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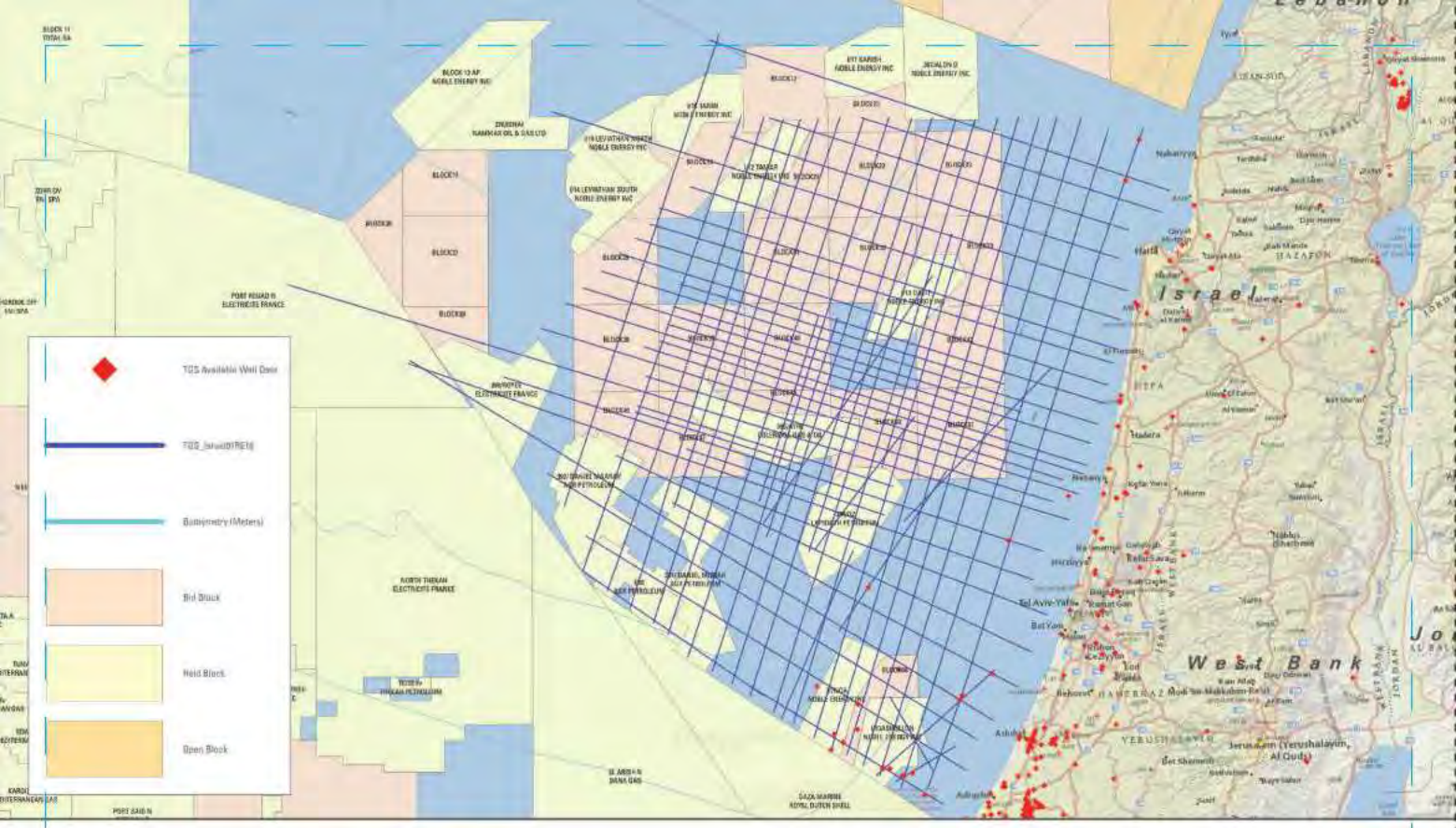
Global Offshore Market Forecast

page 22

Offshore Engineer • January 2017

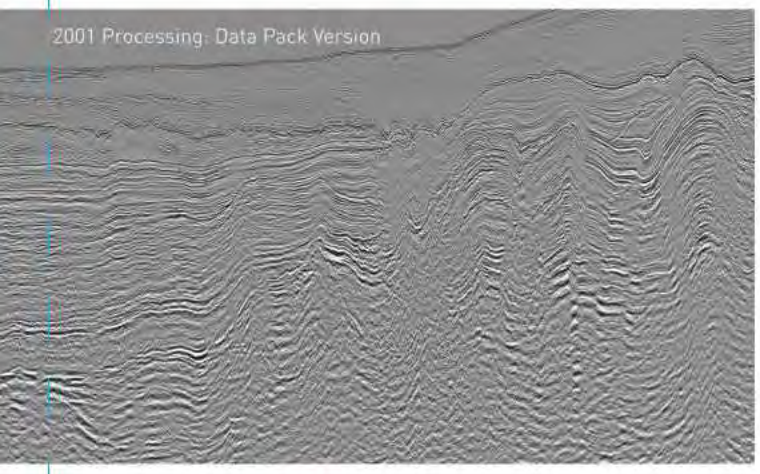


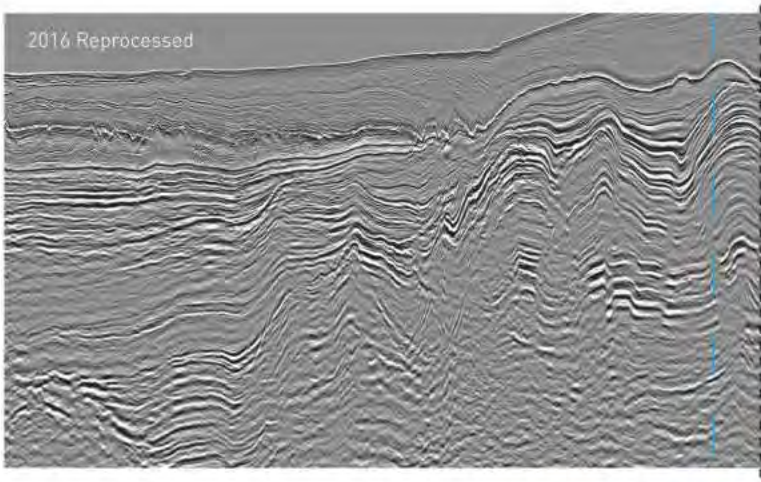
Israel: See Deeper.

Newly available broadband reprocessed 2D seismic in the Levant Basin, offshore Israel, dramatically improves our imaging of the biogenic plays and strengthens our understanding of the deeper geology and associated Mesozoic thermogenic hydrocarbon plays.

Enhancements in data quality greatly improve the intra and sub-salt imaging. In addition, deeper imagery now reveals previously unseen rift infill and dramatically increases confidence in the interpretation of the lower syn-rift and basement surfaces. This allows for better control on basin temperature models, seismic facies identification and analyses, as well as improved definition of potential traps. Improve your data. Improve your assessment. Improve your bid.

It's time to see deeper in Israel.





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TGS

Stampede's topsides during lifting operations.
Photo from Hess.

FEATURE FOCUS

Global Offshore Market Forecast

Features

ON THE COVER

Fantastic voyage. Hess' Stampede TLP hull made its long journey from Korea to its location in the Gulf of Mexico in August 2016. See the full story on page 14. *Cover photo courtesy of Hess.*

****December's cover caption misnamed Heerema Marine Contractor's heavy lift vessel *Hermod* as *Balder*. *OE* apologizes for the error.****

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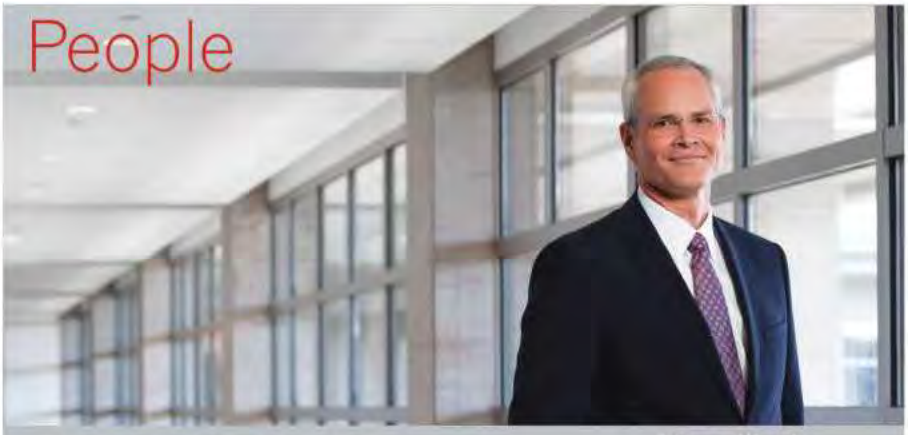
What's Trending?

Big ideas

- US, Canadian Arctic off limits to oil and gas exploration
- BP invests in Mauritania, Senegal
- Mexico delays shallow water round

Canadian Prime Minister Justin Trudeau and outgoing US President Barack Obama at the White House. Photo from Trudeau's Flickr. Credit: Adam Scotti/PMO-CPM.

People



Darren Woods

Following news that ExxonMobil chairman and CEO Rex Tillerson has been nominated by US President-elect Donald Trump to lead the US State Department, ExxonMobil has named Darren Woods to succeed Tillerson in both positions.

Activity

Gullfaks hits 30-year mark

Gullfaks was Statoil's first field where the company was both developer and operator. Since production started 30 years ago in December 1986, 2.6 billion bbl have passed the loading buoys.

Gullfaks C on its way to the field in 1989. Photo: Leif Berge/Statoil.

Undercurrents

New year, new problems

In his final month as US president, Barack Obama moved to ban some 3.8 million acres in the north and mid-Atlantic Ocean and some 115 million acres in the US Arctic Ocean from future mineral extraction. The decision was issued in a joint statement with Canada's Prime Minister Justin Trudeau, who made a similar pledge to ban future offshore exploration in that country's Arctic waters.

While it was not an expected decision, it is an unsurprising move for a president desperate to ensure his legacy on environmental issues continues. That legacy is one of combativeness with the oil and gas industry, and in particular those companies that dared to take on the onerous task of both working in harsh and environmentally sensitive arctic conditions as well as the burdensome regulations imposed by Obama's administration.

Starting in 2015, and into 2016, US Arctic offshore leaseholders Shell, ConocoPhillips, Eni, and Statoil withdrew from their acreage and abandoned their exploration plans. Shell and Statoil, in particular, had a famously difficult time with US regulators. Both had applied for a suspension of work on their leases shortly before deciding to withdraw completely.

While Obama and Trudeau's decision delighted environmentalists, it angered oil and gas industry advocates and politicians from the US states that would be affected by such a ban, namely Alaska.

A joint statement from Alaskan senators Lisa Murkowski and Dan Sullivan, and Congressman Don Young, pointed out the one major flaw of the US decision: "While President Obama's Arctic withdrawal is indefinite, Canada will review the status of its Arctic waters every five years. With Russian development already underway in the Arctic, it may be just a few short years before our nation is bracketed by activity on both sides and importing the oil resulting from it."

Make no mistake – Russia can and will use North America's reluctance to explore the Arctic to its advantage, and it is currently looking for partners to help them continue exploring and producing from the Russian Arctic. Days before Obama's announcement, three Japanese firms (Jogmec, Inpex, and Marubeni) said they would team up with Russia's Rosneft to jointly explore for oil and gas southwest of Sakhalin Island, eastern Russia. In October 2016, Russia and Norway agreed to share seismic data in the Barents Sea.

With all this in mind, is North America's decision to take a backseat to Arctic development limiting itself?

In transition

OE goes to press with this very January issue before the next US president is sworn in. So far, President-elect Donald Trump has made some very oil and gas industry-friendly cabinet choices for select offices.

In December, Trump chose now-former ExxonMobil CEO Rex Tillerson to be his nominee for Secretary of State, citing his experience with foreign governments during his tenure at Exxon. He also picked former Texas Governor Rick Perry to be Secretary of Energy. Trump cited Perry's long tenure as governor, and record of job creation in the state as reasons for his fitness for the position.

Trump also selected Montana Congressman Ryan Zinke to lead the Interior Department, where he will oversee the regulatory bodies Bureau of Ocean Energy Management and the Bureau of Safety and Environmental Enforcement.

Of Zinke's appointment, Trump said: "My administration's goal is to repeal bad regulations and use our natural resources to create jobs and wealth for the American people, and Ryan will explore every possibility for how we can safely and responsibly do that."

The proof, as they say, will be in the pudding. Spotted dick anyone? OE

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Global E&P Briefs

A Anadarko confirms Warrior, Phobos oil

US independent Anadarko Petroleum announced in December that it has hit oil at two wells in the US Gulf of Mexico.

The Warrior exploration well, about 3mi from the Anadarko-operated K2 field, in Green Canyon Block 563, encountered more than 210ft (64m) of net oil pay in multiple high-quality Miocene-aged reservoirs, after reaching a total depth of 26,957ft in 4144ft water depth. Warrior is expected to be tied back to Anadarko's Marco Polo production facility.

At the Phobos appraisal well, Anadarko hit more than 90ft of net high-quality oil pay in a Pliocene-aged reservoir similar to the nearby Lucius field. Phobos is about 12mi south of Lucius, and is being evaluated as a possible tieback to that field.

B Mexico's deepwater round a success

Mexico's highly anticipated deepwater bidding round, Round 1.4, in Mexico City resulted in eight of the 10 deepwater blocks in the Gulf of Mexico to be awarded.

In the Perdido Fold Belt, Block 1, covering 1678sq km and an estimated 458 MMboe of super light oil, went to China National Offshore Oil Corp. (CNOOC). Block 2, covering 2977sq km and an estimated 900 MMboe, went to the consortium of Total E&P and ExxonMobil. Block 3, coving 1687sq km and an estimated 971 MMboe, went to the consortium of Chevron (operator), Pemex and Inpex. Block 4, coving 1877sq km and an estimated 408 MMboe, went to CNOOC.

In the Salina basin, Block 1 and 3, covering 2381sq km and 3287sq km, and an estimated 1.2 billion boe and 1.18 billion boe, respectively, went to the consortium of Statoil (operator), BP, and Total. Block 4, covering 2359sq km and an estimated 2.6 billion boe, went to a consortium of PC Carigali (operator) and Sierra Oil and Gas. Block 5, covering 2573sq km and 467 MMboe, went to the consortium of Murphy Oil (operator), Ophir, PC Carigali, and Sierra Offshore Exploration.

The event also saw BHP Billiton winning the farm-out bid for the Trion deepwater field.

C BP sanctions Mad Dog 2

BP has finally approved the development plan for the US$9 billion Mad Dog Phase 2 project in the Gulf of Mexico, with first production set to start in late-2021.

Mad Dog Phase 2 includes a new floating production platform, moored 6mi southwest of the existing Mad Dog platform, some 190mi south of New Orleans. Phase 2 will boast a 140,000 bo/d production capacity from up to 14 production wells.

The existing Mad Dog platform, at 4500ft water depth, currently produces 80,000 b/d and 60 MMcf/d of natural gas.

BP operates Mad Dog (60.5%) with partners BHP Billiton (23.9%) and Union Oil Co. of California (15.6%). BP's partners have yet to give their approval for the project, although it is expected.

D BGP starts Cuban 2D survey

BGP Marine began a 2D multiclient survey, offshore Cuba, after signing a contract with Cuba-Petroleo Co. (CUPET) in late November. The project comprises 25,000 km of 2D long-offset, high resolution, broadband seismic and gravity data. The survey specifically targets the Cuba Economic Zone of the Gulf of Mexico areas. The acquisition is carried out using the vessel *BGP Pioneer* and the final data will be available to clients in Q4 2017. The bid round will be followed after the completion of the survey.

E Lapa begins production

Petrobras started production at the Lapa field, offshore Brazil through the FPSO (floating production, storage and offloading) *Cidade de Caraguatatuba*. Lapa is in the Santos Basin, about 270km from the coast of the São Paulo, at 2140m water depth.

The *Cidade de Caraguatatuba* has the capacity to process 100,000 b/d of oil, compress 5 MMcm/d of gas, and is interconnected to the Lapa field through production well 7-LPA-1D.

The Lapa field is operated by Petrobras (45%), in partnership with BG E&P Brasil (30%) and Repsol Sinopec Brasil (25%).

F Brazil launches bid rounds

The Brazilian National Agency of Petroleum, Natural Gas and Biofuels (ANP) will hold the 14th Round for exploration and production, and the 2nd Round under the production sharing regime this year (2017).

The 14th Round will include 10 ultra-deepwater blocks in the northern portion of the Campos Basin. In all, 291 exploratory blocks were selected, distributed in 29 sectors, in nine sedimentary basins. Information is expected to be published in early 2017 in order to make the offers in Q3 2017.

The 2nd Round under the production sharing regime is scheduled for Q3 2017 and will offer four areas in the Campos and Santos basins, including areas related to the Cat do Mato and Carcará discoveries and the Green Turtle and Sapinhoá fields.

G Lundin hits at Neiden

Sweden's Lundin has made a ca.25-60 MMboe oil and gas discovery on the Loppa High, 20km east of the Johan Castberg discovery in the Norwegian Barents Sea.

The well, 7220/6-2 R, a deepening of well 7220/6-2, was drilled on the Neiden prospect in production license 609 (PL609).

According to the Norwegian Petroleum Directorate, the Neiden well encountered a 20m total oil column with a 10m overlying gas column in carbonate rocks in the Ørn formation, with good to moderate reservoir properties. In the Snadd formation, the well encountered aquiferous sandstone with moderate to good reservoir properties.

Drilled in 387m water depth by the *Leiv Eiriksson* semisubmersible drilling rig, the well is 60km northeast of Lundin's Alta discovery and on a trend with the Børselv prospect, which Lundin is looking to drill in 2017.

"The well demonstrates high quality karstified carbonate reservoir which reduces the risk of the Børselv prospect, 15km north and up dip from the Neiden discovery in PL609," says Lundin.

I PGS starts Namibia 3D survey

Africa-focused Impact Oil & Gas has tapped Petroleum Geo-Services (PGS) to begin acquiring 1900sq km 3D seismic in Block 2913B, offshore Namibia. PGS will use the *Ramform Sterling* to conduct the survey, which will target the Aptian basin floor fan reservoir.

Block 2913B, which has water depths of about 2500m, lies 300km offshore and is immediately adjacent to the South Africa maritime boundary. Impact holds an 85% working interest in the Block and is the main operator. NAMCOR, a state oil company, holds 10% and

H Engie brings Cygnus online

Engie E&P UK has started production from the giant Cygnus gas development in license areas P1055 and P1731, 150km off Lincolnshire.

Cygnus was developed using four platforms, two drill centers (Alpha and Bravo), a total of 10 wells and two subsea structures, serving an estimated field size of 250sq km. With gross 2P reserves of approximately 18 Bcm, according to a 2015 estimate, it is expected to achieve plateau production of 250 MMcf/d and contribute 5% of UK gas production.

The Cygnus Alpha Process and Utilities platform will receive and optimize the gas from the Alpha and Bravo wellhead platforms, and transport it through a pipeline to the Bacton gas terminal onshore.

Global E&P Briefs

Grisham Assets Corp. 5%.

The block is 150km west of the Kudu gas field, but recent exploration wells along the outer fringes of the Orange Basin have demonstrated that there exists a rich oil prospective zone running through the block, Impact said.

J BP bets on Mauritania, Senegal

BP will invest US$1 billion for a 62% stake in Kosmos Energy's gas prone Mauritanian exploration blocks plus a 32.49% working interest in Kosmos' Senegal exploration blocks – totaling some 33,000sq km. The acreage could contain about 50 Tcf of gas, including the 15 Tcf Tortue deepwater gas discovery resource, and more than 1 billion bbl potential, BP says, and exploration prospectivity across both countries. BP believes the area could become a future liquefied natural gas hub.

Kosmos will receive fixed consideration of $916 million, including $162 million up front, $221 million carry on exploration and appraisal, including a drill stem test (DST) on Tortue expected to be completed in 2017, and $533 million maximum carry on development costs until first gas production on the Tortue project, including the front end engineering and design study.

L Cyprus awards three blocks

The Cyprus Council of Ministers awarded three blocks in the country's exclusive economic zone in the Mediterranean Sea during its 3rd Licensing Round.

Eni and Total (in a 50-50 partnership) took Block 6, while Eni picked up 100% interest in Block 8, and ExxonMobil, with partner Qatar Petroleum won Block 10. According to Eni, these areas have geological affinities with those successfully explored by the Italian firm in the neighboring areas in the Egyptian offshore, with the discovery of the Zohr super-giant gas field.

K Aker BP starts up Ivar Aasen

Aker BP produced first oil from Ivar Aasen on Christmas Eve, four years after the plan for development and operation was submitted.

The Ivar Aasen field is in the northern part of the North Sea, about 175 km west of Karmøy, Norway, neighboring the Edvard Grieg field. It is thought to contain around 186 MMboe. Oil and gas from Ivar Aasen is processed and exported from Grieg platform, which also supplies power to Ivar Aasen, Aker BP said.

Aker BP operates Ivar Aasen (34.8%) along with partners Statoil (41.5%), Bayerngas Norge (12.3%), Wintershall Norge (6.5%), VNG Norge (3%), Lundin Norway (1.4%), and OKEA (0.5%).

M Leviathan takes next step

Delek Drilling and Avner Oil, part of the Leviathan partnership with operator Noble Energy, approved the development plan for the mega-discovery, offshore Israel, in early December. The decision paves the way to Leviathan's final investment decision (FID), which Noble Energy previously said it expected to by early 2017.

The Leviathan partners have also agreed to drill the US$77 million Leviathan-5 appraisal and production well in the Leviathan North I/15 lease as part of an updated field development plan.

The well will be 130km west of Haifa, Israel, and will target layers from Oligo-Miocene age in 1740m water depth, to about 5200m below sea level. Drilling is expected to start in Q1 2017.

N Lukoil adds Caspian pay

Lukoil has struck more pay at its third well in the Vladimir Filanovsky field in the shallow waters of the Caspian Sea.

The horizontal section of the well is 1217m long, with a flow of about 3000-ton/d of crude oil. The field's total oil production currently amounts to approximately 9000-ton/d, Lukoil said.

The Vladimir Filanovsky field, which saw first oil at the end of October, is in the northern Caspian Sea, 220km off the coast of the city of Astrakhan at 7-11m water depth.

O Azerbaijan heats up

Total and SOCAR, the national oil company of Azerbaijan, signed an agreement establishing the contractual and commercial terms for a first phase of production of the Absheron gas and condensate field, in the Caspian Sea. The development includes drilling on one well at 450m water depth. Production from this high pressure field will be around 35,000 boe/d, including a significant portion of condensate.

BP will continue running the Azeri-Chirag-Gunashli (ACG) development in the Caspian Sea until 2050, following SOCAR's approval. ACG is a super-giant field about 100km east of Baku. Discovered in the early 1970s, it is the biggest producing oil field in the Caspian Sea and covers an area of more than 432sq km in 120m-170m water depth. The depth of the reservoir is 2000-3500m.

Elsewhere, Manila's Asian Development Bank (ADB) will invest US$1 billion in the expansion of the BP-led Shah Deniz II project.

P India invests in deepwater gas

Indian officials announced the country will invest US20 billion to develop deepwater gas resources in the country's east coast over the next 5-7 years. The investment will target 20 Tcf of reserves, and will primarily go to developing natural gas discoveries by India's own ONGC and the Reliance Industries and BP-led joint venture off the east coast.

Q Malikai in production

First oil has been achieved from Shell's deepwater Malikai field, offshore Sabah, Malaysia.

Malikai sits about 100km off Sabah, in about 500m (1640ft) water depth. It comprises two main reservoirs with a peak annual production of 60,000 b/d. Oil is transported by pipeline to the shallow-water Kebabangan

platform for processing. The Malikai tension leg platform will use the produced gas for gas lift and power.

The field is part of the Block G Production Sharing Contract and is operated by Shell (35%), with partners ConocoPhillips Sabah (35%) and Petronas (30%).

Japanese trio eye Sakhalin

Japan Oil, Gas and Metals National Corp. (JOGMEC), Inpex and Marubeni have agreed on a project to jointly explore the area southwest of Sakhalin Island, working with Russia's Rosneft under a heads of agreement.

As a part of the cooperation, the trio is considering deploying a seismic vessel, *Shigen*, as well as a scheme of overseas geological and geophysical survey by JOGMEC.

The deal is the result of Rosneft's strategy to attract partners into offshore projects.

Phoenix South-2 hits pay

Operator Quadrant Energy made a gas and condensate discovery at the Phoenix South-2 well, on the Caley prospect, offshore the Northwest Shelf of Australia.

The well, in permit WA-435-P, drilled an estimated 39m hydrocarbon-bearing zone between about 5176m and 5215m, with significant gas influx and elevated reservoir pore pressures.

The well was unable to assess as much as 185m of additional potential hydrocarbon bearing Caley reservoir beneath 5215m, due to the higher than anticipated pressures being encountered.

The higher pressures mean a different wellbore design from that used in the current well is needed to drill further, so the well was stopped.

SBM grabs Liza FPSO

ExxonMobil picked SBM Offshore to perform front-end engineering and design (FEED) for the floating production, storage and offloading unit (FPSO) for the supermajor's Liza development offshore Guyana. Also, subject to a final investment decision (FID) in 2017, SBM could construct, install and operate the FPSO.

Subsea alliance wins Dalmation EPCIC contract

The Subsea Integration Alliance (a collaboration between Schlumberger, OneSubsea, and Subsea 7) won a deepwater integrated subsea engineering, procurement, construction, installation and commissioning (EPCIC) multiphase boosting system contract from Murphy Exploration & Production Co.–USA.

The scope of the contract calls for the supply and installation of a subsea multiphase boosting system for the Dalmatian Field in the Gulf of Mexico. This includes topside and subsea controls, as well as a 35km integrated power and control umbilical. The alliance enables a turnkey integrated project from design through supply, installation and commissioning.

Offshore installation activities are scheduled for 2018.

Aibel wins Snorre A FEED

Norway's Aibel won a front-end engineering and design (FEED) study for modifications on the Snorre A facility in connection with Statoil's Snorre Expansion project in the Norwegian Sea.

The contract includes options for the actual implementation phase of the project – engineering, procurement, construction, installation and commissioning (EPCIC) – as well as for further study work and the implementation of this. If all options are exercised, the project will have a duration of a total of five years. Work starts immediately and will be headed by Aibel's headquarters in Stavanger. An eventual implementation phase will also provide work for the company's yard in Haugesund, including construction of a 600-ton riser hang-off module.

RINA bags Indonesian work

RINA Indonesia, in consortium with PT Depriwangga, has won a contract from Chevron Indonesia to provide QA/QC inspection services as part of the offshore Bangka Field development project, 70km offshore at East Kalimantan in water depths of 3200ft. RINA Indonesia will provide inspection services for material and component fabrication, installation, testing, pre-commissioning and commissioning activities. In addition, the company will perform third party expediting services for various materials and equipment purchased domestically and globally for the project.

Oda contracts awarded

Centrica has awarded a string of contracts to FMC Technologies, Subsea 7 and Aker BP / Maersk Drilling, for its Oda (previously Butch) field development in the Norwegian North Sea.

FMC Technologies will supply the subsea template with associated subsea production system.

Subsea 7's scope covers EPCIC of subsea umbilicals, risers and flowlines (SURF) including the production pipeline, water injection line, umbilical and related subsea services. Subsea 7 and FMC are part of Centrica's strategic partner alliance, signed in Autumn 2015.

Maersk Drilling will supply the Maersk Interceptor jackup to drill three wells – two production wells and one water injection – on Oda. Drilling is due to start in 2018.

Aker BP, which operates the Ula facilities, will use Aker Solutions for topsides modifications work, which will include work related to fabricating new caissons for Oda risers and umbilicals.

Project management and engineering will start immediately from Subsea 7's office in Stavanger, Norway, with offshore operations scheduled to start in 2018.

Pioneering Spirit wins TurkStream gig

Allseas has been contracted to lay the first line of the TurkStream offshore gas pipeline in the Black Sea, with an option for laying the second line. The contract calls for Allseas to lay more than 900km of pipes on the seabed. Allseas will use its mega-vessel *Pioneering Spirit* for the job, which is equipped with pipelay equipment making it possible to install record weight pipelines from shallow to ultra-deepwater, and has an S-lay tension capacity of 2000-tonne.

The vessel, currently in the Alexiahaven in Rotterdam, is equipped with a double-joint factory, six welding stations for double joints and six coating stations. Allseas will start laying the first line in 2H 2017. ▪

In September 2016, Stampede's topsides deck was successfully lifted onto the hull; since then, all the main modules have been lifted onto the two-deck structure, and integration is proceeding well.
Photos from Hess Corp.

Slow and steady wins the race

Hess is dedicated to bringing its Stampede project online on-time and on-budget, with safety being the key to success. Jerry Lee dives into the finer details of the project, slated for 2018.

The Hess-operated Stampede development project is one of the few mega projects in development in the US Gulf of Mexico (GoM), and according to Hess, it is one of the largest undeveloped fields in the GoM. The New York-headquartered firm aims to bring the field online by 2018, and to keep costs down while doing it.

With only one in five mega projects coming within 10% of budget and schedule, Stampede is on track to be one of them, despite the low oil price environment where value erosion is easy, but value creation is difficult to achieve, said Stephen Whitaker, project director-Stampede Development, Hess, at a luncheon hosted by the Marine Technology Society in Houston in back in August 2016.

The strategic imperative is, "Hess has a strong commitment to deliver top quartile performance in safety, quality, delivery and cost at the corporate level, and we embrace that commitment on the Stampede project," Whitaker said. "Safety and the environment is our first priority at Stampede and across Hess; if we deliver on safety and with quality, cost and delivery will be successful outcomes."

Stampede is a joint development of the Knotty Head and Pony fields, discovered in 2005 and 2006, respectively. Stampede, spanning Green Canyon blocks 468, 511 and 512, is 115mi south of Port Fourchon, Louisiana, in 3500ft water depth, and is estimated to hold 300-350 MMboe in gross recoverable resources in Miocene subsalt reservoirs.

"The Stampede reservoir structure lies at a depth of about 30,000ft with several pay intervals layered within a span of 3000ft at that depth," Whitaker noted. "It is one of the deepest developments with in-well gas-lift in the GoM."

The US$6.2 billion project was sanctioned in October 2014 by Hess (25%) and its co-owners Statoil (25%), Nexen (25%), and Union Oil Co. of California (25%), a Chevron subsidiary.

The plan

The subsea project will be developed around two six-slot drill centers, spaced about 1mi apart, which will utilize 15,000psi-rated enhanced vertical deepwater trees (from FMC Technologies), production manifolds and gas-lift distribution units. Production from each drill center will be tied back to the Stampede tension leg platform (TLP) using two piggable flowlines. From the TLP, gas will be exported to the Discovery pipeline system and oil will be exported to the Amberjack pipeline system through a 16mi pipeline owned and operated by Enbridge.

Drilling on the field began in Q1 2016 with Diamond Offshore Drilling's *Ocean BlackLion* drillship drilling the first of six production wells on the field. In total, 10 wells will be drilled on the field, which includes four injection wells. A second drillship, the *Ocean BlackRhino*, is expected to join in 2017.

The field production will be enhanced using in-well gas-lift, and reservoir pressure will be supported through high pressure water injection. The TLP has a capacity for 80 MMscf/d of gas-lift gas and 100,000 b/d of seawater injection.

Progress

The first major milestone for the project occurred in December 2015 with the

installation of the 12, 400ft piles driven 375ft into the seabed on site by Heerema Marine Contractors (HMC), to which the TLP will be moored using 12 buoyancy supported tendons.

Across the world, in South Korea, the Stampede TLP hull was being constructed by Samsung Heavy Industries (SHI). Hess worked with MODEC– contracted for engineering, procurement, and project management of the hull and mooring system – and SHI to fabricate the four giga blocks (4000-5000-ton each) that would comprise the TLP's hull. Over an 18-month period, the hull was fabricated, lifted, assembled, and mechanical activities completed. On 12 June 2016, the 300 ft x 300 ft, 22,000-ton assembled hull was transported by the *Dockwise Treasure* to Ingleside, Texas, a 54-day operation, where Kiewit Offshore Services (KOS) is constructing the TLP's topsides.

The hull arrived at Ingleside on 5 August 2016, for integration with the topsides. Front-end engineering and design for the topsides was performed by Wood Group Mustang, and includes a seawater injection module – being built by Cameron in New Iberia, Louisiana, and capable of treating 100,000 b/d of water; a water injection module- capable of injecting 100,000 b/d of water at 8500psig; a compression module, living quarters for 70 people, warehouses and workshops. Weighing in around 10,250-ton the all-electric topsides will have two decks and be about 200ft-wide and 250ft-long. Earlier in 2016, the main deck was successfully lifted onto the production deck, and since then, all the main modules have been lifted onto the two-deck structure. With the lifts complete, integration has commenced and the work is proceeding well, Hess says.

"All major lifts are now complete," said Greg Hill, president and chief operating officer, Hess, during a Q3 2016 earnings call.

The *Ocean BlackLion* has also safely finished drilling the field's first production well.

"The first well we took very carefully, very slowly, making sure we were able to create the right path for the oil coming back," Whitaker says. "We're spending a lot of time (6+ months) drilling these wells, and even with rig rates the way they are today, that's a significant amount of cash we're investing."

With drilling operations finished at the production well, the *Ocean BlackLion* has moved on to drill the field's first water injection well, but will return to the production well at a later date to perform completions operations, Whitaker says.

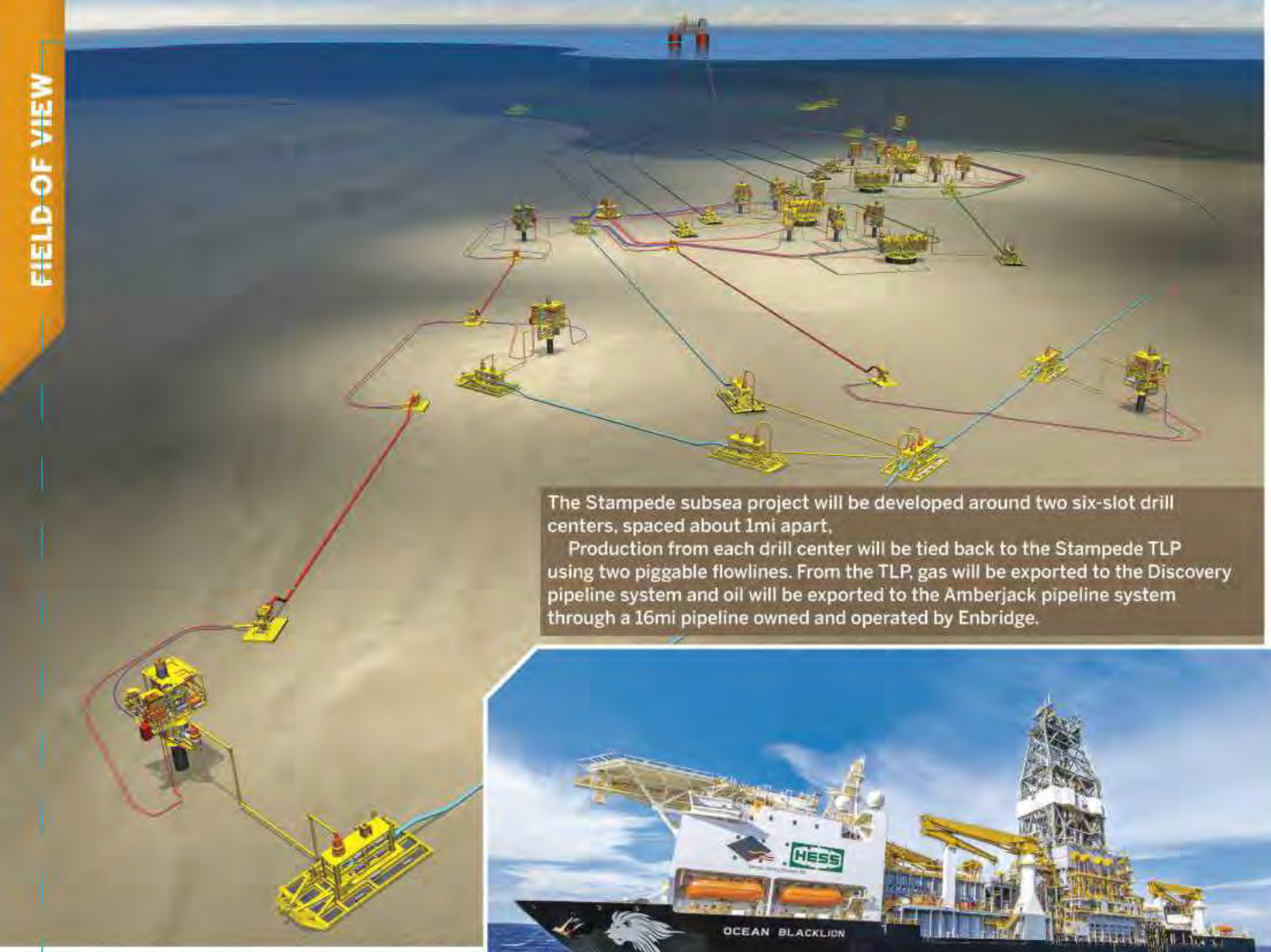
Work to be done

With the topsides set on the hull, the remaining work prior to first oil will involve installing the subsea pipelines and associated architecture, installation of the facility, and commissioning.

"We look to limit the amount of work we take offshore, so most of the work will involve hooking up and pre-commissioning the flowlines and export pipelines, as well as overall commissioning of the facility," Whitaker adds.

In 2014, Subsea 7 was selected to install flowlines, steel catenary risers (SCRs), umbilicals, jumpers and associated subsea architecture for Stampede. The *Seven Oceans* pipelay vessel and the *Seven Pacific* construction/flex-lay vessel will handle the majority of the installation work.

In February 2016, massive columns known as giga blocks used for the construction of the TLP hull, were lifted into the offshore floating dock at SHI on Geoje Island, Korea. Over an 18-month period, the hull was fabricated, lifted, assembled, and mechanical activities completed.



The Stampede subsea project will be developed around two six-slot drill centers, spaced about 1mi apart,

Production from each drill center will be tied back to the Stampede TLP using two piggable flowlines. From the TLP, gas will be exported to the Discovery pipeline system and oil will be exported to the Amberjack pipeline system through a 16mi pipeline owned and operated by Enbridge.

Diamond Offshore Drilling's *Ocean BlackLion* at work on the Hess-operated Stampede oil and gas development in the Gulf of Mexico, located 115mi south of Fourchon, Louisiana, in Green Canyon blocks 468, 511, and 512. Drilling began in Q1 2016. In total, 10 wells will be drilled on the field, which includes four injection wells. The *Ocean BlackLion* is one of two drillships planned for the field.

The vessels will have to lay and install PLETs (pipeline end terminations), manifolds, distribution units, jumpers and flying leads, together with flowlines and SCRs (supplied by Vallourec), and umbilicals and umbilical distribution hardware (delivered by Oceaneering). This follows the installation of the oil export line and SCR by Enbridge using Allseas' *Audacia* pipelay vessel.

When it is ready, HMC's *Aegir* heavy lift vessel will install the field's TLP. But first, the buoy supported tendons will need to be installed on the piles.

"The TLP will then be towed out to the lease, ballasted down over the tendons and connected to them," Whitaker says. "This operation is highly weather dependent."

After the TLP is connected to the piles, the SCRs will be picked up by the *Aegir* and connected to the TLP followed by the installation of the tie-in spools and dynamic umbilicals, thus connecting the TLP to the drill centers.

When the *Ocean BlackRhino* begins its contract in 2017, it will join the *Ocean BlackLion* and begin drilling the first well on the north drill center, which will be the field's second production well. Also on the list, the sister ships will take on "some of the deepest wells in the world," which [Hess] will be executing over the next couple of years, Whitaker says.

"After first oil, we will have to drill and complete the remaining wells and commission the water injection system," Whitaker says. "The completions for both production and injection wells will be multi-zone intelligent well completions."

On track

The Stampede development project is currently on-track and Hess intends to keep it that way, by staying engaged with the contractors and co-owners as the project progresses and challenges arise, the firm says.

"As we move the project offshore, the impact of the weather, in particular loop currents and storms next year, cannot be ignored," Whitaker says. "Chevron and Statoil are co-owners on Big Foot as well as Stampede, so we're taking their learnings from Big Foot and applying them. That's a combination of our handling the tendons, and, operationally, having plans ready should there be problems going forward."

The Stampede TLP is on schedule to come online in 2018. Stampede is expected to produce about 60,000 boe/d gross. Designed with an export capacity of 80,000 b/d and 40 MMcf/d, peak production is expected to range 60,000-70,000 b/d, this extra capacity combined with the spare SCR porches leaves room for future wells or tie-ins.

Hess says it remains committed to delivering on safety, quality, delivery and cost on a corporate level, and it applies this to Stampede. "Safety is key," Whitaker says. "A safe project is a good project." **OE**

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In-Depth

Israel's gas revolution

Israel is eyeing both future energy independence and potential export markets with the launch of its first-ever offshore licensing round. Audrey Leon reports.

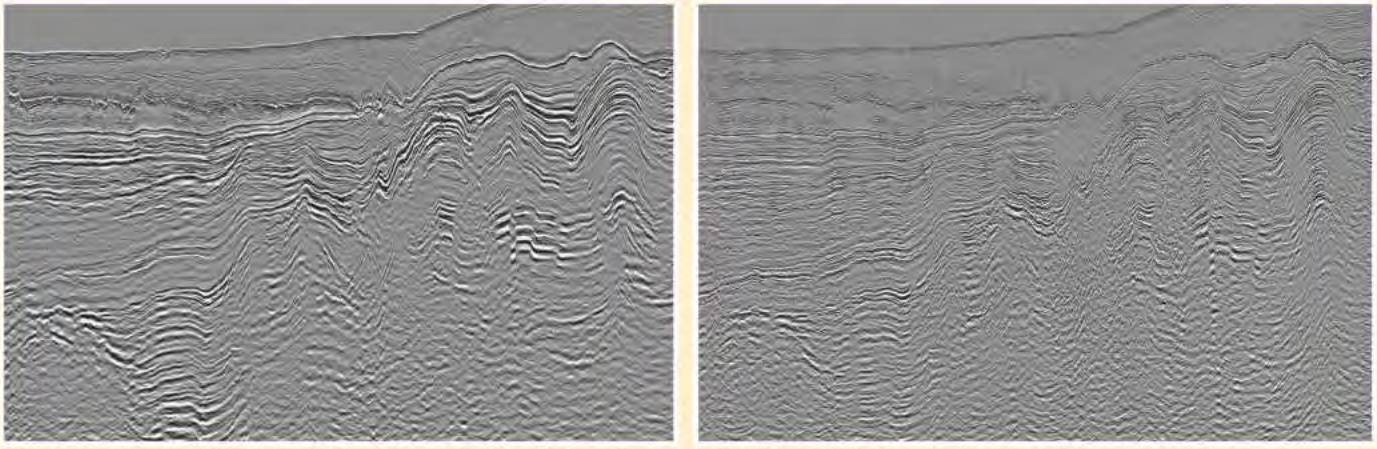
Tiny Israel has big dreams of a gas-based economy. In the last 15 years, the Middle Eastern country has gone from a net importer of fossil fuels, to a natural gas producer with significant export potential in the long-term. With major discoveries being made in the Eastern Mediterranean, such as the 30 Tcf Zohr gas find offshore neighboring Egypt, as well as a few on Israel's side, the country is ready to open its territorial waters to further investment.

"The opening of the sea for natural gas and oil searches is the best investment for Israel and its future. It is the best chance to increase the national resources bag for years to come," said Israel's Minister of Energy, Dr. Yuval Steinitz, in early November.

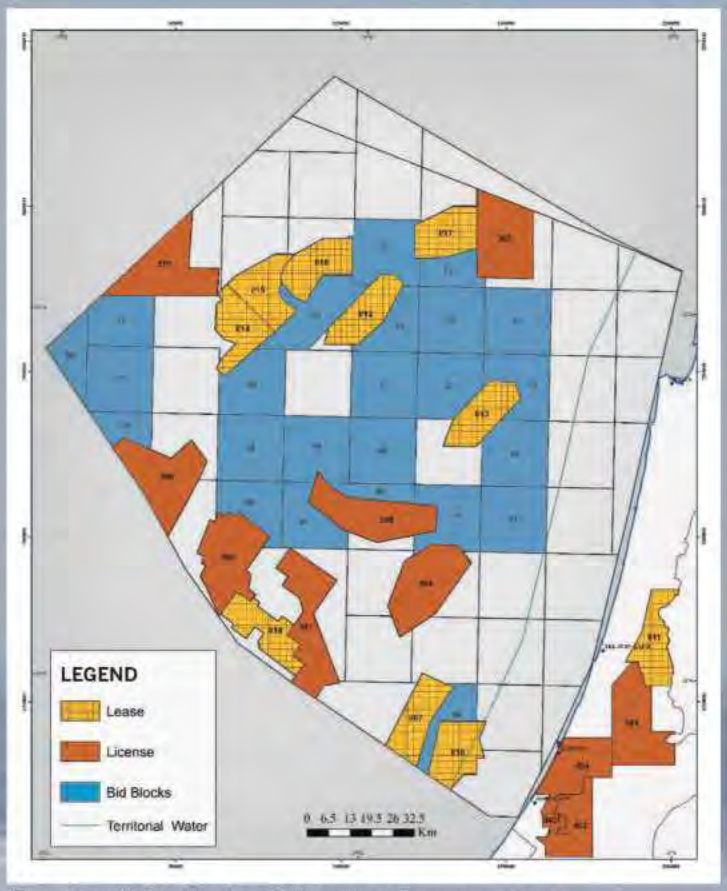
In the summer of 2016, Israel's Ministry of Infrastructures, Energy and Water Resources (MIEWR) announced that the country would finally hold its first offshore licensing round, offering 24 blocks in the Levant Basin in the Eastern Mediterranean Sea.

IHS Energy, which assisted MIEWR with its international road shows, said that a recent, third-party basin modeling study estimated that there are 6.6 billion boe and 2.13 Tcm (75 Tcf) of gas yet to be found in the offshore part of the basin (in-place, yet-to-find, best estimate).

Israel's government hopes that the round will help further break up the monopoly on the country's producing gas assets, which has been dominated by one operator, Houston-based Noble Energy. And while Noble has been highly successful along with its Israeli partners in the Eastern Mediterranean with huge discoveries, such as Tamar and Leviathan, Israel



The reprocessed multiclient 2D line survey (left) and the original shot in 2001 (right) Images from TGS.



Map of available blocks offshore Israel. Image from MIEWR.

wants to drum up some healthy competition.

"We're waiting for you to come," said Shaul Meridor, general manager, MIEWR, at the licensing round road show held in Houston in late November 2016.

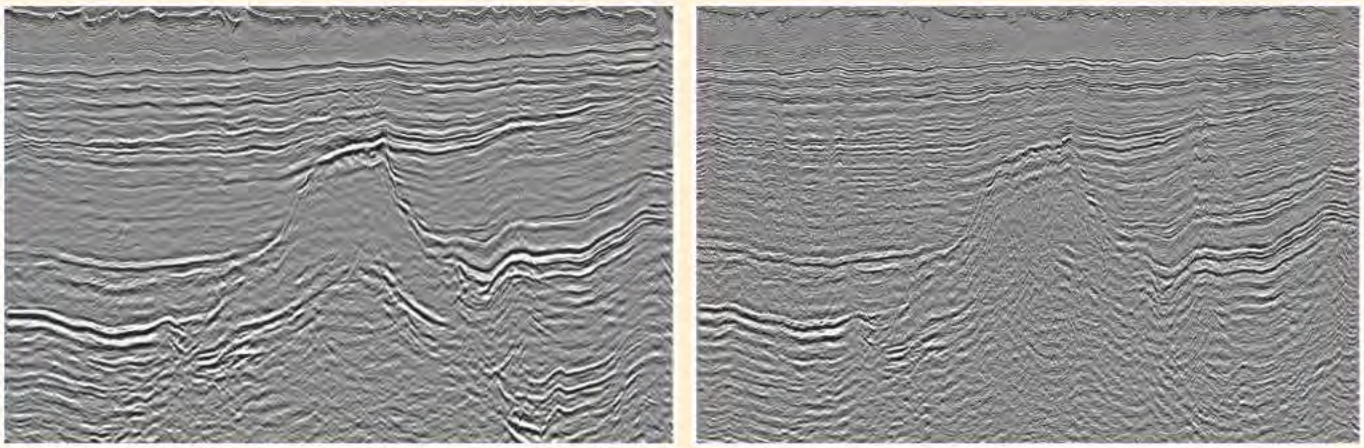
The blocks available are a maximum size of 400sq km, and begin about 7km from shore, some of which are adjacent to recent world class gas discoveries in water depths of between 1500-1800m. The round began accepting bids in November. The bid period ends in April this year with winners due to be announced in July, Meridor told the road show audience.

The 24 blocks made available to interested parties are close to major finds and producing assets, including Tamar (discovered in 2009), Leviathan (discovered in 2010), Karish, and Tanin (discovered 2012-2013) to the North of the prospective offshore area, and the Mari-B and Noa gas fields (discovered in 1999-2000) to the southern portion of the prospective area.

Why choose these specific areas? Michael Gardosh, head of geology and geophysics for Israel's Minister of Energy, said that Israel believes these are the best for exploration.

"They hold good potential," he told the road show audience. "They are outside the territorial waters, far away from the national border. We don't foresee any issues working here. We consider these good areas."

The timing for a licensing round could not be better. In January 2016, according to a resource report by Netherland, Sewell & Associates, two fields – operated by Isramco Negev and Modiin Energy – showed multi-trillion cubic feet prizes. The Og field lower sand contains 8.84 Tcf best estimate,



The reprocessed Jonah High survey (left) and the original (right) Images from TGS.

Quick stats

OE's at-a-glance guide to offshore hydrocarbon reserves and key offshore infrastructure globally is updated monthly using data from leading energy analysts Infield Systems (www.infield.com).

New discoveries announced

Depth range	2014	2015	2016	2017
Shallow (<500m)	77	57	24	0
Deep (500-1500m)	32	20	9	0
Ultradeep (>1500m)	13	12	6	0
Total	**122**	**89**	**39**	**0**
January 2016 date comparison	127	114	72	-
	-5	-25	-33	-

Note: Operators do not announce discovery dates at the time of discovery, so totals for previous years continue to change.

Reserves in the Golden Triangle

by water depth 2015-19

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Brazil			
Shallow	15	400.00	4,649.00
Deep	14	1,149.00	2,735.00
Ultradeep	35	10,783.00	12,756.00
United States			
Shallow	9	39.00	85.00
Deep	18	1,055.00	1,532.00
Ultradeep	15	2,515.00	2,520.00
West Africa			
Shallow	126	4,083.00	16,604.00
Deep	30	3,160.00	4,300.00
Ultradeep	13	1,671.00	2,518.00
Total	**260**	**24,455.00**	**43,050.00**
(last month)	(247)	(23,029.00)	(36,831.00)

Greenfield reserves

2015-19

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Shallow	951	35,765.00	323,176.00
(last month)	(859)	42,722.00)	(412,261.00)
Deep	146	7,647.00	107,641.00
(last month)	(119)	(6,794.00)	(67,663.00)
Ultradeep	74	16,184.00	46,491.00
(last month)	(70)	(15,015.00)	(41,188.00)
Total	**1,171**	**59,596.00**	**477,308.00**

Pipelines

(operational and 2016 onwards)

	(km)	(last month)
<8in.		
Operational/ installed	41,040	(40,907)
Planned/ possible	23,302	(23,814)
	64,341	(64,721)
8-16in.		
Operational/ installed	81,476	(81,264)
Planned/ possible	49,065	(49,708)
	130,542	(130,971)
>16in.		
Operational/ installed	94,263	(94,248)
Planned/ possible	44,991	(45,421)
	139,254	(139,670)

Production systems worldwide

(operational and 2016 onwards)

Floaters		(last month)
Operational	298	(295)
Construction/ Conversion	45	(48)
Planned/possible	295	(300)
	638	(643)
Fixed platforms		
Operational	9105	(9101)
Construction/ Conversion	72	(78)
Planned/possible	1372	(1377)
	10,549	(10,556)
Subsea wells		
Operational	4879	(4878)
Develop	374	(354)
Planned/possible	6425	(6431)
	11,678	(11,663)

Global offshore reserves (mmboe) onstream by water depth

	2015	2016	2017	2018	2019	2020	2021
Shallow	21,242.45	41,358.83	26,780.31	11,369.67	16,406.33	19,157.60	18,986.97
(last month)	(21,242.45)	(41,590.62)	(27,267.21)	(10,773.48)	(19,093.94)	(16,665.07)	(-)
Deep	972.99	1819.37	5356.21	2556.20	4120.72	4561.99	10,025.41
(last month)	(972.99)	(1733.40)	(5442.18)	(2556.20)	(4430.98)	(4561.99)	(-)
Ultradeep	2023.19	3100.10	1767.31	3685.74	4362.19	9359.68	5,206.35
(last month)	(2023.19)	(3137.60)	(2460.70)	(3287.30)	(4144.56)	(9295.86)	(-)
Total	**24,238.63**	**46,278.30**	**33,903.83**	**17,611.61**	**24,889.24**	**33,079.27**	**34,218.73**

Source: InfieldRigs 7 Dec 2016

unrisked gross prospective resources and the Og field upper sand contains 3 Tcf. Both also have some condensate.

In addition to these finds, Israel's neighbor Egypt has racked up new major natural gas finds, including Eni's mega-discovery, Zohr (*OE*: April 2016), discovered in August 2015. Zohr – which is being fast-tracked with an eye on first gas by late 2017 – is also in the Mediterranean Sea, some 190km north of Port Said in 1500m water depth. Thought to be the largest gas discovery made in the Mediterranean, Eni has estimated total gas resources in place to be approximately 30 Tcf. In contrast, Israel's Leviathan, operated by Noble, is estimated to contain 22 Tcf of natural gas.

Geology

As *OE* reported in April, in a profile on Zohr, the discovery itself was almost missed when its previous operator did not consider the area where it was eventually found, the Miocene carbonate build-up.

Gardosh believes that there is likely a similar system to Zohr within Israeli waters, he told the road show audience in November.

He further discussed the Jonah High, which is a structure that is somewhat deeper than Egypt's Zohr, with a good layer of shale covering. He said that the Myra-1 well (near the Tamar and Leviathan fields) was designed to test this. The well, then-operated by GeoGlobal Resources, was drilled in 2012. It ran into some difficulty, and was unable to penetrate the structure, only the top of it. "This could be potentially prolific," he told the audience, and he added that there could be more plays just like it.

Gardosh also noted that Israel's offshore geological conditions, which he said are favorable for generation and accumulation of both oil and gas, adding that of the 35 exploration wells that have been drilled there has been a high success rate (>60%).

A report by French consultants Beicip-Franlab, conducted in 2015, Gardosh said, highlighted the potential for both oil and gas in the lower and upper Jurassic and middle Cretaceous. He added that there is good source rock for biogenic gas in the Oligocene, Miocene, and Pliocene.

Gardosh highlighted four main hydrocarbon plays – three of them in proven (Pliocene, Oligo-Miocene, Jurassic) and one is speculative (Cretaceous). But, he noted that additional traps are likely found in all plays.

Seismic firm TGS shot a multiclient 2D line survey, covering 6831km in 2001 offshore Israel. According to a statement from TGS to *OE*, the Israeli data pack includes the 2001 vintage version, but misses the improved new version, TGS says. "Since reprocessing these data in 2016, TGS has needed to update its interpretation. While the reprocessing has greatly improved the imaging of the biogenic plays and made facies interpretation and identification more reliable, it has also revealed new, deeper structures, and previous assessments of heat flow and maturation now need to be re-appraised. TGS now believes that this deeper, thermogenic set of plays could hold potentially large volumes of mature conventional hydrocarbons in Jurassic and Cretaceous systems."

Easing regulations

Israel has not always been an easy country in which to operate. Famously, Noble Energy and its partners Delek and Avner Oil ran into trouble when it submitted its first Leviathan

development plan. The country was troubled by a growing monopoly that Noble Energy had in the country's offshore and demanded the firm and its partners sell off interest in the smaller Karish and Tanin fields – and, at the time, its interest in the major Tamar gas field, already in production.

Ultimately, a new gas framework was developed by the energy minister and approved by Israel's government and parliament in 2015 to get development activity back on track. Noble Energy received approval from MIEWR for its Leviathan development plan in June 2016. Noble Energy said in early November of the same year that it expects to make a final investment decision by early 2017. The Israeli contingent of the Leviathan partnership approved the field's development plan in December 2016. Wood Group Mustang has been chosen to provide front-end engineering and design work for the project.

But, with the major regulatory issues in the past, Israel is hoping to entice investment and foster competition in the market. Meridor told the road show audience that encouraging industry to come to Israel is one of the government's biggest challenges. Overall, he said, Israel wants a gas-based economy. "Not just because there is gas, but because it is better for Israel," he said. "Our goal is to go natural gas – CNG (compressed natural gas) for cars and buses.

"We will put a lot of incentives there and soften regulations as a whole," he added. "We want to make it easier for plants to move to natural gas, we want to have 100 by 2017. It's our goal and our mission."

Export market

Once the gas is produced it has to go somewhere. Currently, Israel is considering exporting to Egypt, Cyprus and Jordan – where recently Noble Energy and its Leviathan partners signed an agreement to supply some 1.6 Tcf of natural gas over a 15-year period.

Simon Blakely, of IHS, showed the Houston road show audience that there are two main export markets for Israel to consider – Turkey and Egypt.

However, Blakely told the audience, right now there is a very competitive playing field for natural gas and likened the market to a children's game. "When we look at the global gas business today it is a game of musical chairs," Blakely said. "There are parts of the world that have too much gas and parts that don't (outnumbered)."

Blakely cited Russia as a major player and competition for Israel in the natural gas market, with Iran being an unknown quantity at the moment. Russia is already a big supplier for Europe, including Turkey. However, Blakely sees the country as a real commercial opportunity for Israeli gas, calling Turkey a success story. "There are 10 million homes in what was a virgin market – with no infrastructure at all," he says. "It's a very stable market, people have invested in heating systems in their homes."

Additionally, with the lowered oil price curbing investment in liquefied natural gas (LNG) (and floating LNG projects) – Blakely says a gap may soon emerge that will require new LNG contracts, around 2022-23. **OE**

FURTHER **READING**

Egypt's breadbasket – Jerry Lee reports on Italian major Eni's Zohr discovery and its plans to fast-track development. http://bit.ly/2h3VXmP

Rig stats

Worldwide

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	96	65	31	67%
Jackup	399	221	178	55%
Semisub	117	67	50	57%
Tenders	28	19	9	67%
Total	640	372	268	58%

North America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	30	25	5	83%
Jackup	25	5	20	20%
Semisub	9	8	1	88%
Tenders	N/A	N/A	N/A	N/A
Total	64	38	26	59%

Asia Pacific

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	11	4	7	36%
Jackup	116	62	54	53%
Semisub	33	13	20	39%
Tenders	20	13	7	65%
Total	180	92	88	51%

Latin America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	23	18	5	78%
Jackup	50	29	21	58%
Semisub	22	17	5	77%
Tenders	2	1	1	50%
Total	97	65	32	67%

Northwest European Continental Shelf

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	0	1	0%
Jackup	48	30	18	62%
Semisub	38	22	16	57%
Tenders	N/A	N/A	N/A	N/A
Total	87	52	35	59%

Middle East & Caspian Sea

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	2	1	1	50%
Jackup	118	80	38	67%
Semisub	4	3	1	75%
Tenders	N/A	N/A	N/A	N/A
Total	124	84	40	67%

Sub-Saharan Africa

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	18	13	5	72%
Jackup	20	7	13	35%
Semisub	3	1	2	33%
Tenders	6	5	1	83%
Total	47	26	21	55%

Eastern Europe

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	N/A	N/A	N/A	N/A
Jackup	2	0	2	0%
Semisub	N/A	N/A	N/A	N/A
Tenders	N/A	N/A	N/A	N/A
Total	2	0	2	0%

Source: InfieldRigs 9 Dec 2016

This data focuses on the marketed rig fleet and excludes assets that are under construction, retired, destroyed, deemed non-competitive or cold stacked.

Stena DrillMAX. Photo from Stena Drilling.

The show must go on

Despite reductions in exploration spend, work goes on. Elaine Maslin speaks with Wood Mackenzie's Andrew Latham to find out where explorers will aim their drillbits this year.

With investment expected to be less than half of what it was in 2014, operators are likely to be spending their cash more wisely than ever in 2017.

The global exploration budget is expected to be US$40 billion in 2017. This is about the same as in 2016, despite oil prices rising and stabilizing somewhat, but it is less than half that during 2012-2014, according to Wood Mackenzie.

While there may be an uptick in the future, 2017 isn't likely to see much of it, says Andrew Latham, vice president, Global Exploration Research at Wood Mackenzie, with spending expected to remain flat through to 2018. So, where will the limited 2017 spending go?

Overall, there's likely to be a strong focus on nearfield or "infrastructure-led" exploration, where it is easy to monetize, Latham says: value is key. Shell, for example, said that 80% of its $2.5 billion exploration investment would be in this realm, Latham adds. "That emphasis on nearfield, low risk, but high value barrels, will count for many in the industry."

But, those who are looking for a bit more excitement, there are a few glimmers of light. Some companies remain enthusiastic about deepwater exploration, and there are those looking at where positive break even economics give them an edge.

Hot spots

South America has a couple of hot spots, including Guyana, next to Venezuela, where ExxonMobil has focused its interest. The supermajor made its giant >1.4 billion boe Liza find there

The *Dhirubhai Deepwater KG2* drillship. Image from Transocean

in 2015, and has been assessing it ever since. Liza was the first commercial discovery in the country for 50 years. Guyana's government said that Exxon could make an investment decision in 2017. It's large scale oil and that can mean breakeven returns that work even below the current oil price, Latham says. The fiscal regime also makes Guyana favorable, he says.

Total's apparent success on the Raya well offshore Uruguay, between Brazil and Argentina, as well as interest in the country's latest licensing round, could see a return to drilling there. The Raya reservoir was believed to be good, but precious little information has been released, Latham says. Perhaps the majors know more: Exxon, Statoil and Total have taken more equity in Block 13, in Guyana's Punta del Este basin, in a deal with Shell. Block 13 had originally been awarded to BG Group, now part of Shell.

Transformative margin

A similar trend could be mirrored on the other side of the Atlantic, on the West African Transform Margin; another area where ExxonMobil has spun the bit. Recently, ExxonMobil spudded its deepwater Mesurado-1 well in Liberia-13 Block – Exxon's first in the country and one of the first there for a while, Latham notes. The Mesurado-1 well is in 2438m (8000ft) water depth, according to partner Canadian Overseas Petroleum. The Ebola outbreak in 2014 delayed drilling.

Independents Kosmos Energy and Cairn Energy, while smaller players, have some cash with which to play, and will be looking closely at Senegal, following their recent discoveries there.

Kosmos, which also has a hand in exploration offshore Suriname/Guyana in South America, has played a leading role in opening the Mauritania/Senegal Atlantic Margin basin, West Africa, with the Greater Tortue Complex discoveries comprising some 25 Tcf of discovered gas resource offshore Senegal. The firm is now planning a second exploration phase, further offshore – and looking for liquids. The "multi-million" barrel Requin-Tigre (Tiger Shark) is on the firm's mid-2017-start drilling list, alongside the Lamantin prospect.

In December 2016, BP announced it would join Kosmos off Senegal and Mauritania, making a $1 billion investment in a region it hopes will become a future LNG hub.

Meanwhile, Cairn, which made the major 2014 SNE and FAN discoveries offshore Senegal to the south of Kosmos' acreage, plans to further prove up and add to this resource, as it works towards a development concept. The firm has contracted the *Stena DrillMAX* drillship for two-wells, with options, starting Q1 2017. The current outline plan is a 30-well floating production development, potentially starting up in 2021-23.

Myanmar, once bereft of activity due to international trade embargoes, has been back in the limelight, with large discoveries, including the Thalin-1 well in AD7 block in February 2016, by Woodside Energy. The activity will continue in 2017: Woodside recently contracted the *Dhirubhai Deepwater KG2* (a deepwater drillship) for a year-long campaign in the region in 2017.

Another possible hot spot could be the eastern part of Norwegian Barents Sea, which has recently been opened to the industry. The Norwegian Petroleum Directorate (NPD) estimates that almost half of recoverable undiscovered resources remaining in the Norwegian Continental Shelf are expected to be proven in the Barents Sea.

In August 2016, Statoil set out its 2017 drilling plans for the Barents. While the majority of Statoil's 5-7 well campaign will focus on existing areas – around Goliat for example – the Korpfjell well, in PL859 (which covers 12 blocks), awarded in the 23rd licensing round, will break new ground, being to the far east and north of Norway's licensing area.

It is set to be a highly watched well. NPD says that PL859 was the most sought-after license in the round. Statoil describes Korpfjell as being high-risk/high-reward, while partner Lundin believes a structural closure in the license to be 850sq km and over four times the size of that seen in Johan Sverdrup, according to Edison, an investment research firm.

Lundin also sees a 570sq km aerial closure in the Signalhornet Dome in PL857 and describes the potential of the region as being in the order of multi-billion barrels.

Subdued

Over in the US Gulf of Mexico, however, exploration is more challenging, with deeper wells making costs higher, Latham says. Discoveries in 25,000ft deep reservoirs make break-even prices high. "There is lots of exploration potential, but it is slightly up the cost curve."

Drilling expectations have shifted somewhat offshore Australia. BP had been working towards drilling on the Great Australian Bight. But, after numerous knock-backs by Australian authorities, amid strong public opinion against drilling in this area, the firm dropped its plans. That was

really one of the main unknown plays in Australia," Latham says. The spotlight now falls on Chevron; however, it's not likely Chevron will drill here in 2017, he adds.

Black Sea

Beyond 2017, the Black Sea could draw investment. A number of gas discoveries have been made offshore Romania – including the Domino gas discovery. Most recently, Total revealed it had made a deepwater oil discovery offshore Bulgaria. While little has been disclosed about the find, the fact that it is oil, not gas, will heighten interest, Latham says.

The positive news from Bulgaria seems to have inspired drilling in the Turkish Black Sea, Latham says. It may be good timing. "It's a very isolated drilling region and always been high cost because of that," he says. "As costs are low at the moment, it's quite a good time for those that can afford [it]."

Trying something different

It's not all about seeking out plays in new basins or frontiers, however. Some are also taking a new look at mature areas like the North Sea, such as Statoil.

"It's been our view for a while that UK exploration is stuck in a rut and destroying value, even at $100/bbl," Latham says. "Success rates have not been great and discovery costs are exceedingly high." What has been found has often been pools too small to commercialize, he adds.

"Statoil is trying to do something new in the UK," he says. The firm has three firm wells planned for 2017, and at least two are trying new things. One is west of Shetland, the Jock Scott prospect, in which BP recently agreed to take a stake. Another, in the central North Sea, will be on a trend with Premier Oil's Bagpuss heavy oil discovery, which sits in a shallow reservoir (the likes of which Statoil has been addressing in the Barents Sea).

West of Shetland will also be a focus for Nexen, which has two high-pressure, high-temperature wells planned for there, including one on Craster, mid-2017. This is another prospect in which BP has picked up interest.

Longer term

While frontier plays are less fashionable in this low-capex environment, operators are not idle. "What we are seeing is the bigger companies are using this opportunity to grow their exploration portfolios," Latham says, "acquiring licenses at low cost, which contrasts to how difficult it was when oil was $100/bbl. They are taking options for medium-longer term, with not so many commitment wells. Clearly, companies have eye on a 5-10 year view of potential higher prices." **OE**

Colombian exploration heats up

By Audrey Leon

After forming its own offshore-focused offshoot in January 2016, Colombian state oil company Ecopetrol expressed its intentions to stabilize its production with a more "aggressive" exploration drilling program this year [2017].

"We will be aggressively drilling in the offshore in Colombia next year," said Ecopetrol CEO Juan Carlos Echeverry on a November 2016 conference call.

Most of the offshore projects underway are in the northwest of the country, in the Caribbean Sea, an area which Ecopetrol called important to its plans. Ecopetrol's Exploration Vice President Max Torres noted that of the 15 exploration wells the Colombian operator plans to drill in 2017, five will be offshore.

"Our big bet or big promise is offshore," Torres said during the conference call. "[In 2017], we're going to be drilling Brahma, which is a sort of an appraisal of our discovery in Aragua, and two new prospects like Molusco and Siluro. So, as you see, aggressive activity and big promises for the future."

Fred. Olsen's *Bolette Dolphin* drillship in Colombia. Photo from Anadarko Petroleum.

Colombia actively marketed its offshore resources during its 2014 Round, offering 13 offshore blocks, 10 in the Caribbean and three in the Pacific. The round saw Repsol and Anadarko pick up further exploration blocks.

US Independent Anadarko had previously announced in its 31 October operations report that it will drill the Purple Angel-1 prospect in Q4 2016, Anadarko operates Purple Angel and Kronos with 50% working interest. Ecopetrol holds the other 50%.

The Purple Angel-1 appraisal well is designed to test objectives similar to those of the Kronos discovery. Kronos, in a frontier deepwater basin in the Fuerte Sur block, was drilled to 12,200ft (3720m), and encountered 130-230ft (40-70m) of net natural gas pay in summer 2015. Fred. Olsen's *Bolette Dolphin* drillship drilled Kronos prospect and is under contract to Anadarko until 2018. Vessel Tracker placed the drillship near Cartagena, Colombia as of 19 November.

The Brahma prospect is part of the Tayrona Block, which is operated by Brazil's Petrobras (40%). It's partners on Tayrona include Ecopetrol (30%), Spain's Repsol (20%) and Norway's Statoil (10%). Tayrona, offshore Guajira, is home to the 2014 Orca-1 discovery.

The Molusco (Spanish for Mollusk) prospect is inside Block RC-9, operated by Ecopetrol along with partner India's ONGC.

The Siluro prospect is inside the RC-11 block, operated by Spain's Repsol (50%) in partnership with Ecopetrol. According to a 2014 presentation from Repsol, Siluro is in 90m of water and will target the lower Miocene carbonate.

Anadarko also announced in late October that it has completed the Esmeralda 3D seismic survey, covering almost 30,000sq km, making it Anadarko's and Colombia's largest 3D survey and one of the largest 3D surveys in the world. ▪

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Light at the end of the pipeline

Is the subsea market poised for a comeback? Jon Fredrik Müller, of Rystad Energy, sets out the detail.

The subsea market has taken hit after hit over the last years with declining revenues and margins. However, at the same time, the industry has adjusted capacity and is now positioned to start taking advantages of increased activity. First on the tendering side, but then on the revenue and margin side as well. In this article we look at the status of the industry and the likely way ahead.

OPEC back in the game

At the end of November 2016, OPEC announced it would cut production to a level of 32.5 MMb/d. In addition to OPEC, Russia declared that it is willing to cut 300,000 b/d and, according to OPEC, other non-OPEC countries will commit to similar cuts as Russia. However, since the announcement, the oil price has gained close to US$10/bbl and is trading at around $55/bbl at time of writing.

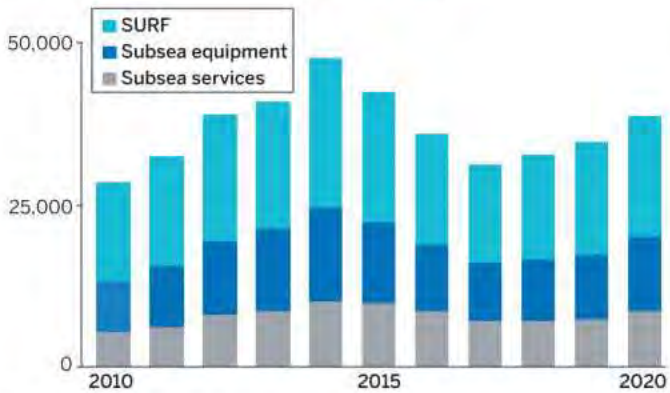
A higher oil price is certainly positive for subsea developments and higher project sanctioning activity. Costs have come down across the entire industry and although several fields are "in the money" at oil prices of $40-50/bbl, these price levels do trigger fewer offshore developments than seen during the 2011-2013 hay days. Looking towards 2020, Rystad Energy sees an increasingly tighter market balance for oil, which implies increasing oil prices. By 2020, Rystad Energy forecasts oil prices to be in the $80-90/bbl range, increasing the need for offshore and subsea developments.

Subsea expenditure – bottoming out in 2017

The bottom of the subsea market is likely still ahead, given the fact that subsea expenditure is relatively late in the cycle. Subsea expenditure (capex and opex) fell from $48 billion in 2014 to $43 billion in 2015 (Figure 1), a negative growth of 10%. In 2016, the market is forecast to contract by another 16% to $36 billion. The market is believed to bottom out in 2017 at $31 billion (-14%), before it returns on a growth path from 2018. By 2020, the subsea market is estimated to reach $39 billion, and it is forecast to continue to grow into the first half of the 2020's, surpassing the last high from 2014.

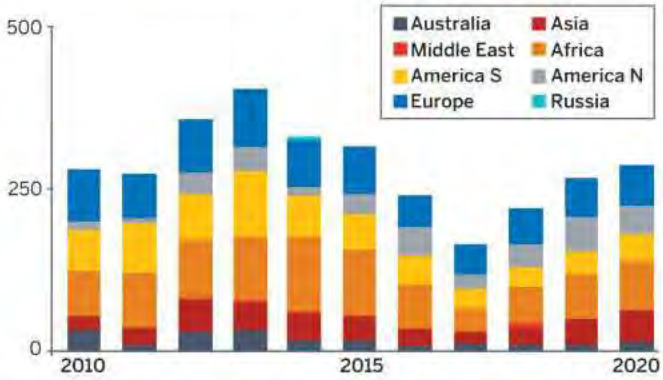
The market development is similar when looking at the number of installed subsea Xmas trees. The number of subsea

Figure 1: **Global subsea expenditure**
(capex and opex, USD billion) by market segment



Source: Rystad Energy DCube

Figure 2: **Subsea Xmas tree installations**
(number of trees) by region



Source: Rystad Energy Oilfield Service Solutions & Analysis

An oil and gas Xmas tree. Photo from GE Oil & Gas.

Xmas trees awarded in 2016 will likely come in closer to 1/10 of the ~550 tree awards of 2013. However, installation activities are smoothened out compared to the awards as there are usually several years from award to installation. Rystad Energy follows installation activity field-by-field. Figure 2 shows the number of subsea Xmas trees installed per year since 2010, with forecast towards 2020. In terms of number of installed trees, the bottom is forecast to be 2017 at approximately 160 trees installed globally. However, Rystad Energy believes that the tree awards have hit the bottom this year and that tendering activity will start to pick up next year.

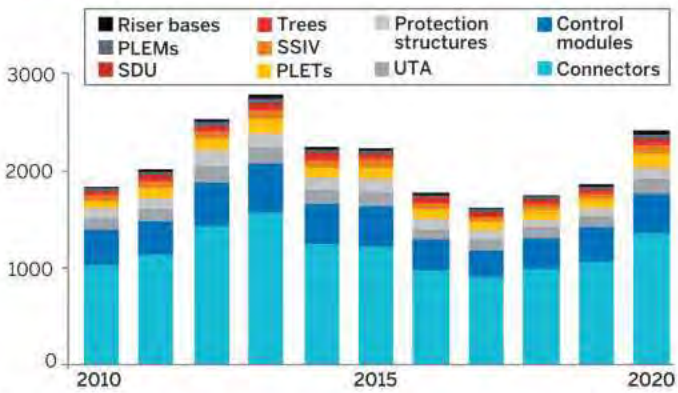
In terms of major subsea markets, it is still the Atlantic basin that will see most of the activity going forward. However, there are also potential deepwater projects in Asia that may drive demand towards the end of the period. Although activity is forecast to improve over the next year, it will likely be into the 2020's before installation activity is back at the high levels witnessed in 2013.

Subsea integration may change field layouts

In terms of subsea structures, the overall market development is quite similar to the subsea Xmas trees. There was a market peak in 2013 and the bottom of this cycle, in terms of installed components, is believed to be in 2017 (Figure 3). However, the different segments fluctuate slightly differently than subsea Xmas trees due to different drivers. For example, protective structures are driven by activity areas/water depths with fisheries, while deepwater developments normally do not include such structures. When it comes to riser bases, you will see much more use in shallow to midwater regions and fewer units in deepwater markets where dynamic loads and riser configurations result in less usage. Figure 3 is based on several years of field–by-field data gathering collected in Rystad Energy. The forecast period is based on communicated plans and subsea developments continuing to utilize similar development solutions that have been seen historically, where plans have not been communicated. It will be interesting to follow the development in subsea infrastructure over the next years to see whether integration in the subsea value chain will result in changes. Mergers like Technip/FMC Technologies and Schlumberger/OneSubsea, and different cooperation agreements between actors involved in subsea production systems (SPS) and subsea installation (SURF), might result in improvements of field design and layout. With potential for single contracts covering the total subsea scope, it would be natural to think that one can improve on interfaces and redundancies in system and work processes. Take pipeline end terminations (PLET) as an example. The structure is an interface between typical SPS and SURF scope as it functions as a "parking lot" for the end of the pipeline while it awaits final hook-up to the SPS. With a single contractor responsible for both SPS and SURF, it should be possible to plan the installation activities in such a way that you could reduce the need for PLETs. Some may argue that the PLET also performs other functions like capturing horizontal movement in the pipe, but Rystad Energy believe that that could be solved by other measures like laying the pipe in S patterns and/or using flex tails.

Going in to 2017, the subsea industry is in many ways at the bottom. 2017 might be harder still for many companies, however, there should be increased tendering activity as the year progresses, giving more transparency on increased revenues for 2018. The market balance for oil, the likely strengthening of the oil price and a large backlog of discoveries that could be developed should, set the scene for 2018 being the start of the next subsea growth cycle. **OE**

Figure 3: **Installation of different subsea structures** (number of components)



Source: Rystad Energy Oilfield Service Solutions & Analysis

Jon Fredrik Müller is a partner in Rystad Energy, based in Oslo. His main area of expertise lies in the oil field service segments and particularly within offshore related segments. He holds an M.Sc. in industrial economics from NTNU, Norway, with specialization in mechanical engineering and finance, including a graduate exchange program at University of Calgary.

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Looking upward


Image from iStock

2017 may be the year things start to look up in the oil and gas sector. Audrey Leon speaks with Robin Mann, of Deloitte, to get a clearer picture on the activity front.

OE: What kind of year is 2017 shaping up to be for M&A activity?

We expect 2017 to be the real start of the rebound for the oil and gas industry as prices will show signs of positive life (not dramatic but steady slow upward movement); however, this will dominantly be on the onshore and in specific areas of the country. The offshore industry will take a little more time to show an increase in drilling activity, but the bleeding should show signs of abating and it is expected that there will be a few transactions occurring as companies position themselves for the future. The offshore is probably still at least a year away from the same optimism that we will more than likely see on the onshore, but this will depend on what part of the world a company is in. For the Gulf of Mexico (GoM), it is anticipated that things will remain somewhat stagnant in the shallow water, but in the GoM deepwater and for other basins such as Asia Pacific and the Middle East, activity and transactions are expected to show positive signs of life.

OE: 2016 saw a lot of high-profile deal activity. How do you expect the offshore industry to evolve and remain competitive? Can you please provide insight on how the market is changing for OEMs specifically?

Companies will continue to pick and choose their areas of activity into 2017, with deepwater being the areas of the most interest – mainly due to the size of the prize and the fact that these are longer term projects that are not as reliant on current daily prices; they have to have a longer term price outlook. For equipment manufacturers and suppliers, 2017 is anticipated to show a slow start with increases in activity toward the latter half of the year. We expect that companies will continue to hawkishly watch their spending on new materials and services early on as prices start to firm up, but will need additional materials as they become more active later in the year. The underlying factor for all projects – and the offshore activity is no exception – is whether the recent cutback in production by OPEC (and related positive price increase) will hold. The industry has become much more skeptical that a positive increase in prices, which we have recently seen, may not be as sustainable as it was in the past due to the increased number of opportunities that are present around the world, and specifically in North America around unconventional plays.

OE: What do you expect to see in 2017 and beyond for the global offshore market? Do you anticipate more consolidation? What regions do you expect to have the most activity?

As mentioned, the areas where we anticipate an increase in activity is in the Asia Pacific and Middle Eastern regions for the offshore. Saudi Arabia and UAE continue to be bullish for the offshore; however, the recent cuts in global oil production may have an effect on this activity in the short-term, but longer term activity should continue to show positive signs of an increase. Through the downturn, offshore Asia Pacific has remained relatively steady and it is anticipated that into 2017 this activity will show an increase. One area where a government is trying to spur activity is in India, where they have revised the price formula for offshore production in underdeveloped fields – with deepwater getting the largest benefit – to increase interest and activity. On the consolidation front, we would anticipate there to be a higher level of activity due to buyers and sellers finally closing the gap on pricing expectations. We do not see this as a flood of activity, but it will definitely show more life than we have seen over the past couple of years – more on the number of deals to consolidate positions and potentially help with operational expenditures in a region versus the magnitude of the total global transactions. **OE**

***Robin Mann** is Oil & Gas Resource Evaluation & Advisory Leader for Deloitte LLP. Mann is a professional geologist with more than 35 years of experience in geological and management positions. He is a partner in Deloitte's Resource Evaluation and Advisory practice where he leads the global practice's technical team and coordinates the firm's Energy and Resources technical capabilities in oil and gas through the Americas.*

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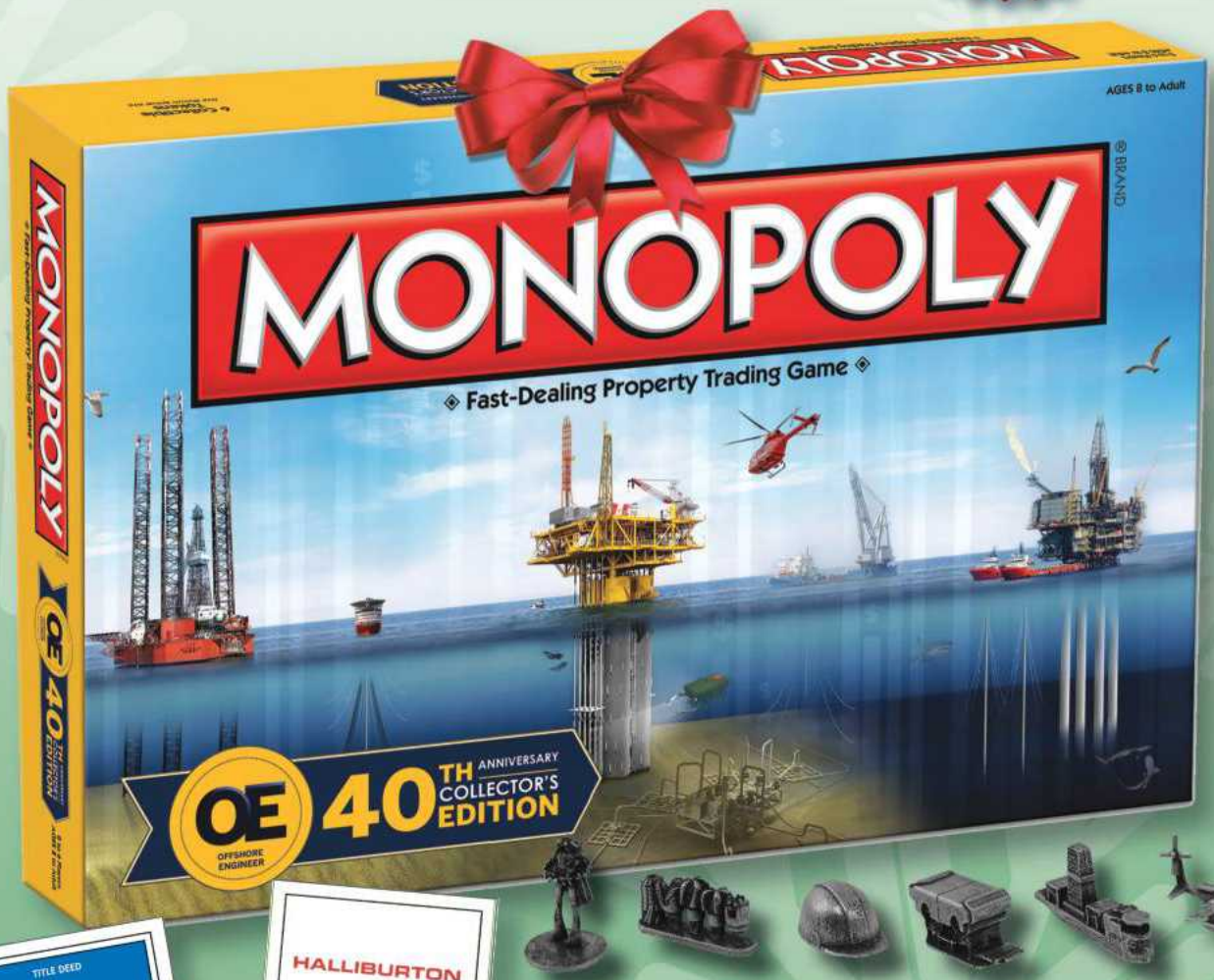

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Allseas' mega-vessel Pioneering Spirit gets into position to remove Yme's topsides in late August. Photo from Allseas.

Decommissioning offshore structures isn't going away any time soon and research points to a US$210 billion bill for this activity from 2020-2040 worldwide. John Bradbury looks at the market.

Field partners face a US$210 billion bill over 20 years from 2020 as more offshore structures reach the end of their economic lives, research by IHS suggests.

That huge sum is based on the belief that decommissioning will cost more as time goes on, from around $2.4 billion in 2015 to $13 billion by 2040, according to a November 2016 Offshore Decommissioning Study released by IHS Markit.

Up to 2000 offshore decommissioning projects are predicted, with a worldwide average of 120/yr. While Europe is expected to swallow up to half of the expenditure, due to major structure removal programs in the North Sea, shallow water platforms off Australia will drive demand for decommissioning services in the Asia Pacific region, IHS says.

"In terms of decommissioning, the global offshore industry is headed for a perfect storm," said Bjorn Hem, a senior manager of IHS Markit's upstream costs and technology service, and one of the study's authors. "We see increasingly stringent decommissioning regulations coming into force while the inventory of structures nearing end-of-life status is getting larger and more complex," Hem says.

Hem says that decommissioning services are fragmented, with no dominant players, making it difficult for exploration and production companies and offshore contractors to predict activity costs and risks.

North Sea

Fiona Legate, a senior UK upstream oil and gas analyst for Wood Mackenzie suggests that the total future decommissioning spend for the UK Continental Shelf will be £53 billion ($66 billion), in 2016 terms.

"Around 140 fields are expected to cease production in the UK over the next five years," Legate says. "Excluding the Brent decommissioning program, most of the fields being decommissioned are smaller developments. Early contractor engagement is key to locking in lower decommissioning costs," she notes.

Turning to the first use of the Allseas' *Pioneering Spirit* and its future viability, she adds: "The investment demonstrates that the service sector is scaling up to accommodate future decommissioning activity," she says, noting the first use of the heavy lift vessel at the Yme platform in Norway in August 2016. "This new technology could be pivotal to future decommissioning projects, but is costly to contract," Legate says, adding: "Collaboration amongst companies could help to reduce decommissioning costs."

Collaboration is evidenced through the formation of alliances such as the Southern North Sea (SNS) Late Life and Decommissioning Special Interest Group – involving Decom North Sea and the East of England Energy Group, based primarily in Lowestoft. One seminar organized by this group has focused on well plug and abandonment (P&A) costs and deconstruction – a major cost during decommissioning.

Asia Pacific

There are over 600 fields in the region (352 offshore, mostly in shallow water) that are expected to cease production over the next decade, says Jean-Baptiste Berchoteau, Wood Mackenzie's upstream oil and gas research analyst for Asia Pacific.

In Indonesia, 81 fields have been identified as potential candidates. Overall, Indonesia currently has over 750 platforms operating offshore, 60% being over 20 years old; over 900 pipelines, with a total length of 8000km; over 60 subsea systems; and over 1400 wells.

"The magnitude of these figures represents a real opportunity for a struggling service sector that saw its activities slashed by a sustained low oil price since 2015. In Asia Pacific, we anticipate that decommissioning costs could surge to over $1 billion/yr, post-2020," Berchoteau says.

Only small-size projects have been decommissioned so far in Asia Pacific and most were only partially done. The most recent in Indonesia were at the shallow Kambuna field, which ceased production in 2013, involving a single platform and three production wells, and the ConocoPhillips-operated Belida field in 2015.

Australia's extensive Thevenard Island project is being decommissioned currently, involving extensive infrastructure encompassing nine platforms, 22 platform wells, one subsea well, and onshore facilities.

Berchoteau says two offshore projects were sanctioned for decommissioning in 2016: Premier Oil's Anoa oil and gas field offshore Indonesia, with an estimated cost of $20-30 million, and the Petronas-operated Dana and D30 fields in Malaysia, involving 12 platform wells, two mobile offshore production units, a small platform and related pipelines, costing $30-40 million.

GE Oil & Gas will P&A four subsea wells at Anoa via its subsidiary Vetco Gray Indonesia starting in Q2 2017.

Issues for Asia Pacific operators include the maturity of P&A techniques and platform removal technologies. "While some countries like Australia and Thailand have clear regulations and guidelines on how platforms, wells and pipelines should be abandoned, most of the other countries in the region haven't reached that stage yet," Berchoteau says.

"Pressure is building on Indonesia, China and Malaysia, which have a significant number of offshore fields to decommission over the next 10 years, but haven't come up with clear guidelines and regulations yet," he says, and continues, "In these countries, regulators have started to realize the importance of the situation and have drafted guidelines, which are yet to be enacted."

Brazil

In a OTC Brazil 2015 paper, three members of Genesis, and Lobo de Souza, of Petrobras, mapped out future demand for decommissioning fixed platforms off Brazil, based on the assertion that only 5% of those have been removed to date.

They stated that: "In the last few years, many oil and gas fields have reached the end of their productive lives and many platform structures are reaching, or already exceeding, their project service life, 20-30 years on average. Changes acting on the global market and the recent sharp fall in oil price are inducing oil companies to re-estimate the profitability of each production unit and to consider, in several cases, decommissioning as a valid alternative." OE

Slim pickings

There are slim pickings for fabricators in oil and gas sector, but as Steve Hamlen reports offshore wind fabrication has given firms some sustenance.

The offshore oil and gas construction industry is suffering along with the rest of the petroleum sector. It has been over two years since oil prices collapsed from a high of around US$112/bbl, in the summer of 2014, to less than $30/bbl at the start of 2015 and trending around $44/bbl through 2016.

While OPEC and Russia have just agreed to production cuts, helping to prop up prices at around the $50/bbl mark, the industry remains in a weakened state and wary of investment in new projects.

The lack of commitment to new projects and the infrastructure these require has seen a swathe of job cuts and even total company reorganizations – such as that announced by Heerema Fabrication Group in November – to weather the fierce storm.

However, the last few weeks has seen some talk of green shoots of recovery and there are indeed some silver linings offered by Statoil's huge, multi-billion dollar Johan Sverdrup development project offshore Norway. Diversification into the renewables sector, especially wind, has also paid dividends for some contractors.

Sverdrup offers lifeline

Norwegian player Kvaerner has been somewhat shielded from the worst of the industry downturn thanks to the huge workload from the Johan Sverdrup

In early March 2016, Sembmarine SLP upended the jacket it is building for the Dudgeon Offshore Wind Farm. The operation was the first of its kind in the UK and involved jacking up the approximately 954-tonne jacket to 14m high using a Mega Jack 800 jacking system provided and operated by global heavy lift specialists ALE. The suction buckets were positioned under each of the jacket legs using SPMT trailers to maneuver them into place. The Mega Jack 800 then lowered the jacket and held it in place while the suction buckets were welded to the jacket. Photos from Sembmarine SLP.

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development off Norway.

During Q3 2016, two jackets and the topside for Johan Sverdrup passed 20% completion, and "accumulated profit for these projects has been recognized."

The Johan Sverdrup utility and living quarters topside project is "moving ahead according to planned progress," said Kvaerner, adding that design engineering has passed 90% complete and construction is ongoing at eight sites in Norway, Sweden and Poland.

"The oil and gas market remains challenging, but Kvaerner is well prepared for a market with continued volatility," said Jan Arve Haugan, president and CEO of Kvaerner. The firm expects a few projects in relevant segments to come up for contract award in 2016, 2017 and 2018.

"There are several signals of upcoming prospects, including floating production, storage and offloading vessels as well as unmanned wellhead platforms with tiebacks to existing infrastructure. The improvements over the last few years mean that Kvaerner can deliver such projects at a cost which is attractive even with oil prices at levels around $50/bbl."

Dudgeon jacket.

Encouraging projects forecast

In terms of new projects, there have been encouraging reports. A recent one by GlobalData forecast that a total of 32 oil and natural gas projects are expected to start operations in the North Sea by 2025.

Of these, the UK will be responsible for 22, while nine will be in Norway and one in Denmark. These key planned projects in the North Sea are expected to contribute 869,000 b/d of oil and 996.8 MMcm/d of gas by 2025.

Total capex for the projects could reach $78.2 billion, according to GlobalData, with $43.1 billion expected to be spent during 2016-2025. Norway is expected to lead the investment in region with $23.8 billion spending, of which GlobalData says $13.2 billion will be spent on Johan Sverdrup.

Globally, the consultancy reported that there are 200 key crude and natural gas projects slated for start-up by 2025, with the highest number offshore Brazil. According to GlobalData, an estimated capital expenditure of more than $800 billion is expected to be spent to bring these projects online, of which about 61% could be spent during 2016-2025.

However, this has not helped construction yards this year, nor is it likely to offer much respite in 2017.

Renewables lend support

A positive note beyond petroleum has been the steady growth of renewables construction work, with many traditional oil and gas players diversifying into this field, especially wind, to help ensure their survival.

A prime example of playing both sides is Sembmarine SLP, which until August this year spent 18 months completing the Dudgeon Offshore Wind substation topside. The facility left the Sembmarine SLP Hamilton Dock 100% mechanically completed and 100% commissioned on 5 August 2016 to sail away to 32km off the coast of North Norfolk, England.

A team of 250 people worked on the Dudgeon topside and spent 850,000 hours on the project. The Statoil, Statkraft and Masdar-owned Dudgeon Offshore Wind Farm would have the capacity to power approximately 410,000 homes in the UK once operational.

Sembmarine SLP then turned its focus to the Culzean gas condensate field development project offshore the UK. Under the contract, Sembmarine SLP is building a power generation module, flare and bridges for Denmark's Maersk Oil.

Culzean has a water depth of 90m (295ft) and is east of Aberdeen in the UK Central North Sea. "This work will take us all the way through to 2018," said Paul Thomson, Sembmarine SLP's managing director.

Meanwhile, Fife-based Burntisland Fabrications (BiFab) is another to benefit from the renewables sector, as it pushes ahead with work on the $127.2 million (£100 million) contract it landed in July this year from Seaway Heavy Lifting to supply 26 wind turbine jacket substructures for the 588MW Beatrice wind farm offshore Scotland.

The workload will be delivered in two campaigns: 10 of the jacket substructures will be ready for delivery in August 2017, with the remaining 16 are due to be completed and delivered in April 2018.

"The BiFab proposal for delivering the Beatrice project is based on utilizing a percentage of capacity at all three BiFab facilities at Arnish and Burntisland, with final assembly and loadout from the BiFab Methil facility," BiFab said.

"The BiFab scope is based on 26 off structures. This is 22,500-tonne of steel fabrication, which is a major project award for the BiFab management team and workforce, giving the company a base load of work through to April 2018," said John Robertson, BiFab

managing director.

Beatrice is in the Outer Moray Firth on the northwestern point of the Smith Bank, around 13km off the Caithness coastline.

Restructuring and job losses

Not all yards are managing so well, with the Netherlands-based Heerema Fabrication Group (HFG) saying just last month that it planned a reorganization of the company to help it survive.

HFG Hartlepool in northeast England saw its last large project leave site back in April 2016 when the wellhead access deck sailed away for the Culzean field. During the same week, HFG's Vlissingen yard in the Netherlands sent the wellhead jacket for Culzean on its way *(pictured, right)*.

"As a result of the restructuring, an anticipated 450 of the existing 770 jobs in the company will be phased out," HFG said, adding that the job losses affected the head office in Zwijndrecht (Netherlands), as well as the other HFG yards in the Netherlands (Vlissingen), the UK (Hartlepool) and Poland (Opole).

Then, on 6 December 2016, HFG signed a memorandum of understanding (MoU) with the UK's Wood Group to jointly offer wellhead platforms "from design to installation, hook-up and commissioning" on the Norwegian Continental Shelf.

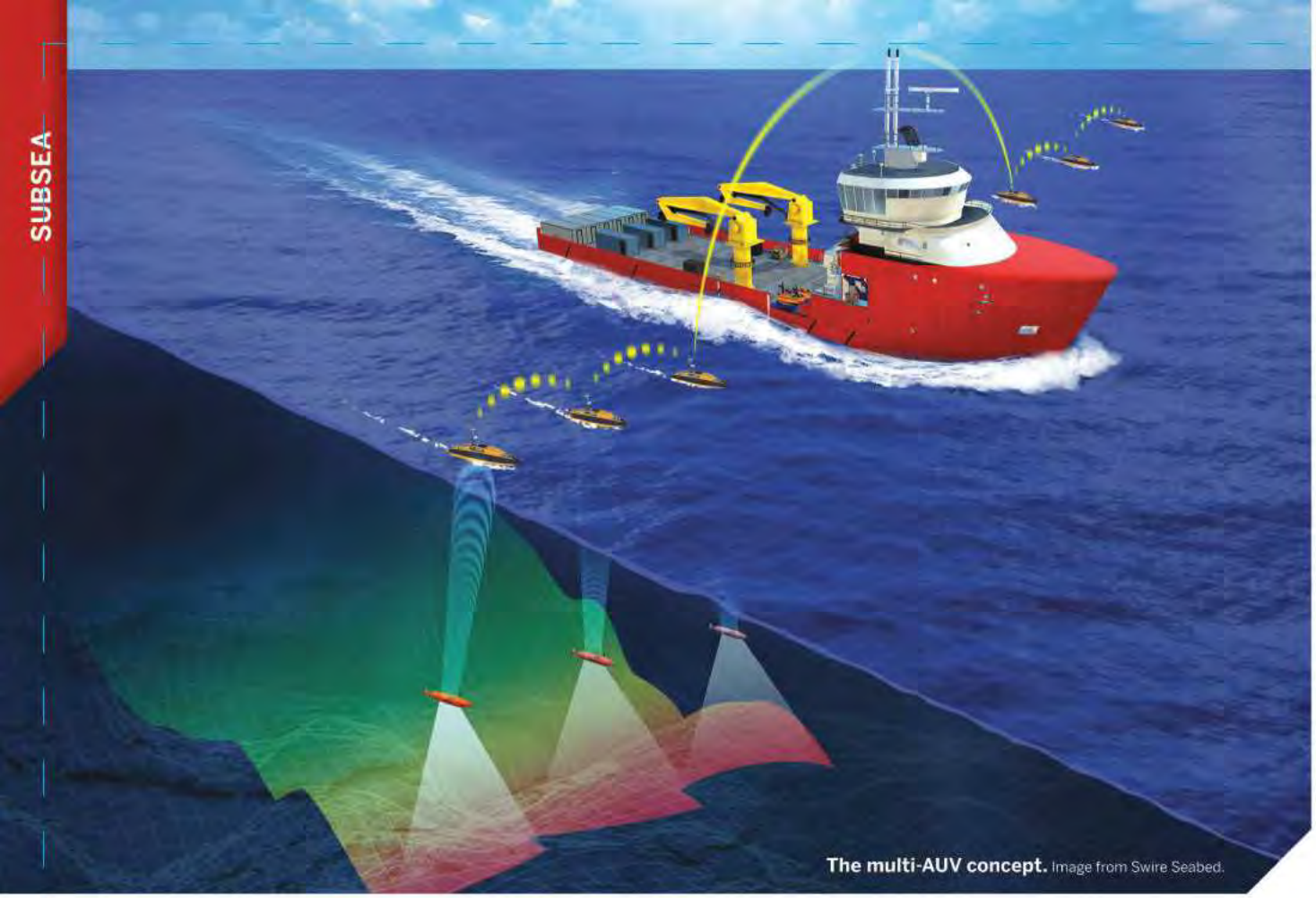
The Culzean wellhead jacket sailaway from Heerema Fabrication Group (HFG), Vlissingen, in 2016. Photo from HFG.

HFG said that the move would bring together Wood Group's engineering expertise and HFG's specialist services in the engineering and construction of large and complex structures for the offshore oil and gas, as well as energy-related industries.

The new partners hope the cost efficiencies offered will appeal to operators considering new platform field developments.

"This MoU positions us to provide innovative services to clients, through integrating Wood Group's strong global engineering expertise and in-depth knowledge of the Norwegian sector with HFG's broad experience and know-how for construction and installation in the North Sea offshore industry," said Dave Stewart, CEO for Wood Group's Asset Life Cycle Solutions business in the Eastern Hemisphere.

Meanwhile, OGN on Tyneside, northeast England, is "currently between contracts." **OE**



The multi-AUV concept. Image from Swire Seabed.

Herding AUVs

Elaine Maslin reports on the launch of a new concept in AUV deployment, which sees six vehicles deployed in conjunction with USVs.

It is said that the oceans are the most underexplored places on the planet, not least deep in the major subsea trenches. Now a Norwegian subsea firm is hoping to help make its discovery – and potential for development – somewhat faster.

Swire Seabed has taken delivery of a subsea vessel that is being modified to carry and deploy up to six, 6000m-rated autonomous underwater vehicles (AUVs). They will be joined by a matching fleet of unmanned surface vehicles (USVs) and two, work class remotely operated vehicles (ROVs), rated to 5000m and 6000m. The vessel, which will also have subsea lifting capability to 6000m subsea, may well be the most kitted out vessel, in terms of autonomous vehicles, in the world.

An unmanned surface vehicle. Image from ASV Global.

"Deploying six AUVs at one time has never been done before," says Jan Arvid Ingulfsen, senior advisor, Survey & AUV Operations at Swire Seabed, which was founded in 2008 in Bergen and bought by Swire Pacific Offshore in 2012.

"Similar work has been done in shallow water and in the military, so the technologies in a way are working today. But, quite a lot of development needed to be done to do this. We acquire six times more data than others, we shall process it [the data] much faster than others and we have an ongoing development program with software vendors."

The move – putting six AUVs on one vessel – is aimed at speeding up subsea seafloor survey work.

Swire Seabed already has a six-year contract in place for its new vessel with UK-based mapping company Ocean Infinity, the owner of the AUVs and USVs. The vessel will serve as the host for the multiple AUV operations in a combined venture between Ocean Infinity, with Swire Seabed providing survey processing and project management, and SeaTrepid DeepSea of Louisiana conducting operations of the AUVs.

"To get a really good mapping product, you need high resolution," says Arvid Pettersen, Swire Seabed's CEO. "This is normally achieved by

flying close to the seabed – using one AUV from one vessel. We will be flying up to six simultaneously – you can do large scale mapping in high resolution in a fraction of the time." This could be for the telecommunications or oil and gas industries, where areas of the seabed need to be mapped.


Arvid Petterson

Interestingly, there's nothing revolutionarily in the technology to do this, Pettersen says, it's what is being done with the technology that is new.

The vessel, recently bought from Olympic Shipping and renamed *Seabed Constructor*, hints at Swire Seabed's plans for this vessel to be more than just an AUV transporter.

The vessel is 115m-long with a 23m-beam. It is now undergoing modifications for it to support its new payload – the six Hugin (Kongsberg) AUVs, and six USVs, from UK firm ASV Global – before starting its six-year contract in April.


Swire's *Seabed Constructor*. Image from Swire Seabed.

Ingulfsen says that the AUVs will be stored onboard in six containers, which will mean they can easily be redeployed to other vessels, if required. There will also be three operations containers, which can also be redeployed. But, on the *Seabed Constructor*, operations will be done from a main control room in the vessel. There are also two davit systems, for launch and recovery of the USVs, plus a station for USV repair.

Each Hugin AUV has enough battery capacity for 72-hour deployments, while the USVs have double that capacity – at 140hrs – from diesel powered propulsion. Each USV can operate up to 43km from the vessel, maintaining communications, which means the six AUVs can be spread out in up to a 90km diameter around the mothership, *Seabed Constructor*.

During an operation, each AUV will be deployed sequentially – with up to 12 hours between each – when they're on a joint operation, with the first deployed also the first retrieved. While this makes operations possible – maximizing battery life for each unit – and smooth, it also means data download and analysis is smoothed out, too.

While each AUV operates independently, according to pre-planned missions, they can also "talk" to each other, which can enable more precise positioning, Ingulfsen says. "We will also have a full team of data processors and geophysicists on board," he says. "The target is to do all the processing and reporting on board," further speeding up to process.

The ROVs onboard will be an FMC Technologies Schilling Robotics HD 5000m-rated and a high-powered 6000m-rated Kystdesign (a Norwegian subsea robotics firm), 150hp WROV, complete with its own tether management system, ordered specifically for this vessel. All the systems on the vessel will have heave compensation systems, Ingulfsen says. Wire rope currently on the vessel's crane will be switched to fiber rope, reducing weight and easing handling requirements.

While few companies are ploughing investment into their fleets, Swire Seabed is investing. It's an enviable position. Furthermore, the company will be able to lean on parent firm Swire Pacific Offshore's extensive network of 20 offices globally. "It's a really good challenge to take on and really exciting. And it's a great time to go full speed ahead on this," Ingulfsen says. **OE**

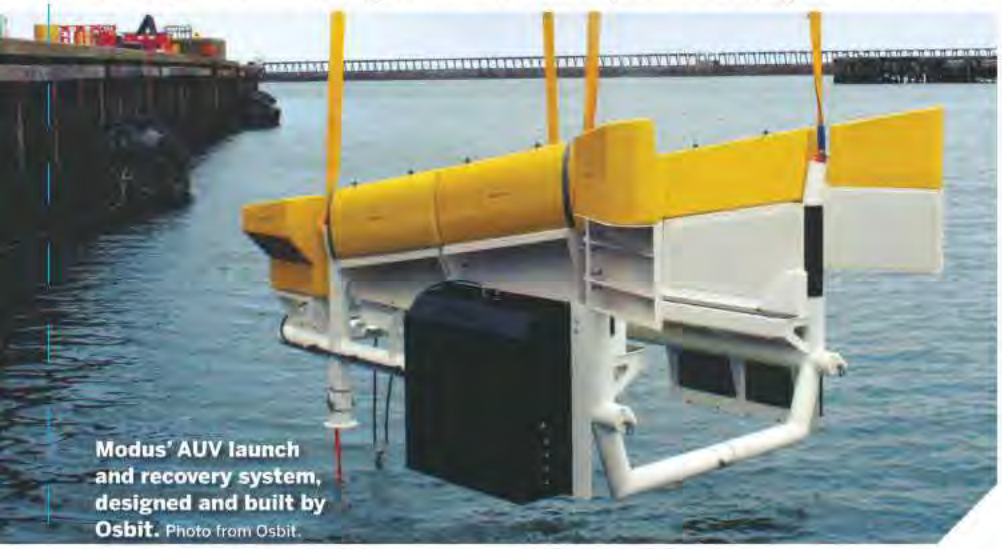
Kongsberg's Hugin AUV. Image from Kongsberg.

Autonomous and ready to work

Elaine Maslin profiles some of the projects moving forward that pledge to deliver autonomous underwater vehicles for life of field operations.

UK-based Modus Seabed Intervention and Sweden's Saab Dynamics agreed last year to jointly develop the operational use and applications of the Saab Sabertooth hybrid autonomous underwater vehicle/remote operated vehicle (AUV/ROV), including applications in life-of-field subsea survey and inspection.

Modus then ordered the first of a planned fleet of Sabertooth vehicles, which launched in Q4 2016. Also, late 2016, subsea engineering and technology firm Osbit delivered a floating launch dock and a sea parking garage for Modus' Saab Sabertooth hybrid AUV. Water trials of the docking systems have been successfully completed.



Modus' AUV launch and recovery system, designed and built by Osbit. Photo from Osbit.

Sabertooth can be operated in both fully autonomous (AUV) and tethered (ROV) modes enabling fully flexible dual operations from one platform. The idea is for the vehicle to be used across a range of subsea operations, from site investigation surveys through to decommissioning support, but a major focus is on its application in long-term subsea operations and maintenance. The deepwater rated unit is also capable of providing light intervention support.

The floating launch dock, which can be used when the AUV is both tethered and untethered, enables the operator to deploy the vehicle and also return it to the deck of the ship. The dock is submerged in the sea as the AUV leaves and returns, and partially fills with air to allow collection from the water surface.

The subsea parking garage provides a safe haven for the AUV when not operational and allows the operator to deploy the AUV at a specific location without having to maintain a presence there. When it has completed its automated tasks, the AUV returns to the garage and safely awaits recovery at a time convenient for the operator.

Modus says that the system has been equipped with additional batteries for extended autonomous endurance and with increased thrust for high speed survey, making it ideal for both high current and deepwater applications.

In the vehicle are a suite of advanced survey sensors including the latest Edgetech 2205 combined triple frequency sidescan sonar, co-located swath bathymetry and sub bottom profiler, HD video/stills cameras, IXBlue Phins3 INS, and RDI workhorse DVL. To manage data acquisition, navigation and processing of sensor data the software package QINSy (quality integrated navigation system) from Saab QPS is fully integrated. The vehicle has been configured to allow additional sensors, such as standard MBES, cathodic protection probes, laser scanning systems and cable trackers to be quickly integrated against project specific applications.

AIV

After completing a test mission for Shell in the North Sea in 2014, in addition to simulation and testing programs at the Underwater Centre at Fort William, Scotland, Subsea 7's autonomous inspection vehicle (AIV) was due out on a live job for Shell in November 2016, said Paul Yeats, products division, director, life of field services at Subsea 7, at Offshore Energy in Amsterdam.

Subsea 7 has been developing the AIV in collaboration with Edinburgh's SeeByte, which provides smart software solutions for unmanned underwater vehicles. Subsea 7 says that the AIV has the potential to revolutionize life-of-field projects by providing operators with a cost-effective, low-risk, inspection system to aid field survey, integrity management and intervention activities.

The AIV has been designed with an ability to recognize and respond to its surroundings, being able to correct its trajectory in real-time, based on information it gathers from its onboard sensors.

The AIV could operate from a host facility, such as a floating production vessel or platform, as well as from infield support vessels or mobile rigs. Crucially, it has no tether, which means its maneuverability is not restricted and it can access confined spaces. It comes with an array of navigation tools and sensors, powered from its onboard battery, which enables up to 24 hours' autonomous inspection, Subsea 7 says. **OE**

The new normal

Neil Gordon, chief executive of Subsea UK

When looking at oil price trends over the years since the 1920s, it becomes apparent that apart from the cyclical spikes every few years, US$100 plus was never going to be the norm. However, we became complacent in that unprecedented period of sustained, high oil price and the thought of living in $50-$55 oil seemed unthinkable in 2014. Well, two years on and we've got to get used to it. This is the new norm and the recovery is much more about how we deal with the current price, rather than waiting for oil prices to "recover."

That's why the theme for Subsea Expo, which begins on 1 February at Aberdeen's Exhibition and Conference Centre, is "Adapting to the New Norm" and will focus on the behavioral changes the industry must make to deliver the cost savings and efficiencies needed to sustain the sector for decades to come.

While I am in no doubt that there will be tough times ahead in the short-term, I do believe the subsea industry in this country is in a strong position to embrace the new norm and, indeed, can capitalize upon it, largely because of our focus on technology, which is fundamental to this new norm.

Despite the drop in sales and confidence in the industry, the UK subsea sector is maintaining high levels of investment in technology. In our recent snapshot survey of members, almost 80% of respondents reported that they were still investing in new technology to secure long-term future growth.

Underwater technology, systems, and processes made in the UK have been helping North Sea operators recover hydrocarbons since the 1980s.

There is no doubt that the industry has become much more receptive to new ways of working and new technologies, and we are starting to see the benefits of real collaboration towards reducing costs and driving efficiencies.

The recovery is much more about how we deal with the current price, rather than waiting for oil prices to "recover."

However, with fewer discoveries and aging fields, the focus is very much on working with the existing assets to extend "life-of-field" without running up unnecessary high costs. Operators are increasing production by using existing, less mainstream technologies that can be readily implemented to enhance and upgrade aging subsea systems.

Devising smarter ways of applying these technologies can also reduce inefficiencies and counter the tendency towards over-engineering, which became a feature of the high cost, high oil price environment.

This doesn't mean that new technologies are no longer needed. In order to extract higher yields from our existing assets and to do that viably we need to develop new technology and smarter integrity solutions that keep these aging assets healthy.

Companies need to invest wisely in the current market and focus on developing technology that will deliver efficiencies and add real value to the industry.

An example of the type of innovation needed is in condition based monitoring, specifically tools that can monitor the health and integrity of subsea systems and calculate when it requires attention, instead of carrying out regular and costly inspection campaigns. This allows operators to carry out planned, risk-based maintenance and repair programs when it's required, rather than reacting when something gets to a critical state which can lead to unplanned interventions and higher costs or even worse, loss of production.

Last year we saw the launch of a new innovative vessel share initiative, which has the potential to provide industry with significant savings through encouraging collaboration, cost-efficiencies, and ultimately increased productivity. The concept focuses on a vessel share agreement, with collaboration from several clients, to deliver a single linked campaign workscope that addresses each client's individual demands.

The model is aimed at reducing the costs associated with mobilization and demobilization periods while also distributing further cost savings for individual clients, helping to ensure a reduction in non-productive time and an increase in overall work time – a cohesive approach to project delivery.

This type of smart collaboration and smarter applications of existing technologies, along with new innovations will help secure the subsea sector's future and the sustainability of our industry in the new norm.

Subsea Expo runs 1-3 February in Aberdeen. For more information, see subseaexpo.com. **OE**

Remote Supervision

Workers ready Hugin AUV.
Photo from Kongsberg Maritime

Richard Mills, of Kongsberg Maritime, discusses survey class AUVs and USVs.

The autonomous underwater vehicle (AUV) market has reached a level of maturity over the past five years, where operators expect the vehicles to perform.

A modern state-of-the-art survey class AUV must be able to do many things, including collecting high resolution data and navigating accurately. The most recent iteration of the Hugin AUV developed by Kongsberg Maritime does those tasks well, but developments are underway to that could potentially change the way in which surveys are conducted.

This will see AUVs able to operate even more autonomously from their motherships, with the use of unmanned surface vehicles (USVs).

Heritage

The Hugin AUV system evolved from a test and development platform back in the early 1990s, to a complete survey system, complete with a range of payload sensors, for autonomous or supervised operations.

It has a common architecture with its little brother Munin. They have the same control processors and algorithms; common user interfaces for mission planning and dive management; common navigation hardware and in-situ processing and they also share the same payload control.

It is the control elements that bring commercial value to the AUV and enable it to meet the requirements of a survey class vehicle. For example, an AUV can collect high resolution sensor data, but if the navigation accuracy is poor, the data has no value.

The Hugin vehicle control and guidance systems rely on high specification sensors, such as the Honeywell HG9900 inertial measurement unit (IMU). The raw output from the accelerometers and gyroscopes is fed into NavP, Kongsberg Maritime's on-board navigation processor. NavP combines the IMU raw data with inputs from the doppler velocity log (DVL) and other external sources.

A well-planned survey pattern can minimize the error budget by having reciprocal tracks. Under ideal autonomous operating conditions, Hugin and Munin AUVs running with a DVL aided IMU can demonstrate a capability on the order of 0.05% of distance travelled in a straight line over a flat bottom.

For many commercial applications, external position updates such as USBL (ultra short base line) are used to limit the error budget of the navigation system. With Hugin, tracking the AUV with a HiPAP positioning system has required the mother ship to remain in acoustic range, usually within 4000-5000m of the AUV. This provides the best position updates for the AUV, but also provides a level of control and real-time data feedback for quality control purposes.

Kongsberg's AUVs are capable of using terrain navigation and underwater transponder protocol (UTP) to improve autonomous navigation accuracy. Terrain navigation requires known bathymetry of the survey area loaded onto the AUV as a digital terrain map (DTM). It also needs an onboard sensor such as multibeam echo sounder and some seafloor features of vertical extent. The position accuracy is determined by the quality of the DTM.

UTP is a feature within NavP. The AUV communicates with a seafloor transponder that has been deployed and

Hugin AUV on the surface. Photo from Kongsberg Maritime.

boxed-in before the mission. When the AUV interrogates the transponder it calculates the range from the transponder, reducing position error over time.

For some applications, supervision of the AUV is essential. To enable operators to conduct concurrent activities, Kongsberg has begun developing an USV. Using a USV to supervise a Hugin could release the mothership from tracking the AUV making it possible for concurrent activity to occur.

ODIN

Working with the Norwegian Defence Research Establishment, Kongsberg is developing ODIN, a new type of USV. It is a modular system comprising a control processor that can accept external inputs for navigation, positioning and situational awareness. Inputs may include GPS, infrared cameras and radar. The control output is fed through a mechanical interface to the vessel's propulsion and steering. The ODIN concept is that it can be integrated with almost any hull with a variety of navigation, safety and survey sensors.

The first ODIN will conduct simple waypoint based survey missions. The control system and architecture leverages the Hugin operating system, adding more external sensor capabilities, particularly for collision avoidance. Future developments include in-mission autonomous generation of waypoints and routes for tasks such as AUV supervision.

To work with Hugin, the USV will be equipped with a HiPAP system and a marine broadband radio (MBR). The AUV position updates, supervision and data link route through the HiPAP with the MBR effectively working as a virtual Ethernet cable to the operator on the mothership or shore.

ODIN will be supervised by an operator; either on the mothership via the MBR, or onshore via satellite communications. Autonomous collision avoidance will override any mission plan or AUV following. The operator will also retain full control for safety purposes.

These topics will be explored at Oceanology International North America 2017 (held in San Diego in February) in a paper *Marine Robotics: Survey Class AUVs and USVs.*

The first generation USV to be tested is a survey boat. Long-term plans include the development of an AUV tender capable of not only tracking an AUV for over-the-horizon mission supervision, but also to launch and recovery the AUV autonomously. **OE**

Richard Mills is director sales – Marine Robotics at Kongsberg Maritime. His previous experience includes a similar role at International Submarine Engineering in Canada.

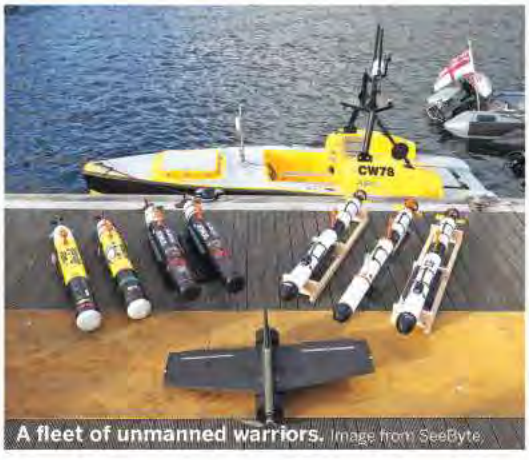
Internet of autonomy

Unmanned autonomous systems and the internet of things are two phrases that are bandied about a lot. But, it's not so often that they have come together and within the marine environment in a project involving offshore industry players – albeit those who also have a foot in the defense sector.

Unmanned Warrior, a military exercise, was one such event, held in the picturesque Loch Alsh, a sea inlet between the Isle of Skye and the Outer Hebrides, off Scotland. It involved 10 surface, subsea and airborne unmanned vehicles operating together on common missions.

UK-based SeeByte, which been providing software for remotely operated vehicles (ROVs), was involved in the exercise. Joining the firm were ASV Global (see page 38), Blue Bear, whose drones have been used to inspect offshore facilities, autonomous underwater vehicle (AUV) manufacturer Hydroid, US AUV firm OceanServer Technology, UK-based QinetiQ, and subsea equipment and engineering firm SeaRobotics.

The exercise was jointly run by the US Navy Lab of Naval Surface Warfare Center Panama City Division (NSWC-PCD), Defence Research and Development Canada, an agency of the Canadian Department of National Defence, and the UK's Defence Science and Technology Lab (Dstl).



A fleet of unmanned warriors. Image from SeeByte.

The joint missions ran through Dstl's Maritime Autonomy Framework (MAF), realized through SeeByte's Neptune software, an open architecture enabling autonomous multi-vehicle collaboration.

Using vehicles from Hydroid, OceanServer Technology, SeaRobotics, Blue Bear and ASV Global, the team networked the 10 unmanned systems, from three different countries, through a single command and control station. By running communications through Blue Bear's aerial drone Blackstart, this relay link meant that the surface and subsea vehicles were able to operate at a far greater distance from the shore.

While geared towards military operations, the technologies could also pave the way for more subsea autonomous systems in the oil and gas industry, in both deep and remote waters. ▪

Managing maintenance

Photo from iStock.

Audrey Leon speaks with Lloyd's Register about a new cloud-based software aimed at optimizing maintenance programs and reducing operational expenditures by up to 40%.

Managing maintenance in the current climate is a tremendous challenge. To help reduce costs, downtime and lost production there is pressure to defer activities where possible, but can this be done safely and what are the true operational and bottom line benefits? There's no denying optimizing maintenance schedules for older assets could produce positive results in the long-term. With work to be done, analysts Douglas Westwood anticipate a recovery in maintenance, modifications and operations expenditure out to 2021.

"The market is forecast to witness expenditure increasing from US$81 billion in 2017 to $95 billion in 2021 for the world's global offshore platform population of approximately 8700 fixed and floating assets. This forecast expenditure will be comprised of asset services (60%), which focuses on the repair and maintenance of structural, mechanical and electrical systems on platforms," the firm said in December.

Many companies are looking to advise operators on how to improve aging asset performance. Lloyd's Register recently acquired RTAMO Ltd. in October 2016, a company that was formed by Dr. Neil Arthur in 2014. RTAMO (Real-Time Adaptive Maintenance Optimization) is a standalone cloud-based software-enabled service that is based on a 10-year development program including government funded academic research, which culminated in establishing predictive algorithms linking planned maintenance to economic and reliability outcomes. In some cases, RTAMO has been able to achieve an up to 40% reduction in operational maintenance expenditure, Arthur says.

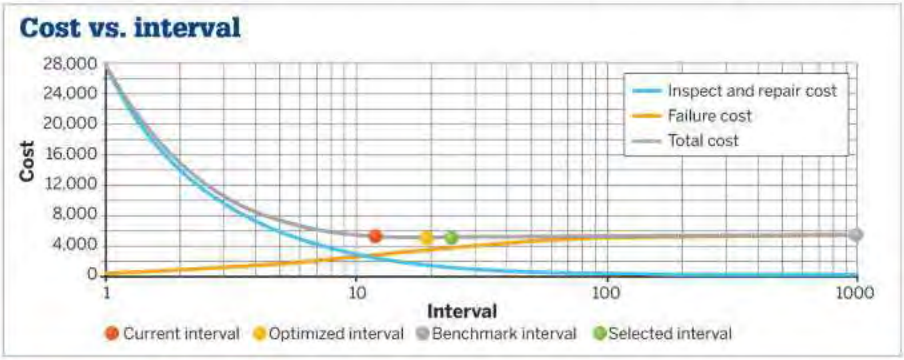
"Maximizing economic recovery" is certainly an industry buzz phrase as of the last few years. With this in mind, Arthur says there has been a huge amount of effort undertaken to challenge both the need for shutdowns and the scope and content, because cutting down or eliminating shutdowns helps to increase the recovery factor and reduce operations costs for the facility.

RTAMO technology

Arthur says RTAMO is different for three main reasons – one, it's a technology that has been developed from academia; two, it's a cloud-based platform, which makes it very scalable and easily adopted; three, the speed of implementation. Arthur says RTAMO can be easily implemented, typically undertaking optimization from start to finish in around four months for a typical facility.

RTAMO, which does not need to integrate with operator's maintenance management systems, takes data from a computerized maintenance management system, as well as some commercial information about the facility, uses the algorithms within its engine to optimize the activity set and pushes that back out to the enterprise asset management system, Arthur says.

"RTAMO is essentially a commercial model of the facility so that at any point in time, if something changes, – be it oil price, labor rate, or the reliability of a piece of equipment – the maintenance changes in direct response to that," he says. "It's called Real-time Adaptive Maintenance Optimization, but as quickly as you implement the change in RTAMO, you can quickly implement the change in the corresponding



Source: Lloyd's Register.

maintenance program. For example, the maintenance program today would look very different in six months' time if the oil price rises or production reduces."

Mid-to-late life management

Most engineers will tell you that the best time to optimize a facility is in the design stage. However, once the facility is built, operators have to roll with the punches as they come.

"The best time to optimize maintenance is at all times because things change all the time," Arthur points out. So far, in response to the low oil price environment, Lloyd's Register has found that most of its implementation of RTAMO has been carried out on mid-to-late life operations.

"Quite honestly – the maintenance that is carried out on a facility that is 20 years old can often be the same maintenance that was carried out at the start of the production facility life," Arthur says. "There's no rational explanation for me why you would maintain equipment with the same cost base and same effort when you are producing 5000 b/d opposed to 105,000 b/d."

Arthur says that operators need to look at, not just reducing the cost of maintenance, but, being more targeted to the pieces of equipment that require the maintenance. "We reduce maintenance on less critical equipment and, if necessary, we introduce more maintenance for production critical equipment to maximize throughput."

One of the issues plaguing operators is the volume of data that amasses throughout the life of a facility, which is too difficult for a human to manage. The key, Arthur says, is being able to take the volumes of data and turn that into information that allows the asset operator to make decisions. This is a true implementation of 'Big Data' concepts.

What if you don't have data? There are plenty of reasons why a facility may have missing historical information (changing operating companies, etc.). Arthur says that there are industry standard data sets (libraries) that can be used for reliability calculations. "We built in proprietary standards so you can still build it in for your facility if nothing exists," he adds.

Lloyd's Register implemented RTAMO on a floating production, storage and offloading (FPSO) unit in the UK North Sea, some 100km from Aberdeen, at 120m water depth.

Lloyd's conducted the optimization project with the operator, seeking site-specific assistance with the offshore community, Arthur says.

"We reviewed and optimized the entire maintenance program on the basis of RTAMO technology and implemented the changes into the maintenance management system itself," he says. "That had the full backing of the team. That included all the necessary approvals from the operational team prior to deployment."

The six-month project involved data downloading, data cleansing, optimization scope rationalization, and optimized maintenance plan upload. Arthur says, the operator is reporting significant benefits in terms of streamlined maintenance burden and a reduction to the maintenance backlog.

Arthur says a huge focus for the oil and gas industry right now is dealing with the volume of maintenance that is being generated from management systems, which can result in a significant backlog.

"Quite often we have found that tuning the maintenance strategies, and the work coming out of the maintenance management system, can help with the ability to manage the maintenance backlog," Arthur says. **OE**

IRM in offshore wind

Audrey Leon speaks with Tom Adams, vice president, Power Business Development, at ABS Group, to find out how the firm is offering its inspection and quality assurance services to the offshore wind industry.

With the downturn in oil and gas, several companies of all types are setting their sights on offshore wind, including inspection and verification firms such as ABS Group.

ABS Group has actively pursued projects in Europe and at home in the US, aimed at servicing the entire life cycle of a wind farm, from the design to commissioning, as well as operations and maintenance (O&M) programs once online.

With growing pressure on the supply chain to keep costs low, the offshore wind segment is also feeling the need for cost reductions.

"With the larger projects in Europe – there is a drive to keep costs competitive. Everyone participating in these projects – whether they are the major manufacturers, contractors, consultants and engineers, and the O&M providers are all under pressure to become more efficient and lower their costs," says Tom Adams, vice president, Power Business Development, at ABS Group. "We are obviously looking to deliver our services competitively: automating our processes and making sure our approach to those tasks is streamlined, targeted – right resources, right time."

Adams says that ABS Group has been successful in both the engineering, procurement and construction (EPC) phase as well as the O&M phase of offshore wind projects. "In the EPC phase, we have raised design questions or issues that the designer may not have focused on, and we have caught in our review," Adams says. "In the O&M phase, we have been involved in foundation conditioning monitoring, ongoing instrumentation of foundations – understanding how they have experienced loads and fatigue processes after installation and how that bears on design life over time."

The first US wind farm, Block Island offshore Rhode Island, went online in early December 2016. ABS Group was part of that project, and also worked with the US regulatory body, Bureau of Safety and Environmental Enforcement (BSEE), to identify and prioritize offshore wind farm inspection procedures. ABS Group has reviewed procedures from around the globe, and has offered BSEE recommendations that have included the logistics for conducting the inspections as well as training for government inspectors.

While Europe is a more mature and competitive market for offshore wind projects, Adams is hopeful about the US. "It's a market in its initial stage, and the US has had success with the first offshore wind farm going commercial. This is great for the industry, and we are waiting for the next round of projects to come," he says. "We are optimistic that the US offshore wind market will continue to develop."

While ABS Group uses a suite of its own in-house tools and software programs to help assess both project designs and O&M programs, in July 2016, the firm signed an agreement with DroneView Technologies to deliver joint aerial wind turbine and equipment inspections.

"Drone wind turbine inspections are a game changing solution for the wind industry, providing safer inspection techniques, faster turnaround times, lower operations and maintenance costs and improved reliability," said Ted Hofbauer, ABS Group Director of Renewables Business Development, at the time of the announcement. "These inspections are ideal for maintenance and especially for emergency situations in which climbing is not possible," added Michael Singer, CEO of DroneView Technologies, at the time.

ABS Group has also secured project certification and quality management work in Europe on several large wind farm projects including: DONG Energy's Borkum Riffgrund 2 offshore wind farm in Germany, and its Hornsea Offshore Wind Farm Project One in the UK, and Hexicon's Dounreay Tri Floating Offshore Wind Farm demonstrator project in Scotland.

In addition to the US and Europe, ABS Group's offshore wind consulting service is also active in Taiwan, where Adams says the island nation has attracted attention already from European and US investors. "It is also an early market, but very promising from a wind resource perspective," he says. OE

Supporting the Greater Gabbard Offshore Wind Farm

ABS Group provided independent structural integrity monitoring services for the Greater Gabbard Offshore Wind Farm, located off the coast of Suffolk in England. ABS Group developed a technique to analyze the data gathered in a way that enables asset owners to implement preventive maintenance, saving valuable time and money, as well as improving certain safety aspects of the offshore structures. ■

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Middle East

What downturn?

Offshore construction activity in the Middle East Gulf has remained buoyant, but that hasn't stopped pressure on costs and dayrates. Mirzi Moralde, of IHS, outlines activity in the region.

More than two years since the slump in the oil price, the Middle East Gulf region has managed to keep offshore construction activity buoyant with existing portfolio of projects, which were awarded prior to the downturn.

Sanctioned projects in 2016, which were either aimed at sustaining hydrocarbon output capacity or increasing natural gas production, are expected to boost offshore construction in the short- to medium-term. However, the volatile oil price coupled with high vessel availability, currently running at only around 45% utilization, continues to contribute to the downward pressure on dayrates in the region's construction vessel market.

In 2016, a number of oil and gas development programs were awarded offshore Saudi Arabia, while greenfield campaigns off Abu Dhabi in the United Arab Emirates (UAE) are underway to meet target production capacity by 2018.

Consolidation of major operators Abu

Saipem's Perro Negro 5 and Perro Negro 7 self-elevating drilling platforms are being used offshore Saudi Arabia by Saudi Aramco. Perro Negro 7 can operate in water depths up to 375ft and Perro Negro 5 is designed to work up to 300ft water depth. Photo from Saipem.

Dhabi Marine Operating Co. (ADMA-OPCO) and Zakum Development Co. (ZADCO) is expected to enhance efficiency and growth in Abu Dhabi's offshore operations.

In the Persian Gulf, Total entered into a Heads of Agreement with the National Iranian Oil Co. (NIOC) for the South Pars gas field Phase 11. Though international sanctions on Iran were lifted in January 2016, NIOC just commenced pre-qualification of exploration and production companies in preparation for the tender rounds during Q4 2016. There are around 15 offshore programs, covered under the Iranian Petroleum Contract (IPC).

Saudi Arabia

In line with Saudi Aramco's maintain potential program (MPP), which aims to sustain crude oil production capacity in existing and producing assets, around US$1 billion worth of engineering, procurement, construction and installation (EPCI) contracts were awarded to Saipem in Q4 2016. The sanctioned projects, which are part of long-term agreement (LTA) contracts under the MPP, will involve a total of 20 decks, 10 jackets and seven deck upgrades for the Safaniya, Marjan and Zuluf oil fields, offshore Saudi Arabia. Other work will cover pipelines, subsea cables, umbilicals and maintenance for Saudi Aramco's offshore fields. These LTA EPCI projects are expected to complete in 2021.

In October 2016, Saudi Aramco released two more EPCI LTA tenders, which involve a total of 17 jackets to be utilized for drilling in the Marjan and Berri oil fields. Offshore installation work is expected to start in 2018.

The MPP also covers offshore gas-producing assets. In July 2016, Saudi Aramco awarded the $1.6 billion EPCI Hasbah gas field facilities expansion program to Larsen & Toubro Hydrocarbon Engineering (LTHE) and the EMAS Chiyoda Subsea consortium (*OE*: November 2016). The scope covers topsides for wellhead platforms, tie-in and flare platforms, bridges, umbilicals, infield pipelines and trunklines, among others. Offshore work is expected to begin in Q4 2017.

Installation of a wellhead platform by Derrick Barge 27.
Photo from McDermott.

Hasbah is one of two non-associated offshore gas fields, developed under Saudi Aramco's Wasit gas program, which started operations between the end of 2015 and early 2016. The other gas field is Arabiyah. Saipem carried out the EPCI campaign for the Wasit gas development from 2011 until completion in 2015. The Arabiyah and Hasbah offshore gas fields are targeted to produce around 2.5 Bscf/d of gas. Production from both gas fields aim to meet Saudi Arabia's increasing domestic energy demand.

There are now five EPCI contractors, which have LTA contracts with Saudi Aramco. The National Petroleum Construction Co. (NPCC) is the fifth contractor and was awarded a LTA in October 2016. The first four contractors: Dynamic Industries, LTHE-EMAS, McDermott and Saipem, were awarded in 2015. The LTA contract will allow them to bid for Saudi Aramco's offshore LTA tender packages.

As recently sanctioned projects will aid in sustaining Saudi Aramco's oil and gas production capacity, continuing exploration activities in the Arabian side of the Gulf will add to its natural gas and hydrocarbon reserves. In June 2016, Saudi Aramco announced the discovery of a new oil field, Faskar, which is near the oil-producing Berri field.

Abu Dhabi

Over in the UAE, Abu Dhabi's multi-billion worth of combined offshore projects like the ZADCO-operated UZ 750, the ADMA-OPCO-operated Umm Lulu and Nasr full-field development programs, along with other continuing maintenance and workover campaigns in producing fields, are on track to meet hydrocarbon production capacity target of 3.5 MMb/d by 2018.

However, contract award for the Umm Shaif pipeline replacement project has been delayed since bids were submitted in April 2015. Around 12 or more pipelines are involved in the program.

Focus is also on gas production with Abu Dhabi Gas Industries' (GASCO) Integrated Gas Development Expansion (IGD-E), involving a 117km-long, 42in offshore pipeline stretching from Das Island to an onshore terminal, which will aid in increasing gas processing capacity by 400 MMscf/d. The IGD-E is set for completion around the end of 2017 or in early 2018.

To help meet gas production targets, in February 2016, ZADCO sanctioned the EPCI for two drilling jackets for the North West Development, in the Dalma field, offshore Abu Dhabi. The jackets are set to be ready for drilling in 2017. Discovered in 1971, Dalma is an oil and gas field. Additional infrastructure like wellhead platforms and pipelines are being planned and a tender has yet to be released. At this stage, gas production will be prioritized in the Dalma field.

In November 2016, appraisal drilling for the Shuwaihat-6 well in the shallow water Shuwaihat gas and condensate field started, while another appraisal well, Shuwaihat-7, is anticipated to be drilled thereafter, pending results from Shuwaihat-6. The appraisal activity is part of the technical evaluation agreement (TEA) between the Wintershall-OMV joint venture and state-owned Abu Dhabi National Oil Co. (ADNOC), which was signed in 2012.

Potential future field development offshore Abu Dhabi is also anticipated, as ADNOC signed a TEA with OMV and Occidental Petroleum (Oxy) in the Q1 2016. The TEA will

Middle East

Saipem's *Castoro* has been working on the Wasit Project. Photo from Saipem.

involve oil and gas fields in Northwest offshore Abu Dhabi, including the Ghasha and Hail areas. The agreement will cover four-year seismic activity, drilling and engineering work for exploration and appraisal.

Meanwhile, consolidation of Abu Dhabi's two major offshore operators ADMA-OPCO and ZADCO is underway and is set to be concluded in 2018. ADNOC has a 60% share in ADMA-OPCO while the rest is owned by BP, Japan Oil Development Co. (JODCO) and Total. ADNOC also holds 60% share in ZADCO while its partners ExxonMobil and JODCO hold the remaining shares. The consolidated offshore operating company, which will operate both ADMA-OPCO's and ZADCO's assets, is set to optimize synergy of resources of both companies for efficiency and growth.

Qatar

Offshore Qatar, Qatar Petroleum (QP) will merge its LNG operating companies Qatargas and RasGas in 2017 to secure its competitive advantage in the current market. QP also signed a joint venture agreement (JVA) with Total to form the North Oil Co., which will develop and operate the Al Shaheen oil field. The JVA covers the development and fiscal agreement, which provides the license for the development and operation of the Al Shaheen field, production, sale and export of crude oil for a period of 25 years. The JVA is set to start in July 2017, following the expiration of QP's existing agreement with Maersk Oil Qatar.

Redevelopment of the Bul Hanine oil field is also moving ahead with QP's request for expressions of interest for a pre-qualification exercise, involving offshore facilities under the early production scheme (EPS). The EPS will involve four topsides, which will each weigh 1000-tonne, flowlines and modification of existing facilities for tie-in operation. EPCIC bids are set to follow, thereafter. The project is anticipated to be commissioned between 2018-2019, which is to be then followed by the full field development of Bul Hanine.

In the contracting front, QP awarded the EPCI North Field Alpha project, consisting of a wellhead topside, pipeline and brownfield modification works, to China Offshore Oil Engineering Co. in Q4 2016, while the RasGas EPCI offshore pipeline repair work on Barzan gas field went to McDermott in Q1 2016. The scope covered four pipelines having a total length of around 200km with diameters of 24 and 32in However, the Qatargas EPCI North Field Bravo LQ platform tender package, which was released for bidding in 2015, has yet to be awarded.

Iran

Since the lifting of international sanctions on Iran in January 2016, the NIOC has signed a Heads of Agreement with Total for the South Pars Phase 11 (SPP 11) development in the Persian side of the Gulf. Total will hold 50.1% interest while NIOC subsidiary Petropars will have 19.9% and the remaining 30% will be held by China's state-owned oil and gas company CNPC.

Included in the agreement, NIOC and its partners will engage in exclusive negotiations to finalize a 20-year contract, which is based on technical and economic terms covered in the framework of the Iranian Petroleum Contract (IPC). The first phase of SPP 11 will involve two wellhead platforms with 30 wells and two subsea pipelines that will be connected to onshore facilities. The decision to carry out a second phase will be based on reservoir conditions.

NIOC has around 15 offshore oil and gas projects on the IPC list. Out of 15, 10 will be greenfield developments while the others will necessitate enhanced oil recovery schemes. The new field program will include the Golshan and Ferdowsi oil and gas fields, among others. The Golshan and Ferdowsi gas fields are planned to be developed together. An integrated development plan is also intended for the Golshan and Ferdowsi oil layers.

Last October, NIOC started the prequalification process for exploration and production companies in anticipation of the tender rounds.

Meanwhile, offshore construction activities in the South Pars Phases 17 & 18, 20 & 21 are ongoing, which are mostly carried out by Iran-based contractors like Sadra Engineering and Kito among others.

In the short- to medium-term, the Middle East Gulf offshore construction market is anticipated to withstand the downturn until the market recovers, buoyed by ongoing and recently awarded oil and gas projects in Saudi Arabia, Abu Dhabi, Qatar and Iran that are set for completion in the next 2-4 years' time. **OE**

Mirzi Moralde *is a senior specialist at IHS based in Dubai. Moralde covers the Middle East Gulf offshore oil and gas construction market, focusing on field development activities from discovery, engineering, procurement, construction, installation and production phases.*

Charting future growth in the Middle East

For McDermott International, the Middle East is a key region. Currently, it is one of five EPCI contractors with a long-term agreement with Saudi Aramco. *OE* spoke with Linh Austin, vice president and general manager, Middle East and Caspian, to get his views on activity in the region.

Linh Austin

OE: Have activity levels in the Middle Eastern offshore been impacted by the fall in oil price?
Yes, we have seen some impact; where projects are not critical to oil production there has been a slow down or in some instances we have seen them postponed indefinitely. However, with projects that are crucial for production there is still a strong market and we are still seeing good levels of activity, particularly in Saudi Arabia and Qatar. Our backlog is strong, we have several bids ongoing and have had some significant awards over 2016.

OE: What type of work is being contracted?
The majority of the awards we are seeing are for lump sum turnkey and EPCI (engineering, procurement, construction, installation) projects.

OE: Has McDermott grown its presence in the region these past couple of years?
Yes, we have grown and continue to grow. We have recently opened a 300-person office in Saudi Arabia and inaugurated our Dammam yard, with a recruitment drive in Al-Khobar to support localization objectives. This is in line with our commitment to the Saudi Arabia vision 2030 and Aramco's IKTVA (In-Kingdom Total Value Add) program.

OE: Is it planning to grow further in the future?
Our outlook is positive. We anticipate further growth locally, particularly in support of the strong Saudi Arabia and Qatar markets. We also see potential opportunities in the United Arab Emirates market, when it picks back up, and in the longer term there are also opportunities in Kuwait and the Caspian.

OE: Where do you see future growth in the region?
We anticipate more brownfield work going forward due to the need for aging facilities, which need to be upgraded and maintained. McDermott has extensive brownfield experience, spanning six decades in the Middle East and therefore are well positioned to capitalize on this trend.

OE: Are there any particular technology needs in the region?
The Middle East fields are predominantly shallow water, which brings with it unique technical challenges. More than a particular technology it's about continually learning and innovating to ensure consistent high levels of quality and safety and part of this is around having the right technology to support that focus. ■

Load out of offshore platform installed through floatover method. Photo from McDermott.

Middle East

Checking in on the Caspian

The Kashagan development off Kazakhstan. Photo from Eni.

Melissa Sustaita charts the progress of two of the Caspian region's famed oil and gas projects, NCOC's Kashagan and BP's Shah Deniz.

Last year (2016) had its share of peaks and valleys; however, it was a year of excellent progress for two huge projects in different sectors of the Caspian Sea. The Kashagan field, offshore Kazakhstan, made its stakeholders proud awakening from its deep slumber after pipeline leaks shut production in 2013. The Shah Deniz 2 project, off Azerbaijan inched closer to completion with the sailaway of its Stage 2 platform jacket.

Kashagan awakens

Kashagan, discovered in 2000, is one of the largest oilfields discovered in the past 40 years, has been referred to as one of the most complex projects ever undertaken due to its location, size, and technical complexity. Thought to contain some 35 billion bbl of oil in place, Kashagan is some 80km southeast of Atyrau, in 4200m of water, and extends over a surface area of about 75km x 45km.

The field achieved a huge milestone in late 2016. Kashagan restarted production, finally shipping the first batch of export crude oil in October. Production is expected to target a 180,000 b/d plateau, eventually achieving 370,000 b/d by the end of 2017, according to Italy's Eni – a partner (16.81%) in the consortium (North Caspian Operating Co. [NCOC]) that operates Kashagan. Other members of NCOC are Kazakhstan's state-owned oil company KazMunayGas (16.88%), France's Total (16.81%), US supermajor ExxonMobil (16.81%), Anglo-Dutch supermajor Shell (16.81%), China National Petroleum Corp. (8.33%), and Japan's Inpex (7.56%).

Paving the way to a production restart, NCOC hired Saipem in February 2016 to replace pipeline infrastructure that was damaged in 2013. The US$1.8 billion deal saw Saipem engineer and construct the two 95km pipelines, with 28in diameters, made of carbon steel, that connect the artificial D island in the Caspian Sea, to the Karabatan onshore plant in Kazakhstan.

Past setbacks

Kashagan originally had achieved first oil in September 2013 from eight wells on the artificial island. However, operations came to a halt after two separate gas leaks that occurred in September and October of that year. Prior to the gas leaks in 2013, Kashagan experienced a 10-year delay, and multiple consortium changes.

It wasn't until November 2014 that the restart of production was in sight. At that time, then-Total President of Exploration and Production Arnaud Breuillac projected that production would resume as early as 2016, and 2017 at the latest.

Previously set to cost $10 billion, Kashagan's price kept rising to more than $50 billion. Famously the project was dubbed, "Cash all gone" by The Economist magazine.

The development layout of Kashagan. Image from NCOC.

Development strategy

The use of conventional drilling and production technologies, such as concrete structures or jacket platforms that rest on the seabed, are not possible due to the shallow water and cold winter climate of the northern part of the Caspian Sea.

To ensure protection from harsh winter conditions and pack ice movement, offshore facilities are being installed on artificial islands. There are two main types of islands: small unmanned drilling islands, and larger manned hub islands. Hydrocarbons will travel from the drilling islands to hub islands via pipeline. The hub islands will contain processing facilities to separate recovered liquid (oil and water) from the raw gas, as well as gas injection and power generation systems, NCOC said.

During Phase I, the consortium said that around half of the gas produced will be re-injected back into the reservoir, NCOC says. Separated liquid and raw gas will be taken by pipeline to the Bolashak onshore processing plant in Atyrau oblast, where export quality oil will be produced. Some of the processed gas will be sent back offshore for use in power generation while some will be used to generate power at the process plant itself.

Challenges

Being that Kashagan is highly pressurized at 770 bar, the crude oil that the field contains has high sour gas content, creating some technical challenges for the project, NCOC said.

In addition, the field has low salinity due to the in-flow of fresh water from the Volga River, combined with shallow waters. Winter temperatures in the area can hit below -30° C, which causes the northern part of the Caspian Sea to freeze for nearly five months out of the year. This results in ice drifts and ice scouring that place heavy constraints on construction activities.

The location of Kashagan also makes it difficult to supply essential project equipment, NCOC said. Logistical challenges are amplified by limited access to waterways, such as the Volga Don Canal and Baltic Sea-Volga waterways, which have thick winter ice for about six months out of the year, making them difficult to reach.

The Kashagan field contains around 52 Tcf of associated gas, most of which will be re-injected offshore to improve oil recovery rates, according to NCOC. However, for Phase I, not all the associated gas is injected offshore. Some of the gas will be sent to the onshore processing facility where hydrogen sulfide is removed, or sweetened. The processed/sweetened gas will be used for onshore and offshore power generation and some will be marketed as sales gas. Phase I is expected produce an average of 1.1 million tons of sulphur per year due to the removal of the hydrogen sulfide.

Shah Deniz: The king of the sea

Shah Deniz is undoubtedly the king of the sea, holding some 40 Tcf of natural gas in place, making it one of the world's largest gas-condensate fields, and one of BP's largest discoveries to date.

The Shah Deniz field, spanning approximately 860sq km, is about 70km offshore Baku, Azerbaijan, in 50-500m water in the Caspian Sea.

The project consists of Shah Deniz Stage 1, with the capacity to produce some 10 Bcm/yr of gas, and about 50,000 b/d of condensate; Shah Deniz Stage 2, which will add an additional 16 Bcm per year of gas production; and

Shah Deniz 2 platform jacket preparing for sailaway. Photo from BP.

Shah Deniz 2 platform sailaway. Photo from BP's Flickr.

Middle East

Night view of Shah Deniz. Image from BP's Flickr.

the Southern Gas Corridor pipeline system that will help deliver 6 Bcm/yr of gas to Turkey and a further 10 Bcm/yr of gas to markets in Europe.

In 2016, the BP-led project saw several updates, from a subsea installation contract, to the reflecting of the *Khankendi* newbuild, to jacket sail away, and a $1 billion investment.

Shah Deniz Stage 1

The first stage of the giant project, Shah Deniz Stage 1, began operations in 2006, and took seven years to develop. According to BP, there were several complexities involved including drilling the wells, building a platform, constructing an onshore terminal and laying the 700km South Caucasus pipeline (SCP) through Azerbaijan and Georgia to the Turkish border.

During the first three quarters of 2016, the field produced some 8 Bcm of gas and 1.9 million-tonne (about 15 MMbbl) of condensate.

The existing Shah Deniz facilities' production capacity is currently 29.5 MMcm/d of gas or around 10.8 Bcm/yr.

During the same time period, approximately $334 million was in spent in operating expenditure for the Shah Deniz project, and about $2.77 billion in capital expenditure, of which the majority was associated with Shah Deniz Stage 2.

In Q3 2016, the Shah Deniz existing (Alpha) platform completed the deep hole drilling of the SDA09 well and started completion operations, which were currently ongoing as of Q4 2016.

The *Istiglal* semisubmersible upgrade and commissioning was completed in mid-September, and followed with the rig beginning completion operations on the SDC04 well, which are currently ongoing.

The *Heydar Aliyev* semisubmersible rig drilled the SDG03 well, and is now drilling the SDG02 well reservoir section.

Together, the *Istiglal* and *Heydar Aliyev* have drilled 10 production wells in preparation for the start-up of Shah Deniz Stage 2 and subsequent production ramp up. Drilling operations will continue to deliver all wells required to reach the planned plateau level, BP said.

Shah Deniz Stage 2

BP's Shah Deniz Stage 2, or full field devlopment, is a giant project that is designed to add a further 16 Bcm/yr of gas production to the approximately 9 Bcm/yr produced by Shah Deniz Stage 1.

According to BP, the concept for Shah Deniz Stage 2 includes two new bridge-linked offshore platforms; 26 gas production wells, which will be drilled with two semisubmersibles; 500km of subsea pipelines, which will link the wells with the onshore terminal; upgrading the offshore construction vessels for the project; and the expansion of the Sangachal terminal to accommodate the new gas processing and compression facilities.

According to BP, as of Q3 2016, the Shah Deniz 2 project is about 83% complete in terms of engineering, procurement and construction, and remains on target for first gas in 2018.

***Khankendi* will be used for the construction of the subsea structures at Shah Deniz 2.** Photo from BP.

In December, Manila's Asian Development Bank made a $1 billion investment for the expansion of Shah Deniz Stage 2.

In September, the Shah Deniz Stage 2 platforms sailed away from the Heydar Aliyev Baku Deepwater Jackets Factory for offshore installation.

The *Israfil Huseynov* pipelay barge completed installation of all four North Flank and West Flank flowlines and is currently making progress on the remaining 32in gas export lines, in which this scope of work will continue through into Q1 2017.

In addition, BP announced that the *Khankendi* subsea construction vessel started up its main engines in September. Once completed, the *Khankendi* will be deployed to the Shah Deniz 2 area for the construction of the subsea structures between 2017 and 2027.

The vessel is 155m x 32m and has a 13m main deck. It will be equipped with dynamic positioning to allow working in 2.5m significant wave height, a 900-tonne main crane for 600m subsea operation, an 18-man two-bell diving system, two work-class remotely operated vehicles, a strengthened moon pool, two engine rooms with 6x4.4 MW + 2x3.2 MW generators and has a total weight of 17,600-tonne and a carrying capacity of 5000-tonne at 6.5m draft.

Meanwhile, at the ATA yard, construction of both Shah Deniz 2 platform topsides is well above 90% complete and commissioning is progressing. The flare tower has been safely installed on the production and risers platform.

Shah Deniz participating interests are: BP (operator, 28.8%), TPAO (19%), Petronas (15.5%), AzSD (10.0 %), Lukoil (10%), NICO (10%) and SGC Upstream (6.7%). **OE**

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Solutions

908 Devices launches compact analyzer

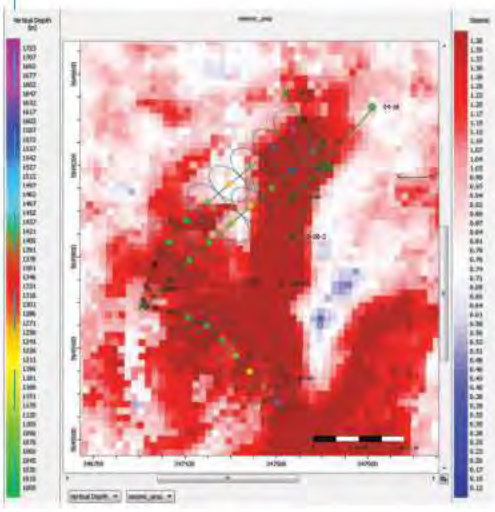
908 Devices released the G908, a compact analyzer for the oil and gas industry that combines the compound-separating capability of ballistic gas chromatography (GC) with the mass-based detection of high-pressure mass spectrometry (HPMS) for rapid detection of molecules in hydrocarbon streams at unparalleled levels of selectivity and sensitivity.

908 Devices has partnered with Schlumberger and Saudi Aramco since 2013 and 2015, respectively, to launch HPMS technology solutions for applications throughout the oil and gas industry. G908 marks the first commercial product made available to this industry.

The unique combination of ballistic GC with HPMS and conventional FID/TCD detection enables ultrafast compound separation, identification and quantitation of complex mixtures. This rugged 28-pound analyzer provides compositional analysis, improved efficiency, and significant cost savings.

G908's compact core HPMS technology and resistively heated column modules provide users with a detection system that does not require high vacuum to operate, and is drastically smaller and more rugged than conventional MS instruments. With a substantially improved size, weight and power (SWaP) signature, the G908 is designed to operate as a robust, low maintenance at-line and online analyzer, easily managed and maintained by operators.

Upstream applications include quantifying BTEX and other aromatics, rapid extended compositional analysis of natural gas, and sulfur speciation in hydrocarbon streams. **908devices.com**



CGG upgrades HampsonRussell

CGG GeoSoftware has released HampsonRussell 10.2, which provides new data conditioning, inversion and map prediction features. The updated reservoir characterization software features attribute extraction, prediction along horizontal wells, and upgraded geostatistical mapping capabilities. Key features include new data conditioning processes, residual Normal Moveout (NMO) correction, and FXY deconvolution for noise attenuation and spectral balancing. Inversion can now output relative impedances for both pre- and post-stack data and extract attributes along horizontal well paths. This new information helps mine and interpret data from derived attributes.

The new MapPredict application is a fully integrated, map-based geostatistical software that integrates well, seismic and attribute data into detailed maps. MapPredict encompasses the functionality of HampsonRussell's former ISMap application and the ability to handle horizontal wells. MapPredict is also suited for finding relationships between multiple seismic attribute slices and properties derived from well information such as hydrocarbon production. **www.cgg.com**

FES introduces new CALM buoy swivel

Flexible Engineered Solutions International (FES) has developed the CALM buoy swivel, certified by DNV

GL, which includes new swivel technology that allows the buoy to rotate while maintaining a leak-free joint between the subsea pipelines and vessel during the transfer of fluid. Because it enables the replacement of seals on board without the requirement to bring the main buoy into a repair yard, the new swivel will significantly reduce maintenance downtime for the CALM Buoy, avoiding it being offline for long periods of time.

The technology also boasts a leak detection system complete with instrumentation to allow the user to monitor the seal performance of the CALM Buoy Swivel, as well as an integrated pressure transmitter to monitor the pressure during loading; and it has an integrated electrical slip ring to allow electrical cable connections from subsea to topside.

www.fesinternational.com

ALE unveils lightweight service crane

ALE has successfully launched its new lightweight service crane, which is fully designed out of light modular parts that can be assembled by hand. Each part can fit in an elevator or transported over an access walkway or stairs, making it ideal for use on projects globally where space is limited and access is difficult. This crane is one of the first of a new range of lightweight service cranes and lifting structures, suitable for lifting equipment and modules. The cranes are certified for offshore, subsea and onshore operations.

"R&D first conceived the idea back in 2015 after we saw a gap in the market for a lightweight and versatile offshore handling system that can also be used for our onshore clients and on other ALE projects," said Harrie Smetsers, R&D Manager, ALE. "We wanted to offer standardized lifting solutions that could work on different, complex offshore assets, as well as our existing solutions." **www.ale-heavylift.com**

Cellula trials seafloor drill

Canada's Cellula Robotics has completed factory acceptance testing of its third CRD100 seafloor drill for Fukada Salvage & Marine Works and Mitsubishi Heavy Industries for the Japan Agency for Marine-Earth Science and Technology (JAMSTEC).

The CRD100 is a fourth generation seafloor drill designed to operate in waters down to 3000m depth for geotechnical surveys, mineral exploration and methane gas hydrates sampling.

The CRD100 is self-contained with a 100hp power pack. The CRD100 provides intelligent control that facilitates efficient core sampling and CPT pushes. A wireline tool system further enhances the speed of operation. The JAMSTEC CRD100 includes "size H" tooling and also supports optional tools for surface sampling (T146) and large cased boreholes.

The drill underwent factory acceptance testing at Cellula's Burnaby facility as well as in local waters. Sea trials will take place in February 2017.

Cellula Robotics is based in Burnaby, Canada, and specializes in the turnkey design and production of seafloor intervention and subsea robotic systems.

www.cellula.com

Innovator 2.0 launched

Saipem launched its latest remotely operated vehicle (ROV), the Innovator 2.0, after three years of design and testing. The heavy work class unit, which complies with Norsok U102 standards and is DNV GL certified, completed sea trials in December 2016.

The design includes a new electrical motor that can provide 210hp, which – combined with a high efficiency of the propulsion system – can provide a bollard pull of 1100kg in each direction, a maximum speed of 3.5 knots and the ability to lift a weight of over 600kg hooked to the front part of the frame.

The ROV is equipped with a 6600V power supply, which allows it to operate effectively with cable lengths up to and over 7000m, and the umbilical cable and tether have been redesigned to transmit the ship's on-board power to the subsea vehicle. The tether management system, in its base configuration can handle 1100m of tether.

Compared to previous models, the console and the human machine interface (HMI) have been redesigned to make the work of pilots less demanding and more efficient. The surface equipment has also been designed for installation in a dedicated control room or a container, making the entire Innovator system transportable by land, sea or air.

www.saipem.com

Activity

Chasing real solutions

Audrey Leon speaks with MJ Hellail, president and CEO of Samoco Oil Tools, to discuss a few of the fit-for-purpose technologies the new firm has launched.

It is often easy for research and development to go by the wayside during a downturn in the oil and gas industry. But, innovation must continue keep operations safe and lower costs.

"One of the good things about the oil and gas industry – we are very innovative," says MJ Hellail, Samoco's President and CEO. "We have some great brains that come up with solutions that don't have to compromise safety."

Houston's Samoco Oil Tools, an offshoot of PISC International, aims to solve unique problems for its clients by providing fit-for-purpose technology, both large and small.

Samoco, formed in 2014 and helmed by Hellail, has launched tools aimed at cutting environmental risks during drilling operations as well as saving time and money for critical BOP testing.

Hellail, who has spent the majority of his 28-year career in procurement, logistics and manufacturing, saw an opportunity to dive into research and development and become a solution provider.

One solution Hellail is proud of took only eight weeks to develop. A Houston-based rig manufacturer reached out to Samoco in need of a zero spill solution to mud handling equipment on the rig floor. The result was a tool that integrates the existing mud handling systems on the rig within the iron roughneck, which is responsible for making up or breaking down the drill pipe. With the pneumatic mud bucket integrated into the iron roughneck (BIMB – Built-in Mud Bucket), Hellail says, when the pipe is in location to be broken up, the mud bucket then surrounds the pipe and mud goes into the bucket, straight into the mud system and back through circulation.

MJ Hellail

"Environment was a driver behind this innovation," Hellail says, "But, another aspect of it was time savings and how to reduce cost. Operators are looking for ways to improve on overall cost of drilling a well."

Additionally, Samoco has launched a tool aimed at reducing the time and cost associated with downtime that often occurs with critical BOP testing. Hellail says that Samoco was approached by an international operator that was looking for a solution that allows them to continue complying with federal regulations, which require three tests to be conducted on the firm's subsea BOPs every 14 days. The downtime associated with the testing was costly.

The test involved include ensuring that the BOP can close on both the largest and smallest pipes using the variable bore ram in the well, as well as performing the shear test.

"Currently, the best anyone can do is perform two trips to test, separately," Hellail says. "Our solution is the One-Trip tool. It goes in and performs all three tests at the same time in one trip. If the test results are not satisfactory, the operator can reconnect while still downhole inside the BOP cavity and test again and again until they get the proper results."

For this tool, development took about a year and a half because of all the engineering and testing required, which was accomplished in collaboration with the operator's engineers, Hellail says. Some of the challenges encountered included ensuring that the seal design held the required pressure experienced downhole at the subsea level.

Another was ensuring that the tool had the ability to hold enough weight under it without having to force the operator to pull everything out of the hole as they perform the test, Hellail says. "That was another challenge because the locking mechanism had to be able to hold enough weight and maintain the tool enact while the test is being performed," he adds.

Hellail says that the One-Trip tool was proved up to 25,000psi of testing pressure and 15,000 of working pressure. After its deployment, the operator was able to save an average 12 hours per test (cutting the time in half), and an average of $600,000 every two weeks when the test was performed during the drilling campaign, Hellail says. The tool arrived on location in April 2016 and was in operation in August of that year. **OE**

OE looks forward to sharing further information about the One-Trip tool in our June 2017 issue.

Samoco Oil Tool's Houston facility. Photos from Samoco Oil Tools.

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Activity

Critical industry gathering to discuss Australia's oil and gas future

AOG attendee. Photo from Diversified Communications.

With Australia recently highlighted as one of the few positive locations in the world for oil and gas expenditure, there will be plenty of interest when industry specialists from around the globe gather for a series of high level discussions at the annual Australasian Oil & Gas Exhibition & Conference (AOG) at the Perth Convention Exhibition Centre (PCEC) 22-24 February.

With local LNG industry heavyweights such as Woodside, and Shell joining with specialist companies such as Deloitte, the Western Australian and Australian governments, and world leading industry bodies, the content for the AOG 2017 forums will provide critical input on where the industry is headed in this region over the next few years.

The Collaboration Forum, which kicks off on Wednesday, 22 February 2017, will feature the latest technological innovations utilizing analytics, drones, cybersecurity, and 3D printing, as well as sharing breakthroughs from other industries.

"In a 'lower for longer' oil price environment a culture of ingenuity and resilience is required," says Michael Utsler, Chief Operations Officer, Woodside. "This forum provides an opportunity to tackle key issues and opportunities together, to share learnings and to seek ways to drive excellence through our combined endeavors."

Subsea UK, is partnering with the Society for Underwater Technology (SUT) and Subsea Energy Australia (SEA) to put together the Subsea Forum program, which focuses on how the Australian subsea industry adjusts to the challenges and opportunities in the current market.

The Knowledge Forum has been created to educate, inspire and inform by bringing specialized industry sectors together to discuss the latest techniques and technology that will enable the industry to overcome both current and future challenges.

AOG 2017 will again feature a number of specialist "Zones" on the exhibition floor, covering key topics such as subsea, health, safety and environment, NDT and condition monitoring, instrumentation control and automation – and new zones for 2017, asset management and maritime – ensuring a very interactive and industry-critical event. For more information, visit: **www.aogexpo.com.au** ▪

Neptune opens Houston office

Perth-headquartered Neptune Marine Services, a provider of engineering, integrated inspection, repair and maintenance solutions, has established an office in Houston.

Operating under the name Neptune Subsea, it will enable Neptune to provide a full suite of services to clients within the Gulf of Mexico and the Americas. The move was supported by the Scottish Development International, the international arm of Scottish Enterprise.

John Allen, a Houston based strategic business development advisor, formerly of GE Oil & Gas, has been appointed to drive the expansion.

Neptune's Kevin Stephen,
Photo from Neptune Marine Services.

Kevin Stephen, Neptune's Operations and Business Development Director for Europe, Mediterranean and Africa, said: "We are delighted that the office in Houston is now in place. I would like to thank Scottish Enterprise for their support and advice."

FMC, Technip merger presses forward

Shareholders of both US-based underwater tech firm FMC Technologies and French engineering house Technip voted to approve the proposed business combination of the two companies on 5 December 2016. The merger was announced back in May 2016, and aims to create a new US$13 billion business under the banner "TechnipFMC." The two have a joint venture, Forsys Subsea, which was established in 2015.

The proposed merger remains subject to certain regulatory approvals and consents, as well as other customary closing conditions. The transaction is

expected to close in early 2017.

It has largely been smooth sailing for both FMC and Technip. At the beginning of December, the two firms received approval from Brazilian antitrust authorities to move forward with the merger. In late November, the two firms received clearance from the EU. Clearance decisions have previously been issued by antitrust authorities in the US, India, Turkey, Mexico and Russia.

Thierry Pilenko, current Technip Chairman and CEO, will serve as Executive Chairman of TechnipFMC, while Doug Pferdehirt, current president and COO of FMC Technologies, will serve as the CEO of the new company.

MTNW rebrands as Rugged Controls

Measurement Technology NW (MTNW) Line Control Instruments (LCI) group has rebranded as Rugged Controls.

Rugged Controls will continue to manufacture MTNW's previous product portfolio including running line tensiometers, smart deck machinery and LCI flagship displays.

Along with a new logo, a new mobile responsive website (www.ruggedcontrols.com) has been launched that includes new resources, product guides and case studies.

Tom Rezanka, Rugged Controls president commented on why the decision was made to rebrand the company: "Over the past five years, our business has diversified beyond 'Line Control Instrumentation,' as we now provide solutions for a variety of applications such as pressure, torque, rig instrumentation and more with a common theme: rugged electronics and sensors, mission critical reliability, data acquisition, control and reporting features. We knew it was time to align our brand with our expanded capabilities and core competencies."

Boeing buys Liquid Robotics

Boeing has acquired autonomous glider vehicle firm Liquid Robotics, which formed a joint venture with Schlumberger in 2012 to pursue opportunities in the oil and gas industry.

Launched 10 year ago, Liquid Robotics developed the Wave Glider platform and SHARC variant, which are able to travel autonomously about the oceans collecting and sending data.

This could include continuous real time data collection of seep and containment loss, meteorology/oceanography and subsea communications. All this is mounted on a self-propelled system, Wave Glider, that doesn't require fuel or power (it has solar cells and uses wave motion to create forward propulsion on planned routes) and is loaded with GPS, navigation and satellite systems.

Liquid Robotics is now within Boeing's Autonomous Systems Division, as part of which Boeing sees the firm being part of an integrated network, seafloor to space.

Subsea UK Awards finalists unveiled

Industry body Subsea UK has revealed the finalists for its annual awards event, to be held early 2017.

The awards, which seek to recognize companies and individuals who are leading the way in Britain's £9 billion subsea sector, will be presented at a dinner during Subsea Expo – Europe's largest subsea focused exhibition and conference – in Aberdeen. *OE* is a principal media sponsor for this year's event.

Among the finalists, Hydro Group, JDR Cable Systems and N-Sea are in the running to win the coveted Subsea Company of the Year award.

In the Global Exports award category, JDR Cable Systems, JFD Global and Ocean Installer have been shortlisted; while the Innovation for Safety award will see Canyon Offshore, JDR Cable Systems and The Underwater Centre compete to take home the coveted accolade.

The shortlist for the Innovation and Technology award comprises Interventek, JDR and Proserv while Chay Telfer of Caley Ocean Systems, Faraz Ahmed of GE Oil & Gas and Aiden O'Sullivan from Universal Pegasus are the individuals shortlisted for the Young Emerging Talent award.

The Small Company of the Year award will be contested by EC-OG, Flex-Tech and Infinity Oilfield Services.

The individual who has made the most outstanding contribution to the subsea sector will be announced on the night.

"Despite the continued downturn, these finalists have demonstrated that the UK subsea sector has what it takes to rise to the challenge – identifying ways to improve productivity and deliver much needed efficiencies," said Neil Gordon, CEO of Subsea UK.

The ceremony will be hosted by former rugby star, Matt Dawson MBE. Subsea Expo runs from 1-3 February 2017. ▪

Subsea UK Awards. Photo from Subsea UK.

Spotlight

Surfing the industry

There are not too many people within the subsea business that saw through – from their very beginnings and from the inside – the growth of two of the biggest players in the business. Elaine Maslin speaks with Allen Leatt to find out more.

Allen Leatt as a graduate engineer and air diver in the late 1970s and today. Photos from Allen Leatt.

Allen Leatt has seen through the creation of both Technip and Subsea 7 into the offshore construction firms they are today, having worked at the likes of Stena Offshore and Stolt Offshore.

Leatt, now CEO of the International Association of Marine Contractors (IMCA), is taking on a different challenge. IMCA, formed in 1995, has roots deeper than Leatt's first days in the industry in 1982. IMCA, formed after the merger of the Association of Offshore Diving Contractors (AODC) (itself formed in 1972) and the Dynamically Positioned (DP) Vessel Owners Association (formed in 1989), now has about 1000 member companies.

Leatt joined the organization in October 2015 and reorganization has been high on the agenda, both to reflect its size, and the current economic environment. It's a new challenge for Leatt, whose roles at Stena, Stolt, Acergy, Technip and Subsea 7 were geared toward delivering contracts and problem solving on projects.

Having been through previous downturns, he's confident the industry will get through this one. "Aberdeen knows better than anyone the state of the industry today," he said at a diving seminar in the Granite City in mid-November. "We know no one has any control of these macroeconomic matters. We also know we have tremendous resilience in this industry. It's a cyclical industry. We will adjust to being fit for the purpose ahead of us."

Rising costs are to blame. Some attributed to post-Macondo regulations (10-15%, according to McKinsey Research), Leatt says, some due to complex specifications and operators choice (45-55%), and 30-40% due to the supply chain. Capex cuts of 25% in 2015, and the same in 2016, means there's less work to go around. New business models, not just rightsizing, are needed to survive and for the industry to again prosper, he says.

A civil start

Leatt is a civil engineer by training, having graduated from at Aston University, Birmingham, where he recently received an honorary DSc. However, from the start, he's been in the marine sector. At his first job, with John Laing Construction, he was given the opportunity to train as a diver, to supervise diving contractors. He qualified as a diver in 1978 and became a chartered engineer in 1982, moving that year to Aberdeen to join the offshore business, working for SubSea Offshore. He's not looked back.

"The glove fit," he says. "(In the marine civils industry) we worked in strong tides with no visibility. I knew the limits of what could be done. When I moved to Aberdeen, there was so much energy, so much initiative you could take, and so much pioneering activity. It was an exciting time."

His career took him to New Orleans in 1986, but then his first oil crash happened. "The cost cutting was brutal. Everything stopped," he says. Leatt decided to do an MBA at Cranfield University, UK. Then, Piper Alpha happened, shaking the industry to its core. Leatt then joined with a relatively new firm, Stena Offshore. "It was a small company, with a fantastic owner, but it was losing money," Leatt says.

New diving support vessels were bought, acquisitions made, such as the reel ship *Apache*, and by 1994 the firm had US$300 million revenues (from $25 million when Leatt started in 1988) and was "very profitable." Stena Offshore merged with Coflexip in 1995, which then, in the 2000s, merged into Technip. During this time, Leatt also helped form Perry Slingsby Systems, by merging Perry Tritech, of which he was CEO for a time, and Slingsby Engineering, bought by Coflexip Stena Offshore. "In a market with zero growth," he helped the company enter the commercial and military fiber optic cable laying markets. The firm was later bought by Forum.

Starting at Stolt

Leatt, meanwhile, went on to work at Technip's Paris headquarters, as executive vice president for the subsea umbilicals, risers and flowlines (SURF) product line, covering ships, equipment, factories, and corporate engineering centers in the SURF segment. But, he was soon to start over, joining Stolt Offshore in 2003. "It was losing money,

so the board brought in a new management team," he says. "Within a year, the market had also turned. It was another marvelous journey."

The business was renamed Acergy, and Leatt became chief technology officer, overseeing the building and conversion of a number of vessels and acquiring what became the *Seven Borealis* from owners who were struggling to finance it at the time. "It's a big Swiss army knife," says Leatt, with clear fondness.

In 2011, Acergy merged with Subsea 7 and Leatt become vice president of engineering and project management, with 2000 engineers on his staff. You could say the rest is history.

Joining IMCA

In 2015, after 33 years in the offshore contracting world, becoming a Fellow of the Institution of Civil Engineers and the Royal Academy of Engineering, as well as a member of the Smeatonian Society, Leatt decided on another change and became IMCA's CEO.

There are of course serious challenges facing the industry, which IMCA can help address. There's gold-plating and duplication – i.e. around engineering requirements – that needs to be challenged, says Leatt, to make the industry much more efficient.

"The technologies are well understood and this industry can solve any technical problem thrown at it, but the requirements have gone up and up over the years, often with little justification, and as a result we are at risk of creating uneconomic solutions," Leatt says. "I've been on projects where the pipeline welding criteria makes it almost impossible to weld. Conservative engineering is fine by me, but there comes a point in time where you have to be pragmatic and make realistic engineering judgements. I learned many years ago to rationalize designs rather than endlessly optimize their performance, and I think that philosophy is as relevant today as it was 30 years ago."

Among IMCA's many current projects, there is one looking at contracting terms and conditions, including attempts by some oil companies to change the traditional knock-for-knock arrangements, in ways that put too much risk onto contractors and will strain insurance norms, Leatt says. This has been an issue since the Macondo disaster in the US Gulf of Mexico in 2010.

IMCA continues to monitor and target improvements in safety in the industry, collecting data every year. "Safety has been the linch-pin since the [AODC] was formed in the 1970s," Leatt says. "The industry was brand new and the safety record very poor, but the regulators couldn't act fast enough so the contractors came together to form AODC."

On the technology side, an area close to Leatt's heart, IMCA has looked closely at DP rules and guidance. But, IMCA also has groups looking at ROVs, survey, competence and training, lifting and rigging, and others.

The latter has had a focus on wire rope; and, more recently it has looked at synthetic rope, as it's become increasingly used for heavier lifts, while there's little by way of an established inspection and maintenance regime for the ropes to ensure their integrity, particularly if they're being used repeatedly.

IMCA is also reviewing industry technologies where others, such as Oil & Gas UK or the Oil and Gas Authority, are not already doing so. One example is around pipelines or subsea construction, where efficiencies could be made.

Technology adoption

Leatt has more experience than many when it comes to the SURF business and in his view it's a conservative business where technology is adopted incrementally, rather than disruptively, "but where improvements are continuous." A hot (literally) area at the moment is flowlines insulation, where he sees trace heated pipelines as showing great promise, helping to reduce the need to service lines in subsea architecture. "But, it is not quite as straight forward as the reading on it might suggest," Leatt says. But, he still thinks this technology will be successful. Likewise, diving and ROV tool development will most likely continue to be incremental in nature.

Areas where the industry faces challenges are the interfaces between operators and their partners, as well as operators and contractors. But, there is an opportunity to reduce the latter. While he thinks operators could do more to improve the industry's current economics, instead of just leaning harder on the supply chain, contractors could work together more to offer simpler interfaces with operators. Leatt lived through CRINE (Cost Reduction Initiative for the New Era) in the early 1990s and feels the industry could benefit from some of that thinking and leadership today. Some of this type of activity has already been going on, but more could happen, Leatt says.

"There's been the drive to take costs out and cut capacity, reduce man power, but it's not enough. If we want to transform things to a different level of performance, we have to think differently and be bold enough to commit to it," he says. "Large operators can do great things, but breaking the mold is very difficult for them. Small players can deliver through a different model, which the larger guys naturally find difficult. Likewise, the large contractors and service companies today have great opportunities to reshape the marketplace. A crisis always creates room for creativity and thinking differently." **OE**

Leatt as CEO of Perry Tritech in the late 1990s early 2000, seen with the chairman of Coflexip Stena Offshore (now Technip).

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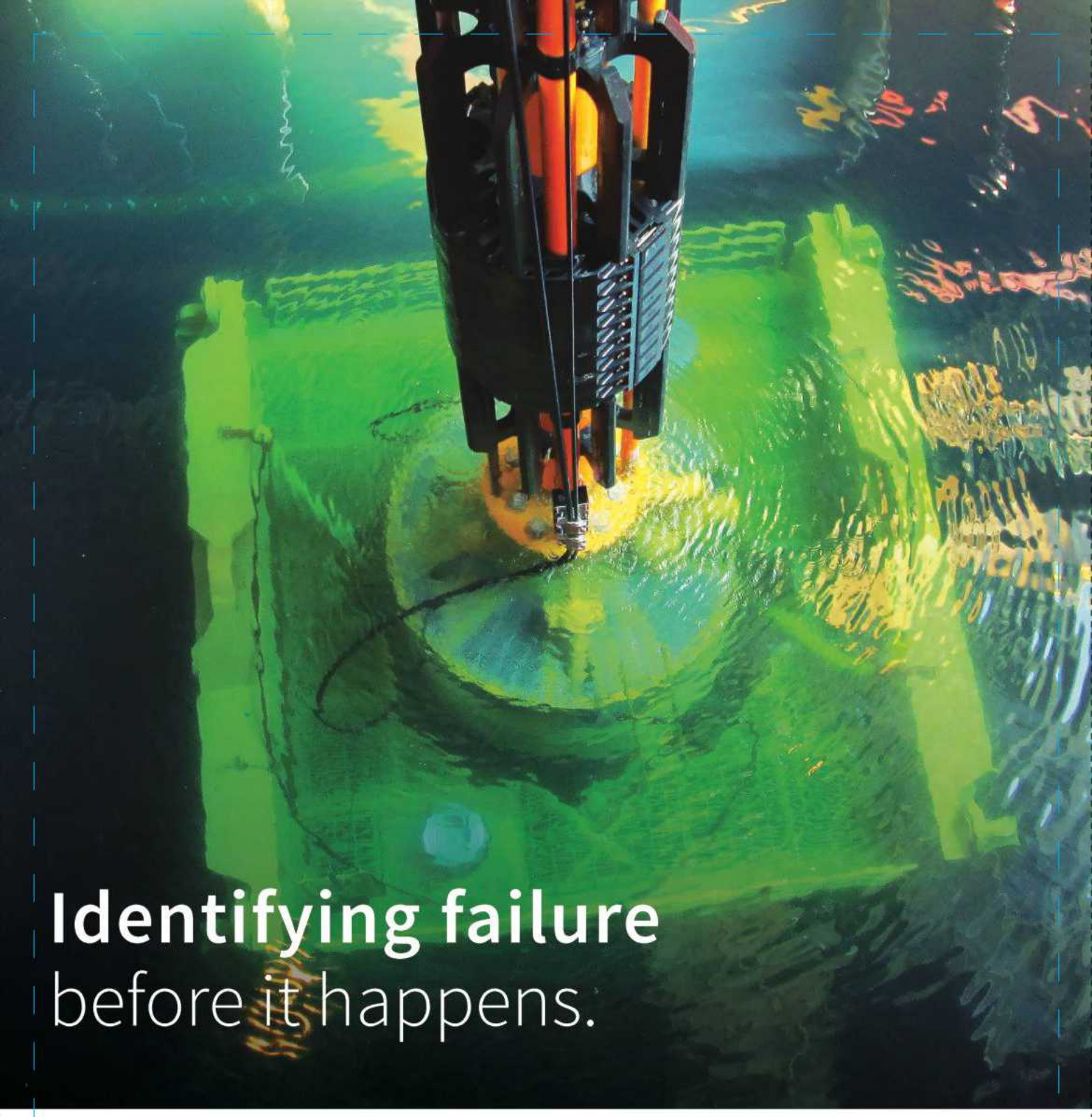

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