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Global Deepwater Review

page 28

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Global Deepwater Review

The Delta House platform in the Gulf of Mexico. Photo courtesy of InterMoor

FEATURE FOCUS

28 Harsh realities
Remaining competitive through the downturn is a tall order for some. Caitlin Shaw, of Quest Offshore Resources, examines how the exploration, drilling and subsea segments are expected to fare through 2017.

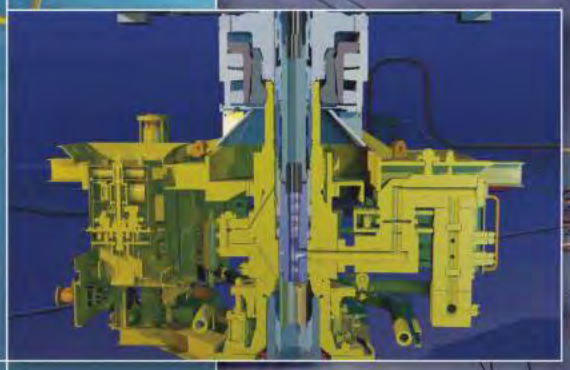
34 Let's get deep
Ultra-deepwater exploration on the Atlantic margin could be the opportunity the offshore industry is looking for, according to geoscience firm Spectrum. Elaine Maslin reports.

38 How deep is your well?
This year, the deepwater drilling record could be broken not just once, but twice, breaking the last record, set back in 2013. Elaine Maslin takes a look.

Features

ON THE COVER

Hard at work. *OE*'s cover features various deepwater projects from around the globe. Included: ExxonMobil's US$4 billion Julia project in the Gulf of Mexico (learn more on page 100), LLOG's recently onstream Delta House development, and Eni's Goliat FPSO in the Barents Sea. *Photos courtesy of ExxonMobil, InterMoor (Delta House), and Eni (Goliat).*



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Installation work on the deepwater Julia field. Photo courtesy of ExxonMobil.

Features (continued)

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What's Trending

On a roll

- US confirms new well control rule
- Mexico moves to strengthen Pemex
- Culzean jacket sets sail

People

Heerema exec named Bumi CEO

After more than a year since Bumi Armada Berhad's chief executive officer (CEO) Hassan Basma stepped down, Leon A. Harland has been named Bumi's new CEO. Harland, who will also be appointed as an executive director, will take office this month.

Harland was previously executive vice president, commercial and technology for Heerema Marine Contractors. Prior to joining Heerema, he worked for FPSO operator SBM Offshore. In 2004, Harland was tasked to start up and build their floating LNG business.

Undercurrents

Checking Mexico's pulse

Left to right: Georgina Trujillo, president of Mexico's Energy Commission, SENER's Lourdes Melgar, and CNH's Oscar Roldan Flores speak at PECOM 2016, held in Villahermosa in April.

by Audrey Leon

Much ado has been made over Mexico in the last three years as the country turned a new page and opened its industry to foreign investment.

Make no mistake, it's a big deal. And, one with rather unfortunate timing. If not for the downturn, who knows what the outcome of Mexico's first two rounds in shallow water might have been? But, one bright spot has been that, because of the downturn, serious companies are electing to participate in bid rounds while Mexico's governmental agencies work out the kinks, improving terms with each round. And, despite the global, and local, industry's current struggles, the mood of the 22nd Annual Petroleum Exhibition & Conference of Mexico (PECOM) was one of bright optimism.

At PECOM, owned by *OE*'s publisher AtComedia, representatives of the country's governing energy agencies (including the Energy Ministry [SENER] and the National Hydrocarbons Commission [CNH]) and state-owned oil company, Pemex, came out to discuss life during the reform process and to reinforce that the country is still learning, but also still striving for transparency and accountability.

"We are seeing the birth of the new way to handle the oil industry in Mexico," said keynote speaker, former head of state-owned oil company Pemex, Carlos Morales Gil, now head of Petrobal, a new, privately-owned Mexican oil company.

Morales Gil discussed the need for not just technology, but people to create and deliver technology. "Technology is not a shapeless entity that creates itself," he told the standing room-only crowd.

Technology is a huge reason for the long-awaited opening of Mexico's energy sector. The other huge reason being financial, as Pemex is unable to afford drilling in shale and deepwater areas.

A capacity crowd listens to Pemex E&P's José Antonio Escalera Alcocer.
OE Staff Photos.

Late March, it was announced that Mexico would opt to have a low local content requirement specific to deepwater. Georgina Trujillo Zentella, president of Mexico's Energy Commission of the LXIII Legislature, said to do otherwise, "would be like a bullet to the brain" for deepwater plays. Mexico's SENER and Mexico's Ministry of Economics set deepwater local content at 3% for 2015 and 8% by 2025. For areas other than deepwater (shallow and onshore) local content was 25% in 2015 and is due to be 35% by 2025.

On the geological front, Oscar Roldan Flores, head of the National Data Repository for Mexico's CNH, noted that Mexico is investing heavily in seismic data acquisition, with awards going to companies such as TGS, ION Geophysical and CGG. Roldan showed a slide stating that 350,140sq km of new 2D seismic had been acquired and 111,805sq km of new 3D seismic had been shot in the Mexican side of the Gulf of Mexico. Some 387,407sq km of seismic data has also been reprocessed.

Trujillo also said that one big advantage of the energy reform is that Pemex is now able to have joint venture partners for its fields. "If Pemex didn't have the option for partners, the projects would go away and the economy would get worse," she said.

Lourdes Melgar, deputy secretary of Energy for Hydrocarbons, (SENER), said of Pemex's mandate, through the energy reform: "Pemex has the tools to take advantage and improve its financial situation, [implement] new business models and tools." What does that mean? Melgar said that Pemex must choose projects where they will be profitable.

José Antonio Escalera Alcocer, exploration director, Pemex E&P, acknowledged as much in his presentation, stating that Pemex has three areas for improvement, including operational efficiency and portfolio optimization.

At PECOM 2016, Mexico's government showed that it has identified key areas on which to work, through the rest of the year and beyond. Mexico's energy future is just on the horizon. Indeed, Melgar noted that the new deepwater round is set for 5 December. **OE**

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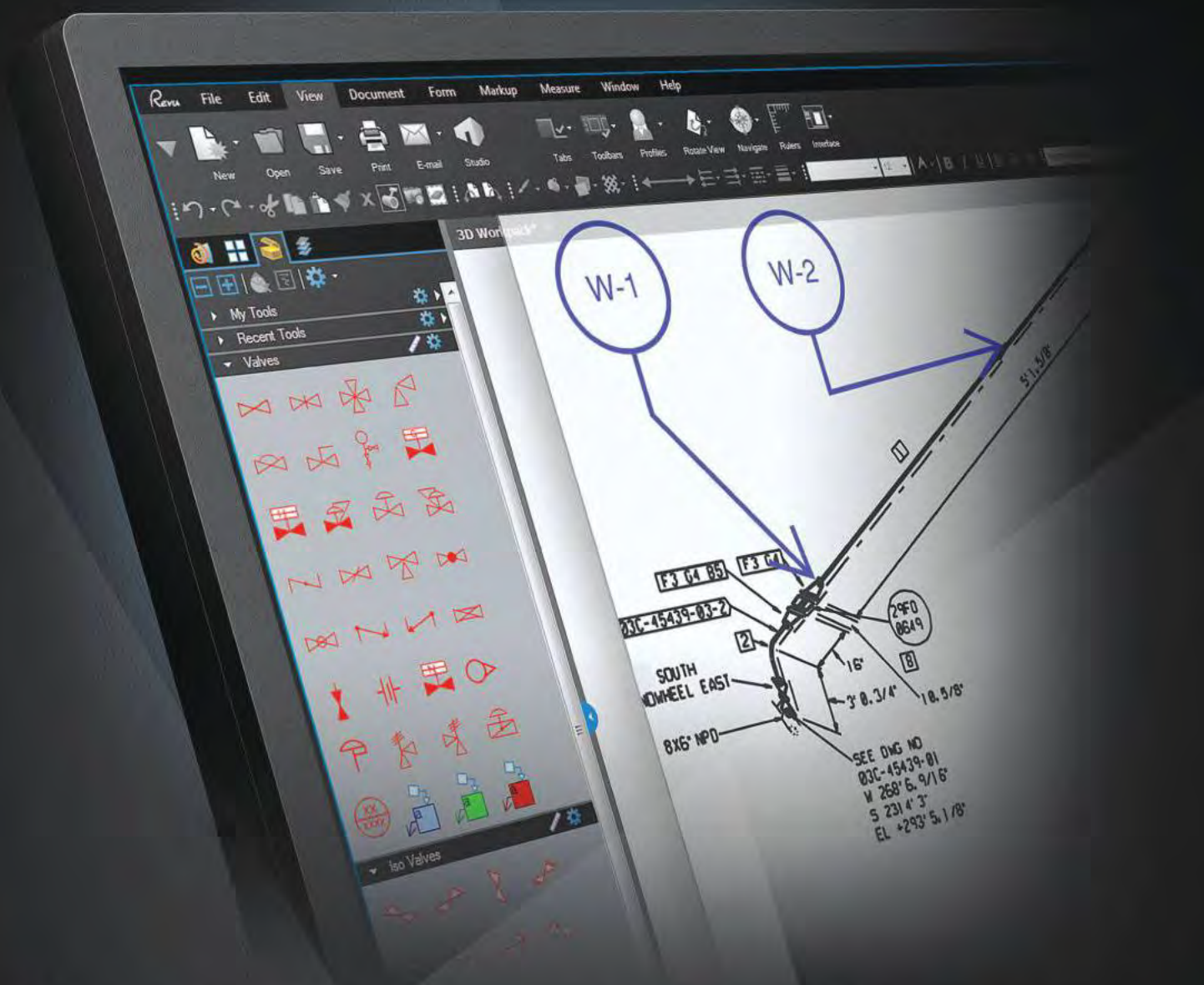

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Survive to thrive

Anyone that reads this column every month will know that there have been some common themes to my take on the oil and gas industry this year.

First, is my criticism of the short-term thinking that has permeated the industry to its considerable detriment. Second, is the assertion that better times will come given the certainty that, provided the broader economy is in decent shape, in time, supply and demand will fall into balance. All oilfields deplete and if they are starved of investment – as has been the case for the last seven quarters – production falls significantly faster than normal.

iStock illustration

In recent weeks, crude prices have begun to firm, rising from US$28/bbl lows to around $40/bbl, partly because of the "production freeze" rhetoric from Saudi Arabia and Russia, but also because the production declines in North American land have been accelerating.

It has also helped that concerns about the health of the giant US and Chinese economies have abated. This has prompted a much more constructive tone by most industry commentators, many of whom now anticipate significantly higher crude prices by the end of the year.

Unfortunately, stronger crude prices will be of little solace to the 350,000 oil workers globally who have lost their jobs thus far. That number is set to rise significantly through the remainder of 2016 and 1H 2017, because higher prices will not percolate through to oil service spending until well into 2017.

Only the fittest companies with the best management and the strongest balance sheets will survive this industry downturn. However, when the market does bounce back, it will come back strongly because of the huge volume of work that needs to be done to catch up on essential activities that have been deferred or cancelled.

In the interim, at Simmons & Company, we hope to help some companies that are operationally sound but cash flow challenged by allocating a proportion of our private equity funds to support distressed businesses. We are doing this in the belief that when the market turns a significant proportion of oil service capacity will have evaporated and that those companies still standing will be strong, efficient and well positioned to respond to the inevitable surge in activity.

The big question is how long we will have to wait for that to come to pass. Notwithstanding my optimism for a 2017 recovery, we are planning for conditions to get even tougher through 2016 and well into 2017 and I would advise other industry participants to do the same. **OE**

Colin Welsh *is head of international energy investment banking at Simmons & Company International, part of Piper Jaffray. He studied accountancy, economics and law at the University of Aberdeen and qualified as a Scottish Chartered Accountant with Ernst & Whinney (now EY).*

Rig Count Overview & Summary Count

As of April 2016

Area	Last Count	Count	Change from Prior Count	Date of Prior Count	Change from Last Year	Date of Last Year's Count
US	8 April 2016	443	-7	1 April 2016	-545	9 April 2015
Canada	8 April 2016	41	-8	1 April 2016	-58	9 April 2015
International	March 2016	985	-33	February 2016	-266	March 2015

Source: Baker Hughes

Thoughtstream

What role for NOCs?

In 1975, the UK's national oil company (NOC), BNOC, was formed. It didn't last long, while others are still going strong. Alex Kemp takes a look at the whys and wherefores of NOCs.

National oil companies have been in existence for many years, but their roles and indeed their very existence, have been, and continue to be, the subject of much controversy.

"The duty of fostering security of oil or gas supply for the domestic market is sometimes bestowed on a national oil company. Where this involves the purchase of oil or gas at prices below the full market value, conflicts with private sector partners can arise."

Their current importance is enormous. According to some estimates, collectively they control over 80% of the world's remaining oil reserves. Several different motives explain their formation and continued existence.

In many cases, national ownership of a perceived valuable resource has been a main reason. A national oil company can reduce what is felt to be excessive reliance on foreign ownership and/or extraction of a key national resource (or treasure as it is described in some countries). National ownership in whole or in part is thus a device to reduce this dependence.

This should be distinguished from the motive of procuring state ownership as a manifestation of socialist principles. This thinking was prevalent in the UK in the second half of the 1970s, for example, when the notion that the state should have ownership of the "commanding heights of the economy" was promoted.

Fashions change. Only a few years later the view that the state should not be directly involved in the production of oil and gas was promoted, and the British National Oil Corp. was privatized.

In other cases the key motive has been to use a national oil company as an instrument of state control rather than for any socialist principle. This reflects a dirigisme view of the role of the state. Examples are in some Middle East countries.

A national oil company can also be an instrument whose main purpose is to collect an (equity) share of the associated revenues to the state. In other respects, the company may play a passive role. An example is Petoro in Norway, which is the custodian of the state's direct financial interest. Such state participation in licenses and contracts is common.

Private sector companies obviously prefer to choose their own partners. Having a state company as a compulsory partner can sometimes increase the investor's perceived political risk, but in other cases it can reduce these risks. Thus a state company partner may have insightful and helpful relationships with the host government.

But, preferential participation terms such as carried interest obligations can cause problems, particularly in circumstances (such as the present) where capital rationing is acute.

Thus, the expected returns to a private sector explorationist can be turned form positive to negative by carried interest terms where the state company is not a full risk-sharing investor, particularly where there is no reimbursement of the state company's share of exploration costs.

Worldwide, the oil and gas sector requires regulation. In some countries the national oil company is given this duty (such as oversight of the performance of petroleum contracts) by the host government. The fact that the state oil company has expert knowledge of the industry is often cited as a reason for this. Unfortunately, when this duty is combined with that of acting as a conventional oil company, conflicts of interest can readily arise.

These can adversely affect working relationships with private sector partners who generally do not appreciate the situation where one organization in effect sits at both sides of a negotiating table. There is a clear virtue in the separation of regulatory and conventional oil company activities.

The duty of fostering security of oil or gas supply for the domestic market is sometimes bestowed on a national oil company. Where this involves the purchase of oil or gas at prices below the full market value conflicts with private sector partners can readily arise.

In sum, petroleum contracts are likely to be most successful when they can accommodate unambiguously the aspirations of both host governments and private sector investors. This is most readily achieved when the roles of national oil companies are clearly designed to prevent the emergence of conflicts of interest. **OE**

***Alex Kemp** is professor of Petroleum Economics and director of Aberdeen Centre for Research in Energy Economics and Finance at the University of Aberdeen. He has published more than 200 papers on petroleum economics and was a specialist adviser to the UK House of Commons Select Committee on Energy in 1980-1992, and in 2004, and 2009. He was awarded the OBE in 2006, for services to the oil and gas industries and wrote The Official History of North Sea Oil and Gas, published in 2011.*

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Global E&P Briefs

A Newfoundland seeks bids, BP delays Nova Scotia

The Canada-Newfoundland and Labrador Offshore Petroleum Board has issued two calls for bids in the Eastern Newfoundland and Jeanne d'Arc Regions under the Scheduled Land Tenure Regime in the Canada-Newfoundland and Labrador Offshore Area.

The round covering Eastern Newfoundland includes 13 parcels, making up 2.9 million hectares. The round including the Jeanne d'Arc Region consists of three parcels, totaling 354,552 hectares. The deadline to submit is 9 November 2016.

Also offshore eastern Canada, BP will delay its Nova Scotia exploration drilling activity until Q2 2018, which it says will help finalize exploration well locations. BP Canada's exploration drilling program is 230-370km off the southeast coast of Nova Scotia.

B US lease sales press on despite mixed results

The US will offer 23.5 million acres offshore Texas for oil and gas exploration and development as part of Western Gulf of Mexico Lease Sale 248, scheduled to start in New Orleans in August 2016. The sale will include 4343 blocks, 9-250mi offshore, in 16-10,975ft (5-3346m) water depth. In March, Lease Sale 241 yielded only US$156 million in high bids. The Eastern Planning Area sale, held concurrently, received zero bids.

C Noble fails at Silvergate

Noble Energy will plug and abandon its Silvergate exploration well in the Gulf of Mexico, after failing to encounter commercial hydrocarbons. The operator will move to drill an appraisal well on its 2014 Katmai discovery in Green Canyon Block 39. The Silvergate well was drilled on Mississippi Canyon Block 339 in 4518ft water depth. Silvergate, a Miocene target with a resource range between 30-100 MMboe gross, had subsea tieback potential.

D Searcher to begin Mexico 3D Ultracube seismic

Searcher Seismic will begin the South Campeche Ultracube 3D seismic reprocessing project offshore Mexico that will see three existing surveys merged. The project covers 260km in the southern part of the Bay of Campeche, providing new depth imaging of the Southern Campeche – Sigsbee Basin and also parts of the offshore Comalcalco Basin, Searcher said. In total, the project covers about 17,700sq km, including areas in the second and third phase of Mexico's Round One. Fast track products are expected to be available in about six months and final volumes will be available in Q2 2017.

E Spectrum starts Brazil campaign

Geoscience firm Spectrum has started a 10,400km multiclient 2D survey offshore Brazil in the Amazonas and Para Maranhao basins, along the Equatorial Margin of Brazil.

The program will tie five of Spectrum's Northern Margin programs, producing a continuous dataset from the French Guiana border through the Potiguar Basin.

The data will be processed in Spectrum's processing center in Houston. PreSTM, PreSDM and Broadband products will be available in Q4 2016.

F Premier Oil to spud Bagpuss

Premier Oil plans to spud the Bagpuss well on 7 July. The well, in Block 13/24c on the Halibut Horst in the UK North Sea, will be drilled by the *Ocean Valiant* semi-submersible rig to 1550ft to evaluate the prospectively of the Lower Cretaceous interval beneath the Chalk and above the granite basement. Drilling is expected to take 26 days, or 30 for logging and sampling in the success case.

Premier's analysis of the 1981 discovery well result suggests that the Bagpuss and the nearby Blofeld heavy oil prospects together could contain up to 2 billion bbl in place.

G PGS in Aasta Hansteen survey

Petroleum Geo-Services (PGS) will start acquiring

4400sq km 3D GeoStreamer survey over the Aasta Hansteen area of the Norwegian Sea this month [May] using the *Ramform Tethys* with a deep-tow acquisition configuration of 16 streamers with 75m separation. The work is due to complete by August 2016, with fast track data available four months after the final shot.

The project is on the Nyk High in the outer Vøring area, and will be used as a baseline survey for future 4D studies.

H OMV wins at Wisting

OMV completed drilling and testing of the Wisting Central II appraisal well in production license 537 in the Barents Sea. Flow rates hit just above 5000 boe/d, which is expected to increase the in-place volumes in the Central South and Central West segments on Wisting, and further reduce the overall uncertainty of contingent resources.

The horizontal well was drilled using the *Transocean Spitsbergen*, about 310km north of Hammerfest in 402m water depth. As well as appraising Wisting, the well sought to prove the technical concept of long-reach horizontal wells in a shallow reservoir, about 250m below the seabed.

J Lukoil approved for Baltic exploration

Russia's Lukoil was granted approval explore and produce oil from two Baltic Sea fields, offshore Russian enclave Kaliningrad, from the Russian government.

Lukoil will explore the D29 and D41 oil fields, discovered in 2015, using the Arkticheskaya jackup drilling rig. D29 is estimated to have 2.1 million ton recoverable resources, and D41 2 million ton.

K ONGC makes big investment

India's Oil and Natural Gas Corp.'s (ONGC) proposed US$5.1 million deepwater oil and gas project, offshore east India, has been given the green light.

I Tyra may halt in 2018

Operator Maersk Oil may shut down production at Tyra East and Tyra West on 1 October 2018, under European Union regulation requirements, if a viable solution for continued operations in the face of aging facilities and subsidence the area is not found by the end of 2016.

"Together with our partners in DUC (Danish Underground Consortium) we are now evaluating long-term economically viable solutions for the recovery of the remaining resources. As part of this, we will consider the terms under which a rebuild of the facilities could take place," Martin Rune Pedersen, Maersk Oil Denmark managing director said. The Tyra field is 225km west of Esbjerg in the North Sea.

Global E&P Briefs

The field development plan (FDP) is for Cluster 2 of the deepwater NELP Block KG-DWN-98/2, consisting of Cluster 2A and Cluster 2B, with an expected 23.53 million tonne, and 50.71 Bcm production during the life of the project.

ONGC anticipates Cluster 2a production to peak at 77,305 b/d, and 3.81 MMcm/d of associated gas through 15 producer wells along with 12 water injection wells with a peak water injection rate of 9400 cm/d.

Cluster 2B peak production is expected to reach 12.75 MMcu m/d gas from eight wells.

L Eni JV wins CTP Block 4

A consortium led by Eni, including GNPC, Explorco, Vitol, and Woodfields, has been awarded a new exploration license, Cape Three Points (CTP) Block 4, in the Tano Basin offshore Ghana, Africa.

GNPC, Vitol and Eni are already developing the Sankofa and Gye Nyame fields to provide gas for Ghana's thermal power sector to 2036. The new block lies near the existing Sankofa / Gye Nyame fields and infrastructure. The block covers 1127sq km in 100-1200m water depth.

M JOGMEC extends Seychelles survey

Japan Oil, Gas and Metals National Corp. (JOGMEC) signed an extension to the joint survey agreement for the evaluation of hydrocarbon potential, offshore Seychelles. JOGMEC has been doing geological and geophysical surveys, including seismic surveys, with PetroSeychelles since 2013. While the surveys ended in February this year, an additional survey was considered necessary and the Government of Seychelles, PetroSeychelles, and JOGMEC agreed to extend the current exploration license for another two years.

N First gas at Kiliwani

Africa-focused Aminex started production from its Kiliwani North gas field offshore Tanzania in April.

Production from the Kiliwani North-1 well (KN-1), tied into the regional pipeline infrastructure, will be delivered to the adjacent Songo Songo processing plant.

Aminex expects production to build up to 25-30 MMcf/d (about 4-5000 boe/d) over 90-100 days. KN-1 represents contingent resources (2C) of 28 Bcf gross.

Aminex (55.575%) operates the Kiliwani North Development license with partners Bounty Oil & Gas (9.05%), RAKGAS (23.75%), TPDC (5%) and Solo Oil (10%).

O Aramco starts Hasbah

Saudi Aramco has started natural gas production at its Hasbah field, 150km northeast of Jubail, offshore Saudi Arabia.

Hasbah is expected to provide up to 1.3 Bcf/d of natural gas from seven single-well platforms.

"The development of the Hasbah and Arabiyah fields to feed nonassociated gas to the Wasit Gas Plant has been a significant addition to our company's overall gas program," Saudi Aramco said in its weekly magazine, The Arabian Sun.

P Mubadala to drill Sri Trang-1

MId-May, Mubadala Petroleum is due to start drilling operations at the Sri Trang-1 exploration well offshore Thailand, 18km northnortheast of the Manora oil development, within the G1/48 concession.

The Atwood Orca jackup will drill the Sri Trang-1 to approximately 2590m over about 10 days, with a view to evaluating the primary middle Miocene lacustrine sand target then late Miocene fluvial sand secondary targets.

Q Trio plans Malaysian seismic

Petronas, through Malaysia Petroleum Management (MPM), has decided to open an area of Malaysian waters, offshore Sabah, to the multi-client model for the first time, led by a consortium comprising of PGS, TGS, and Schlumberger WesternGeco.

The area sits in an active fold-and-thrust province that hosts a number of proven hydrocarbon accumulations. An extension of the Brunei Baram Delta play, the primary exploration target has been Miocene deltaics with some younger Pliocene. With exploration and drilling progressing into deeper frontier waters, there is thought to be potential for new plays in

R Gorgon production halted

After coming online last month, Chevron has temporarily halted production at its Gorgon liquefied natural gas (LNG) and condensate project on Barrow Island, off northwest Western Australia, in early April 2016.

According to Chevron Australia, the propane refrigerant circuit, used to cool natural gas supplied to the plant, on Train 1, is experiencing mechanical issues. Work to complete the repairs is ongoing while the site team continues equipment inspection and assessment. Plant restart is expected within 30-60 days, the firm said.

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Contracts

Shell shells out Appomattox gig

Shell has awarded Materia and Aegion Corp. a contract to supply pipeline insulation materials for the deepwater Gulf of Mexico Appomattox development.

The polymer-based insulation system is said to be unique in its ability to provide an effective thermal barrier between flowlines and seawater. The thermosetting cross-linked hydrocarbon polymer maintains structural integrity in deep water environments as an incompressible solid in more than 10,000ft water depth.

MODEC awards Keppel FPSO work

Keppel FELS' BrasFELS shipyard, a subsidiary of Keppel Offshore & Marine, has been awarded a US$137 million floating production storage and offloading (FPSO) module fabrication and integration project by MODEC Offshore Production Systems (Singapore).

BrasFELS' work scope covers fabrication and integration of nine topside production modules for the FPSO *Cidade de Campos dos Goytacazes MV29*. The vessel is expected to arrive at the shipyard by Q1 2017 for the integration phase.

When completed, the FPSO will have the capacity to process 150,000 b/d and 5 MMcm/d of gas, and store 1.6 MMbbl.

Slated to depart the shipyard in Q3 2017, the FPSO will be deployed at Tartaruga Verde and Tartaruga Mestiça Fields, in the Campos Basin, off the coast of Rio de Janeiro.

Vallourec signs ADNOC OCTG contact

Abu Dhabi National Oil Co. (ADNOC) chose Vallourec to supply oil country tubular goods (OCTG) during the 2016-2018 period to its three operating companies (ADMA-OPCO, ADCO, ZADCO).

Vallourec will supply a full range of standard API and premium OCTG, close to 100,000-ton, for both onshore and offshore oil fields, for applications ranging from conventional to complex wells. The contract includes the supply of high torque VAM connections for extended reach drilling and corrosion resistant alloy steels for sour service.

Field running supervision and inspection will be provided by Vallourec. OCTG will be supplied from Vallourec's mills in France, Germany, Brazil and China.

Proserv bags Gullfaks equipment deal

Statoil has awarded Proserv a multimillion-dollar contract to provide production control equipment for its Gullfaks project in the North Sea. Proserv will supply five wellhead hydraulic power units for the field. The design, manufacture and supply will be carried out by Proserv's teams in Stavanger, Norway.

Jee wins decom investigation

Tullow Oil awarded subsea engineering and training firm Jee a contract to investigate the most appropriate options for decommissioning their Thames area assets: the Horne, Wren, Wissey, Orwell and Thurne fields in the southern North Sea.

Tullow's decommissioning programs and environmental impact assessment with Thames field joint operator Perenco have been approved by the UK Department of Energy and Climate Change (DECC).

Jee will review the approach outlined in Tullow's decommissioning programs for the assets and re-define the most appropriate decommissioning options for the subsea sections, specifically, setting out what infrastructure could be left in situ and, if removal is necessary, process efficiencies to reduce associated costs.

IKM, Bibby in pre-commissioning agreement

IKM Testing in Aberdeen has been awarded a multimillion dollar pre-commissioning services frame agreement by Bibby Offshore.

The three-year contract, with the provision to be extended by a further two years, covers three dive support vessels, one construction support vessel and one ROV support vessel, operating primarily on the UK Continental Shelf. The contract also provides the opportunity for IKM to support Bibby on international projects. ■

the carbonate and syn-rift section.

Indonesia scraps Abadi FLNG

Indonesian President Joko Widodo has rejected Japanese operator Inpex's proposal to build a floating liquefied natural gas (FLNG) plant in the country's east, saying that an onshore plant would benefit its economy more.

Inpex had been considering an FLNG plant with 2.5 MTPA processing capacity. A new plan, submitted in September 2015, called for an increase to 7.5 MTPA. Inpex has said the new mega-FLNG plan was the "optimal" development solution.

The Abadi gas field is in the Masela Block, in the Arafura Sea. The block is operated by Inpex (65%, operator) with partner Shell (35%).

Woodside shelves Browse megaproject plans again

Woodside Petroleum and partners have scrapped plans for the Browse floating liquefied natural gas (FLNG) mega project offshore Western Australia, due to the current economic and market environment. The decision comes after the completion of front-end engineering and design work.

The final investment decision for the Browse FLNG project was expected in 2H 2016. Initial plans were based on three FLNG facilities using Shell's FLNG technology to commercialize the Brecknock, Calliance, and Torosa fields, which lie some 425km north of Broome in 300-700m water depth. The three fields are estimated to contain 15.4 Tcf of dry gas and 453 MMbbl of condensate gross (100%) contingent resources.

This isn't the first trashed development plan for Browse. In 2013, Woodside and its partners opted not to pursue a partially onshore development near James Price Point in northwestern Australia.

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French chemistry

Deepwater subsea tiebacks conjure up all manner of technical innovation requirements, and/or the need for complex subsea processing technologies. Yet, it's not always so. Elaine Maslin explores the particulars of Total's Laggan Tormore development.

While Total's Laggan Tormore development includes the deepest production wells on the UK Continental Shelf, and is the second only subsea tieback off the UK, at an impressive 140km-long (the only other is the relatively nearshore Corrib, brought onstream offshore Ireland last year), the offshore infrastructure isn't actually that complex. It's a relatively simple set of six wells with a control system.

What makes it challenging is the rough Atlantic weather, which plagues the West of Shetland area, making installation challenging and regular intervention undesirable. But, it's also something of a chemistry set, offering some new process challenges to Total's UK business.

Despite its remoteness, the Laggan Tormore infrastructure – Total's first long, remotely operated subsea tieback – is also set to be the keystone infrastructure to unlock other fields, potentially otherwise stranded, including Edradour and Glenlivet, creating a new production hub.

The £3.5 billion (US$5 billion) Laggan Tormore development came onstream earlier this year, initially producing 8 MMscm/d. The fields are expected to continue production for up to 20 years.

Discovery

Laggan was discovered in 1986, 125km northwest of the Shetland Islands, in some 600m water depth. But, it wasn't until Tormore was discovered in 2007, that the larger Laggan gas and condensate field, which was too deep to develop using fixed facilities, could be made economic.

"There is no [existing] infrastructure West of Shetland to produce gas," says David Hainsworth, operations manager, Total E&P UK. "For the investment to put that in place you need a certain amount of reservoir and production. It was not economic with Laggan on its own. Other fields and options were looked at, but then getting Tormore as well made it big enough to make the investment."

Because the fields are gas and condensate, floating production facilities weren't selected, due to gas storage and export limitations.

Development

Total has used two, 900-tonne each, standardized six-slot production templates, with four wells in total planned at Laggan and two planned for Tormore, using FMC Technologies' 10,000psi vertical Xmas trees. These are connected to shore by two, 143km-long, 18in, multiphase flowlines, plus an 8in monoethylene glycol (MEG) line, a 2in service line, for equalizing valves or adding more MEG, etc., and two control umbilicals, for redundancy.

The design includes spare capacity in the umbilicals, in order to add a second manifold upstream from Laggan or Tormore for up to six wells. It also has

Laggan Tormore templates before loadout. Images from Total.

six hot-tap Ts for tie-ins to the multiphase pipelines between Laggan and the Shetland Gas Processing Plant (SGPP) (three on each flowline and the MEG pipeline). Four Laggan wells, which were pre-drilled, are in production. A well at Tormore will be completed this summer and available for production, with another future Laggan well due to be drilled sometime in the future.

Playing chemistry

While the offshore subsea concept decision was relatively straight forward, onshore was less so. "For onshore, we could have gone into [BP's] Sullom Voe Terminal (SVT) and operated as part of that," Hainsworth says. "A key decision was the choice of hydrate inhibitor, methanol or MEG. We chose a MEG-based system because you can regenerate MEG, which you cannot do with methanol. But, it means you need a bigger plant."

Total also had to be able to put a pipeline inspection gauge down the flowlines, due to wax formation risk in the well fluids, which is why two flowlines were built to create a loop. "So, we also had to deal with bulk liquids from the pipe, which means you need a slug catcher," Hainsworth says. Each time the system is pigged, it will create a 21km-long slug of liquid running in front of the pig. The slug catcher smooths out the slug and moves it into one of two storage tanks, one rich and one lean, which will be managed concurrently with the regeneration process, as well as having to strip out salts, Hainsworth says.

"Managing those stocks will be a challenge. The plant is sized for a continuous rate. It takes 10 days to regenerate the MEG, but we only expect to pig once a quarter," he says. A pig run takes 24 hours, with the first one scheduled for March this year. The team will be looking carefully to see how the results match their simulations and will adapt the process accordingly.

To separate the MEG and water from the gas, a three-phase separation system is included in the onshore processing facility. Then the MEG has to be regenerated. Its pH is also modified to minimize corrosion risk. The onshore MEG plant was also designed with overcapacity, to cover possible requirements for future water breakthrough. And then there is also a water treatment plant, with stringent requirements.

Suction cans ready for the deep.

New plant

Because of all these requirements, the footprint of the plant required and the minimal synergies with BP's plant, the new 500 MMscf/d (14 MMscm) capacity SGPP, adjacent to SVT was built. Condensate is exported to the BP facility, while treated gas is exported from there via the new 234km Shetland Island Regional Gas Export pipeline to a tie-in into the FUKA pipeline, which terminates at St Fergus, northeast Scotland.

Uniquely, in order to build the plant, some 650,000cu m of peat was removed and stored in specially designed peat stores, where it will be kept until it's time to rebuild the land to how it was. That's another new piece of chemistry the firm had to learn. Indeed, the peat, which would have otherwise released CO_2 into the atmosphere, is monitored during its storage.

Other environmental limitations have also driven the design of parts of the plant, including incorporating waste heat recovery units, as well as the methodology for how the compressors are operated to minimize emissions.

The site is a significant one, and its construction faced some difficulties, ultimately resulting in delayed first production, from late-2014 to early this year, and huge cost overruns for contactor Petrofac, who took the job on a lump sum basis. Petrofac has blamed bad weather on the notoriously exposed Shetland Islands, industrial action by workers, problems with sub-contractor deliveries and more rectification and reinstatement work than expected. Petrofac's group CEO said last year the firm's lack of experience operating a direct construction model in a wholly new geography, where "labor costs are higher and productivity lower than we are used to, has cost us dearly."

Subsea

While the subsea infrastructure is relatively simple, it's still deserves mention. "We have tried to standardize the equipment subsea so it is easier to order something for Edradour or Glenlivet," Hainsworth says, which means subsea tooling can also be standardized. "The downside is you are stuck with that vendor," Hainsworth says, but there's no easy medium.

That still leaves the West of Shetland weather to contend with, however. "Winter operations have proved to be very challenging, due to the location of the field exposing it to the worst of the

See Infield at OTC Booth #4676

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	2013	2014	2015	2016
Shallow (<500m)	73	72	53	3
Deep (500-1500m)	19	29	17	2
Ultradeep (>1500m)	34	12	12	2
Total	126	113	82	7
Start of 2016 date comparison	127	114	72	-
	-1	-1	10	7

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	8	30.75	333.28
Deep	13	1316.00	1695.00
Ultradeep	42	11,601.00	12,833.00
United States			
Shallow	9	66.60	152.00
Deep	20	917.27	1233.48
Ultradeep	22	2960.50	3050.00
West Africa			
Shallow	126	4084.35	16,876.22
Deep	36	4927.50	6050.00
Ultradeep	14	1600.00	1210.00
Total	282	27,473.22	43,099.70
(last month)	(290)	(28,628.87)	(44,461.70)

Greenfield reserves

2015-19

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Shallow	924	34,953.40	476,110.34
(last month)	(942)	35,201.08)	(482,880.62)
Deep	143	9038.93	90,507.62
(last month)	(143)	(9471.93)	(118,532,62)
Ultradeep	85	16,466.90	43,190.00
(last month)	(88)	(17,210.90)	(44,560.00)
Total	1152	60,459.23	609,807.96

Pipelines

(operational and 2015 onwards)

	(km)	(last month)
<8in.		
Operational/ installed	41,633	(42,095)
Planned/ possible	24,406	(24,250)
	66,039	(66,345)
8-16in.		
Operational/ installed	83,053	(83,458)
Planned/ possible	48,473	(48,839)
	131,526	(132,297)
>16in.		
Operational/ installed	95,109	(95,106)
Planned/ possible	44,547	(44,996)
	139,656	(140,102)

Production systems worldwide

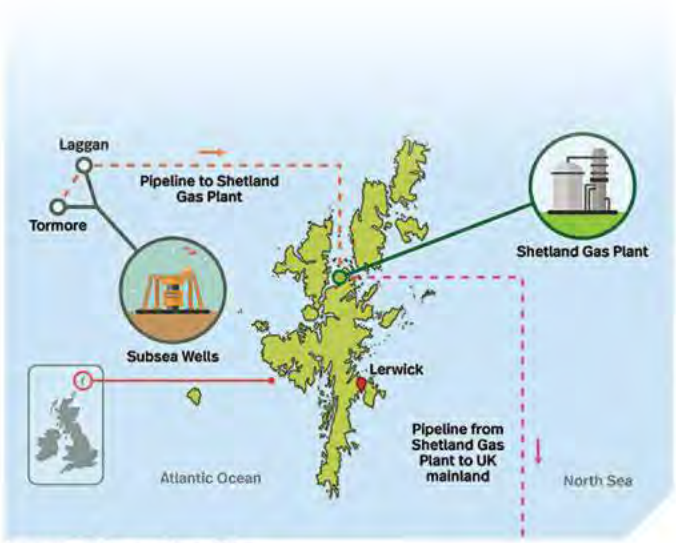
(operational and 2015 onwards)

Floaters		(last month)
Operational	270	(272)
Construction/ Conversion	51	(52)
Planned/possible	299	(309)
	620	(633)
Fixed platforms		
Operational	9190	(9260)
Construction/ Conversion	76	(97)
Planned/possible	1370	(1377)
	10,636	(10,734)
Subsea wells		
Operational	4888	(4872)
Develop	369	(421)
Planned/possible	6323	(6396)
	11,580	(11,689)

Global offshore reserves (mmboe) onstream by water depth

	2014	2015	2016	2017	2018	2019	2020
Shallow	14,558.63	20,483.81	39,103.43	15,994.92	15,560.30	22,747.67	25,578.97
(last month)	(14,528.97)	(20,949.72)	(39,811.33)	(16,372.41)	(15,986.26)	(22,801.80)	(25,454.94)
Deep	4469.26	955.55	5433.92	2408.30	3925.03	6175.47	7093.04
(last month)	(4469.26)	(1085.18)	(5491.04)	(2221.55)	(4423.30)	(6210.09)	(12,063.71)
Ultradeep	2343.00	1922.92	3167.92	3190.03	4503.63	5575.22	7644.87
(last month)	(2342.81)	(1928.92)	(3173.17)	(3231.63)	(4893.14)	(5880.73)	(7888.56)
Total	21,370.70	23,362.28	47,705.27	21,593.25	23,988.96	34,498.36	40,316.88

07 April 2016



Laggan Tomore location.

North Atlantic storms," Total says.

The rig used was modified to fit hull guides to permit deployment of BOPs and Xmas trees in heavier sea and wind conditions. Accurate weather forecasting also helped mitigate some of the effects of weather. But, ultimately downtime was significant in the November- March periods. Indeed, for the 2016 campaign, the semisubmersible drilling rig *West Phoenix* was demobilized from location until March, to avoid the downtime associated with winter operations.

There are also challenges beneath the waves, with significant and hard to predict currents in the water column (*OE*: January 2015). Total used on-site current monitoring to aid decision-making during operations, as well as using powerful, high-specification ROVs, with dedicated heavy weather deployment systems to allow operations during periods of difficult surface and subsurface conditions.

Pipeline management

To help optimize the whole system, Total is using a pipeline management system, supported by a multiphase flow simulator, powered by the latest flow assurance software, Leda Flow, rather than Olga, to help tune what is happening in the pipeline to optimize for the individual flows in each of the wells. "It's the first time we've used a pipeline simulator," Hainsworth says, and it's meant using Venturi flow meters, and multiphase meters for the well fluids – all supported by a pile of instrumentation that can send the data back to the beach.

"There are individual flow meters on each well, then one for each manifold, so if something is not working we can infer what is happening," Hainsworth says. "We can get enough data to allow us to make decisions. We also worked with FMC Technologies to allow us to monitor how the equipment is working," says Hainsworth, which will allow for equipment to be switched out if it looks like it's heading towards a failure. This could be hydraulic response signals showing you a valve is getting harder to operate, he says. "When we are next there we can change that valve or instrumentation."

As part of this philosophy, the equipment Total expects to wear out more quickly, such as choke valves, is designed to be retrievable. "You could retrieve the whole manifold, but you wouldn't want to unless it's really necessary."

The main flowlines, supplied by Corus and installed by Allseas, using its *Solitaire* vessel, are covered in a thermal

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Rig stats

Worldwide

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	104	77	27	74%
Jackup	399	268	131	67%
Semisub	142	95	47	66%
Tenders	31	22	9	70%
Total	676	462	214	68%

North America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	35	30	5	85%
Jackup	23	6	17	26%
Semisub	15	11	4	73%
Tenders	N/A	N/A	N/A	N/A
Total	73	47	26	64%

Asia Pacific

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	12	4	8	33%
Jackup	118	69	49	58%
Semisub	32	15	17	46%
Tenders	21	15	6	71%
Total	183	103	80	56%

Latin America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	29	22	7	75%
Jackup	54	38	16	70%
Semisub	31	27	4	87%
Tenders	2	2	0	100%
Total	116	89	27	76%

Northwest European Continental Shelf

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	N/A	N/A	N/A	N/A
Jackup	48	42	6	87%
Semisub	43	31	12	72%
Tenders	N/A	N/A	N/A	N/A
Total	91	73	18	80%

Middle East & Caspian Sea

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	0	1	0%
Jackup	111	88	23	79%
Semisub	4	3	1	75%
Tenders	N/A	N/A	N/A	N/A
Total	116	91	25	78%

Sub-Saharan Africa

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	22	18	4	81%
Jackup	22	14	8	63%
Semisub	9	6	3	66%
Tenders	8	5	3	62%
Total	61	43	18	70%

Eastern Europe

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	N/A	N/A	N/A	N/A
Jackup	2	1	1	50%
Semisub	1	0	1	0%
Tenders	N/A	N/A	N/A	N/A
Total	3	1	2	33%

Source: InfieldRigs 9 April 2016

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

Ready to go under.

spray aluminum on the outside for the first few kilometers, for heat dissipation, to prevent buckling and reduce corrosion risk.

Oil leg

A possible complication was added to what would be otherwise relatively simple future offshore infrastructure additions – an oil leg, thought to be heavy oil. This was discovered on the Tormore field during appraisal well drilling in 2013. While this will not impact initial production, as the development will initially be one well, tapping the gas zone, it is a future target. Hainsworth says once the first Tormore well is producing it will be monitored and the bigger picture assessed in order to maximize overall recovery from the field.

Future tie-ins

More near-term production targets are the Glenlivet and Edradour discoveries, which are expected to tap around 65 MMboe reserves and are already lined up to be tied into the Laggan Tormore infrastructure, again using standardized templates and subsea equipment.

The development plan was approved by UK authorities in March last year and will see Edradour, discovered in 2010 tied into the main Laggan Tormore flowline, and Glenlivet, discovered in 2009, tied back to the Edradour manifold. Edradour and Glenlivet are due to come onstream in Q2 2017 and Q4 2018, respectively.

"We have tried to design something robust, not overly complicated, which has redundancy in it, and non-critical failure acceptance," Hainsworth says. "We are delighted it is working." While subsea compression has been added to the industry's tool box, it's not something Total is currently looking at for Laggan Tormore. **OE**

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Harsh realities

Remaining competitive through the downturn is a tall order for some. Caitlin Shaw, of Quest Offshore Resources, examines how the exploration, drilling and subsea segments are expected to fare through 2017.

The global deepwater market is facing much the same challenges as the rest of the oil and gas industry during this severe downturn. Oil companies and supply chain members alike are working diligently to realize material solutions to current problems that will provide long-term results positively affecting the overall competitiveness of deepwater.

Offshore operators are enacting strategies aimed at adjusting cost structures in a "lower for longer" scenario, slashing near-term capital expenditure budgets and placing an elevated level of scrutiny on projects that have matured through early stage engineering activities that would naturally be approaching final investment decision and tendering activities in the near term.

While some projects have been deferred outright, some operators are returning to the drawing board. One such example is Noble Energy's Leviathan project, where a transition from the long-held floating, production, storage and offloading vessel/subsea concept to a subsea tie-in to a host fixed platform on the Israeli continental shelf is expected to offer both a quicker path to first production as well as reduced capital outlays.

Quest Offshore has also noted that some operators are assessing phased developments at new Greenfield projects as a means to more effectively spread capital outlays over a greater period of time. For instance, Premier's Falkland Island development of the Sea Lion field (*OE*: March 2016) and associated discoveries is projected to be phased over a longer time horizon, well into the next decade, compared to their initially larger concept focused on a tension leg platform.

The deepwater supply chain, the majority of which have experienced declining backlogs over the last year amid declining field development prospects, have looked toward collaborative approaches as a means to expand capabilities and employ new models aimed at arresting the increase to deepwater development costs noted in the years prior to the oil price downturn. Key focuses have often included earlier involvement in the project development process, such as conceptual and front-end engineering and design (FEED) studies, as well as an expanded and more total approach to offshore development activities from the manufacture of

equipment through to offshore installation and even beyond into areas such as subsea well intervention.

Deepwater drilling outlook

Global deepwater drilling demand has experienced year-on-year decline since 2013 and has created an oversupply of floating drilling assets, which has led to idle and stacking trends not seen before.

New contracts for floating rigs are expected to remain very limited in 2016, resulting in an ever increasing number of idle units. Twenty six floating rigs have been stacked in Q1 2016, bringing the total stacked count to 123, of which 80% have been sidelined in just the past 12 months. Over 60% of the idle fleet remains in warm stack mode incurring costs that range from US$40,000-$100,000 per day. Nearly 50% of the stacked units are over 18 years old and will likely never work again. Nearly 20% are part of a dying 4th and 5th generation fleet that are being squeezed out of the market by an abundant supply of newer 6th generation units. Almost 40% of the stacked rigs are among the newest 6th and 7th generation fleet, which commanded day rates as high as $700,000 just two years ago.

Heavy emphasis is placed on strategic stacking of newer rigs in effort to keep the units in a semi-warm state at a reduced cost capable of rapid reactivation once the recovery begins. With another 42 rigs rolling off contract through 2016, drilling contractors will continue to be challenged with plummeting utilization forcing day rates down to near or below break-even (See Figure 2).

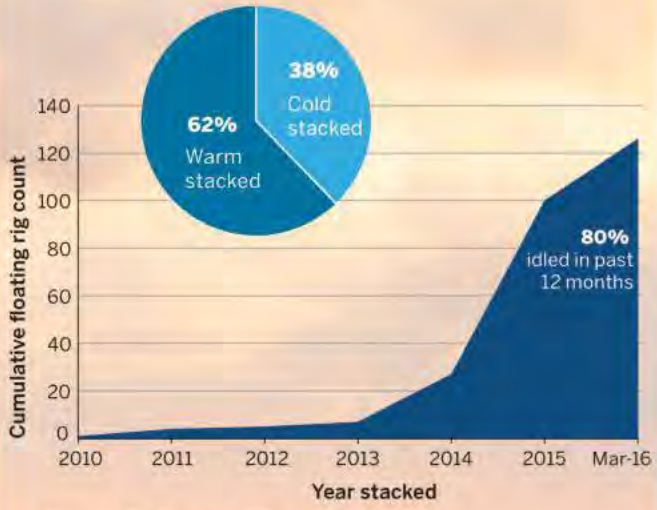
There are currently 260 floating rigs in marketed supply, of which 180 are under contract putting marketed utilization at 70%. Contractors could immediately increase marketed utilization to over 80% by retiring/cold stacking 41 older rigs that are currently warm stacked. Using supply levers to increase utilization will only alleviate some of the pressure, and with more rigs rolling off contract every quarter of this year, the effects could be temporary, but it is a measure that contractors have control over and could act on immediately.

Quest Offshore forecast estimates indicate that rig demand for 2016 is around 165 rigs, which means that operators are likely to let go of 15-20 more units this year. If contractors cold stack/retire at least half of those units (~10), utilization could be stabilized just under 80% heading into 2017.

Closing the oversupply gap will be a long and arduous process as demand recovery is expected to be gradual and the timing is still unclear. As a result, leading edge day rates are expected to remain at or below break-even on higher specification rigs, and the average day rate of 6th and 7th generation units will continue to erode as more of these rigs roll off their initial contracts at the high rates that were committed years prior. Over 70% of rigs working today at $500,000+ rates are rolling off contract in the next 18 months and rig demand is expected to remain soft through this period. The objective for 2017 should be to get leading edge rates back to $400,000 per day for the 6th and 7th generation fleet through aggressive attrition focused on keeping marketed utilization at or near 80% by reducing marketed supply below 200 units

Fig. 1: Floating rigs stacking up

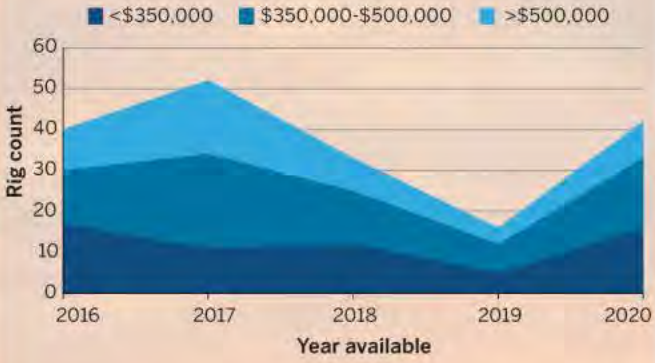
123 floating rigs currently out of work



Nearly 50% are >18 years old

Fig. 2: Utilization and day rates

60% of remaining rigs working at >$500,000/day will roll-off contract by the end of 2017 (excluding early terminations)



Aggressive attrition can lead to more balanced supply heading into 2017 but will not completely alleviate over-supply challenges.

	Current	Potential near term	Potential 2017
Working Supply	180	180	165
Rigs Available	78	37	47
Marketed Supply	258	217	212
Marketed Utilization	70%	83%	78%

Use supply lever to increase marketed utilization by writing down older warm stacked rigs to cold stack or scrapped status

Source: Quest Offshore Resources

Fig. 3: Discoveries by year

Announced 2004-2015 (1908)

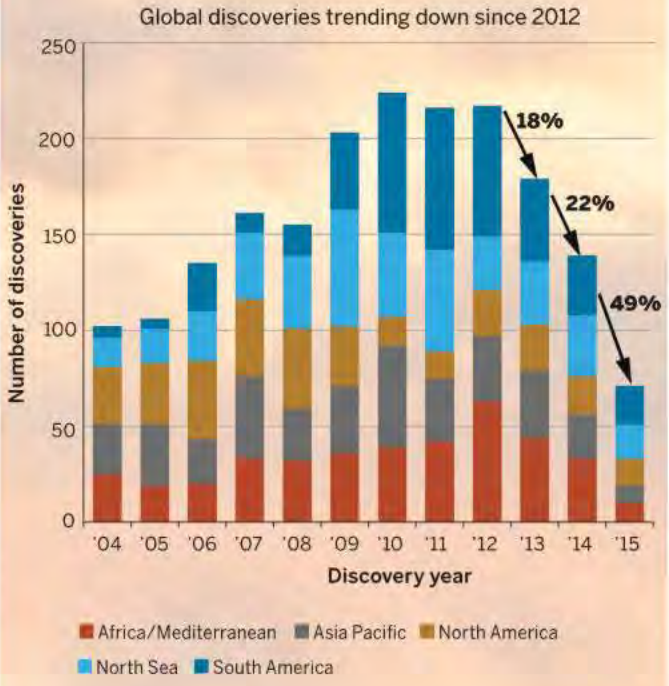
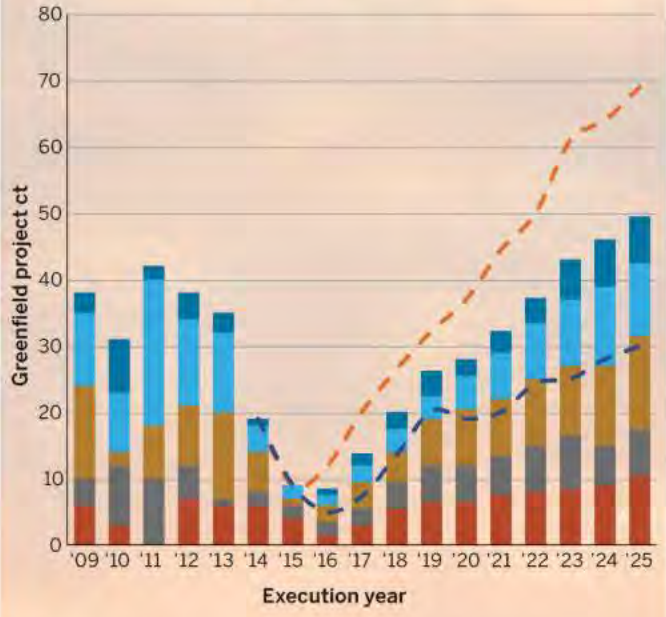


Fig. 4: Global deepwater project executions - greenfield



Source: Quest Offshore Resources

total. This would mean that over 80% of all marketed rigs would be 6th or 7th generation while only about 40 older rigs essential for mid-water or harsh environments where mooring capability is necessary would remain in service globally (See figure 2).

Deepwater discoveries and long-term development opportunities

Deepwater exploration drilling demand has seen the most drastic decline over the past four years or so. Since the high-water mark in 2010, global exploration drilling has gone down in all major deepwater basins. At the same time, the success rates of those exploration spuds was also decreasing as indicated by the lower discovery level for the same years (See Figure 3). This trend could either be due to oil companies going after high-risk prospects while oil prices where high, the easiest of reserves having already been found or a combination of the two and other key factors.

Over 65% of drilling came from exploration activity during the peak years of 2010-2012. High cost campaigns in Brazil, Australia, West Africa, and Norway were enabled by high oil price, increasing rig supply, and a fierce appetite among key major operators to open new frontiers for future development.

Exploration drilling began trending downward in 2013, due to a nearly 60% drop in Brazil exploration activity while partially off-set by increases in US Gulf of Mexico and expansion into East Africa. With the exception of Africa, exploration drilling in most regions in 2014 remained flat or slightly down and by 2015 all regions had dropped leading to a nearly 50% year-on-year decline. Africa and Asia were hit particularly hard in 2015 with 60% and 50% declines, respectively. Both considered to be high cost regions for deep water, it is unlikely that Africa will return to peak levels at oil prices below $70/bbl. Australian LNG projects are slowing down, which deters the need to drill for more gas. In Brazil, Petrobras will likely use what limited funds they have to develop pre-salt. Less than 10 exploration wells are expected to be drilled in Brazil in 2016. The US Gulf of Mexico, which has been the most resilient throughout 2015, is already showing signs of weakened demand as key major operators push plans into the future in effort to preserve cash.

Global deepwater discoveries feed directly into the inventory for future development opportunities. Given the average cycle time for a major deepwater development is somewhere between 7-10 years from discovery to first oil, any potential impact from this lower discovery trend could be seen in the second half of the next decade. The severe stall of projects during the current downturn should mitigate the majority of this potential effect through the middle of the next decade as the industry works through the backlog of viable and undeveloped resources.

Looking at Quest's long-term, greenfield development opportunities, 2016 is in the middle of the trough created by the current downturn, as is no surprise (Figure 4).

Most projects are going through a re-assessment period to ensure the best development scenario while only a handful have been completely scrapped and labeled as uneconomic under any possible revisions. As such, these projects have

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Fig. 5: Medium-term impact on global subsea market

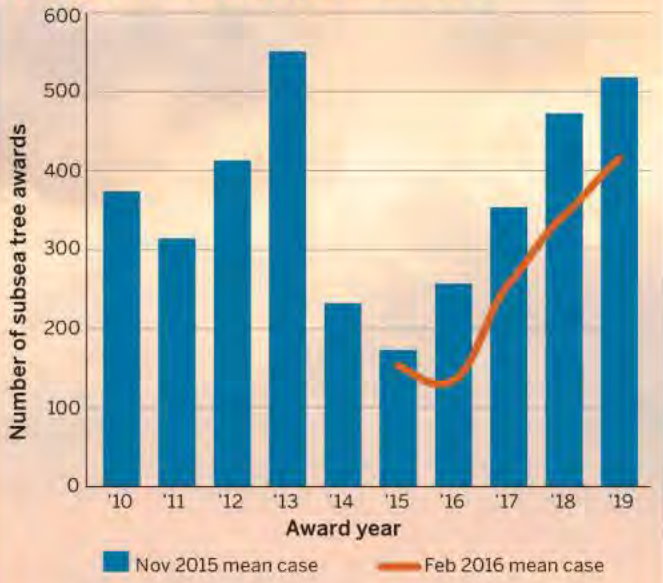

Fig. 6: Global subsea trees by decade

Source: Quest Offshore Resources

been pushed to the right towards the end of the decade.

We expect that the work the operators and supply chain are currently doing around reducing the cost and increasing the returns of deepwater development will result in higher sanction numbers post-2017. Reducing project scope and cycle time are important in deepwater and can potentially result in more projects being awarded each year.

Subsea trends

Quest Offshore tracks subsea tree awards as a leading indicator of the health of the overall subsea market. As such, the vastly depressed demand levels seen in 2014 and 2015 have been mirrored through other market segment trends. The forecast has gone through two material adjustments since the start of this downturn; the first in last 2014/early 2015 when the oil price first fell and then most recently in Q1 2016 when the weakening oil price further exacerbated oil companies concerns over execution timing.

Over the five-year forecast period, the mean (mostly likely) case has been reduced by 20% and the base case by 30% (See Figure 5). The ongoing weakness and lower oil price over the past few months has all but ruled out any kind of recovery this year in terms of subsea demand. That said, recovery is on the horizon for this space and the backlog of opportunities that has been re-assessed and re-worked to find better project economics is real and waiting.

Regionally speaking, the US Gulf of Mexico is expected to be one of the most resilient areas during this downturn. The diversity of projects in queue helps potential activity as they have different reactions to market conditions. Africa has significant opportunity for subsea demand whether from the north or east, but timing is always a risk in the area and is even more in this downturn. The opening up of the pre-salt off Brazil is a real possibility for future demand and has the potential to offset, at some point, some of the demand loss by virtue of Petrobras' challenges. Petrobras' plans continue to trim expectations and push projects to the right materially affecting the local supply chain and their ability to survive to the next up cycle. Other operators have stake outside of the pre-salt plays and are expected to drill towards the end of the decade providing development potential in the 2020's.

One bright spot in the subsea tree market is the install base in place and the life-of-field services they do and will require. Despite the current reduction in spending towards these types of activities, there is no getting around the need for intervention, workover, maintenance and eventual decommissioning and removal of this hardware at some point in time. As this install base grows, albeit slowly at the moment, the larger this demand will grow for future goods and services.

The water depth of these subsea trees is growing significantly as we move through time. This shows that equipment will have to evolve as well to handle the additional challenges and requirements associated with these depths.

Serious challenges lay ahead for deepwater, and they are important to keep in mind. The increased complexity of the future projects is very real and development of innovative technology must remain a priority. Easy oil has been found and developed. Industry must work harder as we move into harsh and frontier areas for the next big opportunities. Volatility in global demand and oil and natural gas prices can cause near-term, temporary disruptions in project cycles. **OE**

Caitlin Shaw *is the senior director of market research and the data division for Quest Offshore Resources. She graduated from Texas A&M University Galveston in 2003 with a BS in marine biology. During her tenure at Quest she has held various strategic positions of increased responsibility leading to senior director in 2013.*

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Let's get deep

Maersk Venturer drillship. Image from Maersk Drilling.

Ultra-deepwater exploration on the Atlantic margin could be the opportunity the offshore industry is looking for, according to geoscience firm Spectrum. Elaine Maslin reports.

In today's low oil price, cash strapped environment, drilling in ultra-deep water might not seem an obvious gambit. However, Spectrum Geo thinks there are some good, and big, reasons for doing so – and there isn't a better time than now.

The Norway-based firm, having filtered through 2D seismic acquired over the last two years, has identified a new ultra-deepwater Atlantic margin play, which focuses on the basin floor (or abyssal plain). This is an area beyond the various Atlantic margin shelves, which are nearer to shore, or slopes, where recent deepwater discoveries offshore Senegal and Mauritania and others have focused industry attention. The basin floor stretches out from the base of the slope to some 150km out into the Atlantic, offering potentially large, widely spread resources.

With rig rates at a significant discount, drilling technology now available for such feats and, crucially, the prospect of massive finds, making exploitation economically attractive, Spectrum thinks there's a huge opportunity.

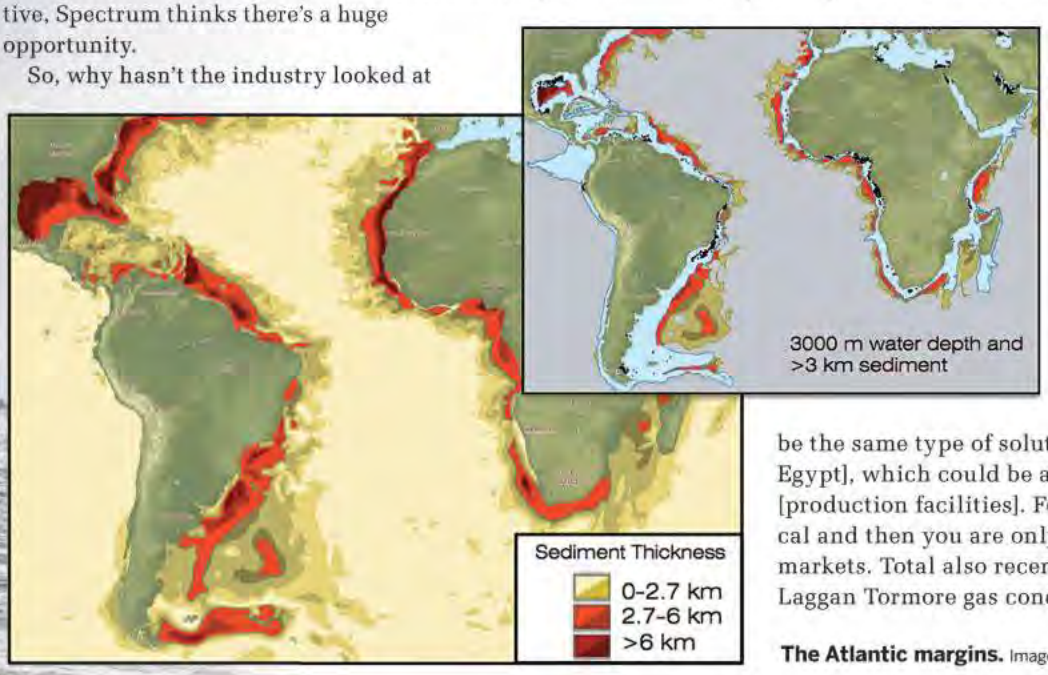
So, why hasn't the industry looked at this before? It's a resource that hasn't been found because no one has been looking, says Neil Hodgson, Spectrum's executive vice president of Geoscience. "It is an oddity of exploration in that we have been shooting seismic in deepwater for a long time. But when in 3-4km of water, people haven't been too interested in looking for prospects because they didn't think they could drill it."

That has now changed and, despite the low price, deepwater drilling records are set to be broken this year. India's ONGC holds the current record at 3174m deepwater offshore west India. This is set to be broken by France's Total when it drills the Raya exploration well offshore Uruguay in 3400m water depth. Later this year, Anadarko is expected to drill an even deeper well offshore Colombia, Hodgson says, tapping resources that could open up another gas basin like Rovuma offshore Mozambique, in terms of scale.

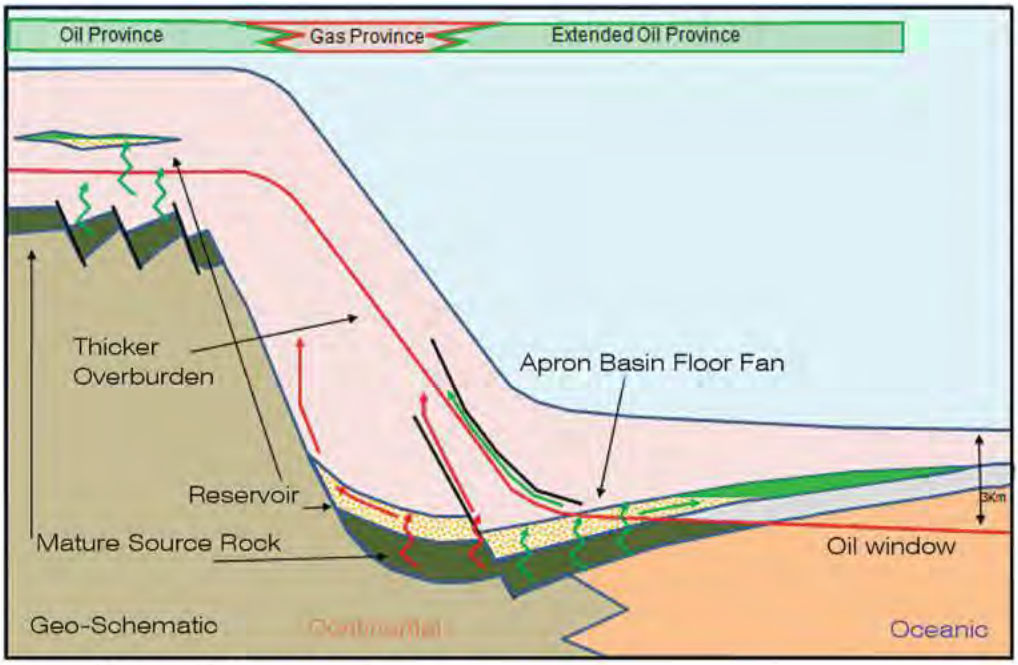
Interestingly, Hodgson notes that, except for a very short period of time, most deepwater drilling records have been set when oil has been at less than US$50/bbl. "You don't need a higher oil price in deepwater because it works against you – increasing exploration costs," he says. In fact, thanks to $30-40/bbl oil prices, deepwater rig rates have plummeted from $650,000/d some 19 months ago, to around $250,000/d. "That means a $150 million well 19 months ago would now cost you $60 million. All of a sudden you realize this is the only time to drill ultra-deepwater."

Deepwater production technology has also been on an upward curve, Hodgson says, especially for gas. He cites the speed at which Noble Energy was able to develop the Tamar deepwater gas field offshore Israel. It was drilled in 2009 in 1500m water depth. "Noble noticed if they could do a subsea tieback to shallow water infrastructure and get it in stream within three years, which is what they did. And that's unprecedented.

"This will be the way to develop these gas resources in the future, providing it is a nice dry gas and it can be tied back fairly easily." It is likely to be the same type of solution for [Eni's] Zohr [offshore Egypt], which could be a subsea tieback to Temsah [production facilities]. For gas, this is more economical and then you are only limited by your access to markets. Total also recently brought onstream the Laggan Tormore gas condensate fields, on the UK



The Atlantic margins. Images from Spectrum Geo.

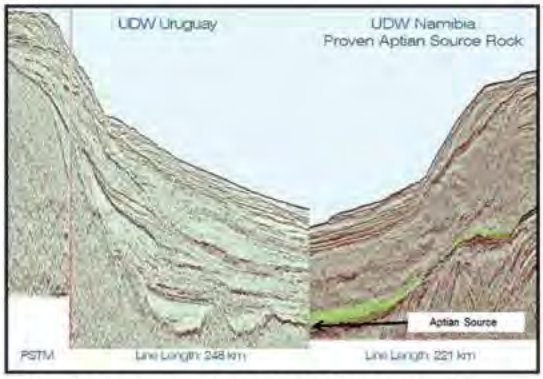


Play model for south Atlantic floor fans.

Continental Shelf, as a 140km subsea tieback to shore (See page 22).

Hunting elephants

Spectrum started first by looking at its seismic data differently, converting it into depth images rather than time images (which use the time it takes the sound in seismic shoots to travel down through the rock and back again). "All of a sudden, you can see trapping potential down to 4km of water depth," Hodgson says. "We haven't seen them because we have not looked there before and we have always looked in time, not depth. It was a big surprise to me."



Seismic reconstruction across the conjugate margin.

It's not just as simple as seeing the trapping mechanism. Source rock has to exist, and it does, throughout almost all of the Atlantic basins, Hodgson says. National Oceanic and Atmospheric Administration mapping suggests its existence and wells drilled deep enough, to date, offshore Namibia, by HRT, and Brazil, in the Sergipe basin, by Petrobras, and others have proved it.

It comes from when the super-continent Gondwana broke up, at the end of the Jurassic and in the early-cretaceous periods, creating a 300km wide basin. This was then filled in with organic rich mud. As the two continents, Africa and South America spread further apart, these layers remained attached to their continents, creating 150km belts along the coastline with underlying source rock. These muds have now been buried deep enough, at 3.5-4km, to create the temperatures to generate oil and gas – 100-150°C.

Next, there need to be reservoirs in which this oil or gas could collect and these were found; sands, which fan out on the basin floor, deposited some 100 million years ago. The difference between these and the sands that have been drilled on the Atlantic margin slopes – the sloping areas which drop from the shelf down to the basin floor – are that the slopes are dominated by channels of sand, like gutters, transporting the sand down the slope, which means higher risk in terms of drilling, for finding seals and to target the right areas. The Sergipe wells offshore Brazil have targeted these channels, Hodgson says.

On the basin floor, the sands fan out, however, creating – yet to be drilled – huge potential deposits. These are covered by multiple kilometers of mud stone, which hold the oil in place. Then, traps, to create pools of oil in the sands, have been created by the pressure of the shelf by the weight of layers and layers of mud stone, which cause "plate-scale" subsidence, creating huge traps. "They are actually phenomenal," Hodgson says. "Some of the biggest structures would stretch from London to Manchester."

So, when might we see this play tested? Hodgson is hopeful that Mauritania might be a good proving ground. Kosmos Energy has drilled on the slope here in 2400m water depth. The basin floor offshore Mauritania is in a modest 3000m water depth, making it reachable, Hodgson says. This is due to the Cape Verde islands – intrusions near Mauritania, which lifted up the basin floor. Mauritania currently has some open acreage, which – as a result of the above – Hodgson thinks could be the most prospective in the world at the moment.

Meanwhile, Total's work offshore Uruguay will help increase confidence in deepwater exploration. "It is trying for a slightly different target [to Spectrum's concept] and it has got a very high chance of success, which will help increase confidence in ever deeper water exploration," Hodgson says. **OE**

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How deep is your well?

This year, the deepwater drilling record could be broken not just once, but twice, breaking the last record, set back in 2013. Elaine Maslin takes a look.

Total's Raya-1 well is due to be drilled offshore Uruguay using Maersk Oil's ultra-deepwater *Maersk Venturer* drillship and could top the deepest water well on record – ONGC's 3174m record (*OE*: March 2016). Anadarko is also expected to drill a potential record breaker offshore Colombia, according to Spectrum's Neil Hodgson (see page 34).

Yet, what might be surprising is that the four current deepest water well records were drilled by India's ONGC (see table). That's not to mention the mild surprise that such costly drilling is still going on in today's US$30-40/bbl environment, using rigs still likely to be on rig rates set at least 18 months ago.

However, while deepwater drilling records look set to be broken, the numbers need to be put in context. Many of the deepest water wells are still in the Gulf of Mexico, where drilling is not just about water depth, but total depth, which can mean adding a further 7km of subsurface to the water depth the drill bit has to travel through, highlights Andrew Latham, VP upstream consulting at analysts Wood Mackenzie.

He also points to the fact that there are less than 30 wells in this ultra-deep category, "which, in the global scheme of things is a pretty small subset," and none of them have been turned into producers. The likelihood that depths continue out to 4000m isn't that strong either, he suggests, due both to the oil price but also the thinner oceanic crust at those depths.

While breaking records, ONGC's wells, ranging from 3107-3174m water depth, have had mixed success. The current record holder, drilled in June 2013, well 1-D-1 off the east coast of India, was drilled using Transocean's ultra-deepwater drillship *Dhirubhai Deepwater KG1* and was dry. The *DD KG1* is rated to 12,000ft water depth and is currently under contract to Petrobras offshore Brazil, through to December 2017 based on a $394,000 day rate.

The *Dhirubhai Deepwater KG1* drillship. Photo from Transocean.

The second deepest well, ONGC's NA7-1, was also dry. The third, ONGC's KGD051NAA-1, also drilled in 2013, had gas shows and the fourth, CYPR-07-A1, drilled in 2011 by Reliance, was a tight hole. Going to press, OGNC had been tendering for deepwater drillships for future drilling, but it wasn't clear if this was for exploration or production wells. For the most part, the remaining deepest water wells are offshore US, followed by Mexico and Brazil.

"In this environment, a lot of the planned wells are slipping somewhat to the right in terms of timing," Latham says. "In particular, the frontier wells in countries where the operator and participants don't have production so they haven't got a tax shelter against drilling costs.

"Even though there has been massive deflation in terms of rig costs, most of the wells being drilled now are with rigs signed two years ago on very high day rates." While rig rates have fallen dramatically, this is mostly theoretical because they are not being used, he points out.

"The general themes we are seeing is de-emphasis of exploration with high costs, high sub-surface risk, frontiers and even play contenders, because they are higher risk, as well as anything that is a longer lead time."

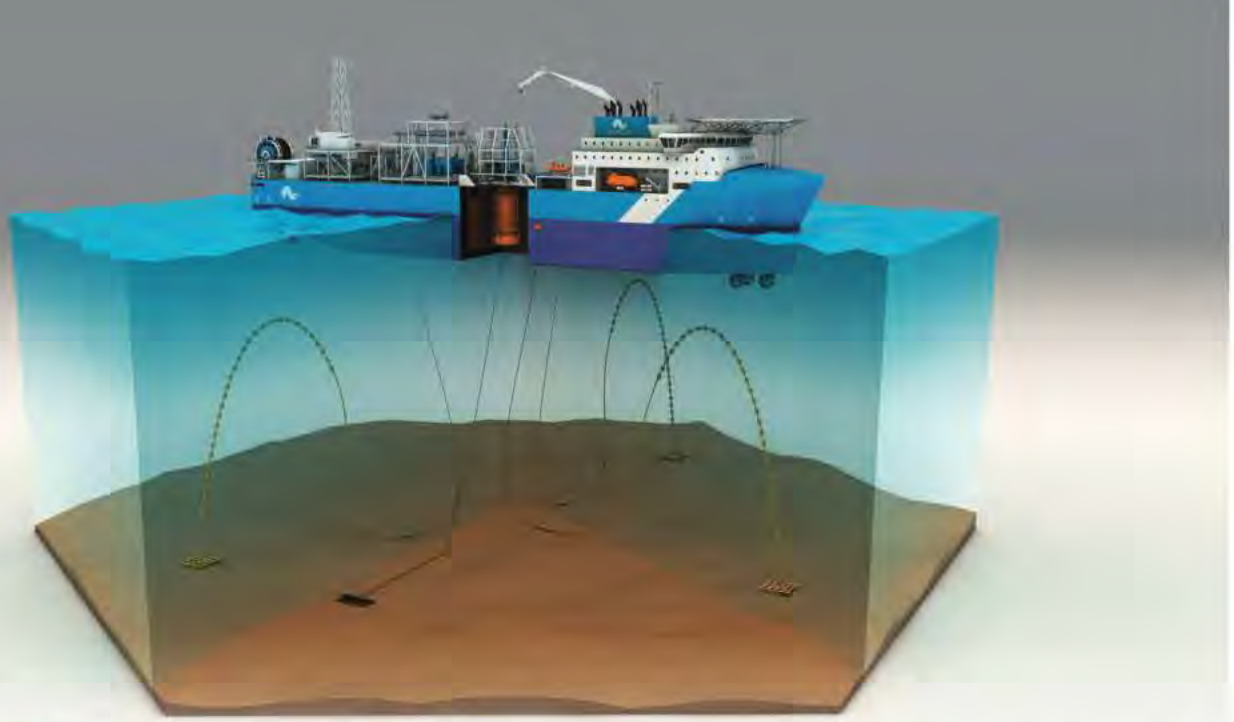
If there is an ultra-deepwater discovery, the next step is commercializing the wells. "Nearly all of these (ultra-deepwater) locations are frontier with very little infrastructure," Latham says. While dry gas discoveries could be more attractive to produce, due to lower complexities around subsea facilities and flow assurance, gas markets are "pretty challenging," and operators still tend to prefer to hunt for more easily monetizeable and transportable oil.

Yet, it's not all doom and gloom. "The Eastern Mediterranean is a nice reminder that ultra-deepwater large scale gas could be very commercial, such as Eni's Zohr. The big gas finds in recent years in East Africa, Tanzania and Mozambique, and also Senegal and Mauritania, have positive routes to market." **OE**

Deepwater drilling records

Well	Country name	Operator	Well type	Result	Water depth	(m) Year
1-D-1	India	ONGC	Exploration	Dry Hole	3174	2013
NA7-1	India	ONGC	Exploration	Dry Hole	3165	2013
KGD051NAA-1	India	ONGC	Exploration	Gas Shows	3150	2013
Raya-1	Uruguay	Total	Exploration	Planned	3150	2016
CYPR-D7-A1	India	Reliance	Exploration	Tight Hole	3107	2011
LL 511 #1 (G10496)	United States	Murphy Oil	Exploration	Dry Hole	3091	2008
AC 951 #1 (G20885)	United States	ChevronTexaco	Exploration	Oil Shows	3051	2004
LL 370 #1 (G31842)	United States	Murphy Oil	Exploration	Gas	3040	2008
3BRSA-1296-SES	Brazil	Petrobras	Appraisal	Oil	2989	2015
LL 411 #1 (G31847)	United States	Eni	Exploration	Dry Hole	2989	2014
AC 903 #1 (G20876)	United States	Unocal	Exploration	Oil	2970	2001
AC 903 #1ST1 (G20876)	United States	Unocal	Appraisal	Oil	2970	2001
AC 903 #2 (G20876)	United States	Unocal	Appraisal	Oil	2965	2001
DWN-UD-2	India	ONGC	Appraisal	Gas	2965	2010
NA6-1	India	ONGC	Exploration	Dry Hole	2961	2013
AC 947 #1 (G20882)	United States	Unocal	Appraisal	Oil	2948	2002
KG-D9-B3	India	Reliance	Exploration	Gas Shows	2948	2011
Mirus-1	Mexico	Pemex	Exploration		2944	
PEP-1	Mexico	Pemex	Exploration	Dry Hole	2940	2013
AC 859 #1 (G20871)	United States	Unocal	Exploration	Oil	2934	2004
AC 859 #1ST1 (G20871)	United States	Unocal	Appraisal	Oil	2934	2004
WR 508 #2 (G17001)	United States	Shell	Appraisal		2922	2006
Maximino-1	Mexico	Pemex	Exploration	Oil	2919	2013
Maximino-1 DL	Mexico	Pemex	Appraisal	Oil & Gas	2919	2015
3BRSA-1239-SES	Brazil	Petrobras	Appraisal	Dry Hole	2917	2014
WR 508 #1 (G17001)	United States	BP	Exploration	Oil	2913	2005
WR 507 #1 (G18730)	United States	Shell	Appraisal		2912	2012
Supremus-1	Mexico	Pemex	Exploration	Oil	2900	2012

Source: Wood Mackenzie.



Amplus' VPU.
Image from Amplus.

Small is beautiful

Tapping small fields and coming up with economic early production system solutions offers engineers an interesting challenge. Elaine Maslin reports.

There are some 210 "small pools" on the UK Continental Shelf, containing less than 15 MMboe each, but more than 1.5 billion boe in total.

Crondall's design, cross-section.
Image from Crondall.

The challenge remains to produce technologies that can economically produce these pools, which largely remain undeveloped due to their distance from existing infrastructure, reservoir complexity or lack of commerciality.

And engineers continue to offer ideas, from innovative subsea power production and controls systems (*OE*: December 2015), to small scale production facilities. *OE* looked at a number of unmanned production buoy type facility concept back in May 2014 and then again in January 2015 (see Further Reading).

During Subsea Expo, in Aberdeen this February, Crondall Energy, a floating production-focused engineering consultancy, and small-scale, dynamically positioned (DP) floating production vessel designer Amplus Energy Services put forward their concepts.

Amplus

Amplus' concept is its versatile production unit (VPU), based on a DP vessel, which could be used as an early production system or a marginal field development option.

DP FPSOs are not unheard of, points out Amplus co-founder and Managing Director Ian Herd, during Subsea Expo. The *Seillean* was a DP FPSO used in the UK North Sea in the 1980s, developed by BP as a single well oil production (SWOPS) facility, before redeploying to Brazil in the late 1990s. The *Helix Producer* was a converted ice class train ferry, with DP, which was used to redevelop the hurricane damaged Phoenix (formerly Typhoon) field in 2010. ConocoPhillips also used the *Munin* FPSO, with DP, on the Xijiang field before it moved to the Huizhou field for CACT, Herd says.

"The advantage is that there's no mooring," Herd says. "We can turn up, and all the client needs to do is wet store the risers. We pick up the risers ourselves with a disconnectable turret and start production. On a conventional FPSO you need tugs for the moorings, survey vessels, heavy lift vessels, subsea construction vessels for the risers, etc.

We do away with about 90% of that." Doing away with mooring requirements reduces about US$25 million costs, he estimates.

For marginal fields, it could be used as an early production system to get cash flow started, or a late life field solution, Herd says. "We thought the main interest would be for small pools, small reserves in the North Sea, but actually we are getting more and more enquiries for early production in places like Angola and Ghana, to give the operator more reservoir knowledge before they decide on a permanent facility."

The VPU concept is modular, so that it can be easily adapted to each field, and based on a previous hull design for the *Orelia* concept, with 30,000 b/d production capacity, potential for gas compression, produced water treatment with discharge to sea and produced gas or crude to be used for fuel. The process equipment would be from NOV, and the turret from FES.

Onboard power would be about 24MW, to handle anything like electrical submersible pumps, etc., and a stock tank heating system for handling waxy or heavy crudes. According to Amplus' modeling of its design, the vessel could remain on station through hurricane force sea conditions and still only use about 35% of its installed power.

"If the client ever wants extra equipment onboard, we can disconnect in four hours, head back to port, add the equipment, then head out again, reconnect via the moon pool using an ROV in three hours and be on production again," Herd says. "In an emergency, it could disconnect in 30 seconds."

Two versions of the VPU, VPU112 and VPU200, have been set out (see table). To get one built would take two years, Herd says. There are three yards in Norway, Germany and the Netherlands that have already been identified with availability. The firm is in discussions about the design with three clients at the moment, Herd said in February.

Late 2015, Amplus struck a deal to work with Technip to offer the VPU solution, with Technip offering its project management, engineering and subsea products and Amplus supplying the vessel. As part of the partnership, Technip is looking to develop risers and umbilicals suited to this type of deployment – i.e. lower cost than might be used on a longer term field development, Herd says.

Crondall Energy

Meanwhile, Winchester, UK-based Crondall Energy has designed a compact, remotely operated, multi-field, floating production system. The idea is a low cost development solution to fill the gap between subsea tiebacks and full facility floaters, said Ramon Kunkeler, project manager, Crondall, at Subsea Expo.

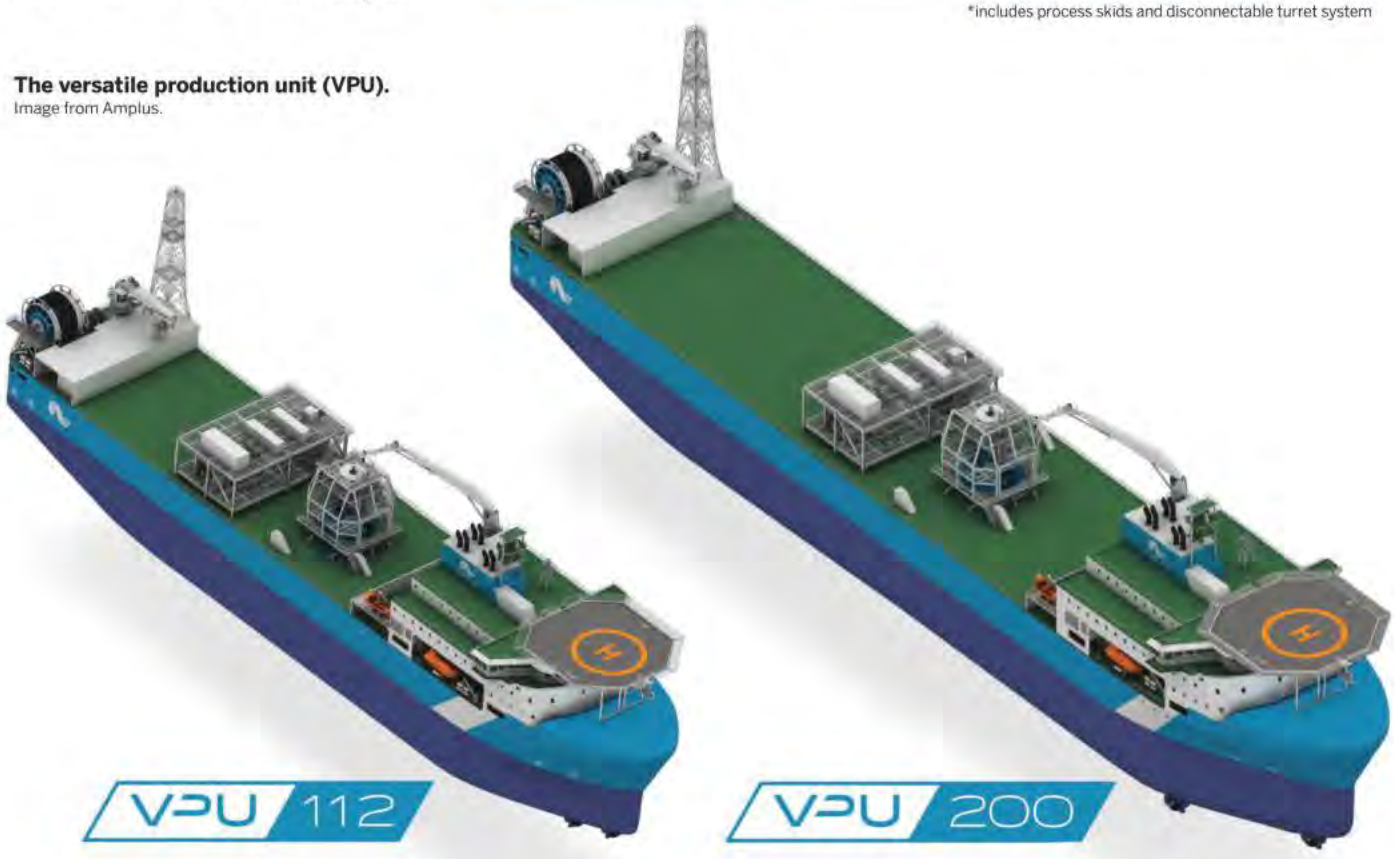
The design is based on a single column hull structure and integrated, buoyant "deck box," with a ballast

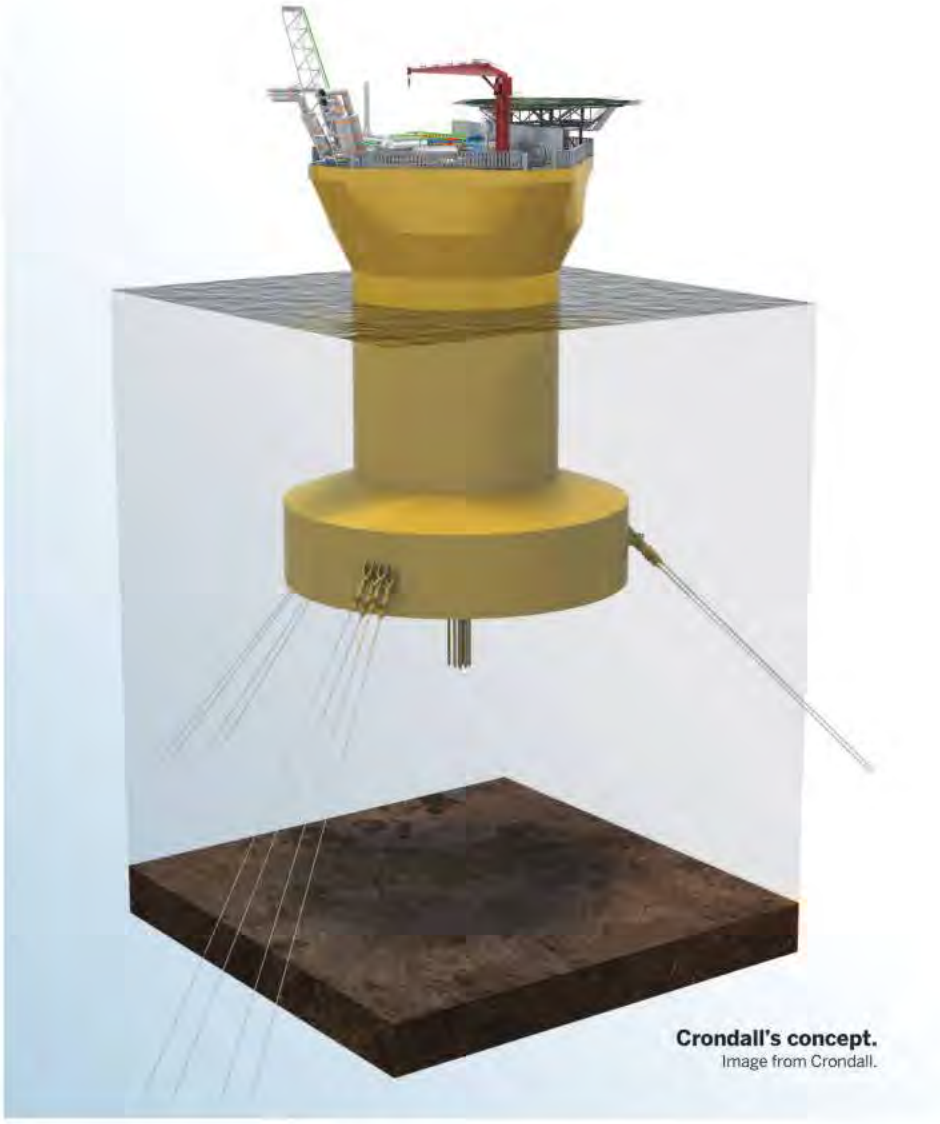
Amplus vessel specs

VPU112	VPU200
114m-long	192m-long
26m beam	32m beam
112,000 bbl storage	200,000 bbl storage
Accommodates 65 (35 person crew)	Accommodates 70 (36 person crew)
Cost from $175 million*	Cost from $200 million*

*includes process skids and disconnectable turret system

The versatile production unit (VPU).
Image from Amplus.





Crondall's concept.
Image from Crondall.

system using water and a high-density ballast. It would have compact process, separation, compression technologies, and use where possible low maintenance materials, such as fiber reinforced plastic. This would be mainly for piping, for instance for the fire water system, replacing steel components, which reduces the need for coating and maintenance, as well as reducing weight, Kunkeler says.

One system has been designed, for a specific application and environment, with 25,000 b/d capacity with a small amount of associated gas. The process deck has a 42m diameter. The total installed height of the floater is 58m with a 28m diameter column. The total installed weight is approximately 15,000-ton with sufficient capacity to increase the payload allowing more process equipment.

But, it could be scalable, making it smaller or larger depending on production capacity requirements, level of associated gas, the environment it would be in, etc., Kunkeler says.

The mooring system would use existing turret mooring technology with diverless installation, similar to existing disconnectable turrets. Production rates would be for ~10-25,000 b/d fields with 20 MMboe, possibly 30 MMboe.

Kunkeler sees the estimated $250 million, redeployable concept (not including risers and wells) as a 3-5 year development option for small fields. "It's easy to build and install and to redeploy. It can be a standalone solution filling the gap between subsea tiebacks and full floaters. It's flexible and scaleable and with low cost design driver," he says.

The aim has been to make it easy to fabricate, at any yard globally, which means the hull is compact with a low draft at under 5m. The deck then floats and can be positioned just using tugs, removing the need for heavy lift vessels. "It is low opex as it's a NUI

Marginal field brainstorming

NSRI (National Subsea Research Initiative), the technology arm of Subsea UK, held a series of series of "hackathons," which brought industry, technology developers, universities and research institutes together to brainstorm possible technological solutions.

But, while the technical community believes technology forms part of the solution, the commercial structure of the industry is constraining the economies of scale needed to make the recovery of oil from these reservoirs viable.

"It was very clear that it is difficult to decouple the commercial considerations from the technical aspects," explains Gordon Drummond, NSRI's project manager. "Access to host facilities and infrastructure, non-collaborative behaviors between operators and small operators who don't have the finances or the will to develop these resources were identified as barriers to the development of small pools.

"Of the technical solutions discussed," he says, "some could have widespread application but, before progressing these, we need to carry out a geographic information system map, which details the size, location and fluid complexity of the small pools superimposed upon a North Sea map showing the ownership of and type of existing infrastructure. From this it will become apparent what type of technical solutions need to be progressed, for example tie-backs, subsea hot tapping, clustering arrangements and standalone facilities."

According to NSRI, the technologies that present the biggest enablers to unlocking small stranded fields are compact FPSOs, production buoys, subsea production facilities including boosting, processing and subsea storage and enabling technologies which attain access to existing infrastructure, such as hot taps and self-sufficient hook up modules.

The potential technical solutions from the hackathons were categorized into efficiency measures, near to market technologies that could be piloted fairly quickly and relatively easily, and longer-term ideas with merit.

Simplification and standardization of subsea components and hardware, less rigorous specifications in order to meet the shorter design lives of small reservoirs and more holistic design are efficiency measures which could go some way towards improving the economics of small pools. ■

(normally unmanned installation)," Kunkeler says, "with high functionality, process intensification, operational efficiency, and minimal motions," because of the hull shape, maximizing process uptime.

However, to keep the size down, it doesn't have any storage, which means production will need to be offloaded to a leased FSO or pipeline.

The idea is for it to be used on small, standalone oil or gas developments, in varying environments and where water depth doesn't permit fixed facilities, or in support of longer range complex tiebacks, Kunkeler says. This could be from small low gas oil ratio fields, where the gas is used for power generation, or small gas fields, where there is an export route, to longer subsea tiebacks to support power and controls or chemical injection.

The only problem is, despite the efforts to reduce costs, at $30/bbl, it's still not that viable. OE

FURTHER READING

Tackling the UKCS' small pools
www.oedigital.com/component/k2/item/11444-subsea-expo-tackling-the-ukcs-small-pools

Unmanned buoy concepts grow
www.oedigital.com/component/k2/item/5621-unmanned-buoy-concepts-grow

Unlocking marginal fields
www.oedigital.com/engineering/design/item/7889-unlocking-marginal-fields

Cutting the umbilical
www.oedigital.com/pipelines/maintenance/item/10929-cutting-the-umbilical

More than mini eyeballs

Meg Chesshyre reports on how mini ROV systems have advanced significantly and, thanks to their size, they can get up close and personal.

Deep Trekker's DTG2. Images from Deep Trekker.

"It's not just a camera in the water anymore," Cody Warner, business development, Deep Trekker, told the Oceanology International conference in London this spring. He was presenting a paper on how asset management can be improved with the use of mini remotely operated vehicles (ROVs), such as the Deep Trekker range.

"We are now using sonars, usbl (ultra short baseline) positioning systems. We're able to have a look outside of [in addition to] getting visual feed," he said. It is possible to have data from acoustic feeds, to use thickness gauges and CP (cathodic protection) probes, grabber arms, navigation sensors, samplers, many different attachments. "This is a great way to have an external look ... almost double-checking."

Deep Trekker's DTX2.

Mini ROV systems can be used to provide historical data for classification surveys of floating production vessels (FPSOs), or other vessels; inspection for damage; inspection for cleaning, fouling; monitoring dive teams at work. Ownership of mini ROV means that the asset owner does not have to rely on third parties.

Warner said that achieving the full lifespan of assets was very important for earning a positive return on investment. Assets are also being used for longer, with the range of FPSOs being extended from 15-25 years.

Right now, there were only three ways to have a live video stream subsea; divers, workclass ROVs and mini ROVs. Some projects, such as welding, need a diver. Platform construction involving large weights need work class ROVs. For inspections, the first two options were often too expensive for a single asset to own on its own. Using a mini ROV is a more efficient option, Warner said.

Deep Trekker was founded in 2010 with a mission to bring fully capable yet portable and accessible ROVs to market. The company is headquartered in Ayr, Ontario, Canada, with all engineering and manufacturing done in house. Based on a clean sheet design, the first product, DTG2, was introduced in August 2011. The first mini ROV was sold to a Norwegian fish farm. Since then, more than 1000 vehicles have been sold in 69 countries, many involved in hydroelectricity projects as well as offshore energy. Offshore clients have included Noble Drilling in Australia and Sea View in Trinidad and Tobago.

For the offshore market, Deep Trekker mini ROV systems offer an alternative, or complement to sending divers down to do emergency or routine inspection work, Warner said. They can be easily deployed by one to two-man teams, and can be launched anywhere without the need for large crane structures, or a generator. The onboard rechargeable batteries require no topside power.

The 270° camera rotation results in efficient inspection. The pitching system allows the ROV to go where it is too small or dangerous for divers. There is no maintenance, no o-rings to service, grease or replace. The mini ROVs just need to be kept clean and charged. Undersea installations at sea-based wind and solar installations can easily be done from a boat. The DTG2 weighs only 8.5kg and has a ca.150m depth rating. The larger DTX2 has a 305m depth rating, well within topsides range for platform legs and undersides. It works in higher currents and can perform lateral inspections.

Deep Trekker announced in March the integration of Tritech International's Gemini 720is multi-beam sonar with its DTX2 vehicles. The new Gemini 720is integrates with a custom mount and the Deep Trekker control console or other laptops. **OE**

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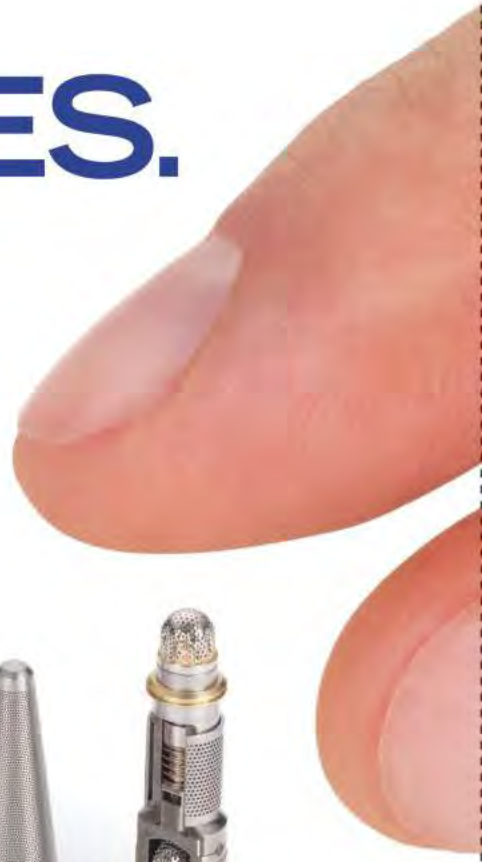

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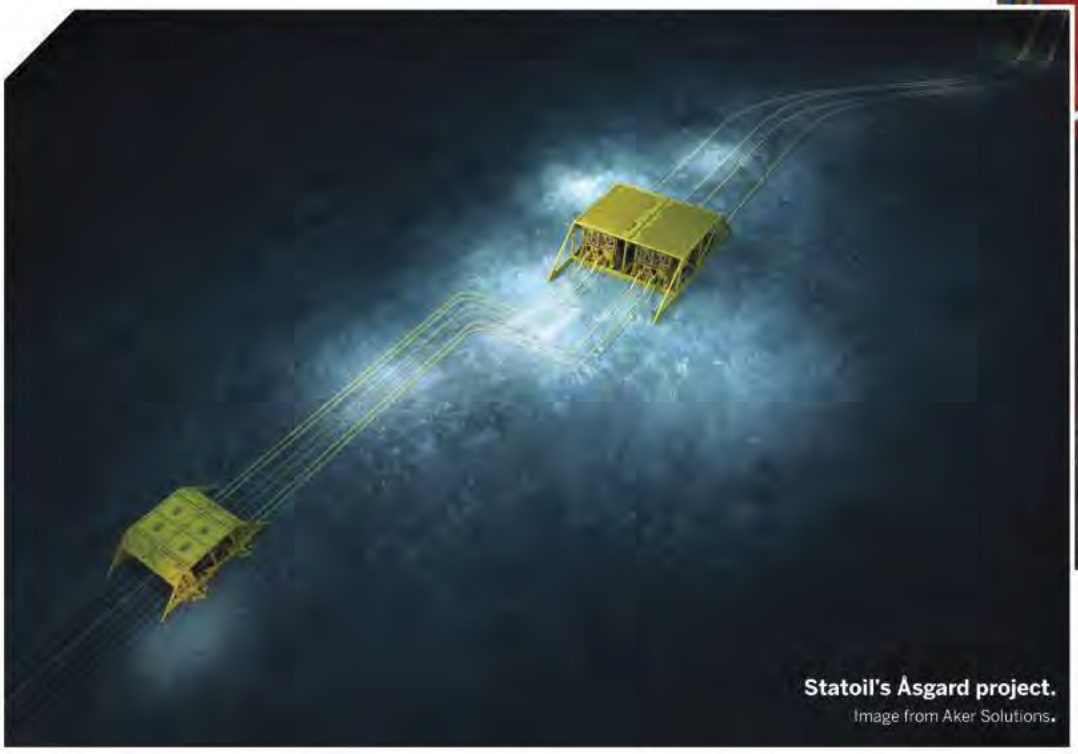
Joining the dots

While it offers a theoretically coherent concept, subsea processing can seem fragmented. Elaine Maslin spoke to Intecsea about how the company views the broader picture.



Statoil's Åsgard project.
Image from Aker Solutions.

Huge strides have been made in the subsea processing arena in the past year: subsea compression, both dry and wet gas, was achieved on Statoil's Åsgard and Gullfaks projects, respectively, offshore Norway late 2015.

Subsea processing has been high on the agenda for a number of years, spurred on by deepwater prospects, the potential for longer subsea tiebacks and even developments in Arctic waters.

Yet, despite the gains made, progress has not been as fast and widely spread as many have wanted or expected, and there are still technology gaps, ranging from water treatment and chemical injection facilities to subsea power distribution.

Work continues, however, in spite of 18-months of across-the-board budget cuts, and technology developers are working to fill the gaps. The pace might be slower, but this might work out for the better, suggests Larry Forster, technology specialist for deepwater oil and gas, Intecsea, Houston. There has also been a shift in greater interest from greenfield projects to brownfield projects driven by the current market conditions, he says, which could make deployment easier.

"In a higher oil price environment, the emphasis is on getting production online quickly and implementing whatever technology is available, within reason," Forster says. "Now, the smart money is on taking a step back and looking for better solutions so that when the oil price returns, they have the right solutions."Yes, projects are being challenged, he says. But there are some operators taking a step back and taking a long-term view, in which subsea processing plays a big role. And it's not all big players, he says.

Bottlenecks

An increasing focus for subsea processing, given the current market environment, is in brownfield modifications, where there is an opportunity to increase production, but also where there is a lack of space or power on existing topsides facilities. By marinizing water treatment, chemical injection, pumps, power distribution, separation, etc., you no longer need space topside for these components, says David McLaurin, subsea engineer, Intecsea, Houston.

Statoil's Gullfaks subsea wet gas compression project offshore Norway, for which OneSubsea produced a wet gas compressor, is a good example, Forster says. "This wet gas compressor went in relatively late in the life of the field," Forster says. "It serves a cluster of fields in the area. That compressor is expected to increase recovery by 22 MMboe and extend plateau production by about two years. There is an upfront investment, and additional cost to install and maintain equipment, but the prize is substantial."

The Åsgard subsea compression template.
Photo from Statoil/by Øyvind Hagen.

However, there are hurdles. The first is having available infrastructure to support additional processing capabilities. On Gullfaks this was possible. However, Intecsea is working with a client who would like to add boosting to an existing facility, but it doesn't have the power or space to support the new equipment. The next hurdle is the fact that there are still many pieces of the subsea processing puzzle to be completed, not least raw sea water treatment.

Subsea water treatment

Subsea water treatment, for sea water injection, is a goal for the industry. "If you could install a module, which treats sea water subsea and uses a single phase booster pump to feed an injection well, you would no longer need topsides facility modification, or a major shut down during construction," Forster says. You would also no longer need the flowlines usually required. "Water treatment is the key," McLaurin says. "But, it requires chemicals and filters and you need to keep up all that equipment. So, there are some reliability concerns and qualification is 4-8 years down the road."

"A lot of details are involved, getting the chemicals for treated water just right, even if it is going straight back into the reservoir," Forster adds. "It might be that the reservoir is sensitive to salinity or other components that didn't get removed, which could cause problems. Both treatment and monitoring, to make sure the chemistry is right, need some ongoing work."

For produced water, which you might want to treat and reinject, the chemistry is even more difficult, as it has hydrocarbons in it. "An even longer term goal is to be able to release treated produced water directly to the sea in vicinity of subsea wells and that's going to be very sensitive to a lot of things," Forster says. "You are going to have to make sure you do that right."

Separation anxiety

NEL, near Glasgow in the UK, has been leading research in subsea separation and production water re-injection or discharge and has an ongoing joint industry project to develop subsea water quality measurement devices up to technology readiness level five, which would be a key enabler.

Subsea separation itself also not new. It was first tried on the Troll Pilot (Statoil), then first used in anger on the Tordis field offshore Norway in 2003-7, followed by Pazflor (Total), Marlim (Petrobras), and Perdido – Great White and BC10 (Shell). A Marlim 2 is in study phase, but on the "backburner." Indeed, on Tordis and Marlim separated water is also then re-injected and sand dealt with through handling and then re-injection, all subsea, using FMC Technologies' equipment. ▪

Subsea chemistry

Due to the environment they are in, deepwater subsea wells require various chemicals. "The first challenge is the

A Gullfaks compressor station, ahead of installation last year. Photo from OneSubsea.

cold ambient sea water temperature, so there is a chance produced oil and gas with water in it will cool and hydrates could form," Forster says. To prevent hydrates, methanol and monoethylene glycol are often used. Then there's wax formation, which needs to be mitigated, in addition to corrosion, scale and asphaltene inhibition requirements.

Typically, people look to topsides for chemical storage and for pumping and distribution, using a steel tube umbilical to get the chemical to the well. For long-distance tiebacks, alternatives are being looked at, such as having a subsea module and storage on the seabed with a distribution network and pumps. "To qualify a subsea chemical injection system, qualifying subsea chemical pumps will be a big challenge," McLaurin says. "When they are topside, we know they have about a two-year design life and we can replace them. Subsea, it's an intervention problem. Also, there is the chemical replacement problem." You could size storage tanks to reduce the number of times you have to restock them, but that's another expenditure and space requirement that wasn't there before, he adds.

"An alternative to chemical injection, however, could be electrical heating for flowlines and other flow components in the system," Forster says. "If you can keep the flow path above a certain temperature, you reduce and maybe even eliminate the need for hydrate inhibitors."

McLaurin says trace heating, which has already been deployed and is in use, seems to be the way flowline heating is moving, because it is more efficient. The alternative is the "direct" method, where

you put heat into the flowline, using the flowline as the resistive current path.

Joining the dots

But, enabling subsea processing is far from being about the individual parts of the system. For subsea processing to work, the complex sub-systems need to be able to work as part of a whole.

"It is a bit of a paradox," Forster says. "Whereas introducing subsea processing equipment is introducing complexity to the system, the challenge is getting the system out there and simplifying the packaging and design so that the interfaces between components can be standardized and consistent. Then if you want to add a module, you just add it. Ideally, you would be able to pick this module from any vendor and be confident it can plug and play." How the systems are supported, in terms of subsea robotics, is also changing. While the industry would now struggle without remotely operated vehicles (ROVs), autonomous underwater vehicles (AUVs) are starting to appear like they will play an increasing role, and potentially move toward being resident in the subsea environment, instead of being deployed from a vessel.

Big data

Of course, with those subsea vehicles, along with the increasing array of sensors and the data they produce, big data is entering the fray and it is perhaps perfect timing. This not only involves getting the appropriate sensors marinized and on the subsea equipment, but also getting the data back to the host facility and beyond and then being able to make use of that data.

"The more sophisticated controls systems are making that easier to do, getting the right information from the subsea system. Then, a significant area of development is having the software to interpret it and make use of it in real-time," Forster says. "Many operators are making some really good in-roads in this new data arena." But, it's a big job and there are obstacles, ranging from initially overwhelming operators with information to bringing in software applications, such as surveillance by exception. "The software can process the data process just enough so that the situations, which need human attention are identified and displayed. It's the first step–and it's the tip of the iceberg," Forster says.

"For deepwater fields that are very concentrated, cost intensive and prolific, it only makes sense to echo investment in the field with comparable investment in managing the information that comes out of it. It is not a debate."

Get kit wet

While the orders might not yet be flooding in for new subsea processing systems, there is still interest and ongoing work. Indeed, McLaurin points out: "It is interesting how, when the sector sees a downturn, unlike other industries, it enables research and development in this type of equipment."

For Forster, who worked on deepwater technology with Shell before joining Intecsea, new technology needs to be exposed to field conditions as soon as possible to help get future development, however. "There are projects going in now where the requirements are not as severe as the deeper fields, so go ahead and install more sophisticated technology to aid research and development when you're not so exposed in the event of a failure, because it's relatively easy to replace components with simpler options if you encounter problems." OE

It's all about the boost

Subsea boosting is coming under the spotlight, despite and also because of the current low oil price environment. Elaine Maslin reports from Subsea Expo and Subsea Valley.

Multiphase subsea boosting technology has been around for some 20+ years and has proven itself on a number of projects, including in deepwater.

It offers the capability to help increase production, reduce topsides facilities and enable late-life production and low pressure or deepwater field production. Where low pressure fields are developed close to high pressure fields it can help increase the low pressure production to the level of the high pressure production and could also help produce the fields with increasing levels of water cut, points out FMC Technologies' Håkon Bruun, during a presentation at the recent Subsea Valley conference.

Yet, despite the perceived benefits, subsea boosting – multiphase or otherwise, has not been as widely adopted as many thought it would be. There are some 5000+ active subsea wells on 1500 fields out there, yet only about 30 of these have subsea boosting technology on them, Subsea Valley, was told early April.

The low take-out is not stopping an increasing number of firms entering the space and ongoing development in new technologies by the established players, however. In today's low oil price market, they think there's an even greater opportunity to be had, as operators look to sweat more out of existing assets.

Some of the latest developments were outlined at Subsea Expo, Aberdeen, and Subsea Valley, held in Oslo, earlier this year.

Marco Gabelloni

Aker Solutions

Marco Gabelloni, Aker Solution's regional concept line manager, presented the firm's latest subsea multiphase pump technology at Subsea Expo, including the latest MultiBooster, which is planned will be qualified this year.

The new MultiBooster is a multiphase, high-range gas volume fraction (GVF), high delta p system. The design trickery on the Multibooster has been to design a mixed-flow shroud impellor that allows for a high delta P, while minimizing phase separation. It has a 6MW, 6000rpm motor, which means it can provide high delta P at high GVF, Gabelloni says.

It also has an advanced condition monitoring system, with two sets of proximity probes in four locations, so you can accurately measure the rotor displacement.

A first prototype has been tested with joint industry project partners ConocoPhillips, ExxonMobil, and Total. The motor has been running successfully, and production models validated, with 8700 Nm of torque, he says. The system has been put through load and heat runs and more tests due, including locked rotor tests and new load tests. A range of tests for a whole range of gas volume fraction, using water and air as well as model oil and nitrogen will also be run and are due to be finalized by then end of the year.

As part of the project, Aker built a new multiphase test loop at its facility in Tranby, Norway. The MultiBooster will join Aker Solutions other subsea pumps, including a single-phase pump, Liquidbooster, and a Hybrid pump for mid-range GVF, the HybridBooster, developed which was qualified in 2012.

Fuglesangs

Oslo-based Fuglesangs Subsea (FSubsea) is developing pumps, single-phase and multiphase, that could eliminate topside support and are seal-less, making it a potentially very easily deployable system on a whole range subsea infrastructures.

"The goal is to make subsea pumps as autonomous as possible," says founder and CEO Alexander Fuglesangs. Seals and the need for additional topside equipment, such as variable speed drives, "are the main hurdles to subsea boosting today," he says. The firm's technology, Omnirise, developed in partnership with National Oilwell Varco (NOV) and help from Innovation Norway, looks to do away with these and make subsea boosting a more attractive option for subsea tiebacks.

Omnirise ECM Subsea Boosting Pump System. Image from Fuglesangs.

The firm, set up in 2013, is a subsidiary of Norwegian firm Fuglesangs, which has been developing subsea pumps and seals for use subsea, as well as in drilling, mining, trenching and naval submarine, for at least three decades.

Omnirise ECM (electric centrifugal multistage) use electric driven centrifugal multistage technology for single-phase and multiphase pumping.

Key to the Omnirise design is making it seal-less and reducing the need for topsides support infrastructure and complex umbilicals, termination end units, subsea pressure casings, topside VSD and HPU., etc., by using a new "Hydromag" technology and a permanent magnetic coupling system to drive the pump and integrating VSDs, created from German firm Voith Turbo's Voith torque converters, described as being like a car clutch system, into the subsea unit.

The Hydromag system has been developed by Fuglesangs in a project involving NOV and Voirth Turbo. It has a fixed low-speed (3600 rpm) pressure compensated electric subsea motor, magnetically connected, using synchronous magnets, to a variable (0-7200 rpm) high-speed pump, which are hermetically separated thanks to the magnetic coupling system and enables low pressure connectors.

By combining Hydromag and Voith's torque converter, the booster only needs a power cable from a host facility or shore, as it no longer needs hydraulic lines, or a barrier fluid system due to the motor cooling fluid and the process pump being by the magnetic coupling system. Fuglesangs says to lubricate seals and provide barrier fluid costs US$1.5-2 million per kilometer of umbilical, in umbilical purchase costs.

Furthermore, the firms say the pumps come in cartridges, which can be switched out, to make the system modular. For gas compression, the firm would

instead use a gas compressor cartridge.

A 45 KW, single-phase prototype has been developed and is at TRL5, having had 6000 hours running time, without the VSD element.

"You have had 20 years of big companies doing big things, some right, some wrong. We have taken a systematic look at what has gone right and wrong. Seals are 75-80% of the failures, either as a symptom of the failure or the root cause."

FMC Technologies

Permanent magnet motor technology has also been used by FMC Technologies. The firm worked with Sulzer Pumps for more than eight years and qualified a hybrid, 3.2MW, 5000 psi high boost multiphase pump system (*OE*: October 2012).

Late last year, a version of this pump was ordered for Shell's BC10 Parque das Conchas fields offshore Brazil in up to 2000m water depth.

Håkon Bruun, FMC Technologies, said the company's work in this area involved buying LA-based DDS, Direct Drive Systems, a firm that makes permanent magnet motors and high speed machines to avoid gears, in 2009.

Single phase

Switzerland-headquartered Sulzer is promoting single-phase boosting supported by subsea separation. The industrial engineering and manufacturing firm launched itself into the subsea separation business in 2014, when it bought Ascom and ProLabNL. Both companies are based in the Netherlands and both have been involved in a technology qualification program with ExxonMobil. This has involved creating a compact subsea system, which includes compact inline separation and boosting.

Subsea separation could enable an increase in production, through more efficient liquids boosting, enabling longer range gas compression from shore, cost efficient hydrate management, riser slug reduction and access to reserves otherwise to challenging to reach.

Putting separation on the seafloor would also reduce topsides infrastructure and could pave the way to subsea water re-injection, further reducing topside process equipment.

For ExxonMobil, the drive towards seafloor separation was due to its portfolio including Arctic and deep water resources (11% of its resource base in 2013), according to a presentation by the firm. Exxon's Upstream Research Co. led a project to qualify, at ProLabNL, a compact separation system for application in 3000m water depth and internal pressures up to 690 bar, while making sure the qualification criteria was wide enough to incorporate multiple field possibilities.

Ascom was heavily involved, producing an inline de-sander and its HiPer MixedFlow two-stage de-oiling hydro cyclones and Canty oil/water monitors.

The work of its subsidiary companies led Sulzer – which also supplies subsea multiphase pumps, water injection pumps and hybrid pumps – to look at the wider industry potential for single-phase pumping.

Rombout Swanborn, head upstream, Sulzer, presented the case for single-phase subsea boosting supported by subsea separation at the Offshore Energy conference and exhibition in Amsterdam late 2015.

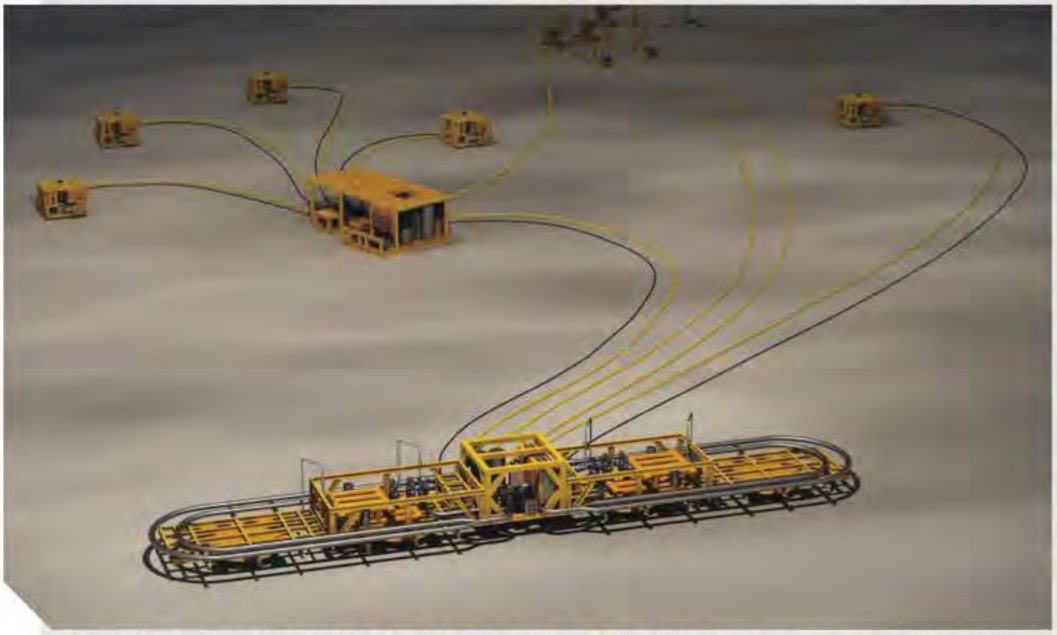
Subsea separation brings "inherent advantages over the conventional way of boosting," i.e. multiphase boosting, according to Swanborn.

For multiphase boosting applications, variable speed drives are currently required topside, as well as power, monoethylene glycol injection facilities, to combat flow assurance issues, multiphase risers, a re-injection system, all supported by umbilical systems, as well as the multiphase pumps on the seafloor. In this scenario production and produced water is transported to the host facility with water treated and then pumped back down to the seafloor and re-injected. This is "complex, energy inefficient and limited reliability," Swanborn says.

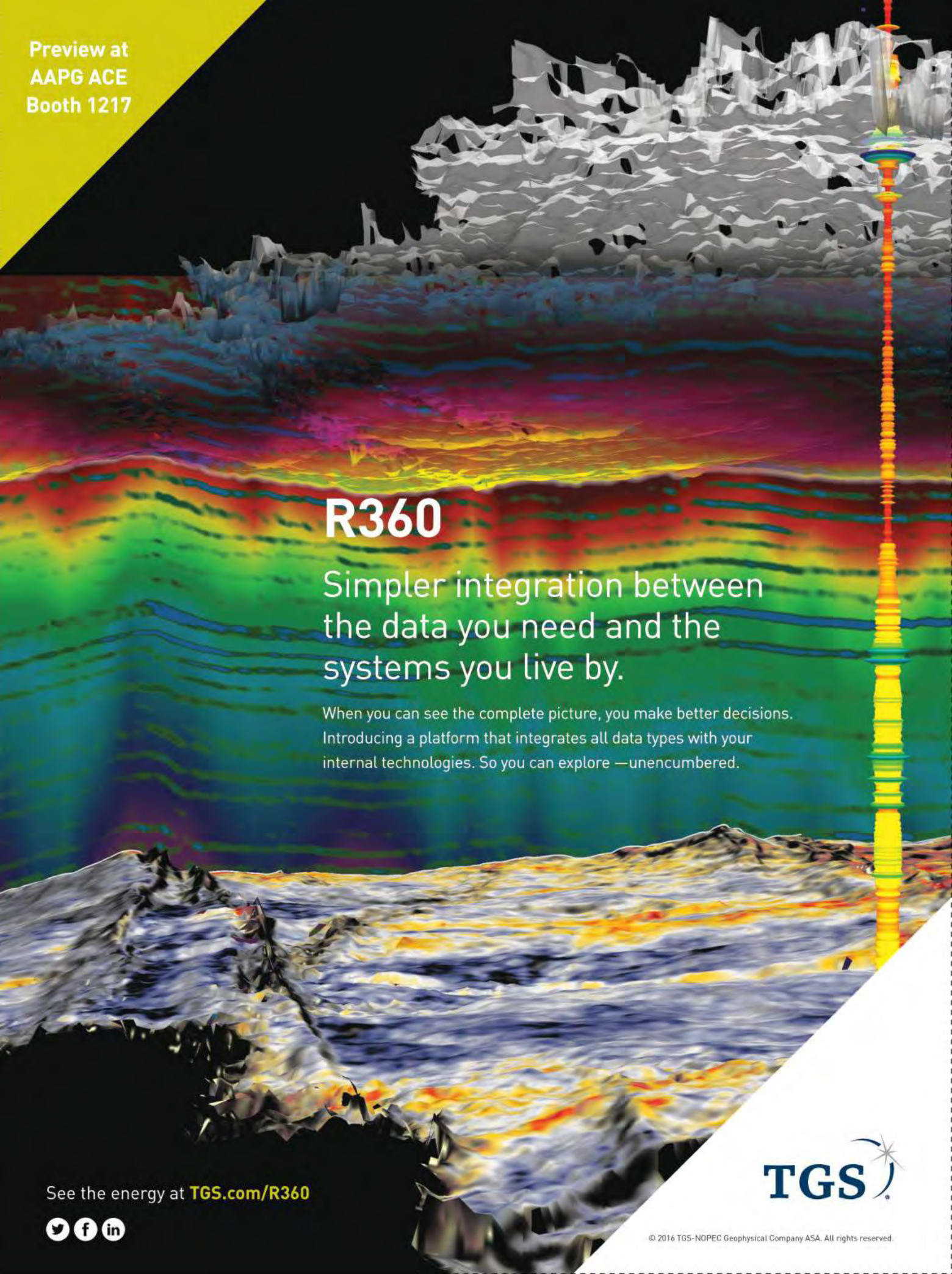
Using separation before boosting reduces topsides facilities and power requirement, just gas and liquid risers are required, with no or minimal need to deal with gas hydrates. On the seafloor, additional equipment includes sand management, which is an area requiring some development, he admits, with either removal required or remixing it into the oil for removal topside, and a produced water reinjection system, which is the main area in which the industry has been held up in its adoption of subsea separation and re-injection.

Swanborn is not deterred. "Single-phase boosting can bring advantages, I think," he says. "It's an easier way to get long step-out distances. In some long step-outs it is really the only possibility. It mitigates certain flow assurance risks, e.g. hydrate formation, uses lower subsea energy requirements, and makes subsea water re-injection possible, at the same time as de-bottlenecking topsides three phase separation and produced water treatment, and enabling smaller flowlines to the host. It also absorbs transient flow conditions and has less complexity on the seafloor."

"Many operators are looking at single-phase boosting systems," Swanborn adds, to gain these benefits, and on both brown- and green oil and gas fields. ▪



ExxonMobil's subsea processing vision, incorporating Sulzer technology. Image from ExxonMobil via Sulzer.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Typically, he says, there are three different types of pump: helicoaxial for multiphase boosting, single-phase pumps using conventional centrifugal pumps for liquids with limited gas, and a hybrid type with one or several helicoaxial impellors in several stages to get the gas volume down so you can then use a centrifugal pump to create high differential pressure.

FMC's high boost is a hybrid type multiphase booster, combining Sulzer's pump hydraulics, FMC's high-speed permanent magnet motor technology and subsea system design into a unit with helicon-axial multiphase pumps, and single-phase centrifugal pumps, which in combination can handle high gas volume fraction and differential pressure.

It's the permanent magnet motor that is the enabler for this technology, allowing for a wider liquid gap between the pump's rotor and stationary elements, reducing drag losses and meaning the pump can operate faster than an induction machine, using less energy. The firm was also developing a 6MW, 15,000 psi version."At FMC, we see subsea boosting has growth potential despite the challenging times in this industry," he says. "We see several new developments being pushed out with increased focus on existing fields and IOR on existing fields. Subsea boosting could be applied. We also see several new developments."

GE Oil & Gas

GE Oil & Gas is running a joint industry project (JIP) to develop a new, simplified subsea boosting system, which could reduce lifecycle costs and improve flexibility. The initial phase of the JIP on the so-called modular contra-rotating pump (MCP) includes Statoil, Total and two other operators.

GE Oil & Gas says the design draws on technology from its aviation business, where it was used as an auxiliary system on aircraft engines, and eliminates equipment, such as the barrier fluid system needed in conventional subsea boosting systems. GE Oil & Gas' system, involves stacking a series of integrated new motor impellors to deliver high delta p and high flow rates, the firm says.

The firm is also aiming to make the MCP system simple, reliable, standardized and scalable so that if one stage fails, the system can be adjusted so the others compensate.

The firm has also been working on optimizing control systems using simulation. In a presentation at Subsea Valley, Dejan Doder outlined a concept for process control and operation of a subsea multiphase boosting station.

Omnirise ECM Subsea Boosting Pump System. Image from Fuglesangs.

The boosting station, in his example, would include separation and a recirculation loop, which twinned with a simulation model and automated control, can be used to ensure safe and optimal operating limits, particularly during start-up. This means using the recirculation loop to help make sure the production stream is stable, and does not have a high gas volume fraction as it goes through the boosting station, but also adjusting the speed of the pumps, based on the pressure at the inlet or outlet, so that the load on both pumps, in a two pumps in parallel configuration, is equal.

Aker Solutions-Baker Hughes

Jonah Margulis, of Aker Solutions, updated Subsea Valley on a joint project that was created under an alliance formed with Baker Hughes to offer seafloor boosting solutions.

These are not the large, 6MW+ booster stations positioned downstream of manifolds offered by others, but a solution, called PowerJump (*OE:* NCE Subsea supplement 2015), based on a high-end Baker Hughes' electrical submersible pump (ESP), which can be retrofitted in a horizontal configuration into the subsea flowline infrastructure on otherwise marginal brown and green fields. The ESP has been developed to handle up to 60% gas, on subsea wells producing less than 30,000 b/d, drawing on 2MW power, with an integrated control system. By being able to slot it into the subsea infrastructure, it means fast installation and minimal downtime, Margulis says.

The first use case, as it were, is aimed at installation on an M type high profile production jumper as a solution for fields in the Gulf of Mexico or offshore West Africa. A low profile version would be more suitable to the North Sea. The unit would be installed within a truss, to ensure the ESP remains straight and rigid, with vertical connectors for easy installation, using a light well intervention vessel, and an upstream gas dampener to protect the ESP. Downstream would be a mini liquid collection unit. There would also be a recirculation line to ensure consistent liquid in the system.

Because the ESP isn't being used downhole, and is no-longer constrained by well size, its length can be shortened and hydrodynamics improved, Margulis says. Use of simple pipeline end terminations also makes it easy to tie-in the system anywhere, he says. To increase the pressure boost, pumps could be added in series. "We have done several studies and we haven't found a field we haven't been able to tie this in to from a field architecture point of view," he says.

The alliance hopes have the system qualified by September and to deliver an entire system in 12-14 months. Rather than selling units, they will be operated on a pay for performance basis, he says. **OE**

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The need for speed

The Surveyor Interceptor. Images from MMT.

There's a war on: who can produce the fastest inspection ROV with the highest quality data?

Is it a bird, is it a plane, is it an ROV or an AUV? Well, they're more like remotely operated vehicles (ROVs) in the shape of autonomous underwater vehicles (AUVs), but on a tether and designed to move faster through the water then standard ROVs.

Pipeline inspection, and doing it faster and more efficiency is top of the list for an industry whose pipeline infrastructure, in the UK North Sea alone, could stretch from the UK to Australia if laid out end to end.

Two companies have come up with specialist tools for the task, as well as seabed and environmental mapping. Swedish marine survey firm MMT, with partner Reach Subsea, is calling its unit a Survey ROV, specifically, the SROV Interceptor. Meanwhile, DeepOcean has developed its "new generation" survey ROV Superior. Both were being presented at Subsea Expo earlier this year.

MMT-Reach

MMT and Norwegian ROV operator Reach Subsea have, working together with Norwegian ROV designers Kystdesign, come up with its concept for a high-speed high flying SROV.

The Interceptor has been designed for maximum stability as well as speed – it can move at up to 8 knots through water, MMT says – but also low noise disturbance, which means survey data is higher quality and can be achieved at higher speeds. It can operate in two modes, high-fly, for acoustic pipeline survey, and low fly, for more detailed inspection on problem areas. The long, flat unit has four rear thrusters, fins port and starboard for maneuvering, driven by 225hp, supplied through an umbilical from its support vessel.

The first unit was built in 2014. In March 2015, its first commercial project was completed over the 140m-long Knarr gas pipeline in 140-400m water depth in the northern North Sea for Gassco. Its task was to check the external condition of the pipeline and rock berm protection after pipe laying.

"The basis for making this SROV was that traditional ROVs were seen as not efficient for this use," says Ellen Svestad, MMT's chief commercial officer. "MMT's founder, Ola Oskarsson, who has been mapping the sea bed since he was 14, said that 'there must be a way to do this better.' The traditional ROV is a square box, with limited speed and also limited with image quality because of disturbance, etc. Work on the Interceptor started to give clients a more efficient tool and better data quality and both of those aims have been achieved."

Interceptor is fitted with a suite of imaging tools and technology. It has three ultra-HD cameras, which are part of a "machine vision" system that automatically create a 3D vision of the survey subject, incorporating metadata, such as time stamps, 3D laser point cloud data and navigation data and using strobe lights for clear images.

Using stills instead of video has very quickly been seen as a better way to acquire better images and data of pipeline condition, as video can, especially at speed, appear blurring when frozen as a still and also takes up a lot more

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The Superior SROV. Photo from DeepOcean.

disk space then stills, even when they're shot at a high-rate. Adding the laser scanner means pipeline ovality can also be assessed.

MMT says the quality of the georeferenced pictures is about 8-10 times higher than that of standard HD video. "From a video you can tell that a thing is round and that a fish was moving, but from a high-resolution still you can make exact measurements and quantity," says MMT founder Ola Oskarsson.

But, multibeam echosounders (MBES) are still also used on the unit. MMT says the quiet and stable running ROV means the multibeam data has less than 0.5% outliers. "The data is less noisy and more reliable than data acquired by a typical ROV," Oskarsson says. "Less automatic and manual processing is required."

The Gassco survey in 2015 was conducted from the *Edda Fonn*, in early 2015, and exceeded offshore tests which had been carried out on the Europipe 2, carried out in 2014. The unit averaged 3.3 knots and achieved up to 4.5 knots at 4-5m above the pipe while performing MBE survey and achieving 0.1m gridsize data and collecting a full 3D photomosaic.

"In 17 hours and four minutes the Surveyor Interceptor inspected 105km of Gassco's Knarr gas pipeline in the North Sea from the Knarr gas field, tied to the FLAGS pipeline system on the UK Continental Shelf, a world record," Oskarsson says.

The launch and recovery system worked in sea state up to 3.8m. The field report was delivered 18 hours after the survey. The final draft report was delivered eight days after leaving the vessel.

The unit went on to survey the world's longest HVDC link, the 1500km-long Atlantic Super Connector from Iceland to UK, in 40-1200m water depths.

DeepOcean

DeepOcean's SROV Superior is a modular ROV, designed to work with an iTMS, or semi-autonomous tether management system.

The ROV's design is flat and long, with the buoyancy at the top, four rear thrusters and an optional skid for mounting of camera booms, manipulators and other types of skid-mounted tools like geotechnical sampling equipment, 3D geophysical equipment etc. In addition the ROV features a new deployment of the pipetracker, a retractable frame at the front.

The iTMS, shaped like an inverted wing, is planned to be used during surveys to take the umbilical weight off the ROV

while it flies beneath its support vessel.

The aim was for an as stable and as silent as possible ROV, capable of flying at 4 knots at 400m water depth, without the iTMS, and at the same speed at 1000m depth with iTMS, says Trond Hagland, GTO Survey and Geotechnics, DeepOcean.

The modular approach to the design was chosen to allow the ROV to be used for three types of fast ROV surveys: bathymetric survey, acoustic pipeline inspections and visual pipeline inspections. Equipment configurations can be adjusted to suit the purpose of the different types of survey. The latest generation MBEs allows acquisition of high density bathymetric data at high speed.

Using CATHX Ocean high definition laser profiler and HD stills camera system enables acquisition of high density point clouds close to the pipe and high quality stills pictures during acoustic pipeline inspection (typically flying 5m above pipeline). And with the skid, camera booms at the front and the pipetracker lowered, the ROV can quickly switch to close-up pipeline inspection.

After working with Norwegian ROV designers Kystdesign, the first unit, without an iTMS, was delivered to DeepOcean in June 2015, with sea acceptance testing in July. The results were better than expected, Hagland says. The ROV has a drag coefficient of just above 0.2 and speeds in excess of 5 knots were achieved. The iTMS part of the concept has therefore been put on hold until the ROV has been tested at depths in excess of 1000m.

In October 2015, the system was mobilized for work in the North Sea, and the Superior ROV performed all three types of surveys at significantly higher speeds than traditional survey ROVs. Seabed mapping speeds averaged above 5 knots with just 1° pitch and -2° roll constant.

The campaign also performed acoustic inspections of all infield lines in one field. During the inspection, flying 5-7m above the pipelines using MBE and side scan sonar (SSS), data with a digital terrain model (DTM) grid cell size at 0.1m x 0.1m was produced at average speeds up to 3 knots. An as-built visual pipeline inspection of a 105km pipeline was also performed, achieving average speed of 1.3m/s overall.

Pipeline tracking was then successfully performed, tracking a 12in pipeline through gravel intervention down to 1.5m.

"During all three types of survey the ROV was very stable in the water column with limited variations in roll and pitch," Hagland says.

The next step is adding laser scanning technology, he says, which will allow a greater scope for pipeline inspection at 5-7m above the pipeline and at higher speeds than using MBE while bringing greater data density.

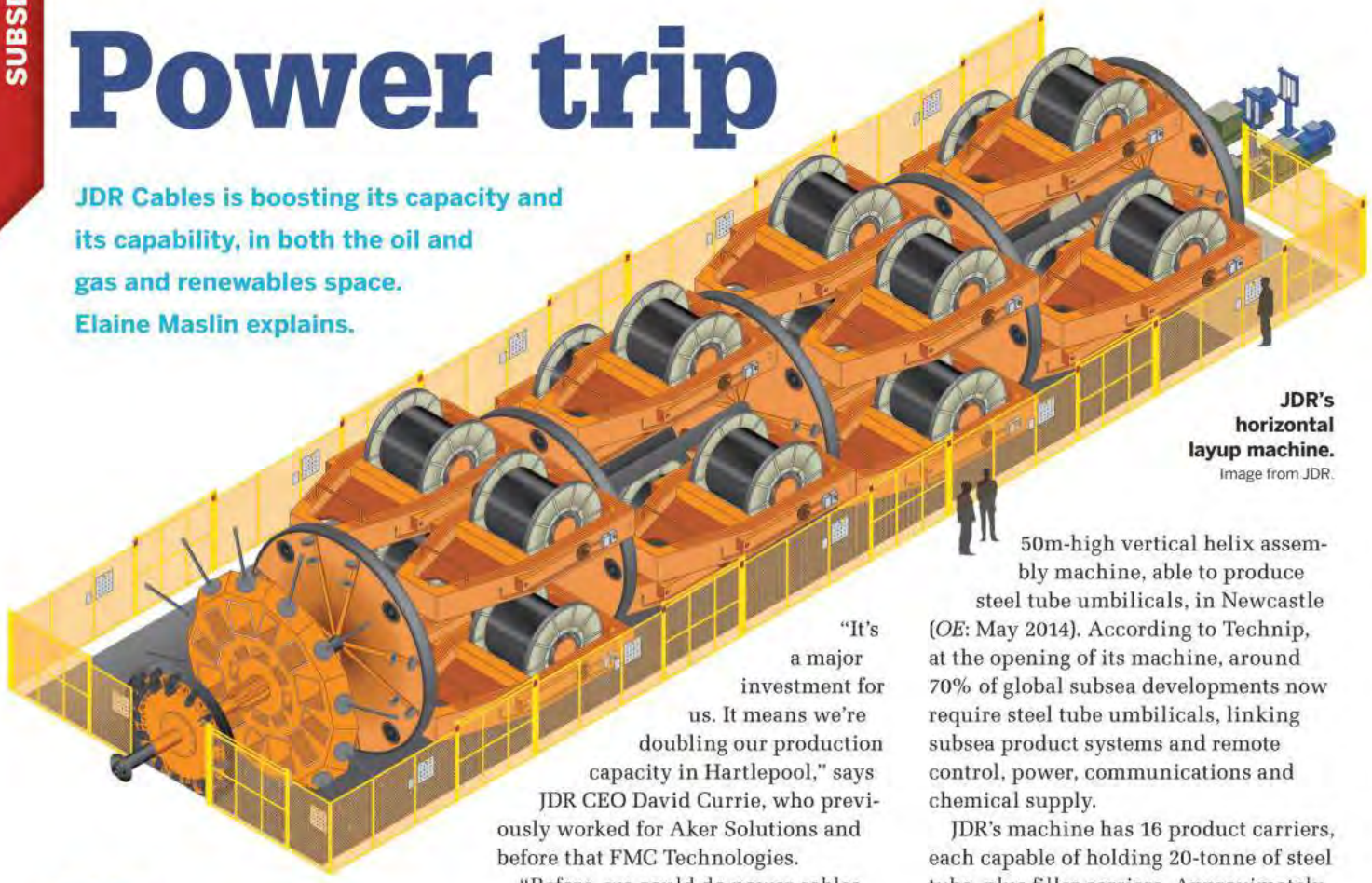
DeepOcean has already tested this technology on an AUV and another ROV. The CATHX laser imaging system was added to the Superior this year for DeepOcean's main client during the 2016 season.

"The data density of the laser data is vastly greater than the data density of the MBES data with a 20-fold increase on the MBEs data density," DeepOcean says. "The laser detects features far better than the MBES partly due to its increased data density."

DeepOcean says further speed improvements will be made by using a launch and recovery system with a thinner umbilical. But, with faster speed, sensors and video quality also need to step up. **OE**

Power trip

JDR Cables is boosting its capacity and its capability, in both the oil and gas and renewables space. Elaine Maslin explains.



JDR's horizontal layup machine. Image from JDR.

UK-based umbilicals and power cable manufacturer JDR Cable Systems took a step into offshore renewables in 2006. Since then, it has quickly ramped up its capabilities in the space, including developing higher voltage inter array power cables for offshore wind farms and aluminum power cables, the first of which will be deployed this year.

Now the firm is also ramping up its capacity. By next month (June), JDR is due to have fired up its new horizontal lay-up machine (HLM) at its fabrication facility in Hartlepool, northeast England, expanding its capabilities in the steel tube umbilical space.

The machine, a MALI horizontal helix machine (KV16/280R), manufactured in Austria, will be used to wind multiple components, into thermoplastic, steel tube, hybrid steel tube and thermoplastic subsea production umbilicals as well as composite power umbilicals and subsea power cables. At 65m-long, from gearbox to exit caterpillar, and covered in an array of component product drums.

"It's a major investment for us. It means we're doubling our production capacity in Hartlepool," says JDR CEO David Currie, who previously worked for Aker Solutions and before that FMC Technologies.

"Before, we could do power cables and other cables. This machine is a horizontal helix lay-up machine for [also] producing steel tube umbilicals. It gives us the ability to have production plant for renewables and a production plant for oil and gas."

Northeast England has become a hub for umbilical manufacture. In 2014, Duco, part of Technip, opened a new, 50m-high vertical helix assembly machine, able to produce steel tube umbilicals, in Newcastle (*OE*: May 2014). According to Technip, at the opening of its machine, around 70% of global subsea developments now require steel tube umbilicals, linking subsea product systems and remote control, power, communications and chemical supply.

JDR's machine has 16 product carriers, each capable of holding 20-tonne of steel tube, plus filler carriers. Approximately 15km of ½in steel tube can be loaded onto each drum and so the number of tie in welds is greatly reduced. Up to 4000-tonne will be able to be manufactured in one length, only limited by carousel capacity. As an example, it could produce an 80km-long 150mm-outer diameter umbilical.

The site currently has a vertical lay-up

Umbilical investment

Fast growing surface to seabed firm Seanamic Group announced plans to build a new Umbilical International facility in Glasgow as well as plans for a larger laying up machine to be based in North America. The private equity-backed firm was founded in 2014 through the acquisition of Glasgow, UK-based offshore handling firm Caley Ocean systems, then-cable and umbilical manufacturer Umbilicals International in Houston. It says that, initially, the new Glasgow facility will offer umbilical repair and refurbishment for operators and contractors, in the lead up to full umbilical and cable manufacture.

Seanamic cables. Photos from Seanamic.

A process to decide a location for the new lay-up machine for the states, which will extend capacity and length of

machine (VLM), which was being used for power cables and umbilicals. The VLM, however, is geared and optimized for long-length power cable manufacture. Adding the HLM will mean the firm can focus on complex steel tube umbilicals, as well as the other product, on a dedicated machine.

This includes hybrid steel tube umbilicals. JDR's first hybrid steel tube umbilicals were delivered last year. The product, an 18.2km umbilical providing power and control between Wintershall's new Ravn platform and an old platform in the Danish North Sea, has a mix of super-duplex steel tubing for high corrosion resistance, as well as thermoplastic hoses, medium voltage power cores and fiber optic cables. "Bringing these two together offers a lot of advantages, chemical resistance, corrosion resistance, high flexibility with the thermoplastic hoses, etc.," says James Young, who was appointed chief technology officer at JDR in February.

Renewables

The HLM is not the only area in which JDR is investing. The firm is looking to create a new offshore support base in the UK to support multiple contract awards in the offshore renewables space.

The firm signed five-year collaboration agreement with tidal energy developer Atlantis Resources in December. The agreement followed a contract to provide 56 array cables for the 336MW RWE Innogy Galloper Offshore Wind Farm, off England, partnering with VBMS as installation contractor.

Last summer, the firm also announced a frame agreement with DONG Energy, coinciding with a contract for 110km of 35 kV inter-array cables, plus ancillary equipment, for the up to 91-turbine Race Bank offshore wind farm, off England.

Vive la voltage

JDR Cables entered the renewable energy market through its work on the Beatrice demonstrator project in the Moray Firth. It involved two 5MW turbines connected to the Beatrice platform.

Since then, the firm has worked on a number of projects and has developed new technologies for the sector. This includes type approved coilable copper and aluminum power cable, up to 630sq mm and 800sq mm diameter respectively. An order for 630sq mm copper cable has already been delivered, to the 72-turbine Sandbank offshore wind farm in the German North Sea. Some 800sq mm aluminum cable is due to be delivered this year, to the 54 turbine Nordsee One offshore wind farm, also in the German North Sea.

Coilability means the cable is easier to store, transport and deploy, Young says. Traditionally, cable has to be wound on to a carousel then transferred onto another carousel on the deck of the installation vessel. Young says that the coilability has been enabled by using polymer roving for the outer jacket instead of an extruded outer jacket. This meant studying how the material twisted when it's coiled.

The firm has also completed type approval of a 630sq mm repair joint. This means if a cable is damaged during installation it can be fully repaired using a joint suitable for the installation and deployment conditions the cable is capable of.

JDR has also developed and qualified medium voltage cable factory jointing, which enables longer lengths of medium voltage power cable to be delivered. The factory flexible joints have been qualified to CIGRE 490 and IEC 60502-2 standards for medium voltage power cables and also meets Statoil's standards.

66kV

JDR is close to completing a project to create 66 kV inter array cables. The firm started the research development and then type testing project in 2012, with funding from the UK's Department of Energy and Climate Change and the Carbon Trust.

"Offshore wind turbines are getting larger and the amount of power you can delivery is much higher," Young says. "There is a drive to reduce cost of the offshore wind, or levelized cost of energy (LCOE), and to do that the Carbon Trust and a number of developer companies has been investing in a move towards 66Kv inter array cables."

Currently, most inter array cables are 33 kV, Young says. There are higher voltage cables available already, but they are large and costly because when the voltage increases is that typically require an additional layer of metallic hermetic barrier to prevent water ingress, which would degrade the insulation, Young says.

"As you move up the voltage range, the electrical stress increases, so the insulating materials are put under more stress. You could increase the insulation, but it would result in a very large cable that is very expensive. So, we have looked at how to bring down the cable to the smallest size and maintain the same reliability as

umbilicals it can manufacture at Umbilicals International, is ongoing.

David Henderson, Business Development Manager, Seanamic, told OE that the goal is to have both facilities ready by the end of 2016. "As part of Seanamic we have the financial muscle to expand. Despite the market being down, we are receiving leads. The market might have stalled, but it hasn't gone away. Caley Ocean systems is also very busy in the oceanographic space as well as decommissioning. "

Seanamic supplies fully integrated umbilical and handling systems for well intervention, workover and BOP (MUX and direct hydraulic), saturation diving and subsea habitats, ROVs and submersibles. ■

a 33Kv cable."

To get around this issue, JDR developed cables using a wet design insulation system, using a water retardant system preventing degradation off the insulation during a wind farm life, often around 25-40 years. It works by using water tree retardant XLPE insulation. Unlike standard polymers, which over a period allow some water molecule migration into the insulation, causing electrical stress and break down of the polymers, creating tree-like tracks, water tree retardant materials retard that process.

"A lot of the technology is proven, but used in a different way," Young says.

A JDR umbilical. Photo from JDR.

Long-term wet aging tests at elevated voltage stress are ongoing and the initial results are positive, he adds.

JDR has type tested its 66kV cables in accordance with IEC 60840 and CIGRA 490, with qualification achieved in December. JDR's repair joint and factory jointing for the 66 kV cable are currently undergoing the final stages of an extensive type testing program and will be complete by the end of Q2, Young says.

The future

"The options for power transmission and distribution are really interesting," says Young, in oil and gas and renewables, particularly by transferring knowledge from each segment to the other, as offshore renewables projects, including wave and tidal, continue to grow, and the oil and gas industry looks to power ever more subsea power consumers. OE

Unitech looks to the bigger picture

Unitech Offshore recently announced a new umbilicals and flying leads manufacturing facility at Stord in Norway, bringing its umbilical manufacture in-house after 30 years' involvement in subsea umbilicals development.

The Stord facility is using a vertical production machine, where tubes are held on cradles and pulled up and bundled together before being MDPE (medium density polyethylene) extruded. At present Unitech is upgrading the facility from four to 13 cradles with the ability for two passes through the machine.

Typical production time for 100m hydraulic flying lead and electric flying lead is four days, although continuous production up to 6km is possible. "We carry a large stock of steel tubes and are geared up for quick production turnaround," says John Knapskaug, Unitech Stord site manager.

Unitech was the first company to develop a steel tube production umbilical for Statoil back in 1987, says Bernt Hellesoe, founder and managing director.

Hellesoe

The firm, which also produces UH-500 Series subsea stab connectors and stab plates for chemical injection, gas lift and electrical connections, on Xmas trees and manifolds, decided to bring umbilical manufacture in-house in 2012, with the first project for jumpers for the Liwan field in the South China Sea.

"Umbilicals were the missing link – this way we are able to offer the complete, end-to-end, flying lead as a single source solution," Hellesoe says.

Flying lead systems have traditionally been for fixed-configurations that involve multiple companies for manufacturing components, and for assembly, and test. In the current climate, the ability to make substantial cost savings on production of flying leads is not lost on the industry, nor are the savings in deployment.

"Our HFL and EFL systems are reconfigurable post-manufacture, providing the opportunity to use a flying lead for numerous applications," Hellesoe says. "Moreover, a reconfigurable flying lead can dramatically reduce spares inventory requirements across multiple developments." ▪

Unitech's umbilicals plant in Stord. Photos from Unitech.

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Worlds collide

Mark Smith, Staci Stephenson and Brent Fergurson, of Oceaneering International, show how NASA's neutral buoyancy lab is helping cut costs and cut risks involved in subsea initiatives.

As reflected in ongoing tests for a major deepwater riser repair project off West Africa, an underwater testing facility near Houston – once dedicated exclusively for space exploration training – has built a niche in the offshore sector, especially in advancing remotely operated vehicle (ROV)-conveyed subsea developments without the risks and costs of real-world subsea deployment.

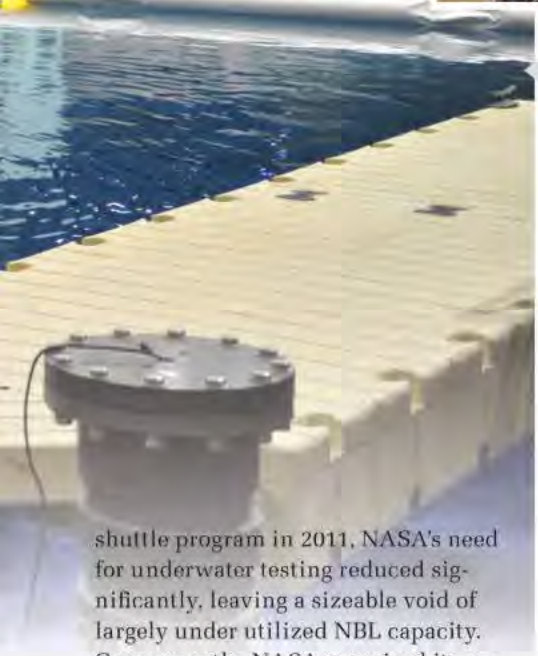
The centerpiece of the Neutral Buoyancy Laboratory (NBL), operated under the umbrella of the National Aeronautics and Space Administration (NASA), is the 40ft-deep (202ft long x 102ft wide) indoor pool, complete with a permanently installed Oceaneering International Millennium heavy work class ROV and operator control room. Since made commercially available to the offshore oil and gas industry, the test tank, which is configured to allow simultaneous NASA space suited dives and ROV operations, has hosted a myriad of cradle-to-grave technology and procedure evaluations. These have been from proof of concept, through design and developmental operations and hardware testing phases, to ultimate functional acceptance and systems integration testing (SIT).

Enclosed within a fully secured 79ft high and 72,000sq ft high bay near the Johnson Space Center, the environmentally controlled facility offers single-source capabilities, including two 20.5-ton overhead cranes, four 2-ton jib cranes, dive team support, on-site repair and light manufacturing, as well as hyperbaric and hypobaric chambers. In it, an array of maneuverable underwater video cameras, and VideoRay capture all diver and ROV operations with live streaming on a bank of high-definition monitors aligning the skybox-like observation rooms.

Until roughly five years ago, these state-of-the-art capabilities were rooted entirely in the US Space Program, particularly in testing and verification support for the installation and maintenance of the International Space Station (ISS). Owing to the strikingly similar physical and operational hazards of the space and subsea frontiers, the transition into offshore oil and gas represented a natural evolution, as illustrated in a number of completed and active projects.

From space to subsea

With the final assembly of the ISS and the concurrent retirement of the space



NBL aka "The Big Pool."

Deployment of MIL 27 ROV at the NBL. Images from Oceaneering International.

shuttle program in 2011, NASA's need for underwater testing reduced significantly, leaving a sizeable void of largely under utilized NBL capacity. Consequently, NASA exercised its authority under the National Aeronautics Space Act to enter into commercial partnerships, making the facility available to the oil and gas industry for complex testing, training and support functions, at a fraction of the cost of performing the same exercises in the often-fickle offshore environment.

While fully accessible and welcoming to commercial applications, most of the work at the NBL continues to support space exploration, specifically with respect to current and future maintenance operations for the space station. For instance, nearly all of the average 150 suited diving operations conducted yearly are in conjunction with ISS maintenance, astronaut candidate training, or other space-oriented projects. In addition, buoyancy and sea state model correlation have been performed at the NBL in support of NASA's continuing development of the Orion spacecraft, envisioned to take astronauts beyond low Earth orbit, perhaps eventually to Mars. Furthermore, as the NBL is engineered to provide real-time mission support, should something go awry on the ISS, pertinent personnel can be "in the water" and performing remedial operation testing within 48 hours. The same rapid response capability is especially applicable to the offshore industry where platform system or component malfunctions, for example, can have severe HSE and economic ramifications.

Among the world's largest undercover bodies of water, the 6.2 million gal. pool is outfitted with full-sized mock-ups of the ISS, including a hydraulic working model of the space station robotic arm. Accordingly, the once-dedicated NBL is well-suited to accommodate underwater SIT of subsea equipment mock-ups, which also can be combined with animation. Experience has shown that SIT is particularly effective in tandem with animation, which together have identified reach and access issues and generally made operations more efficient and cost effective by eliminating or minimizing operational workarounds.

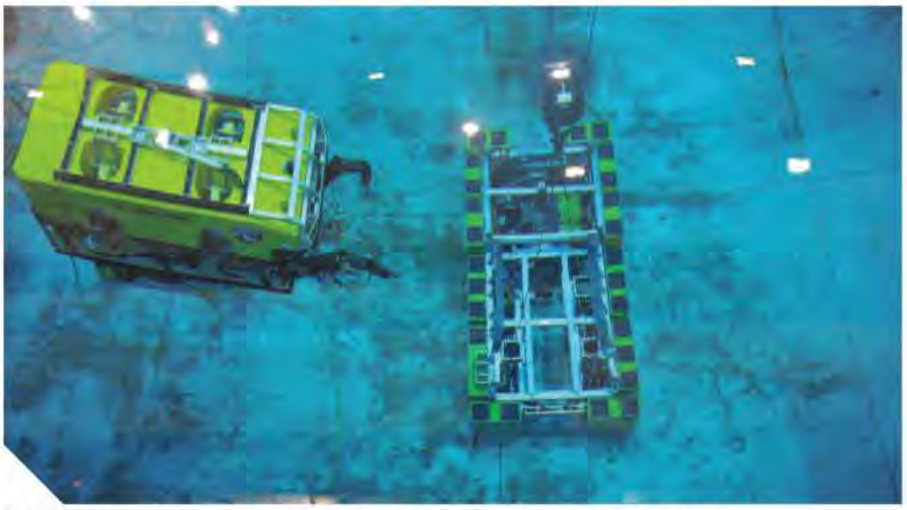
The SIT capabilities of the NBL are expected to be clearly demonstrated in 2016 when underwater testing begins on an Oceaneering designed mock-up riser as part of a West Africa repair project. The remediation initiative entails the repair of two marine gas lift risers that were damaged during original installation of the main hybrid riser tower. The deepwater repair will entail ROV-conveyed cutting out of the damaged sections, which will subsequently be replaced with new flexible risers from the cut end of the gas lift risers to the primary gas-lift manifold.

The impending SIT will be conducted to validate the functionality of some dozen application-specific tools developed by Oceaneering. During the estimated 14-day SIT, the NBL resident Millennium ROV and the replicated riser will be collectively engaged to test tool functionality, evaluate the ROV-tool interface and the ROV capacity to effectively complete the deepwater repair.

This project represents but one example of how the NBL is being used to support a divergent range of client investigations throughout the life cycle of a deepwater field, from greenfield development to ongoing support and continuing through to eventually decommissioning.

Deepwater foothold

Since 2008, the NBL has been engaged to support a number of projects connected to high-profile deep and ultra-deepwater fields, including the completion of functionality tests on a number of Oceaneering designed wellhead cutting tool options for a Gulf of Mexico (GOM) platform installed in more than 6000ft of water. Also in support of a deepwater GOM field, the NBL was used in the



Deployment of subsea hardware in support of system integration test.

development of an American Petroleum Institute (API)-certified suite of subsea flange removal tools developed by Oceaneering. The NBL and the 220hp Millennium were used to support the factory acceptance testing and SIT of the subsea flange removal tools prior to their successful field application.

Not all NBL testing, however, is tied solely to ROV operation, as illustrated in an earlier study to develop a methodology to quickly inspect buoyancy can chains for manufacturing defects. To avoid open-sea failure of suspect buoyancy can chains, which comprise a series of massive interlocked links and ovals, saturation diving and atmospheric diving suit tests were performed at the NBL to compare the time and motion required of each to complete an inspection. With test results pegging saturation diving as the preferred method, the next step was developing hardware to hold the inspection tool and make it easy to attach and position on the chain links. The final hardware configuration, much of which was built at the in-house machine shop, was the outgrowth of 12 design-fabrication-test cycles carried out over six days.

Another example of taking a project from proof of concept to the design stage is the work performed for a major operator aimed at developing an underwater magnetometer for non-intrusive inspection of insulated steel pipe. During proof of concept, evaluations centered on a betatron radiography system, which is an electron accelerator that produces a high-energy directional X-ray beam using a varying magnetic field. While industrial use of betatron radiography technology has been well documented, its application in subsea environments had not previously been characterized.

Fluid sampling projects

Last year, the NBL was the focal point for two unrelated deepwater fluid sampling projects - one in support of a major GOM operator and another in conjunction with the public-private Research Partnership to Secure Energy for America (RPSEA).

In the former, ROV tank testing was performed for an integrated service provider under contract to a major operator to develop a retrievable subsea fluid sampling system. The objective of the NBL testing was to characterize the underwater behavior of a newly engineered and ROV-conveyed retrievable sampling skid as it was being remotely removed and installed into a corresponding receiving structure, both while connected and unconnected to a lift line. As part of the investigation, additional installation and operational testing was performed to demonstrate and verify adequate ROV reach and access.

At the conclusion of the ROV integration tests, the client's established test procedures and objectives had been captured, including the behavioral characterization of the sampling system in the subsea environment.

Meanwhile, the NBL also played a critical role in a sweeping initiative RPSEA orchestrated as part of its ultra-deepwater program to enhance industry's ability to reliably assess deepwater well production and well control conditions. As one of the subcontractors in the multi-faceted research and development program, Oceaneering first designed and fabricated a prototype inline subsea sampling tool to provide operators a means of accessing and retrieving well fluids at pressure and temperature for laboratory analysis. This project was followed by the engineering of a new wet sensor system designed to test the feasibility of installing and replacing a sensor into a live flowline using an ROV-mounted system.

The hardware-ROV integration testing was completed successfully at the NBL in late 2015.

Whether it be space or subsea, the NBL with its state of the art services is available to support the oil and gas industry's underwater testing needs. **OE**

***Mark Smith** has served as a senior engineer/project manager at Oceaneering since 2000, and is currently responsible for capturing and managing underwater testing projects conducted at the NBL. He holds a degree in mechanical engineering from the University of New Brunswick.*

***Staci Stephenson** has supported operations at the NBL since 1998, and is currently the dive operations manager, Oceaneering. She assures efficient and smooth operations in support of testing equipment, training of astronauts and performance of various commercial operations.*

***Brent Fergurson** is the commercial project manager, Oceaneering, and has supported operations, HSE and engineering services at the NBL since 1997. He is currently responsible for integration and project management functions of commercial projects. He holds a degree in Wildlife and Fisheries Sciences from Texas A&M University and a Master of Science in systems engineering from the University of Houston.*

Jackups. Photo by staff.

Strength in monitoring

Structural integrity monitoring should be a lifecycle tool and could make jackup moves safer. Meg Chesshyre reports from Oceanology International.

A call for further development of structural monitoring systems for offshore use was made by a member of the UK Health and Safety Executive's Energy Division at the Oceanology International conference in London this spring.

In a joint paper, presented by Alexander Stacey on behalf of himself and John Sharp of Cranfield University, Stacey said structural monitoring techniques complemented periodic techniques as tools for integrity assurance and that their use provides clear benefits in the maintenance and integrity of offshore structures. But, he said there is wide range of techniques that vary in terms of maturity and applicability, and that further development is required if detection and continuous monitoring of defects is to be achieved.

Stacey says that structural monitoring systems have been used on a number of offshore installations, but they are only being used on an as-required basis, and have not been adopted by the offshore industry in routine inspection. He added: "There is little guidance on the application of structural monitoring techniques." It's an industry not immune to structural failure. Stacey gave examples such as the short-lived Sea Gem rig in 1965, which was the first occurrence of fatigue offshore, resulting in 13 deaths. Next, there was the catastrophic failure of the *Alexander Kielland* semisubmersible drilling rig in 1980, which occurred in Norwegian waters, resulting in 123 deaths.

Stacey says the offshore lifecycle could be divided as follows:

1970 - 1990: The design, construction and installation phase for UK Continental Shelf (UKCS), with codes and standards developed (API, D.En/HSE Guidance Notes);

1980 - 2000: The operational phase, certification in the UK (until 1998), the safety case regime implemented from 1995, following *Piper Alpha*; in the US, reassessment for post-hurricane Andrew damage; the development of international ISO offshore standards;

2000: Life extension, decommissioning and re-use, aging installations institutions in the North Sea and the need to review post design life. More than 160 UKCS North Sea installations, over 60%, are now over 25 years old.

Lifecycle adoption

Stacey says there is a "bathtub curve," starting with early life failures, followed by a steady failure rate, then the wear out phase, pointing to a need to focus on structural integrity management throughout the lifecycle. This requires good data on current condition, and an understanding of degradation processes and structural response. The use of best technology/latest assessment- methods (e.g. system strength) is required to

The need for inspection

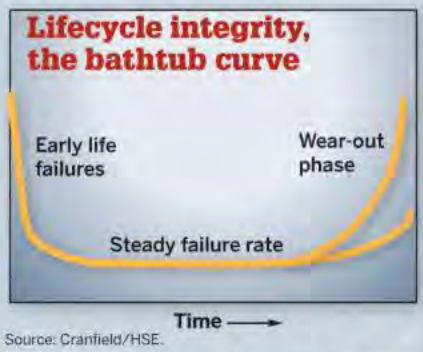
Earlier this year, Marathon Oil's North Sea business was issued with an improvement notice after its failure to inspect the integrity of an 8in high-pressure pipe on its Brae Alpha facility.

A failure in the pipe on 26 December 2016 resulted in an uncontrolled release of high-pressure hydrocarbon gas, causing significant damage to the surrounding area, according to a notice posted by the

determine safety margins, as well as the development of new techniques, such as online monitoring.

There have been lot of technological developments over the past decade. Some structural integrity monitoring techniques are suitable for localized operation, e.g. acoustic emissions and fatigue gauge, and some could provide global platform information, such as natural frequency monitoring, but are limited in capability to detect smaller defects.

Stacey points to the SIMoNET program – www.simonet.org.uk – a joint venture between industry and government organizations, managed by University College London and Cranfield University. It provides a forum for the exchange of information on structural monitoring techniques.



Source: Cranfield/HSE.


Remains of the *Alexander Kielland*, in 1980. Photo from unknown photographer/ Norwegian Petroleum Museum.

Measurement equals management

"If you can measure it, you can manage it," commented Karthik Subramanian senior engineer, ABS London, in a presentation on jackup motions monitoring for safety and operational efficiency.

Key performance indicators (KPIs) could be of use in monitoring rig moves. The KP lagging indicators, which show output results, are easy to measure, but hard to improve or influence. The KP leading indicators, which measure changes in input variables, are hard to measure, but easier to influence, he said. In terms of rig moves, the lagging indicators are the incident rate, and the leading indicators are measuring the hull motions and the sea states.

The hull motions can be captured with accelerometers mounted on the hull. The signals are sent to the onboard data acquisition system, then to signal processing onshore. The sea states can be measured using laser wave sensors mounted on hand rails. The wave elevation signals are then sent to the data acquisition system.

ABS is interested in jackup monitoring because most of the jackup fleet is classed under ABS. "We need our clients to operate safely," Subramanian said. "Basically, we want to bridge the gap between the sensor technology and rig move operations."

Almost 70% of the accidents for jackup units happen during a rig move, he said. The industry has developed a number of monitoring committees. The International Association of Drilling Contractors (IADC) jackup committee was formed 20 years ago. The International Organization for Standardization (ISO) formed Panel 54 working on the installation and retrieval process for jackup rigs. The underwriting community, the Society of Naval and Marine Engineers and ISO have both been developing standards for jackup units for site specific assessments and rig design for over 20 years.

Guidance due

ABS has prepared draft guidance notes on "Hull motions and monitoring systems for jackup units," which it intends to publish around June, once necessary approvals are in place. It will include performance specifications, recommendations, and methodology for data analysis, jackup modeling and analysis. Subramanian said that the guide will help sensor technology developers understand how they can bring their technology into the jackup unit, and how the jackup rig moves and operations can be made safer.

Real-time monitoring of marine conditions, vessel response, and structural integrity are key to managing operational risk and safety for offshore assets, particularly as operators move into deeper, more remote areas, said Robert J. Barker, business development – global sales and marketing, BMT Scientific Marine Services.

An integrated marine monitoring system provides both offshore decision support and the means for conducting long-term integrity assessment over the design life of the facility. It adds value and saves cost. Such systems have been successfully integrated into platform safety management programs. Real-time data is being used successfully to support operational risk and reliability programs. Archived data from marine monitoring systems is key for performing forensic and engineering analysis, he said. **OE**

UK's Health and Safety Executive.

It said Marathon had failed to remove the insulation of the pipework for inspection purposes since its commissioning in 1983, despite its own corrosion under insulation strategy, issued in 2014, which recommended the removal of this insulation at least every 12 years for inspection purposes.

Further, the firm had failed to act on findings from 2010 for the line. The findings instructed sample insulation removal of the pipework for inspection. A planned 2015 inspection of the pipework was also not carried out, the HSE said. "These failures exposed personnel on the Brae Alpha installation to an unacceptable risk of serious personal injury from fire and explosion," it concluded.

The backlog of safety critical maintenance work on the UKCS has been growing year on year since 2010, well before the current down turn. At the same time, efficiency has been falling. ■

FURTHER READING

Tackling the back log
With many assets now more than 25 years old, asset integrity is a daily concern on the UK Continental Shelf. Is the industry keeping up? **www.oedigital.com/drilling/item/11246-tackling-the-backlog**

A new lease on life

Scrap or refurbish and reuse? It's a question being asked on the UK Continental Shelf. Elaine Maslin reports.

At a recent conference in Aberdeen, a speaker made the comment that, after a long delay, decommissioning was coming "hard and fast" to the UK North Sea.

With a bill estimated at anything between £35 billion and £70 billion (US$50-$101 billion)*, it's going to be a costly job. New ways of working will be needed.

A step change is on its way, in the form of the single lift platform removal vessel the *Pioneering Spirit* (*OE*: April 2016). Yet, platform removal is not the only job involved in the decommissioning process. Processing all the structural material and equipment on a platform will also provide a massive amount of work.

To date, the industry has done a good job of recycling these materials. Currently, up to 98% by weight of materials from decommissioned platforms are recycled back into raw material at the end of their life, according to industry data.

But, recovery and reuse of components seems to be lower on the agenda, despite an established market in oilfield pipes and other drilling-related equipment. According to a report by the Royal Society for the Encouragement of Arts, Manufactures and Commerce, called The RSA Great Recovery & Zero Waste Scotland Programme, into North Sea Oil and Gas Rig Decommissioning & Reuse Opportunity, this approach would offer "significantly higher" inherent value than recycling.

The concept has been badged the "circular economy," where old products parts and materials are restored to be reused, resulting in lower use of resources.

According to a report by DecomWorld, the US Gulf of Mexico resale market is facing a different challenge. The market for refurbishment and reuse has dried up due to too many rigs coming offline.

Historically, used equipment such as compressors, generators, cranes and sometimes pressure vessels has been very marketable, it says. But, there have been so many more platforms removed versus installed since 2005 that the used equipment market tends to stay flooded.

But, reusing components or equipment might not be that easy. While drill pipe is, to a higher degree, fairly standardized, thus more suited for reuse, other oilfield equipment is not, and scrapping offers the more convenient route. A "shift in mind-set" is required, according to another report involving Zero Waste Scotland, ABB and Decom North Sea. But, players who are able to "connect the dots" between available inventory and potential buyers – outside and inside the industry – are also needed.

Barriers

There are barriers to reuse. To a certain degree it's simply uncertainty. To date, the decommissioning market in the UK North Sea has been few and far between, which has meant there's little scope to create a market.

There are also concerns about risks associated with using reconditioned materials, which may have been operating in extreme

Pipe, ready for reuse. Staff photo.

conditions, according to the RSA report. There is also a fear the equipment could be less reliable than a new item, so any cost saving would be lost in reduced efficiency or downtime and maintenance costs, says the Zero Waste Scotland report.

Using existing equipment might mean having to make compromises with a system design, and in certain areas (e.g. combustion equipment, pressure vessels, etc.) modern regulatory requirements may not be met by older equipment, resulting in reengineering requirements. Or the equipment may simply not offer the same functionality or effectiveness as modern equivalents, particularly when it comes to control systems, but also other items such a process equipment. This, and regulations, means older equipment is much more likely to be used on older facilities to extend life, says Dorian Hindmarsh, of UK-based Proeon Systems.

A further concern is liability. "Operators have been reluctant to release equipment on to the resale market. One reason for this was highlighted as a concern that some residual risk will remain with the resold or reused equipment," says the Zero Waste Scotland report. Operator's duty of care to trace all wastes returned to shore also adds a degree of uncertainty – at what point does their duty of care end?

Then, of course, there is the predisposition to engineer anew and buy new products, with bespoke designs to specific conditions, says the RSA report.

Some of the issues are around the difficulties in obtaining warranties and assurances, poor data management or knowledge about products being recovered, and even simply insufficient capacity to handle and process decommissioned facilities and lack of integration across the supply chain, says the RSA report. In other words, there's not yet a market for this stuff.

Potential

Other industries (including safety critical industries such as aerospace) have a significant reuse sector, particularly for spare parts, says Zero Waste Scotland, and they actively manage their old equipment with reuse in mind.

Indeed, within the upstream industry, there is an active market in reuse and resale of turbines, pumps and compressors, as well as pipe, with organizations already working in this area, such as Salvex and OilMac and Quipbase in Norway. OilMac lists connectors, winches, valves, BOP rams, cranes, spools and even new, unused lifeboats and production jumpers, presumably ordered and then cancelled. Quipbase has sold BOPs out of the North Sea to Mexico and a pedestal crane to a pipelay barge based in Sakhalin. It currently listed an unused 120-man offshore accommodation module. Salvex has similar inventory, as well as drill pipe, including even pedestal cranes from a North Sea platform, which may one day find another home. Concrete mattress reuse is also being looked at under a separate study.

While the Zero Waste Scotland study suggested just 9.9% of a northern North Sea platform could be reused, this is still nearly 10% of the facility that could return more value than it otherwise does.

An industry workshop by RSA identified 186 reuse propositions. The six considered to have the most potential for component and equipment reconditioning and reuse were:

- Steel sections from jacket and topsides
- Pipelines
- Anchor chains and cables
- Equipment reconditioning and reuse
- Vessels and tanks
- Accommodation blocks

Since being removed in 2011, Perenco's Welland platform topsides has been refurbished and re-installed offshore Cameroon as the Sananga 1 platform. Photo from Perenco.

- Winches

The Zero Waste Scotland report listed items identified by reuse specialists that could be reused:

- Power generation equipment
- Standalone process modules - glycol regeneration, desalination etc.
- Rotating equipment
- High-value or long-lead time fixed items
- Tubulars e.g. for piling

But, finding buyers for these items is the key. "With the scale of what is happening in the North Sea, you need a wider market than what Aberdeen can support," says Ben Williams, a surplus asset broker, Salvex. In fact, it's easier to sell some of the equipment outside the oil industry, sometimes simply because of the procurement processes, although some flexibility is starting to come in here under the current oil price, but also due to having to meet specific design criteria. "For a new $100 million, or $1 billion project they are not going to cut corners on a generator," he says. "There are a lot of opportunities for resale in other markets. It is just shifting the point of view, and finding an industry where it could have value.

The Maureen facility, part reused as a quayside foundation.
Image from Paroscientific, Inc.

"That is what Salvex does," Williams says. "We have stable markets like pipe. But, other items we have access to wider markets. It's just a case of joining the dots. We have interest from people from all over the world looking at items from different angles."

The RSA report agrees, saying the greatest potential for reuse would likely be into other industries. Zero Waste Scotland also points to demand for redundant power and process plants in markets in emerging economies such as India, China, Brazil and Africa. "Most equipment has a resale value, the challenge is to give long enough lead times in order to market and find the person or company who wants to buy," it says.

However, equipment for reuse also needs to have been identified early in the field's late life to make sure it's suitable for reuse and marketed as such. Removing it early in the decommissioning process would also help preserve it and clear space on the facility, the Zero Waste Scotland report points out.

And, it's still hard to resell equipment designed specifically for the oil and gas

industry, where reuse opportunities in other industries is hard to find.

Life goes on

There have been examples of entire platform reuse from the UK Continental Shelf. Perenco reused the Welland platform topsides on a new mobile offshore platform off Congo after it was decommissioned from the southern North Sea.

Statoil recently reached agreement with ConocoPhillips to reuse the complete topsides of the Huldra platform on a new development (subject to project approvals), according to the ABB Decom North Sea report.

Both of these platforms are relatively small (topsides weight; Welland, 1000-tonne, Huldra, ~5000-tonne; both unmanned installations). In the case of the Welland, significant reengineering and refurbishment was required, due to the time between cessation of production and removal, according to the report. However, this demonstrates that the concept of reuse at a platform level is economically viable, the report adds.

The Nenè platform, installed offshore Congo, West Africa by Eni, was a reused facility, too. It had previously been used for 10 years in the Gulf of Mexico. For Italian verification firm RINA, the key to full platform reuse is structural analysis, to make sure a facility will meet new site conditions to ensure in service life would meet acceptable safety levels.

In a decommissioning and reuse study for the Maureen steel gravity-based platform, Arup suggested the facility could be reused as piers for a bridge over deep water in Scotland, or converted into a heavy lift crane, or cut up and used in construction of new port structures. The platform was ultimately reused as the basis of a new quay at Aker Stord's facility in Norway.

According to a report by business consultancy PWC, platform jackets could be reused for offshore wind farm substations, LNG terminals or platforms for wind or solar generation. They could even be used for military use, fish farms, research centers, or, perhaps a little controversially, offshore high-security prisons. Topsides, it says, could be reused as temporary offices or accommodation onshore, or, left in situ, as an emergency training center.

PWC points out that platforms have already been reused as artificial biotic reefs in the US, Brunei, and Malaysia. Indeed, one jackup facility has been used as a hotel-recreational diving facility, and another as a restaurant, on the edge of Rotterdam. Again, where operator liability ends would need to be clearly set out.

Conclusion

According to the Zero Waste Scotland report, the offshore industry is starting to realize the benefit of aligning an asset's obsolescence strategy with the company's decommissioning strategy, which would help pave the way for equipment, which has been maintained, to be reused.

"Platform decommissioning, if managed in line with obsolescence work, can present an opportunity to identify and retain key critical spares for both internal use or for resale to other operators or industries," the report says.

"However, it requires a mindset change; decommissioning strategies should, ideally, be in place before carrying out asset life extension and in parallel obsolescence studies."

With little by way of legislation to encourage reuse, the focus on removal in the most convenient way, while meeting HSE could still prevail. OE

**According to Decom North Sea, UK Oil & Gas and estimates given at the 2015 SPE Well Abandonment Seminar in Aberdeen.*

Taking drillships to deeper

Ken Richardson and Ian Simpson, of ABS, review current deepwater drillship designs and technologies.

Friede & Goldman's DS3810 deepwater drillship design, which is being evaluated by ABS for AIP, is designed to drill in 14,750ft (4500m) water depth.
Image from Friede & Goldman.

Drillship designs have been in constant evolution since the first units appeared more than 50 years ago. While the industry has experienced ups and downs, investment has continued into developing deepwater assets with more and more advanced capabilities.

As a classification society, ABS provides third-party review of new or novel design concepts. Approval in Principle (AIP) is granted in acknowledgement that a proposed concept or design complies with the intent of ABS Rules and/or appropriate codes. Over the past three years, AIP has been awarded to a number of design concepts for ultra-deepwater drillships.

Expanding capabilities for HPHT environments

In 2013, ABS was selected to work with Keppel Offshore & Marine (Keppen O&M) on the *Can-Do* drillship, a proprietary design for deepwater exploration and development drilling and completions. The design was developed in a joint effort between KOMtech (Keppel O&M's research and development arm and technology center) and partner GustoMSC. ABS' scope of work included plan approval for basic and detailed design, including structure and stability assessments.

While most drillships in operation have been designed for exploration drilling, Keppel O&M listened to industry feedback that indicated the need for vessels capable of performing development drilling and completions as well. The innovative concept took the form of the *Can-Do* drillship, which is scheduled for delivery in 2016. When construction is completed, the *Can-Do* will be able to handle next-generation 20,000 psi blowout preventers. According to Keppel, the *Can-Do*'s large functional deck space will accommodate installation of the third-party equipment required for development drilling and completions. The drillship has a double blowout preventer stack integrated into the design and features a riser hold capacity for 12,000ft water (3660m) depth with the flexibility of storing either 75ft (23m) or 90ft (27m) long risers.

The drillship was model tested at the MARIN facility in the Netherlands, and the hull is being built at the IHI yard in Japan. Topsides and commissioning will be carried out at the Keppel FELS yard in Singapore.

Another relatively recent AIP went to Hyundai Heavy Industries (HHI) for its innovative HD12000 heavy duty, wide-beam drillship design. The vessel will be capable of operating in 12,000ft (3660m) water depths and drill to 40,000ft (12,000m) below the mudline. HHI describes the drillship design as "ready for 20 ksi" because it will be able to accept installation of a 20,000 psi deepwater BOP system.

Design features include a high-capacity derrick and derrick pipe setback, a high-capacity marine riser system and large associated buoyancy, a heavier and taller BOP stack, and storage, handling and piping systems that can support deepwater high-pressure operations.

The drillship's refined hull form, developed from the company's experience building merchant ships, will enable a transit speed of 11.5 knots. Additional hull features include integrated, high-efficiency thruster pods and a moonpool designed to reduce internal fluid motions and resistance. The new hull form, in combination with carefully chosen locations for the thrusters, will deliver improved transit speeds and station-keeping performance over previous units.

Capitalizing on size and efficiency

Like HHI, Friede & Goldman has been focusing on efficiency, concentrating its efforts on developing a number of designs that are particularly appealing options for a low-oil-price environment. Among these are the DS 3810 and DS 4500 drillships.

levels

The DS 3810 is designed for operation in 12,500ft (3810m) water depth with 40,000ft (12,000m) drilling depth capability. The DS 4500 is designed for 14,750ft (4500m) water depth and 50,000ft (15,240m) drilling. With a 37,000-tonne payload, a 6800sq m deck area and the capacity to accommodate 250 people onboard, both are designed for 90-day autonomy, which means they can work for three months in a remote location without the need for resupply. The functional layouts for drilling, stand-building, and BOP/Xmas tree handling incorporate space for advanced drilling techniques like managed pressure drilling and dual gradient drilling. The large moonpool, which is 141ft (43m) long, facilitates multiple operations.

Efficiencies are extended by the ability to carry out multiple functions simultaneously. A stand of drillpipe and top hole casing can be prepared while the unit is drilling, and rig moves can be accomplished with setback partially loaded. The design allows a BOP stack to be assembled, connected and tested while the rig is drilling using a separate BOP. The BOP stack can also be hung off while a Xmas tree is being deployed or while the vessel is moving to a new location. The drillship can carry two BOPs with the possibility of eight rams in a 15,000-20,000 psi BOP stack and can accommodate various drilling packages.

Another significant factor in this design is the focus on emissions. The units are fitted with integrated ballast water treatment and IMO Tier III low fuel-consumption engines. Enhanced power management capability reduces the drillship's impact on the environment and improves fuel efficiency.

Efficiency, reliability improved through ISQM

As control systems for offshore assets become increasingly more complex and highly integrated, successful implementation relies heavily on the software developed by multiple vendors and the many interfaces required for software integration. Verifying and validating these software packages and the ways they interact is essential to safe operations.

Integrated software quality management (ISQM) provides guidelines for managing software over the entire life cycle of an offshore asset. ISQM was first used by Rowan Companies in the construction of four high-specification ultra-deepwater drillships, the *Rowan Renaissance*, *Rowan Resolute*, *Rowan Reliance* and *Rowan Relentless* at the HHI yard in Ulsan, South Korea.

Rowan Companies stepped forward to apply the new systems, processes,

The *Rowan Renaissance*, completed in January 2014, was the first drillship in a four-vessel series built using ABS' ISQM process.
Image from Rowan Companies.

and technologies of ISQM on high-end GustoMSC P10,000 design units. The four vessels can drill to 40,000ft (12,000m) in 12,000ft (3660m) water depth. They are DP-3 compliant and have dual-activity drilling capability with a maximum hookload capacity of 1250 tons featuring three 100-ton knuckle boom cranes and one active-heave 165-ton crane for deploying subsea equipment. They are designed with a 4 million pound riser tensioning system, two seven-ram BOPs, incorporating full acoustic backup control, and five mud pumps with dual mud systems. The units have a variable deck load capacity of 20,000-ton and can accommodate 210 people.

Using the ISQM process gave the drilling contractor and yard a software development and maintenance tool that allows software verification to take place at the time of installation and provides a way to monitor for consistency and reliability when software updates or hardware changes are made over the asset's service life.

Because ISQM is a methodology, it requires no new equipment. The focus is on software and interface quality, with the goal of reducing the number of errors related to software and integration. In its first application on the *Rowan Renaissance*, completed in January 2014, ISQM facilitated the reliable integration of products from more than half a dozen major suppliers and more than 35 subsystems on a single drillship.

In its application on these four high-spec vessels, ISQM is helping to maintain system integrity and reduce the risk of safety, health and environmental incidents. It also makes it easier to manage operational and project risks, decrease NPT, review for compliance to specifications, manage programming challenges, simplify programming validation. ISQM makea it possible to identify and address challenges in a way that minimizes schedule and cost escalation.

LNG-fueled drillships

Another way ABS is involved in progressing innovation is through joint development projects (JDP). A recent example is the JDP with Daewoo Shipbuilding & Marine Engineering (DSME) that has the goal of delivering the world's first drillship fueled by natural gas. The plan is for fuel to be stored onboard as LNG.

The project will address challenges associated with safe storage and handling of LNG, bringing DSME's experience in LNG vessels together with ABS' technical standards and experience as a pioneer in the classification of drillship and advanced LNG technologies.

DSME's part of the JDP includes concept design, comparison between two types of LNG containment technologies and analysis of the vessel's fuel gas supply system, while ABS' role includes concept design review, basic engineering review and a risk assessment of tank spaces, access areas, fuel gas supply system and machinery spaces.

The project team sees the Gulf of Mexico as a key market for this unit because inexpensive US gas would allow operators to reduce running costs while also lowering emissions to meet the strict sulfur requirements in the North American emissions control area.

Innovating for tomorrow

Drillship designs will continue to evolve to meet the changing demands of the offshore industry. As innovation propels the offshore energy sector into new areas, services like AIP will continue to have value, helping to make sure safety and reliability keep pace as technologies emerge and mature. **OE**

***Ken Richardson** is executive vice president of Global Offshore Energy Development for ABS in Houston. He has been active in the marine and offshore industries for more than 30 years. Richardson leads the international technology business development team from the ABS Energy Corridor office in Houston.*

***Ian Simpson** is director of Offshore Technology and Business Development for the ABS Offshore Sector Team based in Houston. A 40-year industry veteran, he coordinates survey, engineering and R&D and commercial efforts at ABS. Simpson's experience encompasses marine and drilling operations, technical and regulatory support, new construction projects and existing unit maintenance and repair.*

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Drilling on a global scale

Weatherford's Snorre Lutnes examines managed pressure drilling applications across key regions.

MPD deployment. Images from Weatherford.

Once reserved as a last resort for wells defined as undrillable, managed pressure drilling (MPD) is swiftly moving from niche to mainstream use. MPD has demonstrated a strong track record over the past decade, mitigating well control risks while enhancing drilling efficiency and reducing costs. As a result, operators worldwide are recognizing its broad economic and technological value, especially in the high-cost and risky deepwater sector.

Increasingly, adoption of MPD has shifted from the installation of fixed structures to full riser integration, with MPD equipment being retrofitted onto existing rigs or designed into new builds. Making MPD a standard, integrated part of the rig enables operators to preemptively drill challenging deepwater wells safely and cost effectively. For example, operations in Brazil have called on MPD-capable rigs to drill exploratory and appraisal pre-salt wells.

A recent global survey conducted by Welling & Company on the outlook for MPD sampled the perspectives of nearly 150 national and independent operating companies, as well as drilling contractors, of varying size and scale. The study revealed that 79% of respondents associate MPD as having a high value offering due to its proven ability to eliminate lost circulation, increase wellbore stability, manage losses and control gas influxes. In regions where MPD adoption is more extensive due to inherent geological complexities, the value attributed to MPD rose to nearly 90%.

In another global study of 467 wells applying MPD technology from 2004 through 2015, Weatherford documented a steady increase in the number of global MPD wells and a shift in the type of operations in which the technology was used. Within the 467-well sample, 305 wells were in North America, providing a healthy framework from which to develop of a trend analysis for

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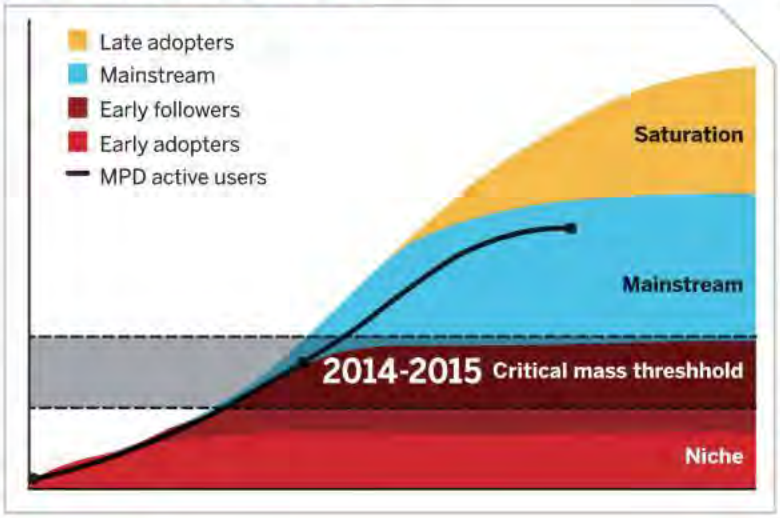
this region. This analysis helped define MPD application from 2004-2015 into three core categories—required, reactive and proactive. A description detailing each of the core categories can be found below.

1. Required: Wells/fields determined during planning to be undrillable without the use of MPD technologies.

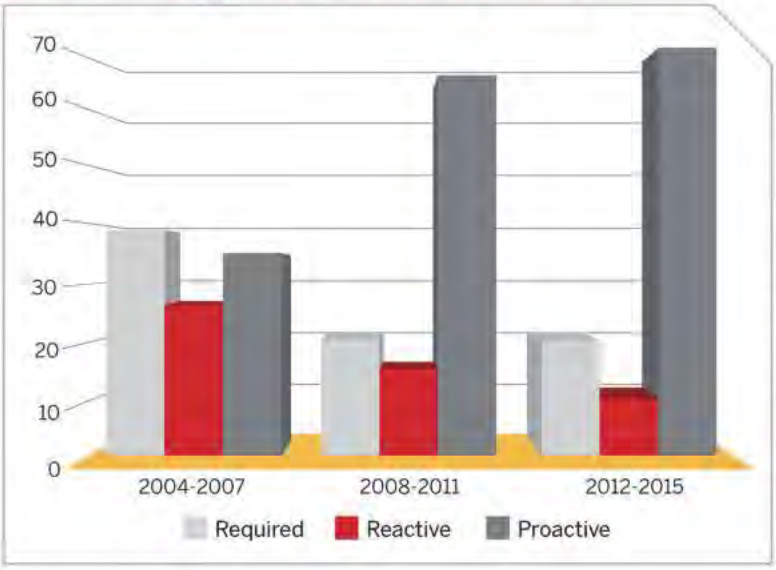
2. Reactive: Wells/fields experiencing unplanned events and deferring to MPD as a solution.

3. Proactive: Wells/fields where MPD is a standard service used to preemptively drill challenging wells and provide cost predictability.

MPD Adoption Curve



MPD development, North America



Global growth

Starting with North America, the study showed that MPD was used primarily for undrillable wells from 2004-2007, a category that stabilized at 20% from 2008-2015. The proactive category experienced continuous growth over the 12-year period and quickly overcame the required category as the main MPD driver, accounting for 70% of all study wells during 2012-2015. Meanwhile, the reactive category decreased gradually from 26% to 10%, yet another indication of the growing rate of MPD adopters.

These core adoption classification categories can also be used to understand the application of MPD across other regions as well. For example, Asia Pacific (APAC) is a major adopter of MPD techniques, due to a widespread need to practice the pressurized mudcap drilling (PMCD) variant of MPD in their predominately offshore operations. Operators in APAC primarily turn to this particular MPD variant as a way to enhance safety and drillability when drilling through total loss zones. For this reason, most MPD wells in this region fall into the required and/or proactive categories.

In the Europe and Caspian Sea (EUCAS) region, many MPD wells are in high pressure/high temperature (HPHT) environments with narrow drilling windows. The primary driver for adoption in this region, which began in 2009 and picked up steam in 2011, was to improve operational safety in these challenging environments. MPD reduces downhole uncertainty and provides the driller with more precise wellbore pressure management to control influxes before they approach a well control level. Further to this point, in 2009-2015 EUCAS experienced a trend of MPD wells that can classified in the proactive category.

Looking at Middle East and North Africa (MENA), another region with a large number of HPHT wells, the study depicts a similar initial trend as North America, with most wells falling into the required category. Sixty-eight percent of the recorded MENA MPD wells were drilled from 2013-2015.

Moving West to Sub-Saharan Africa (SSA) and beyond, many exploration and production companies are turning to MPD to overcome the geologic complexities inherent in the popular "Golden Triangle," a deepwater frontier consisting of Brazil's Santos Basin, the US Gulf of Mexico, and West Africa. In particular, recorded data for the SSA region dates from 2008, and shows more variety, with HPHT and PMCD wells on land and offshore. With HPHT wells becoming increasingly common as industry drills deeper and more complex reservoirs, it makes sense that the data would align accordingly to show that most of the SSA wells in the study were drilled in the past few years and fall into the proactive category.

Despite the industry's adverse economic climate, both studies demonstrate that operators and drilling contractors globally are continually seeking technologies that improve safety and operational efficiency, poising MPD to expand beyond deepwater and pre-salt frontiers and become a standard drilling practice in a variety of fields worldwide. **OE**

Snorre Lutnes *is regional engineering manager for Secure Drilling Services at Weatherford. In this role, he oversees the company's MPD services and engineers in Sub-Saharan Africa. He holds a Master of Science in petroleum technology, and has worked in the North Sea, the Gulf of Guinea, and the east Mediterranean before moving to his current office in Cape Town, South Africa.*

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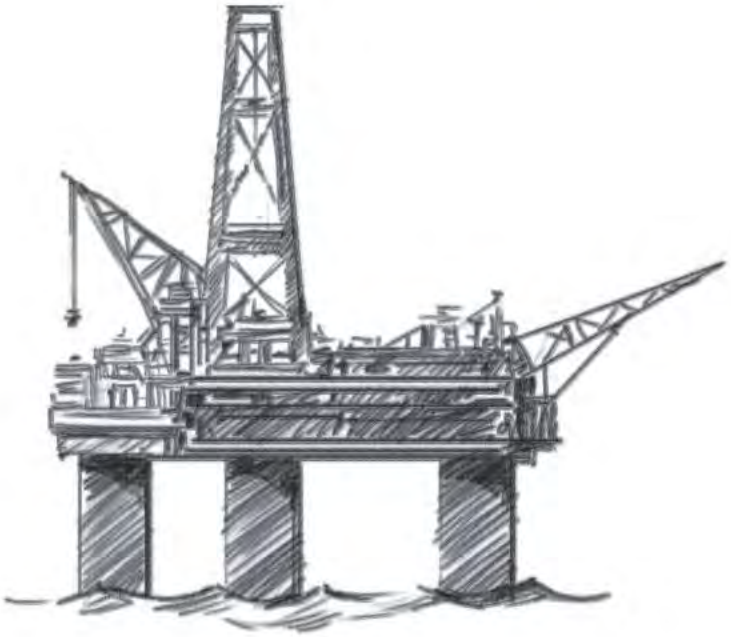

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Are cyber security risks

With big data also comes big risks to security. DNV GL's Nada Ahmed discusses how security standards can be raised within the oil and gas industry.

New IT infrastructures and technologies have modernized the way in which the industry manages operational assets, allowing operators to connect assets and previously isolated networks to operational technologies and enterprise information technology. Motivated by low oil prices and the need to overhaul costs and efficiencies, the industry is coming to terms with the large amount of data being generated and the unprecedented opportunities within big data and analytics.

However, concern is growing not only about how this data should be effectively used, but also how critical oil and gas cyber structures should be protected and safeguarded against the increasing scale and severity of cyber-attack. In addition to protecting data and information as seen from the enterprise IT point of view, it is vital to protect control systems and operation technologies for production and safety purposes. However, the new operational modes expose the industry to new vulnerabilities and threats. There are three key threats: theft of core intellectual property; disruption of a physical plant and other points of capital investment; and compromise of executives' communications about key business decisions. Direct threats can be a combination of malware and hacker tools or attacks from organized crime, rogue states and/or terrorist groups.

DNV GL's recent global research on the outlook for the oil and gas industry in 2016 revealed that the industry is cautiously moving forward to embrace the full possibilities of the new digital era. The principal barriers identified by the report include being able to retrieve and access data, and to ensure that the data is reliable and protected by a robust security system. When asked how advanced respondents were in digital adoption across the physical assets and operations, only 20% of senior oil and gas professionals scored themselves highly.

Developing a robust digitalized strategy

The low level of readiness in the industry can be attributed to the complexity of data produced and the lack of IT infrastructure needed to store and analyze large amounts of structured and unstructured information. Most of today's data is stored in fragmented systems, in various formats, and is not easily accessible to make timely decisions. To unleash the full potential of this data-rich reality, companies will have to aggregate data sets from various databases, standardize formats for easy analysis, and make it available to the right people for decision-making. It is therefore vital that companies implement a robust strategy to capture, manage and utilize critical data. Domain knowledge and technical competence is crucial to put data into practical use.

Advancements in industries like retail, logistics and the aviation sectors have shown the potential for efficiency and cost saving from data-centric decision-making. These industries have pioneered a culture that redefines the human and machine interaction. By closely monitoring the data being generated not only by machines but humans themselves, one is better able to link what were once perceived to be random events to particular outcomes, allowing for better and more accurate predictions.

The value demonstrated by these industries, along with the advent of open source movement, where software is made available for everyone to use or modify, has led to rapid developments in predictive analytics and machine learning technology. The innovation and methodologies developed in other industries can be easily applied to the oil and gas sector to quickly ramp up the IT infrastructure, increase connectivity and remove silos created by operators, equipment and system providers. An initial investment will be required to overcome the challenges posed by the status quo. However, benefits attained in the long run will be significantly greater.

Transforming caution into confidence

Besides the lack of infrastructure, another challenge highlighted in the interviews for a DNV GL white paper *'Industry Perspective: Digitalization in the Oil & Gas Sector,'* was trust in the data on which the industry is dependent. The interviewees revealed a varying level of faith in the data currently used. When data is fragmented and arriving from multiple locations, it needs to be properly sourced and aligned to a central data quality standard. Such standards

deterring digitalization?

Photo from DNV GL.

are lacking in the industry today and more work needs to be done to ensure that all stakeholders uphold the quality of data being transmitted by their systems. Systematic monitoring of data and frequent data quality checks will be needed to ensure that the quality of information is comparable to the impact of decisions informed by it. 'Health checks' to analyze current status can identify vulnerabilities and threats across the entire supply chain. This will allow the assessment and mitigation of risk once found.

Security will also be paramount for rapid adoption of new technology in the oil and gas industry. Field, reservoir and production data is incredibly business sensitive and operators demand uncompromising protection through rigorous security systems. Stringent security standards will be required to minimize security breaches and to enhance the flow of information within projects and with trusted partners. The DNV GL white paper found that although companies are actively managing their information security, just over half (58%) have adopted an ad hoc management strategy, with only 27% setting concrete goals.

> **"Stringent security standards will be required to minimize security breaches and to enhance the flow of information within projects and with trusted partners."**

Secure, reliable and safe cyber structures

Infrequent major cyber security attacks make the news, but there are many more attacks on a smaller scale that go undetected or unreported as many organizations do not know when a system has been infiltrated. The first line of attack is often the office environment of the oil and gas company, from where the hacker is able to work its way through the firewalls to the production network and process control and safety systems. For example, hackers may use social engineering attempts on office domains to harvest passwords and other ways to access production networks. While companies are realizing that information security cannot be ignored, a majority have still not implemented a coherent, strategic management approach, though some investments are being made. Success will depend on leadership and organizational culture that integrates information security in daily routines.

Cyber security vulnerabilities can be addressed through a live risk-based approach using the bow-tie model familiar in dynamic safety barrier management. This allows companies to identify the threats to and vulnerabilities of assets and operations and plan barriers to prevent incidents and mitigate the consequences of cyber risks. This includes procedures to maintain the barrier quality documented in performance standards. DNV GL applies its independent, risk-based approach to designing, implementing, testing, monitoring and maintaining cyber security countermeasures for customers worldwide. The company's software tool, Synergi Life – Risk Management Module, is used to establish a live asset and risk registry. This tool allows vulnerabilities and threats to be assessed and mitigations to be followed up.

Based on the high concern from the industry on cyber security, a joint industry project is being initiated by DNV GL with the aim to standardize cyber security requirements in the oil and gas industry.

The digital transformation is challenging the traditional business models employed in the oil and gas industry, and will introduce new forms of interaction between stakeholders. It will influence the competitive landscape by redrawing industry boundaries and create space for new disruptive companies that change the business landscape. However, the vast majority of industry leaders and decision-makers are still trying to grapple with the implications of the new data reality and may be wary of entrusting too much on data and predictive algorithms. However, players who are quick to embrace the transition will gain a unique competitive advantageas they gain better control of their operations and keep costs down in an increasingly demanding industry. OE

***Nada Ahmed** is a senior consultant working with information risk management at DNV GL in Norway. She has six years' experience in risk management and has recently been working on building the digitalization strategy for the oil and gas business through dialogue and pilot projects.*

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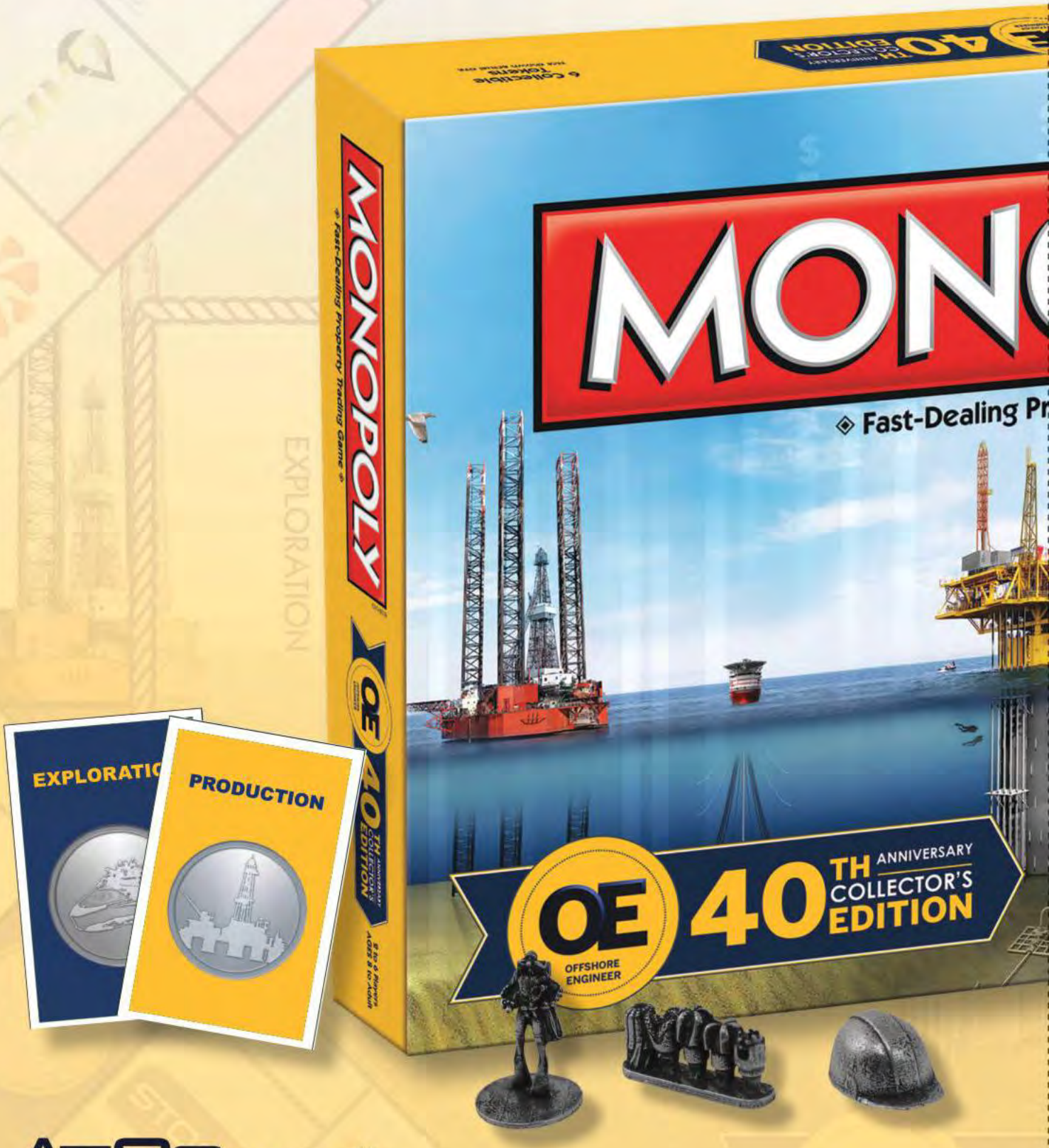

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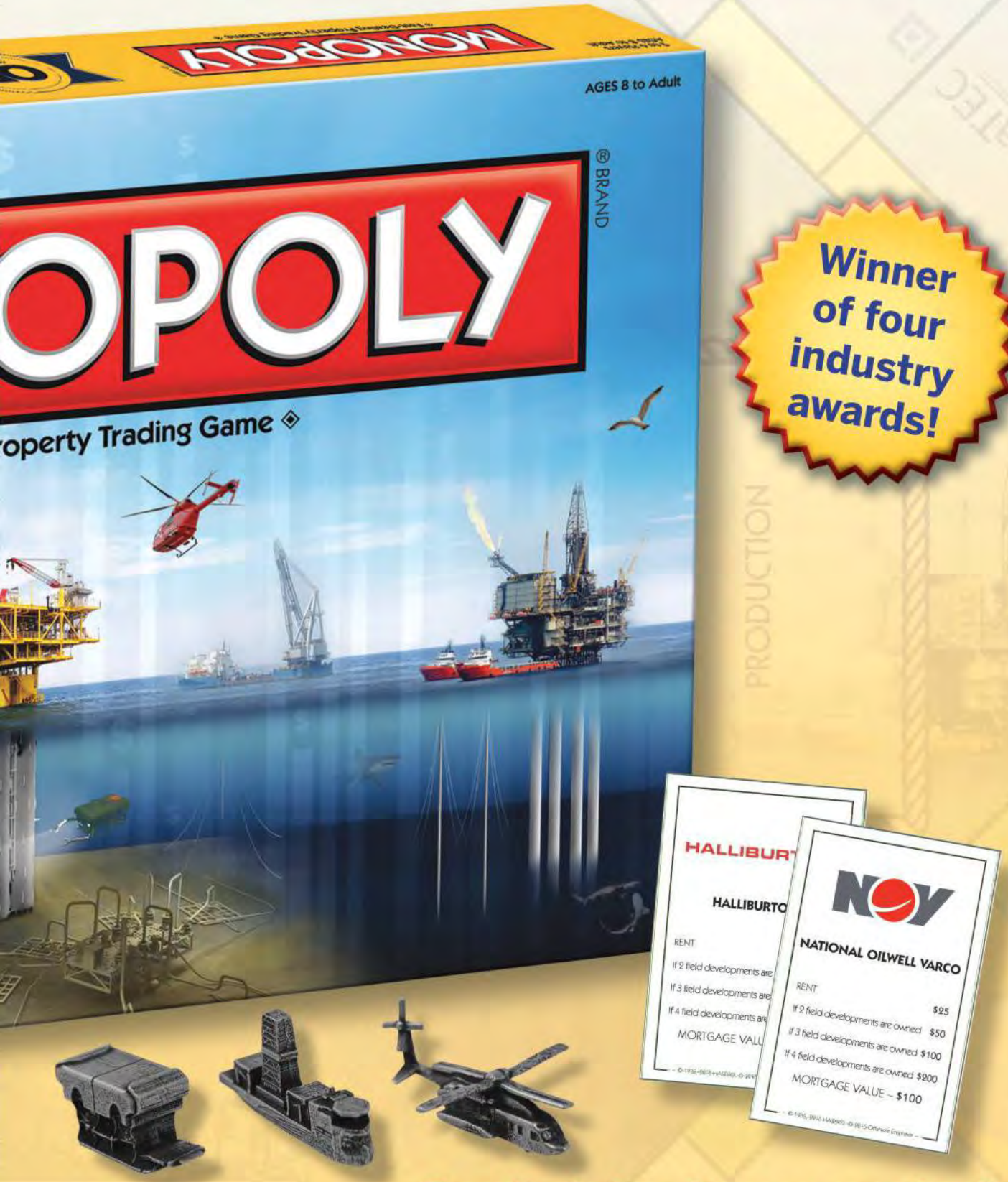

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Gulf of Mexico

Ready for prime time

Kory Kinney, of IHS, takes a look at some of the projects underway in the US Gulf of Mexico.

As we move through 2016, construction activity in the US Gulf of Mexico has begun dwindling. Previously sanctioned projects have started production and new projects are getting delayed as operators face the low commodity price market.

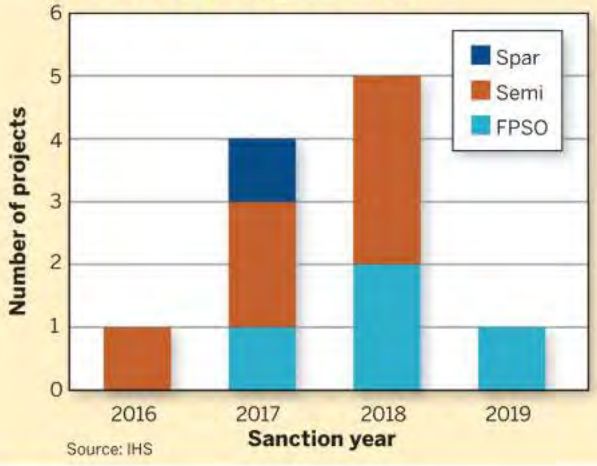
However, given the long life of offshore projects, the industry may see at least one large project in the region sanctioned this year. Subsea tiebacks are also expected to remain popular, with numerous greenfield and brownfield subsea tie-backs anticipated to come online in 2016. However, any project sanctioned this year will first have to make it past the cost-reduction measures being put in place by operators as they face the "lower for longer" oil price scenario.

In the past six months, several high-profile offshore projects have begun production, contributing to lower construction activity levels in the Gulf of Mexico (GoM). These include Noble Energy's Big Bend and Dantzler projects in the Mississippi Canyon area. Both fields were developed as subsea tiebacks to SBM Offshore's Thunder Hawk production facility and were brought online ahead of schedule. Big Bend came online late October, with Dantzler following shortly after.

Anadarko's Heidelberg development in the Green Canyon area has also come onstream. Production started at the facility on 14 January this year, ahead of schedule and under budget. The Heidelberg field was developed using a spar facility capable of processing up to 80,000 b/d with initial production through three subsea wells with plans to add two more. The Heidelberg spar is a twin to Anadarko's Lucius project, which came online in 2015 and is part of Anadarko's "design one, build two" strategy.

Looking forward, several more projects, both large and small, are anticipated to come online this year. One of the largest and deepest of these is Shell's Stones project, in the

Potential US Gulf of Mexico FPS developments



Source: IHS

Activity at a glance

by Sagar Das, EIC

The Energy Industries Council's project tracking database EICDataStream is currently tracking 85 active and future projects in the US Gulf of Mexico, in various stages of development, and the outlook for 2017 and beyond is positive.

Major developments

The Walker Ridge area is a hive of activity with first production expected at Shell's Stones field later this year. In anticipation of this, Shell is leasing a converted floating production storage offtake (FPSO) vessel for the development. SBM Offshore's FPSO *Turritella* will initially host two subsea production wells, although more wells are planned for future phases.

Also well underway is Hess' massive Stampede project, which will consist of two subsea drill centers tied back to a tension leg platform. The project is expected to produce up to

Walker Ridge area. At a depth of more than 9500ft, the Stones field is being developed using a floating production, storage and offloading (FPSO) vessel and associated subsea infrastructure. The *Turritella* FPSO, to be used to serve the field and supplied by SBM Offshore, will be the deepest operating FPSO in the world. At the time of writing, pipelay operations by Technip's *Deep Blue* pipelay vessel were underway at the development and production was anticipated to start mid-2016. The Stones field is estimated to contain more than 2 billion boe. The *Turritella* FPSO is the second use of an FPSO in the US GoM.

Another project slated to begin production mid-year is Walter Oil and Gas' Coelacanth project in Ewing Bank Block 834. Coelacanth is being developed with a steel jacket fixed platform in 1183ft water depth.

The *Turritella* FPSO for Shell's Stones Project. The vessel departed for the Gulf of Mexico from Singapore on 10 November 2015. Photo from Shell/Flickr.

Fixed platforms at depths greater than 1000ft are not often seen any more in the US GoM; the last steel jacket installed in water depth that deep was was Chevron's Petronius platform in 2000. The 30,000-ton Coelacanth platform was installed with Heerema's *Thialf* heavy-lift vessel in late November 2015, with the export lines for the project installed in January this year by Subsea 7.

Two tiebacks to LLOG's Delta House are also anticipated to come online this year. These are Deep Gulf Energy's Odd Job field in Mississippi Canyon Block 214 and LLOG's Otis field in Mississippi Canyon Block 79. Technip is due to install the flowlines for Odd Job in Q2-Q3 2016. Odd Job is a multi-well subsea tieback. Meanwhile, McDermott is handling the installation of umbilicals and flowlines for Otis and work is currently ongoing. Otis is expected online during 1H this year.

The only major project anticipated to be sanctioned this year is BP's Mad Dog Phase II. After significant cost cutting, BP anticipates the project to come in at less than US$10 billion, a more than 50% reduction from the 2011 estimated $22 billion.

Anadarko's Shenandoah project was expected to be sanctioned during 2016, but Anadarko recently indicated that no final investment decision (FID) will be made on the project in 2016, citing low commodity prices. Anadarko is currently deciding between a Technip-designed spar, similar to Lucius and Heidelberg, or a semisubmersible, from SBM Offshore, to serve the field. While 2016 will be a slow year for major project sanctions, there is still a glut of major projects in the pipeline for when operators feel comfortable to push ahead with new projects.

Floaters

IHS' FPSBase database, which tracks the supply and demand of floating production systems around the globe, suggests there is the possibility of 10 floating production system (FPS) based projects in the US GoM between now and 2019.

Among these projects are Shenandoah, possibly a spar development sanctioned in 2017; Shell's Vito, expected to be a semisubmersible production facility to be sanctioned no earlier than 2017; Repsol's Leon field, which is expected to be 80,000 b/d, starting in 2018.

Shell's Coulomb Phase 2 is a redevelopment of its producing deep water field, bearing both oil and gas, and includes the drilling of two wells. Meanwhile, Anadarko will soon increase production at its K2 field, due to its Riser Base Gas Lift project. Chevron's Jack/St. Malo Stage 2 project includes the addition of four production wells and associated subsea equipment.

Contractor activity

Technip remains very active in the gulf. The company was recently awarded lump-sum contracts for Deep Gulf Energy's Barataria and South Santa Cruz projects. As well as providing project management and engineering services for Deep Gulf Energy's Odd Job field, it is also manufacturing and installing the flowline and steel catenary riser. Technip is also supplying and installing major subsea equipment on BP's Thunder Horse South Expansion and Chevron's Blind Faith 2 subsea development.

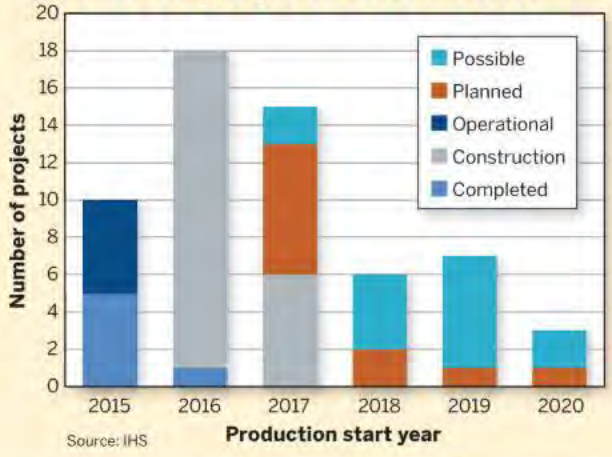
Future outlook for the region

Looking ahead, subsea tiebacks will continue to provide relief in the face of the economic downturn. This trend is set to continue in 2017, with a lot of tie-back activity expected to take place, notably at Freeport-McMoRan's Horn Mountain Deep and Horn Mountain Updip projects, LLOG's Taggart, Statoil's Yeti, and Noble's Katmai and Troubadour fields. ■

Sagar Das is the EIC's head of Oil and Gas. He is a Chemical Engineering and Chemical Technology graduate from Imperial College London with 24 years' experience in process engineering and software industries.

Gulf of Mexico

US Gulf of Mexico subsea projects 2015 – 2020



Source: IHS

Utilization and supply and demand of construction vessels

Source: IHS

an FPSO-based development, to be potentially sanctioned in 2018; and Chevron's Tigris hub, anticipated to be a semisubmersible tying together several northwestern Keathley Canyon discoveries and potentially due to be sanctioned in 2018.

However, the future of these projects remains undetermined while the industry grapples with the current downturn. All projects are expected to undergo rigorous evaluation and cost-cutting measures in order to make them economically viable. Operators will likely follow Shell's and BP's cost-reduction examples, seen at Appomattox and Mad Dog Phase II. Shell was able to shave 20% off the total cost of Appomattox through supply chain savings, design improvements, and reducing the number of wells required for the project; while BP was able to cut down the price tag for Mad Dog Phase II through renegotiating contracts, redesigning the work and capitalizing on market deflation.

Meanwhile, operators working in the GoM continue finding success with subsea tiebacks to existing infrastructure. Given the ample amount of already installed infrastructure in the region, fields are able to be developed with subsea tiebacks relatively quickly and at a lower cost than larger scale scopes. Evidence of this can be seen at Noble Energy's Big Bend and Dantzler fields, which came online three and two years after initial discovery, respectively.

Examining data from IHS' FieldsBase database, which tracks field development data for offshore fields worldwide, 17 green and brownfield subsea tieback projects are anticipated to start production in 2016, with one subsea project already online. Looking forward, subsea development schemes are anticipated to continue being a popular development concept in the region. However, due to the current commodity prices and other run-of-the-mill project delays, we may see first production from some of these subsea projects pushed to the right. Already some operators have delayed tendering processes with planned tiebacks, due to current uncertainty in the market.

Construction doldrums

With low levels of construction activity in the GoM, offshore construction vessel utilization is at an all-time low. While it is important to note that utilization of construction vessels typically falls during the first quarter of every year, due to weather, levels have not been this low since IHS started tracking utilization data in 2007.

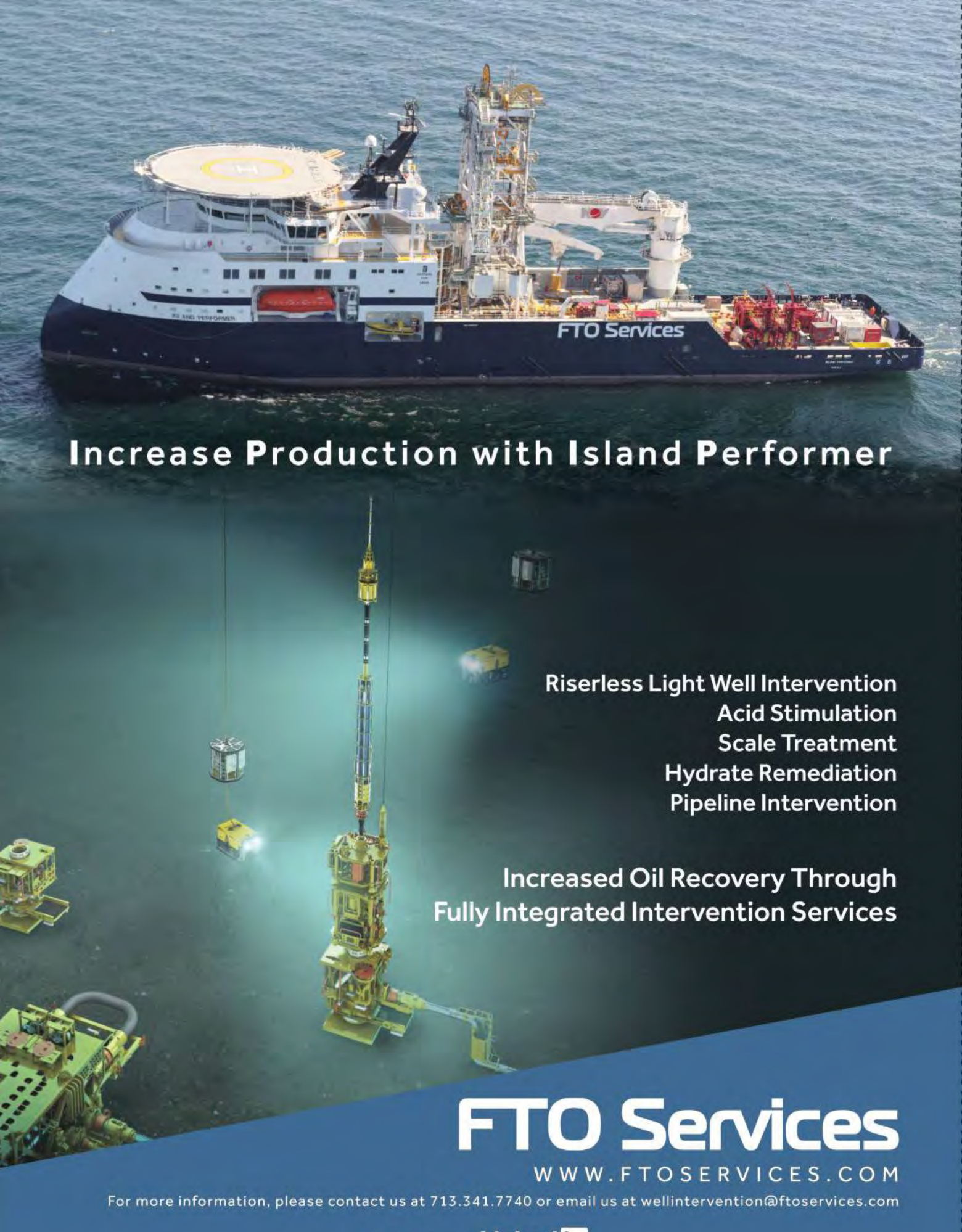
IHS' ConstructionVesselBase database, which tracks global construction vessel activity, shows there are currently 109 construction vessels in the US GoM and only 16% of them are currently being used. In ConstructionVesselBase, IHS classes construction vessels as accommodation; bury/trench; derrick; derrick pipelay; diving support; multiservice; pipelay; ROV support; support and well intervention.

Not only are seasonal patterns bringing down construction vessel utilization, but a lack of large projects is impacting the amount of installation work available for these vessels.

For 2016, it is anticipated that vessel contractors will be primarily focused on winning inspection, repair, and maintenance (IRM) and decommissioning work, a less cyclical type of work than installation work. Without an ample amount of alternative work for the regional supply of construction vessels, it is expected that construction vessels will start leaving the region as their owners increase bidding for work on the international market.

Although the current commodity markets introduce a lot of uncertainty into project schedules and future regional outlooks, the US GoM is poised to remain a concentrated area of activity for the foreseeable future. With 10 large scale floating developments expected to be sanctioned in coming years and numerous subsea tiebacks expected online, operators seem committed to projects in the US GoM. With an increased amount of projects, offshore contractors will enjoy greater utilization of their vessels. The only thing that remains to be seen is when exactly oil prices will pick up in order to help move these projects forward. **OE**

Kory Kinney *is a specialist at IHS based in Minnetonka, Minnesota. Kinney covers the North American offshore oil and gas construction market, focusing on field development activities from discovery, engineering, procurement, construction, installation and production phases. He is a managing editor for IHS FPSQuarterly report and provides content for the IHS publication Offshore Field Development Monthly.*



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Gulf of Mexico

Gulf of Mexico Deepwater Overview

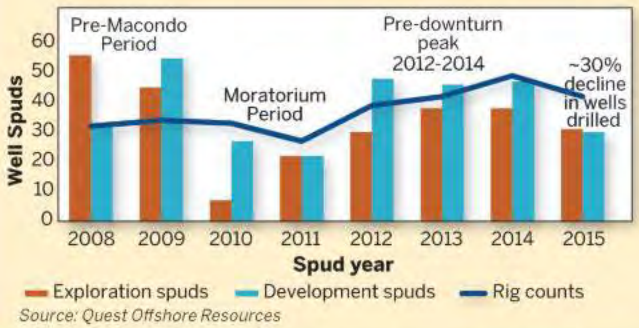
Quest Offshore assesses the drilling, subsea, and marine construction dynamics affecting of one of the world's pre-eminent deepwater basins amid the downturn.

The Gulf of Mexico has long been a region of critical importance to the global deepwater industry, both from the perspective of activity levels as well as the complex nature of executed projects in deep water lending to industry technology advancement. As the Gulf deepwater development remains affected by the global commodity price downturn, Quest Offshore will attempt to analyze market dynamics impacting the region from three vantage points: drilling, subsea, and marine construction.

Drilling

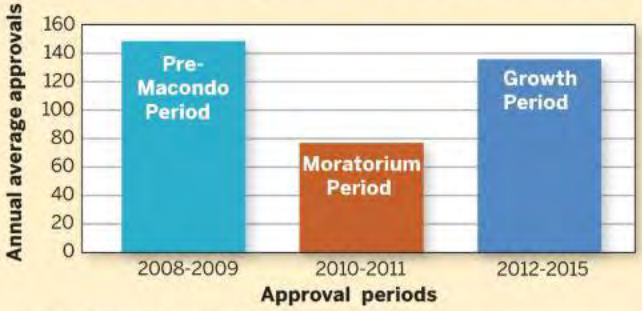
After three consecutive years of growth following the 2010 drilling moratorium, the deepwater US Gulf of Mexico is starting to show signs of weakness amid lingering low commodity prices. In 2015, new well spuds declined by nearly 30% compared to previous three years. From 2012-2014 an average of 80 new deepwater wells were spud annually, representing a nearly 50% increase over the previous two years. Operators, determined to get back to business, brought forth an arsenal of nearly 30 newbuild high-specification rigs designed to meet the most stringent safety standards and highest drilling efficiencies. By the end of 2015, only three new rigs were put into service and the number of units under contract had declined over 15%. Deferment of development projects and priority

Figure 1: Gulf of Mexico deepwater spuds and rig contracts



Source: Quest Offshore Resources

Figure 2: Gulf of Mexico deepwater spuds and rig contracts



Source: Quest Offshore analysis, US BOEM Data

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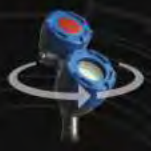

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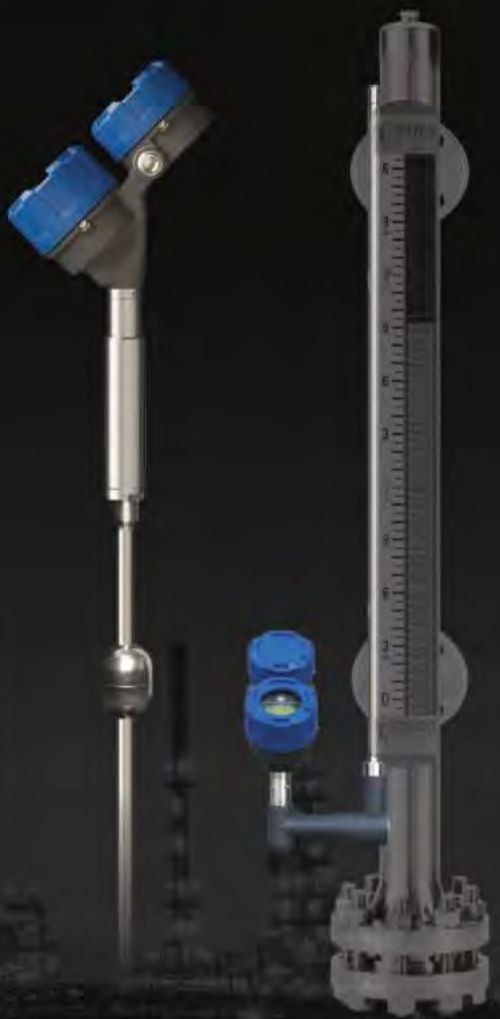

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Gulf of Mexico

Figure 3: Gulf of Mexico drilling operator anticipated activity profile

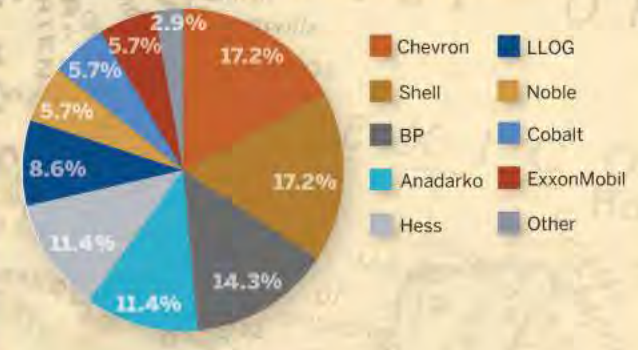
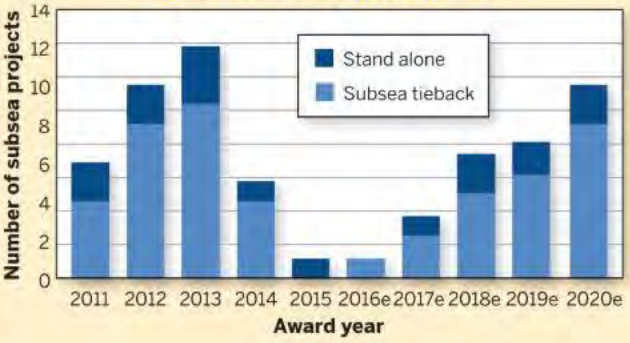
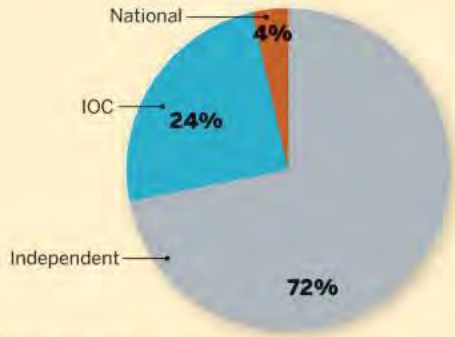


Figure 4: Anticipated Gulf of Mexico regional well demand, rig supply scenario

Figures 5-6: Subsea projects by scenario with operator type breakdown, 2011-2020e award years





Source: Quest Offshore Resources

towards lower risk exploration will have further impact on 2016 drilling counts, and forecast well demand is expected to remain 20-30% below the peak period of 2012-2014 through this decade.

In contrast to the visible decline in activity, what's happening behind the scenes would indicate that operators remain optimistic about their future endeavors in the deepwater Gulf of Mexico. Permit approvals for well in water depths ≥500ft have nearly reached pre-Macondo levels.

Currently five operators are responsible for 60% of the wells underway and 65% of the rigs contracted: Shell, Chevron, BP, Anadarko, and Hess. Operators expected to account for ongoing incremental activity include: LLOG, Cobalt, Noble Energy, Deep Gulf Energy, and ExxonMobil. Previous players of important significance who are expected to reduce activity or exit deepwater include: Stone Energy, Murphy, BHP Billiton, Eni, Statoil, Freeport-McMoRan, ConocoPhillips, and Marathon.

Well demand is forecast to drop again in 2016 and remain below peak 2012-2014 levels through the remainder of the decade. As the year progresses a stability, or lack thereof, in oil prices will dictate the outcome of 2017 exploration and production budgets. Cut backs to programs in the near-term will send more rigs ashore to wait out the downturn resulting in a tighter supply-demand scenario by the end of 2017. With day rates now near the bottom, operators will have an opportunity to resume drilling at a much lower cost than during the peak period once oil prices stabilize. These key factors will set the stage for a return to activity growth late in the decade.

Subsea

The Gulf of Mexico continues to prove itself as a dynamic deepwater basin within the global subsea market. Not only does it have an extensive supply base along the Gulf coast, but the diversity of the demand is unique among other deepwater regions. The area has a strong mix of independent oil company and international oil companies that, for the most part, focus on different project profiles and as such provide the supply chain with high variety in award opportunities. Independent-led subsea tiebacks will continue to dominate the region's preferred development scenario, which, during less trying times, leads to a larger pool of potential work for the supply chain.

International oil companies have established the majority of the floating production infrastructure in the Gulf of Mexico and continue to evolve that into deeper waters over time. This demand is cyclical depending on operator priorities and thus leads to high degrees of variability in floating production demand where subsea hardware and service demand is far more consistent. Chevron, Shell, and BP continue to be leaders in floating production potential demand as they focus on larger reserve potential in more frontier areas of the region.

We have observed a re-definition of the typical independent oil company in the Gulf of Mexico over the past 15+ years. Prior to the 2009 down cycle, the region saw a higher concentration of smaller independent oil companies (IOCs) taking advantage of the high natural gas prices via fast-track subsea tiebacks. Once the natural gas price plummeted and oil prices started recovery, we saw larger profile independent oil companies taking an apparent larger and longer investment stance in the Gulf. We

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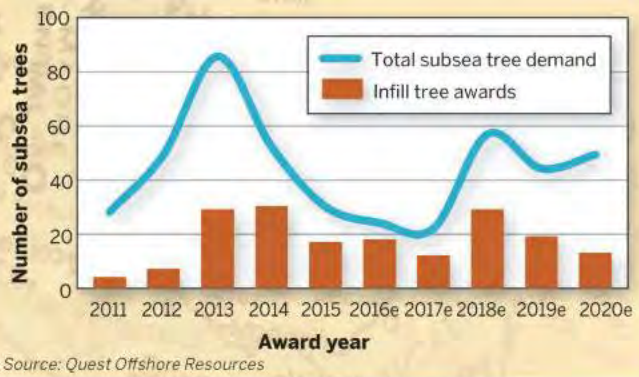
Gulf of Mexico

Figure 7: Subsea tree awards: infill versus total demand (2011-2020e mean case)



Source: Quest Offshore Resources

saw the likes of Freeport-McMoRan and Stone Energy buying older IOC-owned floating production hubs with plans for infrastructure-led drilling to boost and maintain production. In general, the role of these independent oil companies in the region is to develop the marginal fields, which do not fit into the profile of the IOCs, and utilize the well-established network of third-party development infrastructure.

In terms of subsea tree demand, the Gulf of Mexico represents ~15% of total global subsea tree awards. Infill tree orders have been an increasingly more important component of the foundation of demand not just in the Gulf of Mexico, but globally. As IOCs floating infrastructure ages, adding more development wells and ordering additional subsea trees, is a cost effective solution to growing and maintaining production levels. The same is true of independents who have acquired older assets from IOCs. Infrastructure-led drilling around these assets as a means of increasing oil recovery is relatively inexpensive, realize a faster cycle time, and can require less ancillary hardware and equipment to reach first oil. This strategy has proved a successful addition to operators' options for extending the life of field.

Marine construction

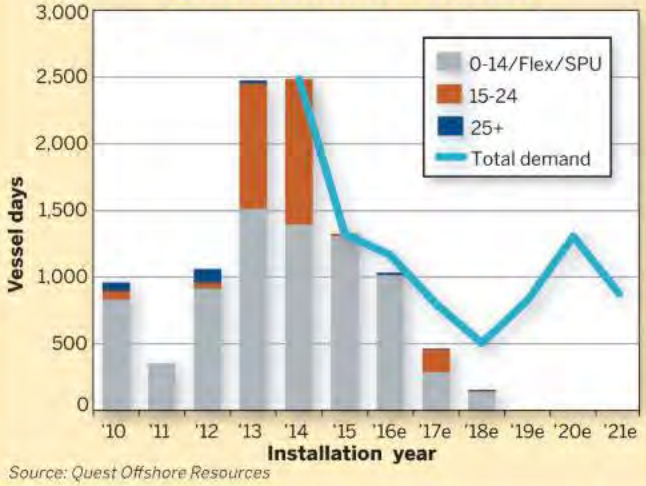
The Gulf of Mexico has seen depressed installation levels in 2015 and this is expected to continue through 2018 after elevated installation activity in 2013 and 2014. Lucius and Jack/St. Malo export lines were the main contributors to the spike in installation activity for 2013 and 2014 as well as other large projects such as the Keathley Canyon Connector, SECKO pipeline and exports serving Big Foot and Delta House. Quest Offshore expects installation activity to begin recovery in 2019 with the forecasted installation demand largely composed of pipeline infrastructure for developments such as BP's revamped Mad Dog Phase 2 and Hopkins development, Shell's Appomattox, Hess' Stampede and Pemex's Lakach deepwater Coatzacoalcos project. The region

is expected to have approximately 3200km of pipeline and umbilical installation demand for the period of 2016-2021, accounting for only 11% of the global total. This is a function of both the depressed overall market as well as cyclicality in the region due to the installation of large exports for new hubs in remote areas.

As of March, there are currently 34 vessels being tracked by Quest in the Gulf of Mexico. By category, there are six multipurpose construction vessels, 10 field support vessels, three deepwater pipelay vessels, three derrick pipelay vessels, two Intervention vessels, four reel-lay vessels and one heavy-lift vessel in the Gulf of Mexico. Vessels expected to remain in the Gulf of Mexico throughout 2016 include *the Deep Blue, Normand Clipper, Normand Pacific, Q4000, Q5000, Harvey Deep Sea, Olympic Boa, Siem Stingray, Ocean Alliance* and the *REM Installer.* Several of the mentioned vessels are performing work scopes such as subsea maintenance, repair and hardware installation including jumpers, umbilicals, and production trees and flying leads under master charter agreements. It is expected that some of the vessels currently occupying the Gulf will mobilize to the Africa Mediterranean region as installation activity ramps up in the region.

Current market conditions both create opportunities for operators looking to execute projects at reduced cost as well as lead to hope that the retirement of older assets coupled with a future recovery will lead to a balanced market. Although installation activity is depressed relative to previous quarters due to the cyclical nature for the region, there is still opportunity for small tiebacks, IRM work and call-offs in a spot market. OE

Figure 8: Gulf of Mexico construction vessel demand forecast



Source: Quest Offshore Resources

Caitlin Shaw *is the senior director of market research and the data division for Quest Offshore Resources. She graduated from Texas A&M University Galveston in 2003 with a BS in marine biology. During her tenure at Quest she has held various strategic positions of increased responsibility leading to senior director in 2013.*

Gulf of Mexico

***OE* presents a deepwater Gulf of Mexico primer compiled by Quest Offshore.**

Recent Onstream (2014 to mid-March 2016)

Project name	Operator	Startup year	Block	Water depth (feet)	Development concept	Subsea well count	FPS type	Host facility / field
Tubular Bells (tieback to Gulfstar)	Hess	2014	MC682, MC725, MC726	4401	Subsea tie-back (SSTB)	8	N/A	Gulfstar Hub
Jack St. Malo Regional Hub	Chevron	2014	WR715 WR718 WR758 WR759	7204	Standalone	12	FPS-semi	Jack St. Malo Regional Hub
Mars B - Olympus	Royal Dutch Shell	2014	MC807	3101	Standalone	Dry tree TLP	TLP	Mars B - Olympus
Thunder Horse North Water Injection	BP	2014	MC776, MC777	5642	SSTB	3	N/A	Thunder Horse South MC778/822
Dalmatian, Dalmatian North	Murphy Oil	2014	DC 48, DC 4	5826	SSTB	2	N/A	Petronius
West Boreas/ South Deimos	Royal Dutch Shell	2014	MC762, MC806	3151	SSTB	6	N/A	Mars B- Olympus
Cardamom Deep	Royal Dutch Shell	2014	GB 427	2691	SSTB	5	N/A	Auger
West Pinto (Main Pass)	Stone Energy	2014	MP 314	276	SSTB	2	N/A	MP 311 fixed platform
Glider Green Canyon Phase 2	Royal Dutch Shell	2014	GC 248	1149	SSTB	4	N/A	Brutus TLP
Gulfstar Hub (Tubular Bells, Gunflint Host)	Williams	2014	MC768	4401	Standalone	0	Spar	Gulfstar Hub (Tubular Bells, Gunflint Host)
Cardona / Cardona South	Stone Energy	2014	MC29	2297	SSTB	2	N/A	Pompano
Main Pass MP 138	Freeport-McMoRan	2014	MP138	148	SSTB	2	N/A	MP fixed platform
Kodiak	Deep Gulf Energy	2015	MC727	4923	SSTB	1	N/A	Devils Tower
Lucius	Anadarko Petroleum	2015	KC875	7089	Standalone	8	Spar	Lucius KC875
Hadrian South	ExxonMobil	2015	KC964	6892	SSTB	2	N/A	Lucius KC875
Delta House Marmalard, Sob II, Neidermeyer	LLOG	2015	MC79, MC208, MC209, MC253, MC255, MC258, MC300, MC431	5842	Standalone	10	FPS-semi	Delta House
Big Bend (Rio Grande Complex)	Noble Energy	2015	MC698	7204	SSTB	1	N/A	Thunder Hawk MC734, 736
Dantzler (Rio Grande Complex)	Noble Energy	2015	MC 782	6584	SSTB	2	N/A	Big Bend (Rio Grande Complex)
Dalmatian South	Murphy Oil	2015	DC 134	6397	SSTB	1	N/A	Dalmatian, Dalmatian North
Heidelberg	Anadarko Petroleum	2016	GC 859	5310	Standalone	6	Spar	Heidelberg

Awaiting startup

Project name	Operator	Startup year	Block	Water depth (feet)	Development concept	Subsea well count	FPS type	Host facility / field
Stones Phase 1	Royal Dutch Shell	2016	WR508	9505	Standalone	8	FPSO	Stones Phase 1 WR508
K2 Complex Phase 2 (EOR)	Anadarko Petroleum	2016	GC561, GC562, GC563, GC605, GC606, GC607, GC518	4047	SSTB	1	N/A	Marco Polo Green Canyon 608
Gunflint (Freedom)	Noble Energy	2016	MC948	6105	SSTB	2	N/A	Gulfstar Hub
Jack St. Malo Phase 2	Chevron	2016	WR758 WR678	7204	SSTB	10	N/A	Jack St. Malo Regional Hub
Julia	ExxonMobil	2016	WR584, WR540	7089	SSTB	6	N/A	Jack St. Malo Regional Hub
Who Dat Phase 3	LLOG	2016	MC503, MC504, MC547	3118	SSTB	3	N/A	Who Dat (Appaloosa)
MC 344	Stone Energy	2016	MC344	5908	SSTB	2	N/A	Pompano
Amethyst	Stone Energy	2016	MC26	1477	SSTB	2	N/A	Pompano
Taggart	LLOG	2016	MC816	5530	SSTB	4	N/A	Devils Tower

Continues »

Awaiting startup (continued)

Project name	Operator	Startup year	Block	Water depth (feet)	Development concept	Subsea well count	FPS type	Host facility / field
Holstein Tiebacks (Holstein Deep)	Freeport-McMoRan	2016	GC645	4267	SSTB	3	N/A	Holstein
Medusa SSTB	Murphy Oil	2016	MC538, MC582	2002	SSTB	2	N/A	Medusa
Oddjob	Deep Gulf Energy	2016	MC 214, MC215	5803	SSTB	2	N/A	Delta House
Cardona / Cardona South Phs 1A Infill	Stone Energy	2016	MC29	2297	SSTB	1	N/A	Pompano
Coulomb Phase 2	Royal Dutch Shell	2016	MC657	7549	SSTB	2	N/A	Na Kika MC474
Otis	LLOG	2016	MC79	3929	SSTB	2	N/A	Delta House

Pending/construction

Project name	Operator	Startup year	Block	Water depth (feet)	Development concept	Subsea well count	FPS type	Host facility / field
Llano Phase 2 Garden Banks	Royal Dutch Shell	2017	GB386	2701	SSTB	4	N/A	Auger
Holstein Tiebacks (Holstein Deep) Phase 2	Freeport-McMoRan	2017	GC599	4267	SSTB	4	N/A	Holstein Tiebacks GC645 (Holstein Deep)
South Santa Cruz	Deep Gulf Energy	2017	MC563	6551	SSTB	1	N/A	Blind Faith
Caesar Tonga II Infill	Anadarko Petroleum	2017	GC726, GC727, GC771	4697	SSTB	4	N/A	Caesar / Tonga / West Tonga
Oregano Infill Phase 2 (Star Program)	Royal Dutch Shell	2017	GB559	3400	SSTB	2	N/A	Auger
Big Foot	Chevron	2018	WR29	5002	Standalone	Dry Tree TLP	TLP	Big Foot WR29
Stampede (Pony & Knotty Head) Phase 1	Hess	2018	GC468, GC512	3502	Standalone	9	TLP	Stampede
Horn Mountain Nw Field Extension	Freeport-McMoRan	2019	MC126, MC127	5422	SSTB	3	N/A	Horn Mountain
Appomattox (Norphlet Play)	Royal Dutch Shell	2019	MC391, MC392	7224	Standalone	13	FPS-Semi	Appomattox
Hadrian North	ExxonMobil	2019	KC919	7319	SSTB	4	N/A	Lucius
King Phase 2	Freeport-McMoRan	2019	MC85	5402	SSTB	3	N/A	Marlin
TVEX (Tahiti Vertical Expansion)	Chevron	2019	GC596, GC597, GC640, GC641	4234	SSTB	2	N/A	Tahiti

Near-term potential (estimated scenarios)

Project name	Operator	Startup year	Block	Water depth (feet)	Development concept	Subsea well count (estimate)	FPS type	Host facility / field
Crown & Anchor	LLOG	2017	VK959	4280	SSTB	4	N/A	Ram Powell
Barataria	Deep Gulf Energy	2017	MC521	6774	SSTB	2	N/A	Blind Faith
Atlantis Phase 2B	BP	2018	GC699, GC700, GC743, GC743, GC744	7076	SSTB	3	N/A	Atlantis/Atlantis South
Troubadour (Rio Grande Complex)	Noble Energy	2018	MC 699	7276	SSTB	4	N/A	Big Bend (Rio Grande complex)
Ourse	LLOG	2018	MC 895	4093	SSTB	3	N/A	Mars B - Olympus
Kaikias	Royal Dutch Shell	2019	MC 768	4470	SSTB	4	N/A	Ursa
Hopkins	BP	2019	GC 627	4418	Standalone	6	FPS-Semi	Hopkins
Vicksburg (Norphlet Play)	Royal Dutch Shell	2020	DC353, DC393, DC397	7503	SSTB	6	N/A	Appomattox
Mad Dog South Phase 2 (Mad Dog 2 Semi)	BP	2020	GC826	5100	Standalone	24	FPS-Semi	Mad Dog South Phase 2 (Mad Dog 2 semi)
Vito	Royal Dutch Shell	2020	MC984	4040	Standalone	15	TLP	Vito MC984
Phobos	Anadarko Petroleum	2020	SE39	8569	SSTB	6	N/A	Lucius KC875

Notes

Project Status Groupings oriented toward subsea production system status
Project listings isolated to United States Gulf of Mexico
Standalone' notes a project with its own dedicated floating production system
Subsea Tie Back' notes a subsea-only project that is intended to produce to a floating production system or fixed platform elsewhere
Subsea Well Count: Dry Tree TLP notes a project that does not use subsea completions but features surface production trees
TLP = Tension Leg Platform

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Learning to be lean in the subsea sector

John Bradbury speaks with ExxonMobil's Marilyn Tears ahead of her presentation at this year's Underwater Technology Conference in Bergen, Norway.

Marilyn Tears has already made her mark in the offshore energy sector as senior project manager for the ExxonMobil-operated Julia deepwater development in the US Gulf of Mexico (GoM), which is due to start production this year.

Julia was discovered in 2007 and with an estimated 6 billion bbl of oil in place in the Walker Ridge area of the US GoM, the field is being developed at an investment cost of more than $4 billion. The initial development phase includes six wells tied back subsea to the Chevron-operated Jack/St. Malo semisubmersible floating production unit (FPU).

After that challenge, in April 2015 Tears took on a new role as Safety, Security, Health and Environmental manager for ExxonMobil Development Co. It is that health, safety and environmental (HSE) perspective that she will share at this year's Underwater Technology Conference (UTC) in Bergen in June. The conference theme will be "Lean subsea – the way forward."

"How we manage and lead health, safety and environmental issues sets the stage for how we manage all other aspects of business in the subsea sector," Tears says. "We often see HSE as a predictor of cost, schedule and quality performance. HSE can serve as a bonding point for establishing relationships that lead to higher levels of trust and teamwork in every part of the business. This is why excellence in HSE is important through the entire life-cycle of subsea projects."

Marilyn Tears

Tears continues: "Development teams need to think through all aspects of HSE and understand the implications for design, manufacturing, installation, operations, maintenance and abandonment. HSE design solutions that are both excellent and fit-for-purpose will ultimately reduce cost across the life-cycle of subsea equipment. Focus on structure and consistency for work execution is not only key to improving safety, reliability and quality, but it will also remove execution variability, which therefore reduces rework and extra costs," she adds. "There have been many scientific studies that conclude improving safety and quality leads to improved cost control."

And at this year's UTC, Tears will expand on the theme of leaner operations: "Being 'lean' is about creating more value for customers with fewer resources. A lean organization understands customer value and focuses its key processes to continuously increase that value. By eliminating efforts that do not add value to customers, costs will be reduced," Tears states. "Looking at technologies across a system to reduce waste in the entire system with multiple vendors will improve value to customers. To become leaner, it is important to focus on the high-risk areas as they drive execution uncertainty. Teams that gain clarity around what is required to address these high-risk areas are rewarded with improved performance."

Specifically on cost, Tears says the industry needs to work "appropriately and collaboratively to figure out how to get leaner and adapt to meet market and industry development needs. We must continue to use lessons learned to improve performance and support new challenges of higher pressure and deeper water depths. Leveraging learnings from others contributes to identifying risks, as well as potential savings."

Tears advocates the use of creative thinking when adapting the deployment of common components in different configurations, which may provide lower cost alternatives to unique, purpose-designed and built solutions. Additionally, industry focus on how to use subsea technology to enable alternative subsea solutions to save costs over traditional surface solutions may bring "leaner" development options.

Industry standardization has already been embraced by the subsea sector, despite its relatively short history, and Tears believes that real inroads have been made. "A good example is the Det Norske Veritas (DNV) Subsea Forging Standard that has recently been published," she says. "There are additional joint industry projects progressing efforts in the areas of subsea quality, subsea welding standards, documentation, topside control systems and electrical

power systems." The International Association of Oil & Gas Producers (IOGP) is beginning an effort to standardize designs for the four primary types of subsea trees used in the world today. "I am proud to say that ExxonMobil has played key leadership roles in many of these initiatives to date," she adds.

The DNV Subsea Forging Standard provides a recommended practice for steel forgings for subsea applications and was developed with 21 companies – operators, contractors and manufacturers in a joint industry project, and sets out qualification, manufacturing and testing requirements for carbon and low alloy steel forgings. DNV said the recommended practice allows less equipment lead time, better stock-keeping and interchangeability of forgings, while improving and maintaining quality.

Although none of the recent standardization work was available for the Julia development, Tears says, ExxonMobil developed standard part numbers with several suppliers on a concentric, monobore vertical tree design, which was used for both the Hadrian South and Julia projects. "ExxonMobil's 'Universal Master Control Station' was also used for the first time on Julia, and is the precursor of standardized subsea and topside controls interfaces," Tears adds. "In the future, subsea controls may be nothing more than a node on a conventional topside (or onshore) process control system."

> **"Being 'lean' is about creating more value for customers with fewer resources."**

Looking ahead, Tears says, "ExxonMobil will continue to focus research and development efforts on supporting our portfolio outlook in challenged resource development areas, and capturing capital expenditure savings associated with infrastructure reductions for offshore opportunities. ExxonMobil has recently qualified subsea processing technologies in the areas of compression, subsea separation and subsea water treatment." Tears says, "We support further work to extend these technologies to include potential applications for wet gas compression, high pressure boosting and long-distance subsea power distribution and transmission." According to Tears, ExxonMobil has begun researching subsea gas dehydration, and it is evaluating opportunities to marinize ExxonMobil's proprietary compact dehydration technology, cMist, for subsea gas fields."

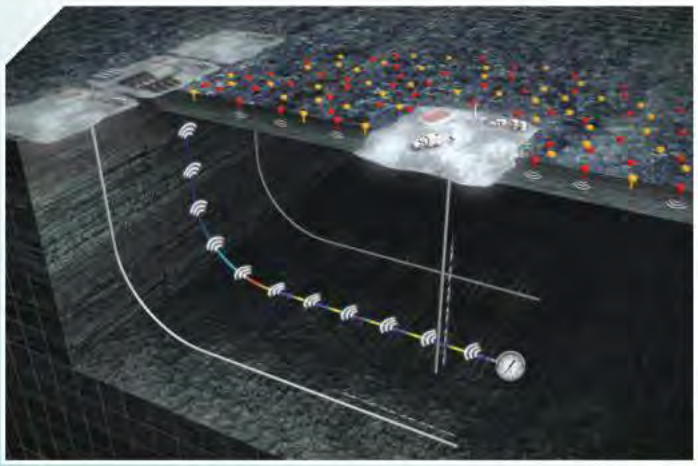
Tears is energized by industry efforts to get leaner and believes that "getting leaner while meeting current development needs will take an examination of the way subsea systems work together – from design through abandonment – to remove inefficiencies. This will take open conversations between customers and suppliers, as well as active discussion and debate on priority needs and potential options to meet those needs across development phases while maintaining focus on safety, quality and reliability of products and execution." OE

Solutions

Halliburton offers real-time coiled tubing services

Halliburton launched the Spectrum real-time coiled tubing services, integrating Halliburton's coiled tubing with downhole measurement tools, fiber optic sensing and telemetry, to deliver real-time data.

Spectrum Diagnostic Services aims to deliver fiber-optic distributed sensing through coiled tubing to assess well productivity and completions effectiveness by identifying fracture initiation points across the wellbore and profiling production. Spectrum Intervention Services aims to deliver real-time monitoring from a bottomhole assembly, with modular sensors for measuring depth correlation with casing collar locator and gamma ray, internal and external pressure and temperature, tool inclination, torque, tension, and compression.



"In this economic environment, customers are evaluating the effectiveness of completion methods and looking to minimize the number of trips downhole," said Ahmed El Demerdash, vice president of Halliburton's Production Solutions business line. "They also want to identify areas of greatest production contribution to determine how best to extend the life of the well. Spectrum real-time coil tubing services enables customers to improve connectivity to the reservoir and reduce uncertainty."

www.halliburton.com

Pulse releases INTEGRIpod NXT

Pulse Structural Monitoring, an Acteon company, launched INTEGRIpod NXT, the third generation of INTEGRIpod subsea motion and data logging sensor systems.

INTEGRIpod NXT offers features in a standard, modular format. Typical applications include linear displacement and static and dynamic inclination of subsea structures such as BOPs, wellheads, conductor systems, mooring lines, and jumpers. With onboard processing capabilities, measured data is processed in real-time and transmitted wirelessly or hardwired enabling instantaneous operational decision-making. The new platform also allows for deployments in excess of one year between battery change-outs due to new features such as 'Smart Logging,' which enables the device to deploy and only record phenomena over client-defined thresholds.

The third generation INTEGRIpod platform underwent extensive sea trials in the harsh weather of the North Sea, and in deepwater offshore Brazil. It is now ready for deployment as part of Pulse's offerings of structural monitoring systems.

www.pulse-monitoring.com

READ launches ZeroTime service

READ Cased Hole has released ZeroTime, its latest logging while working solution. Integrated into the bottomhole assembly, ZeroTime has the potential to substitute standalone logging runs.

ZeroTime aims to facilitate the acquisition of diagnostic data during high-force mechanical interventions. The service comprises of the use of a novel, ruggedized, memory logging system deployed in specifically designed high-strength carrier assemblies for use in slickline, coiled tubing, and drill pipe conveyed well interventions. The assembly requires no special treatment and can be kept at the wellsite for the duration of campaign activities. READ's engineers perform on-site analysis using custom software applications to deliver downhole intelligence.

Through close collaboration with a select number of multinational operators and global oil and gas companies, ZeroTime has been field tested in the North Sea with over 800 successful surveys to date. www.readcasedhole.com

Damen responds to idle PSVs

Damen Shipyards Group has developed a solution to the increasing number of laid up platform supply vessels (PSVs): converting them into vessels capable of taking on roles in alternative sectors such as aquaculture, shipping and defense.

"Our design teams have come up with workable ideas across several

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industries," said Remko Hottentot, Damen sales manager. "For example, we can convert a laid up PSV into a profitable container feeder or, for naval operations, a logistic support vessel. The possibilities are numerous. It will also be possible to transform a PSV into an accommodation, and operations and maintenance vessel."

One example of an already developed proposal is the Damen Live Fish Carrier 8916 for the aquaculture industry.

In addition to permanent conversion concepts, Damen can also create temporary designs. These can be applied to vessels originally built by Damen or other shipbuilding companies. **www.damen.com**

Geoquip Marine unveils new rig

Geoquip Marine, a geotechnical engineering and offshore drilling company, unveiled its new GMTR150 rig at Oceanology International in London. The GMTR150 is a twin ram drilling rig that can be used for drilling, coring, sampling and testing in water depths up to 3500m, including the borehole depth.

Geoquip designed and engineered the rig as the latest addition to a series of modular ram hoist type rigs, which can be mobilized from vessels of opportunity. GMTR150 enables the company to survey at greater depth than the rigs in the existing fleet and therefore expand into deeper water markets.

GMTR150 has been mobilized on board Poseidon-1, a new build DP2 vessel which has been designed and built in Japan, providing a stable platform for deepwater drilling operations. It is particularly suitable for pressure and non-pressure coring of gas hydrates in deeper waters and has already seen its first use, performing deepwater gas hydrate exploration in Japanese waters, including CPT, sampling and pressure coring in water depths in excess of 1000m. **www.geoquip-marine.com**

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1. What is your main job function?
(check one box only)

- ❑ 01 Executive & Senior Mgmt *(CEO,CFO, COO,Chairman, President, Owner, VP, Director, Managing Dir., etc)*
- ❑ 02 Engineering or Engineering Mgmt.
- ❑ 03 Operations Management
- ❑ 04 Geology, Geophysics, Exploration
- ❑ 05 Operations *(All other operations personnel, Dept. Heads, Supv., Coord. and Mgrs.)*
- ❑ 99 Other *(please specify)* _____

2. Which of the following best describes your company's primary business activity?
(check one box only)

- ❑ 21 Integrated Oil/Gas Company
- ❑ 22 Independent Oil & Gas Company
- ❑ 23 National/State Oil Company
- ❑ 24 Drilling, Drilling Contractor
- ❑ 25 EPC *(Engineering, Procurement., Construction)*, Main Contractor
- ❑ 26 Subcontractor
- ❑ 27 Engineering Company
- ❑ 28 Consultant
- ❑ 29 Seismic Company
- ❑ 30 Pipeline/Installation Contractor
- ❑ 31 Ship/Fabrication Yard
- ❑ 32 Marine Support Services
- ❑ 33 Service, Supply, Equipment Manufacturing
- ❑ 34 Finance, Insurance
- ❑ 35 Government,Research, Education, Industry Association
- ❑ 99 Other *(please specify)* _____

3. Do you recommend or approve the purchase of equipment or services?
(check all that apply)

- ❑ 700 Specify
- ❑ 701 Recommend
- ❑ 702 Approve
- ❑ 703 Purchase

4. Which of the following best describes your personal area of activity?
(check all that apply)

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Activity

Seanic unveils West Houston testing facility

by Audrey Leon

Houston-based Seanic Ocean Systems has moved into a new deepwater hardware testing facility in Katy, Texas, just a few miles west of Houston's Energy Corridor. The 5.5 acre facility features a large tank offering an alternative to the testing pool at NASA's Neutral Buoyancy Lab at the Johnson Space Center in south Houston, where other industry companies such as Oceaneering, Petrofac and Raytheon have conducted testing (see page 64 for more).

Seanic, which specializes in ROV tooling and subsea systems engineering, built a 50ft x 50ft x 30ft deep in-ground tank at the facility, which can hold 560,000 gal of water. The bottom of the pool is reinforced with 3ft of concrete, enabling it to withstand up to 2000lb per sq/ft. The walls of the pool are 2ft thick. Additionally, the pool features an infinity edge that will aid in the cleanup of a hydraulic leak and also serve to recapture water displaced once equipment enters the pool.

"Houston is the center of deepwater technology for many of the major operators," says Tom Ayars, president, Seanic. With the high cost of offshore operations it makes sense to perform a system integration test (SIT) on various deepwater components before they're committed to go offshore, he says. "This will allow a full size work class ROV to interact with the hardware in a wet environment as if it was in the field," Ayars says. "In the face of economic challenges in our industry, this facility will substantially reduce the cost of SIT's for our customers that were forced to travel long distances and to more expensive and restricted facilities."

Ayars says over the years tests like these were performed in above ground metal tanks. Above ground tanks leave customers peering through a porthole in the side of the tank or sitting in the ROV shack to witness the testing, he

Seanic's new in-ground tank. Photos from Seanic.

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Activity

Construction on Seanic's tank at the deepwater hardware testing facility in 2015.

Seanic's in-ground tank measures 50ft x 50ft x 30ft deep.

The gantry crane was installed in early April.

says. In some cases, the size of the ROVs and equipment have simply out grown this option. The metal tanks also have limitations on how much weight can be placed on the base of the tank due to the metal bottom, he adds. A few years back the NASA tank became available to the oil and gas industry. "The NASA facility is certainly world class," Ayars says. "The space station typically uses it during the day, and the oil industry often uses it at night, and as you'd expect with a government operation there is strict protocol in and around the facility. Between NASA and our new test pool there really isn't anything like it along the Gulf Coast."

The Seanic test pool's 3ft concrete reinforced base can accommodate large, heavy components. Smaller, above ground tanks can often generate abnormal swirling currents due to the round sides, but Seanic's water depth and interior dimensions will allow an ROV adequate room to perform an effective, functional test. Multiple HD cameras will be positioned in the tank offering a variety of viewpoints that will feed conference rooms with live streaming video to large screen HD monitors, as well as external online streaming video feeds.

Seanic says it is their goal to provide the industry with a local and fully outfitted test facility that can accommodate state-of-the-art work class ROV's and large subsea hardware in a user friendly, cost effective environment.

"The industry is looking for ways to reduce costs without sacrificing performance, quality or safety, this test facility was developed specifically with that goal in mind," Ayars says.

Ayars says he expects the tank will be ready for use around the beginning of May. At the time of this writing, the gantry crane had just been installed at the tank. As for Seanic, building the tank has opened up the possibilities for the testing facility, including the possibility of even testing well containment systems. **OE**

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Spotlight

From Aberdeen to RFID

Elaine Maslin speaks with Dan Purkis, co-founder of Well-Sense, and 2016 Offshore Achievement Awards "Significant Contribution" honoree to discuss his thoughts on innovation, and collaboration within the industry.

In March, Dan Purkis was honored with the SPE Aberdeen section's Offshore Achievement Awards Significant Contribution to the industry award. This is an engineer who has drawn on the bacon industry to create a downhole real time replacement for measurement while drilling (MWD) (i.e. RFID). His latest ideas draw on wire-guided technology and 3D printing.

But, the Aberdeenshire-based engineer isn't one to bury himself solely in invention. In fact, he says his current day job is about creating a new business model to meet today's low oil price environment. He aims to achieve this by bringing together smaller, niche-focused companies in a way that leverages each of their own technology expertise to offer a broader service to operators, enabling them to compete with the larger companies. In other words, collaborating.

"Everyone is talking about collaborating, but what is it and who is doing it," he asks. "It means not being greedy and thinking you can do everything. Together, we can offer better services." And Purkis means business. He helped set up Well-Sense in June 2015, and is already working with Reactive, a downhole rubber swellable packer provider; the pair are talking to a gauge system company to join them.

However, it's not stopping him and his team from coming up with new ideas, including a new intervention tool and a through-tubing plug. It's all about asking "What if," he says, and looking outside the industry for ideas.

"What if slickline didn't exist," he asks. "What if coiled tubing didn't exist? What if electric line didn't exist? How would Apple or Google do this? Would they invent a 15,000-tonne spool of wire on a truck that costs US$2 million and dangle it into the well and pull it out. They wouldn't do that."

Such questioning has led to an idea drawn from the defense sector – wire-guided missiles. Instead of wire, a thin cable, including fiber optic, is wound up inside the tool, which uncoils as the tool travels down the well by gravity. Using fiber optics wound into the tool means HD video, and other data, could be streamed real-time topside, without the need for spools or winches topside. The concept includes the tool and fiber cable dissolving "into mush," once it had done its job, so it doesn't need to be fished out.

Dan Purkis

Well-Sense is also working on a through-tubing plug using 3D printing and Inconel 718, 628 metals – a "holy grail" for the industry. This is a plug which could be put through 2.5in tubing, but then expand by a factor of 300% once inside the casing to provide a sealable plug. It's something he says he's worked on every year for 10 years and has not found a solution. With the advent of 3D printing, the complex geometries required to create a metallic tool that could expand this way and create a seal has become possible, he says. He believes it will work.

Born in Yorkshire, Purkis moved with his family to Aberdeenshire aged 12. From early on, he has been making things, from airplanes to flame throwers. After seeing a film showing a surgeon sewing a severed hand back on, and wanting to be a surgeon, he fell for engineering, as "you can't play at being a surgeon."

He studied mechanical engineering at the University of Aberdeen, winning a string of engineering prizes. But, then he opted to travel for two years, gold prospecting in New Zealand and working in fiber glass manufacturing in Australia. After returning, he found a job with underwater acoustics firm Helle Engineering in Aberdeen, which invented a digital helium speech unscrambler for saturation divers.

He then moved on to Petroleum Engineering Services (PES), a company then-renowned for its inquiring minds. There, Purkis worked on the first smart wells, developing the first intelligent completions. PES was taken over by Halliburton and after his three-year obligation to remain with the firm, he left, setting up Petrowell, which, among other new technologies, developed downhole RFID as a replacement for MWD. Petrowell was then sold to Weatherford, and soon after Purkis and colleague Paul Higginson set up Well-Sense.

He does get frustrated by the industry's enthusiasm for new technologies, but lack of willingness to try them. The industry could do a lot more by looking to other industries, he says. "We are slow as an industry in adopting technology. Other industries, automotive, agriculture, defense, we can draw on." OE

FURTHER READING

Want to read more?
We get more in-depth with Dan Purkis, his life, career, thoughts on technology and more, in an extended version of this article on our website.
Visit: www.oedigital.com/component/k2/item/12170

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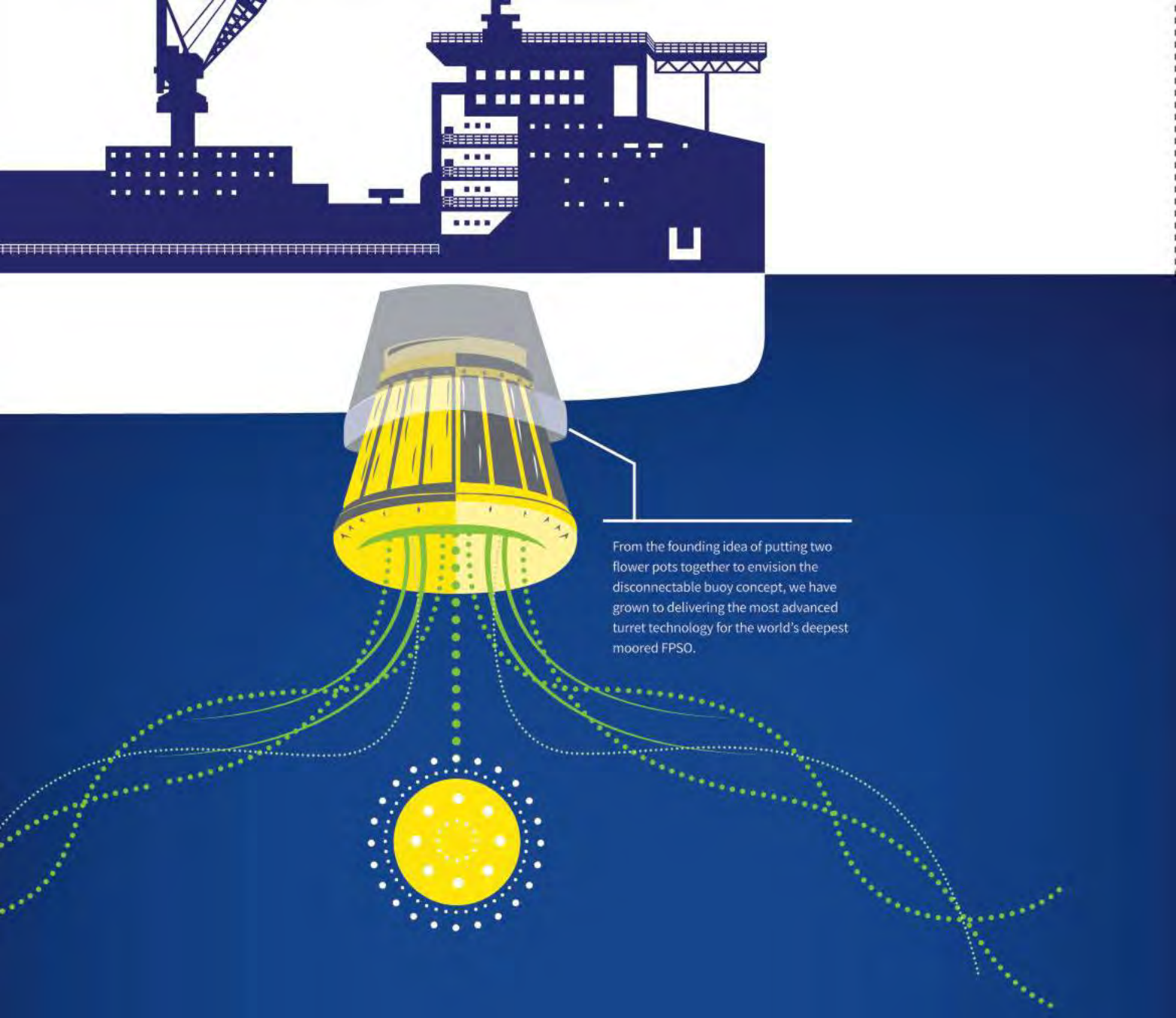

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