SEN
SUBSEA ENGINEERING NEWS

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Subsea Boosting Technology Takes Spotlight

HOUSTON—When it comes to improving field economics, industry leaders say subsea boosting should be considered a "default solution" when developing hydrocarbon resources offshore.

Among the economic drivers are the potential to increase oil recovery, improve flow assurance and lower production time while increasing net present value (NPV) for greenfield and brownfield developments, according to Aker Solutions' Hans Christian Nilsen, who spoke during this month's Offshore Technology Conference (OTC) on how new subsea boosting products can grow profits.

To improve economics Aker Solutions, working with joint industry project partners, is developing new multiphase subsea pump technology powered by a stronger motor. Talk of the new boosting technology, which is expected to be released later this year, comes as operators go farther and deeper offshore in search of oil and gas with subsea technology gaining focus amid a wealth of tieback opportunities.

Subsea pump system manufacturers are rising to the challenge to lower costs and improve performance through technology development and joint industry projects. (Source: Aker Solutions)

Tapping into the need for speed and power could lead to improvements, which is where Aker Solutions and partners took aim. As described by Nilsen during a technical session at OTC, the project involved doubling the motor's power to 6 MW and increasing the speed from 4,000 rpm to 6,000 rpm, suitable for a range of pressures, temperatures and gas volume fractions.

Benefits are that fewer pumps may be needed to perform the job faster, equating to time and cost savings. A key feature of the multiphase pump is mixed-flow impellers that are placed in opposite directions, eliminating the need for a balance piston,which can cause vibrations.

"Up to now the helico-axial principle has been used for multiphase rotodynamic pumps," Nilsen added. "We have developed an extended multiphase technology called helico-mixed flow," which generates more pressure from its use of centrifugal action. It's designed to reduce backflow.

Using a plug-and-play approach, the faster motor with twice the power has many of the same components of the 3-MW pump with 80% of the parts being reusable, he said. The impellers have the same geometry and are interchangeable, which enables the pump to be reconfigured as operations change through the lifetime of the field.

New cables capable of withstanding higher temperatures also are being qualified.

Advancing Technology

Advancing subsea pumping technology has been a mainstay for Aker Solutions, which has several subsea pumps

WHAT'S INSIDE

based on "centrifugal pump technology that utilizes various stages of impellers to provide the required pressure increase," according to the company.

While the MultiBooster subsea multiphase pump—armed with the 6-MW, 6,000-rpm subsea motor—targets hydrocarbon flows with a high gas volume fraction, the HybridBooster with mixed-flow impellers to compress gas is "ideal for low to medium gas content," the company said on its website. Aker Solutions' toolbox also includes a subsea single-phase pump, called LiquidBooster, which uses radial pump technology for liquid hydrocarbon/condensate boosting or water injection.

Such boosting technology has the potential to grow profits. Nilsen pointed to a subsea boosting case that compared using gas lift at riser base with 2-MW, 4-MW and 6-MW motors. The case centered on a subsea field at a water depth of 1,500 m (492 ft) with a 30-km (19-mile) step-out from the host facility. The field had four production wells and two water injection wells along with a high water cut.

The 2-MW boosting increased total recovery by 22%, while the 6-MW boosting power increased recovery by 30%. The NPV jumped, while production time fell.

Nilsen concluded that subsea boosting and multiphase pumps are well-proven concepts with ongoing development to expand their potential with greater pressures and flows. In most cases, subsea boosting will increase profit, and it should be the default choice for any offshore field, he added.

Jack/St. Malo's Story

Subsea boosting is not a new concept, but innovation is pushing the technology to new heights.

Chevron turned to subsea boosting to get hydrocarbons from the Jack and St. Malo fields in the U.S. Gulf of Mexico to the production platform when initial reservoir pressure fell.

During the OTC subsea processing technical session, Mads Hjelmeland of OneSubsea (now part of Schlumberger)—which worked on the development—spoke about subsea boosting's impact on the two fields being jointly developed. Discovered in 2003 to 2004 about 40 km (25 miles) apart, Hjelmeland said successful artificial lift is essential for the fields.

The ultradeepwater fields are located in the Lower Tertitary Trend and face production challenges that include low permeability, low gas-oil ratio, pressures ranging from 17,000 psi to 24,000 psi and temperatures as high as 132 C (270 F).

The fields, which are tied to the Walker Ridge Regional Platform, used single-phase boosting—the first for operator Chevron. The option was selected over others, which included multiphase pumps, electric submersible pumps, waterflood and gas lift. Among the advantages of the subsea boosting was the ability to produce oil at a lower wellhead pressure, which increased production and ultimately the project's NPV. This includes the life-cycle costs, Hjelmeland said.

The fields have three identical single-phase pumps, which went online in 2016. It came following work that started in 2009 that led to the qualification of a 3-MW pump and motor housing rated for 13,000 psi along with a transformer and other components—the world's first high-pressure subsea boosting system.

"The actual performance was very much in line with what we predicted," Hjelmeland said, later adding the technology qualification process lasted three years. It was followed in 2011 by engineering, procurement and construction with the equipment deployed in 2014. The system was wet parked that year because the pressure was so high that production occurred by itself, he added. But the system has been in continuous operation since April 2016 working in automatic mode.

According to Chevron, daily production from the first development stage is expected to rise to 94,000 bbl of oil and 594 Mcm (21 MMcf) of gas over the next several years. Subsea boosting is expected to play a role in elevating production rates for the next 30 years. Production at the fields, with total recoverable resources at an estimated 500 MMbbl, started in 2014.

Hjelmeland called subsea boosting a key enabling technology and a natural concept for subsea tiebacks.

—Velda Addison

DEVELOPMENT

Maria Looks To 1H 2018 Startup

Germany's Wintershall has been buoyed by the good progress it has made on the Maria oil field development offshore Norway and is looking to bring the field onstream ahead of schedule in first-half 2018.

Wintershall reached a vital milestone in March when the *Deepsea Stavanger* rig started drilling on the Maria Field in the Norwegian Sea. Six wells are required for Maria, and the top holes are now complete. Drilling toward the reservoir section is underway, the operator said.

Two subsea templates have been tied back to the nearby Kristin, Heidrun and Åsgard B platforms at a depth of 300 m (984 ft). About 68 km (42 miles) of pipelines also have been installed. The Maria discovery has an estimated 180 MMboe of technically recoverable resources.

Maria is located in the Haltenbanken area of the Norwegian Sea. Output from the field will travel to the Kristin platform for processing, while supply of water for injection into the reservoir will come from the Heidrun platform. Lift gas will be provided from Åsgard B via the Tyrihans D subsea template.

Processed oil will be shipped to the Åsgard Field for storage and offloading to shuttle tankers. Gas will be exported via the Åsgard Transport System to Kårstø.

A number of contracts already have been awarded for the Maria project, with the subsea production system work going to FMC Kongsberg and the contract for pipeline and subsea construction going to Subsea 7.

Wintershall said it will use existing infrastructure for its production, eliminating the need for a new platform, the company said.

"The prospect of recovering significant amounts of oil from the Maria Field is not only good news for Wintershall and our partners but also for the owners of the existing infrastructure, since Maria will contribute to prolonging the lifetime of the connected platforms," Wintershall added.

The company is focusing on quickly bringing its discoveries into production in the coming years. Besides Maria, these include the Skarfjell development.

Good progress is being made on the Maria project, Wintershall CEO Mario Mehren said.

"If this continues, a startup in the first half of 2018 could be possible. With the drilling of the reservoir, we will be passing another critical milestone that moves us a step closer to first oil," Mehren said. "Wintershall believes in Norway. We have invested heavily in the country and are now developing a field that will continue to return value to Wintershall and Norway for many years to come."

Since 2015 Wintershall has participated in bringing on production at three fields—Knarr, Edvard Grieg and Ivar Aasen.

"Together with the acquired Statoil shares in Brage, Gjøa and Vega, Wintershall has expanded its production in Norway to more than 80,000 boe/d," the company said.

The Maria discovery has an estimated 180 MMboe of technically recoverable resources. (Source: Wintershall)

Hugo Dijkgraaf, Wintershall's Maria project director, described Maria as a "smart field solution that uses proven technology to get the most from existing infrastructure in the area," creating value for the partnership and the entire supply chain.

Spending on the Maria development is estimated at about US \$1.78 billion (NOK 15.3 billion). Recoverable reserves on the field are estimated at about 180 MMboe, mostly oil.

The Maria Field is located about 20 km (12 miles) east of the Kristin Field and about 45 km (28 miles) south of the Heidrun Field in the Norwegian Sea's Halten Terrace area.

Wintershall is the operator with a 50% stake with Petoro (30%) and Centrica Resources (20%).

Skarfjell Remains On Course

Plans for the Skarfjell reservoir also call for using existing infrastructure.

Wintershall submitted the field development concept for the Skarfjell project to the Norwegian Ministry of Petroleum and Energy in early 2017. Development plans include connecting the Skarfjell reservoir via a subsea tieback to the nearby Gjøa platform, the company said.

Production is expected to range from 60 MMboe to 140 MMboe, Wintershall said.

"The project is now entering the definition and planning phase, in which the detailed technical and economic plan will be drawn up," Wintershall said.

—*Steve Hamlen*

DEVELOPMENT BRIEFS

BP Launches Taurus, Libra Offshore Egypt

BP has started gas production from two fields in its West Nile Delta development offshore Egypt, the second of seven projects the oil and gas company plans to launch this year.

The Taurus and Libra fields, commissioned eight months ahead of schedule and under budget, are currently producing 700 million standard cubic feet of gas a day to the Egyptian national gas grid, BP said in a statement.

The West Nile Delta development includes five offshore gas fields which are planned to have in 2019 a combined production of up to almost 42 MMcm/d (1.5 Bcf/d), equivalent to about 30% of Egypt's current gas production.

The subsea greenfield development includes nine wells—six in Taurus and three in Libra—and a 42-km (20-mile) tieback to the existing onshore processing facility, BP said. All the gas produced will be fed into the national gas grid.

BP is set to start up seven projects this year, including in Oman, the North Sea and Azerbaijan, the largest number in a single year in BP's history. It hopes to add 800,000 bbl/d of new production by the end of the decade.

Repsol Sinopec Marks First Oil From Montrose Area Redevelopment

First oil has begun to flow from the Shaw Field in the North Sea's Montrose Area, operator Repsol Sinopec Resources UK said in a news release.

The development is part of the Montrose Area Redevelopment project, which is intended to enhance infrastructure in the area. As explained in a news release by the company, the project incorporates the development of the Godwin, Cayley and Shaw fields and a new bridge-linked production platform connected to the Montrose Alpha to provide additional process and plant support facilities.

The Godwin Field was developed via an extended-reach well from the Arbroath platform, while the Cayley and Shaw fields were developed as subsea tiebacks to the bridge-linked platform, the release said. Shaw production will be followed by Cayley by the end of second-quarter 2017. Gross incremental production is expected to peak at up to 40,000 boe/d.

In all, the project is expected to unlock up to 100 MMboe of additional reserves and extend the life of the existing Montrose Area fields beyond 2030, the release said. Montrose Alpha was originally commissioned in 1976, the release said.

Partnering with Repsol Sinopec on the project is Marubeni Oil & Gas (U.K.) Ltd.

Saipem, TechnipFMC Land Contracts For Liza Field Offshore Guyana

ExxonMobil affiliate Esso Exploration and Production Guyana Ltd. has awarded Saipem an engineering, procurement, construction and installation contract for the subsea umbilicals, risers and flowlines package of the proposed Liza project offshore Guyana.

Saipem said it will perform engineering, procurement, construction and installation of the risers, flow lines and associated structures and jumpers. Transportation and installation of umbilicals, manifolds and associated foundations for the production, and water and gas injection systems are also included in the work scope.

The company said it plans to use its *FDS2* and *Normand Maximus* vessels to carry out the work, which will begin in 2019.

In addition, TechnipFMC secured a contract from Esso for the engineering, manufacture and delivery of the subsea equipment for the project.

The award scope includes 17 total enhanced vertical deepwater trees and associated tooling as well as five manifolds and associated controls and tie-in equipment.

Located in the Stabroek Block about 193 km (120 miles) offshore Guyana in waters depths of 1,500 m (4,900 ft) to 1,900 m (6,200 ft), the Liza Field has more than 1 Bboe of estimated recovery oil resources.

Total Brings Onstream Badamyar Gas Project

Total has started up production from the Badamyar project, located offshore 220 km (138 miles) south of Yangon in the Republic of the Union of Myanmar. The project will enable an extension of the Yadana gas field's 8 Bcm/year (283 Bcf/year) production plateau beyond 2020.

"Completed on schedule and with costs 20% below budget, this second startup by Total in 2017 demonstrates our capacity to effectively implement cost reduction programs," said Arnaud Breuillac, president, E&P, for Total. "This project underscores Total's commitment to develop gas projects to provide Myanmar and Thaïland with affordable, reliable and clean energy to support the countries' economic growth over the coming years."

The Badamyar project, launched in mid-2014, involves the installation of a new wellhead platform connected to the Yadana production facilities, and the drilling of four horizontal wells to develop Badamyar gas field as a satellite of Yadana. The project also includes a new compression platform.

Total is the operator of the project with a 31.2% interest. Its partners are Chevron-Unocal (28.3%), PTTEP (25.5%) and the national company MOGE (15%).

BP: Additional 1 Bbbl 'Possible' In GoM Hubs

The head of BP's Gulf of Mexico (GoM) region said last week that the oil company's use of a new seismic imaging technology has identified an additional 1 Bbbl of "possible resources" at four of its U.S. offshore fields.

Richard Morrison, the BP region president, said at the Offshore Technology Conference in Houston that full waveform inversion imaging technology was applied to data from its Atlantis, Mad Dog, Thunder Horse and Na Kika fields. The technology enhances the clarity of images collected from existing seismic surveys, particularly those involving complex salt structures that were obscured or distorted, the company said.

BP said in April that its use of the imaging technology had identified 200 MMbbl of possible resources at is Atlantis Field alone. BP plans to apply the technology to other fields in Azerbaijan, Angola, and Trinidad and Tobago.

Dresser-Rand Will Supply Compressors For BP's Mad Dog 2

BP has selected Dresser-Rand, part of Siemens Power and Gas Division, to provide rotating equipment for its Mad Dog 2 project in the U.S. Gulf of Mexico, according to a news release.

Dresser-Rand will supply two low-pressure D6A4S and two high-pressure D6R9B compressors for the project. The scope of supply comprises two DATUM compressor trains driven by Siemens electric motors for export gas service, the release said.

The equipment is scheduled to ship in 2018. The DATUM compressor is designed to minimize maintenance and reduce downtime. Each compressor train will be driven by a Siemens electric motor and includes a variable speed gearbox.

Oil production of the project' new floating production platform is expected to begin late in 2021. The platform will be capable of producing up to 140,000 bbl/d of crude oil from up to 14 production wells, according to the release.

Total Selects Monitoring, Spill Detection System For Martin Linge

Total E&P Norge (Total) has chosen Aptomar's tactical collaboration and management system, TCMS, to digitalize and manage environmental monitoring and oil spill detection at its Martin Linge Field, according to a press release.

The TCMS will combine subsea, topside and aerial oil spill detection sensors into one common operating picture. Aptomar will customize, commission and maintain a common operating picture for the environmental monitoring at Martin Linge.

The purpose of this oil spill detection common operating picture is to provide an overview of all available sensor information in relevance for prevention, detection and monitoring of hydrocarbon leakage to sea, all in the same surveillance interface.

Delek Group Will Sell 10% Stake In Tamar Field

Israeli conglomerate Delek Group said on April 25 it intends to sell up to a 10% stake in the large offshore Tamar Field, Israel's main supply of natural gas.

Delek Group subsidiaries Delek Drilling and Avner Oil will each sell up to 5% of their stakes in Tamar as well as in the smaller Dalit Field.

Delek said in a statement that a new corporation will be set up that will sell securities, including bonds, on the Tel Aviv exchange to raise money to buy the stake in the gas fields.

—Staff & Reuters Reports

OFFSHORE TECHNOLOGY CONFERENCE REPORT 2017

Mad Dog's $20 Billion Costs Brought To Heel With Focus On Value

HOUSTON—Since its discovery in 1998, the Mad Dog team has found ways to peer through dense salt cathedrals, seen estimated oil reserves grow to 5 Bbbl of oil, and made a crucial find: how to make it profitable.

The journey to become a massive world-class oil field required confronting setbacks with geology. The Mad Dog spar endured hurricanes. And its owners had to find ways to avoid scuttling a project that was simply too expensive.

Technology, exploration, geology and cooperation are at the heart of Mad Dog's success and for the planned Mad Dog 2 project. But it was only after serious review and analysis that three of the largest oil companies saw the wisdom in teaming up.

Underlying the eventual success was a commitment by the owners of the discovery to share their findings and results—in other words, their secrets. The project is led by operator BP, which owns a 60.5% stake in the proj-

BP approved the Mad Dog Phase 2 project in the U.S. Gulf of Mexico in December 2016. (Source: BP)

ect, BHP Billiton (23.9%, owner) and Chevron Corp. (15.6%).

By the time Mad Dog 2 began planning, it was clear it would be far too expensive.

This led to three important changes, panelists said at a Monday morning technical session at OTC on the multidisciplinary techniques used to unlock deep-water development.

Chief among these were following a focus on recovering value, not volume; implementing industry-led solutions; and fostering open co-owner collaboration.

"Instead of going after every barrel, we focused on value," said Bill Steel, BP project general manager for Mad Dog Phase 2. "This translated into capturing the key resources with a smaller facility. The theme at the time was 90% of the resource for 60% of the cost."

The development strategy was called transformer, and it relied on adaptability.

"Rather than designing for a future that may not happen, the principle was to design for something reasonable for day one needs with capacity for expansion if we needed it," Steel said.

Gulf of Mexico (GoM) oil exploration can be blisteringly expensive. After the discovery of the Mars Field off the coast of Louisiana, the oil industry saw an opportunity to turn the GoM into a bountiful oilfield.

"Industry went after this play and we got it dead wrong," said Cindy Yeilding senior vice president of BP America.

At one point, seven spectacularly expensive dry holes in a row had transformed the GoM from a promising reservoir into "the Dead Sea," Yeilding said.

But BP decided to give it another go, this time going back to the basic principles of oil geophysics and geology.

Yielding said the company went back to first principles of geology—namely that petroleum migrates to anticlines.

"Our big shift was to look for structures," she said.

The challenge was the irregular topography, which is complicated by many layers of salt canopy. But while salt had previously been avoided, "salt now is clearly our friend."

Salt is tough to take images through, but with advances in technology, petroleum systems began to emerge.

BP had been looking for an "elephant that would stand alone." The find would need to be big enough that it held the oil needed to require a commitment of resources and talent, Yeilding said.

Mad Dog, discovered in 1998, was thought to hold 800,000 bbl of oil. Mad Dog produced first oil in 2005. The resourced estimate grew with a field appraisal to 1.5 Bbbl of oil. By 2007 the oil estimate increased yet again. Mad Dog was sitting atop a potential 2 Bbbl of oil.

Further exploration of the south side discovered even more oil, bringing the resource estimate to 4 Bbbl.

The Mad Dog spar was capable of producing 80,000 bbl/d, and clearly that "wasn't going to do the trick," said Doris Reiter, vice president of performance management for BP.

As planning progressed, it culminated in a project called Big Dog.

"It was a monster of a spar. Thirty-three wells and a price tag to match," Reiter said.

She said it was clear $20 billion was far too expensive.

Engineers and ownership alike came to the conclusion that the remainder of the resource would need to be developed with more focused and clearer objectives.

In essence, the plan became "Let's get 90% of the resource estimates—for 60% of the cost," Reiter said.

Steel said the new plan balanced exposure to the downside but had flexibility through an adaptable facility and subsea well system. Owners chose equipment they had the most experience with.

With the oil resource now believed to be 5 Bbbl, BP is close to putting its plans to work.

"We now forecast 120% of the original reserve estimate at less than 50% of the cost," Steel said.

—Darren Barbee

The Stones' Odyssey of Installation

HOUSTON—Imagine that Poseidon, god of the oceans in Greek mythology, didn't much care for your offshore project, even after the plans were checked, the financing came through and the lawyers signed off on it.

Imagine he sent tough weather to the Cape of Good Hope to slow the ship transporting your moored turret buoy, then unleashed a 161-km-wide (100-mile-wide) sea monster into the Gulf of Mexico (GoM) as you attempted to install your FPSO unit.

You could text Odysseus to see if he's available for a freelance gig or, like Shell, rely on a team of smart engineers determined to figure out a way to install the Stones FPSO unit, the world's deepest project of its kind at 2,896 m (9,500 ft).

Or you could just read the paper "Offshore Construction—Installing the World's Deepest FPSO

Carl Webb, Shell's turret and installation lead for Stones, speaks at OTC 2017 in Houston. (Source: *CorporateEventImages.com*)

Development" delivered by Carl Webb, Shell's turret and installation lead for Stones, at the May 2 afternoon technical session.

Seemingly everything about this project was of Olympic proportions. It literally took a Herculean effort (the vessel's name is Asian Hercules III) to hoist the 3,200-mt buoy and move it from Keppel's Benoi Yard in Singapore to the heavy transport ship Swift for the 46-day journey to the GoM. A two-day delay to avoid severe weather and other delays at the fabrication yard stretched the trip to 55 days.

In the GoM, Swift joined deepwater construction vessel (DCV) Balder and DCV support vessel Union Manta, along with barges and tugs. The installation plan was straightforward:

Install nine mooring suction piles;

- Assemble the mooring lines and connect them to the suction piles;
- Offload the buoy; and
- Attach the buoy to the mooring lines and have the system properly submerged and ready for the FPSO Turritella's arrival.

That's when things got weird.

Typically, warm water loops the GoM to the east and merges with the Gulf Stream on its way to Europe. But in 2015, inexplicably, that warm water broke off and spun west, creating vast circular eddy currents that grew to more than 161 km in diameter, with depths of up to 300 m (984 ft).

The swirling waters meandered into the steam above the Stones Field, bringing currents of 3.5 knots. Installation activity stopped because the ROVs conducting the work cannot function in currents faster than 1.8 knots.

So the flotilla waited for the eddy to clear so it could get to work. Sometimes the eddy would retreat for periods of six to 24 hours. Sometimes it would drift 1.6 km (1 mile) away and sometimes as far as 16 km (10 miles). Once it hung out directly over Stones for three straight weeks.

In bizarre irony, the ships were exactly where they needed to be but the sea itself was lost, unable to find the Gulf Stream.

So the crew tracked the eddy's movements from reports off of an eddy boat traversing the GoM, studied its pattern and predicted the next retreat of 24 hours or more. They needed enough time to hook up at least three of the moorings. That would be enough to secure the system.

"If the operable current windows are too short, we're going to be taking too much risk, and I don't want to get into a position where we have one or two mooring lines connected when the current hits," Carr said in an on-location video shown during his presentation. "Where I want to be is at the start of the operation and be in a position to finish it or just don't start."

Carr made the call to go ahead, the eddy remained at bay, so to speak, for enough time to connect the nine mooring lines and in September 2016 Stones produced first oil.

For Carr, the key lesson learned was what was needed when working under pressure: competence, discipline and agility. Out in the middle of the GoM, conditions forced changes in the original plan and the offshore engineering team from Heerema Marine Contractors and Shell were up to the challenge.

An eddy can wander a body of water for years. The one that disrupted the Stones installation is still in the GoM, though weaker. And like hurricanes, they are named.

This one's name? Olympus.

—Joseph Markman

Another Jewel Added To Total's Offshore Crown

HOUSTON—It's been a very busy decade-plus for Total in West Africa. The Paris-based operator's success in the region started with Girassol offshore Angola in 2001. Success attracts more success as additional Angola projects at Dalia and Pazflor witnessed first oil in 2006 and 2011, respectively. Success also came to Akpo offshore Nigeria in 2006.

The focus of an OTC luncheon on May 1 was the company's impressive feat of human and industrial innovation off the coast of Pointe-Noire in the Republic of Congo—Moho Nord. André Goffart, senior vice president of development and support for operations at Total, showcased for attendees the innovations responsible for the success at Moho Nord.

Launched in March 2013, Moho Nord is the second project on the Moho Bilondo license 75 km (46.6 miles) offshore Pointe-Noire in the Republic of the Congo. Goffart said the company has come a long way from Girassol, with advances in technologies like subsea processing and subsea separation making offshore production possible. Moho Nord is no exception, he added.

With a production capacity of 100 Mboe/d, Moho Nord is the biggest oil development to date in the Republic of the Congo. Developed through 34 wells tied back to a new tension-leg platform (TLP)—a first for Total in Africa—and to the Likouf floating production unit (FPU). Oil is processed on the Likouf and then exported by pipeline to the Total-operated Djeno onshore terminal.

Moho Nord is, according to Goffart, two subprojects producing from three reservoirs. One subproject developed the Miocene and Albian reservoirs found in northern area of Moho Nord and includes the TLP and FPU facilities. The waters produced from the Miocene and Albian reservoirs are incompatible due to barium sulfate scales. Because of this, the FPU has two separate water processing trains, Goffart said.

Production from the southern area of Moho Nord was made possible via a subsea tieback to the Moho Bilondo FPU Alima that has been in operation since 2008. Modifications to the Alima to accommodate new production include the addition of 1,500 tons of new equipment and increasing of the vessel's capacity to 150,000 bbl/d maximum, Goffart said.

According to Goffart, the facilities were designed to minimize their environmental footprint, with "the best available technology available" used. This includes an all-electric design to improve energy efficiency by optimizing the amount of power needed to run the installations. There will be no routine flaring and all produced water will be reinjected into the reservoir, he said.

André Goffart, senior vice president of development and support for operations at Total discussed the company's impressive feat of human and industrial innovation off the coast of Pointe-Noire in the Republic of Congo—Moho Nord at OTC 2017. (Source: *CorporateEventImages.com*)

For Goffart, key highlights for the project include that with Moho Nord, there are an additional 140,000 bbl/d of oil brought online in less than four years from final investment decision to first oil. Total announced in March 2017 that production had started up at Moho Nord.

Total is the operator of the project with a 53.5% interest, Chevron Overseas (Congo) Ltd. (31.5%) and Société Nationale des Pétroles du Congo (15%) are partners in the project.

—Jennifer Presley

Brazil Embraces Change As It Gets 'Back on Track'

Brazil's Minister of Mines and Energy Fernando Coelho Filho said at OTC 2017 that the country is positioning itself to become more attractive not only for potential investors. (Source: *CorporateEventImages.com*)

HOUSTON—As the oil and gas industry claws its way back from the downturn, Brazil is positioning itself to become more attractive not only for potential investors but for the country as a whole.

This involves listening and being willing to make regulatory changes—qualities seen by Brazil's Minister of Mines and Energy Fernando Coelho Filho as being important to attracting investors to the country.

"I think we are far away from doing everything we want, but we have started moving in that direction," Filho told a full house gathered for a luncheon on opening day of OTC 2017. "We now have a clear calendar of dates of when the auctions will take place. … What is in our reach [and what] we are trying to do to give the stability [that] the industry needs."

The Brazilian government's latest efforts include offering additional licensing rounds such as for coveted presalt acreage in the prolific Campos and Santos basins—something many in the industry have been awaiting. Following OTC Brazil in October, Brazil will have its second and third presalt bid rounds—the country's first since the 2013 presalt licensing round for the Libra Field.

The Libra Field alone is estimated to hold between 8 Bbbl and 12 Bbbl of recoverable reserves. It is one of several massive discoveries made offshore Brazil in recent years, commanding the attention of oil and gas companies worldwide. But the country and its industry still faces challenges—labor concerns that have sparked protests, economic issues and environmental licensing delays that have slowed exploration activity in parts of the country.

"Everybody here knows that Brazil has at least 10, 15, 20 points that we need to solve immediately, but we can't face all the problems at once," Filho said, noting a recently approved cap on government spending, labor reform moving through the legislature and forthcoming social security reform.

In his first-ever OTC appearance in Houston, Coelho told the crowd how the government has made changes to its presalt law, unitization process and local content numbers—which he said will be good for oil and gas companies and for Brazil.

Earlier this year, Brazil dropped the requirement mandating companies to buy equipment locally by about 50% for operations and production onshore. The figure was lowered to 18% for exploration offshore and to 25% for construction of wells. Brazil also lowered the fines against oil companies that do not meet local content percentages from a 60% minimum to 40%, and from a ceiling of 100% to 75%.

It was one of several moves Brazil made in an effort to attract investment during a time of corporate spending cutbacks. Brazil also revamped its presalt law, opening up operatorship of blocks to companies other than Petrobras, and created an auctions calendar scheduling dates for about 10 licensing rounds from 2017 to 2019 for exploratory blocks and mature onshore fields.

"We do want more investments. We do want more people to come to Brazil," Filho said. "Bid rounds like the one we are trying to host in the second semester are going to be responsible for the Brazilian economic recovery to put Brazil back on track."

There are many places in the world with oil and gas resources, not just Brazil, he said. "We need to send the right signs."

While Brazil's energy ministry has made strides, Filho admitted there are many challenges ahead. Brazil is working to increase gas production as the country's agreement with Bolivia nears its end, and the environmental ministry is working on a bill to send to Congress to speed up the environmental licensing process for oil and gas development.

The minister said he is optimistic about the years to come, especially when it comes to oil and gas. He believes the turning point for Brazil will match that of the country's oil and gas industry.

"We are trying to put the country back on track," Filho said. He foresees pleasant years ahead for Brazil's economy from 2017 on as the country's oil and gas opportunities attract.

—Velda Addison

Mexico's Deep Water Is Open For Business

HOUSTON—Mexico is poised to take full advantage of its untapped deepwater potential after ending its decades long oil industry monopoly, according to Aldo Flores-Quiroga, the country's undersecretary of hydrocarbons.

As oil prices continue to stabilize and the industry emerges, Mexico's oil sector has become a highly attractive investment destination. And with round one of the country's energy reform under its belt, Mexico is ready to unleash more of its coveted resources to foreign investors with another deepwater auction set for this year, Flores-Quiroga said during an OTC breakfast on May 1.

"Mexico is perhaps the most important opportunity in the world," he said, adding that the country's untouched resource base is something that is rare to find at this stage of the game. "This is a very large emerging market, but the first time it's opening in the energy sector."

Mexico has some of the world's largest, intact, oil and gas resources available for tender. In the deep water in particular, the country has 2,601 MMboe of 2P reserves still yet to be auctioned, Flores-Quiroga said.

As an example of the country's untapped potential offshore: 2,366 oil platforms exist in U.S. federal waters whereas only 46 wells are in Mexican federal waters.

In addition, Mexico's breakevens are globally competitive. In particular, Mexico deepwater projects are projected to have lower development costs compared to the rest of the world, he said.

Mexico deepwater projects are projected to have lower development costs compared to the rest of the world, according to Aldo Flores-Quiroga, the country's undersecretary of hydrocarbons. (Source: *CorporateEventImages.com*)

Another reason to choose Mexico is that the country is a strong global partner.

"We're fostering free markets, and we're aiming for the most efficient competitive market that we can have … Investing in Mexico means investing in North America as a platform," Flores-Quiroga said.

Mexico already has seen an influx of eager foreign investors. To date, foreign investors have committed about $38 billion to the country's energy sector—86% of which has been in deepwater plays.

Investment interest since the reform has been worldwide, with 37% coming from Asia-Pacific, 36% from Europe and Eurasia, 13% from the U.S., 12%

from Mexican players and 2% from South and Central America.

"In just three years, we have transformed how Mexico's industry works. After 80 years of having only one company in upstream, we finished last year with 48 additional companies—all of them with contracts signed to begin working," Flores-Quiroga said.

During the first round (Ronda 1.4) of its Plan Quinquenal in December, Mexico's deepwater blocks attracted majors and national oil companies alike. Capital investment commitments made by companies on the blocks totaled about $4 billion with each exploratory well expected to cost about $100 million, according to Mexico's National Hydrocarbons Commission.

Flores-Quiroga acknowledged Mexico's energy reform hasn't been without its challenges.

"Few governments [and] few countries have attempted a reform of this kind when prices are high. Even fewer sustain the effort when prices are low," he said. "We started the opening when prices have crashed, and we have continued the pace of implementation and this opening even in a low price environment. What that means is we're doing this because it makes sense regardless of the price environment."

Further, Mexico's commitment to its energy reform is strong because the potential investment and industry development will be what's best for the country's economy and energy security, he said.

"Incidentally, when the price goes up, it will go up for everyone, and given our reforms we know we'll be much better placed to best of the opportunity that higher prices will provide," he said.

Mexico is accepting nominations for its next round (Ronda 2.4) of deepwater and unconventional blocks. The launch of the round will begin in June with bids due the first week of December 2017.

—Emily Patsy

OTC TECHNOLOGY

Slumping Oilfield Services Sector Bets On New Offshore Technology

The oil industry's top equipment and services suppliers are hawking vastly cheaper ways of designing and equipping subsea wells, aiming to slash the cost of offshore projects to compete with the faster-moving shale industry.

At the Offshore Technology Conference, the industry's annual gathering of floating rig and subsea well suppliers, sales pitches this year are all about cost savings and faster time to first production. With U.S. crude priced under $50/bbl, offshore projects with their typically high costs and long-lead times are now borrowing from leaner shale in the competition for oil company investment.

Low oil prices have soured new exploration in the U.S. Gulf of mexico (GoM), for instance, but production volumes there have remained strong due to the long lead times of these projects. GoM producers are expected to add 190,000 bbl/d this year to output now running about 1.76 MMbbl/d.

Tool and services companies are offering new technologies that can do several jobs, taking the place of multiple devices or highly paid consultants.

National Oilwell Varco Inc. exhibited software it touts as performing much like a drilling expert, sorting through vast amounts of data to find ways to speed production and reduce downtime.

The new software "takes actions a person would do and runs them automatically. It's low cost and it's simple," said David Reid, National Oilwell Varco's chief marketing officer.

Baker Hughes Inc. showed a new tool called DeepFrac that it said eliminates several steps now required to complete underwater wells. That saving pares the price of a well by up to 40%, speeding first production and lowering the breakeven cost for producers.

"This helps sharply cut some of the risk of drilling an offshore oil well and, we believe, sharply reduces costs for our customers," said Jim Sessions, a vice president of technology at Baker Hughes.

Graham Hill, an executive vice president at KBR Inc., detailed the construction company's plan for a cheaper floating production vessel, saying the new vessel fits producers' tight budgets. KBR can hope to earn more by selling extra features.

"This is like ordering a Ford," he said. "There's a base package, and you can add extras."

Richard Morrison, president of BP's GoM region, said the industry has accepted that crude prices will probably stay low, meaning oil producers like BP must work with services providers to reduce the multibillion dollar cost of offshore projects.

"That breakeven point can't come back to $80 a barrel, so I've got to figure out ways to work with my supplier over the long-term to keep that in check," he said during an OTC presentation.

Morrison touted BP's use of new seismic imaging technology that helped identify an additional 1 Bbbl of "possible resources" at four of its U.S. GoM offshore fields. The technology enhances existing seismic images to find oil hidden beneath salt structures deep underground.

—Reuters

Surface, Subsea MPD Demands Remake The RCD

AFGlobal has released a design concept and materials technology to produce a nonrotating active control device that replaces the RCD in deepwater applications. (Source: AFGlobal)

The specialization of managed-pressure drilling (MPD) equipment for surface and subsea applications is improving the performance of rotating control devices (RCDs) in land, surface and deepwater subsea applications, eliminating the need for RCDs. AFGlobal offers new application-specific MPD equipment that is designed to enhance safety and efficiency, and is releasing next-generation design concepts, materials and performance.

MPD Sophistication

The equipment advances reflect the growing sophistication of MPD as a common, and often prerequisite, tool for modern wellbore construction. Demand has evolved two design paths for MPD-enabling RCD equipment: land and marine surface applications, and deepwater subsea applications.

The RCD directs the rig's annular fluid returns into a series of chokes and instruments by sealing the annulus between the drillpipe and casing. Traditional RCD designs have achieved this with a rotating elastomer seal element and bearing assembly. The design is very effective, but has wear and maintenance requirements. In deepwater applications, high operational costs make these RCD expenses particularly significant.

AFGlobal, a manufacturer of MPD equipment and provider of MPD engineering services, has released a new design concept and materials technology to produce a nonrotating active control device that replaces the RCD in deepwater applications.

Surface Application

In surface applications, the RCD is installed on top of the BOP stack. In deepwater systems, the RCD is installed subsea as an integral component of the drilling riser. The two applications present different economic and operational demands, which have produced unique variations for improving safety, time and efficiency.

In surface applications, AFGlobal L-Series RCD is a direct, cost-effective tool for implementing MPD operations based on decades of RCD manufacturing experience. The L-Series RCD is technology built and tested to API 16 A, API 16 RCD, and NACE standards. The device improves performance with an element and bearing assembly designed for long service and convenient maintenance.

Subsea Application

Deepwater MPD has resulted in a significant departure from conventional RCD design that introduces a nonrotating device. AFGlobal's active control device seals around the drillpipe with a nonrotating hydraulically controlled sealing sleeve. The sleeve is made possible by a co-molded element that features an enhanced urethane matrix reinforced with a durable polytetrafluoroethylene inner shell. As the sealing sleeve wears, pressure is actively applied to force the element against the drillpipe to maintain consistent seal performance.

Active pressure sealing is a significant advance over RCD operations that degrade the performance of a passive rotating elastomer seal. The new device varies hydraulic pressure on the seal to compensate for wear and accommodate passage of wear-inducing tool joints. In addition, active pressure is a positive wear indicator to inform maintenance and assure MPD operations. Service life and performance is further enhanced by the greater durability of the co-molded element and lubrication of the seal with drilling mud.

MPD Integration

The active control device is a component of AFGlobal's riser gas handling system (RGH), which is an integral part of the drilling riser. It is used to address safety issues that occur when formation gas breaks out of solution in the riser. It also is the basis for establishing an MPD-ready rig with the addition of manifolds, instrumentation, control systems and other MPD equipment. The component-based RGH easily accommodates MPD service company equipment in addition to AFGlobal MPD systems owned by the drilling contractor or operator.

AFGlobal provides a full scope MPD engineering support and MPD equipment. The NControl MPD platform integrates monitoring, data, control, analysis and automation. Its rig floor workstations provide an interface with systems components, including flowmeters, transmitters, sensors and valves. Specialized manifolds enable precise downhole pressure management and integration of mud returns with the rig system.

—AFGlobal

High-Pressure Performance: Innovation Success For Subsea Hoses


JDR's high-pressure hoses allow for projects to operate in deeper and more remote waters. (Source: JDR)

As the oil and gas industry slowly emerges from its prolonged period of depressed prices and constrained capital investment, conversations about the future in terms of innovation are taking on a more positive tone. It's still early days, but with more power delivered to the seabed for subsea processing, concepts such as the field of the future have a more secure place on the strategy agenda.

The habits of the past two years where costs have been driven down through innovation will not be lightly shaken off. The idea that operators can do more with less isn't going anywhere soon. Nor is the idea that existing wells have more life in them than was previously considered financially feasible.

One example of innovation to gain access from greater resources in future deepwater fields is high-pressure hoses for intervention workover control systems (IWOCS) umbilicals and well-bay risers. IWOCS umbilicals have been with us for more than 30 years and perform a vital role in initiating and improving well performance.

For the past 15 years, industry standard IWOCS umbilicals have been able to maintain control of valves at the seabed on christmas trees during various stages of well startup, or during the field life to perform well access activities. These lightweight, highly flexible umbilicals can withstand up to 15,000 psi internal pressure in the flexible hoses, which has proved more than adequate for fields across the world.

However, as the industry sets its sights on reserves in ever-deeper waters or locations with greater stepout distances, the industry-standard 15,000 psi is becoming a constraining factor for new well development, rather than an enabler. Operators now need IWOCS umbilicals that can open a valve against much higher pressures typical in deeper waters, or to pump oil across much longer distances.

Demand has therefore been growing for 20,000 psi pressure functionality within IWOCS umbilicals—a demand that is set to be met by the middle of this year, when JDR's new-generation hose design is to complete final testing. The availability of hose lines capable of 20,000 psi has already been presaged by the successful qualification of a 17,500 psi hose, completed in 2016. The key to making both 17,500 psi and 20,000 psi hoses viable has been material development. Older steel-reinforced hoses result in a heavier umbilical, increasing the deck weight required for the umbilical and its deployment reeler or winch.

The new generation of high-pressure hoses consists of a polymer liner reinforced with a woven material made of strong, high-performance synthetic fibers with an extruded nylon or polyethylene jacket to complete the lighter-weight hose construction. In addition, new designs of end couplings maximize pressure containment.

The extensive potential advantages of the new hoses include smaller and lighter reelers for storage and transport, which have a smaller deck footprint and require much less infrastructure. The new hoses increase the range of vessels that can be used, and consequently assist in reducing the cost of vessel operations, cutting overall costs for operators.

Eventually, the industry is likely to see the extension of these new hose lines at 20,000 psi in self-supporting high-pressure IWOCS umbilicals where there is no need for the clamp. In the Gulf of Mexico (GoM), where umbilicals can be deployed at depths of 3,000 m (9,842 ft), the process of clamping the umbilical to a riser or wireline becomes the deployment constraint. For example, a conventional clamped IWOCS umbilical can take up to eight hours to deploy to full depth in the GoM. A self-supporting IWOCS umbilical takes about 2.5 hours to deploy, significantly reducing costs. Adding the 20,000 psi hose solution to the self-supporting setup would create even greater flexibility and opportunity for operators to exploit significant cost savings.

Prices affect almost every aspect of operations. However, we shouldn't ignore the fact that engineering innovation has been quietly expanding the industry's capacity to deliver, and laying the ground for a renewed era of safe, reliable and efficient production.

— James Young, JDR

TECHNOLOGY BRIEFS

Bureau Veritas Releases Asset Integrity Management System

Bureau Veritas has released its Veristar AIM3D asset integrity management system, based on technology partner Dassault Systems' 3DEXPERIENCE platform.

The technology combines a digital twin of any marine or offshore assets with smart data, providing dashboards for ships, rigs, facilities or entire fleets, according to a news release.

Veristar AIM ^{3D} provides asset management dashboards for vessels, rigs, facilities and fleets. (Source: Bureau Veritas)

Aimed at improving asset visibility, the technology was developed for use in the design, development and implementation of the operational lifecycle to reflect and predict the condition of assets. This can not only enable better decision-making, it also creates the potential to lower operational costs.

"When used to its full potential, Veristar AIM^{3D} could lead to a complete change in how inspection, maintenance and repair activities are prepared and reported," the company said in the release. "The data, presented in concise dashboards, will be immediately available to all stakeholders accessing the asset Veristar AIM^{3D} platform. Accumulated data across asset types and through life should also enable a combination of predictive responses and feedback into better designs."

Emerson Launches Salinity System For Increased Flow Assurance

Emerson Automation Solutions has released the Roxar Salinity Measurement System, which provides quantitative and qualitative real-time salinity measurements in gas production well streams in real-time.

Through the new system, operators can identify changes in the flow stream and the smallest amounts of saline water, Emerson said in a news release.

The technology enables the operator to take action to prevent scaling, hydrate formation, corrosion and other production threats, the company said, adding "the onset of formation water and its salinity, if not controlled, can lead to well shutdowns and cost producers millions in unplanned shutdown time."

Microwave (MW) resonance technology is at the core of the new system. Emerson said the new system is suitable for many types of field conditions, but especially for high gas volume fraction/wet gas flows.

Protection System Aims To Protect Cables From Abrasion, Impact

Trelleborg's offshore operation has released Buoyant Uraduct, a protection system for subsea cables, umbilicals, flowlines and hoses, a press release stated.

Buoyant Uraduct protects cables from abrasion and impact. The protection system reduces the crush risk at crossing locations by reducing the overall weight of a subsea cable. Made from highly buoyant materials, the protection system also minimizes drag and lift, avoiding possible stability issues, the company said in the release.

Buoyant Uraduct can be used for subsea cables, which can be customized for customer specifications for buoyancy, pipeline diameter and multiple subsea configurations. It is also a suitable alternative to subsea crossing bridges and can be installed on the cable or pipeline before it is laid on the seabed.

Xvision Software Launches Cloud-Based FieldAP For Offshore Projects

Technology company Xvision Software launched FieldAP, the first fully Cloud-based technology for the energy industry providing offshore project managers an online tool that provides real-time data, according to news release.

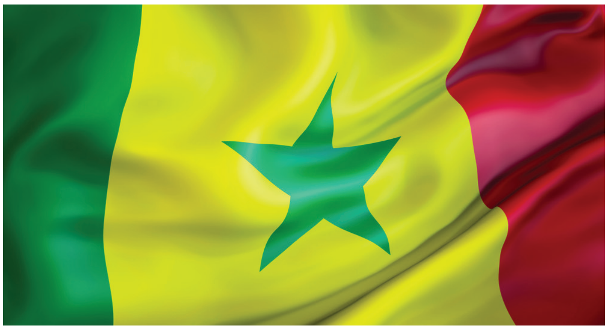
Data on subsea and topside assets and activities will be available through online 2-D/3-D visualizations. Real-time multi-location collaboration will reduce errors and design process costs, the press release said, noting that there are other features including an asset library.

In 2016, Oslo-based Xvision cooperated with Sweden's Lundin Petroleum to ensure that FieldAP was designed and streamlined for field operators. Lundin used it on a North Sea project to develop scenarios of field layout options and coordinate with three different organizations. The press release said that the project time line was accelerated by 30%, with minor errors and little downtime.

—Staff Reports

EXPLORATION

Kosmos Keeps Successes Flowing Offshore Senegal



(Source: Shutterstock)

Kosmos Energy and partner BP are building on a string of successes offshore West Africa, laying the foundation for another LNG hub, with the team's latest exploration well hitting pay.

Drilled to a depth of nearly about 4,700 m (15,420 ft) in the Cayar Offshore Profond Block offshore Mauritania and Senegal, Yakaar-1 hit a 120-m (394-ft) gross hydrocarbon column in three pools within the Lower Cenomanian and encountered 45 m (148 ft) of net pay, Kosmos Energy said May 8, adding the results "confirm the presence of thick, stacked, reservoir sands over a very large area with very good porosity and permeability."

The discovery, which was drilled by the *Atwood Achiever* drillship, is located west of the Teranga discovery and south of Tortue, which is estimated to hold 425 Bcm (15 Tcf) of natural gas. Kosmos believes Yakaar-1, formerly known as Teranga West, discovered just as much.

The find further de-risks exploration in one of the oil and gas industry's most appealing frontier basins. Northern Senegal's inboard Senegal River fairway and southern Mauritania have attracted and maintained the attention of companies in today's lower, but improving, commodity price environment, as the region's leaders turn attention to the outboard with Yakaar-1 leading the way. It is the first well of four tests planned by Kosmos and BP of the basin floor fan fairways, outboard of the trend opened by the Tortue-1 discovery.

Analysts reacted positively to the news.

"We expect interest in the company's ongoing drilling campaign to pick up materially. Kosmos is our favorite 2017 exploration play," RBC Capital Markets said.

Plans are for the *Atwood Achiever* to move to the Tortue-1 well after finishing operations at Yakaar-1. Here, a drillstem test will be carried out, which Kosmos said will enable FEED work to begin in second-half 2017. A final investment decision is expected in 2018 with first gas in 2021.

"Together with the Teranga-1 discovery made last year, we believe this resource will support a second cost-competitive LNG hub," Kosmos CEO Andrew Inglis said. "The result also confirms our view of the potential scale of the petroleum system offshore Mauritania and Senegal, in particular the basin floor fan systems which have now been further de-risked, with the well demonstrating that reservoir and trap both work in these previously untested fairways."

With a 100% success rate in the basin, Barclays analysts pointed out that Kosmos has encountered 708 and 1,416 Bcm (25 and 50 Tcf) of discovered and de-risked potential gas resources. However, "substantial risks remain as there is stiff competition from other large gas discoveries in Egypt, Mozambique and Tanzania," Barclays said. "KOS is seeking to tilt the balance in its favor as it plans to drill three additional exploration wells over the next 12 months offshore Senegal and Mauritania—and is optimistic that it may find liquids."

"KOS previously indicated that if felt it had a strong chance of finding oil or liquid-rich gas on the outboard basin floor fan fairways," Barclays added. "Preliminary analysis suggests a condensate to gas ratio (CGR) of 15-30 barrels per MMcf of gas."

RBC, which put the Kosmos' NAV at $9.29 per share, said the addition of liquids to its 425 Bcm dry gas prospect could add $1 per share of risked upside.

"In addition to the inherent value of the liquids, BP also pays a contingent royalty on gross production," RBC said.

Investing nearly $1 billion, BP entered Mauritania and Senegal in December 2016 when the company agreed to acquire a 62% interest and operatorship of Kosmos' exploration blocks Blocks C-6, C-8, C-12 and C-13 in Mauritania and a 32.49% interest in Kosmos' Saint-Louis Profond and Cayar Profond blocks in Senegal. The deal involved 33,000 sq km (12,741 sq miles) of acreage, including the Tortue Field.

For BP, the Yakaar-1 discovery confirmed offshore Senegal and Mauritania as a "world-class hydrocarbon basin," Bernard Looney, upstream CEO for BP, said in a statement. "This discovery marks an important further step in building BP's new business in Mauritania and Senegal. We look forward to results from the additional exploration wells planned for 2017."

Kosmos appears confident going forward, saying its consecutive successes confirm its "geologic model and geophysical tools are well calibrated."

Lifting Mauritania, Senegal

During an industry breakfast at OTC 2017, Inglis said half a billion dollars has already been invested and that Kosmos is ready to continue its work in the region. The frontier pioneer "saw a region that was underexplored, where we could use our deep technical capability to open up a new basin," Inglis said.

Kosmos and BP are working with both governments as the companies move toward first gas production by 2021 with the Tortue project, Inglis said, adding the governments see long-term benefits. The countries, both considered resource-rich but impoverished, could become LNG exporters. The billions in revenue could support "other sectors such as health, education and infrastructure" and create jobs, Inglis said, making the area more attractive to the oil and gas industry.

The economic benefits of Mauritania's hydrocarbon resources will be realized slowly, said Mohamed Abdel Vetah, the country's minister of petroleum, energy and mines. Currently, progress in the mining sector lags, as it does in other sectors, due to the country's lack of energy infrastructure, Abdel Vetah said.

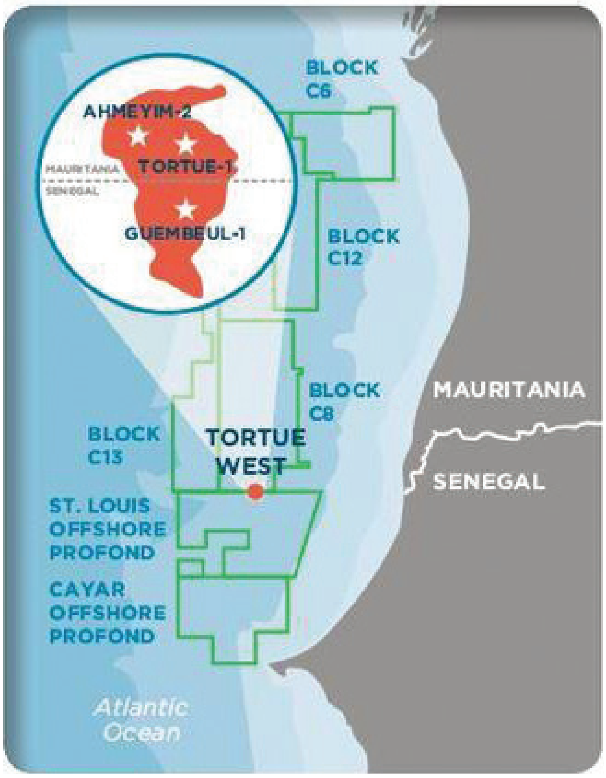
Power generation is the first priority for the country, he said, and cheap gas will be the key. Developing power infrastructure with gas would jumpstart mining in north Mauritania, he added.

This gas will be extracted from Greater Tortue using subsea wells, and sent to treatment facilities, then FLNG modules and storage offtakes. Most of the gas will be exported, with revenue benefiting both Mauritania and Senegal.

During OTC, Looney said that the total acreage of the deepwater Tortue Field, which is 33,000 sq km (12,741 sq miles), could contain 1,415 additional Bcm (50 additional Tcf).

Looney outlined plans for Tortue:

- The exploration program will have four wells drilled over 12 to 18 months, with further work planned;
- The field will be developed in phases and come onstream in 2021; and



(Source: Kosmos Energy)

- Developers will also work with Mauritania and Senegal's governments so resources benefit the people.

Inglis said the first FLNG vessel will have capacity for 2.5 million tonnes per annum (mmtpa), while the second could hold up to 5 mmtpa. He cautioned that all of this will be off to a slow start, noting LNG projects as a trend might start smaller because LNG markets are becoming more diversified.

—Velda Addison & Erin Pedigo

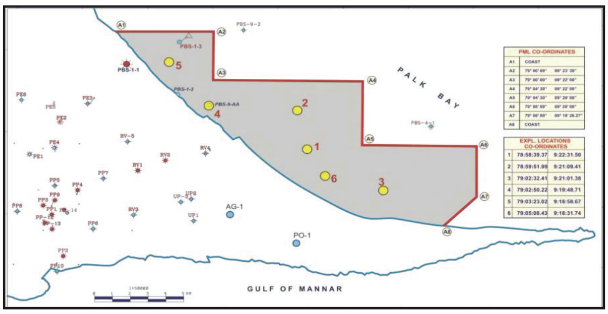
ONGC Firms Up Exploration Plan For Palk Bay

India's state-run ONGC Ltd. is preparing to launch exploratory drilling in waters of Palk Bay Shallow (PBS) concession (PBS-1-1 Extension) located in Park Strait between India and Sri Lanka.

The state-run upstream company has firmed up a plan to drill six exploratory wells in the shallow-water PBS-1-1 extension block located offshore in the southern part of the Cauvery Basin's Ramnad sub-basin.

"Based on detailed G&G [geological and geophysical] studies, about six exploratory locations have been identified in PBS-1-1 extension area to test the prospectivity of the Nannilam, Bhuvanagiri and Andimadam formations. Play maps prepared for different formations have clearly brought out the leads," ONGC said in a report.

The proposed six exploration wells will be drilled, with a target depth of 3,000 to 4,000 m (9,843 to 13,123 ft), at the identified locations in the water depth of up to 7 m (23 ft) in the shallow-water block with an estimated investment of about $38 million.



(Source: ONGC)

An ultra-shallow jackup rig is proposed to be deployed to drill the wells in PBS-1-1 Ext, which is spread across an area of about 86 sq km (33 sq miles). The wells will be drilled up to 3.45 km (2.1 miles) from the coast.

The exploration targets are the Upper and Lower Cretaceous formations.

"The hydrocarbon potential of Upper Cretaceous reservoirs ranging in age from Turonian to Campanian (Bhuvanagiri and Nannilam formations) is well established," according to the report. "[With] the Lower Cretaceous being the source rocks, there is a fair chance of hydrocarbon accumulation in these sequences at favorable places."

ONGC claims that drilling the proposed "six locations are expected to accrete 15 MMt (million tons) in this part of the basin. The provisional initial in-place reserves in the block are estimated to be about 30 MMt of oil and oil equivalent gas."

The operator sees prospects in this area considering the adjacent PBS Field, with the similar geological and geophysical structures, has hydrocarbon reserves of commercial quantity. Gas is being produced commercially from Upper Cretaceous reservoirs in the PBS Field, which is estimated to have about 1.5 MMt of initial in-place reserves of oil and oil equivalent gas.

The operator found gas in the Nannilam, Bhuvanagiri and Lower Kamalapuram formations in 29 of 55 exploratory/development wells drilled in the PBS and four adjacent fields: Pariyapattinam, Perungulam, Ramanavalasai and Kanjirangudi. The Nannilam Formation is main hydrocarbon producer.

The PBS-1-1 extension concession and a large part of Ramnad sub-basin are considered prospective areas for hydrocarbons. The sub-basin—flanked by the Pattukottai-Manargudi ridge to the west and northwest, Mandapam delft ridge to the east and southeast and the Gulf of Mannar to the south—holds sediments that are more than 6,000 m (19,685 ft) thick. The synrift sedimentary column comprises mainly shale and sandstone in the Andimadam Formation. The sedimentation represented in the upper Cretaceous Bhuvanagiri, Kudavasal Shale, Nannilam and Portonovo shale is predominantly sand shale alternations with minor limestone development.

Two regional fault trends—the older NNE-SSW curvilinear fault set intersected by a younger EW fault set—played a vital role in the formation of the structures, subsequent charging and entrapment in Ramnad sub-basin. The established pools at the upper Cretaceous reservoir levels are all located along or at the intersection of these two trends, according to the report.

—Ravi Prasad

EXPLORATION BRIEFS

Norway Doubles Barents Sea Oil, Gas Estimate

Norway's portion of the Barents Sea could contain twice as much undiscovered oil and gas as previously thought when a newly mapped area bordering Russia is included, raising the prospect of drilling in environmentally sensitive ice-covered waters.

Norwegian governments have often said they will only drill in ice-free areas in the Arctic, both because companies lack technology to clean up oil spills onto ice and because icebergs can damage drilling installations.

The Norwegian Barents Sea could hold 2.8 billion standard cubic meters (Bscm) oil equivalent (17.6 billion barrels), including 1.4 Bscm to the southeast of the Svalbard archipelago, the country's oil regulator said.

While the area to the east of Svalbard evaluated by the Norwegian Petroleum Directorate (NPD) is covered by ice for much of the year, according to satellite data, the extent of sea ice is retreating northward because of global warming.

Norway's oil lobby welcomed the prospect of potential activity in the future, although the newly assessed areas will require parliamentary approval for drilling there.

While exploration has taken place in some parts of the Barents Sea for more than 30 years, only the Goliat oil field and the Snoehvit natural gas field have so far begun production.

The NPD said separately it expected a record number of exploration wells to be drilled in the Barents Sea this year.

CNOOC Strikes Oil, Gas At South China Sea Exploration Well

CNOOC Ltd. has struck "fairly good oil and gas flows" at an HP/HT exploration well in the Yingqiong Basin in the western part of South China Sea, according to a statement posted at an official government website on May 10.

The Yuedong 30-1-1 well strikes mostly gas flows. The well was drilled to a depth of 4,235 m (13,894 ft). The formation has a temperature of nearly 200 C (392 F).

Its successful completion marks technological breakthrough in HP/HT wells for the South China Sea.

Norway Offers 87 Blocks In Norwegian, Barents Seas

Norway offered oil and gas companies 87 blocks in the mature areas of the Norwegian and the Barents seas on May 2, the oil and gas ministry said.

The offer includes 34 blocks in the Norwegian Sea and 53 blocks in the Barents Sea, the second-largest expansion so far of Norway's so-called predefined exploration areas, and the offer is in line with a preliminary plan presented in December 2016.

The application deadline was set to Sept. 1, and the ministry aims to award new licenses at the beginning of 2018.

Schlumberger Executes Contract With Pemex For Campeche Seismic Survey

Pemex has signed an agreement to license data from the WesternGeco Campeche wide-azimuth (WAZ) multiclient seismic survey in the Salina del Istmo province of the southern Gulf of Mexico, Schlumberger said in a news release.

The agreement also includes collaboration with WesternGeco in the seismic processing phase of the project as well as for future technology collaborations.

Schlumberger said the contract is the first of its kind for Pemex in Mexico and provides access to new 3-D WAZ seismic data in the province. The data license covers deep and shallow-water areas in the basin near prolific geological trends, including the Cantarell and Ku-Maloob-Zaap reservoirs, the release said.

—Staff &Reuters Reports

FLOATERS

Browse Concept Shifts Away From FLNG

Woodside is starting work on a new study to find the best development concept for its Browse project offshore Western Australia now that it has officially ruled out the use of a floating LNG (FLNG) solution.

"Following the completion of front-end engineering and design [FEED] work, the Browse joint venture (BJV) participants decided not to progress further with the floating LNG development concept selected at FEED entry in June 2015," Woodside said last week.

"The BJV participants are now preparing a new work program to assess and concept select phase activities. It is anticipated that a range of concept options will be considered."

The initial concept called for the use of three FLNG facilities, but in March 2016 Woodside completed FEED work for this option and decided to put the development on ice due to the poor economic environment.

The Browse FLNG development concept was based on three FLNG facilities using Shell's FLNG technology and Woodside's offshore development experience to exploit the Brecknock, Calliance and Torosa fields that hold gross contingent resources (2C) of 436.3 Bcm (15.4 Tcf) of dry gas and 453 MMbbl of condensate.

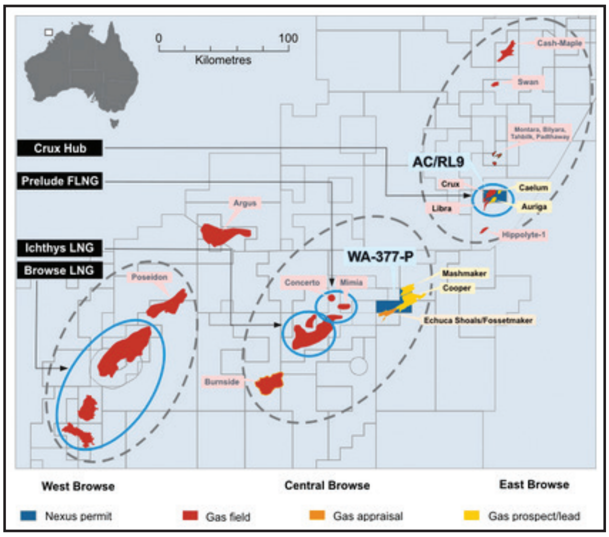
Even when Woodside shelved the project last year, CEO Peter Coleman said the company remained committed to the FLNG solution despite the delay.

However, Woodside's quarterly report suggested this is no longer the case, with a move away from FLNG possibly on the cards. Now the company states on its website that the FLNG is not being pursued any longer.

Woodside said it has made significant progress in "narrowing alternative concepts" for the Browse development.

"Woodside prefers a concept utilizing existing LNG process infrastructure on the Burrup Peninsula, subject to reaching acceptable terms with the Burrup infrastructure owners. Woodside continues to target the selection of a Browse development concept in second-half 2017," the operator said.

The partners in Browse are: Woodside (30.6%), Shell (27%), BP (17.33%), Japan Australia LNG (14.4%) and PetroChina International Investment (10.67%).



Woodside's Browse project is located offshore Western Australia. (Source: Odfjell Drilling)

Startup Planned For Mid-2020s

Despite the ongoing search for the optimum development solution, Woodside forecasts that first gas from its Browse project will be achieved in the mid-2020s, according to Coleman.

When Coleman confirmed that the FLNG option has been abandoned, he added, "As you know, we have worked for some years to find the right development concept for the world-class Browse resources. I'm very excited about where we are headed. Now conditions are aligning for us to look closely at an opportunity to basically double the life of the North West Shelf by bringing the Browse resources into it."

Using the existing facilities has the dual advantage of ensuring the most efficient use of capital, while minimizing risk by relying on proven technologies.

"As operator of both Browse and the North West Shelf, Woodside is well placed to make this happen, and we are talking to joint venture participants in both assets. It is still early days, but we think this is a compelling option and could be achieved at a competitive price and in a reasonable time frame," he added.

Woodside predicts tightening in LNG in the next few years due to the growth in demand from new markets and the current challenging conditions for new large-scale developments.

"These factors point to a supply shortfall in the 2020s, adding to the case for developing Browse. We anticipate that first gas from Browse could enter the North West Shelf plant from the mid-2020s, coinciding with the forecast supply crunch," Coleman said.

Scarborough Could Use FLNG

While the FLNG solution is a nonstarter for the Browse fields, there is another project Woodside is still working on that could be well suited to FLNG facilities: the Scarborough gas field off Australia, which sees Woodside teaming up with U.S. big hitter ExxonMobil.

Scarborough was discovered in 1979 in the Carnarvon Basin off Western Australia. The remote gas field lies about 220 km (137 miles) northwest of Exmouth at a water depth of 900 m (2,953 ft). Woodside acquired a stake in Scarborough last year.

Woodside said development concepts being considered for Scarborough are an FLNG facility or use of existing LNG process infrastructure on the Surrup Peninsula. Both concepts will be studied and evaluated this year.

In January Woodside said that a final investment decision for the Scarborough is scheduled in 2020.

Prelude FLNG 2018 Start

Meanwhile, Shell's Prelude FLNG, which will be the world's largest offshore facility, is set for completion and startup in 2018—despite a fatal incident at the Samsung Heavy Industries shipyard in South Korea last week.

The construction of the giant Prelude facility started in 2012. Once completed, it will be deployed offshore Australia and will produce 3.6 m tons of LNG a year by using natural gas from the Prelude and Concerto gas fields located about 475 km (295 miles) north-northeast of Broome.

During a conference call on first-quarter 2017 results, Shell's CFO Jessica Uhl was asked about the progress of the construction of the Prelude FLNG, and she said Prelude remained on schedule.

"We've indicated that startup was in 2018, and we remain confident in that timing," Uhl said.

After the completion of all work at the shipyard in South Korea, the FLNG facility will be towed to its operating location offshore of Western Australia. The *Posh Terasea* will conduct the tow using five vessels. Once at location the facility will be moored and connected to the subsea infrastructure, with the whole production system then to be commissioned.

—Steve Hamlen

FLOATER BRIEFS

Addax Terminates Contract For BW's Sendje Berge

Addax Petroleum announced termination of its contract in early May with BW Offshore Ltd. for the FPSO *Sendje Berge* operating offshore Nigeria, with demobilization ordered by Nov. 6.

BW received an arbitration award of $61.8 million in March in connection with a claim against Addax for payment of outstanding day rates for the use of *Sendje Berge* based in the Okwori field. The arbitration tribunal's decision went entirely in BW's favor and found that Addax would not be allowed to deduct from future hire payments.

BW said it will continue to pursue the arbitration award for all outstanding claims against Addax. The company said it has received $18.7 million so far.

The INPEX-operated Ichthys LNG Project's CPF sailed away from its construction site in Geoje, South Korea, en route to the Ichthys Field offshore Western Australia. (Source: Inpex)

Ichthys LNG Project Celebrates CPF Sail Away

INPEX Corp. said that *Ichthys Explorer*, the INPEX-operated Ichthys LNG Project's central processing facility (CPF), sailed away from its construction site in Geoje, South Korea, en route to the Ichthys Field offshore Western Australia, following the completion of shipyard commissioning and preparation work.

The *Ichthys Explorer* will be towed to the Ichthys Field over a period of about one-and-a-half months, after which it is scheduled to undergo hookup. The facility will then separate and process the produce lifted from subsea production wells into gases and liquids over 40 years of continuous operation.

The *Ichthys Venturer*, the project's FPSO facility, also is scheduled to be towed to the Ichthys Field and undergo hookup. INPEX and its partners will continue to proceed with construction work on the onshore natural gas liquefaction plant outside of Darwin in the Northern Territory of Australia.

Following the arrival of the CPF and the FPSO unit, installation and commissioning work will be undertaken and production from wellheads will commence. Thereafter, the Ichthys LNG Project will, during the current fiscal year (ending March 31, 2018), begin production of condensate, LNG and liquefied petroleum gas in sequence and then ship these products.

—Staff Reports

VESSEL BRIEFS

Wärtsilä's 34DF Engines Get US EPA Certification

The U.S. Environmental Protection Agency (EPA) awarded Tier III emissions compliance certification to Wärtsilä's 34DF dual-fuel engine family for 2017, the first Category 3 Tier III certificates issued to any manufacturer.

The certification confirms that the Wärtsilä 34DF engine is fully compliant with the EPA's emission standards for engines in gas mode operation with a displacement per cylinder of greater than 30 liters. The engines are required to be equipped with a continuous nitrogen oxide (NOx) measuring and monitoring system for verifying emissions compliancy inside NOx Emission Control Areas (NECA). When sailing outside NECAs, the 34DF engine can be operated with conventional marine diesel fuels if required.

Patrik Wägar, product director, medium bore engines for Wärtsilä Marine Solutions, said "It is an honor for the company to be the first to be awarded this important EPA certification."

Germany Picks Kongsberg For LNG-powered Research Ship

Kongsberg Maritime will build the world's first government-owned LNG-powered research vessel for Germany's Federal Maritime and Hydrographic Agency (BSH).

A contract for construction of Atair II, signed in April and announced in May, will provide BSH with the largest vessel in its fleet at 74 m (243 ft) in length, about 17 m (56 ft) wide and 5 m (16 ft) draught. The ship will have space for 18 crew members and 15 researchers, and it will be able to reach a top speed of about 13 knots. It will be built at the Fassmer yard in Berne.

Atair II will be one of the most sophisticated ships in the world when it is delivered in 2020, Kongsberg said in a statement.

Atair II is expected to be delivered in 2020. (Source: Kongsberg Maritime)

Among its features:

- DNV-GL SILENT class notation—SILENT R, ensuring minimal impact on the marine environment;
- Adherence to the strictest standards for nitrogen oxides (NOx) emissions according to IMO Tier III requirements and U.S. Environmental Protection Agency soot particle emissions regulations; and
- Meeting "Blue Angel" standards for ecofriendly ship design (RAL-UZ 141).

The ship will operate in the North Sea and the Baltic Sea, and it can operate in dual-fuel configuration on high-quality diesel gas oil with a sulfur content below 0.1%, while standalone LNG-powered operational duration is 10 days, thanks to its 130-cu. m tank.

Uwe Frenz, managing director of Kongsberg Maritime GmbH Germany, said, "Kongsberg Integrated Vessel Concepts are a brand new approach to vessel design and building that leverages the power of integration between disparate systems to produce gains in operational efficiency and reduced life-cycle costs across the board."

—Joseph Markman

POLICY

Brazil's Faces Presalt Natural Gas Challenges Despite Potential

RIO DE JANEIRO—Brazil's presalt fields have the potential to make the country self-sufficient in gas production; however, energy policy changes are needed to reach the goal, according to a study released by the Federal University in Rio de Janeiro.

The country remains dependent on Bolivia to supply most of its gas, despite Brazil's output reaching more than 1 MMbbl/d of oil a decade after presalt resources were discovered.

Brazil's domestic demand for natural gas is about 80 MMcm/d (2.8 Bcf/d), while the country produces about 111.7 MMcm/d (3.9 Bcf/d), according to ANP, Brazil's oil and gas regulator. However, most of the gas produced has been used for reinjection to increase oil output. Brazil imports 30% of its total demand from Bolivia.

"For decades, Brazil has been suffering from the lack of strategy for boosting gas output in order to meet the domestic demand," said Edimar Almeida, the professor who coordinated the study. "It is essential to design an energy plan and regulatory changes to promote the best use of the gas potential of the presalt."

According to the study, a new view on Brazil's oil and gas regulatory framework, establishing measures to attract new players in the gas sector, for example, can help to change the situation.

Although a smaller presence by Petrobras in the gas sector is seen as a positive, considering it opens doors for other investors, the study said this is not enough.

The presalt fields's long distance from the coast and high CO_2 content poses challenges. Brazil's government should consider stimulus for investments in logistics and gas treatment.

Increasing pipeline projects for offloading presalt natural gas is highly recommended. It is crucial to evaluate the viability of auctions for structuring thermals for specific natural gas plant project, according to the study.

"Without new regulatory specifications, the access for this kind of infrastructure is submitted to a great asymmetry based on market concentration. In this context, establishing a regulated access that allows dealings between Petrobras and other producers can contribute [to increasing] Brazil's gas attractiveness," Almeida said.

Gas Pipeline Demand

The construction of presalt gas pipeline is expensive due to the distance and the depth of the fields. Currently, only two presalt gas pipelines—Route 1 and Route 2 – are in operation with tan offloading capacity of 23 MMcm/d (8 Bcf/d).

The 359-km (223-mile) Route 1 pipeline, which has been in operation since 2011, has the capacity to offload another 10 MMcm (3.5 Bcf) of gas. Route 1 is divided in two parts: The Lula-Mexilhão Platform section and the section connecting the *Mexilhão* FPSO to the Monteiro Lobato Gas Treatment Unit in Caraguatatuba, São Paulo. The unit has a processing capacity of up to 10 MMcm/d in the Santos Basin presalt area.

The 401-km (249-mile) Route 2, where operations started in February 2016, has the capacity to flow 13 MMcm/d (4.6 Bcf/d) from the Santos region to the Cabiúnas Gas Treatment Terminal in Rio de Janeiro. Route 2 is the largest underwater gas pipeline in operation in Brazil.

Petrobras plans to build a third gas pipeline—Route 3—that will link to the Búzios Field.

The high CO_2 level is another obstacle, posing technical and economic challenges. Conventional CO_2 separation technology is difficult to use in reservoirs with a high gas-oil ratio (GOR) and high CO_2 level. Libra's presalt field, for example, has a CO_2 content of about 45% in the produced gas.

Targeting Goals

Despite the challenges ahead, Brazil's government believes the country will be able to meet its own gas needs by 2021 as presalt fields are developed.

"We are working on that," Brazil's Energy Minister Fernando Coelho Fllho said during a conference in Rio de Janeiro last April. "The Pão de Acúcar's presalt field (located in Campos Basin) alone is predicted to produce 15 MMcm/d (5.3 Bcf/d). This output result accounts for 50% of our natural gas imports from Bolivia.

Brazil hopes to import less gas from Bolivia. The country is working on a new contract to that effect.

In July 2016, Brazil launched the Gas for Growth plan. The plan intends to devise strategies to improve the sector's legal and regulatory framework. Since then, several meetings and discussions have been taken place with stakeholders to highlight priorities for investments in Brazil's gas sector.

—Brunno Braga

BUSINESS

Aker Solutions' First-Quarter 2017 Revenues Drop 20%

Revenues at Norwegian oil service firm Aker Solutions fell 20% in first-quarter 2017 from a year earlier, hit by weak demand and the ending of some projects, the company said May 9.

While most oil companies have reported better-than-expected first-quarter earnings, helped by a rise in oil prices, and while more projects are being approved, subsea developments normally come at a later stage in an industry upturn.

Aker, controlled by Norwegian billionaire investor Kjell Inge Roekke, reported first-quarter revenues of 5.2 billion Norwegian crowns (US$601.7 million), down from 6.5 billion Norwegian crowns (US$751 million) in first-quarter 2016, with revenues at its key subsea business dropping 27% year-on-year.

The company repeated its guidance for overall full-year revenues to be between 10% and 15% lower than in 2016, but said it saw signs of recovery and was currently bidding for contracts worth about 50 billion crowns (US$5.8 billion).

Project revenues for 2017 are expected to be down between 15% and 20% from 2016, it added.

"While we continue to face market uncertainty, the signs of improving brownfield activity and expectations of key subsea projects moving forward bode well for 2018 activity levels," CEO Luis Araujo said.

The company's backlog stood at 30.7 billion crowns (US$3.5 billion) at the end of first-quarter 2017, with quarterly intake of 4.6 billion crowns (US$531 million), including a FEED contract from Statoil for Phase 2 development of Norway's giant Johan Sverdrup Field.

Lower project breakeven costs were likely to spur more projects being sanctioned by oil companies this year, Aker added.

Aker said it expected underlying core profit (EBITDA) margins for 2017 to be slightly down from the current levels of 7% due to continued market weakness, partly offset by its improvement program.

The company said it had achieved more than two-thirds of its 9 billion crowns (US$1 billion) cost savings plan by the end of the first quarter.

—Reuters

Subsea 7 Says Earnings Margin To Be Better Than Feared

Oil services company Subsea 7 reported first-quarter margins that were better than most investors had expected and upgraded its full-year profitability forecast.

The firm has been hit over the past three years by lower demand from oil companies due to falling energy prices, but a recent recovery has helped recover some ground.

Subsea 7, which provides engineering and construction services to the offshore oil industry, reported an earnings margin before depreciation and amortization of 30% for the first quarter.

Brokers Pareto Securities said analysts had on average predicted a margin for the quarter of only 20%.

Looking ahead, Subsea 7 said its adjusted earnings margin this year was expected to be lower than the record level reported in 2016. In March, however, it said the percentage margin would be "significantly lower."

"Our early engineering activity has increased, and we expect this trend to continue as the market recovers in the future," the company said in a statement.

In the first quarter, Subsea 7 posted adjusted operating profit before depreciation and amortization of $268 million, down from $284 million at the same time a year ago. Its backlog was unchanged quarter-on-quarter at $5.7 billion.

No Reuters poll figures were available in this quarter as Subsea 7 acquired in March the remaining 50% of Seaway Heavy Lifting, changing its earnings reporting structure.

—Reuters

Anadarko Petroleum Reports First-Quarter Loss As Costs Rise

Anadarko Petroleum Corp. reported a bigger-than-expected quarterly loss this month, as expenses rose about 53%, failing to offset gains from higher crude prices.

North American oil producers faced prolonged weakness in crude prices after oil hit near-record lows in February 2016, which chewed into their profit margins and eroded cash flows.

Anadarko's total costs and expenses surged to $3.88 billion in the first quarter ending March 31, from $2.54 billion in the same period a year ago.

Exploration expenses rose more than eight-fold to $1.09 billion, the company said.

However, average sales prices for oil were higher in the quarter at $50.34/bbl, from $29.65 a year ago.

Total oil and gas sales volumes averaged 795 Mboe/d, slightly lower when compared with 827 Mboe/d a year ago.

Net loss attributable to the company narrowed to $318 million, or 58 cents per share, from $1.03 billion, or $2.03 per share.

On an adjusted basis, Anadarko lost 60 cents per share, largely missing analysts' average estimate of a loss of 24 cents per share, according to Thomson Reuters I/B/E/S.

The Texas-based company's revenue more than doubled to $3.77 billion.

—Reuters

BUSINESS BRIEFS

Malaysia's UMW-OG Cancels Plan To Buy Icon Offshore

Malaysia's offshore drilling services firm UMW Oil & Gas Corp. Bhd (UMW-OG) has scrapped plans to acquire offshore support vessel provider Icon Offshore Bhd, citing capital constraints and uncertainties in the industry.

UMW-OG said in January it planned to buy Icon in a deal valuing the target at 588.6 million ringgit (US$136.06 million). It also said it planned to buy 95.5% of Orkim Sdn Bhd, an operator of clean petroleum product transport vessels, which it then valued at 495 million ringgit ($114 million)

But UMW-OG said it was terminating the deal "after considering the significant capital requirements of UMW-OG and upon taking into account the need to have greater clarity on the industry consolidation framework and certainty of the industry environment before any such consolidation can be pursued."

The firm said in a statement it would explore opportunities to collaborate in the future, because it believes the creation of a major integrated oil and gas service provider was the right strategic approach for the longer term. UMW-OG said it would pursue a plan to recapitalize.

BP Will Use Exa Corp.'s Digital Permeability Software

BP and Massachusetts-based Exa Corp. signed an agreement for Exa's DigitalROCK relative permeability software, which a senior adviser at BP said would be used by BP.

The two companies have a multiyear commercial agreement. The product will aid decision making on EOR, wells and production facilities, a press release said.

Joanne Fredrich, upstream technology senior adviser, said the software would be used across BP's global portfolio, adding that the product was the result of a three-year collaborative development and testing effort. DigitalROCK generates reliable relative permeability information directly from digital scans, she said.

DigitalROCK is based on Exa's multiphase fluid flow simulation technology, the press release said.

Shipyard Accident Could Delay Martin Linge Platform Delivery

Total said last week that it needed more time to assess whether an accident at a South Korean shipyard could delay the delivery of its Martin Linge oil platform to Norway.

Six people died and more than 20 were injured when a crane collapsed onto a section of the platform at a Samsung Heavy Industries shipyard on May 1 in Geoje, according to South Korea's Yonhap News Agency report.

"It's too early to say how this would affect the platform's delivery. We still need to assess the damage," a spokesman for Total's Norwegian subsidiary said. No Total employees were killed or injured, the company said.

"We planned to sail the platform from South Korea before summer to install it during July or August, and it's still the plan," he added.

The trip takes nearly two months.

Total owns a 51% stake in the Martin Linge license, while Norway's state-owned Petoro has 30% and Statoil ASA has 18%.

Weir Names Managing Director For EMEA Region

Ronan Le Gloahec was appointed as managing director of the EMEA region for Weir Oil & Gas, effective immediately, the pressure pumping provider said.

Le Gloahec will lead the Weir oil and gas business unit, which is based in Dubai, United Arab Emirates. He will oversee manufacturing and service of pressure control equipment, rotating equipment, OCTG products and operational and maintenance contracts with end-user E&P and national oil companies across the Middle East, Africa, Europe and the Caspian regions.

Before joining Weir, Le Gloahec was senior vice president at Welltec A/S, responsible for executive management in the Middle East and Asia-Pacific.

Halliburton, Partners Offer GoM Subsea Well Intervention Package

Halliburton Co., Trendsetter Engineering and C-Innovations will provide Gulf of Mexico (GoM) customers with technologically advanced, integrated well intervention packages to improve efficiency while addressing infield production and subsea challenges, according to a news release.

Mario Lugo, chairman and CEO of Trendsetter, said the partnership's projects have included, to date, complex hydrate remediation, large acid stimulations, pipeline flushing, and inspection, maintenance and repair work in water depths up to 3,048 m (10,000 ft).

Trendsetter Engineering is a subsea solutions provider based in Houston. C-Innovations is a marine transportation and solutions provider based in Mandeville, La.

—Staff & Reuters Reports

UPCOMING

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CONTACT INFORMATION

LEN VERMILLION Group Managing Editor, Digital News Group
lvermillion@hartenergy.com

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

CONTRIBUTORS:

Ariana Benavidez (Houston)
Darren Barbee (Houston)
Brunno Braga (Brazil)
Steve Hamlen (U.K.)
Joseph Markman (Houston)
Emily Patsy (Houston)
Erin Pedigo (Houston)
Jennifer Presley (Houston)
Ravi Prasad (India)

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