SEN
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Shell Talks Up Deepwater Future with Malikai

Shell's deepwater Malikai TLP, destined for offshore Malaysia, is the company's first such platform designed and built outside the Gulf of Mexico. *(Photo courtesy of Shell)*

From Kuala Lumpur: Shell's Malikai tension leg platform (TLP) project hit a key milestone this week with the facility being skidded onto Dockwise's *White Marlin* heavylift vessel in readiness for sailaway to the field at the end of April. The operator also grasped the opportunity to speak out on behalf of the deepwater sector, saying the best projects remain strongly competitive with other sectors.

The TLP is destined for the Malikai oil field about 100 km off Sabah, Malaysia, at a water depth of around 500 m. The field consists of two main reservoirs with peak production forecast to hit 60,000 bbl/d. The TLP will pipe oil to the shallow-water Kebabangan platform 50 km away for processing.

The field is part of the Block G Production Sharing Contract awarded by Petronas in 1995. Shell, the operator, and ConocoPhillips each hold a 35% interest in the development while Petronas Carigali has 30%.

Malikai is an important part of Shell's deepwater ambitions which have not been thwarted by the low oil price, according to Andy Brown, the company's Upstream International Director.

He told delegates at the OTC Asia conference, "There is a significant amount of resource in deepwater and what is so important about deepwater is how prolific it is, not just the sheer amount of production you can get per well but also our ability to innovate and bring costs down."

He said the recent tie up with BG had been made because of the "fantastic resources" it has in deepwater Brazil.

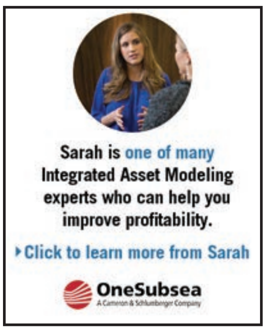
Brown said, "If you look at the production rate you get per well in Brazil, it is a couple of orders of magnitude more than you can get from shale resources in the U.S. Therefore it is not just about the cost and not going for expensive projects, it is looking at unit costs and the best deepwater projects will compete with projects in other parts of our industry. I think that is so important.

"Here in Malaysia we have got Gumusut that is running really well and Malikai, which we are skidding today. We have projects that will deliver and will deliver at competitive costs."

Brown also stressed the importance of the local ties that Shell, which has been in Malaysia for 125 years, has built with the country.

He added, "It plays into local capabilities as well. We built the Gumusut project. It wasn't an easy project, it took some time to come out of the yard and it took some time to rectify things offshore. It now produces well but it actually created this platform together with Technip and Malaysia Marine & Heavy Engineering and now we are building Malikai. It is being delivered on schedule. It is a great example of building local capabilities.

"Petronas were keen that we built it locally and together we were able to deliver the first TLP in Asia following on from the Gumusut FPS and Murphy's Kikeh FPSO. Really now Malaysia is going up the technology curve and in Sabah is demonstrating it can deliver deepwater



WHAT'S INSIDE

projects of all kinds and that is a lasting capability that can be deployed for the future."

Asia slow to respond

On another note, the conference was told that Asia is lagging behind in confronting the oil price crisis. Dato Wee Yiaw Hin, executive vice president & CEO of upstream business for Petronas said not enough was being done in the face of the price downturn.

He said there were mixed messages about where the oil price was heading but added, "We don't need crystal balls, we need balls to get through this downturn.

"In good times we have indulged ourselves in excess and we need to go deeper in cutting costs. In the U.S. they have responded with innovations to reduce costs and increase productivity. In Asia I feel we are lagging behind. Perhaps it is the market, perhaps it is the government. What have we learnt or not learnt from previous cycles?"

FLOATERS

FPSO Sector "in crisis"

FPSO awards will be few and far between, says MODEC. Pictured here is the FPSO Cidade de Itaguai MV26, converted and delivered by MODEC for Petrobras and which came onstream last July. *(Photo courtesy of Petrobras)*

From Kuala Lumpur: Floating production specialist MODEC expects just 20 new FPSO awards will be made up to 2020 because of the current downturn, delegates at OTC Asia in Kuala Lumpur were told.

Boyd Howell, the company's director of sales, said the FPSO nation is in a state of crisis.

Only four FPSOs were awarded in 2015, about a third of the number planned for the year.

Boyd said, "Another thing that is happening in the market is that there are FPSO units coming off hire after the operators deemed they were no longer economical to keep on hire.

"In 2015 there were seven units added to the list, bringing the total inventory of FPSO units available for work to 16. That number will increase to 18 by the end of next month and by the end of 2016 there will be 20 or 21 units available.

"Some of these units may never find more work but some of them will and of course they will be competing for the same sort of projects that we will be working towards with new FPSOs which will put a strain on the FPSO providers as well."

Boyd said the FPSO market is greatly affected by oil prices and a decrease in growth in China has impacted hard.

"Over the last 12 months we have seen a growth in the developing countries slowdown and growth is at its slowest rate since 2001. Brent is at its lowest since 2003. Global oil inventories are at an all-time high. The lifting of sanctions in Iran and the delay in freezing output from Saudi Arabia and Russia has all had an impact on oversupply and hence the decrease in the oil price."

"Another impact is shale and in the US it is about 5.5 MMbbl/d of production. Developing shale oil has got cheaper and cheaper."

He also said there is an expectation that 33% of U.S. based oil and oil service companies will go bankrupt by mid-2017 and disappear.

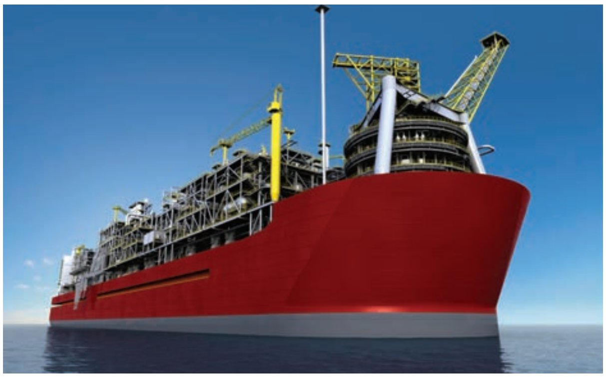
And although there are around 225 floating production projects in various stages of planning, Boyd said that figure is not realistic.

He added, "The best estimate from analysts is that there will be 45 FPSO projects from now until 2020. Five for 2016 and 10 for each year from 2017 to 2020.

"My expectation is that the five will be a zero and that the '10s' for the next four years are probably going to be closer to fives. That is a more realistic picture than what some of the industry analysts are saying right now.

"There will be few FPSO awards until late 2017 or into 2018. However, with any crisis comes an opportunity and we think there is an opportunity for the operators and FPSO providers as well as everybody in the supply chain to work together. We need to figure out how to improve the cost of an FPSO's ownership so they can remain a competitive choice."

Woodside Shelves Browse FLNG


Woodside has put its Browse FLNG scheme on ice. (Image courtesy of Woodside)

Woodside has decided to put its **Browse** (*SEN, 32/19*) FLNG project off Australia on ice after completing front-end engineering and design (FEED) work on the scheme.

Woodside said the Browse joint venture participants have decided not to progress with the development because of the current economic and market environment.

The Woodside-led Browse project, which counts Shell, BP, Japan Australia LNG and PetroChina as its partners, is located 425 km north of Broome in Western Australia and was earmarked to produce 12 million tonnes per annum of gas.

The project's reference case is based on three FLNG facilities to develop the **Brecknock**, **Calliance** and **Torosa** fields in the Browse Basin.

Woodside said, "Since FEED entry, Woodside has been focused on delivering targeted cost savings and value enhancements. While significant progress was made to improve project value, this has been offset by an extremely challenging external environment."

Woodside CEO Peter Coleman acknowledged the high quality of technical and non-technical work completed on the Browse FEED programme to enable the Browse Joint Venture participants to reach this decision.

"We have undertaken a comprehensive and rigorous process to assess all elements of the development. The decision represents a disciplined approach to large-scale capital investment and is consistent with our requirements for a development concept to be commercially robust across a range of scenarios.

"Woodside remains committed to the earliest commercial development of the world-class Browse resources and to FLNG as the preferred solution, but the economic environment is not supportive of a major LNG investment at this time. Accordingly, we will use the additional time to pursue further capital efficiencies for Browse," he said.

Woodside said it will now work with the Browse joint venture participants to prepare a new work programme and budget to progress development activities.

The company said it intends to leverage the high quality work delivered to date, which includes the involvement of the State Government to agree key principles for domestic gas and supply chain arrangements and the State and Commonwealth Governments to manage maritime boundary changes.

"Woodside remains focused on satisfying its work programme commitments under the Browse retention leases. The Browse retention leases were renewed in 2015 and the current term of the leases ends in mid-2020," the company added.

Kraken Spend Cut Again

EnQuest has now cut $425 million off the cost of its U.K. North Sea **Kraken** (*32/21*) FPSO project from the $3.25 billion slated at sanction.

An additional $125 million saving in Kraken's capex was made following a revision of the development plan. A total of 23 wells will now be drilled from three drill centres, instead of 25 wells from four drill centres. Project capex had been reduced by $300 million earlier.

EnQuest said that in 2016, the drilling programme is focused on drill centres one and two and is currently ahead of schedule, despite a particularly harsh North Sea winter. This should ensure that the planned four production and four injection wells will be available for first oil.

Following the departure of the FPSO unit from dry dock in December 2015, work is continuing on the marine systems. The FPSO unit remains on schedule to leave Singapore in 2016 for commissioning and hookup, with production in first-half 2017.

In 2015, the company's average production of 36,567 boe/d was up 31% year-on-year, above the 36,000 boe/d upper end of the company's guidance.

EnQuest said this reflected high levels of operating efficiency and contributions from **Alma/Galia** and a full-year contribution from Malaysia, which is now 25% of total production.

The company expects capex in 2016 to be at the low end of the $700 to $750 million range, including about $600 million of cash capex on Kraken.

EnQuest CEO Amjad Bseisu said, "EnQuest continues to focus on its strategic priorities in this low oil price environment: strengthening the balance sheet, delivering on production and execution targets, and streamlining operations. Significant reductions in both capex and opex have been achieved, in conjunction with continued excellent operational performance, enabling us to produce positive operational cashflows at current oil prices. At the start of 2016, EnQuest had $496.0 million of cash and undrawn facilities, giving sufficient liquidity to fund Kraken through first oil at prevailing oil prices.

"Since EnQuest's Operations Update in December 2015, we have taken further action on costs and are delivering additional savings, with unit operating costs now expected to be in the range of $25 to $27 per barrel for 2016 and into the low $20s per barrel after Kraken is fully onstream."

FLOATER BRIEFS

Eni has finally started production from the **Goliat** (*32/20*) Field, located 85 km northwest of Hammerfest, within Production License 229, in an ice-free area in the Barents Sea off Norway. Goliat has been developed through a cylindrical FPSO unit with a capacity of 1 MMbbl of oil. Daily output will reach 100,000 bbl. The field is estimated to contain reserves amounting to about 180 MMbbl of oil. Production comes through a subsea system consisting of 22 wells (of which 17 already are completed), and of which 12 are oil producers, seven water injectors and three gas injectors. Goliat receives power from shore by means of subsea power cables, reducing CO_2 emissions by 50% compared to alternative solutions, while water and gas products are reinjected into the reservoir.

Fugro said it is to supply ROV drilling support services on board the *Ocean Guardian* MODU under a new contract awarded by Dana Petroleum. Operating one of its fleet of FCV 600 ROVs, specifically designed for North Sea drill support activities, Fugro will carry out drilling and completions projects at the Dana-operated **Western Isles** (*32/1*) developments in the northern North Sea. The scope of work covers standard drilling support, which begins this month, and intervention tooling support, with all ROV tooling designed and supplied by Fugro. Fugro has been operational on board the *Ocean Guardian* since the summer of 2012 and completed a number of successful projects in the North Sea, Western Isles and West of Ireland.

Rig counts in North America have fallen again, dropping to 476 in the U.S. and to 69 in Canada, according to Baker Hughes Inc.'s March 18 report. In the U.S., the overall rig count is down four rigs from the last week, but down 593 when compared with the 1,069 rigs that were operating around this time in 2015. The U.S. oil rig count inched up this week by one to 387, compared with last year's 438. The number of gas rigs dropped by five to 89 compared with last week, down 153 compared with 2015. At 27, the U.S. offshore rig count was unchanged from last week, but down 10 rigs year-over-year, according to the report. The Canadian rig count plummeted by 29 rigs since last week, landing at 69. Both oil and gas rigs show double-digit falls: oil rigs were down 16 to 12, while gas rigs fell by 13 to 57, the report said. In 2015 about this time, Canada had 71 more rigs operating for a total of 140.

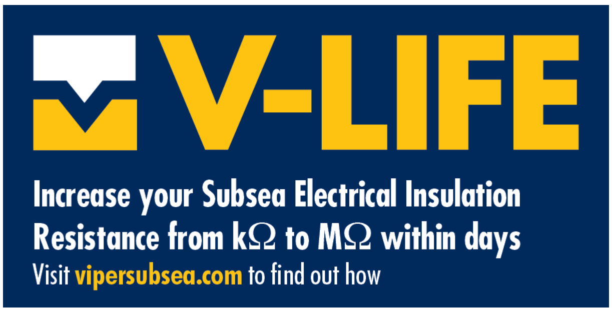
The third of four Ramform Titan-class seismic vessels, the *Ramform Tethys*, has been named at the Mitsubishi Heavy Industries Shipbuilding Co. yard in Nagasaki, Japan. PGS' two first Ramform Titan-class vessels, the *Ramform Titan* and the *Ramform Atlas,* were delivered in 2013 and 2014. Jon Erik Reinhardsen, President and CEO of PGS said, "The Ramform Tethys further strengthens our fleet productivity and together with the other Ramform Titan-class vessels will enhance our competitive edge. In the current challenging market environment we also experience more demand for our best capacity and Ramform Tethys will add to PGS ultrahigh-end value proposition."

ABB has won a five-year contract to deliver equipment and services for Shell's **Prelude** (*32/21*) FLNG facility. The order includes the delivery of motors, generators, variable speed drives and low-voltage switchgear and guarantees service and lifecycle management of the electrical equipment as well as service and support for motors from third-party vendors.

The electrical system will power 14 gas plant modules, allowing the facility to produce 5.3 million tons per annum of liquids. The agility of FLNG allows oil and gas companies to develop fields that would otherwise be uneconomical and their environmental impact is minimal compared with conventional production platforms and pipelines.

ABB will build up a spare parts inventory, workshop repairs, training and provide round-the-clock technical support both over the phone and on-site. Spare parts and replacement systems are being procured this year, with training to begin soon after.

"A reliable service network is crucial for the facility's productivity. Prelude will be equipped with ABB's integrated marine solutions for optimal reliability, flexibility and energy efficiency to assure higher profitability," said Pekka Tiitinen, president of ABB's Discrete Automation and Motion division. "In line with our Next Level strategy of business-led collaboration various ABB businesses will work together to mobilize the strength and experience of our entire global service organization."



DEVELOPMENT

Reinertsen Picked for Pil/Bue Scope

VNG Norge's Pil and Bue discoveries could be tied back subsea to Statoil's Njord A platform. (Photo courtesy of Statoil)

Reinertsen has agreed to a deal with VNG Norge to provide engineering services on the **Pil** and **Bue** (*SEN, 32/21*) project off Norway.

Reinertsen will help VNG Norge on the FEED phase and throughout the duration of the Pil and Bue project.

VNG Norge is mulling three development solutions for Pil and Bue including a shipshape FPSO vessel with gas exports to Åsgard Transport or Polarled, a subsea tieback to Statoil's **Njord A** (*31/9*) platform or a subsea tieback to the **Draugen** (*32/12*) platform.

Pil (Arrow) and Bue (Bow) are located in production licence 586 in blocks 6406/11 and 12 in the Norwegian Sea.

The Pil discovery is estimated to contain gross recoverable resources of 72 MMboe to 172 MMboe, while Bue is estimated to contain between 6 MMboe to 25 MMboe.

VNG said a standalone development—if selected—would be done with an FPSO unit for the storage and export of oil and possible reinjection of gas in the early phase of the field.

Later in field life, gas would be exported via a 30-km to 35-km, 8-in. pipeline linking in to existing T-connections on the Åsgard Transport or Polarled pipelines.

One of the tieback options being considered by VNG is to the Draugen platform, which has the capacity to process 35 Mboe/d to 44 Mboe/d, but limited gas treatment capacity.

Major conversion work would have to be completed on Draugen for it to take more gas.

A tieback option to the Njord A platform would be done by a 36-km-long pipeline with an electrically heated pipe-in-pipe solution.

VNG Norge is the operator of the Pil and Bue discoveries proven in production licence PL586 in the blocks 6406/11 and 12 in the Norwegian Sea.

The licensees of the discoveries are VNG Norge (30%), Spike Exploration Holding (30%), Faroe Petroleum Norge (25%) and Pure E&P Norway (15%).

DEVELOPMENT BRIEFS

The **Buckskin** (*SEN, 32/22*) development in the deepwater Gulf of Mexico looks like it could be back on the drawing board after Repsol took over its operatorship from Chevron. Repsol said it is now evaluating plans for the field following the change in operatorship. Chevron postponed indefinitely the development of Buckskin and **Moccasin** (*32/22*) in February because of low oil prices. Chevron and Anadarko had been touting a subsea tieback of Buckskin and Moccasin to Anadarko's **Lucius** spar. Buckskin is in KC785-828-829-872 with potential expansion into Buckskin South in KC 871, where regulators have approved an exploration plan. Discovered in 2009 in KC872 in 2,109 m of water, Buckskin is about 14 km west of the Anadarko spar and 440 km southwest of New Orleans. Moccasin, discovered in 2011 in KC736 in 2,022 m of water and now unitised with KC692, lies about 19 km northwest of Buckskin. Both fields are in the Lower Tertiary, with discovery wells drilled to 8,962 m and 9,614 m, respectively. Lucius is in shallower Miocene and Pliocene sands, with the discovery well drilled to 6,096 m.

BP has awarded OneSubsea a contract to supply subsea production systems for the **West Nile Delta** (*32/20*), **Giza/Fayoum** (*32/5*) and **Raven** (*32/5*) fields offshore Egypt. Giza/Fayoum will be tied back to modified onshore Rosetta facilities and integrated with a new onshore plant for Raven. The scope of supply for the long-distance gas fields includes large-bore subsea trees, manifold systems incorporating high-integrity pressure protection systems (HIPPS) for the high-pressure Raven Field, connection systems and controls systems, along with project engineering, management and testing. The booking was recognised in fourth-quarter 2015. "BP continues to be successful in driving its standardisation philosophy, and this is the third award to OneSubsea that will utilise the jointly developed large-bore tree already being deployed to other BP projects," said CEO of OneSubsea Mike Garding.

Petrex Developments has scooped a contract from Maersk Oil to work on a riser base recovery study as part of the **Leadon** (*32/07*) Field decommissioning programme in the U.K. North Sea. The Leadon Field is located in Block 9/14 of the North Sea in a water depth of 120 m and was acquired by Maersk Oil in 2005 with cessation of production granted in 2006. Some preparation work already has been undertaken for decommissioning of the Leadon facilities, with the FPSO unit and associated mooring system removed and reused at the **Donan** development in 2006 and the flexible risers recovered and disposed of in 2007, while other works continue in the North Sea.

Chevron has shipped its first cargo of LNG from the **Gorgon** (*32/21*) project on Barrow Island off the northwest coast of Western Australia to Chubu Electric Power, for delivery into Japan. The Gorgon Project is supplied from the **Gorgon** and **Jansz-Io** gas fields, located within the Greater Gorgon area, between 130 km and 220 km off the northwest coast of Western Australia. The Chevron-operated Gorgon Project is a joint venture between the Australian subsidiaries of Chevron (47.3%), Exxon Mobil (25%), Shell (25%), Osaka Gas (1.25%), Tokyo Gas (1%) and Chubu Electric Power (0.417%).

Emerson Process Management has been awarded a contract to automate Maersk Oil's **Culzean** (*32/17*) gas field development in the U.K. North Sea. Maersk and its co-venturers are investing about $4.5 billion in the Culzean development. Three offshore platforms will support 12-slot wellheads and house a central processing facility, control room and living quarters. As the main automation contractor, Emerson will provide automation services and technologies for the three offshore platforms as well as for an onshore observation facility that can support remote operations if needed. Emerson will provide a range of project and support services from its U.K. headquarters in Leicester to help ensure on-schedule project execution, including system design and engineering, configuration, testing, installation, and commissioning. An operator training system will support both engineering and workforce training to help bring the production online safely and as quickly as possible. Production is expected to start in 2019 and continue for at least 13 years.

OMV has signed a deal for a four-year programme to evaluate offshore oil and gas fields northwest of Abu Dhabi with the Abu Dhabi National Oil Co. (ADNOC) and U.S. firm Occidental Petroleum Corp. The fields the companies will analyse through seismic, drilling and engineering studies include the **Ghasha** and **Hail** areas with a view to appraising and developing them. OMV already is working with ADNOC on the appraisal of the **Shuwaihat** Field. The cooperation aims to firm up the volume potential of the undeveloped North-West Offshore fields, to form the basis for the future development of the North-West Offshore area. The deal sees OMV intensifying its strategic partnership with ADNOC alongside its existing participation in the appraisal of the sour gas Shuwaihat Field and its East Abu Dhabi exploration activities.

Shell and its joint venture partners have kicked off oil production from the third phase of the deepwater **Parque das Conchas (BC-10)** (*32/15*) development in Brazil's Campos Basin. Production from the final phase of the project is expected to add up to 20,000 boe/d at peak, from fields that already have produced more than 100 MMbbl since 2009. "The safe, early delivery of this production is a testament to the efficiency of our deepwater project execution," said Wael Sawan, Shell's executive vice president, deep water. "With this phased project, we have again demonstrated value from standardisation, synergies from contractual relationships and the strategic deployment of new technologies. These barrels, like other subsea tieback opportunities across our deepwater portfolio, have development cost advantages and will contribute to the strong production growth we expect from offshore Brazil."

Harkand has been awarded a multimillion-pound contract from Maersk Oil to deliver subsea support services including a commissioning support campaign for the **Flyndre** (*32/21*) development located in the southeastern part of the Central Graben Basin in the North Sea. The Aberdeen office of the global inspection, repair and maintenance company will oversee the mobilisation of its sister dive support vessels the *Harkand Atlantis* and *Harkand Da Vinci*. The Flyndre campaign will involve personnel carrying out choke valve replacement work as well as delivering umbilical tie-in operations. David Kerr, managing director for Harkand Europe said, "We have a well-established relationship with Maersk Oil having delivered successful diving scopes for the company last year including decommissioning work at the Leadon Field and also completing their subsea inspection campaign in 2013."

Statoil has exercised an option with Ocean Installer to replace flexible jumpers on the **Vigdis** (*32/19*) Field. Vigdis is located in Block 34/7 in the Tampen area of the Norwegian North Sea and came onstream in 1997. Water depth is about 280 m. "We are happy to see that Statoil continues to make use of options inherent to existing contracts, further strengthening our cooperation. In the current market, this type of work is important to maintain a steady activity level, and it proves that an unwavering focus on delivering in existing projects pays off," said Ocean Installer CEO Steinar Riise. Ocean Installer will utilise construction support vessel *Normand Vision*. Project preparations started in February and offshore work will take place in June.

Serica Energy said production has been hit from its **Erskine** (*32/6*) Field in the U.K. North Sea by a pipeline blockage. On Feb. 28, Erskine production was temporarily suspended during essential maintenance work to enable a pig to be recovered from the Lomond to Everest condensate line and to repair a condensate export pump on the Lomond platform.

Equipment to safely clear the pipeline is being deployed and the field is expected to recommence production mid-April. Pigging of the Erskine to Lomond line already has been completed successfully. The overall impact is to reduce first-quarter average production to about 2,100 boe/d net to Serica, compared to previous guidance of 2,500 boe/d to 3,000 boe/d. The impact on April production will depend upon how quickly the field can be restarted.

EXPLORATION

Obama Keeps Atlantic Exploration Under Wraps

The U.S. will continue to be the only major producing country with an Atlantic coastline that is not able to explore for oil and gas off its Atlantic shores.

The oil and gas industry's quest to open the Atlantic Basin to seismic gathering and offshore drilling was squashed by the Obama administration, despite support from four coastal state governors and a petition with 180,000 signatures that was delivered to the Interior Department on March 14.

Concerns raised by coastal communities, the Defence Department and NASA, among others, were enough to outweigh the potential for exploration that has led to discoveries in other parts of the Atlantic such as offshore Africa, Brazil and Canada.

The proposed programme for the Outer Continental Shelf (OCS) Oil and Gas Leasing Program for 2017-2022 would have included at least one sale in the Mid-Atlantic and South Atlantic planning areas in 2021, offering acreage at least 50 miles offshore Virginia, North Carolina, South Carolina and Georgia. However, for now at least it is not to be.

"When you factor in conflicts with commercial and national defence activity, market conditions and oppositions from local communities, it simply does not make sense to move forward with the Atlantic lease sale in the near future," Secretary of the Interior Sally Jewell said during a media call March 15.

She called the 2017-2022 proposal balanced, saying it protects sensitive resources, supports safe and responsible development of energy resources and focuses on areas with the greatest resource potential, industry interest and infrastructure.

According to the draft proposed program released in January 2015, some data suggested parts of the Atlantic planning areas could have significant oil and gas resource potential. The extent of this potential is not known, however, because current geological and geophysical data are more than 35 years old.

The American Petroleum Institute (API), which pushed for oil and gas drilling in the Atlantic, said the administration's decision "shuns American consumers, national security and weakens [the nation's] energy future."

Randall Luthi, president of the National Ocean Industries Association (NOIA), called the move short-sighted. "The good news is that there are still lease sales planned in the Gulf of Mexico (GoM) and Alaskan Arctic. The bad news is the disappointing and mind-boggling removal of Atlantic Lease Sale 260 from the 2017-2022 OCS Oil and Gas Leasing Proposed Program," he said.

"This is a short-sighted political decision of an administration influenced by the radical and extreme minority devoted to keeping fossil fuels in the ground. The removal is not based upon science or good energy policy and will certainly inhibit the economic opportunities and energy security of our country."

The proposed five-year lease program includes:

- **GoM**: Ten lease sales. Two lease sales would be held annually in the western, central and part of the eastern GoM that is not part of the current congressional moratorium;
- **Pacific**: No lease sales, unchanged from the draft proposed program and consistent with previous moves given opposition from California, Oregon and Washington to oil and gas development offshore; and
- •**Alaska**: Three lease sales, one each in the Cook Inlet, Beaufort Sea and Chukchi Sea. Jewell noted that during public meetings concerning the environmental impact statement, several North Slope communities pointed out areas that might not be appropriate for leasing, and those areas were marked as potential conflict areas between oil and gas activity and ecological resources and subsistence activities.

—*Velda Addison, Hart Energy*

Kosmos Eyes LNG Project at Tortue West

Kosmos Energy said its **Ahmeyim-2** appraisal well has successfully delineated the **Ahmeyim** and **Guembeul** gas discoveries offshore Mauritania and Senegal, paving the way for an LNG project in the region.

Located in Mauritanian waters about 5 km northwest and 200 m downdip of the basin-opening **Tortue-1** discovery well in about 2,800 m of water, Ahmeyim-2 was drilled to a total depth of 5,200 m.

The appraisal has increased the size of the productive field area from about 50 sq km to 90 sq km.

Kosmos said, "Furthermore, the well confirmed significant thickening of the gross reservoir sequences down-structure and importantly, within the Lower Cenomanian, static fluid pressure communication between the Tortue-1, **Guembeul-1** and Ahmeyim-2 wells. The well encountered 78 m of net gas pay in two excellent quality reservoirs, including 46 m in the Lower Cenomanian and 32 m in the underlying Albian. These results demonstrate fieldwide reservoir continuity and indicate Tortue West is a large, simple gas field."

Andrew G. Inglis, chairman and CEO, said, "Ahmeyim-2 is our fourth successful exploration and appraisal well and continues our 100% success rate in the outboard Cretaceous petroleum system offshore Mauritania and Senegal, further demonstrating that Kosmos has opened a world-class hydrocarbon province. With this well, we believe we have proven sufficient gas resource to underpin a world-scale LNG project in the Tortue West structure alone.

"The combination of the resource size and quality continue to support our view that Tortue is a competitive source of LNG and we are working towards commercialisation."

Kosmos now plans to drill the first of three independent oil tests in its blocks offshore Mauritania and Senegal, starting with the Teranga-1 well, located in the Cayar Offshore Profond Block offshore Senegal.

The Atwood Achiever drillship has been busy working for Kosmos offshore Mauritania and Senegal.

EXPLORATION NOTES

Norway's Ministry of Petroleum and Energy has launched this year's licensing round for mature areas on the Norwegian Continental Shelf—Awards in Predefined Areas 2016.

The predefined area has been expanded by 24 blocks in the Norwegian Sea and 32 blocks in the Barents Sea. Several blocks are located around the **Aasta Hansteen** (32/21) Field in the Norwegian Sea. The blocks in the Barents Sea are mainly located in the area around the discoveries at **Castberg**, **Alta** and **Gotha**. The application deadline for companies is Sept. 6, 2016. The aim is to award new production licences in the announced areas at the beginning of 2017.

New Zealand has launched its latest offer of offshore blocks. Block Offer 2016 includes four offshore release areas in the Reinga-Northland Basin, Taranaki Basin, Pegasus and East Coast Basins, and Great South-Canterbury Basin. Energy and Resources Minister Simon Bridges said, "Since it was first introduced in 2012, the annual Block Offer has provided an effective way for the government to strategically manage how we allocate petroleum exploration permits. It creates consistency for the industry while ensuring we are attracting highly capable companies." The tender will close on Sept. 7, 2016, and the outcome of the tender will likely be announced in December 2016.

Premier Oil will spud an exploration well on the U.K. North Sea **Bagpuss** (*32/7*) prospect on Block 13/24c towards the beginning of July. An option has been exercised for the *Ocean Valiant* semisubmersible rig to drill the well, which is expected to take 26 days with an additional four days for logging and sampling in case of success. The well is to be drilled to about 472 m subsurface to evaluate the prospectivity of the Lower Cretaceous interval beneath the Chalk and above the granite basement. The joint venture partners in the Bagpuss prospect are Maersk Oil (25%), North Sea Energy (15%), Premier Oil (40.1%-operator), EnCounter (13.27%) and Groliffe (6.63%).

Cairn Energy has followed up its first two successful appraisal wells offshore Senegal with the spudding of **BEL-1** on the **SNE** oil field. The BEL-1 well will be drilled in about 1,100 m of water and drilled to a total vertical depth subsea of about 2,757 m before an evaluation program including logging and coring is undertaken. The aim of the appraisal program is to progress towards proving a minimum economic field size for the SNE discovery, which FAR estimates to be about 200 MMbbl of oil. In addition, the BEL-1 well will drill the **Bellatrix** exploration prospect, which will evaluate the untested Buried Hills play. BEL-1 also will be deepened to appraise the northern portion of the SNE oil field. Drilling of the BEL-1 well will be followed by a wireline logging and coring program before the well is plugged and abandoned according to plans. BEL-1 operations are expected to be completed in April.

Gabon's Directorate Generale des Hydrocarbures (DGH) has announced that the 11th Licensing Round for deepwater blocks has been extended to 29 April 2016. The round was formally opened on 27 October 2015. The original closing date for applications was March 31 2016.

The DGH said that the new deadline for bid submissions would give interested companies an extra month to evaluate the anticipated update to the fiscal terms by the DGH due to be announced in the first week of April 2016.

The 11th Round is focused on five blocks covering some of the country's key deepwater acreage in the South Gabon Salt Basin. In response to the exploration challenges CGG was appointed to advise the DGH on the promotion of the license round and has worked directly with the Ministry to acquire more than 25,000 sq km of new 3-D multiclient seismic data.

TECHNOLOGY

BOP Failures Can Be Predicted

National Oilwell Varco (NOV) said it has developed and validated the first solution to predict operational failures in subsea BOP components.

Its RIGSENTRY system now offers a remote condition monitoring service that provides live predictive analytics of subsea BOPs.

NOV said this new predictive capability is expected to give customers real-time visibility into product health and performance within a prediction horizon of about 14 days.

RIGSENTRY now has the ability to identify the specific point of failure and alert customers earlier than a human operator or other traditional detection techniques.

This will result in overall cost savings through a reduction in unplanned downtime and more efficient maintenance practices.

This predictive feature is the result of a multidisciplinary data science team using 14 years of historical sensor data, maintenance logs and more than 60 years of experience in the design, testing and manufacturing of BOPs.

Clay C. Williams, chairman, president and CEO of NOV, stated, "We continue to invest in the research and development of new technologies that will drive our industry forward despite today's challenging environment. The potential that big data offers for condition monitoring and predictive analytics could change the way we support, maintain and design our equipment to deliver better uptime for our customers."

POLICY

Tax Cuts to Boost UK Sector

The dearth in exploration activity and new fields in the U.K. North Sea, like EnQuest's Alma-Galia development which came onstream last October, has prompted a tax overhaul. (Photo courtesy of EnQuest)

U.K. chancellor George Osborne has announced a major overhaul of the North Sea tax regime in response to difficulties facing the oil and gas sector, although whether it is major enough remains debatable.

In his budget statement, he said Petroleum Revenue Tax would be "effectively abolished," having cut it last year from 50% to 35%.

The existing supplementary charge for oil companies also will be cut from 20% to 10%, backdated to Jan. 1.

The budget will effectively reduce the headline rate of tax paid on U.K. oil and gas production from 50% to 67.5% to a rate of 40% across all fields.

In his budget speech, Osborne said, "The oil and gas sector employs hundreds of thousands of people in Scotland and around our country. In my budget a year ago I made major reductions in taxes, but the oil price has continued to fall so we need to act now for the long term. I am today cutting in half the supplementary charge on oil and gas from 20% to 10%, and I am effectively abolishing Petroleum Revenue Tax too—backing this key Scottish industry and supporting jobs right across Britain."

The tax changes are expected to save the industry about $1.4 billion in the five financial years from 2016-2017 to 2020-2021.

North Sea industry group Oil and Gas UK welcomed the changes. Deirdre Michie, Oil & Gas UK's CEO, said, "This announcement does indeed mark further progress in modernising the tax regime for an increasingly mature basin. We welcome these measures as they will build on the industry's achievements in improving efficiency in the face of low oil prices, boosting the sector's competitiveness and helping to restore investor confidence.

"We will continue to work with the Treasury to complete its 'Driving Investment' plan to ensure that the fiscal regime reflects the business needs of a maturing basin and signals to global investors that the U.K. is truly open for business."

The budget also provided certainty on the availability of decommissioning tax relief, where an asset is transferred but the decommissioning liability is retained by a previous owner, which should assist the asset trading market.

Regarding exploration, Michie said the industry appreciates the continued funding of seismic and hopes that the tax rate changes prove sufficiently effective alongside the steps the Oil & Gas Authority is taking to promote exploration activity.

There also has been further adjustment to the Investment Allowance to facilitate investment in infrastructure, which also will support the drive to maximise economic recovery.

The industry has been badly affected by the drop in oil price with investment falling sharply, with nearly half of all oil fields making losses and tens of thousands of jobs lost over the past 18 months.

BUSINESS BRIEFS

Schlumberger said it expects revenue in the current quarter to fall 15% from the fourth quarter, as spending cuts by oil producers take a toll.

The company forecast revenue of $6.5 billion for the three months to the end of March.

"The third phase of E&P spending reductions that we are currently experiencing will have a significant impact on our earnings per share in the current and coming quarters," Chief Executive Paal Kibsgaard said at an energy conference.

Ithaca Energy posted a loss after tax of $121 million in 2015 as the result of a $203 million post-tax impairment charge arising from lower forecast future oil and gas prices, the company said.

Average production in 2015 was 12,066 boe/d (94% oil), representing a 10% increase on 2014. The producing assets performed well over the course of the year.

Solid operational uptime performance across the main fields, along with the benefit of various production enhancement activities and start-up of the Ythan field, resulted in total production being ahead of full year guidance of 12,000 boe/d, Ithaca said.

Completion of the FPF-1 modifications programme remains on track for sail-away of the vessel in the previously guided May/June 2016 period, leading to anticipated first hydrocarbons from the Stella field in the third quarter of the year.

OneSubsea has signed two five-year global frame agreements (GFA) with BP to provide engineering, procurement and construction of subsea production systems (SPS) and subsea aftermarket services. Both GFAs have been specifically designed and formulated to accommodate supplier-led solutions. The agreements provide a framework for worldwide supply of SPS technology and subsea aftermarket services, including service personnel and rental equipment. Mike Garding, CEO of OneSubsea, said, "This is a positive step for the industry, demonstrating how successful collaboration between operators and suppliers can reduce cost and schedules through standardisation. BP has been a driving force in [pushing] a philosophy of supplier-led solutions, where standard designs, quality and materials are aligned with its functional specifications."

U.K. flowmeter specialist Litre Meter has supplied a large range of its VFF flowmeters for the **Shah Deniz** (*32/20*) gas fields located in the Caspian Sea off Azerbaijan. The orders were for stages one and two of the field. Stage two of the Shah Deniz project is now more than 50% complete in terms of engineering, procurement and construction and it is on target for first gas in 2018. The meters will be needed to measure different flow rates and viscosities of fluid for diverse aspects of the project.

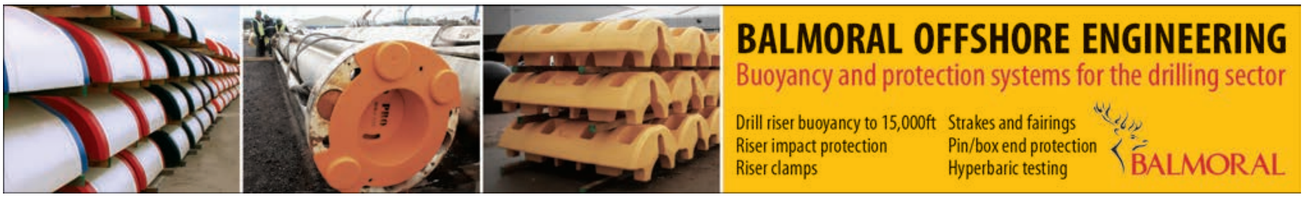
Sparrows Group has lifted an initial five-year contract to deliver cranes and maintenance services for Statoil's **Mariner** (*32/21*) project in the U.K. North Sea. The firm will supply crane operator personnel to support drilling, operations, maintenance and logistics, and will deliver maintenance and engineering services to ensure the availability and reliability of the **Mariner A** platform's two pedestal cranes. Options to extend the contract mean it could potentially run for nine years. The Mariner Field is located about 150 km east of the Shetland Isles and consists of two shallow reservoir sections. The Maureen Formation sits at 1,492 m with the Heimdal reservoir at 1,227 m. Due to begin operation in 2018, it is expected that the field will contribute more than 250 MMbbl reserves with average plateau production of about 55,000 bbl/d. Mariner is expected to have a 30-year field life.

Petrobras posted a record loss in the fourth quarter after booking a large write-down for oil fields and other assets as oil prices slumped. Petrobras made a consolidated net loss of 36.9 billion reais (US$10.2 billion) in the quarter. This compared with a 26.6 billion-real (US$7.3 billion) loss a year earlier, the previous record. Net sales totalled 85.1 billion reais (US$ 3.5 billion) in the quarter and adjusted earnings before interest, taxes, depreciation and amortization, or EBITDA, were 17.1 billion reais (US$4.7 billion). The fourth-quarter result pushed the company's full-year 2015 result to a 34.8 billion-real (US$9.6 billion) loss.

Meanwhile, Petrobras is investigating practices in its human resources department that could have left the state-run oil producer vulnerable to billions of reais in liabilities, newspaper *Valor Economico* reported on March 21. **João Elek**, the company's governance head, is leading the internal probe after an anonymous report of 11 potentially controversial measures taken by the department in recent years, which could have included special treatment for union members at top management levels, Valor said. Petrobras is at the centre of a massive corruption probe that has shaken Brazilian politics over the past two years. Some of the nation's most powerful executives and politicians are in jail or under investigation for billions of dollars in rigged contracts and kickbacks to parties in the ruling coalition.

Eni of Italy is to chop its spending by more than 20% between now and 2019, as well as sell down stakes in various oil and gas assets, as it proceeds with its plans to become a leaner, more exploration-driven company. The state-controlled major said in its recently-revealed 2016-2019 business plan that it would cut group capital spending by 21% and raise 7 billion euros in new asset sales. This would be done "mainly through the dilution of our stakes in recent and material discoveries," said CEO, Claudio Descalzi. It has previously stated it was prepared to sell down its stakes in its giant Mozambique gas development off East Africa and certain oil fields in Congo off West Africa. Last year Eni added 1.4 Bbbl of new resources, compared to a target of 0.5 Bbbl, mainly thanks to the huge Zohr gas field find in Egypt's deep waters. Over the next four years Eni expects oil and gas production to grow by more than 3% per year. It also wants to bring down breakeven prices on new projects to $27/bbl from $45/bbl at present.

Project delays and cancellations, coupled with less spending and ongoing lower oil prices, have cast more cloud over future oil and gas developments in West Africa's deep water areas, prompting an energy consultancy to lower its production forecast for the region. The short-term forecast is actually bright, says Douglas-Westwood, as companies proceed with projects sanctioned before the market started falling. It now believes production will peak at about 2.8 MMboe/d in 2019, a 44% fall from its previous deepwater drilling forecast. Production is expected to then drop to about 2.5 MMboe/d by 2021. The revised forecast was issued earlier this month. Healthy activity offshore West Africa was expected to result in about 483 deepwater development wells between now and the end of 2021. Now the firm predicts the number could drop from 89 this year to 23 in 2020. Douglas-Westwood flagged up stalled projects such as Shell's Bonga South West and Eni's Etan developments offshore Nigeria, and Maersk's recent decision to pause development of its Chissonga field offshore Angola.



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