability to weathervane makes deployment possible in harsh environments and in areas that experience multidirectional environmental loading. A vessel that can weathervane offers more predictable offloading.

The heading of a turret-mooring vessel is dynamic and, as a result, presents challenges to engineers carrying out mooring-system response assessment. Most research to date has focused on the slow motions in the horizontal plane, particularly on the yaw motions (left to right movement around the turret).

For operating environments that have steady-state current, wind and wave direction, the analysis methods employed to date might be adequate, but for environments subject to squall conditions, where there are dramatic changes of wind speed and wind direction, another approach to analyzing the transient responses of the mooring system could be necessary. To date mooring system analysis has focused on mean equilibrium heading and low-frequency yaw motions, leaving transient behavior during the weathervaning process relatively unaddressed.

Defining Parameters

A squall is defined as a sudden sharp increase in wind speed, usually associated with active weather conditions like rain or thunderstorms. While squalls are characterized by an increase in sustained winds over a short time interval, it is important to note that there can be high gusts of wind as well.

In 2004 the West Africa Gust joint industry project (JIP) was initiated to record measurement of squalls and to get a better understanding of squall conditions. Over the next 10 years participants worked together, making the best use of available industry data for squall characterization in engineering design and analyzing measurements to define detailed squall characteristics. Although there is still uncertainty regarding squall characteristics, there now are more squall data records available for use in offshore structure design assessment.

Unfortunately, there is still a lack of consensus on how the squall records should be used for mooring system assessment, how ambient environment conditions should be defined, the number of squalls that should be analyzed or how the maximum mooring for the design should be determined.

Evaluating Assessments

To help the industry improve understanding of how squalls affect turret-moored vessels, engineers at ABS evaluated the weathervaning performance of a turret-moored FPSO system under various environmental conditions. The objective was to study weathervaning on a turret-moored FPSO unit, including damping effects on yaw motions. To perform the evaluation, engineers carried out a number of simulations with turret-mooring systems using typical environmental conditions offshore West Africa. The primary goal of the study was to understand the behavior of a turret-moored FPSO subject to various loading scenarios, paying particular attention to the characteristics of the squall and its effects in combination with other environmental conditions.

Researchers performed time domain numerical simulations for a generic internal turret-moored FPSO unit using typical environmental conditions offshore West Africa with winds considered as the dominant environment condition and current and waves considered as ambient environments.

In outlining the test parameters, engineers selected a squall time series with a peak of 100-year wind speed at a given location. The squall's direction is defined as the direction when wind speed is at the peak. The mooring system used in the study included three mooring line groups, each with four mooring lines. The FPSO unit's initial position for the time domain simulation was assumed at the equilibrium position in the ambient environment, defined as a 10-year current, swell and trade wind. It is in the resultant force direction of current, swell and wind.

Often, when the initial squall heading is in the region of the stern (0 degrees to 90 degrees), the FPSO unit experiences a beam-on wind. Simulations show that the chance of the FPSO unit having both beam-on and maximum wind speed is very low. Using constant wind speed for the simulations can result in a very high transient mooring load. While yaw damping of the FPSO unit reduces the turret excursions, there is no clear indication of the effect of yaw damping on the mooring load.

In squall conditions mooring systems face more challenges than they do in steady-state wind conditions. Using time-domain numerical simulations to study turretmoored FPSO behavior, engineers discovered a number of interesting things.

First among these is that wind speed is the most important parameter, especially in the early stages of the squall when the turret-moored FPSO unit is weather-vaning, changing from its initial heading to face into the weather head-on. Wind speed also is the most important parameter impacting mooring system response. Simulation results showed that the maximum mooring line load occurs when wind speed is at its peak, irrespective of the orientation of the FPSO unit. The rate of wind direction change—regardless of wind speed—does not seem to have much influence.

Further Research

While the results of this study provide increased understanding of the response of turret-moored FPSO units in squall conditions, there are additional areas that require further study, including the treatment of transient response, response-based analysis vs. analysis based on design squalls, and studies that further investigate squall characteristics. An increase in the availability of squall records and increased mooring system monitoring will result in greater transparency between the response of the mooring system and a squall event, which will provide further help on the improvement of mooring assessment in squalls.

Through its participation in additional JIPs and joint development projects (JDPs), ABS is contributing to industry efforts to improve mooring system design, inspection, maintenance and operations. The JIPs and JDPs address subjects that include studies of mooring chain out-of-plane bending, fatigue performance of mooring chains in seawater, seawater corrosion of rope and chain, fatigue and strength assessment of corroded chain, mooring component assessment, Arctic mooring, floating production and storage vessel mooring integrity, and dynamically installed piles. Findings will be incorporated in an upcoming ABS Rules and Guides that will help the industry achieve safer mooring operations.

—Sue Wang, ABS

FLOATER BRIEFS

Main Power Generation Starts Up For Ichthys Offshore Facilities

The INPEX-led Ichthys LNG Project reached another milestone recently with its central processing facility (CPF) and its FPSO facility starting up their main power generators in the South Korean shipyards where they are being constructed, according to a news release.

"Starting up the main generators of the FPSO and CPF allows the commissioning to further progress by providing the required power for both massive offshore facilities," Ichthys Project Managing Director Louis Bon said.

Focus now shifts to load testing, synchronization and commissioning of the power distribution systems for both offshore facilities, which will be permanently moored for 40 years of operation in the Ichthys Field in the Timor Sea offshore Western Australia.

Once in the field, the FPSO and CPF will be linked by an electric cable that will allow power supply to flow from each facility.

Gas will undergo initial processing on the CPF to extract condensate and water, and most condensate will be transferred to the nearby FPSO unit for offshore processing, the release said. The remainder along with the gas will be sent to Darwin via an 890-km (553-mile) gas export pipeline. Additional condensate will be taken from the gas at the onshore plant in Darwin.

FPSO-connected Wells Boosts Petrobras' Production

Petrobras set a new monthly record of 1.36 MMboe/d in August for oil and gas production in pre-salt fields.

"This result was mainly due to the connection of new wells and the increased production in wells already connected to the FPSOs *Cidade Maricá* and *Cidade de Saquarema*, both installed in the Lula Field, in the presalt area of the Santos Basin," Petrobras said.

The company also set a new monthly record in August for oil production in the presalt fields it operates. Oil production averaged about 1.1 MMbbl/d.

VESSELS

Bjørn Åge Hjøllo

Navtor To Develop 'Shore-based Bridges' Solution For EU Autonomous Vessel Project

The EU has tapped Egersund, Norway-based Navtor AS to investigate how "shore-based bridges" can help the organization move toward the adoption of autonomous vessels.

Navtor, a global e-navigation technology and services company, will represent the maritime industry in the three-year ENABLE project, which is intended to prove, verify and validate the safety of autonomous vehicles in Europe. The project was originally proposed by the automobile industry, but the EU broadened its scope to include all methods of transport, including ships.

Navtor's technology connects vessels and shore-based facilities worldwide to optimize routes, safety, efficiency and overall fleet management.

"It's an honor to be selected as the sole representative for our industry," Bjørn Åge Hjøllo, Navtor's e-navigation project manager, said in a statement. "The opportunity to work alongside established leaders in analogous transport sectors—learning from them, sharing knowledge and collaborating for new technical solutions—really is 'once in a lifetime.'"

Navtor will focus on testing the software element of a remote bridge concept. The company will engage in continuous data sharing between vessels and land, with key navigation functions migrating from the crew to office-based teams. Shore-based bridges will not be central to the day-to-day operation of autonomous vessels, but will be a vital part of their support infrastructure, allowing those onshore to take charge of individual ships when necessary.

"We believe autonomous vessels will be a reality within the next 10 to 15 years," Hjøllo said. "Shore-based bridges will be a vital part of realizing that vision.

Other Enable participants include IBM, Philips Medical Systems, Renault, Tieto and Siemens.

DEME Launches Advanced Subsea Cable Installation/Trenching Vessel

Zwijndrecht, Belgium-based DEME said it launched the world's most advanced subsea cable installation and trenching vessel, *Living Stone*, Sept. 18 at the LaNaval shipyard near Bilbao, Spain.

Living Stone formally launched on Sept. 18 at the LaNaval shipyard in Spain. (Source: DEME)

The vessel is equipped with two turntables below deck, each with a 5,000-ton cable capacity. Together the turntables can transport more than 200 km (124 miles) of cable that can be installed in a single trip. The 3,500-sq-m (37,674-sq-ft) deck allows deployment of a revolutionary cable handling system with innovative cable handling tools for cable ends, connections and cable protection systems.

Living Stone can also be equipped with a third carousel above deck with an additional load capacity of 2,000 tons, as well as a 600-ton crane. The system, developed by Tideway, enables the ship to install cables faster and more efficiently in longer lengths and with fewer offshore joints than any vessel in its class.

The vessel will be assigned transport and installation projects as well as offshore power cable installations, interconnectors for the future European Supergrid and other projects.

Living Stone features dynamic positioning 3 capability and, as an environmentally friendly vessel with a 100-person crew, operates dual fuel engines with LNG as its prime fuel. The ship has a Green Passport and the Clean Design Notation awarded to owners and operators who design and operate vessels with an environmentally sustainable approach.

Osbit Delivers 2 Subsea Systems For Modus AUV

Osbit's subsea garage is lowered into the water during an equipment trial. The equipment was designed for U.K.-based Modus for its Saab Sabertooth hybrid AUV. (Source: Osbit)

Northumberland, U.K.-based Osbit delivered two bespoke subsystems—a floating launch dock and a sea parking garage—to Modus for use with an AUV. The new equipment was designed and manufactured to meet launch and recovery requirements for the Modus Saab Sabertooth hybrid AUV, a lightweight underwater platform for survey, inspection and other light intervention tasks.

The floating launch dock, which can be used when the AUV is either tethered or untethered, enables the operator to deploy the vehicle and return it to the deck of the ship. The dock is submerged in the sea as the AUV leaves and returns, and partially fills with air to allow collection from the water surface. The subsea parking garage protects the AUV when it is not operational and allows the operator to deploy the AUV at a specific location without having to maintain a presence there. When it has completed its automated tasks, the AUV returns to the garage and safely awaits recovery at a time convenient for the operator.

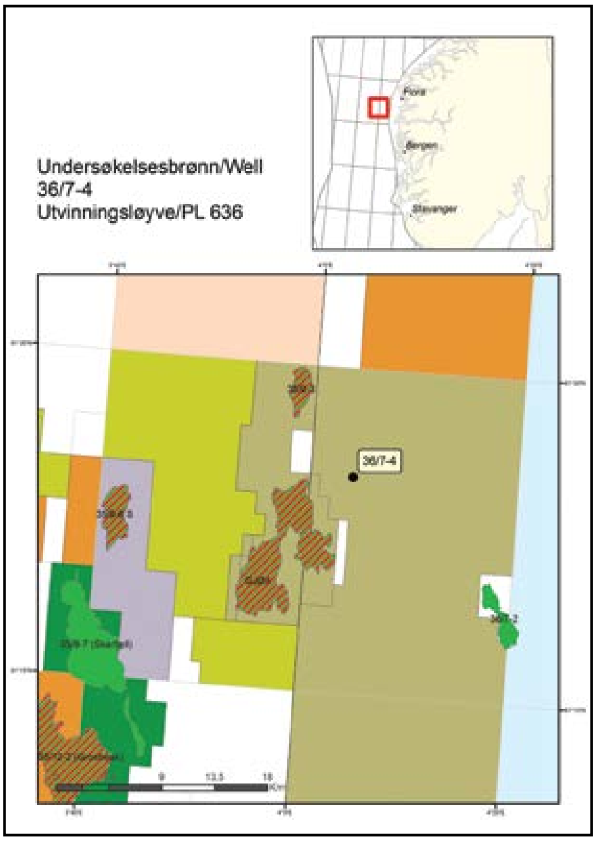
"The ability of our team to deliver bespoke subsystems for AUVs and other submersible vehicles shows Osbit's skill in working at the cutting edge of subsea technologies," Osbit Managing Director Brendon Hayward said in a prepared statement. "Advancements in automation are crucial to the energy industry and its supply chain's drive for efficiency, which in turn are key to its long-term sustainability."

—Joseph Markman

EXPLORATION BRIEFS

Engie, Partners Strike Gas, Oil In North Sea

Engie E&P, Tullow Oil and other partners are considering linking their recent oil and natural gas discovery in the Norwegian North Sea to nearby infrastructure, according to a news release.



The 36/7-4 wildcat well is the first exploration in production license 636. (Source: Norwegian Petroleum Directorate)

The companies said the discovery at the Cara prospect could hold between an estimated 25 million barrels of oil equivalent and 70 MMboe.

Drilled by Transocean Arctic to a total depth of 2,702 m in 349 m of water, Engie hit a 51-m natural gas column and a 60-m oil column in the Åsgard formation at the Cara prospect, which is about 6 km northeast of the Gjøa Field. The Gjøa semisubmersible floating production platform is also operated by Engie E&P.

"The well was formation-tested. The maximum production rate was 1.3 million Sm^3 gas per flow day through a 76/64-inch nozzle opening," the Norwegian Petroleum Directorate (NPD) said in a news release. "The gas/oil ratio is approx. 16,000 Sm^3/Sm^3. The formation test generally showed very good production and flow properties. Extensive data and samples were collected."

Tying the discovery to existing infrastructure will cut time and costs, Cedric Osterrieth, managing director for ENGIE E&P Norge, said in a company statement.

"The discovery is situated in our core area in the North Sea, and confirms our view that even mature areas of the Norwegian Continental Shelf have an interesting exploration potential," Osterrieth said.

The 36/7-4 wildcat well is the first exploration in production license 636, according to the NPD.

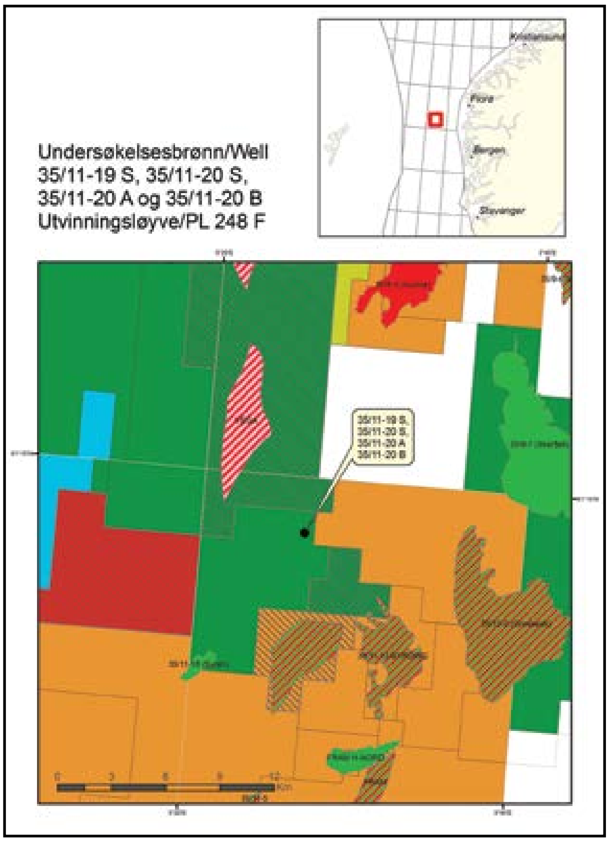
With a 30% stake, Engie E&P Norge AS is the operator of license 636. Tullow holds a 20% stake. Production license partners also include Idemitsu Petroleum Norge and Wellesley Petroleum, holding 30% and 20%, respectively.

Wintershall Makes Small Oil Find In North Sea

Tie-ins to existing fields are among the development options for a small oil discovery, Antares, made by Wintershall and its partners, the company said.

Wintershall said it found oil near the Vega Field in the Norwegian North Sea. Preliminary evaluation suggests recoverable volumes in the Antares discovery—located in wells 35/11-20 S, 35/11-20 A and 35/11-20 B—are between 10 MMbbl and 28 MMbbl of oil.

According to the Norwegian Petroleum Directorate, well 35/11-20 S—drilled of 3,553 m (11,657 ft) below the sea surface—hit an 8-m (26-ft) oil column in the secondary exploration target at the top of intra Heather Formation sandstone, but the reservoir quality was poor. Well 35/11-20 A, drilled to a measured depth of 19 m (62 ft) below the sea surface, encountered a 33-m oil column in intra Heather Formation sandstone, of which the NPD



Wintershall's latest discovery could hold up to 28 MMbbl of recoverable oil resources. (Source: Norwegian Petroleum Directorate) said 19 m (62 ft) were of good reservoir quality. However, technical issues prevented the operator from reaching Middle Jurassic (Brent group) and Early Jurassic (Cook formation) reservoir rocks to find oil.

Drilled to further delineate the discovery, the NPD said well 35/11-20 B encountered a total oil column of 46 m (151 ft) in intra Heather formation sandstone, of which 29 m (95 ft) were of moderate reservoir quality. A 19-m oil column was encountered in the Tarbert formation in the Brent group, while only traces of petroleum were found in the Cook Formation. The well was drilled to measured and vertical depths of 5,083 m and 4,055 m (16,676.5 ft and 13,304 ft) below the sea surface, respectively, and was terminated in the Statfjord group in the Early Jurassic.

The wells were drilled by the Borgland Dolphin semisubsmersible.

Pemex Reports Recent Discoveries Of Six New GoM Crude Deposits

Pemex said on Sept. 13 that it discovered six new deposits in the Gulf of Mexico (GoM), two of which are super-light crude in deep waters and four of which are light crude in shallow waters.

Pemex, which has been struggling with declining output for over a decade, also plans to drill 30 exploratory wells in 2017, it said in a statement.

A Pemex spokesman said the discoveries were made a few months ago but were not announced immediately in order to quantify the reserves and guarantee their commercial viability.

Pemex said that in the oil-rich Cinturon Plegado de Perdido area, which is in the deepwater GoM, it had already drilled the Nobilis-1 Well located 2220 km (137 miles), off the coast of the northeastern state of Tamaulipas, at a depth of 3,000 m (9,842.5 ft) to the ocean floor and at a total depth of more than 6 km (3.7 miles).

The company said that in the two deepwater discoveries, the crude had a super-light gravity of more than 40 degrees API. Pemex said the two wells could eventually deliver 15 Mbbl/d and could have between 140 MMboe and 160 MMboe of proved, probable and possible (3-P) reserves.

The company also said it discovered light crude and gas in the Teca-1 Well located 30 km (18.6 miles) off the Gulf Coast at 44 m below the surface. Its estimated 3-P reserves were between 50 MMboe and 60 MMboe.

Pemex, which has enacted major spending cuts due to the collapse of oil prices, said it would focus the majority of its investments on areas where it thinks it has the highest probability of discovering crude.

Pemex estimates its average production will be 1.9 MMbbl/d in 2017, its lowest level since 1980, as a result of the spending cuts.

SeaBird Gears Up For Barents Sea Multiclient Survey

SeaBird Exploration said it will acquire a long offset 2-D multiclient survey in the Barents Sea.

Jointly designed by SeaBird and Lundin Norway, the survey aims to acquire long-offset profiles that image large scale deep seated crustal structures beneath the Norwegian Barents Sea. Lundin Norway will supervise the processing of the dataset, and SeaBird will use the *Harrier Explorer* for the work.

The profiles will be acquired during September and October.

Schlumberger, Petronas Sign Contract For Deepwater GoM Seismic Survey

Petronas, through its wholly owned subsidiary, Petronas (E&P) Overseas Ventures Sdn Bhd, has signed an agreement to license a significant part of the WesternGeco Campeche wide-azimuth (WAZ) deepwater multiclient seismic survey in the southern Gulf of Mexico, a Schlumberger press release stated. The WesternGeco Campeche WAZ deepwater multiclient seismic survey is located in the southern Gulf of Mexico. More than 80,000 sq km of newly imaged subsurface data, which have been acquired in the last 12 months, are available for oil and gas companies participating in exploration in Mexico. The project follows the Mexican government's opening of licensing rounds to non-government companies for the first time.

—Staff & Reuters Reports

TECHNOLOGY

Technology Innovations Address Mooring Challenge

Today's global mooring industry is facing a significant test with the need to balance the complexity of mooring operations and technology innovations against managing costs and increasing efficiencies in a difficult market environment.

Developments have included a transfer of many responsibilities from operators to rig owners in areas such as procurement and installation, while declining floating rig utilization rates have seen many owners faced with a growing number of idle units (as of May 2016, industry analyst Quest Offshore Resources counted 126 idle rigs globally).

Against such a backdrop, the mooring industry is facing both operational and cost challenges as well as a need for providers to stand out from the crowd in what is a highly competitive market.

Operations

On the operational side, regular challenges include the need to navigate around existing subsea infrastructure such as pipelines, wellheads and umbilicals. With newer operations taking place alongside older infrastructure

Twelve of Global Maritime's 20-tonne mK5 StevShark anchors from its sister company Vryhof were used as part of the Australian semisubmersible mooring solution. (Source: Global Maritime)

such as in the North Sea, mooring arrangements must be more precise and accurate than ever before.

There is also the need to safely secure drilling units in challenging environments, with many rigs often operational in the majority of weather conditions. This requires flexibility in deployment to meet dynamic environments, not just in regard to weather conditions but also in relation to fatigue, wear and corrosion of equipment, all of which can fluctuate over time.

Linked to this, mooring integrity, inspection and monitoring, and the real-time tracking of mooring operations also have come to the fore. Recently, Oil & Gas UK issued updated guidelines on mooring integrity with the support of operators, contractors and vendors.

There is a demand in particular for the real-time monitoring of mooring systems both in their deployment and to track their condition. A lack of monitoring and tracking can lead to mooring line replacement or failure and, if mooring is not tracked in real time, operational dangers such as damage to risers, production or drilling shutdowns, or even small hydrocarbon leaks.

In such cases, effective monitoring and data management— ideally without the need for costly maintenance or subsea sensors—is necessary to detect mooring line failure and ensure continued mooring systems integrity for the lifetime of the asset.

Cost

Balanced against these challenges is the pressure to ensure a continued focus on greater efficiencies and reduced costs while still adhering to the highest standards of safety and asset integrity.

As mooring operations become more complex, the visibility of assets has become increasingly important to reduce costs and risk in operations, linking in to the importance of real-time monitoring.

In addition, every day a rig is in transport is a day lost to drilling. With support vessels such as anchor handling vessels costing up to $15,000 per day (well down from recent years but still a substantial cost), faster mobilization and reduced drilling costs are vital. In such cases, prelaid mooring systems are becoming more popular in the current downturn.

Finally, operators and rig owners need access to a complete mooring solution with fast deployment and transportation. From the latest in new anchors to buoyancy units, mooring chains or synthetic fi ber mooring rope, operators ideally need economies of scale and a single provider.

Australian Mooring Solution

So are mooring technologies and mooring providers meeting these challenges?

A good example of how these challenges are being addressed can be found in Global Maritime Deep Sea Mooring's recent provision of mooring and rig positioning services to a leading Australian oil and gas operator. The contract represented the first time all four sister companies of Global Maritime have been involved in an Australian operation.

The companies consist of Deep Sea Mooring, which offers offshore mooring services from prelay and rig move solutions through to marine engineering and mooring equipment rental; Global Maritime Vryhof, a leader in anchoring; Global Maritime MoorLink, which designs, produces and installs certifi ed swivel links, connections and wire clamps for use on any chain, wire or rope; and Global Maritime Consultancy & Engineering, a marine, offshore and engineering consultancy.

In this case, mooring services were provided for a semisubmersible drilling unit offshore Australia where there was a need to navigate around existing subsea infrastructure. Furthermore, the rig also would be in operation during cyclone season.

12-point System

Global Maritime designed, engineered and supplied a 12-point mooring system, with the initial installation consisting of 12 prelaid anchors that were set and tension- tested prior to the arrival of the semisubmersible drilling unit.

The total mooring solution, when the rig was operational, consisted of eight 1,750-m (5,742-ft) mooring lines—a combination of chain, synthetic fi ber rope, rig chain, subsurface buoys and the relevant jewelry for connections. Four storm-mooring lines at 1,930 m (6,332 ft) were also made available to ensure maximum stability during the cyclone season (only eight mooring lines were used outside cyclone season).

In addition, high-strength MoorLink swivels were used to relieve the twist and torque that builds up in the mooring line, and 20-ton mK5 StevShark anchors from Vryhof helped facilitate performance in challenging soils. In this case, the mud line consisted of very silty sand and the formation sandy clay/silty clay. All products were mobilized quickly and effi ciently with minimal additional costs.

Finally, Deep Sea Mooring's Advanced Distance and Positioning System (ADAPS) and Device Tracking and Control Systems (DTAC) were used. ADAPS is a tool for monitoring real-time anchor positioning—a crucial factor when the distance between the anchor and any subsea infrastructure is critical. It also potentially eliminates the need for ROV work during prelay operations and rig moves, resulting in cost and time efficiencies.

Through the use of a reinforced transponder fitted to the anchor to monitor its position and seabed penetration during installation, the ADAPS helped attach the anchors prior to deployment of the semisubmersible drilling unit. The technology also ensured that the anchor landed in the required position and provided information on its pitch and roll along with the depth of penetration. The DTAC also provided desktop tracking and buoy position monitoring prior to the rig's arrival. The end result was a successful mooring deployment.

Equipment Traceability

One other mooring technology innovation is a newly patented radio-frequency identification marking system that can be found on all Deep Sea Mooring equipment. The system ensures complete traceability and identification of Deep Sea Mooring equipment and increased efficiencies. The data are used to track mooring equipment, leading to an accurate usage history of equipment, and

A newly patented radio-frequency identification marking system helps ensure complete traceability and an accurate usage history of the equipment. (Source: Global Maritime)

ensure that any material inconsistencies or unexpected loading effects are addressed immediately.

In addition, less effort, time and cost are required to handle equipment, and there is also a reduction in operational time during prelay operations and rig moves. Deep Sea Mooring is already collecting data on the sequence in which the equipment is deployed to the seabed to further reduce paperwork and risk from human error.

The result is increased levels of visibility in mooring operations, a reduction in operational time and risk, and a positive impact on safety and efficiencies.

At a time of increased offshore complexity and the industry's heavy focus on efficiency, mooring providers are being tested like never before and need to deliver value-adding solutions like those above to help operators address these challenges head on.

—Wolfgang Wandl, Global Maritime

TECHNOLOGY BRIEFS

Aquaterra, Plexus Launch HP/HT Riser System

Aquaterra Energy and Plexus Holdings have developed a light weight, dual barrier HP/HT riser system capable of being deployed by a jackup.

The companies said the technology, which is suitable for depths of up to 150 m (492 ft), is a viable and cost-efficient alternative to semisubmersible installation for HP/HT well operations. The system merges Aquaterra's HP/HT riser system and Plexus' POS-GRIP wellhead engineering technology.

"An inner riser string is installed inside a conventional high pressure riser (HPR) to span the gap between a dry surface BOP and a wet subsea tree. It provides full 20,000-psi capability and utilizes all metal-to-metal gas tight seals on both the external and internal riser string," ," Aquaterra said in a news release. "The system also eliminates the issues associated with surface wellhead developments that contain elastomeric seals, particularly those located between the mudline and surface."

Subsea UK Gears Up To Discuss ROV Technology

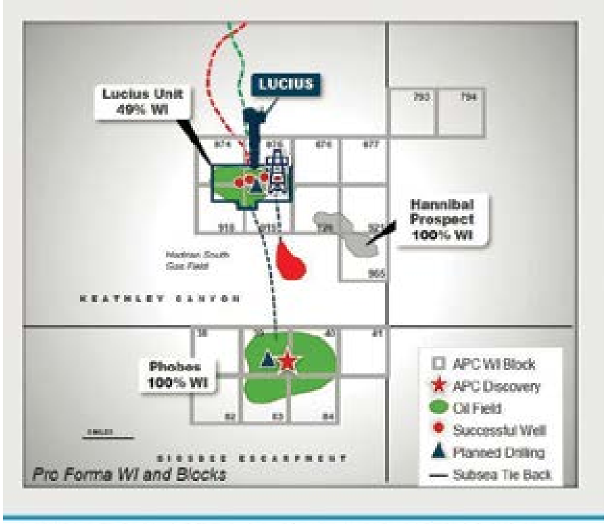
ROV engineering and advances, autonomous inspection technology, enhanced data collection and the challenges posed by lower oil prices will be among the topics featured at Subsea UK's 2016 Underwater Vehicles Conference.

"The global underwater vehicle market is expected to grow significantly over the next five years as operators delve into deeper, harder to reach seas and the demand for enhanced ocean data increases," said Subsea UK CEO Neil Gordon. "Since the sharp drop in oil prices, underwater robotics have been seen as a key area of development for subsea interventions, as the industry has been forced to consider smarter ways of working, by adopting new techniques and technologies."

Infield Systems Ltd., Shell, Seatronics, Subsea 7, SeeByte, IMCA, and Ecosse SubseaSystems are among the presenting companies. The conference is set for Sept. 27 at the Aberdeen Exhibition and Conference Center. For more information, visit *www.subseauk.com/events.asp*.

BUSINESS

Splashdown: Anadarko Lands $2 Billion Gulf Deal



ANADARKO PETROLEUM CORPORATION

Anadarko Petroleum Corp. said Sept. 12 it agreed to buy Freeport McMoRan Oil & Gas deepwater Gulf of Mexico (GoM) assets for $2 billion.

The deal doubles to about 49% Anadarko's ownership in the Lucius development and adds production of 80,000 boe/d more than 80% oil.

Anadarko said the acquisition will generate about $3 billion in incremental GoM free cash flow during the next five years at current strip prices. The deal will also allow the company to accelerate capital into the Delaware and Denver-Julesburg (D-J) basins.

"This immediately accretive, bolt-on transaction strengthens our industry-leading position in the Gulf of Mexico and is a catalyst for the company's oil-growth objectives, with quality assets being acquired at an attractive price to create significant value," said Al Walker, Anadarko chairman, president and CEO. "We expect these acquired assets to generate substantial free cash flow, enhancing our ability to increase U.S. onshore activity in the Delaware and D-J basins."

Anadarko also said Sept. 12 that it will offer about 35.3 million shares of its common stock. The company expects to grant the underwriter, J.P. Morgan Securities LLC, a 30-day option to purchase up to 5.3 additional shares of its common stock.

Anadarko will add two rigs in both the Delaware and D-J plays later this year and plans to further increase activity afterward.

Walker said the company's expectation is to more than double production to 600 Mboe/d from the two basins during the next five years.

"This increased activity would drive a company-wide 10% to 12% compounded annual growth rate in oil volumes over the same time horizon in a $50 to $60 oil-price environment, while investing within cash flows," Walker said.

The company's GoM position, with the addition of the properties, will have net sales volumes of about 155 Mboe/d. The purchase expands Anadarko's operated infrastructure in the GoM as well.

For Freeport the divestiture is its third following announced deals to sell net mineral acreage in the Permian and nonoperated interests in the Haynesville for a total of $189 million.

The transaction, effective Aug. 1, is expected to close prior to year-end 2016.

—Darren Barbee

Petrobras Raises Asset Sales Goal In Five-year Plan

Petrobras on Sept. 20 cut its planned investment by 25% in a drive to reduce the largest debt burden among global petroleum firms and revive investor confidence battered by a corruption scandal.

In a securities filing, Petrobras pledged up to $74.1 billion in capital spending for the 2017-2021 period. The total of planned investments, which is Petrobras' smallest since 2006, compares with the prior 2015-2019 plan at $98.4 billion.

The new spending blueprint also fell short of the $82.7 billion forecast on average, according to eight analysts surveyed by Reuters. Petrobras reaffirmed a $15.1 billion target in asset sales for the 2015-2016 period and a goal to fetch an additional $19.5 billion through divestments and partnerships between 2017 and 2018.

The plan comes as CEO Pedro Parente seeks to cut the company's $125 billion of debt, amassed after years of state-directed policies that overstretched the company. Still, with oil prices near a decade low, a scandal that laid bare governance flaws and huge losses from years of government-mandated subsidies may complicate those efforts, analysts said.

In a sign that investors endorsed the new plan, preferred shares posted their biggest gain in more than two weeks, jumping 3.5% to 13.50 Brazilian reais (US$14.50).

Speaking to reporters in Rio de Janeiro, Parente vowed to cut costs and sharpen the focus on high-return activities to restore profitability. World economic and oil industry changes justify a leaner, less ambitious spending program, Parente said.

"This plan should start bearing fruit within two years, when we expect to have strong metrics that will allow us to return to the good situation of a few years back," said Parente, who took office in May.

In line with prioritizing oil and gas production, Petrobras said that it will exit the biofuels sector.

The plan will also show how far Parente, appointed by new President Michel Temer, is prepared to go at Petrobras to reverse the policies of former Brazilian President Dilma Rousseff, removed from office in August for breaking budget laws.

Output

"Lower capital spending makes absolute sense as the company aims at decreasing cash burn to accommodate interest and debt payments and to avoid stretching even further its balance sheet," Rodolfo de Angele, an analyst with JPMorgan Securities in Sao Paulo, said in a note to clients.

Of the money budgeted for investment, 82% will go to E&P.

Petrobras expects to produce 2.77 MMbbl/d of crude oil in Brazil in 2021. This is about the same amount the last company plan foresaw for 2020.

Total output of domestic and international oil and natural gas equivalent is expected to rise to an average of 3.41 MMbbl/d in 2021, 19% more than the 2.84 MMbbl/d produced in August.

The business plan is based on a price of Brent crude oil averaging $48/bbl in 2017 rising to $71/bbl in 2021. The plan expects the U.S. dollar to be worth an average of 3.55 reais in 2017, strengthening to 3.71 reais in 2012.

Petrobras' controlling shareholder, the Brazilian government, is also counting on those fields to kick-start the country's recession-mired economy. Petrobras is responsible for about 10% of Brazil's GDP.

—Reuters

BUSINESS BRIEFS

Akastor, Mitsui Form JV For Skandi Santos Hull, Topside

Norway's Akastor ASA oil service investment company signed an agreement with Japan's Mitsui & Co. Ltd. to acquire the Skandi Santos hull from DOF Subsea Rederi AS and the Skandi Santos topside from AKOFS Offshore AS through a joint venture with 50:50 ownership.

Mitsui & Co. will be working with its Japanese partner.

The JV will subsequently enter into a lease agreement with AKOFS corresponding to the remaining contract duration between AKOFS and Petrobras. DOF Subsea will continue providing ROV and marine services onboard the vessel as part of the subsea equipment support vessel contract with Petrobras.

The agreement is subject to Petrobras' consent, bank approvals and certain other conditions, which are expected to occur during the fourth quarter of 2016.

Arctic Securities is the financial adviser and BA-HR law firm is the legal adviser.

When the transaction closes, AKOFS will gain US$66 million net of investments in the JV.

The annual bareboat charter and related costs will increase by US$8.5 million per year over the remaining contract period. The contract with Petrobras for the operations in Brazil will remain in a fully owned subsidiary of AKOFS.

Flexlife Group, Deep Water Concession Sign Work Contract

The Flexlife Group (Flexlife) and Deep Water Concession Ltd. of Nigeria have taken their two-year working relationship to the next level by signing an exclusive cooperation agreement to work with each other in Nigeria.

Flexlife provides specialized engineering, design, delivery, integrity and technology in the area of subsea and topside flexible risers and flowlines, while Deep Water Concession provides subsea engineering, pipeline management and construction, well engineering, engineering procurement, PMS and EPC project delivery for the Nigerian oil and gas sector.

The two companies have worked together on several projects on a non-exclusive basis for the past two years, according to a news release.

UK Taps University To Create Subsea Sector Training Framework For India

The U.K. government has awarded Robert Gordon University (RGU) in Scotland funding to set up a training framework, focusing on accelerating skills development in deepwater subsea, for India's energy sector.

The funding was awarded to RGU following India's commitment to reduce its energy imports and the country's intention to fully exploit its field development plans for the deepwater block in the Krishna-Godavari Basin offshore eastern India, a news release said.

RGU will draw on its subsea expertise and experience of working in the North Sea and internationally to appraise the future skills profile of India's industry and propose a framework that focuses on engineering disciplines and management. As part of the six-month project, RGU will conduct a feasibility study with goals of learning more about the subsea skills gaps in India, identifying opportunities for good practice sharing and providing recommendations, according to the release.

In addition, RGU also received funding to advise the Mexican Government on skills development for its oil and gas sector. The university will give recommendations on how to address the potential skills gap over the next 15 years at the graduate and vocational levels.

Nominations Open For Annual Subsea UK Awards

Nominations are being accepted for the 2017 Subsea UK Awards, which recognizes companies and individuals that are leading Britain's subsea sector.

Entries are being sought for the best subsea company of the year (large and small), the most promising young person in the sector, the most exciting new enterprise and the individual who has made the most outstanding contribution to the subsea industry. The awards also will recognize achievements and innovations in technology, safety and exports.

Entries can be made online at subseaexpo.com by Nov. 4. An independent judging panel of industry leaders will score each entry according to the agreed criteria and the shortlist of finalists will be announced in January 2017. Accolades will be presented at a gala dinner Feb. 2 during the Subsea Expo.

KKR, Other Lenders Will Control Expro Group


Joe Price

British oilfield services group Expro International Group Ltd. will be controlled by four lenders including KKR & Co. LP and Goldman Sachs Group Inc. as part of a financial restructuring, the U.K.'s Sky News reported.

The lenders, which also include hedge fund Highbridge and Park Square Capital, will exchange their debt for equity, giving them a controlling stake in the company, according to Sky News.

Confirmation of the news could come as soon as the end of the week of Sept. 19, Sky News said, citing sources. Expro was not immediately available to comment.

Specializing in well flow management, Expro provides subsea, completion and intervention; well test and appraisal; and production services.

InterMoor Names Canada Country Manager

InterMoor, an Acteon company, has appointed Joe Price as country manager for InterMoor Canada, the company said in a news release.

Price brings with more than 14 years of offshore oil and gas industry experience.

The Newfoundland native has worked extensively on the engineering, procurement, construction and installation of mobile/permanent mooring systems in the majority of the world's offshore markets, the company said.

Training Center Improves Diver Safety

JFD, a subsea operations and manufacturing company, has signed a new agreement with Fugro to provide training courses delivered by the National Hyperbaric Centre (NHC), part of JFD Ltd., at the Fugro Academy Training Centre in Abu Dhabi, a company press release stated.

The agreement with Fugro will see JFD-approved local and U.K. trainers delivering the full range of courses that are currently offered by the NHC, including client representative, dive system auditing and assurance, dive technician and kirby morgan helmet technician courses.

The addition of another training facility allows the NHC to expand its global presence and provide training services to a wider audience.

Delegates will have access to Fugro's two 15- to 20-capacity training rooms, a computer training room and onsite ROV and dive systems to carry the practical modules of courses.

Shell Offers GoM's Mad Dog, Julia Field Interests

Royal Dutch Shell Plc is selling overriding royalty interest in 17 leases in the Gulf of Mexico (GoM).

The assets have an estimated 10-year revenue stream of $450 million, according to EnergyNet, which is handling the transaction for Shell. Areas consist of Ewing Bank, Garden Banks, Green Canyon, Main Pass Area, Mississippi Canyon and Walker Ridge.

Highlights:

- 17 leases across nine total properties;
  - 13 producing and receiving revenue (Including Mad Dog Field operated by BP Plc);
  - Three recently producing with first check received July (Julia Field operated by Exxon Mobil Corp.);
  - One nonproducing (Sheba Field);
- Current average historical production is 54,000 bbl/d of oil and 29 Mcf/d;
  - 10-year estimated revenue stream of about $450 million;
- 15-year estimated revenue stream of about $750 million;
  - Estimates are based on Wood Mackenzie's forecast and are net to Shell's interest, EnergyNet said;
- Total 2015 revenue is about $14 million;
- 12 total payors; and operators include: Anadarko Petroleum Corp.; BP Plc; Exxon Mobil; Deep Gulf Energy Cos.; Eni US Operating Co. Inc.; Enven Energy Ventures LLC; Lobo Operating Inc. (Saratoga Resources Inc.); Marubeni Oil & Gas USA Inc.; and Marathon Oil Corp.

Sealed bids were due Sept. 22.

Indonesia Will End Taxes On Oil, Gas Exploration

Indonesia said on Sept. 22 that it will eliminate taxes on oil and gas exploration this week in an effort to bolster investment in the country's flagging oil and gas sector.

Wiratmaja Puja, director-general of oil and gas, said the government was aiming to remove all taxes on exploration, including a value-added tax on imported goods and a land tax that had been a deterrent to investment since it was introduced in 2010.

"Global exploration [companies] will return enthusiastically," Puja told reporters on Sept. 22. "Investment will increase."

The government has been trying to revive flagging oil and gas production, but investors have been deterred by low global oil prices and regulatory and investment risks in Indonesia.

Indonesia's crude oil output peaked at about 1.7 million barrels per day (MMbbld) in the mid-1990s. But with few significant oil discoveries in Western Indonesia in the past 10 years, production has fallen to roughly half that as old fields have matured and died.

Acting Energy Minister Luhut Pandjaitan had earlier told reporters the new regulation was due to be announced on Sept. 23, and "will definitely be attractive."

"There needs to be compensation," he said, referring to the "high risk" in offshore and deepwater exploration wells that could cost more than $100 million each to drill.

Under the new regulation, the government will provide oil and gas contractors an internal rate of return above 15%, Pandjaitan said.

While the government is scrambling to prevent oil production from falling next year to its lowest level since 1969, it is also under pressure to keep a lid on how much the government is liable for regarding contractors' recoverable costs. Those are predicted to hit $10.4 billion in 2017, higher than the $8 billion targeted in 2016.

"We are seeking an equilibrium [where] production climbs but costs can be low, so we are talking about efficiency," Pandjaitan said.

Cost recovery is the amount of money spent on exploration, development and operations that contractors can reclaim from the government after their oil and gas operations start producing.

The government has slashed cost recovery spending with efforts to improve efficiency since 2014, but this could also discourage oil well development and maintenance and constrain its ability to boost output, an official at the industry regulator said in June. Production costs are typically higher from mature wells.

The industry is a vital part of the Indonesian economy, but its contribution to state revenue has dropped from about 25% in 2006 to an expected 3.4% this year, according to data compiled by consulting firm PricewaterhouseCoopers.

"Interest in exploration in Indonesia nosedived in 2013 due to the land and building tax issue and has yet to recover," the Indonesian Petroleum Association said in its 2015 annual report.

Most of Indonesia's oil and gas production is carried out by foreign contractors including Chevron Corp., ExxonMobil Corp., BP, Total, and ConocoPhilips, whicj operate under production-sharing contract arrangements.

Indonesia holds proven oil reserves of 3.7 Bbbl and is ranked in the top 20 oil producers globally.

—Staff & Reuters Reports

UPCOMING

The next issue of Subsea Engineering News will be distributed Oct. 7. Until then, visit *epmag.com*.

JOBS

Looking for a new job in the industry? Find opportunities in the jobs section at *epmag.com/jobs*.

CONTACT INFORMATION

MARK THOMAS Editor-In-Chief, E&P Franchise
mthomas@hartenergy.com

VELDA ADDISON Senior Editor
vaddison@hartenergy.com
(713) 260-6400

CONTRIBUTORS
Steve Hamlen (UK)
Ravi Prasad (India)
Joseph Markman (Houston)
Darren Barbee (Houston)
Erin Pedigo (Houston)
Emily Moser (Houston)

GUEST CONTRIBUTORS
Sue Wang (ABS)
Wolfgang Wandl (Global Maritime)

Subsea Engineering News (ISSN 0266-2205) is published twice monthly by Hart Energy Publishing LLP, Houston TX, USA. Telephone: +1 713 260 6400; Email: **sen@hartenergy.com** or **custserv@hartenergy.com**; Website: **www.epmag.com/subsea-engineering**. Email for subscriptions: **mpigozzi@hartenergy.com**.

2016 ANNUAL SUBSCRIPTION: £425 + VAT (WHERE APPLICABLE), $675 USA. FOR MULTI-USER SUBSCRIPTIONS, CONTACT US OR CHECK THE WEBSITE. CREDIT CARDS ACCEPTED SUBJECT TO CHARGES.

HARTENERGY
1616 S. Voss, Suite 1000 • Houston TX 77057-2627 • USA
www.hartenergy.com | www.epmag.com

Follow us on Twitter @Hart_EPMag