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ON THE COVER

Heavy lift. This month's cover shows a wind turbine mating operation, performed by *Saipem 7000*, at Statoil's Hywind project off Scotland. See page 22 for more. *Photo: Ørjan Richardsen / Woldcam / © Statoil.*

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What's Trending

Huge deals

- Mexico's Round 2.1 awards 10 blocks
- Eni sanctions Coral South
- Exxon sanctions Liza

People

Seadrill names new CEO

Anton Dibowitz has been picked to lead Seadrill as its new CEO, effective this month. Dibowitz will succeed Per Wulff who will remain a director of the company.

White Papers

Check out the latest White Papers on OEDIGITAL

Offshore service sector: 5 trends to watch in 2017

As operators across the supply chain adapt to challenging market conditions, we explore the themes set to dominate the offshore service sector this year and beyond.

IoT in Oil & Gas: Don't Get Left Behind

In today's cost-conscious Oil & Gas industry, data is king. With fully digitalized, remote production sites generating huge volumes of data every second, how can you analyze and act upon this massive quantity of information to cost-effectively achieve your critical business objectives?

Undercurrents

Fighting for survival

If we thought the industry was challenged, a comment from a leading subsea CEO has helped give some perspective: **"If we cannot compete with shale, we are going to be obsolete."**

Rod Larson, Oceaneering's CEO, made the remark at the Underwater Technology Conference (UTC) in Bergen. To add context, earlier this year, Norwegian analysts Rystad said key shale oil areas had reduced costs to US$35/bbl.

It's not just about cost either, Larson says. It's the time it takes to bring a subsea project (usually a bespoke solution) to fruition, committing costs to (unknown) prices and demand curves years into the future. Furthermore, subsea operates in some of the harshest environments of any industry. Investors like easy return, and when deciding between near-term return in low cost, easy to access areas or in challenging deepwater environments – they may not favor subsea.

However, $35/bbl projects are not so far-fetched. Petrobras' Libra 35 project aims for just that price on its mega-Libra pre-salt project, said Cristina Pinho, the firm's executive manager, subsea engineering, at UTC. Shell also plans to go ahead with its Kaikias deepwater tieback in the US Gulf of Mexico, using the existing Ursa facility as a host, with a $40/bbl breakeven price tag. Both Petrobras and Shell cite work with the supply chain as enablers to cost reduction.

Nils Arne Sølvik, president processing, OneSubsea, thinks it's time the industry went further, with vendor-based specifications to enable the industrialization needed to reduce costs. This would sit alongside systems engineering, enabled by the various company mergers over the last couple of years. Furthermore, contracting philosophies need to move to being performance-based, he says. "If it is just about cost, if the [oil] price goes up, we will go back to the way we were."

Stuart Fitzgerald, vice president, Technology and Strategy, Subsea 7, says such approaches are paying off, but that the structural changes in the business need to continue to ensure sustainable improvements, "as shale is breathing down our necks."

There's also positivity due to the potential for what new technologies – not least big data, artificial intelligence and the likes of machine vision and learning – can offer, Larson says. The latter is helping to enable remote piloting and automation of subsea robotics. The trick with technology is to make sure it's leading edge, not "bleeding edge," he says, where technology isn't ready yet. But, companies also need to be flexible. "The pace of change is going to be high," he says. "The direction technology goes will be unpredictable. But, if you prepare and have the skills in today's environment, we are going to be OK."

Marine renewables were on the agenda at Oceans 17 in Aberdeen. Wave and tidal energy has been facing something of an existential crisis of late – see page 28 – and you could be forgiven for wondering if these technologies, which are struggling to achieve costs anything near the levels offshore wind has been achieving of late (see page 22), are worth pursuing. Yet, despite being uncompetitive with wind (never mind gas-powered electricity), there's a dynamic at work in electricity markets – intermittency. Tidal, and to a lesser extent wave, offer reliable regular energy, year-round. Wind and solar, while being competitive, are not so regular or predictable, and as yet we don't have the ability to store what they produce in order to use it at times of low generation. Some believe that even by scaling up to overcapacity we'd still not be able to smooth out the "intermittency curve." So, despite being higher cost, could wave and tidal still have a place, producing a base load?

Cost reduction is key. We will need both – continued oil production and renewable power generation – to supply energy and meet petrochemical demand. Take a look around you and count what you see that doesn't use petrochem in some form – it'll be faster than counting what does. **OE**

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NEWS

Global E&P Briefs

A Hilcorp eyes Cook Inlet

Hilcorp Alaska was the sole bidder in the US Cook Inlet Lease Sale 244, the first lease sale held in Alaskan federal waters since 2008. Hilcorp offered nearly US$3 million in high bids for 14 tracts covering approximately 76,615 acres in Cook Inlet offshore south central Alaska, the Bureau of Ocean Energy Management (BOEM) said.

B Eni to drill Nikaitchuq North

Eni submitted its exploration plan for the Nikaitchuq North project to BOEM in mid-June. Eni will drill from a man-made island, Spy Island Drillsite, which is about 3mi offshore of Oliktok Point, in 6-8ft water depth. The proposed wildcats will begin from the surface of the man-made island and extend subsurface of the ocean floor, ending in federal leases on the Outer Continental Shelf of Alaska-Harrison Bay Block 6423 Unit. Drilling is schedule for in December using the Doyon Rig 15. BOEM has 30 days to evaluate Eni's plan.

C Stone spuds Rampart Deep

Stone Energy and its partners spudded the Rampart Deep prospect in the Gulf of Mexico, 9mi from the Pompano platform in 2666ft of water. Drilling is expected to take two months, and will target the Miocene interval. If successful, the well will be tied back to Stone's Pompano. Deep Gulf Energy III will drill and operate the Rampart Deep well (30%).

D BP sanctions Angelin

BP sanctioned its Angelin gas project, off Trinidad and Tobago in early June. Angelin will see a new platform built 60km off Trinidad at 65m water depth. The development will include four wells and will have a 600 MMcf/d production capacity. Gas from Angelin will flow to the Serrette platform hub via a new 21km pipeline. Drilling is set to start in Q3 2018, with first gas from Angelin expected in Q1 2019.

BP also made two gas discoveries off Trinidad, unlocking about 2 Tcf at its 100% owned Savannah and Macadamia wildcat wells.

E Mexico's Round 2.1 a success

In mid-June, Mexican regulators held Round 2.1, awarding 10 of 15 shallow water blocks in the Mexican Gulf of Mexico. Twenty individual companies, and 16 consortia from 15 countries participated in Round 2.1.

Eni's Mexico subsidiary won three areas out of the five on which it submitted a bid, both solo and as part of a joint venture. Eni's wins were in the Sureste Basin, where it drilled the Amoco prospect in Area 1 earlier this year. "The new blocks are joined to Area 1 and, in the case of a successful exploration campaign, will allow Eni to build up a new core area of considerable size with significant operational synergies in Mexico," Eni said after the round.

Round 2.1 also marks Colombia's official entry into the Mexican market, with the state-owned firm Ecopetrol winning two areas in consortium with other state-owned oil and gas firms, Malaysia's Petronas (Area 6) and Mexico's Pemex (Area 8).

Supermajor Shell teamed up with France's Total to submit the winning bid for Area 15, spanning 972sq km in the Sureste basin, and consists of wet gas.

F Petrobras awards Santos seismic

Petrobras has chosen Seabed Geosolutions, a joint venture between Fugro and CGG, to conduct a 3D ocean bottom node (OBN) survey in the Santos Basin. The new Manta node system will be used for the OBN survey, which will span over 1600sq km. The seven-month, US$90 million contract, set to begin at the end of 4Q 2017 or early 2018.

G Sea Lion nears sanction

Premier Oil's Sea Lion project is on the path to being sanctioned next year following substantial progress, with first oil targeted in 2021, according to partner Rockhopper Exploration.

Sea Lion Phase 1's front-end engineering and design (FEED) process has substantially progressed and de-risked the development.

H Kraken comes online

EnQuest has achieved first oil from the US$2.5 billion Kraken floating heavy oil development in the UK North Sea in late June.

The Kraken development, about 125km east of the Shetland Islands, off Scotland, will comprise 25 wells (14 for production and 11 for injection) via the *Armada Kraken* floating

production, storage and offloading vessel. Gross peak oil production expected to be approximately 50,000 b/d.

I Norway unveils 24th licensing round

Norway's Ministry of Petroleum and Energy will offer 102 Norwegian Continental Shelf blocks for bidding in the 24th licensing round. Nine blocks in the Norwegian Sea and 93 blocks in the Barents Sea will be offered. New production licenses will be awarded in 1H 2018. The application deadline is 30 November 2017.

J Njord, Bauge get greenlight

Norwegian authorities have approved Statoil's US$2.3 billion (NOK20 billion) plan of development and operation for the Njord and Bauge fields in the Norwegian Sea.

Statoil will upgrade the Njord A platform and Njord Bravo floating storage and offloading vessel to recover the remaining resources in the Njord and Hyme fields of 175MMboe. The upgrades – estimated to cost $1.8 billion (NOK15.7 billion) will allow Njord, which started production in 1997, to produce for another 20 years. Ten new production wells are planned for the field.

Statoil plans to tieback Bauge to the Njord A platform, with expectations of producing 73 MMboe. The development concept includes one subsea template, two oil producers and one water injection well.

L Exxon, others add EG acreage

ExxonMobil has signed a production sharing contract for a deepwater block located 36mi west of the country's capital city, Malabo. Exxon will operate deepwater Block EG-11 with 80% working interest. Its partner, GEPetrol, holds the remaining 20%. The block covers 307,000 acres (1242sq km) and is adjacent to Exxon's Zafiro field in Block B.

Winners from Equatorial Guinea's EG Ronda 2016 were announced. Out of 23 companies that expressed interest in the round, 12 submitted bids. Of those, seven companies were awarded acreage in the round: Ophir, block EG-24; Offshore Equator PLC, Block EG-23; Clontarf Energy, Block EG-18; Elenilto, Block EG-09; Taleveras, Block EG-07; and Atlas Petroleum and Strategic Fuel Fund, Block EG-10.

M ION to shoot off Gabon

ION Geophysical will shoot a new 2D multiclient program offshore Gabon, EquatorSPAN

K Exxon sanctions Liza, Tullow orders seismic

ExxonMobil will proceed with the US$4.4 billion first phase of development of the giant Liza field, in the Stabroek block, offshore Guyana.

Gross recoverable resources for the Stabroek block are now estimated at 2-2.5 billion boe, according to Exxon.

The Liza Phase 1 development includes a subsea production system and a floating production, storage and offloading vessel designed to produce up to 120,000 b/d. Production is expected to begin by 2020. Partners on Liza include Hess (30%) and CNOOC Nexen (25%).

Nearby, Tullow Oil is planning a 2550sq km 3D seismic survey, to be carried out by WesternGeco, on the Orinduik Block offshore Guyana, with plans to drill on the block as early as next year, according to partner Eco Atlantic.

The Orinduik Block is up dip and just a few kilometers from ExxonMobil's recent Liza and Payara discoveries.

Global E&P Briefs

II. The program includes over 1900km of new high-quality, deeply-imaged seismic data.

N Chariot eyes Namibia

Chariot Oil & Gas has begun preparations for drilling offshore Namibia. A new report identified 1.75 billion bbl of gross mean prospective resources. The report, covering Namibian Blocks 2312 & 2412A (the Central Blocks), is based on 2500sq km of 3D seismic shot in 2016. It has identified five structural prospects ranging from 283-459 MMbbl gross mean prospective resources, with an up to 29% expected chance of drilling being successful.

O Energean submits Karish, Tanin plans

Energean Oil & Gas has submitted the field development plan for the Karish and Tanin fields off Israel, with a target of reaching a final investment decision by the end of the year and first gas by 2020. Energean expects to invest US$1.3-1.5 billion for the two fields, which boast 2.7 Tcf of natural gas and 41MMboe of light hydrocarbon liquids.

Karish will have three wells tied to a new floating production storage and offloading (FPSO) unit installed about 90km from shore, with a capacity of 400 MMcf/d. It will also include a dry gas pipeline connecting the field to the Israeli natural gas transmission system. Tanin will have six wells tied back to the same FPSO.

P Eni to study Iran gas field

Eni has inked a memorandum of understanding with the National Iranian Oil Co. (NIOC) to study the offshore Kish natural gas field. Eni has been given six months to submit a proposal outlining plans to boost recovery from the fields, said Gholamreza Manouchehri, NIOC's deputy managing director in development and engineering affairs.

Q BP, Reliance sign deepwater pact

BP and Reliance Industries will spend US$6 billion on three projects to develop deepwater gas resources offshore India that would bring 1 Bcf/d of dry gas production onstream from 2020-2022. The companies will award contracts for the development of the 'R-Series' deepwater natural gas fields in Block KGD6. The fields will be tiebacks to the existing control and riser platform off Block KGD6.

Production from the first of the three planned projects is expected to produce up to 12 MMcm/d (425 MMcf/d) and come onstream in 2020.

R Statoil, BP in Aussie swap

Norway's Statoil will take over BP's mantle in Australia's Great Australian Bight after agreeing to a swap with the supermajor.

BP was operator of four permits, EPPs 37, 38, 39 and 40, with Statoil holding 30% interest in all four. Statoil will give its 30% interest in 37 and 38 to BP, while BP will transfer its 70% operated interest in EPPs 39 and 40 to Statoil. The National Offshore Petroleum Titles Administrator has approved the transfers, making Statoil the operator of EPP 39 and EPP40. Statoil has also been granted a suspension and extension of the work commitments in EPP39 and EPP40.

Contracts

Angelin prizes awarded

McDermott International has been chosen by BP Trinidad & Tobago to provide engineering, procurement, construction, installation and commissioning (EPCIC) for the Angelin gas field, off the east coast of Trinidad and Tobago.

McDermott will provide a turnkey EPCIC solution to design, procure, fabricate, transport, install and commission a six-slot wellhead platform and 26in (66cm) subsea pipeline using its project management and engineering team in Houston. The 900-tonne four-legged main pile jacket and 1200-tonne four-deck topside for the Angelin project will be constructed at the Altamira, Mexico fabrication facility. The platform and pipeline are scheduled to be installed by McDermott's *DLV 2000*.

McDermott has also chosen PJ Valves and PJ Piping to supply valves and piping elements for Angelin. PJ will manufacture more than 500 specialty ball, gate and double block and bleed valves, and compact flanges from their state-of-the-art facilities in Italy and India. All valves will be metal-seated to ensure durability against the gas field's abrasive conditions.

SBM lands Liza FPSO

ExxonMobil has awarded SBM Offshore a contract to construct, install, lease and operate a floating production, storage and offloading vessel (FPSO) for its giant Liza project offshore Guyana. The FPSO is designed to produce up to 120,000 b/d, will have associated gas treatment capacity of 170 MMcf/d and water injection capacity of 200,000 b/d. The converted VLCC FPSO will be spread moored in water depth of 1525m and will be able to store 1.6 MMbbl of crude oil.

Firms line up Coral FLNG work

The TJS Consortium, made up of TechnipFMC, JGC and Samsung Heavy Industries, won an EPCIC contract for work on Eni's Coral South FLNG facility. TJS Consortium will also cover the project's associated risers and subsea flowlines system, as well as the installation of the umbilicals and subsea equipment. The FLNG facility will produce close to 3.4 MTPA of liquefied natural gas and will be moored in 2000m of water in Area 4, offshore Mozambique.

Aker Solutions will deliver three umbilicals and associated equipment for Coral South. Work includes three steel tube umbilicals that will total more than 19km in length and connect the Coral South FLNG facility to the field's subsea production system. The umbilicals are scheduled for delivery at the end of 2019.

Saipem won a 15-month contract for the *Saipem 12000* drillship, to start in mid-2019.

GE Oil & Gas has signed a long-term contract with Eni for Mozambique's Area 4, which includes the supply of seven Xmas trees, three two-slot manifolds with integrated distribution units, MB rigid jumpers, seven subsea wellheads with spare components, and a complete topside control system for the FLNG facility.


no bridge too far
Allseas

Caught between worlds

Karen Boman charts Chevron's success at its large Jack/St. Malo development in the deepwater Gulf of Mexico, a project that was sanctioned just prior to the downturn.

Chevron's Jack/St. Malo development project marked many firsts for the company. Not only is it Chevron's first in the Gulf of Mexico's Wilcox Lower Tertiary trend (LTT), but it is also the supermajor's first seabed boosting project.

Situated at Walker Ridge Blocks 758 and 759 in 2133m (7000ft) water depth – a nearly two-hour helicopter ride away from New Orleans – the Jack and St. Malo fields took just over a decade to develop after their respective discoveries, in 2004 and 2003. Prior to project sanction, Chevron drilled seven exploration and appraisal wells at the fields between 2003 and 2010.

Formed 38-65 million years ago, the Jack/St. Malo's Wilcox reservoirs are buried deeper than the more predominant Miocene reservoirs found in the Gulf of Mexico and were formed 5-24 million years ago. According to an OTC 2017 paper by Hjelmeland et al, LTT reservoirs are characterized by strong rock formations, ultra-deep reservoirs of 7620m to 9144m (25,000-30,000ft), high pressures of 17,000-24,000 psi, temperatures of 220-270°F, and a 170-250 scf/stb gas to oil ratio and low permeability, due to tight sandstone reservoirs. With reservoirs starting at 5943m (19,500ft), the floating production project has a total depth of 8077m (26,500ft).

Chevron holds 50% working interest in the Jack field. Statoil and Maersk Oil are partners in the field with respective 25% interests. Chevron owns 51% working interest in the St. Malo field, with partners Petrobras (25%), Statoil (21.5%), ExxonMobil (1.25%) and Eni (1.25%).

Chevron also owns a 40.6% ownership interest in the host facility, with co-owners Statoil (27.9%), Petrobras (15%), Maersk Oil (5%), ExxonMobil (10.75%) and Eni (0.75%).

Writing the playbook during the game

Chevron sanctioned the project for development in 2010. To reduce cost and capture scale, Chevron decided to jointly develop the fields, which are 40km (25mi) apart, said Travis Flowers, Jack/St. Malo asset manager for Chevron at a recent Marine Technology Society luncheon in April. Chevron decided to develop the fields with subsea completions to a single host, a semisubmersible floating production facility located between the fields. The facility has a production capacity of 170,000 b/d of oil and 42 MMcf/d of natural gas, with the possibility of future expansion.

The technology necessary to bring the Jack/St. Malo on production didn't exist when Chevron first discovered the two fields. To develop them, the company and its partners had to create that technology, Flowers said.

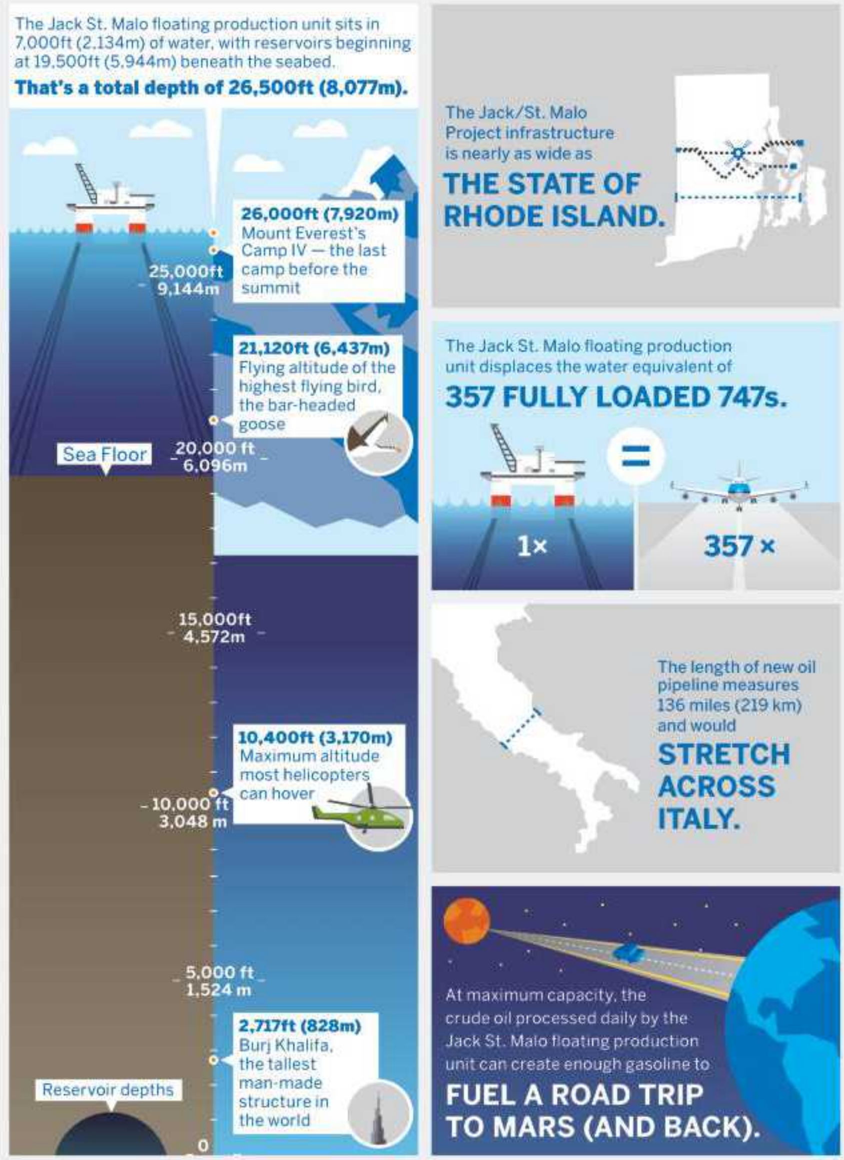
Chevron and partners "wrote the book as they went and still got great results," Flowers added.

"We went in expecting surprises," Flowers said. "Most of the surprises have been positive and within the range of surprise as part of any reservoir, particularly a lower Tertiary/Wilcox reservoir."

Dockwise Vanguard **hauling Jack/St. Malo hull.**
Photo from Dockwise/Boskalis.

Scaling up production

Deepwater production goes big with Chevron's Jack/St. Malo Project.



STATEMENTS ARE BASED ON THE FOLLOWING FACTS (CLOCKWISE, FROM UPPER LEFT):
1) The facility sits in 7,000 feet of water, with reservoir depths at 26,500 feet. 2) The field layout includes two separate fields 25 miles apart. 3) The floating production unit has a water displacement of 160,000 metric tons. 4) A 136-mile crude oil pipeline was installed to connect the Jack and St. Malo fields to an existing platform. 5) The floating production unit has an initial capacity for 170,000 barrels of oil per day.

The low reservoir permeability – on a level seen in the Permian Basin – posed a challenge for Chevron. Unlike the Permian Basin, where land rigs can drill on five-acre spacing, Chevron was forced to conduct drilling with 400-acre spacing, Flowers said.

To address these challenges, Chevron and Halliburton teamed up in 2007 to develop an enhanced single trip multi-zonal completion system (EMTSZ) (*OE*: December 2014). This technology allows an operator to run and fracture five zones in a single trip. The ability to reduce the number of trips to perforate wells save not only time, but drilling rig day rate costs, Flowers said.

At Jack/St. Malo, Halliburton's tool allowed Chevron to conduct successful hydraulic fracturing jobs to effectively open up cliff-based inflow wells. Unique production tracers in each zone allowed Chevron to study samples. As a result, the Jack/St. Malo completion team completed 47 fracs in 10 wells without missing the target, Flowers said.

Besides the first successful demonstration of the completion system, one of the biggest wells that Chevron has ever drilled was at Jack/St. Malo. For that well, Chevron ran a 2.3 million-pound casing string. Chevron also is seeing the highest completion pressure its ever seen, with Jack/St. Malo wells at 9500psi. Chevron will work towards 11,000psi over the next year or two.

Chevron's Jack/St. Malo development also set another milestone with its first application of deepwater ocean bottom node seismic technology in the Gulf of Mexico, providing images of subsurface layers nearly 9144m (30,000ft) below the ocean floor.

Adding value

Chevron chose subsea boosting technology over artificial lift methods because the technology yielded the best impact on the net value added to the project's overall present value, according to Hjelmeland et al, 2017. To gain confidence in the technology, Chevron opted to establish a two-year technology qualification program to qualify all components to Jack/St. Malo specifications, such as water depth, pressure rating and shaft power.

Chevron chose OneSubsea, a Schlumberger company, in 2011, to provide subsea pumps, which reside on the seafloor, to boost production to the topsides facility. OneSubsea provided 12 subsea trees, production controls and four manifolds. The boosting technology included three pump stations with 3MW single-phase pumps (rated for 13,000psi design pressures, and differential pressures up to 4500psi), subsea transformers, and pump control modules, associated controls and instrumentation, and a complete topside power and controls system.

The pumps carry production through two, 20km (12.4mi) tiebacks, and risers to the topside processing system on the floating production unit. The pumps were installed in 2133m (7000ft) of water. The boosting system was brought online 2014, with production following late that year.

The use of both subsea boosting and multiphase flow meters allowed

McDermott's *North Ocean 102* at work. Photo from McDermott International.

Chevron to achieve production of 12,000-17,000 b/d. A constraint in the design means Chevron had to pull the subsea pumps to achieve maximum potential. But, Flowers is hopeful that a minor upgrade of 3000-4000psi next year will boost production from existing wells.

Initially, Flowers said that he was skeptical about using multiphase flow meters, adding that technology is only as good as the quality of data. But, data analytics has allowed Chevron to monitor real-time rates and pressures. Tracking this data also helps Chevron and other owners allocate production, making fiscal management easier.

Working together

In 2014, McDermott International concluded the in-house fabrication of 21 high-specification rigid flowline, manifold and pump jumpers, and the installation of the structures using *Derrick Barge 50*. The vessel also was used to install over 80 flying leads, five additional rigid production well jumpers and other subsea control and production boost components, including three pump stations weighing 209 tons, to a depth of 2129m.

McDermott also transported and installed 65mi of three control and two power umbilicals with its subsea construction vessel *North Ocean 102 (pictured above)*, along with other related subsea structures.

Samsung Heavy Industries built the Jack/St. Malo semisubmersible hull at its Geoje, South Korea, shipyard. Kiewit Shipyard of Ingleside, Texas constructed the topsides and mooring piles for the platform. In 2013, the hull was transported via Dockwise's semi-heavy lift vessel *Dockwise Vanguard* from South Korea to Ingleside, where Kiewit performed lift and set work, and then integration and carryover work to support the semi's sail away to its final destination in the Gulf of Mexico.

Nexans installed the power umbilicals for Jack/St. Malo that integrate HV power supply and umbilical functions within a single cable cross section.

Lessons learned

Stage one of the project came online in 2014. The second phase of wells started production earlier this year, and a third phase has been sanctioned. The Jack/St. Malo facility has initial production capacity of 170,000 bo/d and 42.5 MMcf/d of natural gas. The company expects to recover more than 500 MMboe over the production facility's life span. Flowers anticipates that production might be closer to 200,000 b/d of oil in the next year or two.

Crude oil from the facility will be transported approximately 140mi to the Green Canyon 19 Platform via the Jack/St. Malo Oil Export Pipeline, and then onto refineries along the Gulf Coast.

Chevron and partners have seen positive results from the early stages of Jack/St. Malo production. With the project just entering the toddler years of a 30-year life span, however, calling Jack/St. Malo a success may be premature, Flowers said.

Chevron is now looking at future development such as additional manifolds, and ways to enhance reservoir recovery, such as waterflood.

Though it has broken ground in many ways, the Jack/St. Malo development had the misfortune of being designed and built in a $140/bbl price environment, then brought online shortly before oil prices crashed into the $20/bbl range, Flowers said.

"The current $50/bbl [range] oil prices are feeling good right now for Chevron," Flowers said.

Thanks to digital technologies, Jack/St. Malo is making money in today's low oil price environment. Well costs are falling and performance rising. But, Flowers said that oil and gas companies also need to collaborate to make new technologies more cost-effective at lower oil prices.

Would Chevron still have pursued the project had it known what oil prices would do? Flowers says yes. But, the project would have been designed differently. Chevron tackled the Jack/St. Malo project because the company needed a host facility in the deepest part of the Gulf of Mexico. The prospectivity of Jack/St. Malo also convinced Chevron officials to move forward.

If developed today, the technology for the project would be cheaper. However, Chevron would have made the project more scalable, and the pace of tiebacks would have slowed. Still, Chevron is excited about the performance, Flowers said.

As for lessons learned, Flowers said that learning from its experience using EMTSZ for fracs would be carried over to other developments. Chevron also will apply the idea of a standardized platform concept to multiple projects. **OE**

Work cited

Hjelmeland, M., Reimers, O., Hey, C. et al. 2017. Qualification and Development of the World's First High Pressure Subsea Boosting System for the Jack and St. Malo Field Development. Presented at the Offshore Technology Conference, Houston, Texas, 1–4 May. OTC-27800-MS.

In-Depth

Subsea strikes back

The Njord A production facility, into which the Pil and Bue discoveries are set to be tied. Image by Thomas Sola, from Statoil.

While significant costs have been stripped out of the oil and gas industry, shale is fighting back. And, if the subsea industry is to survive, it will need more than just reduced costs, industry executives told the Underwater Technology Conference (UTC) in Bergen. Elaine Maslin reports.

Subsea has a fight on its hands – the opponent is the shale business, the challenges are high costs, a harsh environment to work in and a fragmented market.

So far, huge costs have been stripped out of the industry, through business "right-sizing," but also product and process rationalization and project simplification. Vertical integration, through mergers and alliances, are also making their impact felt.

The scale and duration of the downturn has meant strategies have had to change, Stuart Fitzgerald, VP technology and strategy at Subsea 7, told UTC Bergen, a city which, like others, has felt some of the pain of the downturn.

To paint the picture, he says that, in 2016, just one project was sanctioned in Norway. Over the past three years, just five have been sanctioned, compared to 25 over the three years before that. "It has been a very painful process for many companies and the people in those companies. Shale has changed the game and created a different dynamic in the industry and subsea has had to fight back."

Shale is also fighting back, with what Rystad has called Shale Chapter 2, and while the oil price has been resting at above $50/bbl or above for some months, offering some stability, recent drops below $50 have injected some nervousness.

However, to date, there have been more projects sanctioned in Norway than there were in 2016 (which was just one), more are expected and there's more optimism about substantial final investment decisions being made in 2018, he says. "A recovery is not assured, but sentiment has shifted, for now, mostly because of better project economics," Fitzgerald says.

He cites Statoil's Johan Castberg, which he says was put at US$16 billion in 2014, and is now at $6 billion. According to IHS, deepwater projects have also reduced breakevens, from an average full cycle, including drilling, of $60/bbl to under $40/bbl, Fitzgerald says.

$40/bbl, Fitzgerald says.

Knut Nyborg, head of front end, Aker Solutions, reflected some of the uptick in sentiment. He told UTC: "We have won more front-end engineering and design (FEED) in the last six months than ever before in a six-month period." He says cost has been cut and efficiency improved, with a 50% reduction in lead time and 30% reduction in man-hours for Xmas trees. Digital and automation technologies had also helped to drive a 50% increase in the speed taken to produce umbilicals, he says.

"Subsea has reacted well," Fitzgerald says, by revisiting solutions and field designs, looking at staging projects. "We've had time to revisit projects," he says. The results were evident at UTC. Australia's Woodside, Murphy Oil and VNG presented new slimmed down, simplified concepts for subsea tieback developments.

On Pil and Bue (bow and arrow in Norwegian), offshore Norway, VNG has to deal with waxy oil and host facility (Njord) constraints. VNG plans to remedy this through use of electrically trace heated pipe-in-pipe technology. Murphy is working on its Gulf of Mexico Dalmatian project – a 50km tieback on which it is planning a subsea multiphase pump at 35km step out. Woodside has managed to circumvent the issues around getting the Greater Enfield project – a 32km subsea tieback offshore Australia – into an existing floating production system swivel designed for 3km tiebacks by modifying the slip rings and using uprated subsea pumping, without having to have a subsea transformer.

Improving processes and early engagement have helped, as has also changing cultures and attitudes towards removing waste, Fitzgerald says. Lower raw materials costs, currency variations and deflation due to excess capacity in the supplier market have also helped, he says. "The key is, what's structural (sustainable) and what's cyclical (reversible)? Estimates are that only 50% is sustainable if we revert to business as usual," he says.

Nyborg agrees. "We need to explore contract models. We must change from contractual silos. We see opportunity to optimize the entire field, from wells to products. Bundling saves cost, but why stop there?"

As part of a project with Statoil, called NCS2017+, a portfolio of projects was gathered and then looked at collaboratively. "Nothing was sacred, no requirement went unchallenged," Nyborg says. "Then, we came up with solutions for the whole portfolio of projects and that's a clever and effective way of doing standardization. I'm optimistic, if we see more of that."

The challenge to develop cost-effective, but smart, field solutions is getting harder, however, says Tore Havlorsen, executive vice president and senior advisor, TechnipFMC, who has a similar vision, albeit from a different route. "We, as suppliers, are trying to deliver a system to an operator that has less and less information about the field. Fewer wells are being drilled. This [the concept selected] has to be frozen 2.5 years before it is used.

"For me, a perfect project would be that you buy a small starter package," Halvorsen says, "And, from there on, I will configure the next tree based on what you find out in the next well. Need water injection? I will configure that for you, which means we become more dynamic as a supply industry as the operator is. We are far from that, but think about what

Quick stats

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

New discoveries announced

Depth range	2014	2015	2016	2017
Shallow (<500m)	76	57	32	10
Deep (500-1500m)	30	19	12	1
Ultradeep (>1500m)	13	11	8	4
Total	119	87	52	15
January 2017	127	114	72	-
date comparison	-8	-27	-20	15

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 2017-21

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Brazil			
Shallow	14	350	2649
Deep	9	820	1295
Ultradeep	36	11,250	13,256
United States			
Shallow	3	27	71
Deep	20	780	1277
Ultradeep	17	2089	1780
West Africa			
Shallow	115	3588	16,104
Deep	24	2075	3430
Ultradeep	12	1611	2398
Total	236	22,240	39,611
(last month)	(243)	(22,622)	(41,096)

Greenfield reserves

2017-21

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Shallow	887	33,381	329,080
(last month)	(902)	(35,441)	(344,813)
Deep	121	5208	78,071
(last month)	(130)	(5390)	(96,952)
Ultradeep	76	16,155	47,097
(last month)	(76)	(16,307)	(47,132)
Total	1,084	54,744	454,248

Pipelines

(operational and 2017 onwards)

	(km)	(last month)
<8in.		
Operational/ installed	41,535.20	(41,514)
Planned/ possible	22,186.84	(22,290)
	63,722.00	(63,803)
8-16in.		
Operational/ installed	82,300.37	(82,335)
Planned/ possible	46,890.47	(47,116)
	129,191.00	(129,451)
>16in.		
Operational/ installed	96,167.85	(95,171)
Planned/ possible	46,364.99	(44,677)
	142,533.00	(139,848)

Production systems worldwide

(operational and 2017 onwards)

		(last month)
Floaters		
Operational	308	(307)
Construction/ Conversion	44	(46)
Planned/possible	287	(289)
	639	(642)
Fixed platforms		
Operational	9041	(9039)
Construction/ Conversion	90	(83)
Planned/possible	1304	(1296)
	10,435	(10,418)
Subsea wells		
Operational	5148	(5090)
Develop	342	(337)
Planned/possible	6330	(6356)
	11,820	(11,783)

Global offshore reserves (mmboe) onstream by water depth

	2015	2016	2017	2018	2019	2020	2021
Shallow	21,275.90	32,136.74	24,737.17	17,328.56	12,834.19	15,683.92	20,790.44
(last month)	(21,263.41)	(32,083.32)	(32,393.42)	(11,182.31)	(12,065.06)	(16,124.58)	(24,438.45)
Deep	959.22	4215.67	1401.45	2730.28	2628.92	4569.01	7640.63
(last month)	(958.84)	(1411.48)	(4324.15)	(2965.09)	(2504.24)	(4908.87)	(7778.66)
Ultradeep	2015.69	3100.14	1653.94	4090.4	3847.95	9459.94	5406.84
(last month)	(2015.69)	(3075.34)	(1633.94)	(4082.03)	(3851.47)	(9609.94)	(5439.84)
Total	24,250.81	39,452.55	27,792.56	24,149.24	19,311.06	29,712.87	33,837.91

Source: Infield 7 June 2017

Rig stats

Worldwide

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	86	58	28	67%
Jackup	395	236	159	59%
Semisub	109	62	47	56%
Tenders	27	15	12	55%
Total	617	371	246	60%

North America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	28	20	8	71%
Jackup	24	6	18	25%
Semisub	8	6	2	75%
Tenders	N/A	N/A	N/A	N/A
Total	60	32	28	53%

Asia Pacific

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	10	4	6	40%
Jackup	114	73	41	64%
Semisub	29	12	17	41%
Tenders	20	12	8	60%
Total	173	101	72	58%

Sub-Saharan Africa

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	19	14	5	73%
Jackup	15	8	7	53%
Semisub	3	1	2	33%
Tenders	5	2	3	40%
Total	42	25	17	59%

Northwest European Continental Shelf

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	N/A	N/A	N/A	N/A
Jackup	49	27	22	55%
Semisub	37	20	17	54%
Tenders	N/A	N/A	N/A	N/A
Total	86	47	39	54%

Latin America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	22	17	5	77%
Jackup	50	27	23	54%
Semisub	24	18	6	75%
Tenders	2	1	1	50%
Total	98	63	35	64%

Middle East & Caspian Sea

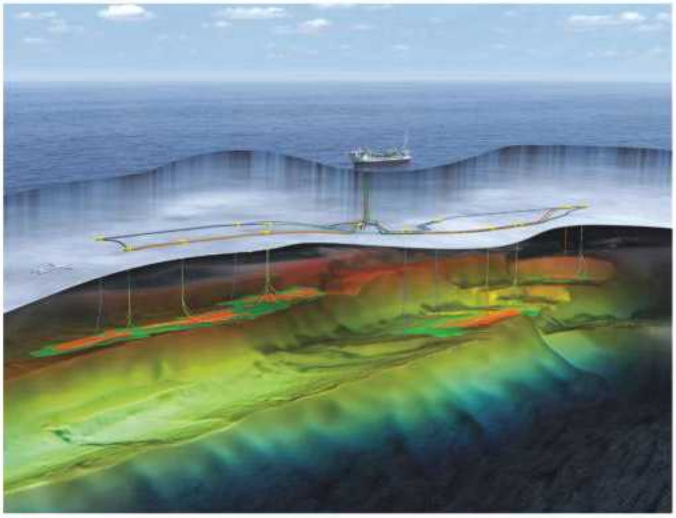
Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	1	0	100%
Jackup	119	81	38	68%
Semisub	3	3	0	100%
Tenders	N/A	N/A	N/A	N/A
Total	123	85	38	69%

Eastern Europe

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

Source: InfieldRigs 7 June 2017

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



Johan Castberg, an artists' illustration. Image by Kåre Spanne, from Statoil.

that could achieve. Vendor-based specifications are mandatory and agreements have to be in place." Like Nyborg's idea, such an approach would enable a more industrialized manufacturing process and, therefore, cost and lead time savings.

Nils Arne Sølvik, president - processing, OneSubsea, also thinks vendor-based specifications would enable the industrialization needed to reduce costs (consider there are four main vendors yet some 140 clients – 200 before 2014). But, Sølvik told UTC that contracting models also need to change, with performance-based philosophies a way to avoid the potential return to "business as usual" and the cost escalation we had in the recent past, alongside integration and life of field solutions.

However, a structural change is happening, Fitzgerald says. "The majority of operators are now introducing a different approach. These include design competitions, partnerships and client-driven alliances.

Indeed, on Dalmatian, Murphy has developed a "unique contracting strategy" – a turnkey engineering, procurement, installation and commissioning contract, with a back-end loaded payment structure – with the multiphase pump vendor, OneSubsea, which has helped Murphy get the project over the line. "With the EPIC approach, we can save three months of schedule. We are not telling the market what we want, we are letting them come to us with solutions," Mike Clarke, project manager, Murphy Oil, said at UTC.

"These models allow suppliers to engage earlier, drive optimization of fields and work on value driven delivery," Fitzgerald says. Through a FEED process with Centrica, costs on a project were reduced 45%, he says.

"We are seeing a shift in commercial models and client partnerships," with the likes of paying for performance, design competitions, design through to installation. "These are delivering results for Subsea 7. But we need to continue the structural change to ensure sustainable improvements in value creation for subsea because shale is breathing down our neck."

Fitzgerald also offers a word of warning. In a slimmed down industry with fewer staff, careful planning will be needed as the market recovers in order to maintain execution quality. The industry should also use more of the tools it already has in its technology tool box, Nyborg adds, such as separators, pumps, etc., to increase from mature areas. **OE**

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The future floats

Elaine Maslin surveys a variety of floating offshore wind projects due onstream in the near future.

This year, floating offshore wind will make a significant splash in UK waters with not just one, but three floating offshore wind farms – albeit demonstrators – being built, alongside others around the world.

Fixed foundations such as monopile and jackets are a popular choice for shallow water (in areas such as the North Sea). However, floating could be used in areas such as offshore Japan or Hawaii, where steep shelves are unsuitable for fixed installations and government mandates call for increased renewable power generation, as well as other deepwater areas.


Statoil's Hywind project. Image from Statoil.

Offshore Floating Wind Projects List

Name	Capacity	Country	Expected commissioning date
Dounreay Tri	2 x 5MW	Scotland	2018
Gaelectric	30MW	Ireland	2021
Hywind Scotland	30MW	Scotland	2017
WindFloat Atlantic	30MW	Portugal	2018-19
Kincardine	49MW	Scotland	From 2018
French pre-commercial farms	4 x 25MW	France	2020
Atlantis/Ideol	100MW	UK	2021

Data from WindEurope

Hawaii, for example, has the potential for 28GW of offshore wind resource in <1000m water depth, according to the US National Renewable Energy Laboratory (NREL). Alpha Wind Energy says that Hawaii has decided to become 100% renewable for all electricity consumption by 2045. Alpha Wind Energy proposes to develop two, 400MW floating offshore wind energy projects near Oahu, Hawaii, and has submitted unsolicited applications for the projects. Each would involve 50 floating turbines, 15mi (24km) or further from the coast in >600m water depth. Úna Brosnan, Atkins offshore wind growth manager, told the All Energy

Ideol's Floatgen, taking shape in northern Spain. Photo from Ideol.

conference and exhibition in Glasgow in early May that there are a further 800MW in unsolicited bids for projects offshore Hawaii.

Meanwhile, NREL says that 80% of the offshore wind resource in Europe is in water over 60m deep and has the potential to produce 4000GW of floating wind. NREL says that there's 2450GW potential offshore the US and 500GW potential offshore Japan. The UK's Energy Technologies Institute (ETI) says that the UK has many high-energy offshore wind sites within 70-100km of the coast in 50-100m water depth – prime for floating wind, which is most suited to 50m+ depth, it says.

Another factor that could be in floating wind's favor is the ever-increasing size of turbines. Burbo Bank Extension in the UK came online in May with 32, 8MW turbines, each with 35-tonne a piece, 80m-long blades. There's talk of 10MW turbines and even 20MW units. Could they be more viable on floating structures?

"This is the technology that has the potential to enable us to reach the high-energy yield sites without being limited by water depth, etc.," said Johan Slătte, senior consultant, DNV GL, at All Energy.

Furthermore, "Floating wind means more wind and less turbulence," Brosnan adds, as well as not being restricted to water depth or ground conditions. They can also be towed to shore, she says.

According to wind energy association WindEurope, floating offshore wind is no longer confined to research and development (R&D). It has now reached a high technology readiness level.

"While floating offshore wind technology was previously

Ideol's floating foundation, an artist's illustration. Image from Ideol.

confined to R&D, it has developed to such an extent that the focus is now moving into the mainstream power supply. The technology readiness level (TRL) related to semisubmersible and spar buoy substructures has entered a phase (>8) in which the technology is deemed appropriate for launch and operations. The barge and the tension leg platform (TLP) concepts are projected to reach this stage in the coming years," says WindEurope in its June Floating Offshore Wind Vision statement.

There are currently about 30 different floating offshore wind concepts, which mostly fall into certain concepts: spar, semisubmersible, TLP, multi-turbine and hybrid units, which combine with other technologies, Brosnan says. Atkins is involved in several projects, including Kincardine Offshore Wind (KOW), Hexicon's Dounreay Tri project, and Statoil's Hywind, all offshore Scotland, as well as Principle Power's Windfloat concept.

There are challenges, however. The Hywind, Hexicon, and KOW projects are at TRL5-6, she says. Questions remain if they'll reach TRL7 to meet a renewable obligation certificate (ROC), a

Hexicon's system, artist's illustration. Image from Hexicon.

form of funding, by a 2018 deadline and, what will replace that funding. Access to the grid and consenting processes are other challenges, alongside making floating offshore wind competitive with other technologies.

But, while it's not that long since the first floating wind demonstrators went into the water, "We are well on way to demonstration, the next step is commercialization," Brosnan says. And, oil and gas technologies, such as turrets and moorings, could play a role in the build out of this technology.

Ideol

"The density of pilot projects is a sign of the maturity of the industry," Ole Stobbe, business development manager northern Europe for design and engineering company Ideol, told All Energy. "The next step is commercial scale arrays."

Ideol has developed a floating substructure for floating offshore wind floating, which is due to be used in the single 2MW Floatgen project demonstrator, being built at Saint Nazaire in 33m water depth, 12mi offshore France. The demonstrator is one of four demonstration projects commissioned by the French government. The project involves Ideol's ring-shaped surface platform, with a moonpool, which acts as a damper to wave motion, with three clusters of mooring lines at 120 degrees from each other.

Ideol, which recently gained investors Siem Offshore Contractors and the Japanese company Hitachi Zosen, is also part of the four-turbine, 24MW EolMed pilot farm project, which will use the damping pool concrete floater, offshore southern France. It is due online in 2020. Another 24MW project, also due online in 2020, is being developed by Engie, EDP Renewables, Caisse des Depots, GE, and Principle Power (which was behind the Windfloat concept and one of the first floating wind demonstrators offshore Portugal in 2011). It will use four 6MW GE Haliade turbines.

Principle Power is also part of the WindPlus consortium's Windfloat Atlantic project offshore Portugal, a three, 8MW farm 20km offshore in 85-100m water depth. JDR Cables recently announced it had won preferred supplier status for the farm. This could see the first application of JDR's 66kv cables on a floating wind project.

Meanwhile, EDF EN is working on the Provence Grande Large project, offshore France, with SBM Offshore and IFP Energies Nouvelles producing the foundations, with three 8MW Siemens turbines and support from Technip.

Ideol also has a contract for the design of two of its structures, one steel and one concrete, to be commissioned next year by Marubeni and the University of Tokyo. It is also working in Taiwan, where it is due to commission a floating

Testing a new wave energy converter

CorPower's resonant wave energy converter, the CorPower S3, has started a dry test program following system commissioning.

The first power was delivered to the Swedish grid in April 2017, with the device operating in simulated waves using a 500kW hardware-in-the-loop (HIL) test rig in CorPower's integration facility in Stockholm.

CorPower hope that dry testing will accelerate product development and de-risk an upcoming ocean test. The HIL-rig is used to supply the device with mechanical loading representing the full range of sea states, allowing debugging and stabilizing the system in simulated waves, including storm conditions.

Multiple earlier prototypes have been tested at smaller scales in Portugal, France and Sweden since 2013. Once it has been through dry testing, the latest 1:2 device will be deployed at the European Marine Energy Centre's (EMEC's) Scapa Flow test site in Orkney, Scotland.

HiDrive is the most advanced project funded by Wave Energy Scotland, scheduled to complete Stage 3 testing within 2017. A total of €6.5 million has been invested in the Stage 3 program by InnoEnergy, the Swedish Energy Agency and Wave Energy Scotland. ▪

Gicon's semisubmersible. Image from Gicon.

turbine, next to a bottom fixed turbine, in 2019. And the firm is working with Atlantis Resources on a UK floating offshore wind project, and with Gaelectric on a project offshore Ireland.

Kincardine

KOW is one of three Scottish floating offshore wind pilot projects being built this year. Allan MacAskill, its director, worked in the oil and gas industry for Talisman, where he was involved in building the first Beatrice offshore wind turbines. In 2008, he wrote a European Commission report that said floating offshore wind was something for after 2030. Then, he got involved with WindFloat.

"I saw that I wasn't right," he told All Energy. "In the 1970s, in the oil and gas industry, very little was done floating," he says. "Companies were proud to have big fixed facilities. Then Amerada (now Hess) and others came in with floating facilities and within a decade it was a norm. That same application is coming now to offshore wind."

The first turbine for KOW, a demonstrator project 15km off Aberdeenshire, Scotland, will be installed and begin operating this year. Construction work is due at Kishorn Port (*OE*: May 2017), on Scotland's west coast, a site which has been out of use for more than 20 years. In total, eight 6MW turbines, no less than 1km apart, and with 176m maximum blade height, are due to be installed on a semisubmersible structure, moored with drag embedment anchors in about 45-143m water depth. KOW was originally looking at using one of Principle Power's Windfloat substructures, but then switched to a Cobra semi-spar concrete substructure, due to being easier to manufacture, assemble and not requiring heavy lift crane capacity.

"The big benefit of concrete is the speed with which you can build. We could build one in four months and could build more," MacAskill says. The technology consists of a central column connected to three outer columns by rectangular pontoon sections, with the outer columns about 6m below the water surface when operational, allowing support vessels to approach from all directions.

Interarray cables and two 33kv or 66kv export cables to the Redmoss substation south of Aberdeen will also be installed. KOW is a joint venture between Pilot Offshore Renewables and Atkins.

Dounreay Tri

Founded in 2009, Sweden's Hexicon has been working with Atkins and RES Offshore on an 80m-wide, 180m-long, triangular semisubmersible platform design, supporting two 5MW turbines, offshore Dounreay, northern Scotland. It will be moored using a turret and electrical swivel, enabling it to weather vane. Construction started in April, with assembly due at Nigg, near Inverness, Scotland. The site is near the former Dounreay nuclear power station, which means there's a 33kv substation connection to the grid. The project is due to be commissioned by September 2018.

Hywind

Statoil's Hywind project continues to make progress offshore Scotland. Statoil, which installed a 2.3MW demonstration floating turbine off Norway in 2009, is now building a 30MW, five-turbine pilot park on spar structures, moored with suction anchors. It will spread out over 4sq km in 95-100m water depth, with 10.1m/sec average wind speed and 1.8m average wave height, off Peterhead, northeast Scotland. The turbines will reach 258m-high, including the 80m-long blades.

Halvor Hoen Hersleth, operations manager, Hywind Scotland Pilot Park, Statoil, told All Energy that all 15 suctions anchors had been installed in April, using the *Deep Explorer,* and that all five substructures, built at Navantia, had now been shipped from Spain on the *Albatross* by Offshore Heavy Transport under contract to Technip. The turbine towers, built by Navacel, with their nacelles and blades, have been assembled onshore in Stord, Norway, on temporary flanges. In late June, they were lifted and mated on to the spar structures using the *Saipem 7000*. Tow-out – one at a time – to the Buchan Deep site, 25km off Peterhead, is due in the middle of July using two tugs. The mooring chains were be installed in late June.

Operations out of Peterhead will see technicians traveling on crew transfer vessels to the turbines for commissioning and then future maintenance work. Subsea 7 will install the

Nexans 33kV export and infield cables in July-September, with first power is due in late Q3, or early Q4.

Scaling up from the initial 2.3MW single turbine will hopefully achieve cost reduction and demonstrate the project, Hersleth says. The nacelles will be instrumented, lidars and strain gauges installed, with all the data being used to qualify the concept.

It's not been entirely smooth running, with the number of contractors and interfaces proving a challenge, he says, "some our own fault because we were not clear enough, but that needs to get better. We also see improvements we can make in our marine operations. Having the *Saipem 7000* waiting on weather is very expensive."

TLPWind

Away from Scotland, Iberdrola is working on a floating wind foundation, called TLPWind. It is based on a "shipyard friendly" cruciform pontoon structure, with a single main column. Moorings connect to the ends of each cruciform, with a tension mooring spread which can be engaged using two vessels. Iberdrola has also designed a transport and installation system for its concept, based on a semisubmersible barge, with a bow slot to accommodate the cruciform structure, complete with its installed tower and turbine. This could be towed out using a tug or anchor handler, Juan Amate López, Ibedrola, told All Energy. TLPWind is looking at up to 10MW turbines in more than 60m water depth. "Key to the solution is that it is something easy to manufacture," López says.

Meanwhile, Principle Power and Mitsui Engineering & Shipbuilding agreed to collaborate on promoting floating wind projects in Japan, having already achieved approval in principle for Principle Power's WindFloat concept by Japanese classification society, Class NK. US-based Glosten Associates, which is behind the Pelastar TLP concept, and Germany's Gicon, which has developed a similar technology, agreed earlier this year to work together on floating wind for 20-350m water depths.

Cobra, part of the ACS group, which owns offshore construction yard Dragados, is developing the Flocan5 demonstrator in the Canary Islands, with a concrete semi-spar incorporating three outer cylinders and a central column. Five floaters with 5MW turbines are planned. FID is due in 2018.

Saitec, based in Biscay northern Spain, is looking to bring its SATH (swinging around twin hull) concept to market. It has a DemoSATH 2MW single point moored, twin hull low draft concrete platform able with heave plates. It will be able to weather vane and be "plug and play," Amaia Martinez, Saitec, told All Energy. The firm hopes to start construction on its first prototype in 2018 and be fully operational in 2019.

Challenges

With fixed structure offshore wind costs falling, floating wind will need to focus on cost reduction to give it a chance of finding a viable market, says director of policy and innovation Jan Matthiesen at the Carbon Trust, a not-for-dividend company that supports carbon reduction initiatives. "We think floating can take a similar path, if there is more competition," he says. "More players in the supply chain, optimization and doing things smarter, learning through doing and scaling up."

Improvements in electrical systems, different mooring designs, logistics, and understanding wake models for floating wind, are also on his list, alongside the need for high voltage wet- and dry-mate connectors and a solution for floating – or even seafloor – substations.

Indeed, in early June, oilfield services firm Petrofac was awarded a floating offshore wind research project by the Carbon Trust's Floating Wind joint industry project. It is to investigate the key electrical system challenges associated with large scale floating wind farms including deepwater substations, dynamic cables, cable connectors, and array cable layout and burial.

Mid-June, verification house Bureau Veritas issued a preliminary design approval for a floating offshore wind turbine designed by France's DCNS Energies, based on a semisubmersible floater.

The design is part of GE (ex-Alstom) and DCNS' Sea Reed project, supported by the French Environment and Energy Management Agency. Other areas that need to be explored include anchor and mooring types and layouts, including sharing mooring lines, Matthiesen added. **OE**

Buckets and bases

While most offshore wind farms are built on monopile and jacket foundations, there are projects testing alternatives, including suction buckets and gravity based foundations.

Vattenfall's European Offshore Wind Deployment Centre (EOWDC) is set to trial number of new technologies, including 11, MHI Vestas v164-8.4MW turbines (the first commercial 8MW turbines were deployed this year), with 80m-long blades, and JDR Cable's 66kv inter array and export cables.

Meanwhile, Smulders Projects will carry out the work on the 11 suction bucket foundations at its Wallsend-based manufacturing facility, which Smulders acquired from OGN Group, at the end of last year.

The project, off Aberdeen Bay, is believed to be one of the first UK offshore wind projects where suction buckets will be deployed on a large scale. Construction is due to be complete by April 2018.

EDF Energy Renewables 41.5MW Blyth Offshore demonstrator project will also use 66kv cables, but it is going to be built on hybrid gravity-monopile foundations in up to 45m water depth about 5.7km off the coast of Blyth, northeast England. Installation is expected in Q3 2017.

The gravity based foundations comprise two elements, a concrete caisson and a steel shaft. The caissons are being constructed in the Neptune dry dock on the Tyne by BAM. The shafts were fabricated in the Netherlands and due to be shipped to Newcastle where BAM would install them into the caisson. The complete foundations were due to be floated out of the dry dock and towed to Blyth in May/June. From there, they will be immersed to take up their permanent position on the seabed. They will then be ballasted with sand and the wind turbine generators installed.

EDF says that the structures are potentially economical in 35-60m water depth, depending on ground and/or environmental conditions. ▪

Rising tides

Elaine Maslin examines the market for wave and tidal, and reports on industry efforts to drive down costs and eventually scale up.

A Tocardo device, supported on a Damen-built "UFS," at Hatston Pier, Orkney, earlier this year, before being deployed at the Fall of Warness tidal test site. Photo from Colin Keldie.

The pace at which offshore wind costs have dropped over the last few years has surprised many. The once expensive energy source has taken on the challenge of becoming competitive, hitting sub-£100/MWh (US$129/MWh) levelized cost of energy (LCOE) in 2016, a 32% drop on the previous year and making it cheaper than nuclear power. This year has even seen a wind farm bid based on supplying subsidy-free power for an average of €4.40/MWh ($4.90/MWh) in Germany, and the UK is poised to follow suit.

While such a reduction in cost has been welcomed, it has given pause for thought for wave and tidal energy developers because what once seemed a bridgeable gap in cost of energy now seems further away than ever.

The situation is even more troubling for wave energy. "A rethink is required on wave energy technology if it is to be an affordable source of renewable electricity," said a report by the UK's Energy Technologies Institute (ETI) earlier this year. Despite having shown an ability to work technically, wave energy is up to 10 times more expensive than other renewable technologies. Tidal technologies, the ETI says, have more chance of success, but will require government support.

Offshore wind has reduced a lot of its costs by scaling up, to up to 8MW currently, with 10MW predicted for the 2020s, up to 15MW from 2030, and even 20MW beyond that. Yet, tidal energy turbine size has not grown much since Marine Current Turbines (MCT) put its twin, 1.2MW turbine SeaGen S installation in the water, back in 2008, says tidal energy veteran an MCT co-founder Peter Fraenkel. Indeed, Atlantis Resources' MeyGen tidal stream project – billed as the first tidal array, with four machines – is using 1.5MW turbines.

There are others, meanwhile, who argue against scaling up. Simply scaling up a single turbine, as has been done in offshore wind, would not be feasible in depth limited

Scotrenewables SR2000. Photo from Scotrenewables.

tidal stream sites, they say. There are also companies with completely new ideas, such as Minesto and its subsea kite concept. However, there is still the concern that without some sign of government support (subsidies and funding), and the opportunity to scale up, the industry will be stuck where it is for some time – if not just disappear altogether, Fraenkel warned the All Energy conference in Glasgow, early May.

Tim Cornelius, CEO of Atlantis Resources, told the event that the question is how to get to £100/MWhr. Atlantis Resources is behind the MeyGen project in Scotland's Pentland Firth – a gravity-based, seafloor-installed four turbine array – with plans to build out to 396MW.

Going big

Brendan Corr, CFO at OpenHydro, which is delivering 2MW "open hole," seafloor fixed turbine devices in France and Canada, thinks scaling up is the way to go. However, the environment has to be right. "We have 100 engineers and I think they can do [design] bigger," he says. "That will happen. But, you have to start somewhere and have line of sight on build up and, at the moment, we don't have that in the UK," he told All Energy.

OpenHydro uses a bi-directional permanent magnet motor ring generator on a gravity-based foundation. Its first device was connected at the European Marine Energy Centre (EMEC) in 2008 and has been operating there since, with various generation models, up to today's 16m-diameter device. Over that time, a 16% improvement in turbine efficiency has been achieved, said Sue Barr, external affairs manager for OpenHydro, at All Energy. The firm says it has 3.7GW of projects in the pipeline, including two, two-turbine demonstration arrays in France and Canada and a project for one turbine offshore Goto, Japan. Barr says the firm is hoping it can deliver commercial turbines by 2020.

David Collier, project manager on Atlantis' MeyGen project, points out that energy density is higher in tidal stream, with devices a quarter of the size of wind needed to produce the same power. Bigger devices also help to hold gravity based devices on the seafloor, he adds.

Andrew Scott, CEO at Scotrenewables, whose 2x1MW turbine SR2000 sits on the surface with the rotors hanging submerged beneath, says increasing the swept area, i.e. that covered by turbine blades, is the way to go. Indeed, the firm, whose device is being tested at EMEC, is looking to increase its machine's rotor diameter from 16m to 20m, with composite blades, he told All Energy. But, it's not the only cost driver, he says. "There are different constraints on tidal. We are

Atlantis Resources AR1500 turbine. Image from Atlantis Resources.

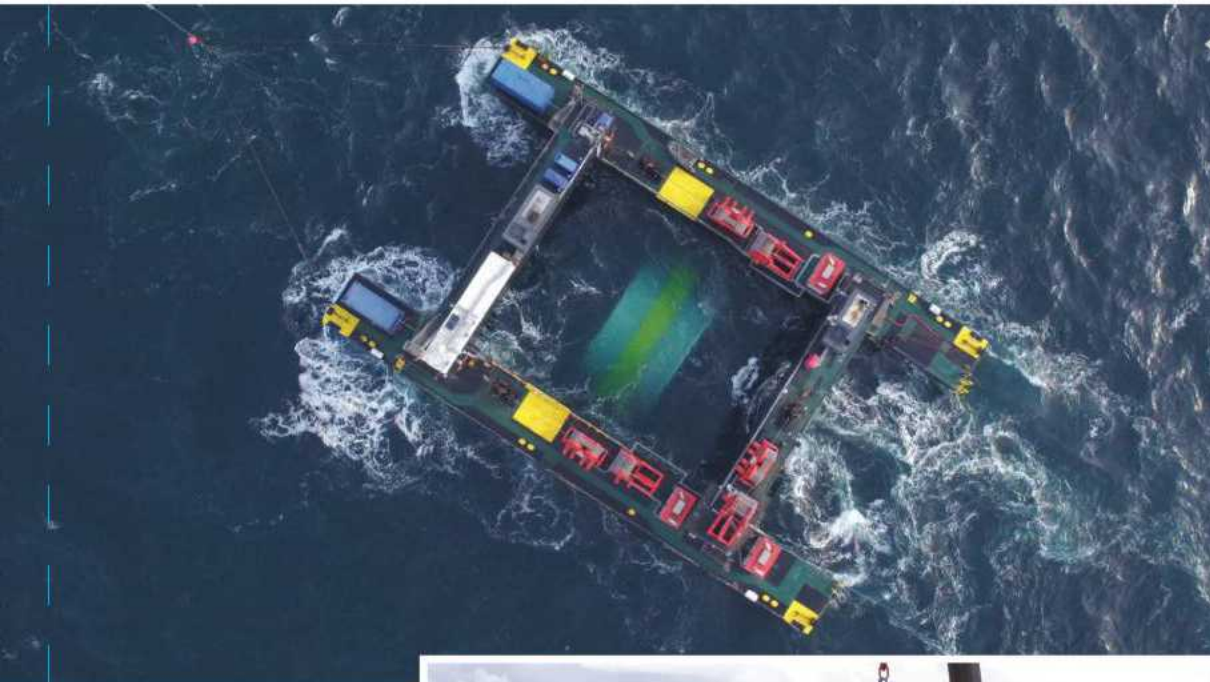
constrained by the seabed. That will lead to a desire to build bigger machines, balanced against the constraints at sites and water depths."

Strength in numbers

"Unless we start to scale tidal turbines up, we will go bust because it will have no commercial future," Fraenkel says. "System costs are too high by a factor of three and output too low. By whittling down costs, at best you get 10-20%. You can't just halve costs unless you have a stupid design in the first place. But, you can scale up rotors, 400-500%. This is what the wind industry has been doing."

Fraenkel has proposed SuperTideGen, a floating structure with two connected structures, each with two blades, totaling 4MW at 2.4m/sec or 6MW at 3m/sec. Being near the surface yields 20% more energy than submerged systems, he says, and the rotors could be raised out of the water for maintenance. It would also be a "cheap and simple to install or reposition."

Dutch turbine maker Tocardo sees a future for smaller



OpenHydro's device mid-deployment.
Photo from OpenHydro.

Nova Innovations M10. Photo from Nova Innovation.

turbines, mounted on a single structure, which it's calling the Universal Foundation System (UFS). Tocardo's 100-250kw turbines direct drive turbines have so far just been used as part of sluice gates, but it is now working on the InToTidal project with EMEC, Leask Marine, and French test house Ifremer. This hopes to put five Tocardo turbines on a UFS totaling 1.4MW by 2017-2018. One of the firm's T2 turbines was deployed at the Fall of Warness site, offshore EMEC, this March.

Nova Innovation's managing director Simon Forrest says starting small will help development, making it easier and cheaper to fix issues, with less risk. The firm installed its third 100kw M100 turbine in its three-turbine Shetland Tidal Array in the Bluemull Sound this year and is producing power to the grid.

To float or not

Views also remain divergent on how tidal turbines should be deployed – on the seafloor or from floating structures. MeyGen's turbines are gravity based and set to be re-designed for the Phase II of the project. OpenHydro's devices are also seafloor fixed. But Scotrenewables, described as the first commercial utility scale device and most powerful in the world, and Sustainable Marine Energy (SME) have floating devices from which turbines hang, as favored by Fraenkel.

"I think floating has a number of benefits going for it," says Scotrenewables' Scott, including ease of installation and operation using £300/day ($387/day) multicat vessels, or even ribs, and having the turbines closer to the higher flowrates. "Floating means a vast majority of components are above the surface for access and maintenance," Scott says. Outages relating to an AR1500 turbine on the MeyGen project meant it has had to be retrieved from the water, which would be costlier than sending a rib to a moored structure. Scotrenewables' SR2000 was installed in October 2016 and recently produced 18MWh of power over a continuous period. Scott says the SR2000 has a 40% capacity factor, which favors well compared with offshore wind.

Magallanes Renovables, based in northwest Spain and founded in 2007, has been testing a scale version of its 45m-long, 25m-deep, floating tidal energy platform, mounted with two 18m-diameter rotor turbines, in Spain and at EMEC. A full-scale device, moored from lines on its bow and stern, for sites with more than 100m water depth, is due at EMEC this year. Magallenes, which has support from ABB and Orkney firm Leask Marine, says 90% of the device's equipment will be able to be fixed inside the structure's space.

Schottel Hydro, also has a floating concept, based on a single point moored structure – using oil and gas technology – holding multiple turbines. "The small turbines we have are very light weight and easy to handle, easy to exchange in an hour or two," says Niels Alexander Lange, managing director at All Energy.

The big benefit of smaller units is seen as the ability to use smaller vessels. However, Dave Rigg, head of operations at Atlantis Resources, told All Energy: "In the future, when you get more deployments, the seabed will get very busy and you wouldn't want to use moorings in that space." He also says that, while using smaller vessels might seem attractive, "using DP vessels in that environment offers more certainty than any other asset you might want to use in that environment."

Maturity

Maturity is also an issue. OpenHydro's Corr told All Energy that he believes tidal is at the same point offshore wind was in the 1980s. Following the learning curve of offshore wind can get tidal to the same point, he says, and faster.

"We can learn from their mistakes, how they reduced the levelized cost of energy, and that's a huge benefit," Atlantis Resouces' Collier says. "The turbines are only a proportion of the cost – less than half. The rest of the cost has to come down proportionately and I think we have done this. We are in a position shortly to identify a direct path to reduce the cost of energy to compete directly with offshore wind.

"The turbines we currently have are fat and I think we can take a lot of fat out, reduce the cost, reduce the size, find a way to combine the power offshore, in strings, like in offshore wind, and we need to find a way of increasing the system voltage. We are also looking at going to fixed speed rotor, rather than variable speed, which also has advantages. When you put that together, you have a different type of farm and different costs. It's a process and I think we're going to get there."

Projects have been underway at EMEC, to reduce costs. An Orkney vessels trials project, with 20 companies working together, looked to more 60 different vessel operations more efficient, enabling local, smaller vessels to be used, saving 70-80% cost compared to using DP vessels, EMEC's Eileen Linklater told All Energy.

Further projects are ongoing around sub-systems, integrated monitoring, component analysis, subsea cable life cycle studies, and others. FORESEA, an EU project, has also made an arrangement with EMEC to offer free access to test berths. OE

Converter station inspection

Cyberhawk discusses a recent offshore wind inspection operation using drone technology.

Drone inspection and survey firm Cyberhawk Innovations has made a move into offshore wind converter stations.

The firm, which whas already used its drones to inspect offshore wind turbines and met masts, was picked by Siemens to perform close visual inspections of three converter stations – Borwin B, Helwin A and Sylwin A – offshore Germany, belonging to transmission system operator TenneT.

A two-man team did the inspections in seven days during December 2016. Alternative methods for the inspection would have included using rope access or elevated platforms.

The use of its asset management software, iHawk, allowed Siemens to access high definition images of the entire converter station structure, and quickly see the defects identified. This quality of the data, and speed in which it was provided, helped quick and effective asset management decisions to be made.

Thanks to Cyberhawk's inspection team working closely and effectively with a third-party maintenance team in a single mobilization, the project proved to be extremely time and cost efficient for Siemens. ▪

A drone's eye view of Helwin Alpha. Photo from Cyberhawk.

Efficient winds

Westwood Global Energy Group's Marina Ivanova sheds light on the global offshore wind market.

Westwood Global Energy Group (Douglas Westwood) has tracked the emergence and development of the offshore wind market for the last 17 years. Over this time, we have seen a niche industry supported by subsidies and delivering near-shore, small-scale projects grow into a multi-billion-dollar industry. As we look to the future, we see several emerging trends that will define the industry over the next decade.

A step-change underway

Increasing project scale has been a major underlying trend in the industry. Early offshore wind farms were in water depths of 10m or less, and were less than 5km from shore. Capacity, water depth, and distance from shore have all been increasing since these early projects. With the development of floating foundations, offshore substructures can now be deployed with efficient connection in 50m-500m water depth, delivering a step change in technology innovation. Some floating projects have emerged in recent years. Statoil's Hywind Demo, off Norway, is the first floating wind turbine, which started operation in 2009. Interest in floating wind is growing, with a number of pilot and early stage developments investing in floating infrastructure.

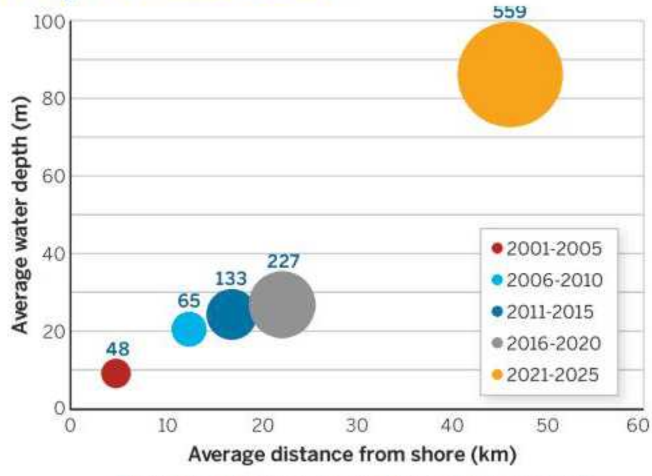
Costs efficiency vital

With the surge in offshore wind construction activity, and the reliance on subsidies to encourage construction, targets have also been set to encourage cost efficiency in the sector. This includes the joint UK government and industry target of US\$127/MWh (£100/MWh) by 2020, originally set in 2012. Since then, a combination of economies of scale, increased turbine efficiency, standardization of equipment and supply chain consolidation have contributed a great deal to material cost reduction across the sector. Subsequently, the UK has reached its government cost target four years earlier than expected, with the cost of offshore wind in the country falling to \$122/MWh (£97/MWh) as of January 2017. Furthermore, with the reduction in installation costs, offshore wind continues to improve its competitiveness over fossil fuels and it could become a competitive business proposition when compared with new combined-cycle gas turbine (CCGT) plants by the end of the decade. As the market is becoming more independent of government support, DONG Energy, the largest offshore wind developer globally, has already committed to constructing two zero-subsidy wind projects off the German North Sea, relying solely on wholesale prices in place of government funding. Both projects are expected to be commissioned in 2024.

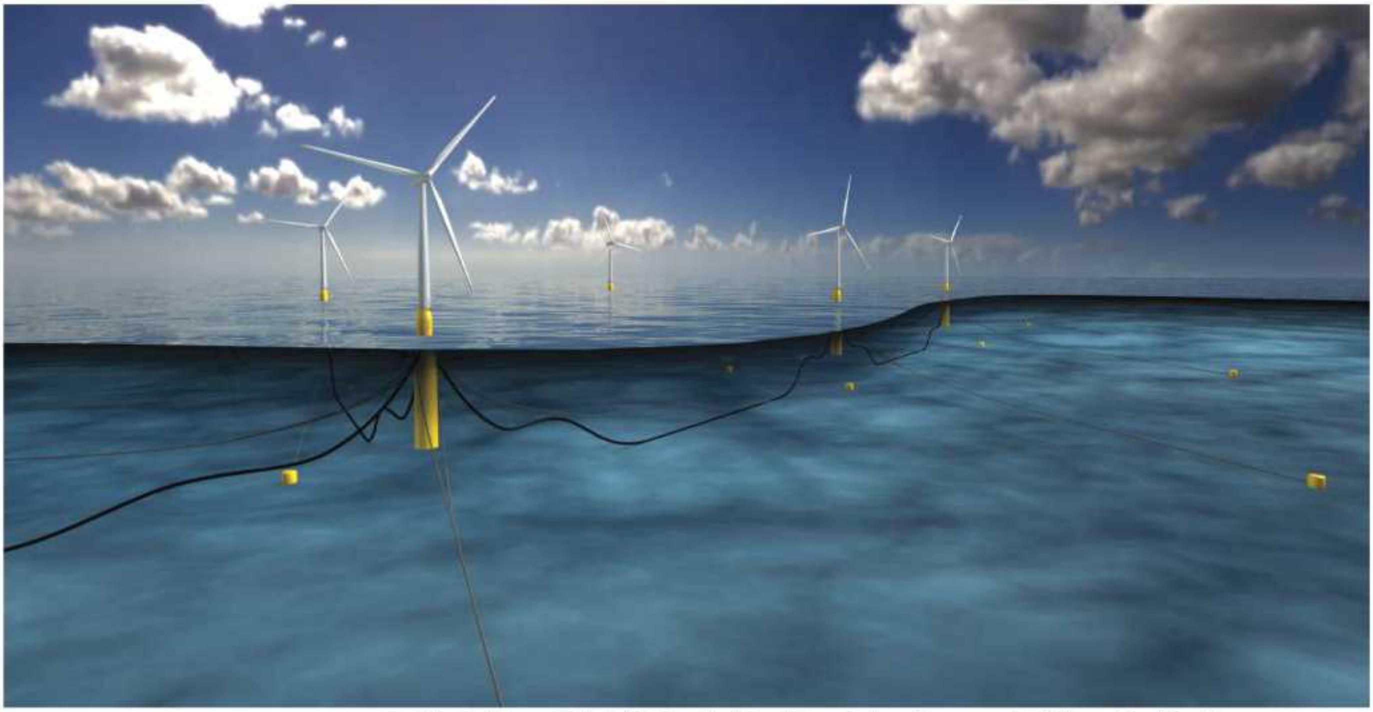
Collaboration and clustering

As projects increase in size, offshore wind farms are increasingly being developed by consortia. There are several benefits to this approach; firstly, and most importantly, the project risk is shared. As projects increase in size, the risk associated with investment becomes too large for a single developer to bear.

Project scale chart



Source: Westwood Global Energy Group.



An illustration of Statoil's Hywind floating wind park concept offshore Scotland. Image from Statoil.

Secondly, consortia allow developers to specialize and concentrate on a specific element of the development (e.g. one company may specialize in environmental impact assessments, while another may focus on engineering), thus increasing efficiency. One example of this is the UK Round 3 project, Dogger Bank, which is being jointly developed by SSE Renewables, RWE Npower Renewables, Statoil, and Statkraft.

Furthermore, collaboration between countries to enable electricity trading to manage peaks and troughs in demand/supply is expected to continue to develop, as is the need for technology 'clusters' to form in the major development hubs. The UK is a prime location for the clustering of supply chain players at strategic ports to serve the rapidly growing offshore wind market. Humber Renewables is a key example, with Hull and Grimsby ports being developed as construction, and operations and maintenance bases, respectively. We have also seen bold proposals for artificial islands in areas such as the Dogger Bank (e.g. the 'North Sea Wind Power Hub'), which would encapsulate port facilities, accommodation, and logistics (including airstrips/helipads) in addition to hosting wind turbines and photovoltaics solar generation.

Floating potential

Helicopters are increasingly being used as wind farms are installed farther from shore. Helicopters can install turbines via the "heli-hoist" method, which is widely used in Germany. However, the majority of demand for helicopters occurs during the operational phase and offshore this will be important as sites extend beyond the reach of near-shore workboats.

Unmanned Aerial Vehicles (UAVs) are increasingly being used to inspect offshore wind turbines, which reduces both costs and safety concerns, but cannot be used in bad weather. Specialist radars have also been developed to identify aircraft which fly over wind farms.

Reduction of transmission losses as wind farms are installed farther from shore is being addressed by developers utilizing high-voltage, direct current (HVDC) cables. Substations are also now common, whereas historically, wind farms were typically less than 100MW capacity and close to shore, negating the need for a substation. The majority of substations will be AC. However, DC substation demand is set to grow, following the installation of the first DC substation in 2013.

Floating wind turbines look set to finally see commercial deployment, following a number of successful prototype offshore wind turbines installed with floating foundations, including: Hywind (Norway), WindFloat (Portugal), Forward – Fukushima Pilot (Japan), and Seatwirl (Sweden), all of which are currently operational. Industry participants on the whole expect increased uptake of floating wind turbines after the end of the decade. We are expecting investment in floating infrastructure further from shore and in higher wind resource areas to improve revenues for operators. Joint industry projects and consortiums will remain key to successful standardization of floating wind turbines, leading to a further decline in fabrication costs and enhanced project economics. Overall, as of May 2017, 15 floating foundations are forecast to come online between 2017 and 2026 across the UK, Germany, France, Portugal, China, South Korea and the US.

Without doubt, the offshore wind business is here to stay and is becoming self-sustaining. We look forward to a period of remarkable transition for the industry that will no doubt offer significant market opportunity for the supply chain. **OE**

Marina Ivanova *is an analyst at Westwood Global Energy Group, currently involved in the production of quarterly market updates and is a contributor to Upstream Investment Outlook, Offshore MMO, Downstream Maintenance, Helicopter and Offshore Wind market forecasts. She has a First Class Honours in European economics with econometrics from the University of Kent.*

Reduce, reuse, recycle

Installation at the Block Island Wind Farm offshore Rhode Island. Photo from Deepwater Wind.

While offshore wind has taken off rather successfully in Europe – the US offshore wind industry has some way to go. Karen Boman reports on how existing offshore oil and gas technologies can be applied on offshore wind projects in the states.

By the end of last year, nearly 4000 offshore wind turbines had been installed in the North Sea. The industry has matured enough that the first offshore wind farm – DONG's Vindeby, commissioned and installed in 1991 southeast of Denmark – is now being decommissioned.

The US has now also joined the ranks of offshore wind farm players, thanks to the start of operations at the first US offshore wind farm, the Block Island project off Rhode Island in December last year (*OE*: July and November 2016).

Momentum is building in this space, said Alanna Duerr, offshore wind energy lead for wind energy technologies office in the US Department of Energy (DOE), during a luncheon at this year's Offshore Technology Conference (OTC) in Houston.

Duerr says that there are 13GW of projects in various planning stages currently ongoing. In December 2016, Statoil paid US$43 million for a 79,350-acre wind lease 14-30mi offshore New York in water depths ranging 65-131ft. Of the lease, Statoil says the area could potentially accommodate more than 1GW of offshore wind. Statoil is seeking a phased development with 400-600MW to start.

"The US is a key emerging market for offshore wind – both bottom-fixed and floating – with significant potential along both the east and west coasts," said Irene Rummelhoff, Statoil's executive vice president for New Energy Solutions, in Statoil's December 2016 announcement.

Other European wind players such as DONG Energy and Copenhagen Infrastructure Partners also are starting to invest heavily in the US. DONG took over an offshore New Jersey wind lease previously held by RES America Developments in early 2016, its second lease off the US. The first lease area, Bay State Wind, was acquired in 2015. Copenhagen Infrastructure Partners acquired a 166,886-acre offshore lease south of Massachusetts, called Vineyard Wind, in 2016.

Offshore wind power will be needed not only to meet electricity demand, but is viewed as a potential economic boon for parts of the US economy, such as the nation's marine transportation sector.

Current cost challenges and lack of supply chain for the US offshore wind sector could also be met by using existing oil and gas technologies, Duerr says. These include spars,

Image from Statoil.

semisubmersibles and tension leg platforms (TLPs), which could expand offshore wind capacity out beyond fixed foundation water depth capability, Duerr says (See page 22 for more on this topic).

Challenges ahead

Repurposing these technologies for offshore wind presents challenges, however. Spars need to be assembled in a protected area, which works well in Norway's deep fjords, but could limit the use of spars for offshore wind in other parts of the world. Spars also must be floated out, and turbines must be installed from a stable platform, not a floating vessel, Duerr says.

Semis for offshore wind can't be one-off designs, but should be designed to be replicated by the tens of hundreds to create an offshore wind farm. Semis can be assembled onshore and floated out, making them an attractive option for deployment offshore the US west coast, which has deeper waters compared to the US east coast. TLPs designed for offshore wind use the same basic technology as oil and gas, but are leaner and require smaller foundations, Duerr says.

By integrating more expertise from oil and gas, Duerr says that DOE can tackle the technology challenges for offshore wind. DOE also plans to work with the Bureau of Ocean Energy Management to address regulatory challenges that pose barriers to offshore wind growth.

To meet US electricity needs, DOE is seeking to develop US offshore wind power capacity and industry. Nearly 80% of national US power demand lies in coastal regions. In these regions, approximately 2000 GW of offshore wind energy exists that could be accessed and exploited with technology available right now, Duerr says.

"There are lots of good wind resources in the Midwest, but no great infrastructure to support bringing that energy in the Midwest and Texas to the US coasts," Duerr explains. To produce electricity near densely populated regions, the US needs to tap into its offshore wind power potential.

DOE not only looks to offshore wind to meet US electricity demand in its coastal regions, but reduce greenhouse gas emissions. Further developing the US offshore wind industry could also strengthen local manufacturing centers and economies in regions such as the US Northeast.

"If offshore wind develops as we think it can, in 20 years, there could be 43,000 permanent jobs in the US offshore wind industry," Duerr says.

But, first, market barriers that block development of US offshore wind must be removed. These include cost and technical risks; establishing regulatory certainty and understanding and mitigation of environmental risks; and understanding of the benefits and cost of offshore wind, according to DOE's 2016 National Offshore Wind Strategy.

In addition to Block Island, several additional projects could be operating by 2020, including two DOE Advanced Technology Demonstration Projects in Ohio and Maine – the Lake Erie Energy Development's (LEEDCo) Icebreaker project, and the University of Maine's New England Aqua Ventus I (*OE*: July 2016). The University of Maine project, expected to be deployed by year-end 2019, will address the technical challenges of a deepwater offshore project in a highly energetic wind regions. The LEEDCo project will address technical challenges of deploying fixed bottom infrastructure in an area with weak soil and ice accumulation. The project will be deployed about 7-10mi offshore Cleveland, Ohio, Duerr says.

To develop US offshore wind, vessel installation capacity will need to grow as well. Enough jackup/lift vessels exist in Europe to install increasingly larger turbines and structures, but more are needed in the US. With larger turbines, monopiles also will have to grow. The North Sea offshore wind industry can handle that, but the US currently doesn't have that type of manufacturing capability. Monopile installations are the most prevalent in Europe; but soil conditions along the US east coast make it unlikely that many monopile structures will be used.

One pervasive challenge – and a question asked at every wind conference – is how to develop a supply chain for the US offshore wind industry to help bring down costs. The situation facing the US offshore wind sector is the chicken and egg scenario. Companies aren't willing to expand their manufacturing capabilities because there is no supply chain. But without this investment, an effective supply chain can't be formed.

"The federal government won't invest in infrastructure development," Duerr says. "That's not our role." States can play a role by creating tax incentives and structures to develop the offshore wind supply chains in their states. These incentives could be tied to an RFP (request for proposal) for a power purchase agreement, or require a local content piece that would drive investment in manufacturing. OE

Photo from iStock.

Strait wind

The Taiwan Strait could be on the verge of an offshore wind boom. Elaine Maslin reports on ambitious targets and challenges.

Taiwan has set itself an ambitious offshore energy target, using both offshore wind and marine energy, to get itself off nuclear power by 2025, with 20% renewable energy by the same date.

To do this, the country wants to build out 3GW of offshore wind capacity by 2025, and increase that to 4GW by 2030. To put that in context, the UK, which has led European offshore wind build out, has 5GW installed to date, while Taiwan has just 8MW.

"We are at an early stage," Prof. Kuang-Chong Wu, CEO of the National Energy Program-Phase II (NEP-II), told *OE* at All Energy in Glasgow in May. "At this point we only have two, 4MW turbines erected," he says. These were at the Formosa I project, installed by Swancor and operating in 15-35m water depth, 2-6km offshore, from February this year. Denmark's DONG Energy has 35% interest in this project, which is expected to be built out into a 120MW farm, with construction expected in 2019.

Another 16MW, through two 8MW turbines, was due to be installed at Fuhai by TGC (Taiwan Generations Corp.) in 2017. Taiwan is hoping to have demo wind farms totaling 520MW via 120 turbines by 2020, before reaching its 3GW by 2025.

On the Strait and narrow

To meet its goals, the country has its sight set on the Taiwan Strait, a 180km stretch of water between it and China that runs along Taiwan's west coast. The strait has been the subject of various disputes over the years. This area, with sub-50m water depths, has wind from the northeast blowing at 10-15m/sec, Wu says. About 36 potential offshore wind sites have been identified and laid out by the Taiwanese government, at about 30-40km off the coast.

DONG Energy is involved in four offshore wind sites in the Changhua region, which NEP says could have 2GW capacity when completed, sometime between 2021-24. Wu says that fixed turbines would be used, but floating foundations are also being considered. But, Taiwan doesn't currently have the technology it needs to build out wind farms in these waters.

On the east coast of the country there are strong currents, moving north at a steady 1-2m/sec, which could also be tapped through marine energy devices, Wu says. But, the steep seafloor gradient - it drops away to about 1000m, just 203km from shore, poses a challenge for possible marine energy devices, he says.

Both sets of challenges are why Taiwanese officials have been visiting Europe to speak with European companies with experience in the area, such as Vattenfall's Aberdeen Bay wind farm. But, ultimately, Taiwan wants to build its own capability and infrastructure.

Second coming

Andy Oldroyd, managing director at Oldbaum Services, an offshore wind consultancy, says Taiwan has been interested in offshore wind for some time. Attempts in the late 2000s stalled when European companies that had entered the market, but were set back by a lack of legislation and finance. Since then, there has been legislation put in place and three pilot projects initiated: Formosa, led by Swancor; Fuhai, led by TGC; and Changhua, led by TPC (Taiwan Power Co.). Formosa, supported by DONG, is the most advanced.

Wind speeds are cited as 10m+/sec, Oldroyd says. However, there's large variation in speed and a lack of data, making things difficult," he told All Energy.

"Annual wind patterns need to be studied in more detail. Soil conditions are generally terrible, a lot of mud and silt. Also, it's an earthquake region."

Oldroyd says that Taiwan's ambitious timeframe is relatively tight, but they have two different financial support mechanisms, one with 20-year guaranteed income.

However, barriers remain, such as access to finance, access to infrastructure, i.e. established ports, access to equipment, and a concern that some companies would use obsolete machines, i.e. older 4MW devices.

"Fishing is one of the main barriers to offshore wind in most of the Asian markets," he adds. And then design codes will also be a consideration. "IEC and DNV codes are based on data from the North Sea, which bears no relation to what happens in Taiwan, which has cyclones. There were a number of turbine failures last year when cyclones went through. There is an investigation into that."

Within the 36 areas earmarked for wind farms there are also shipping concerns, and a cluster of the turbines, mapped out in the middle of the area, is very tightly spaced, which could reduce wind conversion efficiency, he says, which could also make it unattractive to investors. OE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Advanced materials

Stronger, lighter, smarter – Steve Hamlen reports how advanced materials keep pushing the envelope.

The use of advanced materials is becoming increasingly important to the international oil and gas industry, as the somewhat Olympian quest for materials that are stronger, lighter, intelligent and even self-healing could help to tackle some of the main challenges facing facilities, products and techniques in the sector.

ICAM's $100m research budget

In 2012, BP set up the International Centre for Advanced Materials (ICAM) – pledging US$100 million spread over 10 years – which includes four universities collaborating to advance the fundamental understanding and use of materials in the energy industry.

The University of Manchester's Faculty of Engineering and Physical Sciences is the hub for the ICAM network, which also includes the University of Cambridge, Imperial College London and the University of Illinois at Urbana-Champaign (UIUC).

Some of the challenges ICAM is researching: finding materials that are more resistant to corrosion; stronger steel; surface interactions; protection; separation; underpinning tools; and structural materials and metallurgy.

Smart coatings

ICAM is researching the potential of smart protective coatings that would flag up damage, and even fix it, before it is visible to the naked eye.

"Two trillion dollars a year – that is the estimated cost of corrosion globally for all industries," BP said in a report this March. "Unfortunately, coatings are prone to damage/deterioration, particularly in environments such as offshore or in the desert, and to incidental damage incurred, for example, during pipeline transportation. Cracks in the coating compromise the coating's integrity and shorten its lifespan, raising the likelihood of corrosion, leaks and/or structural failure."

New research is underway at UIUC into the potential of smart autonomous coatings that would enable engineers in the energy industry to see cracks in the coatings applied to structures, equipment, pipelines and tank walls and signal before overall coating failure occurs. This would drastically improve the ability to identify and manage risk, and significantly reduce maintenance costs.

"Our team embedded microcapsules, containing an indicating agent in their core, in the polymer coating," said Nancy Sottos, principal investigator at UIUC. "We then scratched the coating to damage it, causing the capsules to rupture, release their core contents and trigger the damage-indicating reaction in the form of a bright red color change or, for use in dark environments such as inside tanks, fluorescence visible under ultraviolet light."

Self-healing

The next stage of the team's coatings research involves looking at the self-healing properties in certain materials. Not only would the coating indicate its own damage, but its reaction would enable it to self-repair.

"In fact, the most sophisticated smart coatings would see the environmental factors that contribute to corrosion in situ, such as sun, wind and salt, actually harnessed to indicate and heal the damage that leads to corrosion in the first place," Sottos added. "Not only would use of such coatings reduce the possibility of significant corrosion issues, it would also reduce the need for human intervention. Inspections will still always be critical, but this self-indicating technology means they will be easier.

"Coatings will last longer and need to be reapplied less often, making them safer and more cost effective by highlighting the damage by color change or fluorescence and letting the inspector know the coating was damaged and healed in a particular spot."

Nanotechnology

Nanotechnology is the design and application of engineered or naturally occurring nanoparticles with at least

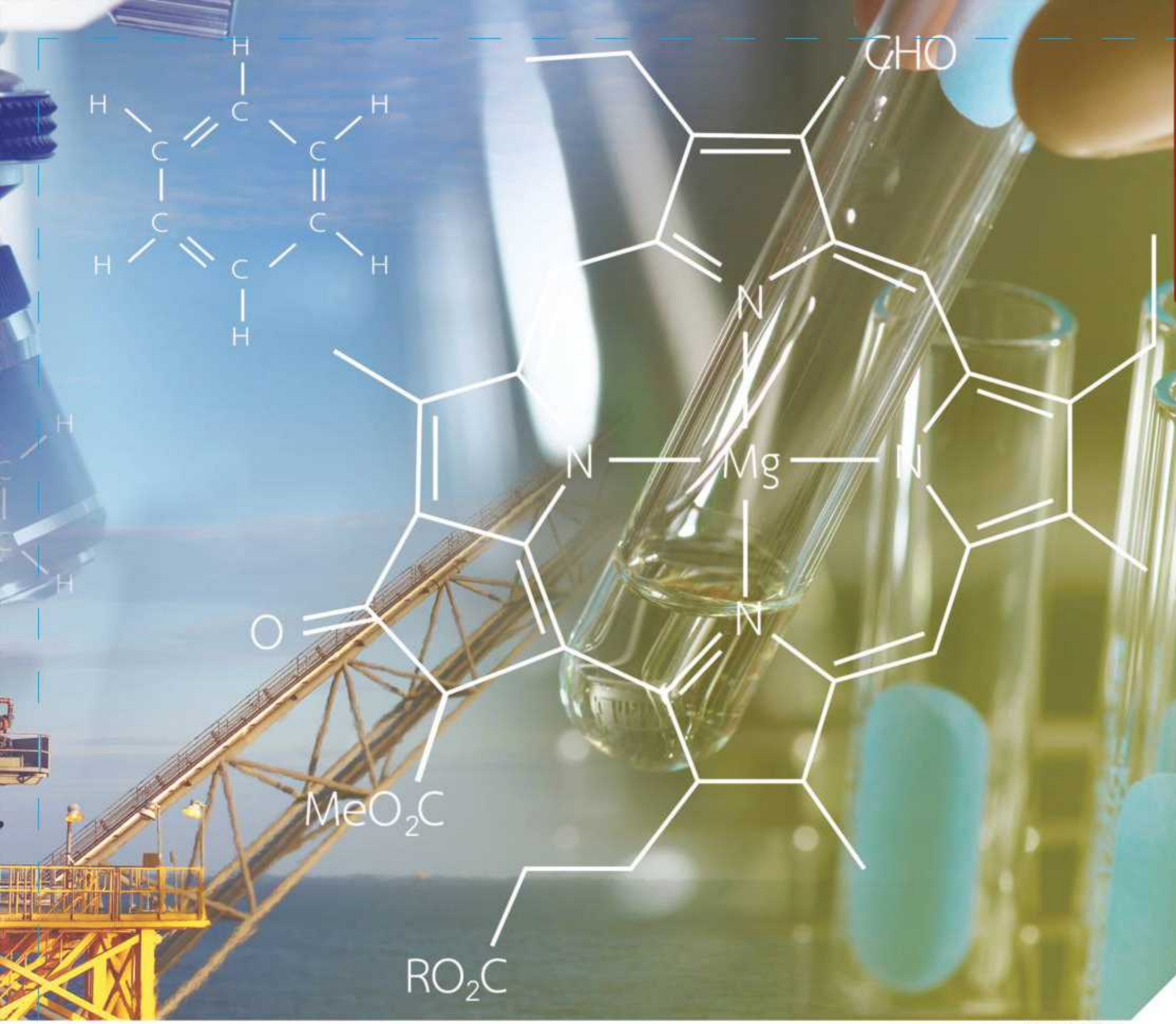


Photo from iStock.

one dimension on the order of 1-100nm to accomplish specific purposes.

"The unique properties of nanoparticles allow them to be used for many purposes in the oil field," said a paper titled 'Nanotechnology for Oilfield Applications: Challenges and Effects' by Hon Chung Lau (National University of Singapore), Meng Yu (Shell Exploration and Production Company) amd Quoc P. Nguyen (University of Texas at Austin).

"One nanometer is 1-billionth of a meter. A water molecule is approximately one-tenth of a nanometer. A glucose molecule is approximately 1 namometer. So, a nanometer approaches the size of molecules," says the paper..

"Nanoparticles possess three unique properties. First, their small size enables them to be transported into formation pores not accessible to larger particles. Second, at nanoscale, material properties are size-dependent because of the large surface-area-to-volume ratio. Therefore, nanoparticles can be engineered to contain specific optical, magnetic, interfacial, electrical, or chemical properties to perform specific functions."

Six areas of study

Most of the proposed applications of nanotechnology in the oil field are in six areas: sensing or imaging, enhanced oil recovery (EOR), gas mobility control, drilling and completion, produced-fluid treatment, and tight-reservoir application, according to Lau et al.

"A review of the literature showed that much of the current research is focused on the performance of nanoparticles (NPs) in the reservoir. Some work is being conducted on the propagation of NPs, and very little work is being conducted on the delivery and recovery of NPs.

Of the six application areas, the authors ranked imaging, drilling through unstable zones, and tight-reservoir applications as having the biggest potential effect. "Using NPs to detect hydrocarbon saturation in a reservoir can have a significant effect on field development planning, such as well placement," the paper says.

"Similarly, using NPs-enhanced drilling fluid to stabilize and drill through unstable zones can increase the rate of penetration, reduce drilling costs, and minimize environmental effects. Furthermore, using specially designed NPs to image and prop up induced and naturally occurring fractures in tight reservoirs can lead to sweet-spot identification and more prolific wells." OE

Interventions in the digital age

Audrey Leon discusses the next game-changing intervention technologies with *OE's* Deepwater Intervention Forum advisory board members ahead of this year's show.

Every industry segment has felt the hurt from the downturn that began at the end of 2014. *OE's* Deepwater Intervention Forum, next month (8-10 August 2017), will showcase how the intervention industry has adapted to the "lower for longer" lifestyle, and will feature new techniques and technology that aims to help reduce time and cost.

OE: There is plenty of buzz in the industry surrounding digitalization. What are some new advances that may change the way interventions are done?

Alex Lawler, Drilling & Completions Engineer, LLOG: The oil and gas industry can be slow to implement new technologies. Because of the high cost implications of permanently-installed equipment failures, companies are reluctant to incorporate emerging technologies into their portfolios. Digital technologies certainly have a role to play in the oilfield of the future. The industry still seems to be working through what data can be acquired and how to best incorporate this data in order to optimize well performance.

For example, digital slick-line is providing downhole information never before accessible. This is improving the success of long, challenging runs, thus eliminating costly re-runs. In production operations, fiber optics have intriguing applications to record high data volume along the entire wellbore at lightning-fast speeds. The incremental cost of these technologies must be properly evaluated against the benefits they provide.

David Carr, commercial vice president, Helix WellOps: Digitization and 'Big Data' have been buzz words in many industries for several years now. They are finally making an impression on the subsea intervention segment. The complex interaction of well and reservoir properties, combined with an ever-increasing suite of downhole technologies, as well as different well access philosophies (which themselves drive the selection of an increasing array of marine platforms) has resulted in a huge number of potential subsea well intervention options for any given operation. Helix has been supporting many of its clients in determining what are the most impactful parameters to consider in this analysis, but ultimately, the processing of 'Big Data' is becoming a factor that will determine the selection of methods in the future. In no segment is this more important than in the abandonment and decommissioning realm, where selection of the most efficient and cost-effective solution will drive dollars to the operator's bottom line as new technologies drive down this looming burden.

Colin Johnston, director, SeaNation: Digitalization and corresponding data acquisition are the key issues of the moment. The ability to gather the data now seems to be the easy bit, but the challenge is two-fold; 1) how the data is analyzed for optimum value; and 2) how the data is shared across companies and regions for maximum value. The days of focusing on what information is needed have been replaced by massive information gathering capability. Such development provides opportunities for the ability to better risk assess operations and, therefore, make calls on probability of success during the planning stages. Thus, more desktop operations ahead of time can be utilized to better improve efficiency of the actual operations. In addition, better planning and utilization of assets should result in cost reduction. All of this is only possible based upon information sharing being the key.

OE: What are some of the intervention technologies you have an eye on right now?

Alex Lawler, LLOG: There are some exciting advancements being made with acoustic technology. This technology is enabling a wide array of data measurements along the work-string. Pressure and temperature data can be acquired throughout the work-string and annulus to calibrate density profiles, verify downhole tool movements, optimize frac models, as well as several other applications. Additional capabilities are being added, such as downhole weight and deflection. The challenge is to effectively understand and incorporate this technology so that it becomes a clear enabler of efficiency and value, as opposed to simply "nice to have, but not necessarily needed."

David Carr, Helix: In my opinion, there

Onboard the *Well Enhancer* looking aft towards the moonpool and showing the CCTLF and riser section supported during operations.
Image from Helix WellOps.

are three technologies that are going to drive change in the industry in the next 18 months.

The first is the emergence of the first rental 15K Intervention Riser System (IRS). This equipment will allow the numerous operators with high pressure, high temperature wells in the Gulf of Mexico (GOM) and elsewhere to access their wells efficiently and at low cost, allowing them to perform wells operations from the most mundane to the most invasive on their own contracted vessels, or aboard dedicated intervention vessels. This technology will allow production sustaining and production enhancing operations to be performed that would have otherwise have been economically unviable.

The second is the emergence of coiled tubing operations from smaller, lightweight intervention vessels of the type that typically operate in the British and Norwegian sectors of the North Sea. The addition of this capability (albeit presently only in the calmer summer months in that latitude) has allowed previously uneconomical operations to be planned and executed, helping to fulfill the UK industry's goal of Maximum Economic Recovery.

The third game-changer is the arrival of a host of new Riserless Abandonment and Abandonment-in-Place technologies. Among many interesting new technologies, these include the Subsea Services Alliance's Riserless Open-Water Abandonment Module (ROAM) [See page 53 for more detail] that will facilitate open-water tubing pulling, as well offering full-bore access for a range of downhole, upper abandonment technologies.

Colin Johnston, SeaNation: Technologies that are going to have impact are based around material developments and increased subsea technology capability. One such area that will benefit from both of these is subsea coiled tubing (CT) operations for well intervention. Applying smaller vessels via improved technology capability as a result and combined with improved CT material technology provides a new niche of subsea well intervention capability.

OE: What does the future of the intervention industry hold?

Alex Lawler, LLOG: Though the effects of low oil prices are being felt throughout the industry, intervention service providers have used the depressed market as an opportunity to tout the efficiency of their capabilities. There is an uptick in demand for intervention services because they have proven to be a cost-effective means to address well productivity issues and execute most plugging and abandonment work. Data suggests this trend will continue well into 2018. Because of the depressed market, the cost difference between riser-based and riserless solutions is shrinking. Riserless providers will be asked to increase capabilities, such as in-well coiled tubing, and expedite mobilization timing to compete with their riser-based brethren.

David Carr, Helix: Integrated service offerings will have to play a significant role in this industry in the near future. The traditional model of contracting a mobile offshore drilling unit with discreet services on board does not fit with the leaner, fitter, lower cost reality of the industry today. This model misaligns the incentives of the marine operators with those of the services providers, which are in turn misaligned with those of the operator. Nothing can be more frustrating for an operator than paying the full spread cost of a rig, ROVs and services when the whole package is unable to work due to the failure of a $10 widget provided on a separate, discreet contract. Only by fully integrating the entire spread and sharing risk can the incentives of all parties be aligned with those of the operator footing the bill.

In terms of projects, P&A has been considered the 'next big thing' in the subsea industry for many years. However, operators, while taking care of their regulatory obligations, are naturally going to postpone this process for as long as possible to delay the expense and also to anticipate new technologies that will reduce this liability. So, in the leaner, lower oil price mid-term future that we face, I believe that stimulation and flow assurance projects will play an important part of the subsea operators' strategy of maintaining and enhancing production.

In the last 12 months, coiled tubing conveyed acid stimulations from Helix's semisubmersible fleet in the GOM have helped operators in that area to increase production at a time when adding reserves from new exploration is unviable. Equally, we have seen our trenchers increasingly utilized in the Brazilian basins and elsewhere to bury flowlines for thermal advantage and improved flow assurance. All of this points to a bright future now that both operators and service providers have scaled their businesses and cost bases to reflect the new reality in the industry. In recent years, it has become a cliché to note that there is no 'easy oil' available anymore; in fact, the 'easy oil' is being found in the existing well stock and the subsea infrastructure that continues to convey this important resource to market.

Colin Johnston, SeaNation: Future intervention will see more specialized service providers and a more efficient capability for operators to mix and match what is required across the full gambit of tools covering surface (vessels and handling systems), subsea (technologies and interface capabilities) and subsurface (well services and downhole tools and techniques). The ability to select what is required along with the capability to marry the different aspects needed will improve overall intervention operations. Increasingly the operator will be comfortable to assign the management of this to those who provide such service day in and day out and rely on dedicated operational experience and expertise. **OE**

The 13th Annual Deepwater Intervention Forum takes place 8-10 August 2017, at the Galveston Island Convention Center, in Galveston, Texas. For more information, including the full agenda, and registration and hotel details, please visit: ***www.deepwaterintervention.com***.

Photo from HWCG.

Ready to respond

HWCG's David Coatney stresses the importance of developing comprehensive response plans to prevent deepwater blowouts.

To respond to future offshore deepwater drilling incidents, offshore energy companies must be prepared and develop comprehensive deepwater containment response systems and plans. A response plan is vital for mitigating the impact to people, property and the environment. HWCG is one of three consortia and additional well containment providers committed to operators in the Gulf of Mexico.

The concept of balanced drilling to maintain well control is achieved through sophisticated design considerations involving construction and mud programs. Applications in harsh deepwater environments requires increasing collaboration of companies, contractors and service sector engineering expertise.

Companies must be prepared for capping or flowing back wells at well flowback rates of "worst case discharge" and are oftentimes in need of design capacity handling of over 100,000 b/d and 200 MMcf/d.

Testing and optimizing the RCD

Deepwater blowout response planning in the Gulf of Mexico continues to evolve, following the resumption of drilling, post-Macondo. That resumption was founded on the cooperative effort of the industry and the Bureau of Safety and Environmental Enforcement (BSEE) and its forerunners. The Well Containment Plan (WCP) detailed the equipment and procedures that would be used as well as providing an accepted method of assessing wellbore integrity (the Well Containment Screening Tool (WCST)). In HWCG's case, the WCP has been supplanted by a higher-level regulatory filing called the Regional Containment Demonstration (RCD).

It contains all the information necessary for BSEE to determine an operator's ability to respond to the covered operations. The result is a streamlining of the regulatory process that focuses on individual well design while still providing the assurance that deepwater blowout response is up-to-date.

Fundamental to HWCG's RCD are assets that would be mobilized in any incident. The primary components are capping stacks (rated at 10,000psi and 15,000psi), a top hat, a subsea accumulator module and a subsea dispersant manifold.

The heart of HWCG's members' response plans is the equipment that operates in the GoM and is accessed through pre-existing agreements between HWCG and contractors. Ranging from capping stack deployment vessels to tankers for delivering captured effluent to shore for processing, this equipment and Mutual Aid reflects the philosophy of the consortium.

Testing and optimizing response efforts

HWCG consortium members respond to another member's deepwater well incident through Mutual Aid, a pre-planned commitment of intellectual and equipment resources, bringing to bear the collective and collaborative input of a diverse set of companies.

To help improve response efforts, HWCG conducts an annual source control exercise designed to test the effectiveness of member's RCD by incorporating HWCG resources, while providing realistic response training to the host, members and various vendors. Lessons learned from these exercises helps improve response efforts and are shared with HWCG members, dedicated vendors, regulatory agencies and the industry as a whole.

Ultimate goal for rapid response plans

Multiple pieces of equipment, technologies and personnel play essential roles in an integrated rapid response plan. Although the goal for well containment equipment and technology is to quickly contain a blowout, the emergency responders and the Responsible Party ultimately want to protect the environment, other operators and all involved response personnel.

Deepwater well containment has evolved remarkably since 2011, by enhancing and creating structured safety management systems. However, there is no replacement for "good oilfield practices," like always honoring the fundamentals of sound engineering in designing wells of ever increasing complexity and picking personnel on capacity of judgement and technical capabilities. **OE**

***David Coatney** is managing director of HWCG. He has more than 40 years of global experience in the upstream oil and gas industry and has acted as an Incident Commander – domestically and abroad, leading successful responses in operational, natural disaster, well control and civil unrest incidents.*

Going where no coilhose has gone before

Marie Morkved shows how a desire to eschew 'how we've always done it' helped Maersk Oil take a different approach to well intervention – using coiled hose on its UK North Sea Balloch field.

The Balloch field came onstream in May 2013, with three wells: P17, P18 and P20. Balloch produces through the *Global Producer III (GPIII)* in Quad 15 of the UK North Sea. The field has exceeded expectations and has delivered a significant amount of *GPIII*'s production. However, in 2016, we saw a decline in one of the wells, P18. To maximize economic recovery and deliver value for our business, we had to brainstorm ideas to sustain as many barrels as possible.

The problem

The subsurface team considered several possible reasons for P18's production decline, including eroded screens, collapsed screens, formation collapse and screen plugging. The well has a downhole gauge so reservoir pressure decline could be ruled out.

In the end, the most likely problem appeared to be screen plugging. The sand is very clean, but we experienced losses when drilling into the Devonian formation just below the reservoir sand. The first Balloch well drilled into the Devonian without problems, but in P18 it resulted in a number of barrels of mud being lost, which required us to pump plugging material (LCM) as a control measure. This also resulted in a very basic clean-up of the well before the screens were run, and it was considered likely that there was still some plugging material remaining. This material could plug the screens, resulting in decline in production over time.

Solution

The upshot was that these sand screens needed to be cleaned. We believed we could do that by pumping a cleaning fluid across them to dissolve the

Coilhose being deployed via the moon pool on board the LWIV during well operations. Photos from Maersk Oil.

Coilhose being deployed on board the LWIV.

residue that was blocking them. But, we needed to act quickly, and the go-to method of using a semisubmersible drilling rig with coiled tubing to carry out this intervention work was going to take too long to mobilize and get on location. We needed to think differently.

Ultimately, we chose to use a light well intervention vessel (LWIV) – the *Well Enhancer* – and a 19mm outer diameter coilhose from Quality Intervention. The coilhose is as thick and light as a garden hose. However it's very strong (four times the yield strength of slick line) and capable of pumping at pressures of up to 50,000psi and at the depth we required – 9300ft (2834m).

It doesn't require the heavy equipment that coiled tubing does, and it could be used on a LWIV, which could be in the well within 36 hours during the winter months, which was critical for us. However, nobody had ever done this before – either in a subsea well or deeper than 2000ft (609m).

Testing

One of the key components in this project was the creation of a subsea stripper– a new piece of kit created for this project. It is essentially housing for rubber packings that seal around the hose. If it was too tight, the hose wouldn't move. If it was too loose, we may risk spilling oil to sea. It was vital that it was tested thoroughly, first in a test well in Norway and then yard tested in the UK.

We also needed to test the last line of defense: a shear seal – a massive 7in valve that will cut whatever is in the hole and seal off the wellbore. The idea that the shear seal would not cut the tiny hose was almost unthinkable, but we couldn't leave that to chance. We sent the hose to Houston to be tested with the shear seal. It passed.

A special nozzle was built for the hose to jet the cleaning fluid on to the screens. We tested the hose using different types of acid: formic acid and citric acid. We cooked the hose in different strengths of the acid to check what would happen to it under those conditions. We were able to see that the hose performed well with 20% formic acid.

What's next?

The result was a world first – the use of a LWIV and coilhose at depths of 9300ft (2834m) to perform a well intervention at around 30% cheaper than traditional methods. Our ultimate aim was to clean the sand screens and get the well flowing better and we achieved that.

While we were able to almost double production from P18 post start-up, the big success is the testing and trialing of this way of performing a well intervention. We're looking at using a LWIV for more well interventions this year. **OE**

Marie Morkved is head of Production Technology for Maersk Oil UK. Marie has more than 20 years' oilfield experience including seven years with Schlumberger and 10 years with BP. She joined Maersk Oil in 2011. Marie has an MSc in mechanical engineering from NTH Norway and an MSc in petroleum engineering from Imperial College London. Throughout her career, she has worked on well interventions and well and reservoir management in Germany, Holland, UK, Norway, Egypt, Denmark and Azerbaijan.

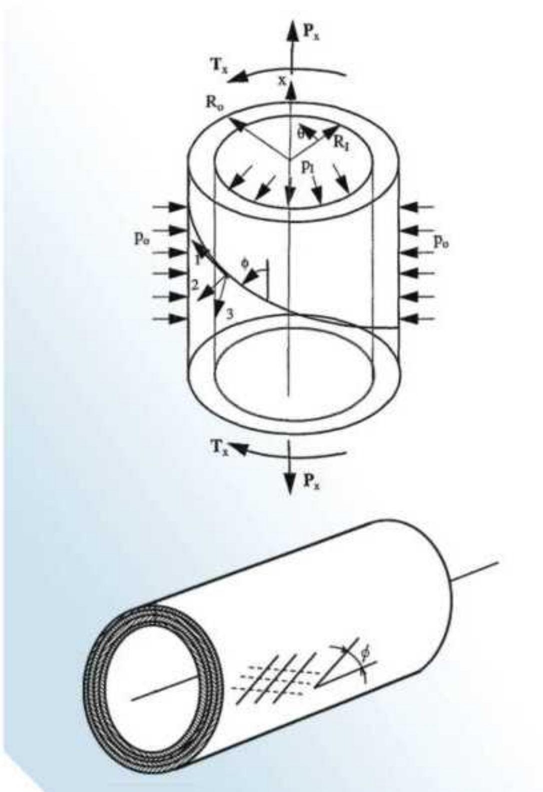
Composites are coming

Composite for coiled tubing has been tried before, but the industry wasn't ready yet. Norway's Prototech is taking another look.

It is well known that composites are being increasingly recognized for their suitability in the most specific and demanding areas across many industries. Advantages of composite materials such as lightweight, resistance to a wide range of fluids (including seawater, aerated water and hydrocarbons) which can attack metals, good thermal insulation, excellent damping and fatigue performance, and high specific stiffness make them ideal candidates for use in the water environment for structural and non-structural applications. These properties combined with the unmatched tailoring of fiber reinforcements along load paths have motivated the industry to promote the use of composites in several critical load-bearing applications: particularly for risers, spoolable tubulars and tethers. Other areas where composites can be used include pipework, paneling, casings and structural repairs.

Furthermore, composites also have very interesting directional properties and are even more unique when high strains are introduced. The applications for flexible composites in high-strain structures are numerous though their implementations have not yet been fully realized due to the complexities in design optimization and characterization. Examples of flexible composites in high-strain structures are: wind and tidal turbine blades, helicopter blades, some aircraft wings, and some tethers. Design of each of these structures is a very multidimensional task which involves optimizing the composite layup based on the structure's geometry, loading conditions and failure criteria. Loading on aero and hydrodynamic structures is dependent on the structure's shape, requiring additional understanding to address fluid-structure interactions.

However, despite their undoubted advantages for oilfield systems targeting increasing depths, the introduction of composite materials is a very slow process and they have not received a wide application yet (as it has been successfully done in aerospace industry). The major barriers holding composites back are the lack of appropriate performance information, full scale parametric testing under different types of loading for verification and certification, regulatory requirements, efficient design procedures and reparability issues. Thus, the composites' ability to stand up to impact and cyclic loading, stability and fatigue performance, resistance to the environment (aggressive fluids, temperature and pressure) are the topics of the current research. In particular, composites subject to high-strain deformations, which can be found in coiled tubing (CT), will be considered.



New software optimizes composite pipe based on typical CT loading conditions. Image from Prototech.

Analyzing the structure

Tubing materials with high corrosion resistances like carbon fiber reinforced plastics (CFRP) are ideal for transporting various substances and operating in harsh environments. At the same time, a CFRP pipe must be capable of withstanding working internal and external pressure, high temperatures and axial loads.

Researchers from Prototech in Bergen, Norway, and the University of Aberdeen engineering department are collaborating through a grant from Regional Research Fund Vestlandet to explore flexible composite materials for use in CT applications. Several topics from both materials engineering and structural performance viewpoints are being explored. From the materials engineering perspective, optimization-based analysis programs have been developed to calculate composite fiber orientation, ply thickness and stacking sequence.

The optimized tube materials are calculated based on pressure differentials, bending, torsion and axial loads. The analysis tool requires a number of simple user inputs like material properties, tubing diameter and load requirements and produces stresses (and failure coefficients) at any point through the tube wall/composite layup. The software is capable of optimizing for both thick and thin-walled composite tubes, and isometric layers like metallic or plastic can also be include in the optimization algorithm.

Investigating the costs

The overarching goal of the technology is to develop a CT system that improves energy efficiency and has a lower lifetime cost than today's low-alloy carbon steel CT market. These goals are achieved by relation to two basic properties inherent to the composite material: material density and fatigue resistance. CFRP are roughly five times less dense than steel, and in the high-strain setting, can be superior in fatigue resistance if designed correctly. Fatigue life of CT has a direct effect on the cost; for example, a two-fold increase in cost can be justified by a two-fold increase in allowed installations before decommissioning.

The 5x reduction in material density has numerous secondary effects on the cost of the equipment including transportation costs, logistics, operations, etc. Lower masses also promote reduced energy consumption and emissions during every operation. From a logistical perspective, there exists some surprising cost-savings potential as illustrated by the simple example below. Fully loaded (steel CT) spools weight upwards of 20- to even 30-ton, have typical diameters between 3-4m and widths about 2m. Many standard shipping trailers support these diameters and widths, provide a length dimension of 8m+ and support a maximum load of around 22-ton. The maximum capacity of these trailers however is met with just one fully loaded spool. When taking a conservative approach, the researchers anticipate the CFRP CT with spool to weigh less than half. This provides the advantage to use the remaining space in the length direction of the trailer. Thus, a second spool can be transported on the same trailer and at the same cost as transporting just a single steel CT spool. There are, of course, many other transportation options, but they certainly also come with a cost.

When considering base materials, the cost of steel is about US$0.5/kg and that of CFRP is upwards of $10/kg; however, this doesn't tell the whole story due to the 5x difference in density. The strength-to-weight ratio for steel is about 50 kNm/kg while CFRP is roughly 390 (for bi-directional loads as is common for CT). Instead of comparing cost per mass, it might be more reasonable to compare the cost per strength since the tubing is a type of structural equipment. When calculating this, we find steel has factor of 100 kN/USD and CFRP has 39, a difference of only 2.5x.

Despite popular belief, material cost may not be a main driver for CFRP flexible tubing, especially when the other benefits are considered. Manufacturing CFRP CT however still represents a major challenge. Fabrication costs for several kilometer-long CRFP tubes would be markedly higher in comparison to the steel CT fabrication method which has several decades of maturity. It is difficult to estimate these costs now and especially how they will improve with time. Nonetheless, there are exciting opportunities ahead to develop these innovative manufacturing techniques.

The potential improvements in fatigue life along with the extensive list of secondary benefits related to lightweight materials are sure to bring the cost of this technology closer to competing with the steel tube solution of today. OE

Kevin Cox, PhD, is at CMR – Prototech and holds an MSc in mechanical engineering and a PhD in materials engineering. He has more than 10 years' experience in structural design, analysis and research and development withing the oil and gas, renewables, marine and aerospace industries.

Oleksandr Menshykov, PhD, is at the University of Aberdeen and holds an MSc in applied mathematics and a PhD in solid mechanics. Menshykov has more than 15 years' experience and has contributed to more than 100 publications.

Island Offshore's *Island Frontier.*
Image from Island Offshore.

Time for an intervention

Well intervention spending has been hit harder than other areas, but it is not due to a lack of opportunities. Elaine Maslin reports.

While well intervention spending has been hit harder than average industry cuts, the opportunities are still there, not least from mature North Sea assets.

But, companies need to have the right attitude, processes and resources in place to achieve what could be double digit percentage increases in production. They also need to increase well intervention intensity and use a broad range of tools to benefit the most, says Dan Cole, general manager, energy insights, McKinsey & Co.

It's a message that hasn't gone unheeded by Statoil, which has a dedicated well intervention team working across its assets. For the past two years, the company has done an average 48 operations a year, with results to show.

Overall, well intervention has been having a tough time of it, however. A third of the cost has been taken out of the sector since its peak in 2014. Spending levels are the same as they were seven years ago, Cole says, who was speaking at Offshore Network's Offshore Well Intervention Europe Conference in Aberdeen. North Sea well maintenance spending has seen an even greater decrease, down 43%, from $1.3 billion in 2014*.

"Could it be the opportunity is not there? Absolutely not," Cole says. "We have been at US$50/bbl or so for a year, more or less, and there are signs investment is starting to pick up. But, he adds, it is hard to ignore the backdrop."

Opportunity knocks

What is the opportunity? Cole points to the number of shut-in wells, relative to their maturity, measured by water cut. "There are more shut-in wells as fields become more depleted and have higher water cut," Cole says. "One in five depleted wells are shut-in, some permanently. But, if some could be restored to a level similar to [comparable] onstream wells, you could very quickly get some good production numbers. From a rough calculation, you could get to a couple of hundred thousand barrels of oil equivalent a day production [across the North Sea]."

Production losses, i.e. maximum production capacity compared with actual production, also point to potential. McKinsey categorized production losses into two categories: reservoirs losses – where a well is not producing as expected, maybe due to mechanical impairment, sand inflow, lack of pressure support, etc. The second category is losses incurred due to testing and intervention work.

"From 2008-12, the amount of losses incurred increased year on year and peaked in 2012 (partly driven by the Elgin Franklin well control incident)," Cole says. "Since then, every year has seen fewer losses. The share of the losses has also moved from reservoir losses to losses due to testing and intervention work, which is encouraging to see." The data suggests companies are doing more.

Better benchmarking

Through experience and benchmarking, the industry now also knows more now about what good and bad well work and reservoir management looks like, Cole says. It's been shown that when two operators with similar assets are compared, the one which performs more interventions and with a wider range of intervention tools and techniques sees greater production increases than the other.

In a comparison of two operators, one who intervened in one in 15 wells and the other one in three, McKinsey found that the second had 9-10% increase in production, compared with 2% on the first.

"Consistently, operators with higher levels of intervention and production use a broader range of intervention tools," Cole says. "Add a broader range of tools and more intensive intervention levels drives overall better performance around well intervention and reservoir management."

By seeking additional recovery, restoring shut-in wells, improving reservoir management, increasing the ratio of water injection and doing infill drilling could bring $70-350 million additional returns in the first year, Cole says. Indeed, he adds that he's been recently talking to operators that have been getting 5-7% increases from wells that are years and even months from their cessation of production date.

Previous work the firm has done has shown that well intervention can give higher – and faster – rates of return on investment. "We found, as a portfolio activity, intervention stacked up very well against drilling on payback time, and also on overall returns, at about 1.5x better then drilling," Cole says.

Organization matters

McKinsey has also looked at the difference between companies with successful intervention programs and those that are less successful.

"Typically, the difference between the good and the not so good are: differences in technical systems, i.e. the process side; the organization and how it is organized; and the philosophy or attitudes towards the activity," Cole says. "Making sure there is a process in place, identifying the opportunities and getting them through the operation, performance tracking and a good way to transfer knowledge between jobs that go well and those that fail," all help to put the process in place, he says.

"It also matters, having an organization lined up around this, and you need clear responsibilities, key performance indicators and targets as resources – cash and capability.

It is also important that they [decision makers] understand this is a core part of the business and considered at the top level. We know some interventions fail and some are extremely successful.

"The success rate overall is more than 50%, but people remember the ones that fail. That needs to be challenged."

Poor plant reliability and poor execution of interventions also results in poor performance in this area, he says. "To get this activity humming, you need all of the cogs to work," he says. The North Sea industry could also learn from outside Europe, including the way onshore North America operators "ruthlessly" approach their wells.

Based on data from across 50 assets in the Norwegian, UK and Danish sectors of the North Sea.* **OE

Island Offshore looks to next gen

Norway's Island Offshore is as aware of how tough the market is as any other company. But, the market isn't stopping it from pushing ahead with the newbuild *Island Navigator*, due to be delivered from Kawasaki Heavy Industries in January 2019.

The firm has three other LWIVs. These include the second generation *Island Constructor* (built in 2008), which works in the UK and Norway; the *Island Frontier* (built in 2004), a first generation LWIV; and *Island Wellserver* (2008), a second-generation vessel, which works for Statoil in Norway. The latter two were laid up through winter and brought back into service for the improved weather when operating times were more favorable.

This is part of the reason that the fifth generation DP3, UT777 design *Island Navigator* is under construction. The *Island Navigator* will offer greater capability.

Demand for higher capability and ability to operate in greater weather windows is driving vessel size up, says Tor Erik Grønlie Olsen, operations manager, Island Offshore.

Already, Island Offshore is incorporating pumping capability with a 2in hose and 2in breakaway connector on its LWI package, with 8-10b/min pumping capacity, he says.

"What we are meeting now is pumping jobs that are high-rate and high-volume stimulation jobs in high-permeability reservoirs, so there's a requirement for larger diameter hoses, which brings challenges," he says, including how to connect on top of the well control package and emergency quick disconnect systems.

The sleek-design *Island Navigator* will be 170m-long, and 28m-wide. It will be cheaper to operate, boasts better station keeping and has better deck equipment enabling it to lower items into deeper waters, Olsen says. It will have a 150-tonne active heave compensated subsea crane and accommodation for 91 people.

Future vessels will need to be able to withstand harsher environments and work in deeper waters, he says, where station keeping is an issue. The capability to do open water completion, top hole completion, cementing and pilot hole drilling are all being studied. It could be that future vessels are designed to stay out more than 30 days (currently).

Island Offshore agreed to the contract with Kawasaki for the *Island Navigator* in July 2015. The Rolls Royce design vessel will be a combined well intervention and top hole drilling vessel built according to Mobile Offshore Unit regulations.

The ice-class (OCE-1B) vessel will be equipped with a built-in handling tower to secure a safe working environment during operations in harsh conditions, and two work class remotely operated vehicles. Its helicopter deck is towards the middle of the vessel, to secure optimal landing conditions in rough weather. The vessel is fully financed through Japanese finance institutions.

It will be able to perform top hole drilling; construction work; subsea installation work; secure wells; trenching, plugging and abandonment work; tower and module handling; inspection, repair and maintenance work; and Xmas tree installation.

"In the near future, we are going to see exciting solutions from several vessel operators on how vessels look," Olsen says.

In the current market, new vessels not only need to be able to meet demands for higher capability, but remain competitive with ongoing low rig rates. These factors. offer a double challenge to the LWIV fleet. This could be where commercial models could play a role, with ideas for consortia of operators requiring work being set up, with help from the likes of the Oil and Gas Authority in the UK. How far such ideas could be hindered by legal agreements is yet to be seen. ■

The newbuild *Island Navigator*.
Image from Rolls Royce.

Carbon composite ComTrac

Archer and IKM Group joint venture C6, set up in 2010, has developed ComTrac system package using a carbon composite rod.

The system comprises a spoolable, 12mm diameter semi-stiff carbon composite rod with electrical cables (up to 10km-long) embedded for communication with downhole tools, which is driven in and out of producing wells by a ComTrac surface unit. The surface unit includes a control/spooling unit and an injector unit and head that can push or pull the rod into or out of the well, and provide well pressure control.

C6 says using a carbon composite rod has advantages over traditional intervention methods, including a low friction factor, high tensile strength, and the capability of power and signal communication with downhole strings of the composite rod. It can also enter pressured wells and has a flexible constant-tension surface rig-up of the deployment system.

This means it can provide logging, perforating, electro-mechanical intervention, and standard mechanical interventions in well depths and well conditions other current rigless conveyance methods cannot. The surface deployment equipment also removes the need for line-of-sight or sheave wheel rig ups and place the maximum tension point within the injector system, enhancing operational safety.

The system has so far been used onshore in the Middle East and offshore in the North Sea, with several runs completed and further operations planned. C6 is also working on a suite of downhole electro-mechanical tools to work with its ComTrac system. ▪

The ComTrac system. Photos from C6.

Statoil champions LWI

Statoil's approach to well intervention has enabled it to run annual subsea well intervention campaigns across its portfolio, reducing operations time year after year.

"We are a large user of light well intervention vessels (LWIV)," says Øyvind Jensen, manager, drilling & well subsea well intervention at Statoil. "We have been using them since 2000 and, over the last couple of years now, we have had 48 different operations using two vessels per year and we think we are the largest user of this service in the world. We have approximately 525 subsea wells in operations and a fairly high demand for performing these services, for improved oil recovery, well work, etc."

Jensen says that much of the work is reliant on tractor services and includes data acquisition, perforating/re-perforating, zone isolation, installation of insert downhole safety valves, scale removal, installation or change of subsea Xmas trees, well killing or pumping operations, change out of gas lift valves, sleeve operations, and pre-rig plugging and abandonment work, all without diver intervention.

With firm's 525 wells spread across 27 different fields – and operating units – having a planning organization which communicates with those units enables Statoil to run long term year on year campaigns, Jensen says. It also means there's more learning, improving performance and reducing time taken to do jobs.

"Five to six years ago, we took around 17 days per operation on a [LWIV]. Last year, we were just a bit more than a week on a job (7-8 days per LWI operation)," Jensen says. On the two vessels Statoil has been using, the *Island Wellserver* and *Island Frontier*, days per well have been reduced from 17 and 18, in 2011, to six and just over 10, in 2016, respectively. The average for both vessels in 2016 was 7.8 days.

"The organization is set up just for [LWI] and the key is to cooperate across different licenses. And by working closely with Island Offshore we have solved a lot of issues," he says.

Jensen is also hoping to expand the scope of what can be done with LWIVs, including more preparation work for plugging and abandonment, handling cement, and open-water coiled tubing. "We are also looking at new kinds of contracts, such as performance driven contracts," he says.

Vessels that could work more of the year would also be welcome. Currently, Statoil doesn't do LWI in winter because it's too expensive – too much waiting on weather. "Year-round operations would need something else in the market than what there is today," he says. "110m-long is too short for full year operations. We would like to see 150-160m. That could be stable enough through winter." But, ultimately, it boils down to cost per barrel, Jensen says. ▪

Going rigless

Audrey Leon chats with Schlumberger, Baker Hughes and Weatherford to learn about the latest technologies available for rigless plugging and abandonment operations.

Rig-Free heavy-duty pulling and jacking unit. Photo from Weatherford.

OE: Please describe your rigless abandonment offering.

Euan Stephen, rigless intervension system (RIS) manager, Baker Hughes: [Baker Hughes] currently has two different units within our rigless abandonment fleet, the Mastiff Rigless Intervention System (RIS) and the Retriever Jacking Unit System (JUS). The RIS is a portable, modular, mast-style unit with a 320-tonne pulling capability delivered via a winch and travelling block. This unit can be configured in several different ways, depending on the operator's requirements. This includes provisions for well control and drillpipe racking to reduce in-hole tripping time. Once installed at the wellsite, the RIS has full X-Y axis skidding capability. This capability requires the unit to be rigged up only once to gain access to all well slots in a short time. The JUS is also a modular design. The unit's pulling capability is delivered by hydraulic cylinders and has a maximum pull of 200-tonne. Integrated into the unit are power tongs, a guillotine saw and a dual-drill machine, all essential equipment in the tubular recovery process. The unit also has full X-Y axis skidding ability to deliver the same time-saving, single-rig-up benefits as the RIS.

Euan Stephen

Rod Smith, integrated well abandonment global operations manager, Schlumberger: In the current landscape of abandonment, higher well complexity, increasing regulation, and well integrity issues have all combined to increase the challenge of achieving full isolation using a rigless methodology. This requires portfolios of technology to address industry needs and ensure robust barrier installation and verification.

Rod Smith

Schlumberger has leveraged a portfolio of technology for plug and abandonment (P&A) applications, such as LIVE digital slickline services, for more accurate depth control, confirmation of jarring, and risk reduction through head tension and on-demand release for stuck tools. These services provide electric line measurements and capabilities, but with the smaller footprint of slickline.

Further enablements in wireline include a mechanical services platform, ReSOLVE instrumented wireline intervention service, to retrieve stuck plugs or tools from wells and enable access. The system can also mill scale and obstructions to prepare the well for cementing.

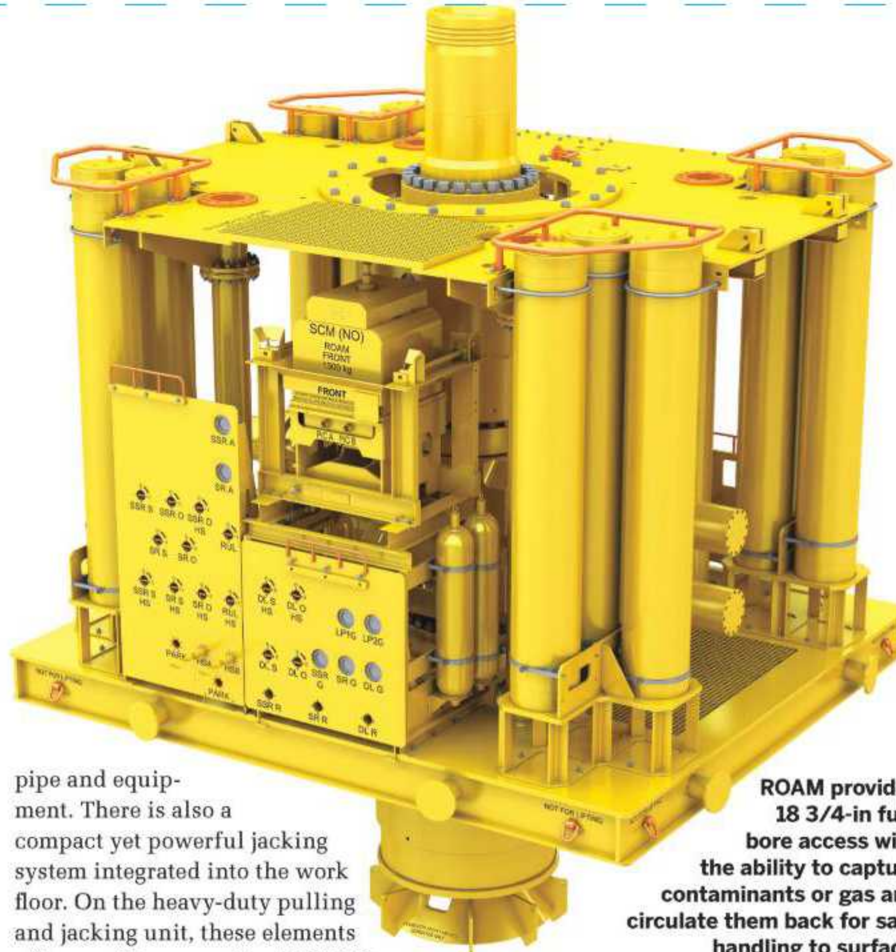
Advancements in coiled tubing (CT) technology have also allowed more downhole confirmation of barrier placement through the use of ACTive real-time downhole coiled tubing services.

Currently, Schlumberger is working on several new technologies focused specifically on rigless abandonment. Specific to subsea wells, the Subsea Services Alliance (a collaboration among Helix, Schlumberger, and OneSubsea, a Schlumberger company) is developing the first riserless open-water abandonment module (ROAM) system (*OE:* April 2017). Enhancing the capabilities of the well intervention vessel by providing 18¾-in full-bore access, ROAM is deployed after the reservoir isolation phase and allows tubing to be pulled in open water safely and with environmental containment. Once the tubing is removed, the well intervention vessel can perform the upper abandonment. The system offers a flexible and cost-effective alternative to rig-based P&A well isolation more safely and with environmental containment.

Delaney Olstad, global business development manager – well abandonment & intervention services, Weatherford: The Rig-Free pulling and jacking unit (PJU) is an integrated system for efficiently completing offshore well abandonment and intervention operations. These systems are designed to complete tasks normally performed by a jackup rig or workover unit, but at a lower cost and with a higher degree of safety. It is well-suited for pulling tubulars and conductors on platforms with downgraded structural capacities and in situations where space is limited.

Delaney Olstad

To accommodate a wide range of operations while being adaptive to platform limitations, Weatherford has two versions of the PJU. Each PJU has a hydraulically powered telescoping mast, which sits directly above the well center and incorporates a power swivel for rotating pipe and equipment. There is also a compact yet powerful jacking system integrated into the work floor. On the heavy-duty pulling and jacking unit, these elements offer a pulling capacity of 220,000 lbs (99,790 kg) in 60ft (18.2m) increments and a jacking capacity of 600,000 lbs (272,155 kg) in 5ft (1.5m) increments. The light-duty PJU provides a pulling capacity of 35,000 lbs (15,8676 kg) with a stroke of 44ft (13.4m) and can jack in 5ft (1.5m) increments at up to a capacity of 1 million lbs (453,592 kg).



ROAM provides 18 3/4-in full-bore access with the ability to capture contaminants or gas and circulate them back for safe handling to surface.
Photo from Subsea Services Alliance.

OE: Please give an example of where it has been used and when.

Euan Stephen, Baker Hughes: The Mastiff RIS was used in the North Sea from June 2015 to March 2016 to enable an operator to save valuable time in a platform removal operation. The operator faced time constraints as a heavy lift barge was scheduled to remove the platform. The Baker Hughes solution allowed simultaneous operations to progress on the platform on both the RIS and the platform drilling derrick, enabling all abandonment work to be completed within the required time.

Rod Smith, SLB: Making the abandonment process more lean is key in reducing costs without comprising barrier integrity—and in many cases will improve verification success with less risk and HSE exposure.

LIVE digital slickline services have been used extensively in the North Sea and Gulf of Mexico for well abandonment. In some cases, the service is used only for well preparation, plug setting, and tubing cutting and punching. In other applications, it has been used for full abandonment, saving numerous trips for correlations and adding certainty to plug tagging. In the North Sea, the service was used for plug and lubricate operations as part of a well abandonment scope that saved the customer 24 hours per well.

ROAM is engineered and being built at the OneSubsea manufacturing facilities. The system is leveraging existing in-house technologies such as BOPs from Cameron, a Schlumberger company, and workover controls technologies from OneSubsea, packaged into a fit-for-purpose solution. Available later in the year, ROAM will complement existing intervention riser systems (IRS) and subsea intervention lubricators (SIL), expanding applications by enabling completions recovery in open water with environmental control and full well isolation capability without

Baker Hughes' Retriever jacking unit system. Photo from Baker Hughes.

the size of the respective unit and handle the combined load of RIS unit weight + maximum pulling capacity, as this will be transferred to the platform substructure. It is not water depth, but the size of the platform, load capability and occasionally bed space, that determine whether RIS is a good option.

Rod Smith, SLB: As the industry looks to address the abandonment process in its entirety, there will probably be an application for using these Schlumberger technologies in most scenarios. The key benefit of simplifying equipment spreads with more intervention-enabled deployment methods is in reducing reliance on costly and complex drilling rigs while reducing the support costs for operations. High-cost applications such as subsea wells and complex abandonment environments will realize the greatest cost, risk, and efficiency benefits.

Delaney Olstad, Weatherford: As efficiency and profitability become increasingly important throughout the industry, the need for cost-effective, compliant abandonment and intervention resources is critical. Our innovative Rig-Free PJU has demonstrated its ability to improve efficiencies and limit the expense of abandonment and intervention operations.

The primary innovation and benefit of the Rig-Free pulling and jacking unit is in the name—it eliminates the need to employ costly jackup and workover rigs for offshore abandonment and intervention campaigns. For well abandonment or intervention operations involving multiple wells, the elimination of a rig can represent tens of millions of dollars in savings.

With the ability to improve the efficiency for both plug-and-abandonment and late-stage intervention, the Rig-Free PJU has already changed the well economics for many of our customers by increasing operational efficiencies and reducing overall operating costs. OE

the need for a riser to surface—saving considerable running time.

Delaney Olstad, Weatherford: Our pulling and jacking units have been in operation for a decade, primarily in the Gulf of Mexico. They have also been deployed in the Asia Pacific market. The modular design of the system allows for rapid mobilization and efficient assemblage on the platform. Once on location, an innovative self-clamping skidding assembly enables movement from well to well without the need to rig down any main system components. The numerous capabilities of the PJU also allow it to conduct the majority of operations without assistance from the platform crane, facilitating simultaneous operations. By reducing the time spent on setup and well-to-well relocation, in addition to the minimal need for crane support, the PJU saves time and money.

OE: If you haven't seen your system used commercially yet, how would it benefit the operator?

Euan Stephen, Baker Hughes: Using a specially designed Retriever JUS for a tubing, casing and conductor removal operation in the southern North Sea from February to April 2017 eliminated the requirement for mobilizing a jackup. This resulted in cost savings of approximately £20 million (US$25 million) to the operator since mobilizing a rig would have required removing a considerable amount of subsea pipe work.

OE: Please tell us the benefits of using this technology. i.e. where are the best instances for using this technique?

Euan Stephen, Baker Hughes: The main benefit of using rigless intervention systems is that mobilization of a jackup rig or full-size platform rig can be avoided, providing significant cost savings to the operator. The biggest benefit of the Baker Hughes rigless abandonment offerings is flexibility. Having two units with different designs means the ability to install units on a variety of platform sizes while providing a cost-effective solution. The unit can be supplied in a basic, lighter-weight version and can also be supplied with additional enhancements to deliver options such as drillpipe racking, well control, surface rotation and integration of services from other product lines.

Rigless intervention systems are used for platform applications. It is important that the platform can accommodate

Rigless P&A: Increasing efficiency, reducing cost

Halliburton's Ernst Schnell discusses a recent collaboration between Halliburton's casing equipment team and a Scandinavian operator, which helped develop a rigless method for plugging a well through the Xmas tree.

Rigless AbandaSystem schematic.
Image from Halliburton.

Time is money. In offshore operations time is a lot of money. Looking for ways to operate more efficiently and lower costs is essential to ensuring the viability of offshore operations, especially when market conditions are as challenging as they've been over the past two years.

Halliburton and a Scandinavian operator recently collaborated to develop a new rigless, time-saving method for setting controlled-volume abandonment plugs. Unlike a conventional plugging operation that requires extra personnel and complex logistics, the rigless AbandaSystem entails a AbandaSpool cement spool, connecting to the Xmas tree, a wireline-deployed packer to serve as a base, and two AbandaPlug wiper plugs to land on the packer and isolate the cement to prevent contamination.

The AbandaSpool cement spool is a plug container body equipped with three plug-release plungers and a manifold with six plug valves.

Atop the retrievable packer is a seal-bore landing profile adapted for a specialized lower wiper plug. An optional water injection valve can be added to the bottom of the packer to act as a check-valve to prevent flowback from the well; this valve can also be configured for specific pressure overbalance to ensure that the cement and not the valve is holding the pressure.

The lower AbandaPlug wiper plug is rubber and has a seal mandrel on bottom to land on the packer's seal-bore, creating a seal and acting as a base for the following cement slurry. This wiper plug includes a shear disc designed to burst at 1000–4000psi, depending on well requirements; this allows testing the seal of the cement plug after it's cured. If the plug does not hold above the required pressure, the shear disc will burst and open a path for pressure to bleed off below, indicating failure.

The upper AbandaPlug wiper plug is a conventional plug to separate the cement from the displacement fluid.

Candidate wells for this method should have confirmation of a reliable cement barrier in the annulus, acceptable injection rates and pressures by running an injection test, and that a packer can be run and set in the tubing by running a caliper log in the tubing.

The packer is run on a wireline connected to the AbandaSpool cement spool — this speeds up the operation and reduces rig downtime. The wiper plugs are installed and released from the AbandaSpool cement spool. Pumping and displacement of cement follows a conventional casing cement operation. When landing the lower wiper plug, which seals in the top of the packer, the crew must focus on limiting pumping pressure to avoid exceeding the shear disc threshold.

After waiting on cement to achieve sufficient compressive strength, a cement pressure test is performed at the required pressure, exceeding the shear disc threshold to ensure a reliable confirmation of the cement plug.

The rigless AbandaSystem method can be applied to a range of casing and tubing sizes. The packer used in the operations thus far is available for tubing ranging 4.5-7in.

Placing the cement plug without using the retrievable packer is another option. The lower wiper plug can be modified with an elastomer seal bottom sub to land in any geometry.

The four operations performed to date have saved the operator 1-2 days of rig time per plug. The current regulations in the North Sea require a cement barrier plug to be tagged with drillpipe; where this is not a requirement more time can be saved.

The next challenge Halliburton and the operator are working on is adapting this novel method for subsea wells, as the potential cost savings will be even greater compared to platform wells. **OE**

Ernst Schnell is the cementing technology & business development manager for Eurasia, Europe and Sub-Saharan Africa at Halliburton. He was trained as a chemical engineer at the Karlsruhe Institute of Technology in Germany and has his Master of Laws in Oil & Gas Law from the Robert Gordon University. His career has been internationally focused, taking him from Nigeria, to the UK, the Netherlands and Angola. Ernst joined Halliburton in 2012.

M. Olsen et al.: "Improved Through-Christmas-Tree P&A Plug Placement with New Innovative Cementing Methodology", SPE Paper No. SPE/IADC-184653-MS, SPE/IADS Drilling Conference and Exhibition, The Hague, The Netherlands, 14-16 March 2017.

Seeking P&A alternatives

Elaine Maslin surveys some of the plugging and abandonment solutions presented at Sintef's Experimental P&A Research for the North Sea event in Trondheim, Norway.

Plugging and abandonment (P&A) work is not drilling. It sounds obvious, but it's perhaps a phrase needed to help drive new solutions in the P&A space, a challenge that Norway's research institute Sintef has set itself.

Private equity cash in Norway is also setting its sight on this space, because it is hugely costly area, and one in which a new technology could save operators time and money, with the potential to have a global impact – and not just in oil and gas wells, as geothermal and CO_2 storage wells will be seeking similar solutions.

Norwegian private equity house ProVenture, which invests in early stage start-ups, is one of those diving into the P&A technology space.

"P&A is a huge cost for operators," said David Lysne, ProVenture's senior partner, addressing Sintef's Experimental P&A Research for the North Sea event in Trondheim, Norway, in late March. "The numbers are so big, it is a huge market and of a lot of interest to us and others."

A Norwegian, but also global challenge

Alexandra Bech Gjørv, president and CEO at Sintef, told the Trondheim event that there are 4200 wells on the Norwegian Continental Shelf. Of those, only 250 have been plugged and abandoned, and a further 1650 have been partially abandoned.

Alexandra Bech Gjørv

"In the UK, there are 5000 wells. Globally, millions of wells need to be plugged." There's a large opportunity for those wanting to tackle this issue, and not just in the oil and gas

Statoil's Huldra platform.
Image from Statoil/Kjetil Alsvik.

industry, she says.

The chief aim is to reduce costs, mostly via reducing rig time. "Some new innovations have been introduced, but targeted research and development are needed for a step-change. Well plugging isn't reverse drilling," Gjørv says.

But, when it comes to investing in P&A technology firms, "there is a dilemma," Lysne says. "If one [technology] succeeds, many others will not and they will take over a lot of the market."

One company with such potential, he says, is Interwell, which has been testing a thermite plug technology. The plug uses a thermite reaction to effectively burn through the well and into the formation creating a seal without having to remove casing, etc. "If that's excepted by the operators, that will wipe out the need for a lot of other technologies," Lysne adds. "That is one of the dilemmas we face [as an investor]."

Government regulations in P&A are also a little bit vague, creating uncertainty, he says. "We have NORSOK guidelines, but they are just guidelines. Interwell goes beyond the Norwegian standards. We also know others that do the same, go beyond the Norwegian standards."

There's also the problem of when the work will come. "We are all waiting for the Tsunami of P&A wells we have been hearing about over the years," Lysne says. "We want to know when it is coming. Maybe it's building up and becoming bigger than we think."

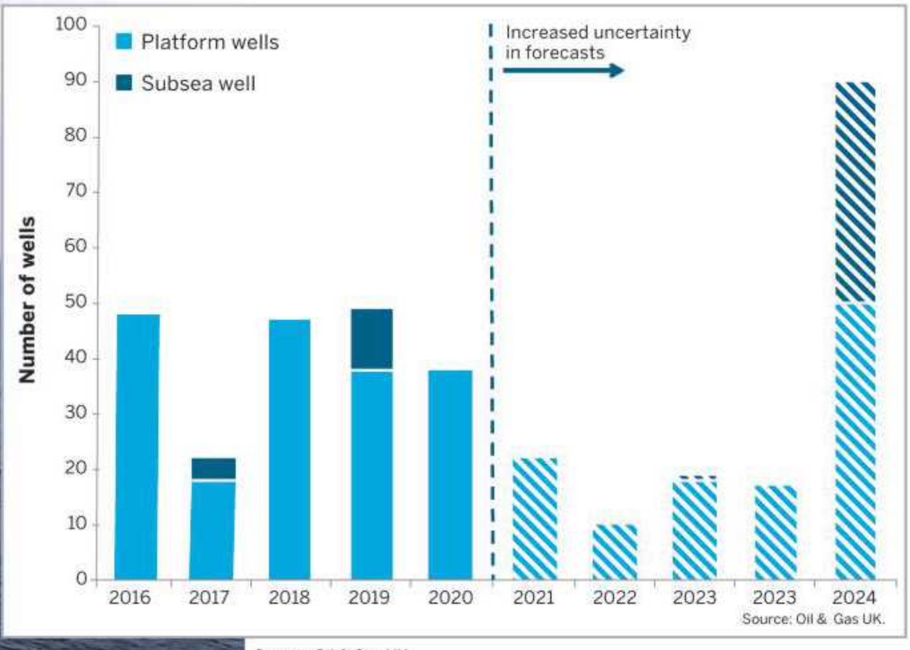
Reducing rig days, the Statoil way

Statoil will have limited P&A activity until 2020, because it is focusing on keeping production rates up, says Pål Hemmingsen, project leader P&A technology strategy, Statoil. Statoil will start major campaigns on platforms in 2020, and then subsea wells from 2025, he says, adding that these dates could change as life time expectations of fields and oil prices change. The work the Norwegian major has been doing, however, has seen it reduce rig time on P&A work considerably. Hemmingsen says that Statoil has reduced P&A per well time by 47%. Last year, Statoil P&A'd 18 wells (nine on Volve, six on Huldra and six single P&A jobs), taking an average 17.8 days compared to 33 in 2014.

The reduction stems from an improvement plan set out in 2014. This plan focused on three steps: performing best practices and improving planning; incremental technologies; and then game changing "radical" technologies. These are technologies that can be run using well intervention methodologies, or on a platform when the rig is being used for other purposes.

The 47% reduction in 2014-2016 was achieved largely through improved planning and focus on costs, Hemmingsen says, as well as simplifying P&A design – making it "fit-for-purpose." Rig time was reduced by using production tubing as a cement stinger by cutting it and lifting it to the desired area.

Projected Norwegian P&A activity



Source: Oil & Gas UK.

"When we started investigating, we found that, in most cases, barriers are good, and we don't need to do section milling. In many cases, the formation has crept in to the casing, and can be used as an element in the well barrier," he says.

To use the in-place cement as a barrier, it needs to be verified, which poses a difficulty. At the moment, pipe or tubulars between the outer casing and cement must be removed.

"You have to have efficient placing of the plug, but you need to be able to verify it too," Hemmingsen says. "Using different barriers will also require qualification, unlike current cement when used to agreed lengths. But altering the length [of cement used] or using a different material would need verification."

An intervention

Statoil has been assessing its well stock – 1200 to date – and is categorizing them on how easy it would be to do intervention-based P&A, including using wireline or coiled tubing. Almost half of platform wells were in this category. Subsea wells were more complex, however, with multiple tubulars and smart wells with control lines. "There is a huge range of well designs and we will need different types of technology to P&A these wells," Hemmingsen says.

Statoil is looking at various concepts, including using explosives to create a radial cut around one or more casing sections, and using a thermite plug, such as Interwell's concept. But, to use such technologies, questions around how to place barriers and how to verify them still need to be answered. Hemmingsen says that it is believed cement barriers could also be shorter, but that issues around placement and verification remain.

Formation as a barrier

Verification is also something of a challenge for another technique in the P&A space – formation as a barrier. This is where the surrounding formation exerts pressure on the well such that it creates a natural seal. Truls Carlsen, advisor for wellbore stability and drilling practice, Statoil, says the Norwegian major has been looking at this for over 12 years, mostly in the southern [Norwegian] North Sea and Norwegian Sea.

Carlsen says that there's a wide range of lithologies in which this sort of "creep" can happen. Statoil first saw it

Sintef's Experimental P&A Research event in Trondheim.
Image from Sintef.

at the Oseberg field, where it got a signal from a cement bond log, where there wasn't supposed to be cement. These were in clay ridge intervals, Carlsen says. It was cut and pressure tested to check there was no leakage across the section. It can take just two days, from drilling a well, running casing, and cementing, especially in green clay, he says.

After the results on Troll, over three years, more than 300 wells have been tested for formation bonding and the technique has been used on 25 fields, across 11 different formations, Carlsen says. Carlsen estimates US$791 million (NOK6700 million) has been saved by using formation as a barrier over the same period as a result.

Statoil is building an atlas of its results, so it can make more use of the technique and improve or standardize testing. In general, rocks which creep are those with high clay content, less than 25% quartz and under 5% carbonate.

However, it's still an area with uncertainties. Areas which show promise for formation as a barrier don't always prove to be so, as happened in a well on the Troll field, Carlsen says. "It may be lower pore pressure, lower temperature, lower stresses," Carlsen says. The unexpected results will provide calibration, he says. In other cases, however, the creep can be so strong that it deforms the casing.

Aker BP

Aker BP also has been interested in creeping shale. It has been looking for cement bond log signals in previously uncemented intervals, then verifying the data with pressure tests. However, Tron Kristiansen, senior operations geologist, drilling engineering, Aker BP, says results can be variable, even in similar rocks. Aker BP wanted to see if it was possible to deliberately activate shale and be more certain about the end result. "By engineering it, can you get a more consistent barrier," Kristiansen asks. Activation via pressure, temperature and a combination of both has been tried, and the best result was through a rapid pressure drop in the annulus. But more work needs to be done, he says.

Sintef has a project to understand the mechanisms that create shale barriers in order to establish methods of predicting or improving it. It has been running lab tests with core samples, including flow tests, after it thinks seals have been formed, and then takes CT scans, to see what's been going on. Part of this work is to verify if it's plastic deformation going on, rather than elastic – because plastic deformation would not be reversible. Ways to improve these properties would be to change pressure, temperature and use fluids to change the rock properties, says Erling Fjær, professor, department of geoscience and petroleum, Sintef. But there are still questions around the long-term effects, and if lab tests can be used to qualify shale as a barrier in the field, Fjær says.

Salt, a natural sealing formation, is also a possible natural barrier, or self-healing formation, says Bogdan Orlic, reservoir geomechanics specialist at TNO. It's common in the Zechstein reservoirs in the northern Netherlands, and elsewhere in northwest Europe, over Permian and Rotliegendes sandstones, Orlic says, usually at about 3000m deep.

Pulling teeth (or tubes)

Where the barrier behind casing cannot be verified, cutting and pulling tubing and removing casing, a job which usually requires a drilling rig, must be done. Various alternatives are being researched, including dissolving the casing.

Astrid Bjørgum, a senior advisor at Sintef, says that by using an electrolysis reaction, in which the casing acts as one electrode, you could dissolve right through the steel. Alternatively, you could put an aggressive fluid in the well – or you could do both. "We have seen you can get high dissolution rates with strong acid and electrolytes," Bjørgum says. At 60 degrees celsuis, acid and electrolytes used on 7in casing helped dissolve the casing in eight days and it could be less using higher temperatures, she says.

Using an electrochemical dissolution with an external, unlimited power source – power and dissolution were found to have a linear relationship – saw the 7in casing dissolved in four days using 900amp/sq m. However, conventional wireline cable is power limited, she says. Using a wireline set up, limited to 10KW, 1m of 7in tubing could be dissolved in one day, she says. This means a casing window could be created without using a rig.

When questioned about the products of the corrosion process, such as chromium, she says that they would mostly remain in the well. **OE**

The last frontier

EIC's Andrew Scutter details the challenges and opportunities present offshore Senegal and Mauritania.

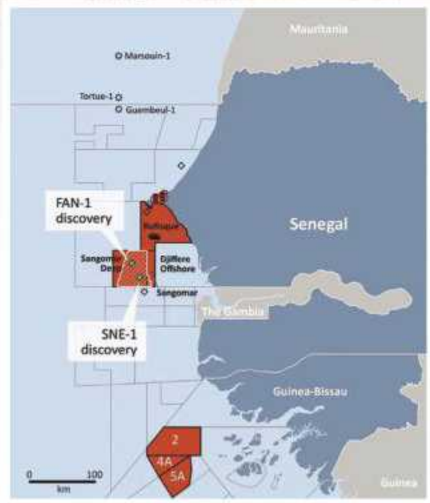
During a challenging period for the industry, West Africa has managed to further justify its position as one of the last true frontier regions. Discoveries in Senegal and Mauritania have the potential to transform both countries into net exporters within the next five years.

Senegal persevered with over 140 exploration wells of limited success until Cairn Energy's FAN-1 and SNE-1 wells in the Sangomar Deep Block in 2014 yielded major results. Both wells discovered significant hydrocarbon resources, with the SNE field having an estimated 285m barrels of 2P (proven and probable) reserves. Cairn is currently planning the SNE-6 appraisal well and could reach first oil as soon as 2021.

In 2015, a second major discovery was announced by Kosmos Energy, the Tortue West structure, which straddles the Senegal/Mauritania border. Subsequent discoveries in both Mauritania and Senegal established the Greater Tortue Complex that has a Pmean gross resource estimate of 25Tcf of gas. A unitization agreement is currently being worked on between the two countries, and the partners, on how best to jointly develop the field. A development concept is set to be finalized in 2017 or early 2018, and will most likely be a near-shore, 2.5MPTA FLNG vessel, with a pre-treatment platform and a condensate offload vessel. KBR was awarded the pre-FEED contract for the upstream aspects of the project, and sources suggest that the company is preparing to carry out FEED studies.

The most recent discovery in the region was made south of the Tortue Complex in the Cayar Offshore Profound Block. In May 2017, BP announced the discovery of a 15Tcf gas accumulation within a Lower Cenomanian reservoir. The size of the find, combined with the nearby Taranga discovery, makes it possible that a second LNG hub, after the Greater Tortue Complex, may be created within the area.

Both Senegal and Mauritania were quick to enter a memorandum of understanding with Kosmos,, and later BP, which sets out the principles for an intergovernmental cooperation agreement for the development of the cross-border Greater Tortue resource. Kosmos believes that gas demand will have risen by the time the field becomes operational, and is looking to capitalize on the current low contractor costs.



Senegal Discoveries Map. Image from Far Ltd.

Due to the continued exploration success, there has been increasing interest from companies to explore the region. A new 3D seismic survey was completed offshore The Gambia by Erin Energy. The area has massive potential as it lies in the block directly south and on the same trend as the FAN-1 and SNE-1 hydrocarbon discoveries. Likewise, France's Total recently signed an exploration and production sharing contract for the Rufisque Offshore Profond Block, which is a deepwater and ultra-deepwater concession.

Significant challenges will need to be overcome to develop these fields as Senegal and Mauritania lack the infrastructure and capabilities required for these billion dollar projects. Senegal and Mauritania are realistic about their capabilities, and are keen to utilize experienced foreign suppliers, so long as some form of local partnership is made. This provides opportunities for UK supply chain companies with extensive offshore experience to offer their services. OE

Andrew Scutter is the Upstream Sector Analyst at the EIC, and covers this remit globally. He has a degree in Geology from the University of Leeds and a master's degree in Petroleum Geoscience from the University of Aberdeen. Andrew has also gained experience working with an international operator, CNR.

West Africa

Slow progress

Karen Boman assesses the market for West African oil and gas projects, and profiles Total's Moho Nord development offshore Congo.

Around 15 offshore West Africa projects are forecast to come online between now and 2020, with another 15 estimated for 2020-2025. There are a few tiebacks/additional phases planned in major production areas, such Usan in Nigeria, Zinia and Ochigufu in Angola, and Nene Marine in Congo. However, most will involve new infrastructure, as the fields are spread out across a much larger area than the North Sea or Gulf of Mexico.

"Given that less fixed infrastructure, such as pipelines and platforms, is available off West Africa, most of the production is developed using floating vessels and exported via tankers," Jonathan Markham, GlobalData upstream analyst, told *OE*.

Billions of barrels of oil remain offshore West Africa, and recent discoveries in Senegal have opened new plays in frontier areas of North West Africa, Markham says. Operators also are increasing their focus on natural gas projects, which have typically been overlooked due to lack of local markets, as new technology such as floating LNG is being implemented.

"Much of the remaining hydrocarbons offshore West Africa are in deepwater and ultra-deepwater fields, and this is similar to challenges faced in many parts of the world," Markham explains. "Operators now focus more effort on optimizing well locations and drilling trajectories to ensure maximum productivity per well to reduce drilling costs."

More equipment is being installed on the seafloor, such as subsea multiphase pumps, to reduce the pressure differentials between the surface and the wellhead and maintain flowrates. Operators also are using electrical heating technologies, such as trace wires and composite materials, to maintain the temperature in the flowlines, or chemical additives to prevent the hydrocarbons congealing in the extreme conditions of ultra-deepwater, Markham says.

To cope with the downturn, operators are trimming capex budgets by opting for simpler solutions with greater equipment standardization, instead of bespoke designs. Project breakevens are currently around US$50-60/bbl for deepwater fields in West Africa.

"Overall though, companies are simply delaying sanctioning new projects and reducing the amount of investment in the area," Markham says. A steady price above $60/bbl is necessary before widespread investment starts picking up again.

Fortunately for West Africa, a significant number of massive projects such as Moho Nord had already been sanctioned prior to the oil price downturn, Mark Adeosun, analyst with Douglas-Westwood, told *OE*. Since the downturn, however, regional activity has been quiet, with only one floating production, storage and offloading vessel ordered. That order was placed in 2005. In recent months, operators have been looking at extending existing fields with brownfield drilling to maintain a certain level of production, Adeosun says.

Political tensions present another challenge for operators working offshore West Africa. Such tension between countries can often be an impediment to developments, as maritime borders are often disputed, Markham adds.

Adeosun says that he believes that political instability and local content issues are the real challenges for offshore West Africa projects.

"Local content rules are making it more difficult for some of these projects to be completed in a timely and effective manner," Adeosun says. One of the issues delaying the Bonga SW project has been the Nigerian government trying to negotiate local content requirements for the construction of components for the Bonga SW's floating production storage and offloading vessel.

Adeosun has seen an improvement in this area over the past two years. Companies such as TechnipFMC are setting up factories in West Africa, allowing operators to meet local content requirements for manufacturing.

The tension leg platform and *Likouf FPU* at the Moho Nord field. Photo from Total.

Some companies also have been collaborating with local firms to train local workers. Developing the local workforce will take time. Workers will gain significant experience as they work on projects, creating a situation that is more of a win-win for international oil companies and local companies, Adeosun says.

Over the next two years, Douglas-Westwood anticipates a significant oil production increase due to massive projects coming online. After that, a decline is expected due to lack of project sanctioning before another uptick when more offshore projects come onstream.

Moho Nord raises stakes

Moho Nord, which started production in March, confirms Total as the largest oil and gas operator in the Congo, and establishes Congo as a deepwater producer, Andre Goffart, senior vice president development and support to operations for Total, told attendees at this year's Offshore Technology Conference in Houston.

Moho Nord, which came on stream four years after Total made a final investment decision on the project, is the French major's latest project on the 450-1200m water depth Moho Bilondo license offshore Congo. The first Moho Bilondo project came onstream in 2008, with 12 wells to two manifolds producing to via the *Alima* floating production unit (FPU). In 2015, Total then brought the Moho Bilondo Phase 1bis development online, in the southern portion of the license, which involved an upgrade to the *Alima* and the subsea system, including new subsea multiphase pumps. Moho Nord, the latest project, is in the northern portion of the license, 75km offshore Pointe-Noire, Congo.

Moho Nord was developed using 34 wells, 17 (including six water injection) tied back to a new 14,600-tonne minimal facility tension leg platform (TLP) – a first for Total in Africa – and 17 were tied back to the new 62,000-tonne *Likouf* FPU. Moho Nord has a 100,000 b/d capacity (40,000 b/d from the TLP and 60,000 b/d from the FPU). Combined with Phase 1bis (which had 11 additional wells come online), the Moho Bilondo license has the capacity to produce 140,000 b/d.

Engineers on the Moho Nord faced a challenge due to the different oil types within the different reservoirs the project aims to tap. Moho Nord comprises two sub-projects over three reservoirs, Goffart says. The northern portion contains both shallower Miocene and deeper Albian reservoirs; the southern portion contains a Miocene reservoir. In the north, unconsolidated Miocene sand is buried 1000m below the seabed, in 1200m water depth. The Albian carbonates reservoir is buried 3000m below the surface, but lies in 800m water depth.

Because the Miocene and Albian produced waters are incompatible, Total would have to produce the resources separately. To address this challenge, Total opted to use both a FPU and a TLP, Goffart says. For the northern Miocene reservoir, Total deployed a conventional subsea network, with 17 subsea wells tied in to the *Likouf* FPU and the existing *Alima* FPU. Oil started producing from this Miocene reservoir in March this year.

Due to the shallower water depths of the Albian reservoir, the company decided to use a TLP with surface wellheads connected to 17 wells, Goffart says. This reservoir was scheduled to come onstream in May. The TLP will be used to drill deeper, longer wells, and allows for frequent well interventions using coil tubing. Production from the TLP is routed to the *Likouf* FPU for processing, then sent to the Djeno terminal onshore. The two oils are processed separately via the FPU, which was built by Hyundai Heavy Industries in South Korea, as was the TLP.

The downturn posed another challenge for Total in developing Moho Nord. "We signed the contracts before oil prices fell," Goffart told the OTC audience. To cope with lower oil prices, Total pre-installed the anchor tendons on the TLP and fast-tracked subsea production system deliveries.

Speaking at the Underwater Technology Conference in Bergen, Joel Cazaux, SPS manager for Total, said in total some 10,000-tonne of subsea equipment was delivered for the project. Cazeux outlined some lessons learned on the project, including the need to streamline documentation packages, but also issues with the project's subsea control modules, having large (65-tonne) Xmas trees, and delivery schedules.

New technology is also playing a role. A new multipurpose workover system, with an interface for dual intervention mode systems, had by mid-late June already been used on 15 wells successfully, and is being developed to be able to work in tubing hangar mode, by Q4 this year, Cazeuz said.

Technip was contracted for project management, engineering, supply, fabrication and installation of pipelines, umbilicals and other subsea structures for the project, in addition to installing the manifolds, control system components and multiphase jumpers. Aker Solutions was chosen to supply 28 vertical subsea trees including wellhead systems, two installation and workover control systems, seven manifold structures, subsea control and tie-in systems for the project.

Ocean Installer was selected to install and pre-commission an umbilical, multiphase pump, flying leads and spools. Fugro was selected to provide remote operated vehicle services and remote subsea tooling for the field. Dockwise, owned by Boskalis, was tasked with transporting the FPU from South Korea to the Congo.

Total operates Moho Nord with 53.5% interest. Its partners include Chevron (31.5%) and Société Nationale des Pétroles du Congo (15%). OE

Offshore Europe

Planning a sustainable future

Where technology and collaboration can help the industry reduce the cost per barrel in a sustainable way will be a strong focus at this year's SPE Offshore Europe, says conference chairman Catherine MacGregor, Drilling Group President, Schlumberger.

This time two years ago, we were heading toward SPE Offshore Europe 2015. It was just over a year into the downturn and perhaps many were still hopeful that the pain would be short-lived. They will have been disappointed and the backdrop of almost three years in a downturn will be hard to avoid at this year's event although we are starting to see signs of recovery. On a more positive tone, this period offers as many opportunities as there are challenges for the industry to re-invent itself. We are actually starting to see a number of initiatives moving in that direction.

Exactly how some of the biggest players see the current environment will be discussed at the event's opening plenary, which features Shell CEO Ben van Beurden, BP Group CEO Bob Dudley, Petrobras CEO Pedro Parente, and Wood Group Chief Executive Robin Watson.

"The context remains a challenged industry," says Catherine MacGregor, Drilling Group President, Schlumberger, chairman of this year's SPE Offshore Europe, being held 5-8 September in Aberdeen. "But, it must be recognized that even at US$100/bbl, for some, projects were already uneconomical." In other words, the industry was already in need of a change and that change has been happening.

"Our industry is tackling the problems in many different ways," MacGregor says, who joined Schlumberger as a drilling engineer, working in Congo. "One of them is the application of new technology to reduce cost." Another way is embracing the digital era. "Other industries are embracing it as a very core topic and our industry is taking it on. This is very exciting because it has a huge potential to change the way we work and significantly bring our industry costs down in a sustainable way.

"Disrupting and digitizing our industry, harnessing technology to shape all aspects of our industry, including automation or remote operation... That's the prize. It is not easy to do, because there are so many interfaces. But, it has the potential to shake up who we are and continue to make us attractive to young talent. People who are coming in to the industry today are digital natives. They will be looking to go to work with digitally transformed companies."

But, while digitalization can take us so far, reducing costs and manning, improving and enhancing operations, performance and subsurface understanding, and how companies interact and work together, will also be in the spotlight. "When you look at some of the big development projects, there have been a high number with delivery and cost overruns, even delays to production start-up, and technology issues," MacGregor says. "There has been a lot of analysis around what happened. One issue identified was that the relationship between the operator and contractor or suppliers was not necessarily conducive to the best collaboration or the best outcome."

Offering different models is even more important for mature basins like the North Sea, MacGregor says. It's about real commercial alignment, setting out a project with real collaboration. All this can only happen when trust is established between different players. It's about a mindset, not just a contractual relationship. Technology, workflows, solutions, are going to be developed and they cannot just belong to one side or the other."

The North Sea has other unique challenges, such as its interesting reservoirs and some very thin sands, MacGregor

Catherine MacGregor. Photo from Schlumbereger.

says. "Placing the well in the sweet spot to maximize contact, hard to drill abrasive formations requiring ruggedized drilling systems, are just a couple of the challenges," she says.

While the industry is conservative, especially when it comes to trying new technologies, MacGregor says technology that has value is getting attention. "We've seen over the last three years, operators are quite keen on new technology that adds value," she says. "And it's the introduction and adoption of technology that's important – the appetite to field test new technology and try new things. It will be exciting to discuss some of these technologies in the conference."

This year's SPE Offshore Europe will feature a Technology Zone and a Tech Trek, highlighting new technologies on show, as well as a Decommissioning Zone, reflecting the increasing activity in this space.

While few imagine oil prices will rise to pre-mid-2014 any time soon, the risk could be there that the industry reverts to its bad habits. However, MacGregor thinks this downturn has been more of a wake-up call and that sustainability has become a key theme.

But, to sustain itself into the future, following a period of deep staffing cuts and experience loss, recruitment and training will need to continue, she says. "It is very clear we are going to have to recruit new talent to our industry to replenish the bench."

Technology could play a role here, however. "If there were to be skills shortage, some of the technology uptake could help us mitigate the risk in not having enough experts, by sharing experts across several facilities and operations, having operations centers that monitor facilities," she says.

"The industry is working on mitigation measures. However, we still have to continue to recruit people, develop expertise and be attractive as employers. Modernizing how we work is fundamental and will help us catch up on the lag our industry has on the digital front. We are at a time when there's no turning back. It's just a matter of change, which comes with many exciting opportunities." OE

Activity

Proserv expands

Energy services company Proserv is preparing for future growth by investing in a new purpose built technology center for subsea controls and communications in Great Yarmouth, UK.

The move will see around 190 employees consolidate from two sites in the area into the new 65,000sq ft Beacon Park site.

Construction was due to start this month [July], with the building expected to be completed during March 2018.

David Lamont, Proserv CEO, said: "Consolidating operations into a modern purpose-built site will make us leaner, more efficient and better placed to deliver for our global customer base, while creating capacity for future expansion. The center will serve as a global hub and Centre of Excellence for our subsea communication and controls activities and ensures we remain at the forefront of our field.

Proserv has recently secured more than £12 million in contract awards for its new-build, after-market and decommissioning services. ▪

Baker Hughes, GE merger wins approvals

In mid-June, Baker Hughes and GE Oil & Gas passed a massive hurdle, reaching an agreement with the US Department of Justice (DOJ) that will allow the two companies to complete their proposed merger under US law. GE agreed to divest its GE Water & Process Technologies business after closing the Baker Hughes deal. GE has previously said it will sell GE Water to Suez for US$3.4 billion.

At the end of May, the EU gave their blessing for the duo's merger, which was announced in late October 2016. The combination will create a company with $32 billion combined revenue, with operations in over 120 countries. The deal has already been unanimously approved by both company's boards of directors.

Stress Engineering, DeepMar team up

Stress Engineering Services (SES) has teamed up with DeepMar Consulting to expand its existing upstream service offerings. The integrated team will work alongside clients to increase assurance of successful projects in regards to health, safety and environment (HSE), reliability and efficiency.

The partnership is focused on providing 'end-to-end' solutions that address the entire life of field across all disciplines: drilling/completion, production/asset and various intervention solutions. A seamless integration of verification and validation processes can be provided by using core competencies of both companies, including analysis, testing, materials, real-time health monitoring, predictive forecasting, efficient work flow processes and operational guidance.

Three-way merger forms SolstadFarstad

A merger between three companies: Solstad Offshore, Farstad Shipping and Deep Sea Supply, have formed the new company SolstadFarstad, creating an offshore service vessel giant.

SolstadFarstad owns a fleet of approximately 150 vessels, and has offices in Norway, Australia, Brazil, Singapore, the Philippines, Scotland, Cyprus and the Ukraine. In addition to the offshore activity, the company holds significant activity within the renewable energy segment and aqua culture.

"We are operating in a tough market. As a merged company, we are better equipped to meet the challenges and the possibilities that will arise," says SolstadFarstad CEO Lars Peder Solstad. "With the merger, we may benefit from synergies through operation of a larger fleet, our collective competence and experience, and hence ensure profitable operations in the future."

Remote milestone

What is thought to be the world's first commercial controlled-from-onshore ROV operations started at IKM Subsea headquarters in Norway in June.

Soon, up to three Work class ROVs and one observation ROV on Statoil's Snorre B and Visund installations will be controlled from IKM Subsea's onshore control center near Stavanger.

One of the Work Class ROVs (RROV) has been designed and engineered to be permanently based on the seabed and will only be brought to surface for periodic maintenance.

A company acceptance test with Statoil was completed on 12 June, with the ROV at Snorre B, and the dual control center is now up and running.

"We foresee a potential significant cost saving for our clients with less POB and increasing operational time offshore for the ROVs," says Hans Fjellanger, business development manager, IKM. "With this setup and proven technology in place we see this as the first of many stepping stones into the future of ROV technology for IKM Subsea."

IKM's Merlin UCV (ultra-compact vehicle) work class ROV are being used, along with new technology to supply the residential capacity and communication links needed to support the project. ▪

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