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Subsea Giant In The Making Tackles Innovation, Integration

Technip's deepwater support and subsea installation workhorse vessel Deep Pioneer is shown in action offshore West Africa. (Source: Technip)

By reinventing products, integrating technologies and simplifying architecture, FMC Technologies and Technip aim to redefine the subsea industry while improving project economics—as one company.

The two, which will become TechnipFMC if their pending merger closes as expected in early 2017, are targeting segments of the value chain where their offerings are complementary and connected. They also want to reduce interfaces with optimized designs, speed up time to first oil and ultimately improve life-of-field solutions and subsea economics, according to Doug Pferdehirt, president & CEO of FMC Technologies.

"That is our approach," Pferdehirt said Sept. 6 during the Barclays CEO Energy-Power Conference. "The market will react as the market will, but we have seen a strong acceptance from our customer base for this approach."

Looking to past decades, Pferdehirt pointed out some pitfalls the subsea industry has faced as leaders in subsea production systems (SPS) and subsea, umbilicals, risers and flowlines (SURF) focused on going deeper and producing better reservoirs. They worked to deliver production both safely and economically at higher pressures, he said, but equipment and technologies were not integrated, with packages offered and tendered separately.

"We didn't come together until we met on the seafloor," Pferdehirt said. "Because of that, contingencies needed to be built in. Additional interfaces needed to be built in. Very costly connection systems needed to be deployed. No one had the view and no one had the incentive to look at this as it is—one complete subsea production system."

The planned merger, which was announced in May, comes as the oil and gas industry struggles to rebound from lower commodity prices caused by a global hydrocarbon oversupply. Companies have sought ways to lower project costs, become more efficient and work smarter in hopes of preserving cash flow and growing profits.

Redefining Industry

The three-step strategy toward redefining the industry involves reinventing products, integrating technologies and redefining subsea.

Pferdehirt used a subsea manifold to make his point. It is an important piece of equipment, but over the years it has become bigger and more complex due to engineering specifications and other requirements—all of which have driven up costs. However, the almost 200-ton subsea manifold has been reinvented. A smaller version does the same job, but with half of the parts and half of the weight. Plus, it can be delivered in half of the time, he added.

"This isn't a dream. This isn't a prototype. This is an actual product that we are manufacturing for customers today, taking orders and will be including in our tenders going forward," said Pferdehirt. "This is substantial

WHAT'S INSIDE

change, and this is just the beginning of how we'll reinvent our products."

From here, the companies integrate their technologies: subsea processing joins electrically trace heated pipe-in-pipe to better handle flow assurance issues and increase efficiency; connectors integrate with flexible pipe to reduce installation times and lower costs; and subsea architecture such as manifolds is simplified while equipment or technology needed to connect different companies' packages is removed altogether.

These were among the few examples presented.

"This is how we will redefine subsea," Pferdehirt said.

The so-called TechnipFMC integrated approach has the potential to shave up to 30% off the SPS and SURF costs, lower the number of SPS interfaces needed and reduce flowlines and risers, he added. It is also expected to hasten installation, lower execution risk and accelerate time to first oil.

Budding Relationship

FMC and Technip are building on a relationship formed in 2015 with the Forsys Subsea joint venture. Since the alliance was formed, Forsys has landed 16 integrated FEED studies, Technip CEO Thierry Pilenko said, before noting the diverse mix of the joint venture's FEED studies.

Field types include both brownfields and greenfields, and customers are IOCs, NOCs and independents working in just about all parts of the world.

The two companies are addressing concerns by enabling brownfield and long tiebacks, engaging in the design optimization process early, integrating full-field development and using technology to drive efficiency and simplification, according to Pilenko.

"We cover everything in the subsea space from the wellhead to the platform," Pilenko said while pointing out the benefits of having all subsea offerings under one roof. These include FEED and subsurface expertise, SPS, SURF, life of field, and monitoring and topsides and facilities.

The combined force could lead to integrated technology, a more cost-effective operating structure and integrated offerings outside the subsea space, he added.

One of the latest contracts awarded to Forsys Subsea was for a FEED study for Statoil's Testakk Field offshore Norway. The field is being developed as a subsea tieback to the Åsgard A FPSO.

Henning Gruehagen, head of Forsys Norway, told *SEN* in May that FMC and Technip saw cost increases in the subsea space as a challenge that needed to be solved. He estimated that integrated offerings could drop the time from concept to first oil by six to 12 months. Cutting the amount of equipment installed on the seabed and using smaller vessels helped cut costs on Trestakk by 25%.

The merger essentially pushes the Forsys Subsea concept.

Merger On Track

The all-stock transaction is expected to produce pretax cost synergies of about $400 million by 2019.

"We will be one of the largest oilfield service providers worldwide and we will have an industry-leading balance sheet from which to deliver and execute this new platform," Pferdehirt said.

In May, Reuters reported Technip had a market value of about $6.2 billion, compared with FMC Technologies' $6.5 billion. Technip has annual revenue of $13.5 billion, more than double that of FMC Technologies.

Pilenko will serve as executive chairman of TechnipFMC while Pferdehirt will be CEO, the companies said.

In July, the companies said the pending merger received an early decision from U.S. antitrust regulators under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 (HSR Act), concluding antitrust review of the transaction in the U.S. under the act. But other conditions must be met before the pending merger becomes reality, including the conclusion of antitrust reviews in other countries and approval from each company's shareholders.

—Velda Addison

DEVELOPMENT

Shell Brings Deepwater Stones Online In GoM

Just more than three years after unveiling the final investment decision for the Stones subsea development in the U.S. Gulf of Mexico, Royal Dutch Shell has fired up production for what is being heralded as the world's deepest oil and gas project.

At a water depth of 2,900 meters, or 9,500 feet, production from the Lower Tertiary geologic trend development began in September. The reservoir is located about 26,500 feet below sea level in the Walker Ridge area.

The 100% owned and operated Shell development utilizes innovative technology such as steel lazy wave risers. Advantages include added buoyancy and flexibility needed to absorb motion and help boost production performance, according to Shell.

SBM Offshore's *Turritella* FPSO sits dockside in Singapore before setting off on its journey to the GoM. (Source: Shell)

The development's subsea production wells are tied back to the *Turritella* FPSO vessel, which has some unique features of its own. The FPSO vessel—which has a processing capacity of 60,000 bbl/d of oil and 424.7 Mcm/d (15 MMcf/d) of gas treatment— is equipped with a turett and a detachable buoy configured with steel lazy wave risers, the first ever application on an FPSO vessel.

The FPSO has nine mooring lines—three bundles of three—which are comprised of a lightweight combination of polyester rope and chain. The system also incorporates in-line mooring connectors, which enables the ability to adjust line tension during operations, according to Intermoor, which completed the chain tensioning and cutting on the FPSO in the GoM earlier this summer.

The features will prove beneficial, especially during hurricane season. As the wind blows during normal weather conditions, the design enables the FPSO to turn; however, the operator is able to disconnect the vessel from the buoy and move to safety if a tropical cyclone approaches.

"Stones is the latest example of our leadership, capability, and knowledge which are key to profitably developing our global deep-water resources," Andy Brown, upstream director for Shell, said in a news release. "Our growing expertise in using such technologies in innovative ways will help us unlock more deep-water resources around the world."

Shell also pointed out expectations that the project's "more cost-effective well design, which requires fewer materials and lowers installation costs" could deliver up to $1 billion reduction in well costs when all of the producers are completed.

The development currently has two subsea production wells. However, six more could be added—all connected to the *Turritella*—along with a multiphase pumping system to help move hydrocarbons flow from the seabed to the FPSO.

Of more than 250 million barrels of oil equivalent (MMboe) of recoverable resources at Stones, the first phase of the development is expected to produce an estimated 50,000 boe/d at its peak. But Shell believes the field has significant upside potential, considering it is estimated to contain more than 2 billion boe of oil in place.

—Velda Addison

Indonesia Starts E&P, Marginal Field Push

Indonesia is forging ahead with its plan to raise the country's level of exploration and development activity—and is approaching domestic and regional players alike to help meet its target of bringing down Indonesia's energy shortfall.

Indonesia's Coordinating Minister for Maritime Affairs Luhut Binsar Panjaitan, who is also acting minister for energy and mineral resources, recently invited Malaysia's state-owned Petronas to join in an exploration campaign covering 10 new blocks in the country with its Indonesian counterpart Pertamina.

The invitation was extended during a meeting with Malaysian Deputy Prime Minister Ahmad Zahid Hamidi in Malaysia.

"Pertamina will be offering seven oil and gas blocks in the Exclusive Economic Zone and three in Natuna Islands through an open tender," Zahid said.

The deputy prime minister added that the invitation would open new cooperation opportunities between the two state players.

"Petronas is now focusing on exploration within ASEAN [Association of South East Asian Nations] for better management and reduced cost," Zahid said.

Pertamina also plans to sign a production-sharing contract (PSC) to develop the giant East Natuna Block with U.S. major ExxonMobil and Thailand's state-owned PTT Exploration and Production (PTTEP) this month in order to bring the field into operations by 2019.

Pertamina recently met with representatives of the Ministry of Energy and Mineral Resources' (MEMR) oil and gas directorate general to discuss the issue.

"We are still studying the possible terms and conditions. Before the East Natuna PSC is signed, we will make sure that we have prepared all that is needed," Pertamina's senior vice president for upstream planning and operation evaluation said.

According to MEMR's director general for oil and gas, IGN Wiratmaja Puja, the government would grant incentives to Pertamina to develop the East Natuna Block, adding that a timely signing of the PSC would help achieve first production in 2019, while the joint venture continues its two-year study on the field.

The PSC area has proven gas reserves of 1.30 Tcm (46 Tcf) but development of the resource is not easy due to a high concentration of carbon dioxide (CO_2), estimated at 72%, in the field.

As a result, the cost to develop East Natuna gas resources is expected to be high. The joint venture will need to spend in the area of US $20 billion to US$40 billion, using advanced technology, to optimise production from the block.

The East Natuna concession could also yield estimated oil reserves of 46m bbl underneath the gas reservoir, which could produce at a rate of 7,000-15,000 b/d of oil.

Marginal Field Fast Tracking

AIM-listed Andalas Energy and Power has sealed an agreement with Indonesia's state-owned Pertamina to establish a joint working and steering committee to fast track the development of marginal gas fields in Indonesia.

The agreement will use Andalas' technical expertise and Pertamina's local knowledge to make "a significant contribution at the local level towards fulfilling the government's goal of reducing the country's power shortfall", Andalas said.

Indonesia plans to increase electricity generation capacity by 35,000 MW by 2019, with domestic supply to fuel the plants.

Both companies will primarily focus on identifying a minimum of five stranded gas fields in Pertamina's acreage in the Riau, Jambi and South Sumatra provinces, which are suitable for sub-100 MW gas-to-power development in the form of an independent power project (IPP).

Andalas said it has identified all target areas that have an abundance of stranded gas fields, with all field and independent power project (IPP) development plans to be based on modular/mobile power plants.

When the fields have been identified, both companies will sign an exclusive Joint Development Agreement (JDA) to design, construct, fund and operate the IPPs.

"Suitable partners may be invited to join the two companies in the JDA for each development. They will work to generate IPP commercialisation plans for each of the identified marginal gas fields covering all key aspects of any future investment and approval; covering project design, project cost and economic analysis and all regulatory requirements," Andalas added.

"Working in partnership with Pertamina is in our view a testament to the strength of Andalas' gas-to-power business concept and the caliber of both our board and local management team, who have an intimate understanding of the country's energy sector. Andalas already has the team and network to make sure the partnership has at its disposal everything needed to deliver the targeted IPP commercialisation plans," said Andalas' CEO David Whitby.

"Pertamina has in-depth knowledge of Indonesia's oil and gas sector, as well as a substantial portfolio of stranded gas discoveries in South Sumatra where there is a major need for power. Together Pertamina and Andalas are uniquely positioned to make a significant contribution to Indonesia's economic growth by helping to meet the country's growing demand for electricity at both the industrial and household level," Whitby added.

Kalimantan Production Boost

Meanwhile, U.S. major Chevron has started gas production from the Bangka field development project, the first stage of the Chevron-operated Indonesia Deepwater Development (IDD) project in East Kalimantan.

The Bangka project has a design capacity of 3.12 MMcm/d (110 MMcf/d) of natural gas and 4,000 b/d of condensate.

Chevron owns a 62% stake in the project, while Eni holds 20% and Tip Top has 18%.

The company said a Final Investment Decision was reached in 2014, following government approvals, with the drilling of development wells starting in the second half of 2014.

Chuck Taylor, managing director of Chevron IndoAsia Business Unit, said: "The project represents Chevron's commitment to bring global capabilities and advanced technology to Indonesia and applies best practices and expertise from our deepwater developments around the world," Taylor said.

—Steve Hamlen

DEVELOPMENT BRIEFS

Aker Solutions Secures Work For Utgard Tie-in To Sleipner Area

Statoil has chosen to stick with Aker Solutions for engineering, procurement, construction, installation and commissioning (EPCIC) services to enable a tie-in of the Utgard gas and condensate field to the Statoil-operated Sleipner facilities in the North Sea.

The work, valued at about NOK 500 million (US$6.1 million), follows a contract won for preliminary engineering work on the tie-in. The contract had an option for EPCIC work, Aker Solutions said.

"We've worked closely with Statoil to find the most cost-efficient solution for this project, which builds on our capabilities in complex modifications," said Knut Sandvik, head of Aker Solutions' maintenance, modifications and operations business.

The Utgard subsea development will be connected by pipeline to the Sleipner T processing and CO_2 removal platform and by umbilical to the Sleipner A processing, drilling and living quarters platform, Aker said.

Work on the contract is scheduled for completion in fourth-quarter 2019.

EnQuest Lowers Production Guidance After Slow Oil Field Startup

North Sea-focused oil producer EnQuest lowered its full-year production guidance on Sept. 8 after initial output at its new Alma/Galia Field was less than expected.

The London-listed company also said it had reduced gross capex on its Kraken Field in the North Sea by $150 million to $2.6 billion, squeezing costs to contend with low crude prices. The project remains on track to produce first oil in first-half 2017.

EnQuest also reported a 51% rise in first-half profit before tax and net finance costs to $150 million, helped by output that jumped 43% year-on-year.

The increase in production, however, was weaker than expected, prompting the company to lower full-year output guidance to between 42,000 boe/d and 44,000 boe/d, down from the 44,000 bbl/d to 48,000 bbl/d previously expected.

FMC Technologies Lands Contract For Eni's West Hub

FMC Technologies Inc. has secured a contract to provide subsea multiphase boosting pumps, manifolds and installation support services for Eni Angola's Block 15/06 West Hub Development Project offshore Angola.

By reducing backpressure on the reservoir, increasing flow rates and total recoverable resources, FMC said it aims to improve production economics with the subsea multiphase boosting pumps.

"This is our second award for our new subsea multiphase boosting system, and we are confident that this technology will be a critical and important part in supporting increased deepwater field recovery," Tore Halvorsen, senior vice president of subsea technologies for FMC, said in a news release.

With water depths ranging from 1,000 m to 1,500 m (3,281 ft to 4,921 ft), the West Hub project develops the Sangos, Cinguvu, Mpungi, Mpungi North, Ochigufu and Vandumbu fields through the N'Goma FPSO unit, according to Eni.

Block 15/06 is operated by Eni, which has a 36.84% stake. Partners in the joint venture are Sonangol Pesquisa e Produção (36.84%) and SSI Fifteen Ltd. (26.32%).

Wood Group Secures $1 Million Contract For Subsea Tieback Work

Statoil has selected Wood Group for the detailed design scope of the subsea tieback from the Utgard gas and condensate field to the Sleipner facilities in the Norwegian North Sea, Wood Group said in a news release.

The $1 million work scope is the first call-off under the master service agreement signed in May 2016. Wood Group said the three-year contract will be executed from its Stavanger and Oslo offices.

Earlier this year, Statoil tapped Wood Group for FEED work for the same project.

The Utgard tieback consists of a 21-km-long (13-mile-long) pipe-in-pipe production pipeline from the four-slot template at Utgard to the Sleipner T platform and an integrated service umbilical from Sleipner A, the release said.

The contract was one of several snagged up recently by Wood Group.

Wintershall Norge AS awarded a new four-year frame agreement to Wood Group to tender for the provision of modification and maintenance services for its Norwegian Continental Shelf assets. The agreement has two three-year extension options.

Wood Group also was successful in securing an engineering framework deal with DONG Energy. The contract took effect immediately.

DONG Energy awarded Wood Group a new engineering services framework agreement to support oil and gas assets across the Danish, Norwegian and U.K. continental shelves, according to a news release.

The four-year contract is for front-end development, maintenance and modifications, engineering, and late life and decommissioning services, for topsides and subsea facilities.

—Staff & Reuters Reports

ONS 2016 CONFERENCE REPORT

Barents Sea Drilling Plans Unveiled

STAVANGER, Norway—Statoil is planning to sink about $250 million into its ongoing exploration drilling campaign in the frontier Barents Sea over the next two years, including its northernmost wildcat yet.

Tim Dodson, the company's global exploration chief, also forecast at the Offshore Northern Seas (ONS) conference and exhibition that up to three standalone projects could come to fruition in the Barents. That includes plans for an FPSO vessel on its Johan Castberg discovery as well as OMV's Wisting discovery and one other find not yet made.

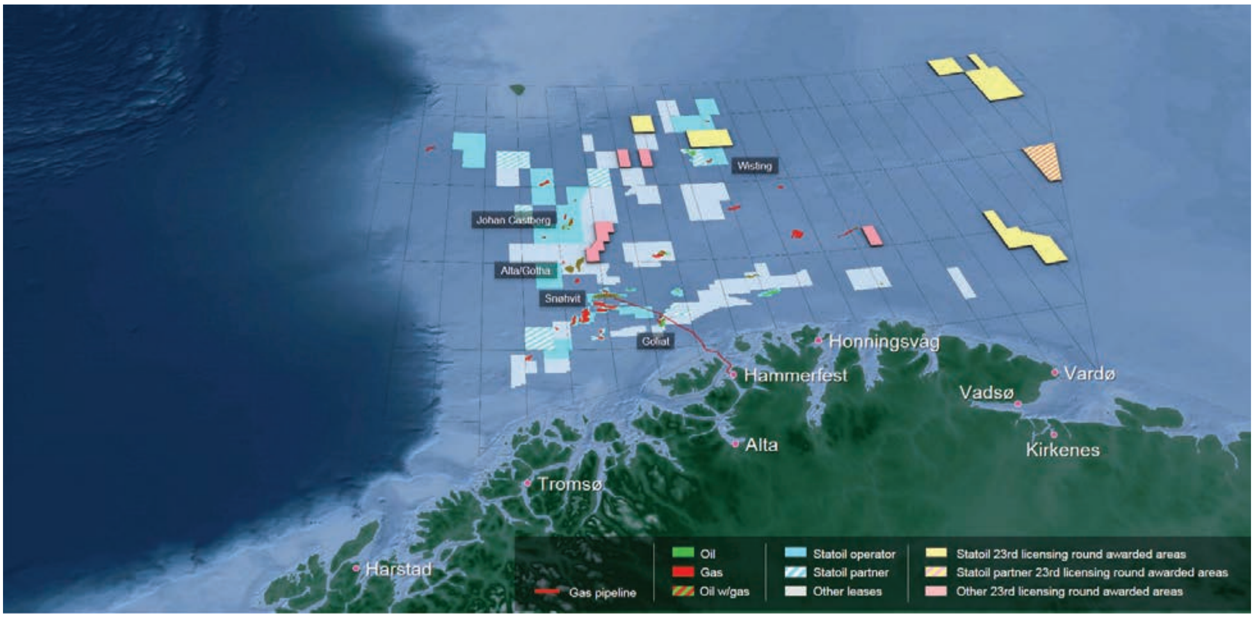
"We see the potential for two to three new standalone developments in the Barents Sea," Dodson said. "The next few years will tell if we're right or not."

An investment decision on the Johan Castberg development, which is well underway, could be made in 2017, he said.

Also on Statoil's radar is the Wisting discovery in the Hoop Area and the southeast Barents, where "we will over the next two or three years test some of the last remaining large structures on the Norwegian Continental Shelf [NCS]," Dodson continued.

"The testing of those licenses awarded in the 23rd round will be crucial to determining the potential of the Barents Sea and the NCS."

Statoil will drill at least five exploration wells in 2017, with Dodson estimating their cost at about $25 million per well—making them the cheapest offshore exploration wells the company will drill globally next year, he said.



Statoil will drill at least five exploration wells in 2017 at an estimated $25 million per well. (Source: Statoil)

He also agreed that total exploration drilling spend for both 2017 and 2018 in the Barents could be extrapolated accordingly.

"We aim to test the potential of the [Southeast] Barents, to prove up additional resources in the Hoop Area around the Wisting discovery and to strengthen our core position in the western part of the Barents Sea in the vicinity of Johan Castberg," he added.

"In any new petroleum province the biggest discoveries are typically made fairly early on in the exploration of those provinces. So that really underlines the importance of opening up new areas like the Barents Sea that have that kind of potential. The structures are clearly there; the reservoir is there," Dodson said. "But do they contain oil and gas, and how much would there be?"

Looking Ahead

Jez Averty, head of exploration on the NCS for Statoil, gave more detail.

"We have worked systematically on developing an exploration portfolio for testing good and independent prospects in 2017 and 2018. For 2017, we see promising prospects in different parts of the Barents Sea," Averty said.

"For example, we want to explore the Blåmann prospect in the Goliat area, Koigen Central in PL718 on Stappen High and the Korpfjell prospect in PL859 that was awarded in the 23rd licensing round."

Korpfjell would be Norway's northernmost well, a title currently held by the Wisting discovery well. In addition to the exploration well on Blåmann, which was awarded to Statoil in January, Statoil and well operator Eni have also agreed to drill a new exploration well in PL229 (Goliat) next year.

A rig that is suitable for operation in the Barents is already on contract, and the company is working to get approval from partners and authorities for the 2017 exploration campaign that includes between five and seven wells.

In addition, a separate campaign is being planned for 2018. Averty pointed out that the company has been careful to distance the wells sufficiently far apart so that a failure in one will not damage the prospectivity of others.

Keeping Costs Down

Statoil has also been busy strengthening its position in the area through several transactions with other companies. In recent months it has entered or increased its share in five licenses in the Norwegian part of the Barents Sea by a number of agreements with Point Resources, DEA, OMV and ConocoPhillips.

"Through these agreements we are strongly increasing our presence in the Hoop area," Averty said. "We are fortifying our position around Johan Castberg, and we see new opportunities in the southwestern part of the Barents Sea."

He also flagged up the company's work in reducing costs by developing new technology and improving drilling efficiency. This has been further aided by the global fall in rig rates.

Dodson said of the planned wells: "These can be tested in a very cost-effective manner. Drilling efficiency has improved dramatically in the last few years at Statoil. In our last exploration campaign in the Barents Sea, we made seven discoveries out of the 12 wells we drilled. But also, more importantly, we saved NOK 1 billion [US$150 million] compared to earlier years due to efficiency gains, and that equates to seven additional exploration wells."

He also rubbished claims that the cost of exploration drilling in the Barents would make any discoveries uneconomic. "It's just not true," he said, giving the US$25 million per-well figure.

Dodson also highlighted Statoil's work in reducing its development breakeven costs, such as on Johan Castberg, where the figure has fallen from about $80 per barrel (bbl) to below $25/bbl.

He also pointed out details such as ice being surprisingly rare in these areas of the Barents, while the wind and waves were comparable to the North Sea norm "where we have operated in a sustainable manner for 50 years."

Norway Dominates

Overall, Statoil will drill about 20 exploration wells in Norway and the U.K. next year, but Norway remains by far the most dominant target area with 17. A total of 11 wells will be drilled in the Norwegian and Barents Seas, with the others in the mature Norwegian North Sea.

Drilling is currently underway near the producing Njord Field. From here, a rig will move to drill the Cape Vulture prospect, which was awarded to Statoil in January. After that a rig will move to drill the Blåmann probe, another that will be drilled within 12 months of being awarded to Statoil.

The other wells planned for 2017 in the Barents are the Kayak and the Gemini North prospects, the latter being near the Wisting discovery.

—Mark Thomas

Statoil Starts Up North Sea's Gullfaks Rimfaksdalen Early

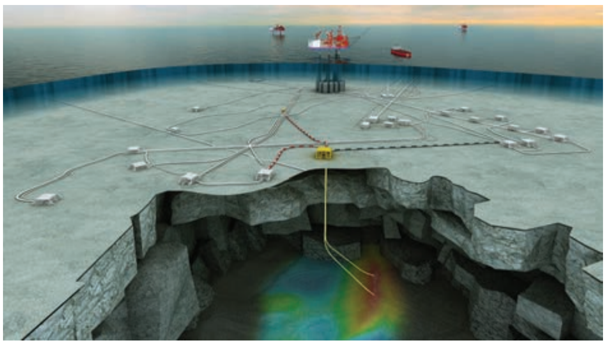
STAVANGER, Norway—Statoil has brought a relatively small two-well subsea tieback project onstream four months earlier than scheduled at half of the development cost originally envisaged.

The Norwegian operator gave itself an early Christmas present by confirming first production from the Gullfaks Rimfaksdalen Field well ahead of its Dec. 24 scheduled startup.

The original development cost for the project was NOK 8.8 billion (US$1 billion), according to Arne Sigve Nyland, executive vice president of development and production for Statoil. After undergoing an intensive cost reduction exercise, this fell to NOK 4.8 billion (US$580 million) by the time the plan for development and operation was submitted.

Since then, the project's development cost has dropped to NOK 3.7 billion (US$445 million).

Nyland admitted that when the project was first mooted, it was at a time of "higher oil prices but also higher costs." He described the oil price downturn as having been "a true wake-up call for the entire industry." For Statoil, the challenging times meant improving the way the company works with its partners and suppliers.



The development consists of a standard subsea template in a water depth of about 135 meters, or 443 ft, with two gas production wells. (Source: Statoil)

However, this project "is a sign of recovery, not of the market, but that the industry is recovering," he added. "We are gradually regaining our competitiveness on the Norwegian Continental Shelf."

Recoverable reserves from Gullfaks Rimfaksdalen are about 80 million barrels of oil equivalent (MMboe), mostly gas. The licensees are Statoil (operator, 51%), Petoro (30%) and OMV (19%).

The development consists of a standard subsea template in a water depth of about 135 meters, or 443 ft, with two gas production wells and the possibility for the tie-in of two more wells.

The wellstream is connected to an existing pipeline leading to the Gullfaks A Platform.

Existing pipelines transport gas and condensate to the processing plant at Kårstø, north of Stavanger, for processing. From there, the gas is exported to markets on the European continent.

Nyland also pointed out that Statoil currently has 30 projects in the non-sanction phase, where the company has reduced the estimated breakeven cost from $70/bbl to currently $41/bbl as it continues its cross-company cost-efficiency drive.

—Mark Thomas

Norway Launches 24th Licensing Round

STAVANGER, Norway—Norwegian Prime Minister Erna Solberg has launched the country's 24th oil licensing round for new exploration areas, mostly off Northern Norway.

Speaking during the Offshore Northern Seas (ONS) conference and exhibition, she said the nominated areas would be confirmed before the summer of 2017, with acreage awards to follow during first-half 2018.

Solberg stressed the importance of maintaining a "steady and predictable" petroleum policy after launching the round, with the oil and gas sector set to remain the country's most important industry for decades to come.

Companies must nominate their proposed blocks by Nov. 30, 2016, with nominated blocks divided into two categories: "interesting" and "very interesting." The total number of blocks that can be nominated is limited to 15.

"A central element of the policy is to offer a high number of awards in prospective exploration acreage," Solberg said. "Starting the 24th licensing round today is a concrete follow-up of this policy."

Norway's Petroleum and Energy Minister Tord Lien added: "Awarding prospective exploration acreage is a central element in order to maintain employment, activity and high value creation. This is particularly important in the present situation with weaker employment figures in the petroleum industry and related industries.

"The results that we got from the 23rd licensing round were really good, in my opinion, when we have seen that shelves elsewhere in the world have really struggled to put forward new acreage," he continued. "We went through with quite a successful round. Now, in a rebalancing market, I have great expectations that the industry will be eager to nominate and later apply for acreage on the Norwegian Continental Shelf."

The ministry is accepting nominations for acreage in the Barents Sea, Norwegian Sea and North Sea. In the Norwegian Sea, laying the foundation for efficient utilization of the existing transport system—in which there will be considerable spare capacity after 2020—is important for future exploration activities, the ministry stressed in a news release.

Norway's strategy for licensing rounds in newly opened and frontier areas, such as the Barents Sea, has mainly adhered to the principle of sequential exploration. This means results of wells in certain blocks in a given area should be available and evaluated before new blocks are announced in the same area. This approach, according to the ministry, ensures that large areas can be mapped with relatively few exploration wells. In this manner, available information is used for further exploration, while drilling of unnecessary, dry wells can be avoided.

The ministry also hopes to put forward a proposition to the Norwegian Parliament before summer 2018 regarding the controversial potential offering of acreage in the pristine Lofoten Islands area in Norway's far north, Lien added.

—Mark Thomas

Statoil Hits $25 Per Barrel Breakeven On Johan Sverdrup

STAVANGER, Norway—Statoil ASA reduced the development cost for the first phase of its giant Johan Sverdrup project offshore Norway by 21% to NOK 99 billion (US$12 billion), while raising the full field development's planned production capacity by unveiling an additional processing platform.

The Norwegian major's CEO, Eldar Sætre, made the most of the international spotlight on Stavanger at the start of the biennial Offshore Northern Seas (ONS) conference and exhibition Aug. 29 to give an update on the four-platform initial project and future phases.

The 21% cut in the forecast capex for the project's first phase represents a reduction of NOK 24 billion (US$2.9 billion) from when the original plan for development and operation (PDO) was submitted with an estimate of NOK 123 billion (US$14.9 billion).

It also means the operator and its partners have achieved a breakeven price of less than $25 per barrel (bbl) for Johan Sverdrup's first phase. Contributing to this has been a focus on areas such as debottlenecking; and optimizing the Phase 1 processing facility, which has raised the production capacity from its original range--between 315 Mbbl/d and 380 Mbbl/d of oil—to 440 Mbbl/d. Other improvements came from higher drilling and well efficiencies and better project planning and execution.

Phase 1 production is scheduled to begin in late 2019.

Although Statoil confirmed the full field development's schedule was delayed by about six months for

Phase 1 production for Johan Sverdrup is scheduled to begin in late 2019. (Source: Statoil)

further improvement work, the company still plans to bring the full development onstream in 2022. The PDO for Phase 1 originally called for project pre-sanction of future phases during 2016 and an investment decision by year-end 2017. According to the updated plan, the project pre-sanction will now be made in first-half 2017, with a final investment decision reached and the PDO submitted in second-half 2018.

With the extra processing facility added to the plan—a move that field partners agreed to, but which is still subject to formal approval at the pre-sanction stage—Johan Sverdrup's eventual full-field production capacity is now put at 660 Mbbl/d. The original range was 550 Mbbl/d to 650 Mbbl/d.

Lower-end recoverable reserve estimates were also firmed up and raised slightly higher to between 1.9 Bboe and 3 Bboe, said Margareth Øvrum, Statoil's executive vice president for technology, projects and frilling.

Improvement was achieved "by challenging every single element," she added, noting Statoil saw full-field investment estimates fall from between NOK 170 billion and NOK 220 billion in 2015 to NOK 140 billion to 170 billion. This equates to between US$16.9 billion and $20.5 billion. This drops the full-development breakeven to less than $30/bbl.

"At the same time we want to stay on schedule for full-field production start and for establishing an area solution for land-based power by 2022, as per conditions stated in the approved PDO for Phase 1," Øvrum said.

"It's a massive project. We're spending NOK 24 billion per year on it. But it is running to plan, and we have completed 31% of the first phase so far," said Øvrum, who pointed out that more than 70% of the Phase 1 contracts went to Norwegian companies.

She also stressed that further reductions may be on the way. "We still see further room for improvement," she said. "There's no time to relax."

Her words echoed an earlier comment from Sætre, who pointed out that the oil price was nearly $100/bbl on the opening day of ONS 2014.

"The low oil prices have exposed us all," Sætre said. "We need a culture where we allow improvement, irrespective of where we are in the commodity cycle."

Overall, the Johan Sverdrup improvements were the results "of good cooperation between Statoil, its partners and suppliers, he added. We are strongly reducing investment costs, and we are increasing the process capacity, resource estimate and value of the field. Johan Sverdrup is a world-class project, and we want to create high value for the owners and society for generations."

The Johan Sverdrup project's partners are Statoil (operator, 40.0267%); Lundin Norway (22.6%); Petoro (17.36%); Det norske oljeselskap (11.5733%); and Maersk Oil (8.44%).

—Mark Thomas

Statoil, Petrobras Strengthen Brazilian Partnership

Petrobras and Statoil have signed a memorandum of understanding that aims to evaluate their joint participation in future tenders and upstream collaboration in producing fields in the Campos and Santos basins.

The two companies are already partners in 13 exploration or production blocks, mostly in Brazil.

The agreement, signed during ONS 2016, also sets out a potential framework for cooperation on value creating opportunities in the gas value chain, Statoil said in a news release. With technology and simplified operations, the two aim to capture value.

"Statoil has very high levels of oil recovery in their producing fields, for example, and we will have access to this experience and know-how through a partner, with obvious benefits for both sides," Petrobras CEO Pedro Parente said.

The agreement is for two years, and joint activities undertaken will depend on negotiations following the signing of the document, Statoil said.

—Staff Reports

TechInvent, Island Offshore/Centria Take ONS Innovations Honors

A jury of industry experts, R&D professionals and top executives selected TechInvent and Island Offshore/Centrica for ONS 2016 Innovation Awards.

TechInvent's FluidCom technology was deemed the winner of the SME Innovation Award, which is given to small- and medium-sized companies. The FluidCom chemical injection valve and metering controller is a fully automated, simple and reliable device with integrated autonomous valve control, continuous flow metering and self-cleaning functionality, a news release said.

Island Offshore and Centrica were selected winners of the Innovation Award, which is given to large companies, for the riser-less coiled tubing (CT) drilling system. Island Offshore successfully drilled four wells with the system, marking the first time riser-less CT operations have been performed, the release said. Centrica E&P Norway used the same system to check for shallow gas in the seabed above its Butch Field in the Norwegian Continental Shelf.

—Staff Reports

PROJECTS

Shah Deniz Project Takes Shape

FINANCING (IN USD MILLION)	
The two borrowers together	$780
World Bank/International Bank for Reconstruction and Development	$1,000
European Commission/European Investment Bank	$1,120
Export Credit agencies of national governments	$5,700
Foreign private commercial sources	$1,200
Total Project Cost	*$9,800*

After meeting in August, Turkish President Recep Tayyip Erdogan and Russian President Vladimir Putin hope to remove some barriers preventing the development of a number of joint projects, especially the planned Turkish Stream gas pipeline under the Black Sea.

Yet, while Ankara and Moscow might soon return to pipeline negotiations, the situation of supplying gas to Europe has changed since November 2015. Moscow's made substantial progress on pushing an alternative option—an expansion of the Nord Stream Pipeline. All of this is background for strategic gas drama unfolding in the Caspian.

Money, equipment and global competitors are still moving in Azerbaijan's direction, in large part due to the current state of play with Stage II development of the Shah Deniz gas field.

The field, located in the Caspian Sea, is being developed by BP, the State Oil Company of the Azerbaijan Republic (SOCAR), Lukoil and others to produce 16 Bcm per annum (565 Bcf), all for export markets.

Turkey is the host country of the Trans-Anatolian Natural Gas Pipeline (TANAP), which runs from Azerbaijan through Georgia, Turkey, Greece and Albania to Italy. The project is the first realization of the Southern Gas Corridor (SGC). The term Southern Gas Corridor, sometimes called the Southern Corridor, is used to describe infrastructure projects aimed at improving the security and diversity of the EU's energy supply by bringing natural gas from the Caspian region to Europe.

How big and expensive will all of this become? Consider the World Bank's effort to integrate different pieces of the puzzle: Their entire project will include four elements: Shah Deniz 2 Field; South Caucasus Pipeline Extension; TANAP; and Trans Adriatic Pipeline (TAP). The loan package's two borrowers will be BOTAŞ and the Southern Gas Corridor Corp.

Shah Deniz is a HP/HT offshore gas field located 70 km (43 miles) southeast of Baku, under 50 m to 500 m (164 ft to 1,640 ft) of water. It has a reservoir thickness of more than 1,000 m (3,281 ft) and is 22 km long (14 miles long).

The gas field contains nine vertically stacked reservoir units, which are targeted for depletion in two stages. The estimate for initial gas in place for the field is 938 Bcm. Stage I of the gas field has been operational since December 2006.

Shah Deniz is massive, and the project will require constructing two new bridge-linked offshore production platforms, 26 subsea wells drilled with two semisubmersible rigs, 500 km (311 miles) of subsea pipelines, and expansion of the onshore gas processing terminal at Sangachal.

Gas extracted from the field's Stage II development will be delivered from Azerbaijan to Europe via the separate SGC. SGC consists of three sections: the South Caucasus Pipeline from the Caspian Sea to the Georgia-Turkey border; the TANAP from the Georgia-Turkey border to the Turkey-Greece border; and the TAP from the Turkey-Greece border to Italy.

An advisory council on the SGC held its first meeting in February 2015 in Baku, Azerbaijan's capital city. Setting up an advisory council is a joint initiative of the European Commission and Azerbaijan. The council's aim is to steer implementation of the project at political levels to have the SGC operational by 2019-2020.

The council issued a joint statement expressing strong support for the implementation of the SGC. The statement was signed by representatives of Azerbaijan, Albania, Bulgaria, Georgia, Greece, Italy, Turkey, the U.K. and the U.S. as well as the European Commission.

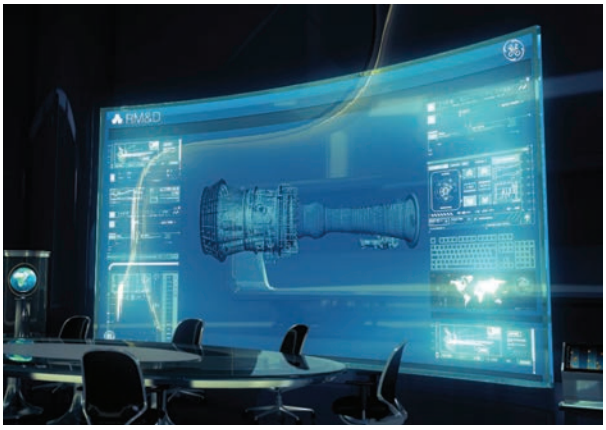
BOTAŞ Petroleum Pipeline Co., Turkey's state-owned crude oil and natural gas pipeline and trading company, contracted 6 Bcm (211 Bcf) for the Turkish market. Several gas traders have contracted the remaining 10 Bcm (353 Bcf) for the European market, mostly Italy.

With 1,820 km (1,131 miles) of pipe, TANAP accounts for more than half of the 3,500-km (3,175-mile) pipeline system. TANAP will start from the Turkish border with Georgia, beginning in the Turkish village of Türkgözü in the Posof district of Ardahan. It will run through 20 provinces and end at the Greek border in the İpsala district of Edirne. From this point, TAP will connect to convey natural gas to European gas markets.

—Gordon Feller

FLOATER

GE Locks In 25-year FPSO Deal With MODEC



GE Oil & Gas will be maintaining gas turbines like this digital model as part of its deal with MODEC. (Source: GE Oil & Gas)

A newly signed agreement between GE Oil & Gas and Tokyo-based MODEC covers maintenance and data analytics on six FPSOs as well as maintenance for 22 gas turbines over a 25-year period.

The deal is one of GE's largest service arrangements on FPSOs and vaults MODEC's Brazilian fleet into a global leadership position for technological capability. The vessels are owned by consortiums of MODEC and its partners, with MODEC providing operational and maintenance services.

GE Oil & Gas operates in Petrópolis, a city in southeast Brazil, north of Rio de Janeiro, which will enable onshore repair work and reduce turnaround time when necessary.

The service agreement includes data analytics for advanced monitoring and diagnostics, which can help the FPSOs achieve better equipment availability and operational efficiency.

The deal follows a growing trend in the FPSO segment toward long-term contractual service agreements for FPSOs and away from the single-event approach. Including onboard digital solutions in the contract will allow MODEC to maximize operational efficiency and production output and reduce offshore staffing.

"This agreement reinforces GE's proven leadership in turbomachinery solutions and how uniquely positioned we are to integrate digital capabilities to optimize industrial assets and increase operational efficiency," said Rogerio Mendonça, president and CEO of GE Oil & Gas in Latin America, in a statement. "It also highlights our capacity for partnering locally, thanks to our robust footprint in Brazil which allow us to have the necessary capabilities, investment and talent in place."

The growing FPSO market is expected to reach $43.39 billion by 2021, according to Transparency Market International.

—Joseph Markman

FLOATER BRIEFS

Shell Selects Emerson For Prelude FLNG Work

Shell Australia has chosen Emerson to provide automation maintenance and reliability services for the Prelude floating LNG (FLNG) facility, Emerson said in a news release.

Emerson and its partner, Western Process Controls, will provide equipment monitoring, diagnostic services, spares support and maintenance for the facility's control and safety systems as well as thousands of instruments and valves, the company said. Two Emerson engineers onboard Prelude will work with other team members who remotely monitor the facility's automation from Shell's operations center in Perth.

Currently, Prelude FLNG is under construction in South Korea. Once complete, it will move to Australia to begin operations.

The facility is expected to remain on station at least 25 years as Shell and its partners develop gas reserves in the Browse Basin's Prelude and Concerto fields. Prelude will process natural gas from subsea wells offshore Western Australia.

GustoMSC Introduces OCEAN-HE Series Semisubmersibles

GustoMSC has released a new series of drilling semisubmersibles designed for harsh environments.

(Source: GustoMSC)

Called the OCEAN-HE, the hull shape of the new semisubmersibles has been designed for low motion characteristics and optimum station keeping capabilities, the company said in a news release. The series includes the OCEAN850-HE and OCEAN1600-HE, the company's largest to date.

Aimed for use in deep water, the OCEAN1600-HE features a maximum displacement of about 70,000 tons, a large derrick, DP3 and a 16-point mooring system for station keeping, combined with a large deck area and large variable deck load.

The OCEAN850-HE is designed for midwater harsh environments, the company said. The semisubmersible has a displacement of about 50,000 tons with a water depth rating of 1,000 m (3,281 ft) and a sixth generation single derrick combined with horizontal riser storage.

Global Maritime Completes Njord A Disconnection

After a 641-km (346 nautical-mile) journey, Global Maritime Consultancy & Engineering said it has successfully led the disconnection and towing operations of the Njord A semisubmersible floating production platform from the Njord Field in the North Sea for Statoil.

The Njord A platform disconnection and towing operations are complete. (Source: Global Maritime)

The Njord A platform was handed over to Kværner after arriving safely in Klosterfjorden on Aug. 23.

"With a project of such complexity and with the subsea infrastructure still intact, it was crucial that mooring disconnection activities and the towing of the platform took place with maximum precision and care," David Sutton, CEO of Global Maritime Consultancy & Engineering, said in a news release. "This is what Global Maritime achieved with the platform being disconnected from its moorings, departing the field and arriving in Stord ahead of schedule. We look forward to working with Statoil on future similar projects."

The accomplishment followed Global Maritime's successful towing of the Njord B oil storage and offloading vessel Njord B to Sterkoder, Kristiansund earlier this summer.

Wärtsilä Will Supply Regasification System For Höegh FSRU Conversion

Wärtsilä's water glycol-based regasification system has been chosen for Höegh LNG's conversion project on a floating, storage, regasification unit (FSRU) vessel. The choice of water glycol provides a solution that is about

Wärtsilä will supply the regasification system for an FSRU conversion project that Höegh LNG plans to carry out on a modern LNG vessel. (Source: Wärtsilä)

15% smaller and lighter than a propane-based system. Wärtsilä will deliver the water glycol regasification module, water glycol/seawater heaters and pumps. Delivery is scheduled for late 2017. Höegh LNG already has relied on Wärtsilä for eight regasification systems.

—*Staff Reports*

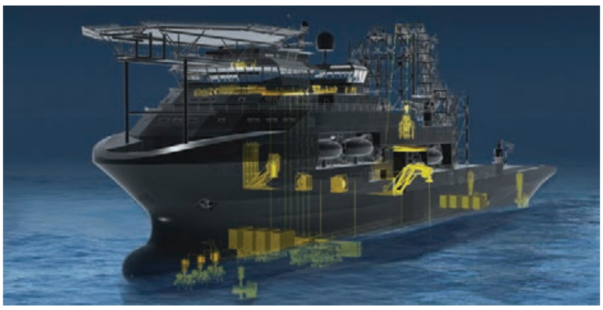
VESSELS

Kongsberg's 'Integrated' Promises Improved Onboard Power Efficiency

Norway-based Kongsberg Maritime's "Integrated Vessel Concepts" puts it all together for shipowners grappling with power management for disparate handling, operations and energy systems.

The new portfolio leverages existing and new Kongsberg technology to achieve improved operational efficiency in a variety of vessels, including containers, forage carriers, FPSO units, inspection maintenance and repair, research, ro-pax, shuttle tanker, small-scale LNG, superyacht, trawler and wind farm support.

Kongsberg is further developing its product line for the global shipbuilding industry with a focus on electrical systems, including switchboards and drives. Those systems will be fully integrated with onboard technology, ensuring optimal power consumption for dynamic



Kongsberg Maritime has developed Integrated Vessel Concepts for a wide range of vessel types, including this IMR vessel. (Source: Kongsberg Maritime)

vessel operations. The integration will allow enhanced data sharing onboard and ashore, which will improve the decision-making process across the operational chain.

The integration ties vessel dynamics into the power management layer. This distributes control functions closer to consumers with fast-acting sensors to bolster efficiency. "A primary driver for the development of our integration strategy and Integrated Vessel Concepts is conservation and predictable utilization of energy, resulting in lower fuel consumption and the associated environmental benefits," said Srinivas Tati, vice president, business development, in a statement. "However, we also want to create 'free' energy for hybrid or even fully electric power configurations, which are now becoming more viable due to less expensive batteries and more sophisticated power management."

"Our approach to integration goes much deeper, though," he said. "We have studied in-depth how different vessels operate to understand how the unification of on board technologies can change how we think about and conduct maritime operations at every level."

Deep Investment Cuts Slow Rebound For Offshore Oil Services

French oil services company Bourbon said on Sept. 8 that any rebound in oil and gas prices will take a while to reach companies in the offshore marine sector because of deep cuts in investments during the prolonged oil downturn.

Bourbon, whose fleet of about 513 vessels provides offshore services for oil and gas companies, said its net loss in first-half 2016 widened to 104.3 million euros (US$117 million) compared with a net loss of 19.2 million in first-half 2015.

Adjusted revenues fell 21% to 599.2 million compared with first-half 2015, the company said.

"After the drastic reduction of the level of investments of oil and gas companies over the past couple years, oil producers are now thinking of the future, particularly to maintain their level of production in the medium term," the company said.

"However, the inevitable rebound in activity will take some time to reach offshore marine services," it said in a statement, adding that deepwater and shallow-water segments of the industry will continue to be affected by overcapacity of vessels.

Bourbon said a rebalanced demand and supply outlook for the oil market in 2017 will have a positive effect on the company.

—Staff & Reuters Reports

EXPLORATION

Cairn India Pushes Revival Plan For Ravva

Cairn India Ltd. is looking to launch a 26-well exploration and development program in the aging Ravva oil and gas field in PKGM-1 block, off the Bay of Bengal.

"The exploration and development is aimed to maximize production of hydrocarbons from the Ravva Field and optimally utilize the existing infrastructure and facilities," a Cairn India official said.

The upstream company is awaiting coastal regulation zone (CRZ) clearance from India's federal environment ministry to launch the development program.

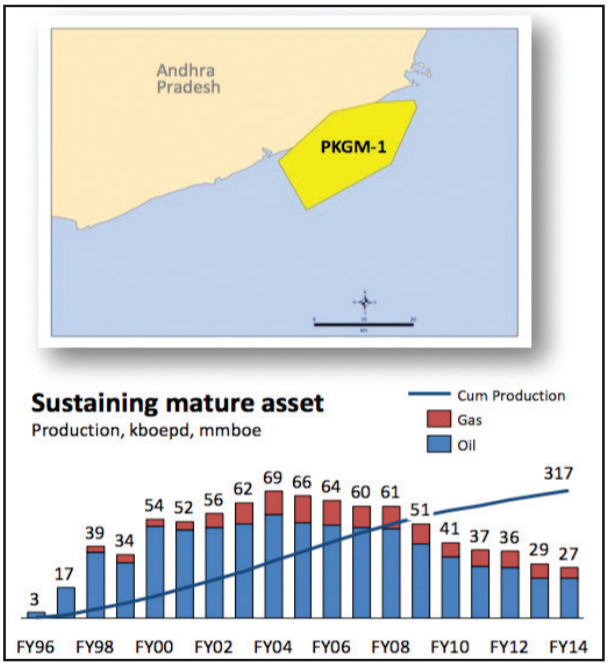
The development plan involves:

- Installing one new unmanned platform;
- Drilling 20 development wells, including six from the new platform and 14 from the existing platforms;
- Drilling six exploratory/appraisal wells to assess the presence of hydrocarbons in identified pockets; and
- Laying three new interconnecting pipelines totaling 14 km in length in the offshore region, connecting the proposed new platform with the existing two platforms.

The operator proposes to drill 20 developmental (production) wells—six from the new platform and 14 from the existing platforms—to tap identified resource pools in the Ravva Field. The development wells will be drilled from the platform using a mat supported jack-up drilling rig.

The target depth of the development wells will range from 1,600 m to 3,500 m.

Plans are for the proposed six exploration/appraisal wells to be drilled within the field to assess hydrocarbons in the identified prospects and further assess the production potential through testing. The target depths of the wells will range from 2,000 m to 4,500 m.



(Source: Cairn India)

After analyzing 3-D seismic data, the operator has identified nine high-ranked prospects near the field's currently producing areas.

The new unmanned offshore platform, called RI, will consist of multiple decks with minimum facilities including well head slots, test separator, well head control panel, drain collecting system, helipad, and boat-landing deck.

The new interconnecting pipelines offshore will run from the new RI platform to the existing RB and RG platforms. The pipelines include an 8-in. subsea oil pipeline that stretches 4 km from the new platform to existing RB Platform for oil production; a 4-in. subsea gas lift pipeline of 4 km in length from the new platform to existing offshore RB platform; and an 8-in. subsea gas pipeline of 6 km in length going from the new platform to existing offshore RG platform.

Well fluids from the proposed wells will be routed to the onshore terminal at Surasaniyanam on the Andhra coast through subsea infield pipelines interconnecting platforms.

The Surasaniyanam onshore processing facility has the capacity to produce 70,000 bbl/d of oil and 95 MMscf/d of gas.

The new development plan aims to curtail the decline in oil and gas production from field, which currently produces about 19,000 bbl/d of oil and 15 MMscf/d of gas. The figures are down from its plateau production of about 50,000 bbl/d in 1999. The field produced at the plateau rate for nine years before starting to decline by the end of 2007.

Cairn India in 2015 launched a well stimulation program with coil-tubing based rig-less well intervention, deeper gas lift valve installation and de-bottlenecking of the water separation unit to reverse falling oil and gas production from the existing wells; however, the results of this effort are yet to be seen.

The company reported production of 20,845 bbl/d of oil and 18 MMscf/d of gas in the fiscal 2015-16 (ending March 31, 2016), down from 22,565 bbl/d and 21 MMscf/d in the previous fiscal, from 16 wells spread around eight unmanned platforms in the Ravva field. Six platforms (RA, RB, RC, RD, RE and RF) are meant for oil production and remaining two (RG and RH) for gas.

So far, the operator has drilled 48 wells in the field. Eight of these are self-flow producing, eight are gas lift wells, and seven are injectors.

Operator Cairn India holds 22.5% participating interest in the block, while ONGC Ltd,Videocon Industries Ltd., and Ravva Oil (Singapore) Pte. Ltd. hold 40%, 25% and 12.5%, respectively.

—Ravi Prasad

EXPLORATION BRIEFS

Fifth Zohr Appraisal Well Confirms Resource Potential

Eni has proved the presence of a gas accumulation in the southwest part of the Zohr structure after drilling its fifth well, the company said Sept. 1 in a news release.

Drilled to a total depth of 144,350 meters (m), the Zohr 5x well encountered a continuous hydrocarbon column of about 180 m. The results confirm Zohr's potential of 30 Tcf original gas in place.

Located 12 km southwest of the Zohr 1x discovery well and in a water depth of 1,538 m, the well also successfully tested opening 90 m of reservoir section to production, Eni said.

"The data collected during the test confirmed the great deliverability of the Zohr reservoir, in line with the Zohr 2 well test, producing more than 50 mmscfd limited only by the constraints of the drilling ship production facilities," Eni said. "In the production configuration, the well is estimated to deliver up to 250 MMscf per day."

The company plans to drill a sixth well later this year as it works toward first gas by year-end 2017. Eni is targeting a startup production rate of 1 Bcf/d.

Eni, through its subsidiary IEOC Production B.V., holds a 100% stake in the Shorouk Block, where Zohr is located.

The Saipem 10000 drillship drilled the Zohr discovery well for Eni offshore Egypt last year, hitting 600 m (1,986.5 ft) of gas pay. (Source: Eni)

Shell Makes Natural Gas Discoveries In Egypt

Royal Dutch Shell announced on Aug. 31 new natural gas discoveries in a concession area of north Alam El-Shawish in Egypt's western desert.

The initial quantities discovered were estimated at about half a trillion cubic feet of gas with more possible reserves, Shell CEO Eden Murphy said in a statement.

The discovery could produce from 10 to 15% of the total production of Badr el-Din Petroleum company, which is a joint venture acting on behalf of the state-owned Egyptian General Petroleum Corp. and Shell in production operations, Murphy added.

Shell owns the license of the entire area, which includes the well. Badr el-Din is expected to manage the operations.

Schlumberger, ION Announce Campeche 3-D Reimaging Program

Schlumberger WesternGeco and ION Geophysical Corp. said Sept. 7 that the Campeche 3-D reimaging program, a new 3-D multiclient reimaging broadband program offshore southern Mexico, comprises three survey areas in the Bay of Campeche.

The program will be processed using a combination of custom technologies and techniques from both organizations that will maximize data quality and offer geological insights for upcoming licensing rounds.

The program is fully supported by industry funding. Fast-track data are available now for Round 1.4 deepwater bid preparation decisions.

The program uses Mexico's National Hydrocarbons Commission (CNH) data library.

The complexity and variability of the geological areas being surveyed require a set of consistent, advanced workflows to maximize bandwidth, while producing data with strong low frequency content for subsalt areas and high-resolution data for non-salt areas of the basin.

CGG Forms JV For Seismic Services Offshore Ghana

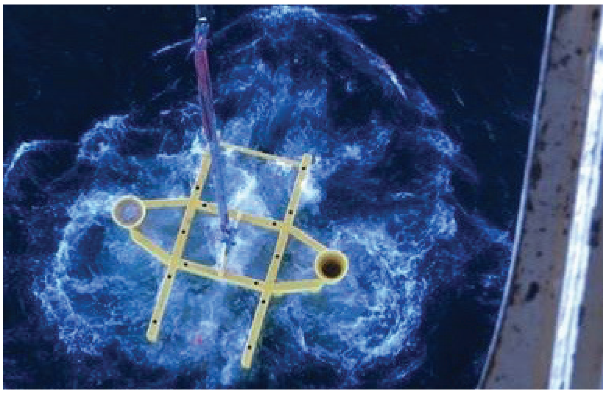
France-based geoscience company CGG signed an agreement with Ghana's GNPC Operating Services Co. Ltd. to form a joint venture (JV) company that will conduct high-end 2-D, 3-D and 4-D marine seismic acquisition and related services in the territorial waters of the Republic of Ghana.

The JV company, known as GOSCO Geoscience Ltd., will provide world-class seismic vessels and state-of-the-art marine seismic acquisition technologies and services to oil and gas companies operating in Ghana.

GOSCO Geoscience will be based in Accra, Ghana, according to a press release from Aug. 30.

—Staff & Reuters Reports

TECHNOLOGY



(Source: Pipetech)

GE Puts Compression, Power Technology To Work For Ormen Lange

In a move that advances subsea oil and gas production, A/S Norske Shell has successfully completed system testing of the world's first subsea gas compression system with a full subsea power supply, transmission and distribution system, project partner GE Oil & Gas said in a news release.

The accomplishments comes after Shell and partners Petoro, Statoil, Dong and ExxonMobil embarked upon a multiyear test program of Shell's Ormen Lange Pilot. The companies, working in collaboration with GE, started the project in 2011 at Shell's Nyhamma test facility in Norway, where gas from the Ormean Lange Field comes ashore, the release said.

The project was designed to test a full-scale submerged integrated subsea compression system using hydrocarbons. Crucial to the development were several GE-provided technologies, which were tested as part of the pilot. The technologies, as highlighted by GE, included a 12.5 MW vertical Blue-C centrifugal compressor and subsea power supply, transmission and distribution system, which eliminated the need to generate more power on nearby offshore facilities.

The compressor was driven by an electrical package, provided by GE's Power Conversion business, that featured a high-speed motor and high-power drive, GE said, noting this enabled operations to reliably take place hundreds of meters below sea level.

Other technologies tested included IFOKUS Electric Actuators, anti-surge actuators developed for 80kN fail open operation, and the NAXYS Acoustic Leak Detection System, which is used during the submerged pit testing to monitor for potential gas leakages as well as operation of rotating machinery and power modules, GE said.

Pipetech Unveils Chemicals-Free Subsea Cleaning System

Specialist cleaning company Pipetech has launched a cleaning system for subsea infrastructure that uses only water.

Called the Deep Water Cleaning System, Pipetech said it devised the solution for a major operator in the North Sea less than six months ago. As explained by Pipetech, equipment for the system is sunk through the rig's moon pool down to the subsea infrastructure, where it is placed over the wellhead. With the help of an ROV, the water supply is connected and the unit is secured to the manifold with a pipe end connection tool before cleaning begins.

"It carries away everything in its way—deposits of calcium, polycarbonates, copper, sulphur, coal, asphalt—removing even rock hard concrete deposits," Arve Martinsen, director of operations for Pipetech in Norway, said in a statement. "We are able to reduce downtime and return the pipeline to its original state. We are literally reclaiming metal."

A rotating hose drum that feeds the hose and nozzles into the pipe gates allows the line to be kept taut.

Avre added: "A significant point is that the nozzles handle all kinds of bends with ease, and may be navigated in many directions, even through the sharpest of pipe bends."

Pipetech said the system is also effective when it comes problems such as stuck cleaning pigs. "Instead of intrusive and prolonged repairs, involving the cutting of pipes or hoisting devices to have pigs recovered, Pipetech just flushes them away," the company said.

Lindsay Young, managing director for Pipetech, called the system an "innovative and time-saving technology" that could change the way the industry works.

—Staff Reports

POLICY

Goliat Platform Concerns Prompt Offshore Safety Rules Review

Norway will review whether to tighten offshore safety rules after "repeated failures" at Eni's Arctic Goliat Platform, including a power outage during the week of Aug. 22, a minister said.

Norway's only oil-producing platform in the Barents Sea has been shut since Aug. 26 when a power supply loss triggered a partial evacuation, the second such incident since the platform, which has capacity for 100,000 barrels per day (Mbbl/d) of oil, started up in March.

"We have received disturbing information about repeated failures on Goliat," Minister of Labor and Social Affairs Anniken Hauglie told Reuters in an email before meeting with Norway's Petroleum Safety Authority (PSA), which supervises offshore installations and reports to the ministry, to discuss the issue.

The PSA asked Eni to present a plan in writing by Sept. 5 on how to avoid new incidents on the Goliat Platform. Andreas Wulff, the spokesman for Eni in Norway, said the company had submitted preliminary findings to the PSA on Sept. 5, but that further investigations were ongoing.

Production at energy firm Eni's Arctic Goliat oilfield will remain shut at least until Sept. 9. Output from the field has been shut since Aug. 26 when the Goliat rig was hit by a power failure.

"It's been a long and winding road for Eni and Goliat. The number of incidents is worrying, and we see that we need to follow it more closely," Eileen O'Connell Brundtland, a spokeswoman for the PSA, told Reuters.

Apart from power cuts, there have been several gas leaks, and one person was injured during unloading operations in June.

In January, the PSA asked Statoil, a license partner in Goliat with a 35% stake, to confirm in writing that Eni, the operator and 65% stakeholder, was prepared to start production at Goliat.

O'Connell Brundtland said she could not recall that the PSA had ever before asked a license partner to verify the operator's steps in the same way. She said that did not signal a lack of trust.

"We have granted Eni consent to operate the Goliat, and we haven't withdrawn this consent. This is an indication of our trust," she added.

Norwegian oil unions, which have members working at Goliat, complained to the PSA in June about what they called a lack of safety, and communication problems with the management.

After the latest incident, some workers told one of the unions, SAFE, that they were afraid to go back to work, Owe Ingemann Waltherzoee, the secretary of the union, said.

Waltherzoee said union members have previously complained about safety at other installations, some operated by Statoil; but the number of incidents made Goliat "a special case."

O'Connell Brundtland said the offshore safety rules applied to everyone equally, but the PSA had "a magnifying glass" on Goliat because of the previous problems, including during the installation. During this time, she said, "serious breaches of electrical system were found.

"In Norway, we have had a trust-based system between government and companies and it has worked well," Hauglie said. "Developments in the industry with several companies, several small companies, foreign ownership and cost pressures can put this system under pressure," she added.

Mexico Sets Minimum Royalty Value For Deepwater GoM Auction

Mexico's Finance Ministry announced on Sept. 6 the minimum value of additional royalties for companies participating in a deepwater oil tender, one of the most highly anticipated auctions since the opening of the local oil industry.

The ministry set the minimum value of additional royalties at 3.1% for contractual blocks one through four, and at 1.9% for blocks five through 10.

Ten license agreements for the exploration and extraction of hydrocarbons in the oil-rich areas of Cinturon Plegado de Perdido and the Salina Basin will be offered in the so-called Round 1.4 tender in December.

—Reuters

BUSINESS

Report: Offshore Norway Investment May Fall By $50 Billion

Lower commodity prices have resulted in the delay or scrapping of 10 Norwegian offshore projects as companies seek cost reductions, forcing Wood Mackenzie to shave $50 billion off its 2016-2020 investment forecast for Norway.

Sinking profits brought on by the world's supply-and-demand imbalance—the result of a global abundance of hydrocarbons—have pushed oil and gas companies to optimize their operations by seeking out drilling

and operational efficiencies and other avenues. The pursuit of lower costs is expected to continue.

"We can't change the oil price, but we can look to bring costs in line with it," Malcolm Dickson, principal analyst for upstream oil and gas for Wood Mackenzie, said Aug. 29 in a statement. "The most prevalent type of optimization has been simplification of projects, such as moving to lower-cost drilling techniques, scaling down vessel specs and moving from large platforms to subsea."

Statoil, for example, said it slashed development costs for the Johan Sverdrup project offshore Norway by 21% to $12 billion. The lower costs were attributed to "higher drilling and well efficiencies and high-quality project planning and execution."

A Statoil Arctic project, the Johan Castberg oil field development in the Barents Sea, has also seen its costs cut by half to about $5 billion or $6 billion. Plans for the project include use of an FPSO vessel, eliminating the possible need for a pipeline to a new standalone oil terminal. Developers had previously considered a production semisubmersible.

The projects, however, are among those awaiting a final investment decision (FID). A decision for Johan Sverdrup is expected in second-half 2018, while word on Johan Castberg could arrive in 2017.

Offshore companies are also working to cut expenses in other ways.

"Companies are seeking lower-cost solutions, be that from cheaper market rates or different development options," Dickson said. They are also seeking standardization, collaboration and improved technology.

Wood Mackenzie pointed out new technology approaches such as Åsgard's subsea compression. Statoil and its partners put the world's first subsea compression facility online in 2015 in the Norwegian Sea. The compression was part of an effort to maintain pressure needed to continue high production from the Mikkel and Midgard fields. Subsea compression added about 306 million barrels of oil equivalent (MMboe) to the total output over Åsgard's field life.

"While costs have come down, there's a lot further to go," Dickson said of offshore oil and gas projects.

Among the areas with the most cost deflation so far this yearbased on Wood Mackenzie's research, are subsea equipment, drilling and seismic. The biggest cost reductions are forecast in the areas of seismic and drilling, "where a vessel oversupply has meant expectations of a 20% drop this year."

Wood Mackenzie estimates there are about 3 Bbbl worth of pre-FID projects awaiting sanction. The timing of these decisions will play a crucial role in the developments' costs.

The firm believes the market will bottom out in 2017.

However, "mid-2017 is the bottom if you believe in oil price recovery, as we do. That means that cost inflation will begin to creep into fields from 2018 onwards. FID in the next year or so would make sense to capture lower costs," said Dickson. "However, cost optimization can trump everything. Too many of those projects have breakevens in excess of US$50 a barrel—and simplification, standardization and optimization,--not cyclical benefits--are the keys to new investment."

—Velda Addison

GoM Deal Pushes Shell Toward $30 Billion Sales Goal

Royal Dutch Shell Plc continues to chip away at a massive divestment goal with the sale of Gulf of Mexico (GoM) assets to an affiliate of Houston's EnVen Energy Corp. for $425 million.

On Aug. 29, Shell Offshore Inc., an affiliate of the Netherlands-based company, said it entered an agreement to sell its Brutus/Glider assets to EnVen, a private upstream E&P with GoM operations.

The sale includes 100% of Shell's record title interests in Green Canyon blocks 114, 158, 202 and 248, which has combined production of about 25,000 barrels of oil equivalent per day (boe/d). Tudor, Pickering, Holt & Co. (TPH) estimates the transaction equates to $17,000 per boe/d.

"It is a relatively low price but likely due to a low reserve life," TPH said in an Aug. 30 report. Assuming a five-year reserve life, the transaction implies about $9 per boe, the firm said.

Shell, which made one of the largest oil and gas mergers of the last decade with the February acquisition of BG Group, intends to divest $30 billion of its portfolio by 2018. The company's merger with BG was worth about $70 billion, mostly in stock.

The company's divestment plans include between $6 billion to $8 billion of asset sales by year-end. So far, TPH estimates it has agreed to sell close to $4 billion of its assets.

Up to 10% of Shell's oil and gas production is earmarked for sale, including exiting several countries, midstream assets and downstream positions.

Simon Henry, Shell's CFO, emphasizes the asset sales will be driven by value, not time.

"As we've said before, we're not planning for asset sales at giveaway prices," Henry said during the company's second-quarter earnings call on July 28. "There's no reason today to think that the $30 billion figure won't be achieved."

The Brutus/Glider asset sale consists of the Brutus tension leg platform (TLP), the Glider subsea production system and the oil and gas lateral pipelines used for TLP production. The sale is expected to close in October.

Shell is also looking to sell its overriding royalty interests in 17 leases in the U.S. GoM with an estimated 10-year revenue stream of $450 million. The assets are up for sale through EnergyNet, with sealed bids due Sept. 22.

In addition, the company is said to be in the process of selling a large portfolio of fields in the U.K. North Sea, according to a Reuters report on Aug. 30.

—Emily Moser

Shell's 2016-18 Divestment Targets

Asset/Location	Status	Value ($MM)
Midstream MLP	*Completed*	$800
Denmark marketing	*Completed*	$300
Maui pipeline/New Zealand	*Completed*	$200
MGL IPO/India	*Completed*	$100
Others	*Completed*	$100
Total completed:		**$1,500**
Showa Shell/Japan	*Announced*	~$1,400
Malaysia refining	*Announced*	~$200
Anasuria cluster/North Sea	*Announced*	
Maclure/North Sea	*Announced*	
Total announced:		**~$1,600**
TOTAL:		***~$3,100***
Motiva JV/Gulf Coast	*In progress*	N/A
New Zealand upstream review	*In progress*	N/A
Thailand review	*In progress*	N/A
Selective North Sea review	*In progress*	N/A

Source: Royal Dutch Shell Plc; As of July 28

Woodside Buys Stake in Australian Gas Fields

Woodside Petroleum Ltd. has agreed Sept. 5 to buy half of BHP Billiton Ltd.'s stake in the Scarborough area gas fields off Western Australia for $400 million, in a move that could help speed a decision to develop the long delayed project.

The sale fits with BHP's effort to shift its petroleum focus to the U.S. and more on oil, while boosting Woodside's resources without any exploration spending at a time when weak oil and gas prices have dented earnings.

Scarborough has been stuck on the drawing board since its discovery in 1979. BHP and operator ExxonMobil Corp., whose lease was extended last year to 2020, have been looking at a $10 billion floating LNG (FLNG) project.

The remote fields are seen as one of the best options for supplying gas to the North West Shelf LNG plant, Australia's oldest and biggest, when its existing fields start to run out of gas in the next decade.

The deal helps align the interests of the Scarborough project and North West Shelf LNG, with Woodside and BHP stakeholders in both.

Woodside will pay BHP $250 million up front for a 25% stake in the Scarborough Field and 50% stakes in neighboring fields, which Woodside will operate, plus $150 million when a final investment decision is made to develop the fields.

BHP and Woodside declined to comment on whether Woodside had sought to buy BHP's entire stake. Woodside said it supports the Scarborough partners' studies on a FLNG project.

"If the Scarborough JV elects to look at other development options, including an onshore tie-back via Woodside operated infrastructure, then Woodside would offer its support in understanding these opportunities," CEO Peter Coleman said in an emailed statement.

A final investment decision would have to be made by 2019 in order for Scarborough to meet North West Shelf LNG's gas needs around 2025, he said.

—Reuters

BUSINESS BRIEFS

Aker Solutions Reveals New Leadership Team

Starting Nov. 1, a new executive management team will be in place for Aker Solutions. The change comes as the company reorganizes with goals of strengthening operational and financial performance and better meeting customer needs.

The company will have five delivery centers: customer management, front end, products, projects and services as it works to boost cost-efficiency by at least 30% by year-end 2017, according to a news release.

Dean Watson, who joins Aker Solutions from Schlumberger, has been named COO.

Other executive management team members were selected internally, Aker said. As detailed in a news release, Valborg Lundegaard, currently head of engineering, will lead the customer management center. Svenn Ivar Fure will continue to lead the company's front end efforts. Egil Boyum, head of the subsea business in Europe and Africa, will lead the products center. Knut Sandvik will move from being head of maintenance, modifications and operations to lead the projects center.

David Clark, currently regional head for Europe and Africa, will lead the services center.

Svein Stoknes will remain CFO, and Mark Riding will continue as head of strategy.

Current Head of Subsea Alan Brunnen and Head of Operational Improvement and Risk Management Tore Sjursen will remain at Aker Solutions through the end of the year.

Åsgard Licensees Win NPD's IOR Prize

The world's first subsea wet gas compressor has earned the licensees of the Åsgard Field in the Norwegian Sea the Norwegian Petroleum Directorate (NPD) improved oil recovery (IOR) prize for 2016.

Standing in 300 m of water, gas is recovered from reservoirs 2,500 m beneath the seabed. The compressor, which began operating in October 2015, will help to yield nearly 50 million standard cubic meters in additional gas and condensate from the Midgard and Mikkel reservoirs, the NPD said in a news release.

The licensees are Statoil, operator with 34.57%; Petoro, 35.69%; Eni, 14.82%; Total, 7.68%; and ExxonMobil, 7.24%.

"The Åsgard subsea compression technology not only represents an important contribution for improving recovery from that field, but also provides opportunities to recover more oil and gas from other reservoirs on the NCS," NPD said. "Subsea processing—and gas compression in particular—could make it easier to develop discoveries in deep water and in areas far from existing infrastructure."

New Subsea Inspection Company Receives First UK Contract

Rovco, a new subsea company based in the U.K., officially launched Sept. 5 with its first U.K. contract, which was secured with a U.K. marine trust.

With a fleet of 10 ROVs for onshore/offshore services and inspections, the private company plans to become a leading ROV inspection company within the next three years, carrying out global underwater inspections.

Rovco also said it will soon undertake its second underwater survey project in partnership with a southwest diving company.

CEO and founder Brian Allen said Rovco will use high resolution state-of-the-art 4K cameras and 360 degree scanning sonars.

Allen has more than 15 years' experience in the subsea industry, previously having managed multiple ROV systems on construction, inspection and lay vessels as a superintendent for Deepocean.

Verisk Analytics Acquires Quest Offshore's Data, Subscriptions Business

Sugar Land, Texas-based Quest Offshore Resources Inc. sold its data and subscriptions business to data analytics provider Verisk Analytics Inc., Quest said Aug. 29.

The data and subscriptions business will become part of Wood Mackenzie, a Verisk Analytics business, complementing Wood Mackenzie's existing upstream analysis expertise.

"Through this acquisition, our upstream oil and gas clients will be able to make better investment decisions through access to a unique understanding of availability, capability and price in key offshore equipment and service markets," said Neal Anderson, president of Wood Mackenzie, said.

Quest Offshore will continue focusing on the energy markets through its consulting and conference divisions, both of which will be retained by Quest Offshore.

Quest Consulting will continue providing energy strategy and management consulting, and will expand Quest Offshore's strategic due diligence services related to M&A for financial clients, particularly U.S. private equity.

Hunting Wins License Deal For Surface Well Intervention Valve

Interventek Subsea Engineering has awarded a sole license for its new surface well intervention valve to Hunting, a news release said. The product, which will be called the Ezi-Shear Seal, will become part of Hunting's pressure control equipment portfolio. The valve incorporates Interventek's Revolution technology and provides a mechanism for the shearing of slickline, wireline and coiled tubing to isolate or seal the wellbore. It also offers a cutting and sealing capability for standard, offshore or high-pressure applications where an additional level of pressure barrier contingency is required, the release said. The compact design allows for deployment through a standard offshore intervention hatch cover, negating the need to remove main hatch covers. Its use also reduces heavy lifting and potential shutting in of adjacent producing wells.

Petrofac Names Former BG Executive As CFO

On Aug. 30, British oilfield services company Petrofac Ltd. appointed Alastair Cochran, a former BG Group executive, as the head of its finance department.

Cochran, who oversaw BG's integration with oil major Royal Dutch Shell, would replace Tim Weller as CFO and executive director at the company's October board meeting, Petrofac said.

Weller is set to move to security provider G4S Plc in October, becoming its CFO.

Decom North Sea Appoints New Chairman to the Board

Decom North Sea has appointed Nigel Lees at its board chairman following Callum Falconer's decision to step down after two years, according to a news release.

Nigel Lees, Decom North Sea Chairman (Source: Decom North Sea)

An active member on the Decom North Sea board of directors for the past five years, Lees is the vice president responsible for decommissioning at Wood Group.

"As the spotlight intensifies on decommissioning and how the industry will prepare for the challenges ahead, this is an exciting time for me to take up the reins as chairman," Lees said.

Ashtead Technology Lands Deal with Dutch Engineering Firm

Aberdeen-headquartered Ashtead Technology has secured a deal with Van Oord to provide video processing systems for worldwide offshore construction operations.

As part of the contract, Ashtead supply five SubC Imaging DVRO systems to the Dutch-based company, allowing them to record multiple 3-D, HD and SD video channels simultaneously for future offshore construction, dredging and marine engineering projects, according to a news release.

Built to deliver video footage in real-time, add overlays, stream video and audio over a secure network, the DVRO system provides high quality footage of the underwater world, the company said in the release. The system is also fitted with a remote technical support function to provide live, around the clock assistance.

Flowline Specialists Accepts Prestigious Accolade

In recognition of its export achievements over the past six years, Flowline Specialists has received a Queen's Award for Enterprise in International Trade.

The Aberdeenshire energy industry equipment manufacturer and service provider is one of a few Scottish companies to be awarded the accolade in 2016. A Queen's Award for Enterprise is the highest official UK business award and is conferred by the monarch on the advice of the prime minister following consultation with an advisory committee composed of business leaders.

The company, which was established in 2001, designs, engineers and manufactures a range of equipment that safely handles flexible pipes, umbilicals and cables in the global oil and gas, subsea and renewable industries. Seven years ago the firm began a concerted push to grow its international business, having previously focused its efforts on the UK oil and gas market.

—Staff Reports

UPCOMING

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