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Plug & Abandonment

A New Slant on Decommissioning

Big Data
Doubling Down on Digital

Resident Subsea Vehicles
New Tech Takes Off

Brazil
Rife with Opportunity

VOL. 44 / NO. 5


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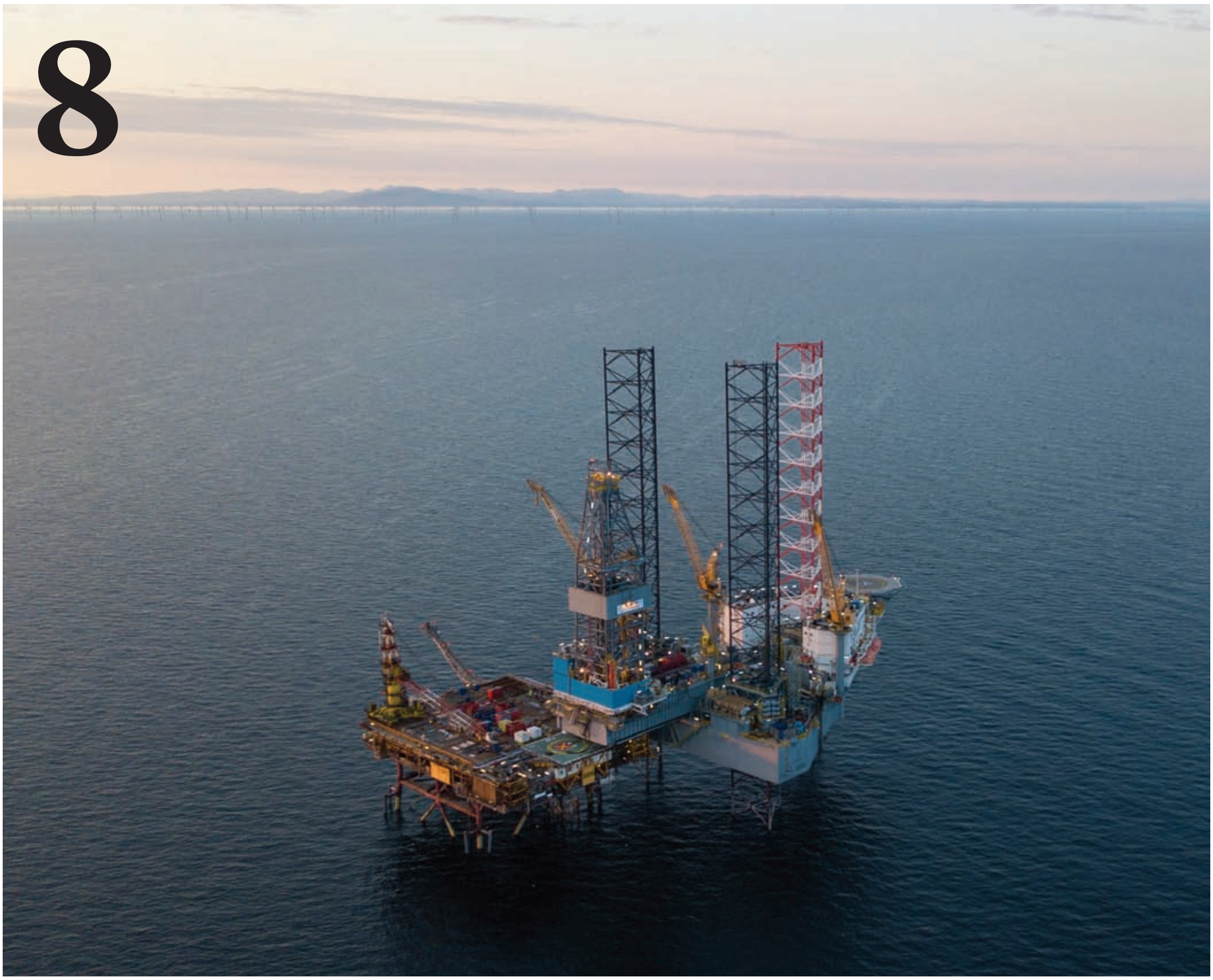
FEATURES



Source: MW Visuals Ltd.

ON THE COVER: Spirit Energy's Morecambe Bay complex, in the East Irish Sea (Source: MW Visuals Ltd.)

FEATURES

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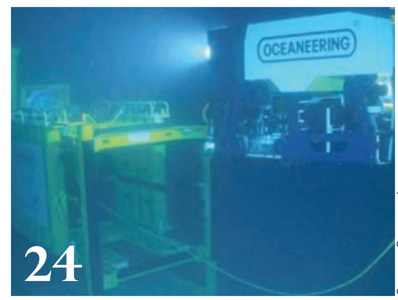
DEPARTMENTS

Source: Petrobras



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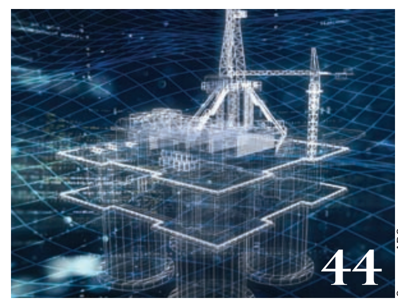

Source: ABS

Source: Aker BP

Source: Sonardyne

BY THE NUMBERS

RIGS

Worldwide

Rig Type	Available	Contracted	Total	Utilization
Drillship	24	65	89	73%
Jackup	118	327	445	73%
Semisub	34	72	106	68%

Africa

Rig Type	Available	Contracted	Total	Utilization
Drillship	2	16	18	89%
Jackup	11	24	35	69%
Semisub	1	3	4	75%

Asia

Rig Type	Available	Contracted	Total	Utilization
Drillship	5	6	11	55%
Jackup	46	94	140	67%
Semisub	13	14	27	52%

Europe

Rig Type	Available	Contracted	Total	Utilization
Drillship	13	1	14	7%
Jackup	6	44	50	88%
Semisub	9	30	39	36%

Latin America & the Caribbean

Rig Type	Available	Contracted	Total	Utilization
Drillship	3	19	22	86%
Jackup	4	6	10	60%
Semisub	7	4	11	36%

Middle East

Rig Type	Available	Contracted	Total	Utilization
Drillship	0	1	1	100%
Jackup	24	116	140	83%

North America

Rig Type	Available	Contracted	Total	Utilization
Drillship	0	22	22	100%
Jackup	22	34	56	61%
Semisub	2	10	12	83%

Oceania

Rig Type	Available	Contracted	Total	Utilization
Drillship	1	0	1	0%
Jackup	2	1	3	33%
Semisub	0	6	6	100%

Russia & Caspian

Rig Type	Available	Contracted	Total	Utilization
Jackup	2	7	9	78%
Semisub	1	5	6	83%

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

Data as of October 1, 2019.
Source: Wood Mackenzie Offshore Rig Tracker

DISCOVERIES & RESERVES

Offshore New Discoveries

Water Depth	2015	2016	2017	2018	2019
Deepwater	25	12	17	14	8
Shallow water	85	67	71	46	23
Ultra-deepwater	20	16	12	17	12

Shallow water (1-399m)
Deepwater (400-1,499m)
Ultra-deepwater (1,500m+)

Offshore Undeveloped Recoverable Reserves

Water Depth	Number of fields	Recoverable reserves liquids mbl	Recoverable reserves gas mboe
Deepwater	566	52960	23209
Shallow water	3222	312633	109477
Ultra-deepwater	347	53154	38199

Contingent, good technical, probable development. The total proven and probably (2P) reserves which are deemed recoverable from the reservoir.

Woodmac Child Fields

Offshore Onstream & Under Development Remaining Reserves

Water Depth	Number of fields	Recoverable reserves liquids mbl	Recoverable reserves gas mboe
Africa	741	30296	41465
Asia	1031	17090	39752
Europe	979	21748	25443
Latin America & the Caribbean	238	39766	11337
Middle East	141	164778	115604
North America	623	26344	4554
Oceania	122	2771	24118
Russia and the Caspian	71	27414	24141

Onstream and under development. The portion of commercially recoverable 2P reserves yet to be recovered from the reservoir.

Woodmac Parent Fields

Source: Wood Mackenzie

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OE WRITERS

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Pallanich

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Stoichevski

SHOW ME THE **MONEY**

While safety is historically number one on the agenda of most offshore energy operators, money is "1A". As the offshore oil market endures a fifth year of downturn from the halcyon days of 2014, the 'new normal' is the phrase of day as energy producers and all who support them have been forced to find more efficient, cost effective means to discover and recover oil and gas in the offshore sector. As you flip through this edition, keeping a lid on costs is a recurring theme. *'A New Slant on Decommissioning'* looks at how shallow gas reservoirs drilled into at a slant in the 1980s have posed a unique decommissioning challenge. For the facilities in Spirit Energy's Morecambe Bay complex, in the East Irish Sea none the traditional solutions were available. Because the original wells had been drilled from two rigs designed and built just for this field, the unique drilling packages no longer exists. Read up on the solution, starting on page 8.

The matter of underwater vehicle residency has long been discussed, but it appears that the tide is turning according to Elaine Maslin's report *'Residency in Waiting'* starting on page 18. The ability to keep AUVs in an underwater 'garage,' ready, willing and able to be manually or automatically dispatched to care for subsea system maintenance issues – planned or a surprise – effectively eliminating the need for more costly surface ships and support crews has been discussed for more than a generation. But a convergence of technologies from docking to charging to data download and transmission has brought real progress closer to reality.

To say that we're in the midst of a 'digitalization' trend seems a bit trite, as everywhere we look in our business and personal lives digital solutions are ubiquitous, enabling tremendous new efficiency capability as well as challenges in step. In this edition we have a pair of features on the power of digitalization, the first *'Doubling Down on Digital'* by Jennifer Pallanich starting on page 29, and the second *'Digitalization as Life Extension'* by William Stoichevski starting on page 34.

In the former, as digitalization has become somewhat of a marketing buzzword, Pallanich explores what terms like big data, digitalization, artificial intelligence, machine learning and the digital oilfield actually mean. It's one thing to say it, another to buy it, and yet another to 'walk-the-walk' and 'talk-the-talk' to ensure that these next-generation solutions are researched, procured and properly integrated throughout your operation to truly reduce capex and opex costs, while at the same time not opening a new cyber security can of worms.

In the latter Stoichevski discusses *'Digitization as Life-Extension,'* looking at how operators are on digitization journeys that aim to make the most of older infrastructure. Proposed projects from ConocoPhillips and Aker BP look set to reveal a special benefit to "freeing data", both for operator and supply chain. But while digitization comes with much promise, peril is never far behind and many still caution to be "careful when you digitize."

As we steam toward the conclusion of 2019 with just one print edition remaining for the re-launch of *Offshore Engineer*, we thank you for your interest and support and stand ready to serve you in print and online in 2020 and beyond. The 2020 Editorial Calendar is complete and our freshly minted BPA circulation audit is not far behind. If you haven't seen one or both, drop a line to Managing Editor Eric Haun at **haun@offshore-engineer.com** for your copies.

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A NEW **SLANT** ON DECOMMISSIONING

Shallow gas reservoirs drilled into at a 60-degree angle from the surface in the 1980s have posed a unique decommissioning challenge – resulting in a new design modular plug and abandonment (P&A) unit.

BY ELAINE MASLIN

When it comes to decommissioning, many operators face the challenge of how to decommission their wells. Many platforms either never had a derrick or it's not been maintained, so expensive rig reinstatement programs are needed, a jack-up rig brought in or a modular package installed on the facility.

For the DP3 and DP4 facilities in Spirit Energy's Morecambe Bay complex, in the East Irish Sea, offshore west England, none of these options were available; there was no rig either onboard or available from elsewhere that could access the platforms wells – because they are slant wells, drilled at a 60-degree angle from the platform. They had been drilled from two rigs designed and built just for this field – the Morecambe Bay Driller and Flame – whose unique drilling packages no longer exist.

These slant wells were drilled in the 1980s by previous owner British Gas when directional drilling technology wasn't as advanced as it is today. Drilling at this 60-degree angle from the platform meant a significantly greater outreach was possible compared with conventional drilling at the time. "By opting for slant drilling, the Stage I development required only three drilling platforms as opposed to the seven re-

Source: MW Visuals Ltd.

The 'slant well' P&A unit by Herrenknecht, installed and ready to get to work on Spirit Energy's DP4 platform late July.

Source: Spirit Energy

WHAT BECAME OF THE RIGS?

The Bay Driller and the Bay Flame were ordered by Houlder Drilling Inc. in the early 1980s from UIE Shipyard on Clydebank, Scotland. At some point after it finished drilling in Morecambe Bay, the Bay Flame was converted to an accommodation module for use on the Lennox gas field, part of the Douglas complex in the Irish Sea. The Bay Driller became the GSF Adriatic XI jackup rig. Following an upgrade in 2004, it continued to work before being sold to Buccaneer Energy subsidiary Kenai Offshore Ventures in 2011, for use in the Cook Inlet, Alaska. It was renamed Endeavour Spirit of Independence and transported to Saldanha Bay in South Africa for a refurbishment but, following the bankruptcy of Buccaneer, it's languished there since, cold stacked. The slant well drilling packages were removed from each prior to their conversions. Spirit Energy believes they were then scrapped. Tell us if you know where they are!

Source: MW Visuals Ltd.

quired if vertical drilling rigs were to be used," says SPE paper SPE-16151-MS, presented at the SPE/IADC Drilling Conference, in New Orleans, in 1987. While it worked for Morecambe Bay, it's not a commonly used technique; no other offshore field in the UK used it and it's little known of elsewhere (your author found a reference to use of a "Tilt rig" offshore Peru in the 1960s (SPE-2312-MS), except perhaps west Africa.

Although these types of well are uncommon, Spirit Energy has a large number of them in Morecambe Bay. There are 50 wells in total in the field, split across six of its eight platforms, with four subsea wells. Of the platform wells, 28 are slant wells with five on DP3 and four on DP4 facilities, which are the first platforms in the field to reach the end of their productive lives (while others are being refurbished).

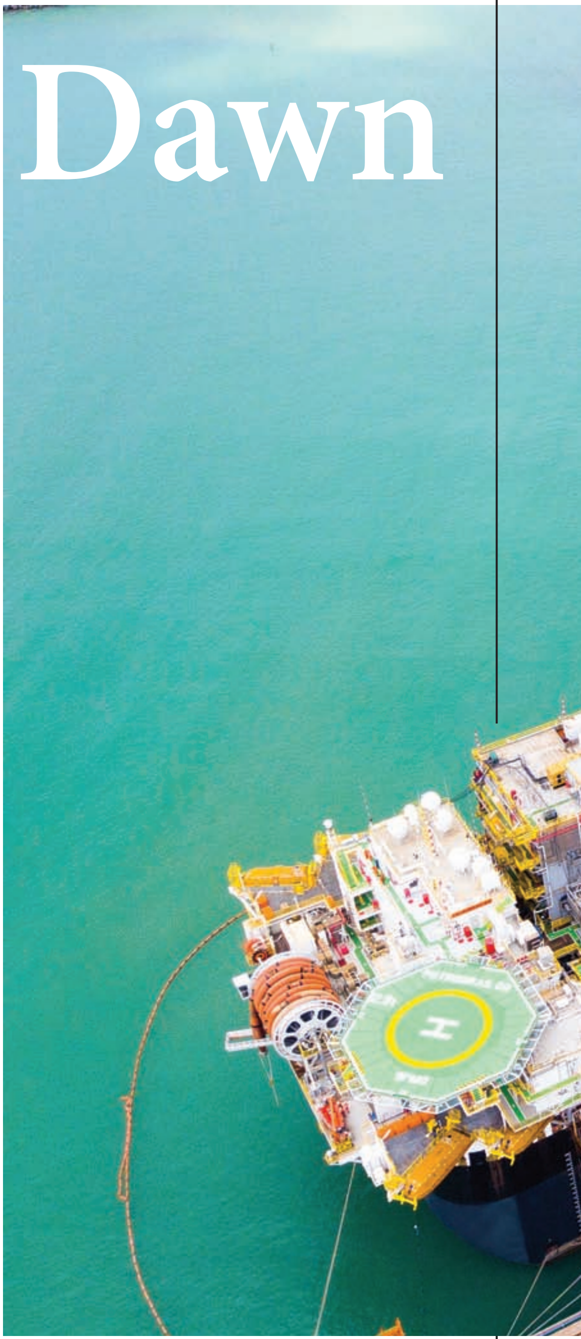
Faced with this challenge, Spirit Energy went to the market for solutions. The preferred vendor Herrenknecht, a German tunnel boring technology firm leveraged their existing onshore slant well drilling packages. "Instead of re-designing offshore drilling technology, you can tilt the hydraulic mast between vertical and slant wells," says Donald Martin, Project Manager at Spirit Energy. The technology required significant modifications for offshore, including the ability to skid around the drill deck and rotate the mast to align at the correct angle for each well.

It's a modular system, about 12-14 square meters in footprint and 30 meters high, able to enter wells at angles from 90-45 degrees for all P&A operations, from wireline to milling operations and from pulling tubing to pulling conductors. No single part weighs more than 30 metric tons, to make it easy to install using a platform crane, and the total package weighs under 200 metric tons. It has a self-propelled skidding base, powered by a hydraulic power unit, which means it can move around the well bay, while its rotary table can rotate through a full 360 degrees, so it can access each well with the help of a laser alignment tool mounted at the top drive on the top of the mast. During the design a 3D laser scan of each platform was done to make sure the design would be able to access each well. The mast itself is lowered or raised with a hydraulic cylinder which is then locked off, when in position. The unit comes with a drilling control cabin with automated handling systems to minimize risk to personnel. "We also had to fabricate a bespoke blowout preventer (BOP) with a loading cradle so that it could handle 60-degree installation to the wellheads," says Martin.

Solving this problem has been a nearly three-year challenge. But, following factory acceptance testing in June, the system is now built with well engineering firm Petrofac and drilling operator Borr Drilling have supporting its design and installation on the DP4 platform where in mid-August, it commenced its first P&A operations. To support staffing on board the DP4 during P&A operations, Sprit Energy is using the Borr Ran jack-up for accommodation.

Spirit Energy own the package, but says it would be willing to rent it, for anyone needing a modular P&A system – it being able to access vertical as well as slant wells. "We're expecting some start-up challenges, for sure, but our initial shakedown will be useful for learning how best to use it. How to efficiently construct the modules, move it around and apply those learnings to future wells and decommissioning projects," says Martin. "The next phase of evolution could be bringing in a low-cost conventional construction barge with a crane, the slant unit and some cement systems on it, to drive down the costs further."

Brazil's New Dawn



Brazil's offshore oil and gas sector: it's complicated, challenging and rife with opportunity.

BY ERIC HAUN

Brazil today is seeing offshore activity increase, production is on the rise, and its government has made significant strides to remove obstacles for investment. But not long ago the picture looked very different for one of the planet's foremost offshore oil and gas regions.

Brazil, just like the rest of the world, was hit hard by the oil price downturn, but the slump's effects were amplified in the South American country by the so-called Operation Car Wash corruption scandal which saw executives from Brazil's state oil firm allegedly take bribes in return for awarding inflated contracts. On the back of the industry downturn and scandal, spending and activity offshore Brazil were reduced more than other regions, said Lars Lysdahl, a principal analyst at Rystad Energy. "An example is the demand for floater rigs, which has declined by almost 80% since the 2013 peak, while other comparable regions like US Gulf of Mexico and West Africa are down by 30-50% in the same time period," he said.

But these days, following impactful policy shifts, and with a number of large high-impact fields slated to come on stream and ready for development, things are looking up long term for the country and its largest exploration and production company, Brazilian state-run oil firm Petroleo Brasileiro SA, or Petrobras, as the firm is commonly known.

"Now that Petrobras has pretty much gotten the corruption scandal under control, activity in Brazil should be brisk over the next decade or two," said Jim McCaul, head of International Maritime Associates and World Energy Reports. "The country is also opening up to foreign investment. This will help draw more international players and augment Petrobras' project start capabilities."

Lysdahl, too, said he sees promise. "Brazil is one of the regions with the best potential for an activity boom going forward," he said, but noted, "This boom has not started yet, we need to see more field sanctioning first, which is an early indicator of activity."

Local regulatory changes have played an important role. In a rethink of the nation's offshore strategy, the Brazilian government in 2016 instituted the Pedefor (Program for Stimulating the Competitiveness of the Supply Chain, the Development and the Improvement of Suppliers of the Oil and Natural Gas Sector) to relax local content rules and incorporate new financial incentives for foreign companies.

"On recent license rounds Petrobras is not mandated to be the operator, although they still have the first right of refusal. This opens up for other exploration and production companies, spurring their interest as they can influence field development and build local competence and organization as operators," Lysdahl said.

Brazil's recent pre-salt rounds have been competitive and attracted global majors, with foreigners such as BP, Equinor, ExxonMobil and Shell all now operators and expected to compete again in upcoming rounds, including the licensing bonanza soon to commence in the final quarter of this year.

On October 10, Concession Round 16 will offer 36 blocks in five basins, including three that are frontier. On No-

P-68 will produce up to 150,000 barrels of oil per day. It has a 1.6-million-barrel storage capacity and can accommodate 154 persons.

Source: Sembcorp Marine

vember 7, PSC Round 6 will offer five blocks in the Campos and Santos basins. Half the acreage on offer is in the prolific Santos, where the Brazilian government is looking to cash in big, said Marcelo de Assis, Head of Latin America Upstream Research at Wood Mackenzie. "We expect fierce competition."

A big prize, de Assis said, will be offered up during the transfer-of-rights (TOR) surplus round slated for November 6 (one day before PSC round 6).

The TOR areas encompass six high-quality pre-salt fields holding 15 billion boe, found between 2010 and 2013 and declared commercial in 2014. The government, which in 2010 assigned Petrobras 5 billion boe, will now auction rights to all resources beyond the original assigned volume in four of the areas (Atapu, Buzios, Itapu and Sepia), via production sharing contracts. According to Wood Mackenzie, recoverable reserves estimates for the surplus volume range from 6 billion to 15 billion boe.

The round is expected to attract a swathe of large global oil companies, including Petrobras, with 14 firms approved to take part. Government officials have said the auction could raise more than 100 billion reais ($26 billion).

PRODUCTION RISING

Brazil's monthly oil and natural gas production reached a record 3.828 million boe per day (boepd) in August 2019, regulator ANP reported.

The majority (63.4%) of production was from the pre-salt, where 110 wells produced 2.427 million boepd. Lula, in the Santos basin, produced the most oil, an average of 1.026 million boepd. It was also the largest producer of natural gas: an average of 43.4 million cubic meters per day.

"The size and productivity of the reservoirs in the Santos basin offshore Brazil are huge," McCaul said. "Production achieved by floating production, storage and offloading units (FPSO) placed in operation in the Santos basin over the past decade has been astounding."

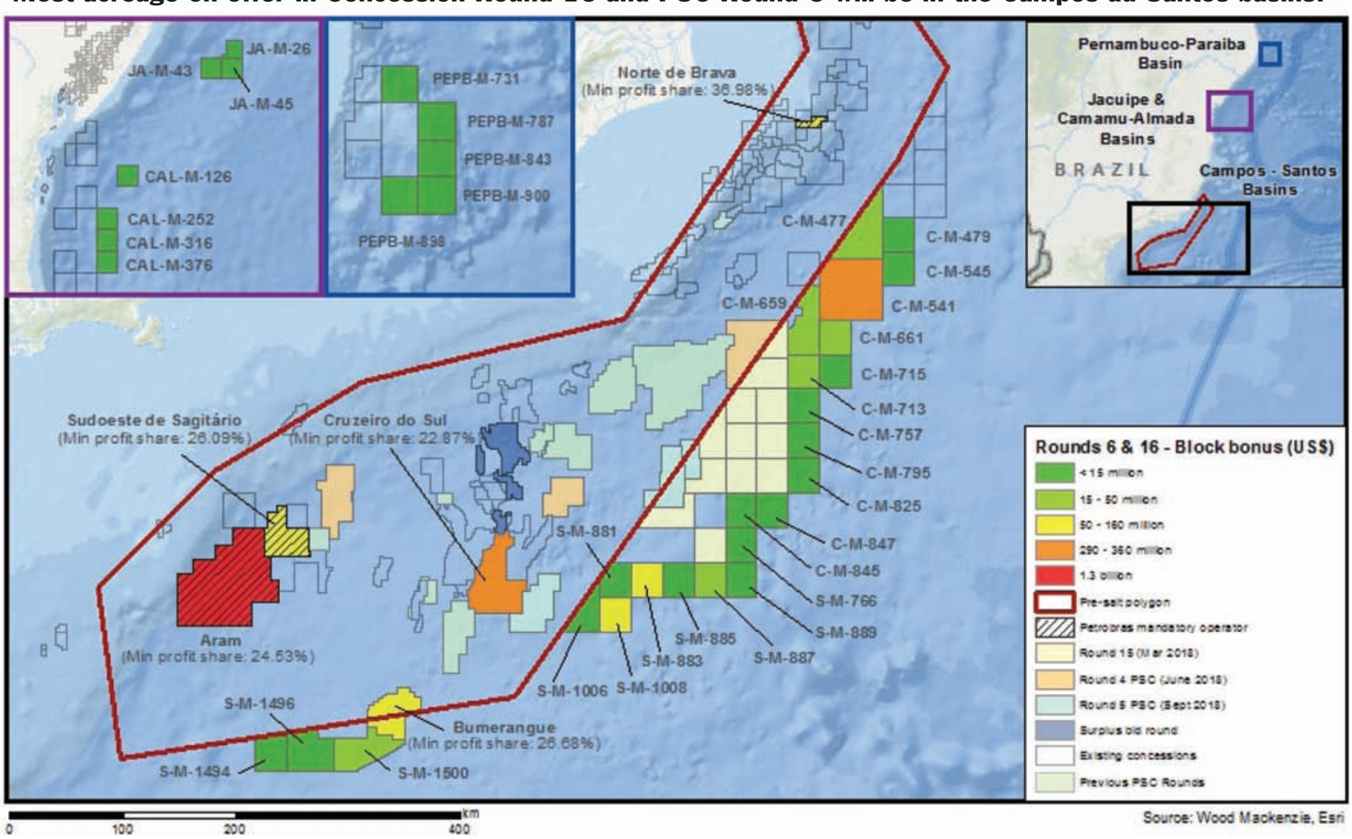
The output leader in August, ANP said, was the FPSO Cidade de Maricá in Lula Field, producing 150,600 boepd through seven interconnected wells.

More large producers are on the way. In mid-September, the newbuild FPSO P-68 left the Sembcorp Marine's Estaleiro Jurong Aracruz (EJA) shipyard in Brazl for deployment in the ultra-deepwater Berbigao and Sururu fields, adding up to 150,000 boepd production from the Santos basin. The same shipyard is also working on the P-71 FPSO, also destined for Santos.

"Santos output has been increasing ever since the first large fields started in 2010 and is now producing around 1.5 million boepd. With all the pre-salt developments and large projects such as Iara, Buzios and Mero, we expect a boom in new FPSO installations and production exceeding 3 million boepd by 2025," Lysdahl said.

Source: Petrobras

Most acreage on offer in Concession Round 16 and PSC Round 6 will be in the Campos ad Santos basins.



Some 32% of the world's 219 planned FPSO projects are in Brazil, according to World Energy Report's August 2019 update. There are five FPSOs on order for the Santos basin alone.

"The largest field development hub is Buzios, where two FPSOs started up last year, two more are coming online this year and another two by 2023. The hub will be producing over 600,000 boepd by 2025, so 20% of Santos' output," Lysdahl said. "Altogether, the four hubs Buzios, Lula, Iara and Mero represent almost 40% of Brazil's rig demand over the next five years."

PETROBRAS

On a mission to reduce its debt, Petrobras has received nearly $13 billion from non-core asset sales in 2019. In August the company reported a second quarter net profit of 18.87 billion reais ($4.92 billion) – its highest ever – and well above analyst estimates. In the same month the company produced 3 million boepd on average (including 2.2 million boepd from the pre-salt area), up 21.6% from the same period a year ago.

Local reports indicate that Brazilian president Jair Bolsonaro wants to privatize Petrobras before his term concludes in 2022. "This would be good for Petrobras – and good for Brazil," McCaul said.

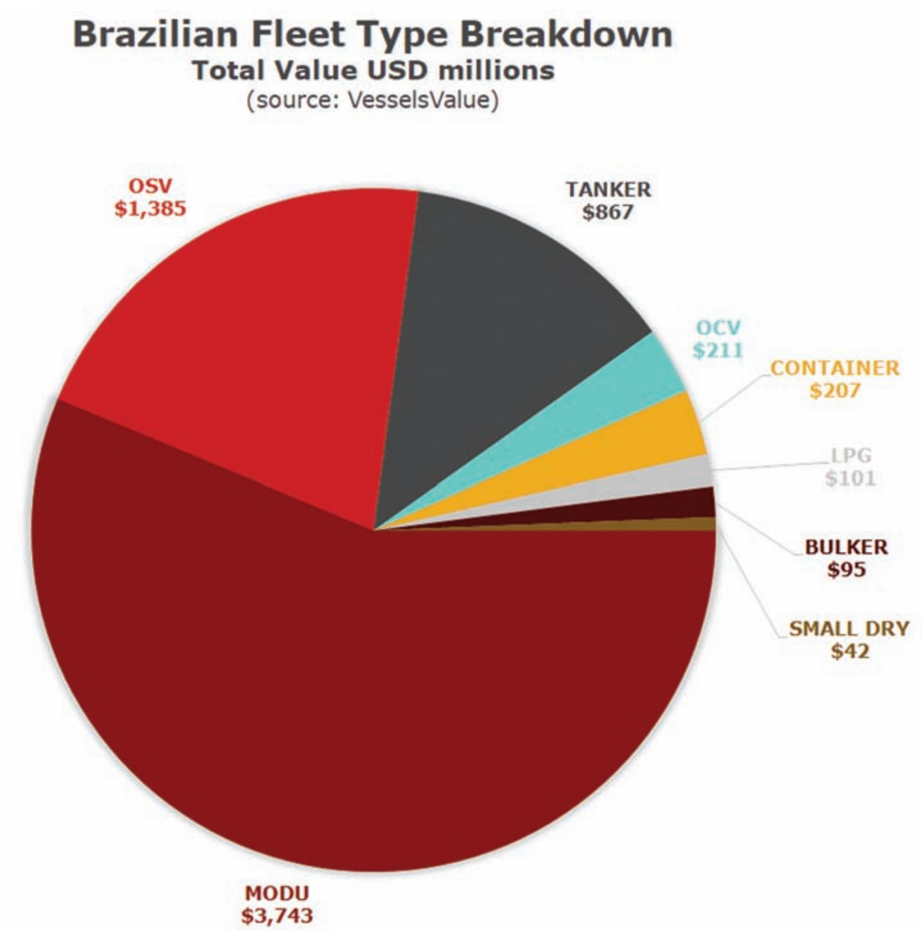
"The government holds more than 3.7 billion common shares in Petrobras, roughly 50.3% of the total common shares outstanding." McCaul said. "Being removed from the continuing political pressures of the government could enable Petrobras to operate as an independent company and help attract international investors – which it will need to implement its plan to spend $105 billion on capital projects by 2024."

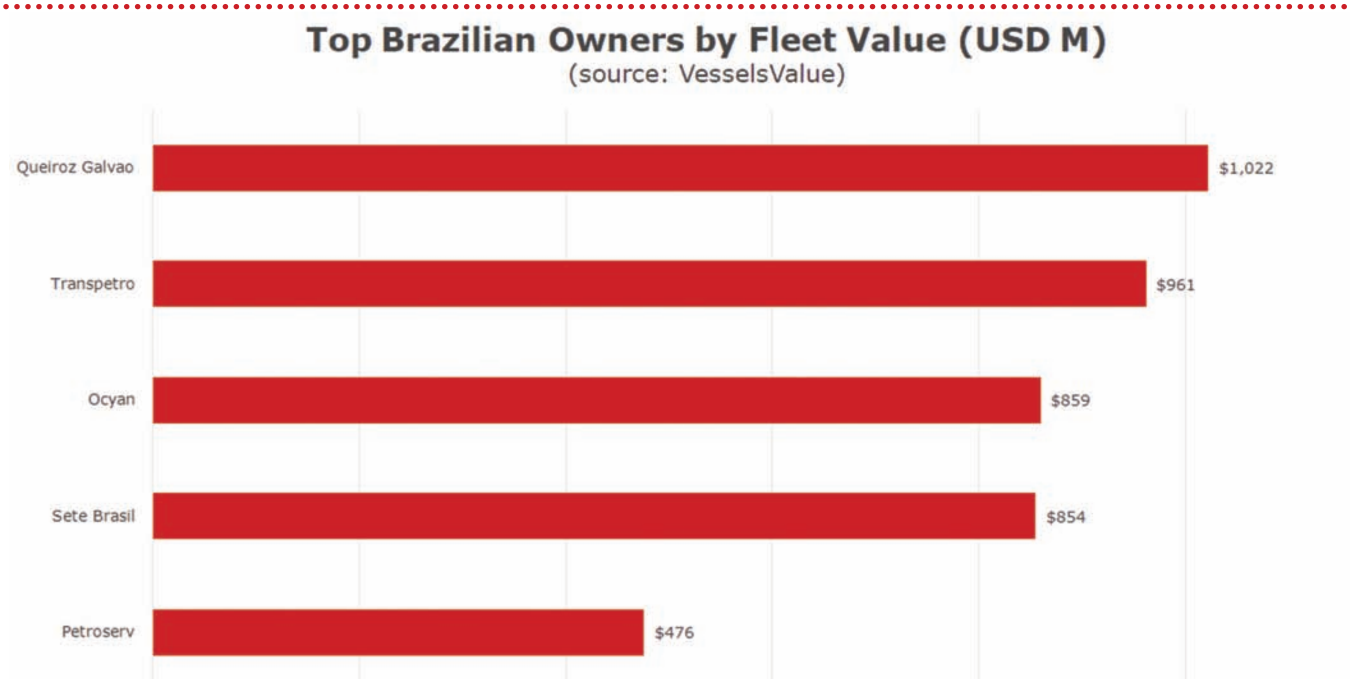
A stronger Petrobras, coupled with an improved regulatory environment and many large, attractive fields ready to be developed, has gone a long way to increase global interest in Brazil. The presence of more international players will improve economic resiliency in the sector as projects will not necessarily hinge on the financial performance – or difficulties – of one company alone.

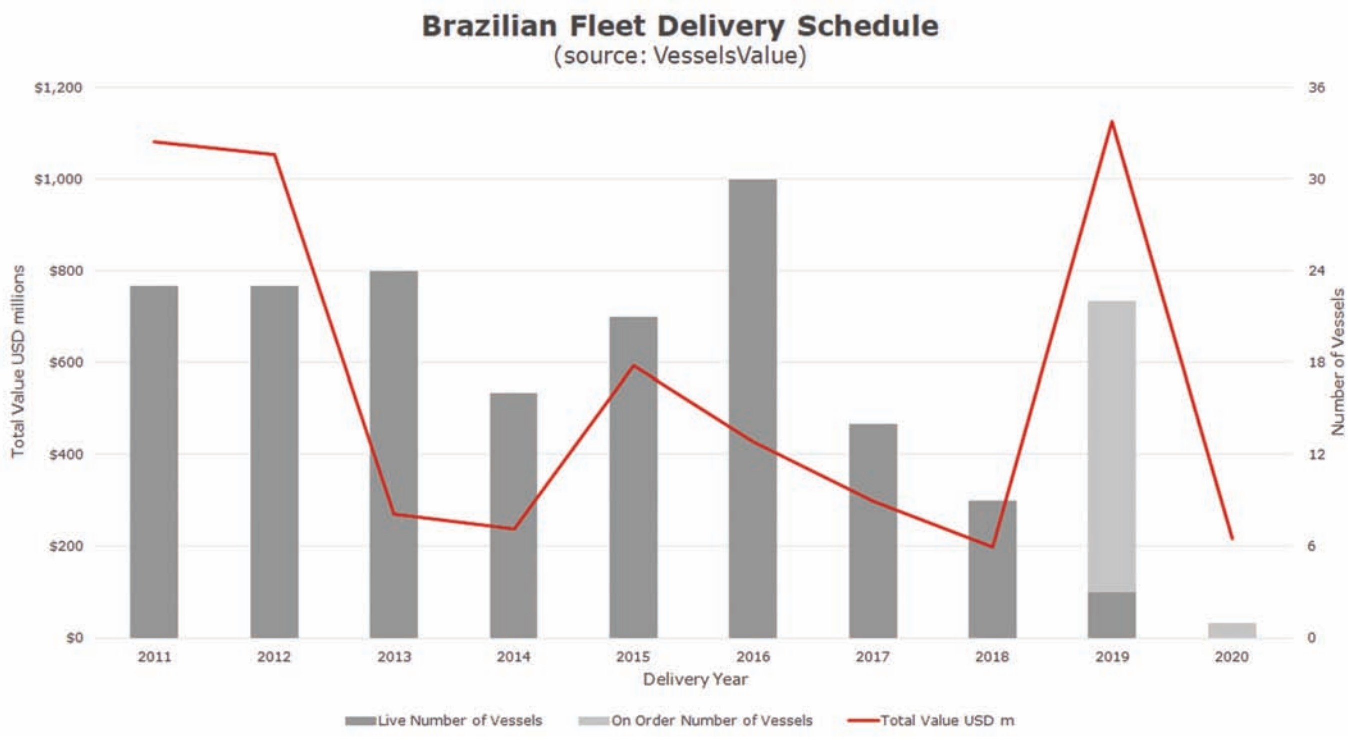
"Brazil will be one of the global offshore hot spots going forward, mainly due to the large portfolio of low-breakeven discoveries ready to be developed," Lysdahl said. "This will spur strong demand for drilling rigs, SURF contracts and new FPSOs."

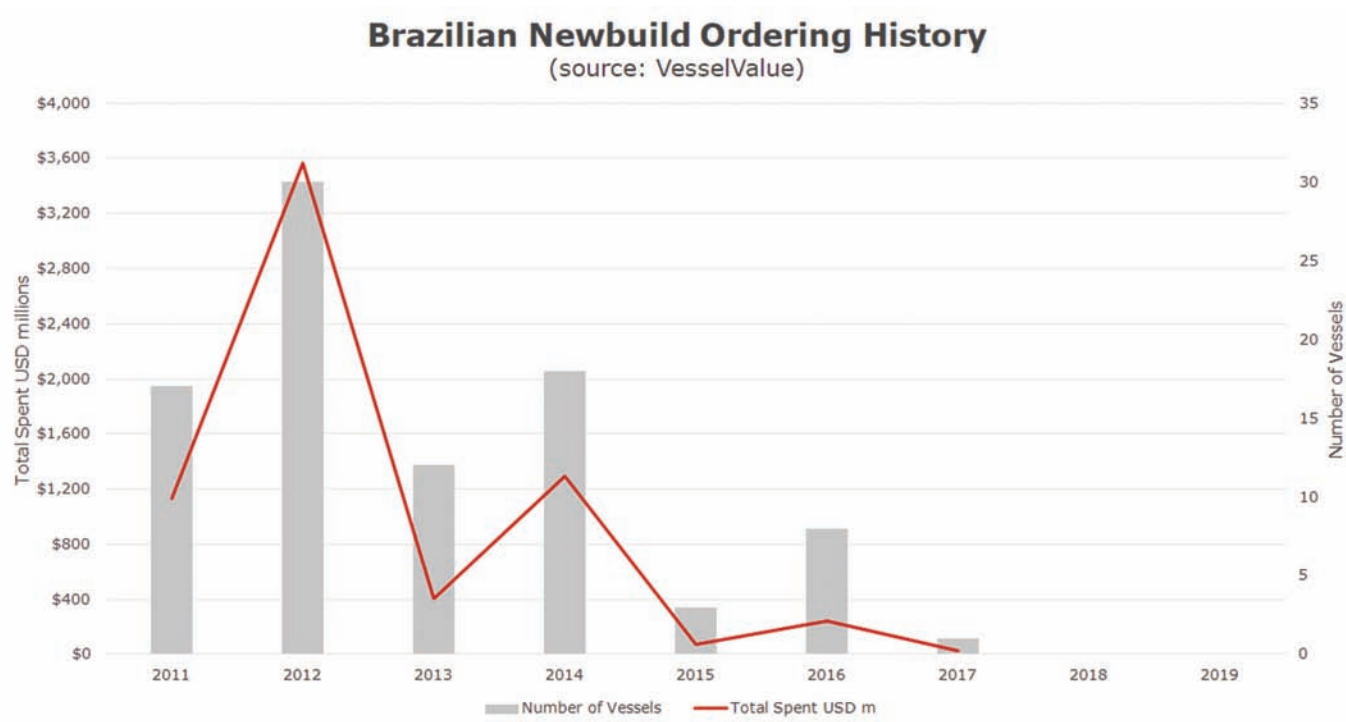
"Strict budget control and delivering on time will be even more critical in the future than in the past. The credibility of the global industry, and in particular the local Brazilian industry, is at stake and another failure would be crucial."

Powered by VesselsValue






Brazilian Fleet Delivery Schedule
(source: VesselsValue)
$1,200
$1,000
$800
$600
$400
$200
$0
Total Value USD millions
36
30
24
18
12
6
0
Number of Vessels
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
Delivery Year
Live Number of Vessels
On Order Number of Vessels
Total Value USD m


Brazilian Newbuild Ordering History
(source: VesselValue)
$4,000
$3,600
$3,200
$2,800
$2,400
$2,000
$1,600
$1,200
$800
$400
$0
Total Spent USD millions
35
30
25
20
15
10
5
0
Number of Vessels
2011
2012
2013
2014
2015
2016
2017
2018
2019
Number of Vessels
Total Spent USD m

Residency in Waiting

It's long been a vision to have underwater vehicles able to support subsea operations without reliance on a surface vessel. We're closer to this vision than ever before, but what's new that wasn't in place before to make this happen?

BY ELAINE MASLIN

Earlier this year something of a milestone was reached in underwater vehicles in the oil and gas business. An autonomous underwater vehicle (AUV) wirelessly docked, charged and downloaded data, all inductively, with remote automated control and live visual control during a demonstration in a lake in Sweden. The dock was Equinor's open standard subsea docking station (SDS) and the vehicle was Saab Seaeye's Sabertooth.

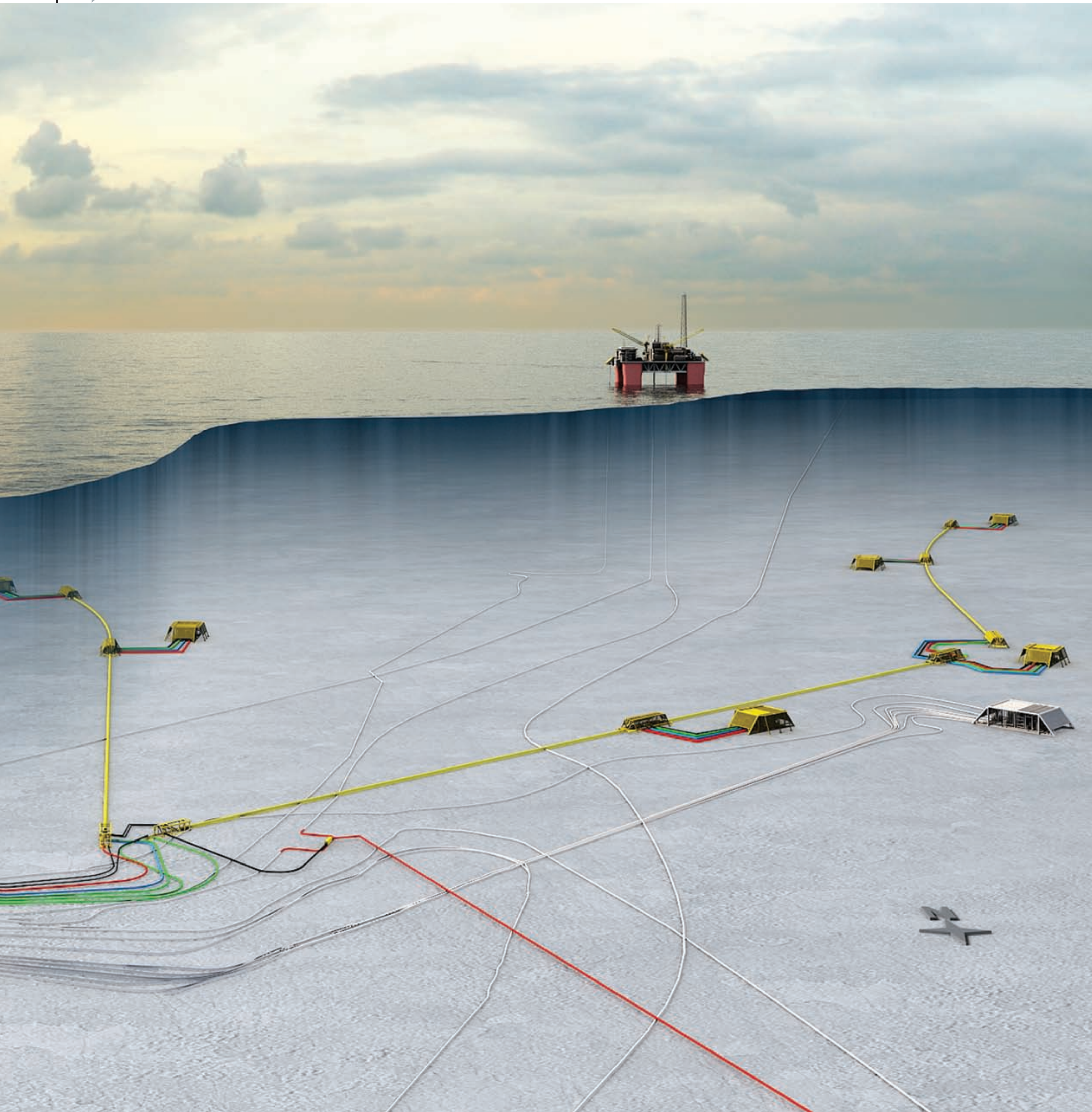
It's a step toward having vehicles permanently resident subsea and more such demonstrations are coming as others put their new vehicles to the test. But, some will say we've been here before; this was tried in the 1990s. So, what's new? It's a combination of forces – market driven and technology driven.

For Gro Stakkestad, manager of subsea intervention and pipeline repair, at Equinor, it's a combination of the downturn, a drive for automation and increasing environmental awareness. Steffan Lindsø, Director of Emerging Technology, Europe, at Oceaneering, says communications offshore has been the primary missing component, as well as advances in battery and navigation technologies, while Sean Halpin, Director, Product Management and Marketing, at new entrant Houston Mechatronics, says cost reduction and access to computing power are big drivers. You can read their views in more depth in the following pages. Moves toward all electric field infrastructure will also help.

The final piece

For Jan Siesjö, Saab Seaeye's chief engineer, bringing together docking, charging and data download was the final piece in the puzzle to

The Snorre Expansion Project field layout, which could soon be supported by underwater drones.

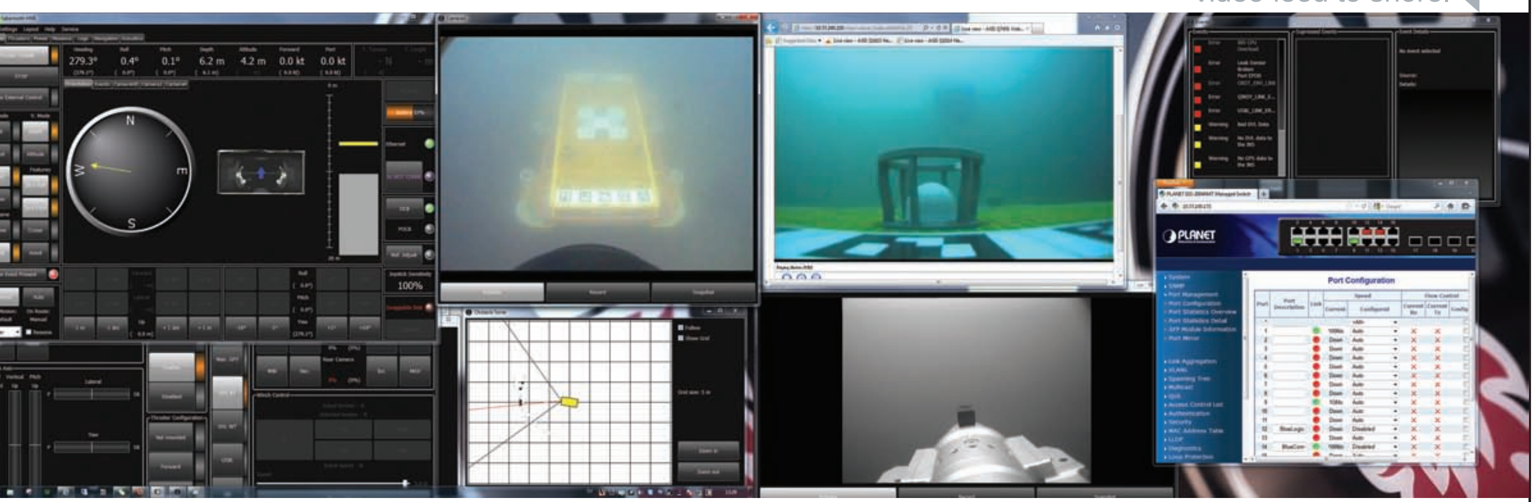


Source: Equinor

Source images on this page: Saab Seaye

Saab Seaeye's Sabertooth which demonstrated inductive charging and data download in Sweden earlier this year.

With simple to use advanced remote controls, docking was demonstrated, with a live video feed to shore.



bring this capability into the field. But, there's been a lot of other work in the background, largely around remote control capabilities.

"Remote control over long distances might seem simple but to make it reliable you need a lot of stuff in place. It's not just sending commands over the internet, it's having systems that can keep themselves safe, can be maintained so they don't go wrong and if something does go wrong it's not so complex you need a university grade engineer to fix it." That includes station keeping, waypoint navigation and obstacle avoidance.

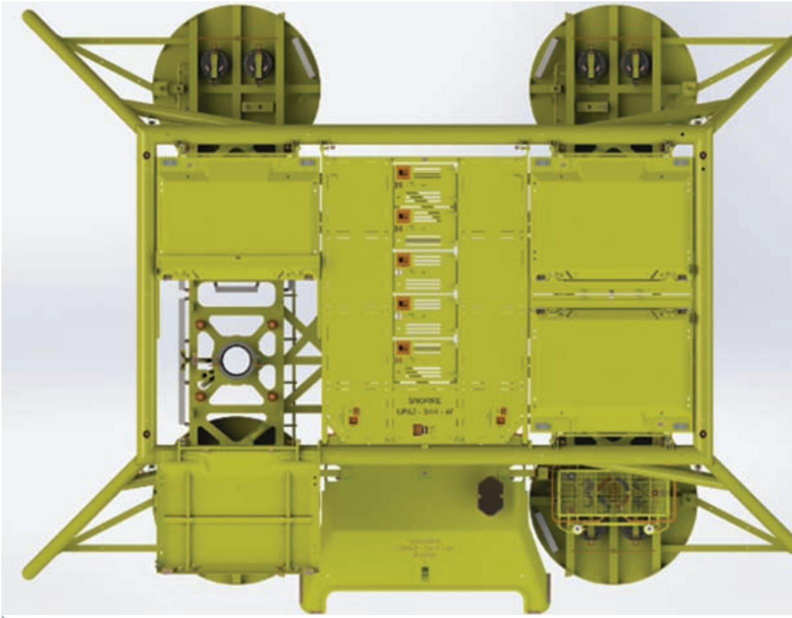
On the communications side, Saab Seaeye has been working with Boeing, running a Leopard light work class remotely operated underwater vehicle (ROV) over a satellite link across the US, doing manipulator work, mating connectors, flying missions, waypoint control, etc. "We had some pretty strict limitations, just 1mb/sec, and a latency that we pushed up to three seconds and we intentionally messed with the data quality," says Siesjö. "Despite that, we were able to mate flying lead connectors and do a lot of other things. The longer term goal is to fly an ROV out of very large AUV and do intervention work in various ways."

Working at depth is another challenge – both getting to a site then maintaining communications links. Earlier this year, Saab Seaeye trialed this scenario, doing three weeks' tests in 2,400 meters water depth in the Mediterranean – tethered and autonomous – with 100% successful communication with and positioning of the vehicle, even at full thrust up to 4 knots, says Siesjö. Work in these depths included determining how to travel to a work site efficiently – 2,400 meters is a long way down – while maintaining positioning, using a combination of inertial navigation system (INS) and ultra-short baseline (USBL) positioning.

Saab Seaeye is supporting its work with high fidelity simulators (like those used to test its parent company's fighter jets), so it can run all autonomous and human-in-the-loop control systems with its native control software and find out if they work – long before they go into the water.

In addition, it's working on how vehicles can build, in real time, 3D maps of the environment they're in by using a stereo camera system to do 3D simultaneous localization and mapping (SLAM). This will let the vehicle navigate through and measure what it sees relative to itself. Saab Seaeye has been testing this capability since 2018, building 3D clouds of the underwater world.

Source: Blue Logic



Equinor's open-standard subsea docking station design, shown slotting into a manifold, like a small helicopter pad.

Geosub to AIV

Another company that has been building this capability for some time is Subsea 7. In the 1990s, it was behind Geosub, a technology licensed by Subsea 7 from the National Oceanography Center (NOC). Its main goal was autonomous pipeline inspection, using waypoint navigation and autotracking to increase seabed survey data gathering quality and efficiency and reduced surface vessel support. While it was a success in terms of data quality, it still had to be launched and recovered from a vessel and needed surface support for positioning. It also couldn't do cathodic protection measurements, so it was limited.

Subsea 7, through its i-Tech 7 business, has moved on and now has its autonomous inspection vehicle (AIV), central to which is relocalization capability, developed under its precursor, the Prototype AIV, so that it doesn't need regular position updates from a surface vessel. "The development was triggered by a decision to move to autonomous hovering vehicles, focusing the capability at infield subsea infrastructure inspection. As the purpose was now focused at inspecting existing equipment, the equipment itself could be tracked to provide the high accurate positions needed to navigation without updates from a surface vessel." It's similar to autotracker, but in 3D and could be described as a form of SLAM.

The AIV also has its own subsea docking system, which disconnects launch and recovery operations from vessels. "The introduction of simplified mission planning, linked to the relocalize powered navigation and a process where the AIV could self-dock to the basket, effectively broke the link to vessel reliance," says Jamieson.

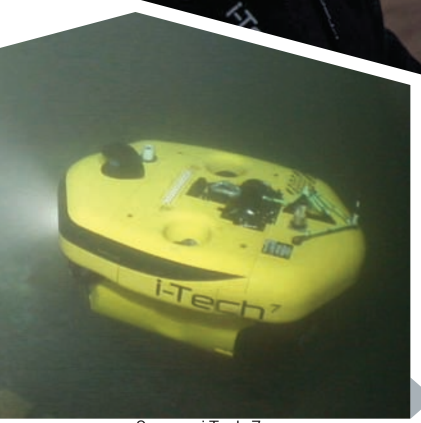
Standardized docking

A big boost in this area has come from the likes of Equinor pushing a vision for "underwater intervention drones" (UID), as it's called them, and awarding contracts, including for the design of an open-standard SDS that any vehicle can use. The SDS design incorporates inductive connectors from Blue Logic and WiSub and AruCo and ChaRuCo markings, which the drone's camera sees work out its relative position. Trondheim based acoustic communications and positioning firm Water Linked is also supplying small acoustic modems for vehicle positioning onto the station. The SDS can also accommodate other sensors, such as Sonardyne's BlueComm free space optical modem for live video feeds or high bandwidth data download. There are also standard interfaces, being developed through the SWiG (Subsea Wireless Interface Group) group and Deepstar, for the mechanics.

SDS, built by Blue Logic in Norway, have been deployed in a dock in Trondheim and also 2.2 kilometers offshore at the Trondheim Biological Station in 350 meters wa-

Source: i-Tech 7

Remote operations are also being done with ROVs. This is i-Tech 7's onshore control center for ROV operations.



i Tech 7's AIV has performed trials with Equinor.

Source: i-Tech 7

ter depth. Another is going to the Åsgard field where an Eelume "snake robot" will operate on a power and fiber optic tether connected in to the Åsgard A floating production unit. Next steps include a wider rollout in the Snorre Expansion Project, where seven SDS could be used (integrated into manifolds or standalone with fiber glass protection covers) 15 kilometers apart and connected into power and communications in the field layout.

Developing new models

These developments, are now influencing the way that new greenfield developments are being planned, says Jamieson. Indeed, i-Tech 7 has investigated field-wide IRM services for Equinor using a UID on the Snorre Expansion Project (SEP) and Snorre A (SNA) field in the Norwegian Sea, as well as for other fields.

The study assessed the potential for introducing subsea hybrid vehicles by identifying any technical gaps that would prevent the long-term deployment of the UID on the seabed. It also evaluated and recommended options for docking station configurations to support the vehicle by providing an overview of the configurations and characteristics required. As power and a reliable data network are integral to its success, the company examined operational and management provisions to support activity by the subsea hybrid vehicle. The ultimate aim of the project was to recommend a development plan to enable the drones to go 'live' by late 2020.

"Seabed hosted vehicles that are supported by seabed docking stations, utilized for autonomous inspections and linked to onshore control rooms, for human in the loop

In Italy, Saipem has been busy with its Hydrone R, which started a six-month trial in Saipem's underwater "play park" near Trieste Harbor, northeast Italy. It was recently announced that the vehicle will be deployed by Equinor offshore Norway in 2020. Equinor, on behalf of the Njord licence, has awarded Saipem a $43.7 million, 10-year subsea service contract to use the technology starting when the Njord field resumes production.

Hydrone R is described as a hybrid ROV with AUV capabilities, e.g. it will have manipulators, for intervention work, and can work on a 300-meter-long tether, for full bandwidth real-time control, but it can also travel distances between subsea fields, untethered like an AUV, with acoustic communications out to 4 kilometers. Once at a work site, it could switch to high bandwidth optical communications for supervised operations. Hydrone could deploy either from a seabed garage or a surface deployed system on a mission basis. Rated to 3,000 meters, it could operate for 8-10 hours without a tether, and out to 10 kilometers, says Stefano Maggio, technical manager at Saipem. Deployment from a surface host could be easier because you don't need subsea infrastructure, says Maggio. "You could be sensitive to weather conditions for deployment, but you have easy maintenance ability." However, "the subsea resident system is insensitive to weather, so you deploy it and stay there for six months, a year, before recovery. But, it means you can't maintain it regularly, so the highest reliability is required."

control on intervention tasks is again pushing the requirements in a positive way," says Jamieson. "Vehicles will be required to be resident subsea for months at a time, with no servicing or recovery for repair. This higher bar in reliability and control is also empowering traditional ROV operations, with remote control of vehicles from onshore control centers and electrification of vehicles for increased reliability and efficiencies." This all adds up to fewer vessel days and people offshore.

There's potential to make subsea systems simpler. Actuators, other than on safety critical systems, could be manual, instead of hydraulic or electric, reducing the hydraulic and electric systems that need to be installed subsea – that means less cable.

Helge Sverre Eide, business manager at Blue Logic, says that for drones to take off subsea, the subsea system and operating philosophies need to change. "For this to be economical, you need to increase the scope of work of drones," he says. "You need new tools and you need to adjust or change the subsea production system. You need to change both sides of the equation. New tools must be lightweight so a drone can fly them. Subsea maintenance needs to change to having smaller pieces to change out. A different mindset - if something shuts down, you can just change it out – is now possible. That's a new philosophy."

Source: Houston Mechatronics

PACKING AI INTO OFFSHORE ROBOTICS

BY ELAINE MASLIN

Sean Halpin, Director, Product Management and Marketing, at relatively new entrant Houston Mechatronics, says that cost is driving a willingness to innovate. "Financial efficiency is a significant priority for the world's oil companies in this market – so they are starting to open the door for transformational technology," he says. Meanwhile, growth in and access to computing power is helping drive technology. "Most, if not all, of the latest ocean robots have a ton of edge computing in them. That just wasn't possible 10 years ago," he says. "Aquanaut has dedicated computational resources just for processing machine vision data. We are implementing deep learning algorithms on the edge and are loading a ton of computational power onto the machine to enable greater autonomy," so that it no longer needs a support vessel and can operate even when there's latency in communication.

Set up in 2014, Houston Mechatronics has been busy, moving from its lab in Houston to trials at the Neutral Buoyancy Lab (NBL, NASA) and now to trials in a lake in Texas. At the NBL, core vehicle functionality was tested, including automated manipulation. The field trials this year are in 60 meters water depth, with a fiber optic tether. The next tranche of testing will include untethered operations, says Halpin. "We will be testing common AUV mission constructs (survey, etc.) and more trials are planned for this fall and winter where we will demonstrate Aquanaut's ability to automatically detect and manipulate objects."

The current trial Aquanaut is rated to 300 meters water depth but the first full commercial system will be designed for up to 3,000 meters water depth, says Halpin, and could include inductive charging, so it could be a resident system. Working in ROV mode, its power capacity is expected to last a day (using all imaging systems, arms, and its seven thrusters). In AUV mode the vehicle uses less power, so a more realistic scenario is a mix of both modes, extending mission duration by at least 50%. But, stresses Halpin, work is still ongoing and system improvements being made all the time.

For communications to shore, via a surface gateway (such as a buoy or unmanned surface vessel), Houston Mechatronics is evaluating latency from pure satellite backbone to cellular modems (e.g. 4G). Subsea, the robot will use acoustic communications and optical communications when appropriate. They key, however, is building in intelligence to manage communications constraints. "We don't intend on live-sticking Aquanaut when working over-the-horizon," says Halpin, "but, if we are using a cellular modem it will be possible. Latency can be managed with creative software and a combination of hardware and software."

The firm is also looking at new business cases. "We are very focused on developing a lighter, more customer friendly, service offering," says Halpin. "Aquanaut was developed to enable service models like 'on-demand' services." While this may take some time to achieve, the company and robot are "engineered to accomplish that mission," meanwhile offering services through more conventional models. "The great part of our robot and company is that we don't require a lot of infrastructure to make Aquanaut successful. We can be cost competitive even when operating in a peer to peer scenario. Our goal is to halve the cost of ROV work, and we think we can do it."

Source: Equinor

STANDARDIZING DOCKING STATIONS

We asked Gro Stakkestad, manager of subsea intervention and pipeline repair, Equinor, about her company's thoughts on subsea resident vehicles.

BY ELAINE MASLIN

Why are subsea resident vehicles attractive now?

The recent downturn in the oil price combined with ever increasing environmental awareness forced responsible companies – such as Equinor – to think less conservatively and to investigate cleverer ways to operate. This led to Equinor's sharpened strategy, including our technology strategy, which among several things sees automation through, as an example, underwater drones as a way to increase safety, lower emissions and decrease cost simultaneously.

At the same time, Equinor observes that there are numerous strong actors developing underwater drones, meaning that there can also be a healthy market with competition and continuous development. However, to maximize competition and development, we see the need for standardization of interfaces. That's including our subsea docking stations (SDS).

Among the technological drivers there are the recent advanced in artificial intelligence (AI), which is a key technology for tetherless underwater intervention drones. This is due to limitations in range and bandwidth on subsea communication causing limitations – and sometimes preventing – teleoperation by a human pilot. Due to limited assistance from a human pilot, drones need built-in functions to detect anomalies, understand their environment, recognize features and make the right decisions autonomously. This is typically done through AI in the form of artificial neural networks.

What's Equinor's vision?

Equinor has never produced cars, but we have built gas stations. We will not produce underwater drones, but we will build charging stations for them on the seabed. We call it subsea docking stations (SDS). Our ambition is that this infrastructure will contribute to a market for underwater drones and our intention is to buy or rent underwater drones developed by others to do inspections and intervention work for us in the near future.

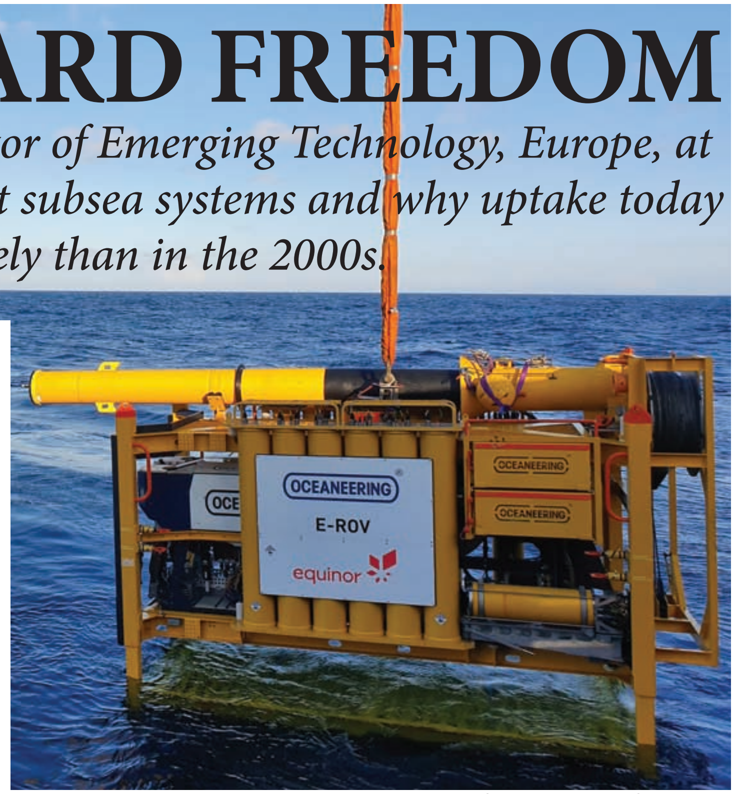
Equinor's vision is that all major tetherless vehicles with hovering capability will be compatible with our SDS. Hovering drones are more agile than traditional ROVs, making them capable of station keeping, autonomous intervention with torque tools etc., and docking onto a flat standardized "helipad" – the SDS.

There are several alternatives, and I envisage these will happen in steps as the technology matures. Let me give some examples. With a standardized docking station and network solution, we can have several types of drones in the same field and do adjustments to the drone fleet as technology progresses. Depending "on a case-by-case basis" of the particular tasks (e.g. inspection, intervention, environmental monitoring), we will make specific business cases and determine the type(s), numbers and density of the docking stations. The setup may vary quite much field by field. If we can combine drones over several fields – "inter-field operations" – this will strengthen the individual business cases further. Some of the drones have relatively high range, in excess of 100 kilometers (for example Oceaneering's Freedom), so in some cases it can travel between fields. We are also looking into the use of unmanned surface vessels (USV) which could be used to deploy drones to remote locations (as a mother ship), but this could also be used to transport drones between locations, if the distance between the SDS are too large.

What is being done now?

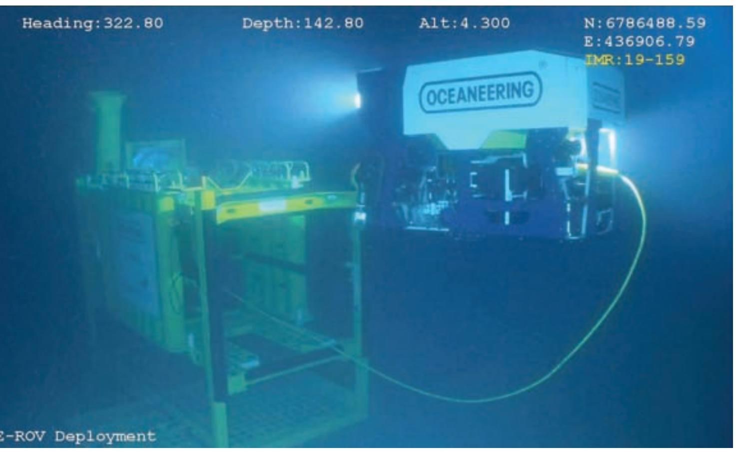
The SDS in Trondheimsfjorden is permanently installed at 365 meters depth, and available for test and research activities thru NTNU (Norwegian University of Science and Technology). We plan to install a similar docking station at the Åsgard Field, and more docking stations in the years to come.

(An evaluation of the potential use of UID on the Snorre field is ongoing. A final decision is expected to be taken later this year).



STEPS TOWARD FREEDOM

We asked Steffan Lindsø, Director of Emerging Technology, Europe, at Oceaneering, about how resident subsea systems and why uptake today looks more likely than in the 2000s.



Source all images: Oceaneering

BY ELAINE MASLIN

What was missing in the early 2000s?

The primary missing component for this to make any operational sense has been communications. Without reliable communications to shore, there would not be enough scenarios where cost could be decreased to make it viable to invest in this technology.

Oceaneering demonstrated remote piloting as early as 2004 from a satellite link in the North Sea. It worked then, but advanced in communication networks and increased coverage make remotely operated and autonomous systems a true option today.

What is making these systems possible now?

Again, surface communication is a big hurdle that has largely been overcome. This goes both for 4G in the North Sea and also in the Gulf of Mexico. Satellite communications have also become faster, cheaper and more stable and many offshore installations have direct fiber to shore connectivity now. The industry has a number of contingencies when it comes to communication.

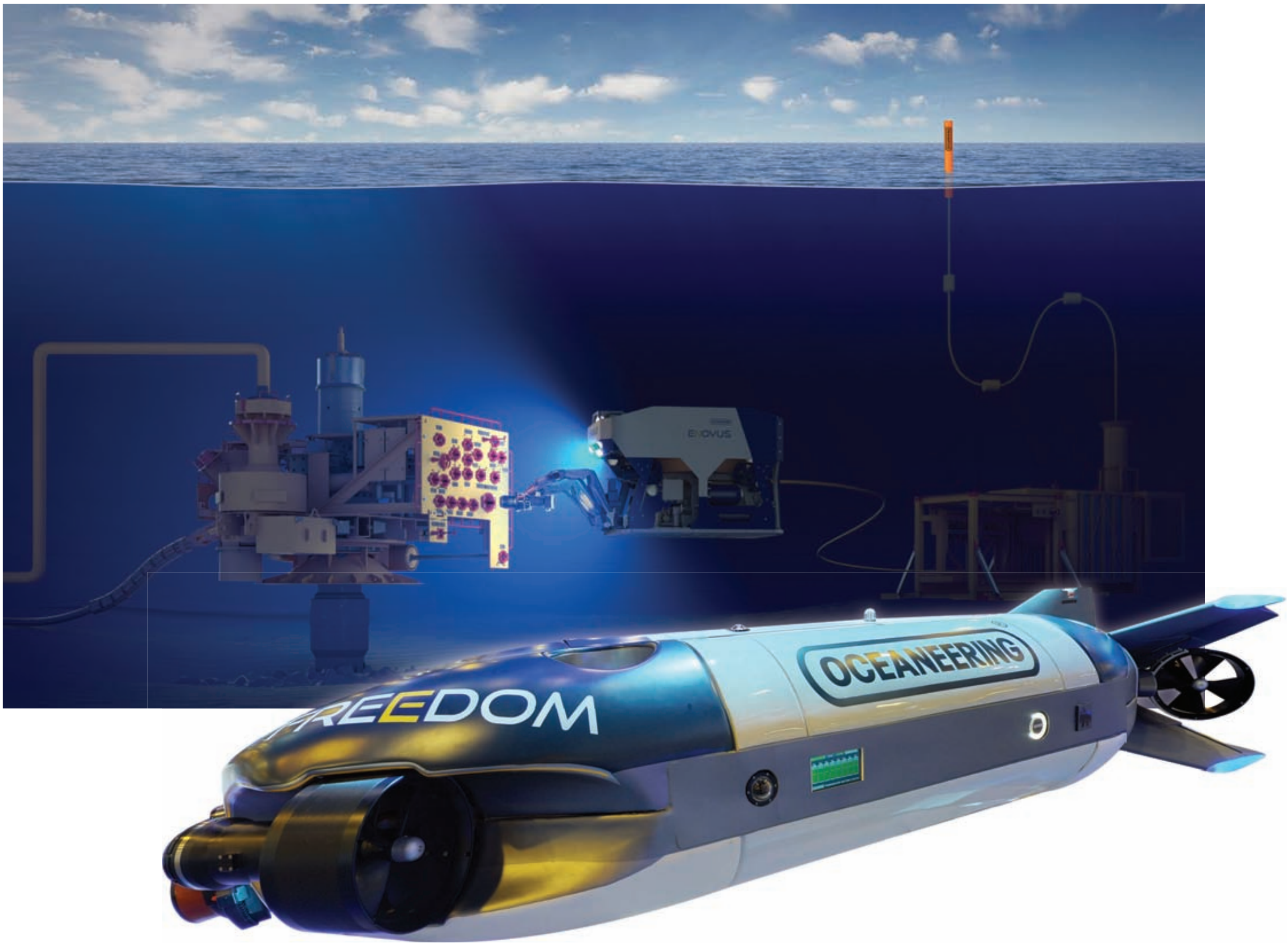
From an autonomy perspective, we would argue that battery and position sensors are the main improvements that make these technology advances possible commercially.

I remember studying at the University of Southampton and seeing AUVs [autonomous underwater vehicles] loaded with thousands of non-rechargeable D-cell batteries in order to perform under-ice missions. While that may have been a technically viable solution, it isn't viable commercially. Battery technology has evolved and improved. We can now offer more cost-efficient, and ecologically friendly solutions. Now we have super high-power density batteries that can withstand the pressures of the ocean down to 6,000 meters water depth. This enables us to design smaller, hydrodynamic vehicles with ranges in the hundreds of kilometers.

From a positioning viewpoint, we are using Doppler velocity loggers and inertial navigation systems (DVL/INS) that calculate relative movement and extrapolate the best estimated current position in relation to a known start position. These systems have been around for many years, but the technology has moved fast and the improved accuracy of these systems enables us to increase the range of our subsea missions while still maintaining accurate positioning.

What are your thoughts on open-standard subsea docking stations?

The current work on docking stations is very much in its infancy. One positive aspect of the current docking station design is that it is relatively simple and cost efficient while providing easy access for any form factor vehicle to dock and communicate. There are a number of limitations we are looking to overcome as any 'one-size-fits-all' solution comes with compromises. Ocean-



eering does expect to use both the current design docking station as well as docking stations designed for better protection of the vehicle and higher capabilities within tooling storage that can add more value to the concept of underwater drones.

What's the latest with Freedom?

Oceaneering has set up what we call our Living Lab in a fjord in Norway. The location enables us to run daily testing of our software, both in very shallow water, but also in water depths of up to 300 meters. We use the facility and the test vehicle to evaluate software packages as they are being created by our internal software development team. In order to ensure we maintain the development pace we are working in two time zones. The software team is in the US where they can develop new software and ready it for our Living Lab team to upload to the vehicle first thing in the morning. Once our US software team starts their day, they effectively have a full day's testing available to dig into and improve their code. This process has enabled us to make great strides.

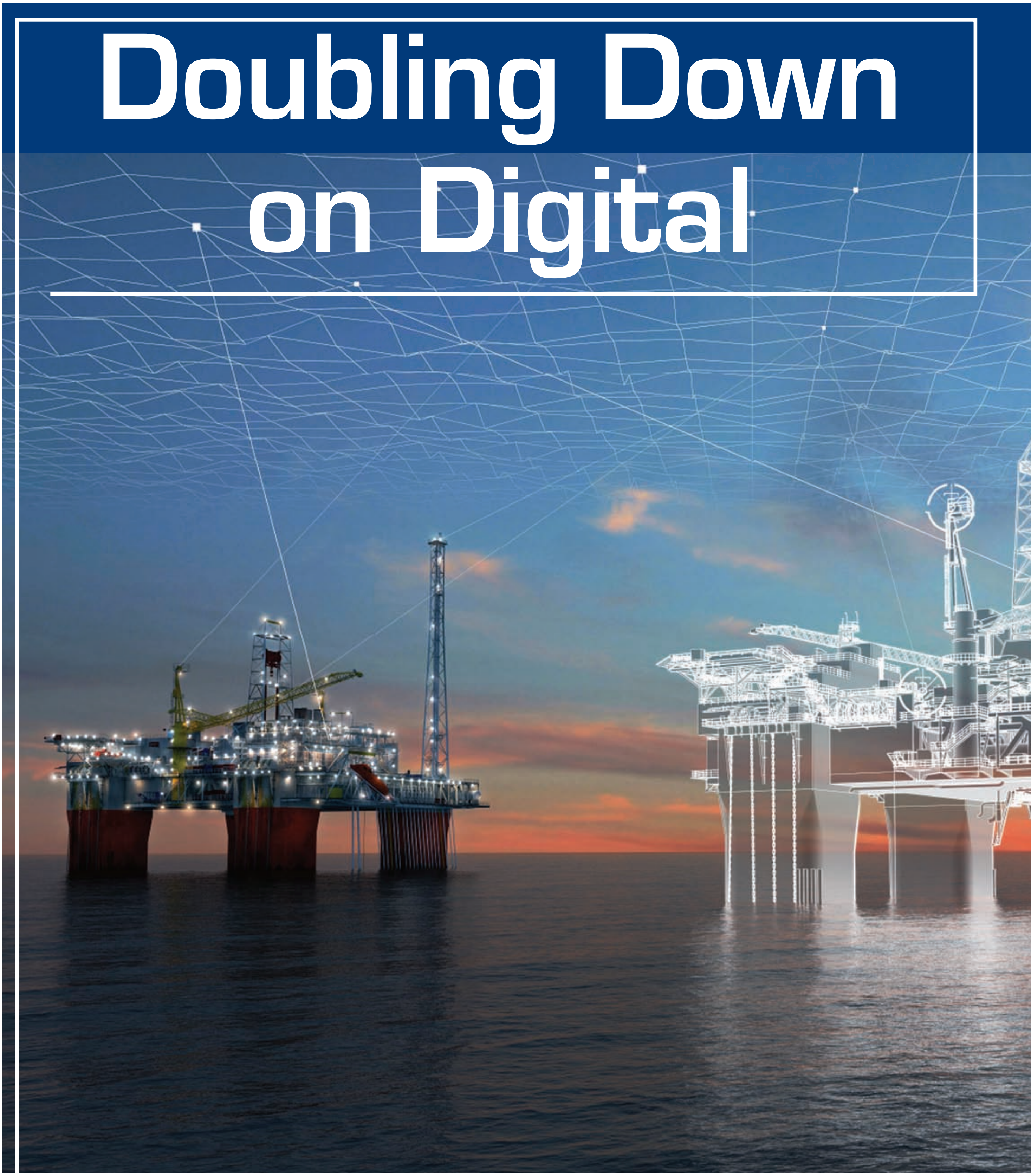
What're the next steps?

After SPE Offshore Europe, our Freedom vehicle will be shipped to Norway, where it will undergo commissioning trials, first in our test tank and then later at our Living Lab. We are currently building a mock-up of the current open-source docking station design. This will be installed at our Living Lab for further development of auto docking and communications and charging through inductive technology.

Finally, what has the E-ROV concept (also dubbed 'Liberty') been doing?

The E-ROV has been deployed a number of times now and has already proved its usability as an IMR solution for light work scopes. As with all new technology, we have of course experienced technical challenges in the initial phases, but so far nothing we haven't been able to solve. We expect this first E-ROV to become a great value asset for our customers and we do expect that this concept, which we have formally named Liberty, will be developed further.

Doubling Down on Digital



Source: ix3

BY JENNIFER PALLANICH

The Integral digital twin platform from ix3 contextualizes data, which means it makes data consistent, coherent and connected throughout the entire life of the asset.

Companies successful in reducing their capex and opex costs in the real world often do so by taking advantage of the digital world.

There's a reason terms like big data, digitalization, artificial intelligence (AI), machine learning and the digital oilfield dominate conversations about technology and business plans. But what do these terms actually mean? How can companies mitigate the cybersecurity risks they face? And how, exactly, can these technologies benefit the oil and gas industry?

Vendors, doubling down on digital, are offering a plethora of solutions in fields as diverse as asset integrity management, Internet of Things (IoT) applications, engineering and the weather.

Going digital

Digitalization takes the analog into the digital world, or, as Russ Bodnyk, principle at Coded Intelligence, puts it, "takes the reality around us and translates that into usable information on a computer." That could be in the form of sensors taking temperature, pressure or vibration readings and logging the data.

The amount of digitalization is growing exponentially, partly due to the sheer volume of data generated through internet of things (IoT) devices, Bodnyk says.

"We've run into the limits of traditional big data," he says. "Machine learning was born partly out of necessity."

Machine learning might be supervised or unsupervised by humans. Artificial neural networks, which are computer systems modeled on the human brain and nervous system, and deep learning are also responsible for advances in AI.

"AI can't do 100% of someone's job. What AI can do, generally speaking, is the more routine, more mundane and more predictable," Bodnyk says. "AI is not good with context, causal relationships or cognition."

Yet.

Within the next 25 years, AI will probably be able to do more than half of what humans can do, and handle more than three-quarters of it in the next 50, he says.

"Creativity is one of the last bastions of human-only traditional intelligence," he says. "AI gives people the ability to follow their dreams and the freedom to interact in ways they like already. There are so many ways AI can help companies. In the long-term, it makes jobs easier, makes profitable decisions, reduces risk, gives the right intelligence at the right time."

AI is not yet a big part of information security, he says, but he expects developments on that front to be interesting.

"The scary part is security is often reactive. AI is making more convincing deep fakes, making biometric authentication hacking easier, increasing ransomware and other attacks," Bodnyk says.

Security in the digital age

One of the challenges the oil and gas industry faces with cybersecurity is that information technology (IT) security is vastly different from operational technology (OT) security, according to Ian Bramson, global head of cyber security for ABS Group, a subsidiary of the American Bureau of Shipping (ABS). IT attacks are often aimed at gaining a financial advantage or disrupting business activities while OT attacks are geared at disrupting or stopping real-world operations, which can result in site safety, public safety, and environmental safety ramifications, he says.

As the oil industry connects more OT systems, it also creates exposure points, which means more ways for "bad guys to get in" and affect core operations. "Systems that were never meant or designed to be connected are now connected," he says.

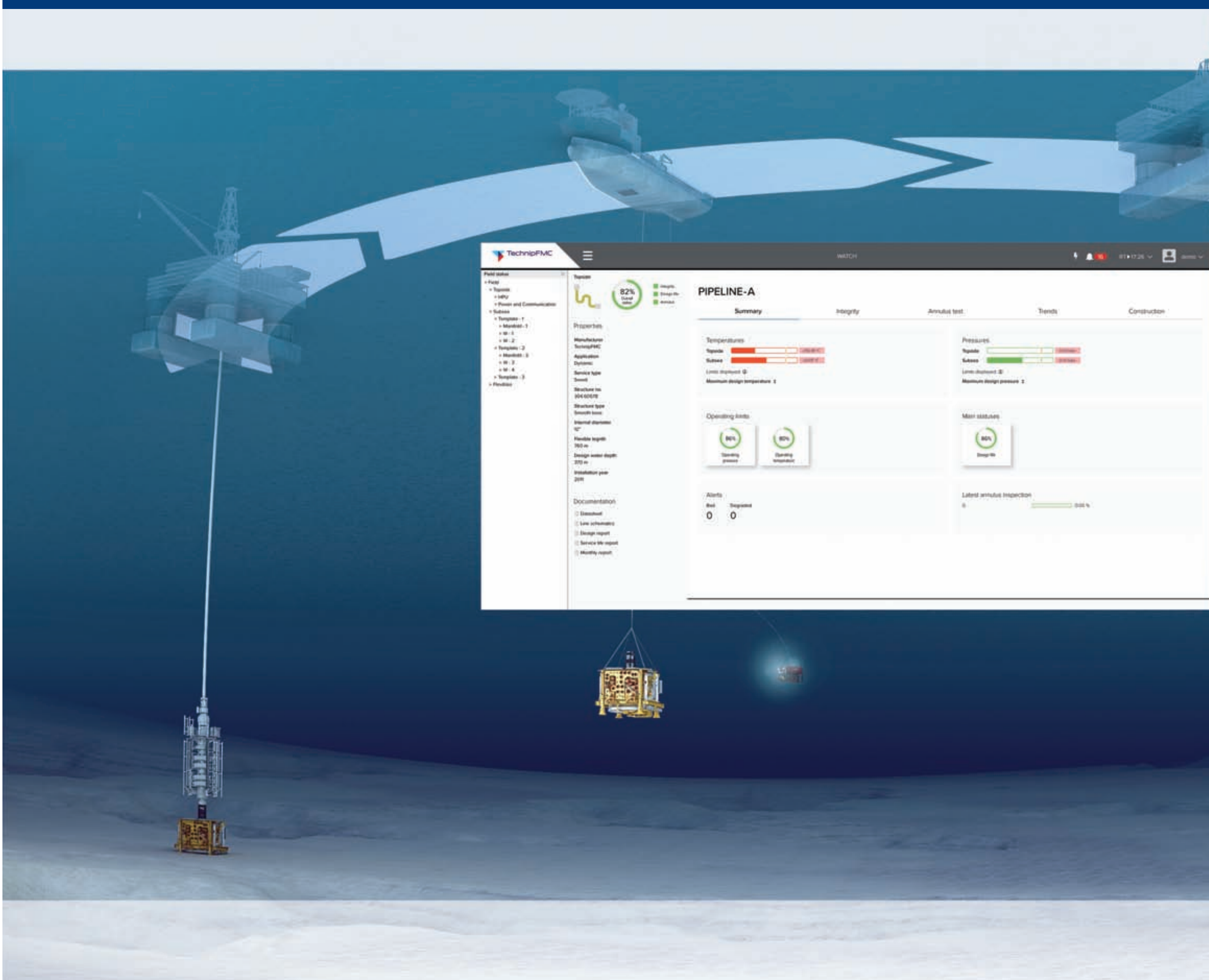
A clear understanding of an operation's connectivity is the foundation of a solid cybersecurity plan. That means looking at how two items are connected in both the real world and the digital one, who has access in each, and figuring out the potential consequences of an attack, he says. The next step is determining what to do if an attack occurs.

"Cyber security comes down to two things: visibility and control. Can I see what's happening, and can I do something about it?"

And it's an ever-changing landscape, particularly because the OT environment is a new one for both the attackers and defenders, he says.

"Operators are trying to figure out how to put the basics in place and then how to get ahead of it. Cybersecurity is not 'set it and forget it.' As you add digitalization, connectivity goes up, and how they attack is going to change," he says. "There's an active adversary that most of this industry has never faced before."

CPM from TechnipFMC provides valuable insights to support operations.

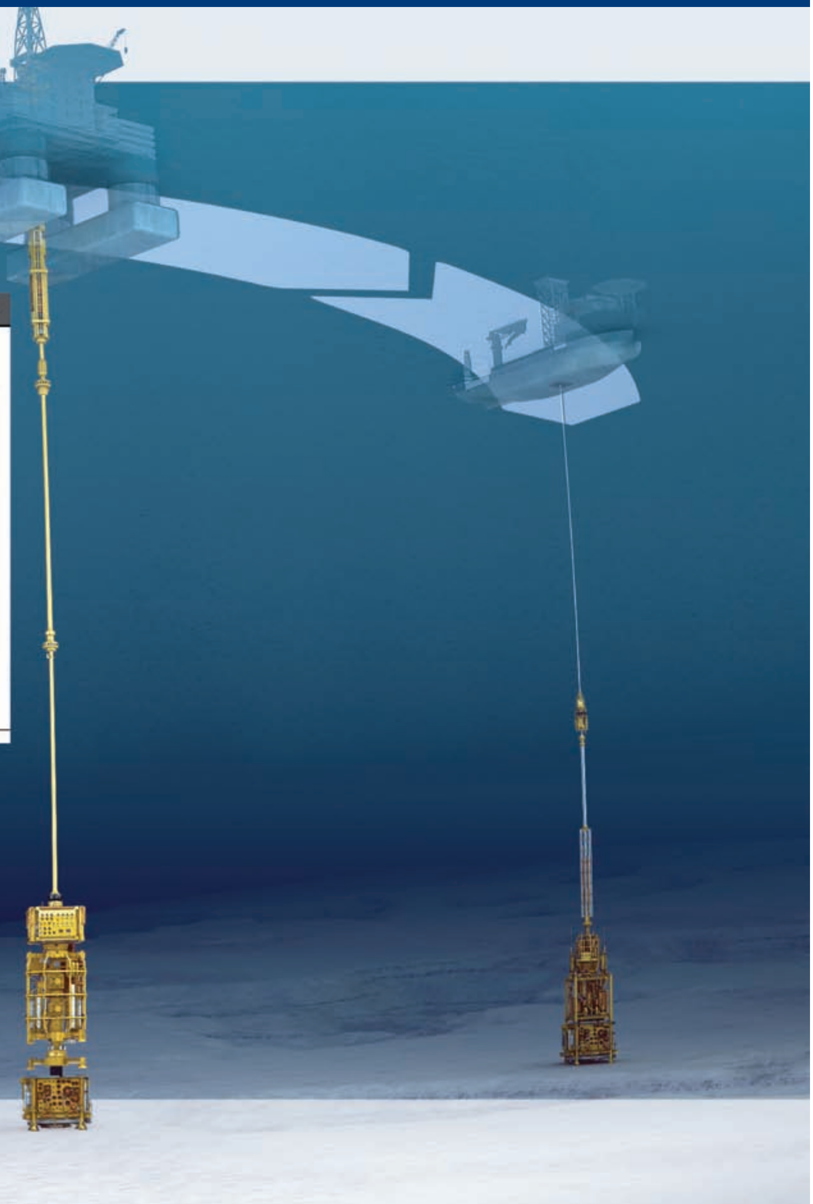


And when attacks happen, they're rarely reported publicly due to the risk of exposure, Bramson notes.

Regulations around OT security of critical infrastructure are emerging, and Bramson believes that will drive some to begin cyber assessments. But, he cautions, there is a difference between being compliant with regulations that may be in place and actually being secure.

"Cybersecurity is a core business imperative," he says. "It helps protect your OT systems to prevent the likelihood of an attack, and if you do get attacked, it helps you limit consequences of the attack."

Source: TechnipFMC



Monitoring systems

TechnipFMC's combination of domain knowledge with digital technology brought the subsea industry Condition Performance Monitoring (CPM), a surveillance system that provides continuously updated knowledge about asset integrity management in real time. CPM helps asset owners maximize operations while avoiding downtime, equipment failures and safety incidents, says Julie Cranga, TechnipFMC's VP for Digital Subsea.

CPM ferrets out the root cause of equipment issues and predicts equipment failure so preemptive maintenance can be planned, she says. CPM does this by crunching vast volumes of data generated from numerous sensors on equipment.

"What clients like with a system like CPM is they have more confidence," Cranga says. "They have more information about their assets. All the data arrives in the control room. They can see in real time what's happening. It gives them additional insights to make the right decision."

Using CPM, some of the company's clients have documented reductions of up to 30% on specific inspection, maintenance and repair scopes costs and reduced the required number of personnel sent offshore, she says. In one subsea intervention, an operator used TechnipFMC's CPM services to prevent shutting down a well, saving an estimated $50 million in repairs and saving production deferment.

The company sees no limit to the "potential of digitalization to do what we do better and be able to unlock some new possibilities," Cranga says.

One of those is harnessing the power of AI to manage inventory.

"We are able to fulfill materials demand with stock availability," she says. "The Excess Inventory app is performing millions of combinations to help match materials against our excess stock."

That inventory management system, launched in 2018, has so far saved TechnipFMC more than $1.5 million internally, she says.

"Today we have both the ability to access data and the technology to leverage these data," she says. "Until a few years ago, the digital infrastructure, the connectivity and the computing power were not available."

Deploying IoT

Baker Hughes, a GE company, and AI specialists C3.ai created a joint venture (JV) in June to bridge the information technology (IT) and operational technology (OT) domains. The JV, called BakerHughes C3.ai, is intended to deliver digital transformation technologies to drive new levels of productivity for the oil and gas industry.

Ed Abbo, president and CTO of C3.ai, says the company helps companies accelerate the design, development and deployment of AI and IoT applications to transform businesses, including oil and gas.

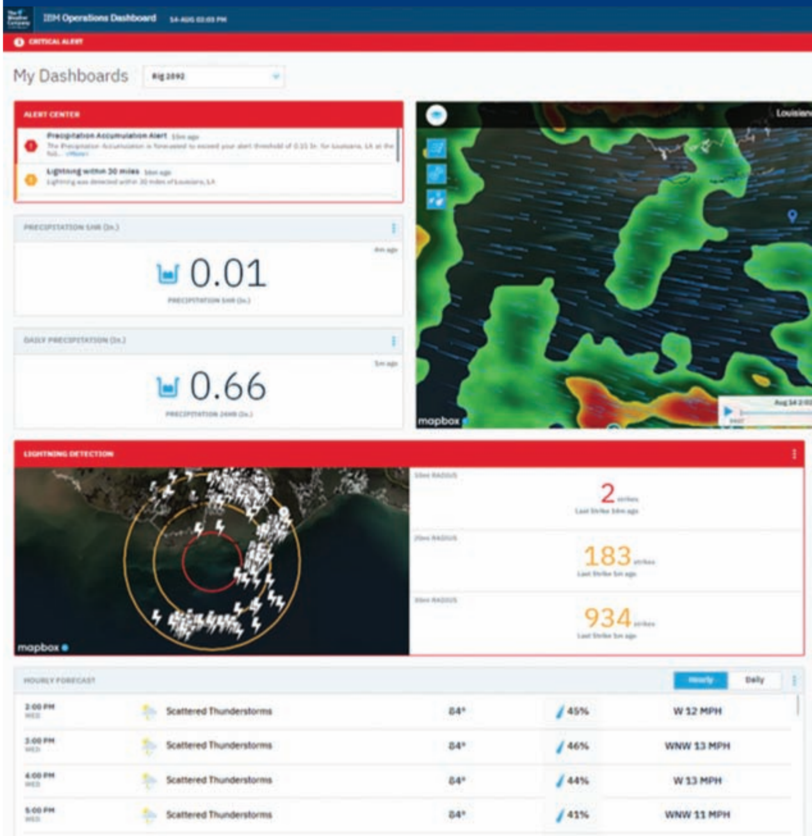
"A majority of data is not really analyzed or processed. It's collected and neglected," Abbo says. He believes this data is the key to enormous potential: reducing the breakeven price of oil and improving safety and reliability of operations.

According to BHGE, AI in the oil and gas segment helps improve overall performance by ingesting massive quantities of data, becoming intelligent about specific operational environments and predicting problems before they occur so that operators can improve planning, staffing, sourcing and safety.

Dan Brennan, BHGE's VP of Digital, says, "Artificial intelligence and machine learning technology can really help add significant value" in categories like equipment reliability and production optimization. The promise of AI is that it can help companies "unlock value from the constant influx of operational data as well as data that has been stranded from 10 years ago," he says.

Shell has long used BHGE's JewelSuite for reservoir modeling, and in 2018 announced use of the C3.ai platform to accelerate the company's digital transformation, focusing on using AI and machine learning to improve overall operations starting with predictive maintenance.

Recently, BHGE and C3.ai announced the launch of the AI-enabled BHC3 Reliability application, which uses historical and real-time data from entire systems to identify anomalous conditions that lead to equipment failure and process upsets.



The Weather Company provides its offshore customers a weather-based dashboard that drives alerts.

Engineering practices

"Oil and gas has been digitalizing forever. Reservoir models, seismic, but nobody's really digitizing the topsides," says Dean Watson, Aker Solutions' chief operating officer and executive vice president for subsea lifecycle services.

Part of the problem has been around making sense out of the data because manufacturers digitally refer to equipment in different ways and operators use different naming convention for equipment such as compressors on a facility. Further, various software systems all represent data in different ways, making it difficult to integrate and extract data.

"Even though they are similar, they are different," says Are Føllesdal Tjønn, who heads up ix3, the software and digital services company to enable operators to accelerate field development projects and optimize asset performance that Aker Solutions launched in May. "We needed a solution where we could extract data from many sources and conceptualize it, bring meaning to it in a coherent and consistent way across different sources and customer bases."

At its most basic, ix3 is about different ways of classifying data, so the team spent a lot of time and effort building the semantic web and creating a semantic model of an industrial asset.

One of the challenges EPC contractors face is the ability to tap into an offshore installation's history to search for information about how a problem was solved, he says, so the company created the Engineering Assistant app, which is basically "a search engine for engineers" to extract data from previous projects much more quickly than before.

"That has enabled us to develop completely new solutions for how we do concept studies, FEED and engineering projects," saving weeks or months of engineering time, Tjønn says.

Forecasting

Big data is even changing weather forecasting. Rob Berglund, energy solutions lead at The Weather Company, an IBM Business, said a decade ago, TWC would forecast 100,000 different points around the world. Doing so required major spreadsheets that forecasters around the globe used to put out forecasts which they updated throughout the day.

Source: The Weather Company

"We could train the satellite imaging going forward as to what a gaseous leak looks like, from space at scale, and they can do that across the entire global assets."

- Rob Berglund, Energy Solutions Lead at The Weather Company

"It was a massive, incredible amount of data to manage," Berglund says.

Now, TWC devotes about 24 terabytes a day to generating hyper-local forecasts, to the tune of forecasting 2.2 billion locations every 15 minutes, he says. To do that, TWC had to transition away from just using data from Federal Aviation Administration sensors at airports and buoys in the ocean. Now the data comes from a variety of sources. TWC relies on voluntary crowdsourcing of weather sensors around the world, even including pressure sensors on mobile phones with user permission. Airlines dispatch data about upper atmospheric conditions airplanes encounter while flying over oceans. TWC then uses artificial intelligence to break down all the data.

TWC provides its offshore customers a weather-based dashboard that drives alerts. The company also sells radars to help fill in gaps for offshore areas with inadequate sensing. It sends the feedback to the operator's dashboard, where it can be interpreted.

"It's more than just a remote guess. You've got information at the asset you really care about," he says.

The ways artificial intelligence can be used are evolving. It is possible, he says, to train satellite imaging to spot gas leaks, combine that image with weather and wind patterns, and determine where the leak originated.

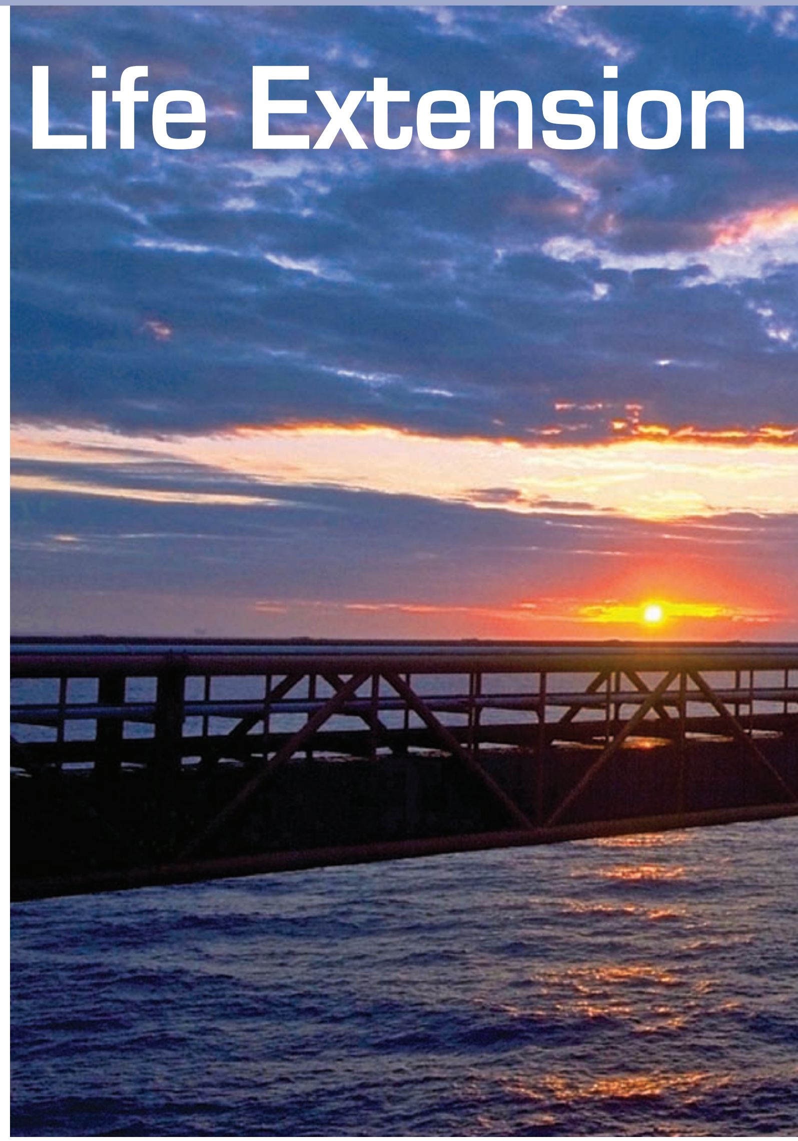
"We could train the satellite imaging going forward as to what a gaseous leak looks like, from space at scale, and they can do that across the entire global assets," Berglund says.

Going forward, he believes real-time images shared from "millions of mobile devices" could further improve forecasting.

"Imagine the modeling you can do, no matter where you are, in remote areas," Berglund says. Artificial intelligence could analyze "real-time images from millions of mobile devices, stitch them together and say, this is what's happening in that area."

Digitization as Life Extension

BY WILLIAM STOICHEVSKI



Operators are on digitization journeys linked to life extension projects that aim to make the most of older infrastructure. Proposed tiebacks at ConocoPhillips' Tor II and on Aker BP's Ivar Aasen projects look set to reveal a special benefit to "freeing data", for operator and supply chain. Digitization has altered the way these operators see themselves, their operations and life extension. Newly contextualized big data builds on earlier automation and digital documentation drives to cut manhours. Still, some warn, "Careful when you digitize."

Digitization has strong support in Norway, where artificial intelligence (AI) and cloud computing go-to Google is in the market for a large forest lot to house a vast data farm. Local math minds critical of the AI-run Facebook chatbots that ran amok and created their own language are nevertheless in favor of Google's build-up in tech-it-or-leave-it Norway.

AI — algorithms, cloud-based machine learning and computer vision — is being cheered on here, especially offshore. Modernizing older infrastructure with tagged and networked sensors topsides and subsea is part of the requirement when digitizing for life extension. Yet, reining in and displaying in new ways the information from those tags hasn't until now been a top priority.

"It's not like they're looking around and saying, "Where can we do life extension." If you can extend the life of equipment, I mean it's like increasing the life of your dishwasher," a Norwegian analyst who studies oil companies all day confides, before adding that the big value offshore has hitherto been in megaprojects, and only lately has "quick payback" been a thing.

Digitization offers easier management of these new reserves — witness the modern data room — but improving overall operations (beyond drill tech) by digitizing has been an elusive quick fix. The sum of automated but not-so-management-friendly legacy equipment and commendable human behavior has hitherto been the only path to improved operations: ditto "life extension".

DIGITAL JOURNEYS

Enter the digital twin — enabled by AI and machine-learning — and made possible by a company commitment to "the cloud". An operator and the supply chain can now build their own apps and employ the new management software to zero-in on physical fixes with a pin-prick examination of the twin.

Before this ability, there was ConocoPhillips, with its 4,000 "analytics practitioners" and "hundreds of proprietary applications".

With help from class DNV GL and wireless suppliers, the supermajor has long been automating and then digitizing its operations in the North Sea off Norway. ConocoPhillips now awaits royal assent for a life extension project (Tor II) at the ultimate life extension project, Greater Ekofisk. Among the company's most recent digitizing efforts was installing supplier qualifying app, EPIM JQS, early in 2019.

TOR II

In the decade since DNV GL first guided a ConocoPhillips digital-archiving effort, the class flag bearer has intensified its digitizing push and now has the ability to check for errors and conflict in all the sensors and coding running an oil platform, rig or subsea template.

DNV GL's evolving Veracity Data Fabric platform builds on that ability and is populated by the managerial tools pro-


Source: ConocoPhillips

Life-extended: the sun never quite sets on Ekofisk projects.

duced by "app" developers with strong life extension offerings. That's good news for most of the 20 or so projects offshore Norway that will seek to rapidly control new area reserves from "legacy assets".

At Tor II, ConocoPhillips will likely deploy its own compressive seismic imaging software; a drilling execution efficiency platform (DEEP) and reservoir simulation capabilities. The Ekofisk-extending Tor tieback, however, would seem ideal for trying out a cloud-based management suit: a challenging new reservoir hook-up to gas-lift pipeline; riser and umbilical to the older Ekofisk 2/4 M platform. The seabed IT link will also have to secure new types of subsea multiphase pumps between wellhead platform and the two-by-four slot subsea production system. There's much to manage.

EARLY-MOVERS

Apart from production wells, a pilot well "to test long-term productivity in the Ekofisk formation" — including up to 70 million barrels at Tor II — seems ideal for digital observation. At stake is up to $800 million ahead of first oil at year-end 2020. Still, ConocoPhillips knows life extension: "Having produced the Tor field for 37 years, we are proud to continue to extend development enabling a production lifetime beyond 60 years," states Trond-Erik Johansen, president, Norway & North Africa.

ConocoPhillips is an early digital mover that awed us a decade ago with a real-time oilfield revenue calculator; tagged and barcoded maritime logistics and remote, video coms.

MAINTENANCE CGI

Putting ConocoPhillips and Tor II in perspective is the digitizing drive of offshore operator, Aker BP, where "in-house" and supplied visualization are in-play to manage life extension.

Under a 2018 pact with digital visualizations company Cognite (part of the Aker "family"), Aker BP is focusing on digitally enabled preventive maintenance (of a pump) and a digital twin (of the control center). Life extension projects at Ula, onstream

Source: Aker BP

Digitizing partners: Jens Umehag, CFO BP Ventures and Karl Johnny Hersvik, CEO Aker BP signed a cooperation agreement to promote new technologies together.

in 1986, Alvheim (2004) and Skarv (2012) stand to benefit.

As at Tor II, Aker BP at Ivar Aasen (its digital pilot) will employ subsea lift. It is hoped the Cognite partnership will yield preventative maintenance benefits for field partners — and for supplier Framo which, Aker BP chief exec Karl Johnny Hersvik says, “will be able to make better pumps in the future” as a result of pump data streamed to onshore engineers via satellite (for more on this, see page 48).

The digital oilfield twin (and Cognite’s REVEAL 3D viewers) will show instant CGI of the exact location of equipment in need of maintenance. Crews need only consult their devices to identify the part. With the expectation of more maintenance for older facilities, the savings are in “no list checks” for crews and the ability of managers to locate docs, visualize and better plan for production events and maintenance.

So, “smart maintenance” contracts could come to dominate life extension. Actionable big data triggers repairs and eliminates scheduled maintenance. Hourly rates fall. Terms based on uptime emerge.

AUGMENTED AUDIENCES

Austrian operator OMV and German Wintershall Dea agreed to share digitization learning with Aker BP, which in turn has partnered with new subsidiary Resoptima to deliver a “digital twin” of its reservoirs.

All of that requires digital infrastructure. Cognite appears to be partnering with OEMs already in the preventive maintenance business but unable, perhaps, to free their data for management contextualization.

An early benefit of digitization for life-extension seems to be that management concerned about overall field integrity gain the apps they’re used to along with oilfield equipment readouts. So, the offshore-onshore video conference between, say, a platform manager offshore and a wellhead expert or executive in Stavanger is supplanted or augmented by an instant, Google-assisted meeting and Cognite contextualized visuals.

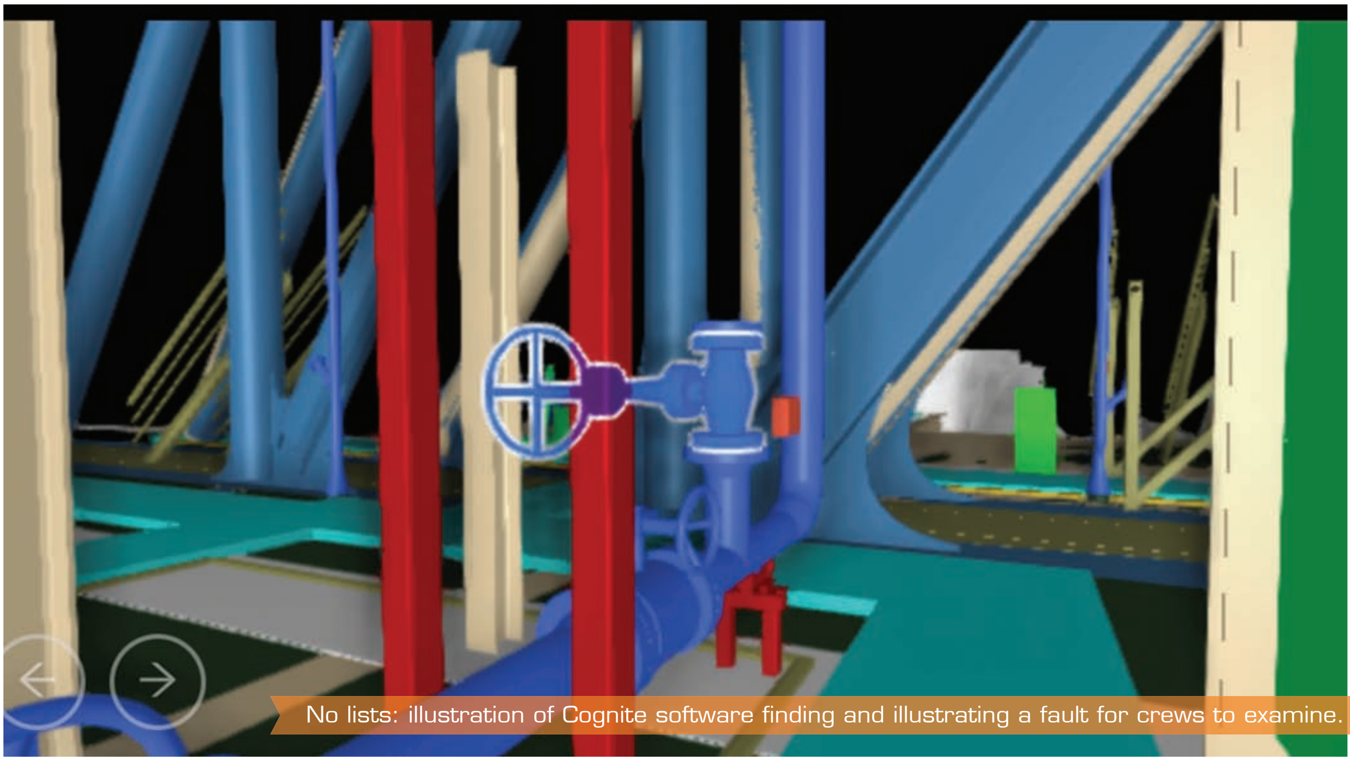
For life-extension purposes, Cognite software would have to liberate, present and make useful the “live” and historical data sent by myriad production equipment of varying age, type and make. At Ivar Aasen or Tor II, that would include the vibrations of a subsea pump.

“We have instant access to all our live streams on our computers, tablets and phones and through the Google Assistant,” Hersvik, tells a conference audience.

SUPPLIER SURGE

While Aker BP frees its data and rolls out the Cognite and Resoptima tech across its portfolio of five operated assets, some digitization suppliers argue caution is needed when going all-out digital.

“Let’s not start with the data. Let’s be clear about what our data needs to do before we start,” Biarri Supply Chain chief exec, John Payne, tells a shipping conference audience. His company has helped Shell and Rio Tinto assess their data needs, and he warns that just 4% of companies are getting value from big data.



Source: Aker BP

No lists: illustration of Cognite software finding and illustrating a fault for crews to examine.

"Big data will not deliver direct value," he declares, adding that storage and choices on what to monitor are crucial at the beginning. His presentation, The Big Data Fallacy, prompts instant soul-searching, as he reiterates, "Liberating data creates no value. Data is not knowledge. Data is an enabler. It will not tell you what to do next."

His best advice on data is not to start at diagnostics and then move to predictive data and finally prescriptive data — but the reverse. "We need to do the prescriptive data at the start" of decision-making, he says.

For contrast, Hervik says digitizing is "easy to buy, easy to implement and easy to use." And liberating more data ostensibly generates commercial value thrice: as management tool for the operator; as data sold to the OEM by the digitizer and by the OEM selling maintenance as a "smart service" based on uptime.

IOT

While Internet of Things (IoT) reports we've read suggest oil and gas lags other industries in IoT, Cognite may be ahead when it comes to life-extension management, if only because it was ostensibly commissioned to be a data-aggregating software suite by its current majority owner, Aker ASA.

Similar offerings — DNV GL's Veracity Data Fabric, marine-savvy Kongsberg's Kognifai and multi-industry Cognizant of New Jersey — all offer improved data visibility, insights and access security.

While Cognite seems to have pre-sold a long list of well-known partners providing wireless solutions to oil and gas, there are other, more specifically life-extension digitizers emerging.

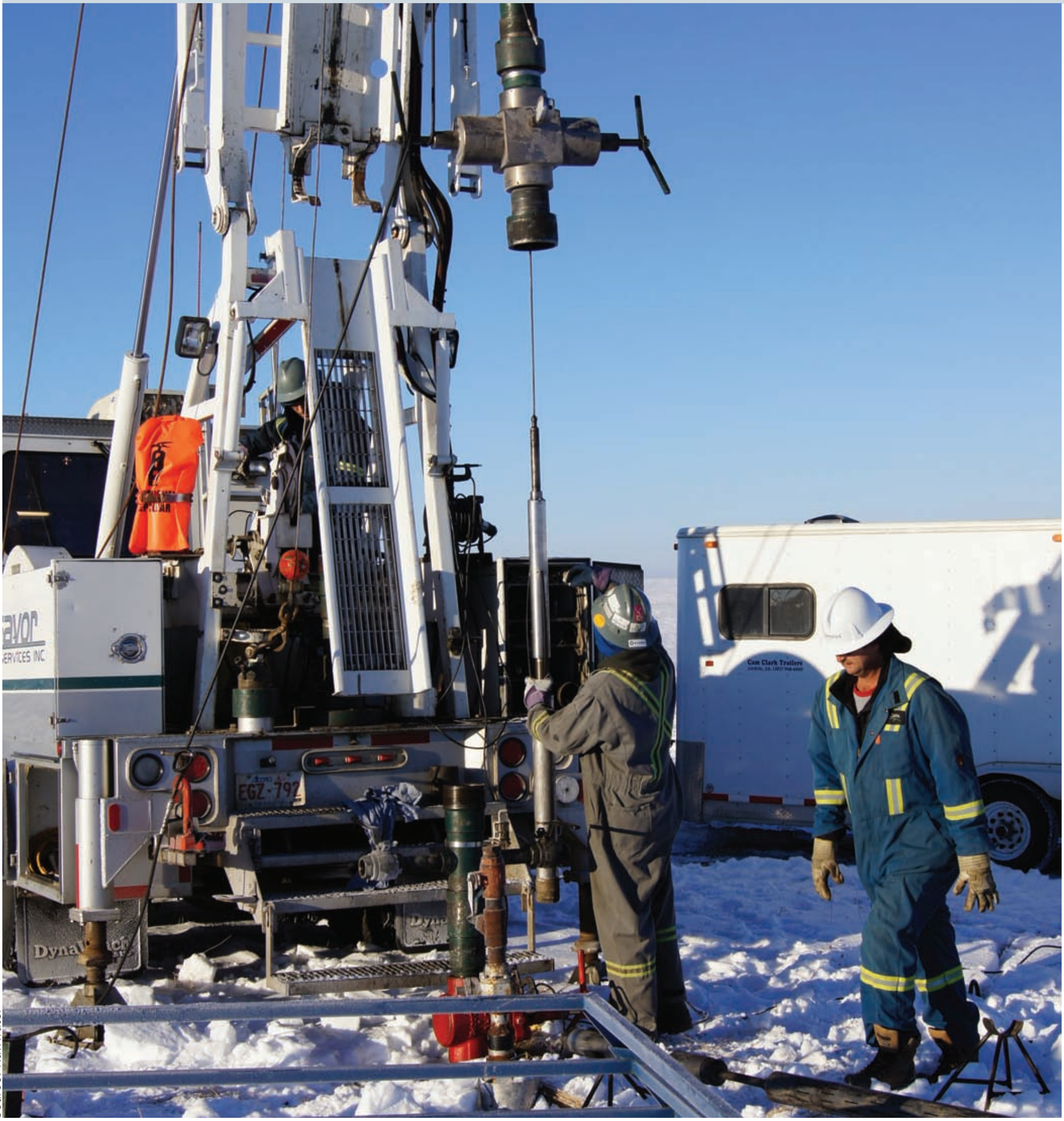
Software tools once aimed only at efficiency gains excel when applied to life extension: "It just so happens that by making these (digitizing) improvements asset owners can work more (efficiently) allowing the asset to run more economically which helps the business case for asset life extension," DNV GL spokesman, Neil James Slater, tells *Offshore Engineer*. Several digital tools have emerged out of Veracity data.

PSV Manager Tool uses pressure safety valve certification and failure rate data to determine the right certification intervals for platform supply vessels (PSV). DeepSearch Cogitive Search engine will dig up handwritten docs, engineering drawings or "the needle in the haystack" that might "extend the life of a field," Slater says.

DNV GL has been at structural safety for years. Now, it offers digitally its Oreda reliability database in an older trouble spot finder called Corrosion Under Insulation (just the thing for life-extension). With life extension projects adding up, those able to offer digital structural and downhole monitoring; legacy equipment digital harmonization or remote pump and reservoir control find a sales edge.

Some operators we talked to in Norway with high-profile life-extension projects are content not to be the poster people of digitization despite wanting to keep marine infrastructure working to 2050. "It's a strategic decision. We're not first movers, so we're catching up with some of the others after leading (until recently)," an operator source says.

P&A Finding New Alternatives



Source: Rawwater

In 2010, **Rawwater** set a bismuth plug onshore Alberta.

While it doesn't always grab the headlines when it comes to decommissioning, well plugging and abandonment (P&A) is the biggest cost and headache.

BY ELAINE MASLIN

The P&A scope is large and the challenges diverse. It's also an activity that's increasing. In 2017, for the first time, more wells were abandoned in the UK North Sea (approximately 160) than new wells were drilled (less than 100), as fields reach the end of their productive lives. Here, some 1,400 wells are expected to be plugged and abandoned over the next 10 years. It's a costly endeavor with no economic return.

The UK Oil & Gas Authority's (OGA) UKCS Decommissioning 2019 Cost Estimate Report says P&A activity is estimated to account for 44% of decommissioning costs (down from 48% in 2016). It's hoped that bill can be cut by 35%. Inroads are being made. The Cost Estimate Report says well P&A costs have benefitted from improved scoping of required work, and better execution practices, while subsea wells have benefited from cyclically low rig/vessel rates. But, costs still fluctuate and more has to be and can be done.

The Oil & Gas Technology Center (OGTC), a public-funded body tasked with technology development based in Aberdeen, is supporting various projects. Malcolm Banks, Well Construction Solution Centre Manager, at the OGTC, says, "Abandonment work is increasing in volume and the scope is quite significant. Its was one of the first areas the industry wanted us to address (when the OGTC was founded in 2016)." Key aims are moving more toward rigless abandonment technologies, reducing the scope involved and alternative barrier materials, to replace long cement plugs, which would in turn reduce scope and reliance on rigs.

"Historically, cement has been the default, but it's not perfect," says Banks; getting it in place over long well sections can be time consuming and challenging. "So, industry is looking at alternatives, as well as economically implementable solutions." The goal is plugs that can be quicker and easier to place, with integrity at least as good as cement. That also means finding easier ways to place barriers. "Historically, that's meant removing whole tubulars, completions and cutting and pulling casing, and that can take weeks," says Banks. "So, we're looking at how to cut or remove sections with thermal or mechanical means.

"Another challenge is understanding the condition and the integrity of the well and geology surrounding it. A lot of wells have changed hands three or four times, and information is lost. But, that information can help reduce risk and uncertainty. So, we're looking at cheap internal surveys up front and modeling using data and data analytics to reduce risk and uncertainty."

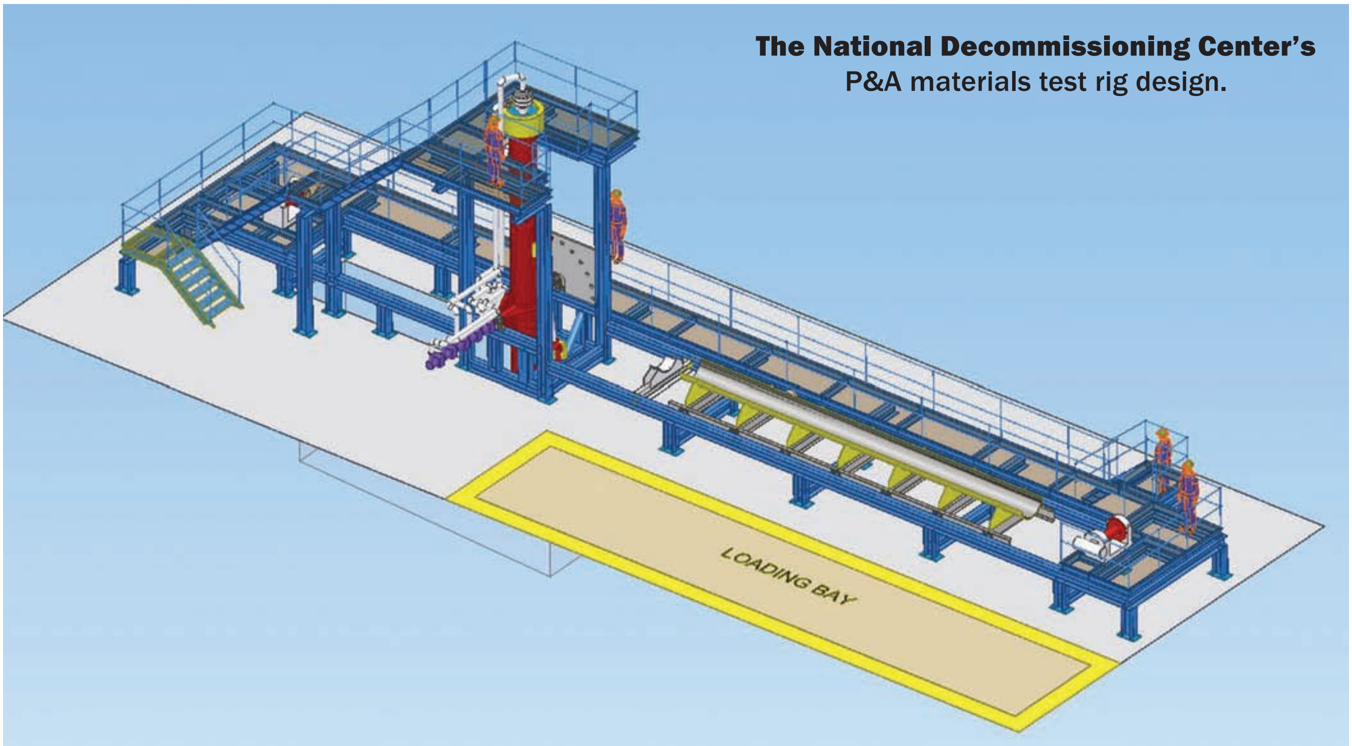
Fields trials

A number of projects are at field trial stage. For example, the OGTC supported two fields trials by operator Spirit Energy of thermite – a pyrotechnic composition of metal powder and metal oxide – as a way to form a barrier by burning through tubulars and casing to the formation rock. These saw Norwegian company Interwell's thermite technology used in a well at Caythorpe, in England, in 2018, and also from the Audrey platform, in the southern North Sea, earlier this year.

The OGTC is also supporting work with BiSN, supported by BP, looking at qualifying bismuth alloy as a barrier material followed by a potential deployment. As reported in *Offshore Engineer* (January 2019), BiSN, based in England, is using bismuth alloy that's melted down hole using a thermite heater. When it sets, bismuth alloy is unique in that it expands. BiSN, whose name stems from Bi for bismuth and Sn, for tin, in the periodic table, has already had a trial in Norway with Aker BP, as we reported in January. Another firm looking at use of alloys, deployed through tubing on electric wireline or slickline and used with thermite downhole as a replacement for cement, is Aberdeen-based Isol8, led by former Interwell managing director Andrew Louden. Isol8 is also working with the OGTC and looking for field trial opportunities.

Separately, Rawwater, in England, is developing expanding bismuth alloys as sealing elements. The firm's work with bismuth (which it calls 'molten metal manipulation') dates back to

Source: Rawwater



The National Decommissioning Center's P&A materials test rig design.

Source: NDC

2000, when the material had been used in test rigs, simulating nuclear submarine cooling circuits. Following a meeting with an oil major the same year, the firm directed its attention at P&A, using an electric downhole heater developed for heavy oil extraction, from Canadian firm SealWell, and downhole telemetry to control the heating. Prof. Bob Eden, Rawwater's managing director, says two trial plugs were eventually set in wells in Alberta in 2010 and the company has continued working on the technology ever since, running a series of research projects. The first focused on 4-inch plugs, which were deployed onshore but subsequent pressure testing was hampered by through-wall corrosion of the casing. The second targeted offshore deployment of 7-inch plugs, working with OTM and then the Industry Technology Facilitator in the UK, supported by Shell, Nexen, Equinor and ConocoPhillips, focusing on the bismuth alloy metallurgy to achieve a 3,000-year life expectancy. In 2016, the company started an Innovate UK project focusing on developing higher temperature alloys for medium to high temperature wells, working also with the Oil & Gas Innovation Center (OGIC) and Aberdeen University.

The project has recently completed, and the result is two alloys, Alloy 80 and Alloy 150, which resist creep to 80°C and 150°C respectively, and resist corrosion in sour environments. Both alloys were certified by Bureau Veritas to be fit for the 3,000-year life requirement. Rawwater has recently formed a partnership with UK-based engineering consultancy Astrimar, and is looking for partners to deploy trials, following workshop tests at the firm's facility in Culcheth, England. Meanwhile, Rawwater continues to advance the technology to seal micro-cracks in nuclear facilities.

Some believe cement just isn't sufficient. Prof. Brian Smart at Encompass ICOE, an Edinburgh-based health, safety and environment resource for the offshore industry, says, "We believe cement isn't sufficient for the long-term as a plug material one recognized reason being its chemical deterioration. The other reason its reaction to ground movement – such as reservoir subsidence or its reversal as the reservoir recharges – that stresses the rigid cement, cracking it and destroying its integrity as a plug. Richard Stark, from the same organization, says, "One of the problems is that there's very little information about plug deterioration in situ. Integrity issues have, however, occurred in every basin due to corrosion of the steel or loss of integrity of the cement. With those two materials, that's what's stacking up for the future."

They have an idea for an alternative plug material: quick clay. It's a naturally occurring clay – found in Scandinavia and North America – that, over many years, has had the halite or salt that makes it form into a clay solid washed out. Without the salt it remains thixotropic – i.e. it tends to liquify when shaken. This property would mean it would accommodate ground movement effects without cracking bentonite has similar properties, and has been tested, but because it swells (unlike quick clay), it can fracture the well, says Dr. Carl Fredrik Gyllenhammar, who is working with Encompass ICOE and runs Norwegian firm Cama GeoScience, which received research funding to test this concept at the International Research Institute of Stavanger and the University of Stavanger.

Quick clay liquifies when agitated

Source: Encompass ICOE

Sticking with cement

Some companies are looking to stick with cement, but to improve it. Well-Set, based in Norway, is looking at magneto rheological cement. This involves using traditional cement but controlling how it is set – its rheology – more accurately by impregnating the cement with magnetic particles then using a magnetic field to place it, says Banks. It's similar to a process used in car suspension where a magnetic field hardens the suspension hydraulics for "sport mode". The OGTC has supported a desktop study with Well-Set and is now moving to a Phase 2 project, supported by ConocoPhillips, involving full scale and bench testing.

Meanwhile, at the University of Strathclyde, Glasgow, nanoparticulate silicate and biogrout technologies are being looked at. "Cement, over time, will shrink, crack and degrade," says Banks. "The ability in the annulus to retain the barrier long term is something that's a concern to industry." Especially as there's no way to go back in and repair it. So, ideas from civil engineering are being looked at, including biogrout, which uses enzymes that deposit calcium carbonate in the downhole environment. "The nanoparticular silicate, meanwhile, would get into the cement or cracks where it gels and, while hasn't got compressive strength," says Banks, "it has pressure retaining capacity so it helps to seal areas in a well bore that might otherwise flow."

Another cement adaptive technology is being developed by UK-based Resolute Energy Solutions, who are testing using additives in cement that expand downhole to eliminate shrinkage. They're on the OGTC's TechX program, to help accelerate their work.

Testing, testing, testing

A challenge for new design well barrier materials is the criteria they must meet. Cement has been used for decades and is the default, even if it's not perfect, as some assert. If other materials are to be used, they need to be proven. One challenge is exactly what they need to be proven to do.

Another challenge is that current criteria for well barrier materials are based on cement. "If we were to apply the same scrutiny to cement that applies to new materials, cement plugs would struggle." says Brian Willis, research and development engineer at Astrimar. "The requirements are still very much written with a cement mindset. Qualification is done against the values and strength of cement as opposed to how a plug functions as a barrier. Not enough is being done to understand how new plugs might fail and how that may affect performance in sealing a well and remaining in place. That means there are materials that have gone through recommended qualification and field trials and which are now experiencing issues and it's hard to ascertain what's going wrong because early qualification testing was not as extensive as may actually be required."

Astrimar has developed a STEM-flow predictive analysis tool to help assess the predicted life of barrier materials and P&A designs. It's been created based on a database of materials, including cement, built by Astrimar following extensive data gathering. It was used as part of Rawwater's product development. "With the addition of extensive TRL4 testing, the predicted life of the bismuth alloy compared with cap rock was improved greatly," says Willis. But, he stresses, it's not just about the material that's deployed, it's also about the interfaces between the material and what it's sealing against. "In reality, the industry hasn't fully quantified what the true risks are yet." He says, "The regulator will have to come to grips with this, probably driven by from pressure from society as a whole." There are also sticky questions about what level of leakage would be acceptable, given that there is natural leakage from the seabed unrelated to any oilfield activity already.

A new (test) rig

The recently created National Decommissioning Center (NDC), part-funded by The Oil & Gas Technology Center with the University of Aberdeen, is looking at building a test chamber at their Newburgh based center near Aberdeen that could put barrier materials to the test.

With funding from the Scottish Government's Decommissioning Challenge Fund, the NDC tasked Aberdeen-based engineering firm Apollo Offshore Engineering to design a rig in which barrier materials could be tested to 150 °C and 10,000 psi, covering 80% of UK continental shelf (UKCS) wells. The 20-inch internal diameter test chamber will be able to house cartridges that can simulate the different annuli in a well, with different tubing and casing (up to 18¾-inch diameter) arrangements, in a repeatable way. It is also designed to simulate inflow from the well or rock and flow return through the annulus. It would even have a slickline equipment interface to mimic real downhole conditions.

Dr. Richard Neilson, who's been working on the project, says it would be a pretty unique test facility, designed with industry input, including from the OGTC's Alternative Barrier Material Collaboration Group, which includes developers and operators.

"There are a number of barrier technologies being developed, like the use of thermite and thermite combined with bismuth alloy, and also resin and well scaling," says Dr. Neilson.

Interwell's thermite barrier technology

"Once it's down in a well, there are things you can do to test it, such as putting instrumentation down, like pressure transducers above and below. But at some point you want to see what's happening. We can set a plug and test it under pressure and then

AN UNUSUAL ABANDONMENT

The North Sea oil and gas industry's 50-plus year heritage now means that history is being revisited as facilities – including subsea wells – installed decades ago are decommissioned.

One is the first early production system tieback, which included the first Through Flow Line (TFL) subsea tree design. The well, in the Murchison field, was one of three early production subsea tiebacks installed in 1980 to support early production from Murchison ahead of the platform wells coming on stream. The well was shut-in and suspended in 1982 and remained untouched for 36 years as plans to decommission it were developed.

Source: Helix Energy Solutions

Using a drilling rig would pose some challenges on this older well design, including: a potentially weak well head, which would require the blowout preventer (BOP) to be supported; a lack of available BOP for the 13⅝-inch bore and a lack of available dual bore riser. Finally, there was also a requirement for diver support, again due to the age of the wells.

An alternative was to use a light well intervention vessel (LWIV) with onboard saturation diving capability, do deal with any unknowns. But, with old wells come complex issues, including tree valves that aren't guaranteed to work, incompatible tree controls and the unknowns that come with a well that's not been entered since 1982.

Helix Energy Solutions got involved using its Seawell LWIV, with onboard saturation capability. To ensure barrier integrity, a safety valve package was designed to supplement or replace the tree valves, and the incompatible tree controls were bypassed by installing remotely operated underwater vehicle (ROV) panels to the valve actuators. Wireline retrievable diverters, set above the production master valves to direct the pumped through toolstring into the well, were the first items to be recovered to allow vertical well access.

Once in the well, many of the expected problems were encountered and planned contingency operations were implemented to overcome the challenges. So, a project which was meant to involve 26 wireline runs to set two barriers in the well ended up with more than 40, including setting a combination of cement and wireline plugs, performing punches, drifts, fishing operations, etc.

The final stages included removing the subsea tree, and then the dual tubing strings were then cut 300 feet below the mudline using Eline in open water to allow the recovery of the tubing hanger along with the cut tubing. Once pulled clear of the well, the tubing was laid out on the seabed for later recovery.

Source: Interwell

examine it; the morphology of what's been generated. There's a big advantage to being able to do that. You can show that these materials will do what was expected in downhole conditions."

The examination of the materials can go even further at the university, using computed tomography (CT) scanners it's invested in over recent years, which means the porosity of the material can be seen. The next challenge is funding to make it a reality. With that in place, Dr. Neilson says it could be built in about 18 months.

Getting mechanical

In the well placement arena, the OGTC supported initial work with Oilfield Innovations, an Aberdeen based startup that's looking at ways to cut and compact tubulars, so that rock to rock sections can be opened without removing the material from the well. In 2017, the firm ran trials of the concept and, last year, it worked with the University of Strathclyde to better understand some of the processes.

The OGTC is also working with Aberdeen-based SPEX at a system development stage – pre-bench testing – to use controlled explosives to crumble targeted sections which would then fall down the well. The OGTC is also supporting another Aberdeen firm, Deep Casing Tools, to develop its Casing Cement Breaker tool – a kind of eccentric roller that's run downhole to deform the casing and break up the cement. The technology was run offshore, in a trial with Equinor, earlier this year. The OGTC project's goal is to make it a one-trip tool, able to cut, break down the cement, and then latch, in one trip.

And there's more. The OGTC's TechX technology accelerator program also has Sentinel Subsea on its books – a firm developing a hydrocarbon sniffing technology which would detect any traces of a pre-placed substance that have leaked from beneath the well barrier. On detection, a signal would be sent to shore, noting where the leak came from in the well.

There is plenty going on, plenty more to do and many questions to be answered. Luckily, there are many people trying and much more to come.

INTERWELL CONTINUES TESTING

Interwell's goal is to deploy thermite P&A technology on wireline, hugely reducing rig requirements. Since 2016, the firm has run trials in 18 different wells: 15 onshore Canada and one in Italy, as well as the two in the UK. The most recent trials were last winter/spring in Canada, with three different operators in nine wells.

"The main focus was surface casing vent flow/sustained casing pressure fix, as an alternative to today's methods," says Christian Rosnes, Commercial Manager – P&A, Interwell. "So far, there are some very promising results. One well has been cut and capped while the remaining eight will be evaluated this autumn.

Source: Interwell

"We are fortunate to have a full-scale test rig, which allows us to build a wellbore to test the system in. We are then able to section cut the well bore and barrier to investigate the complete cross section, as well as to see the actual result. This gives us useful knowledge about how we can improve the robustness of the system. Field trials and full-scale testing combined with comprehensive CFD modeling enables us to understand and control the physical aspects of our barrier. Going forward we are working on adapting the system with the new information we gained in the field and also at our test facilities.

"Our main focus areas, aside from CFD- and phase modelling, laboratory and HP testing are looking at geochemistry/geology, chemistry, well elements, thermo science and mechanical design. In the coming months we are preparing for more trials with several operators."

The Drilling Evolution

Source: © Mohammad Fahmi Abu Bakar/Shutterstock

By Jennifer Pallanich

Following a few years of low oil prices and a drop in rig utilization rates, drillers remain focused on ways to improve operational efficiency and safety.

Many of the improvements to rigs are evolutionary, such as automation, remote control and sensing, and how rigs make sense of the vast volumes of data generated by sensors. The interconnectedness of all those sensors raises cybersecurity concerns, while environmental concerns have led some drillers to investigate energy-efficient methods to power their operations. Newer technology like managed pressure drilling (MPD) is making its mark on rigs, and a 20K drillship brings a step change to the industry.

“There’s a lot of focus on operational efficiency,” says Joseph Rousseau, ABS director for offshore exploration.

One way to vastly improve operational efficiency and safety levels is through automation such as iron roughnecks and pipe handling.

“If you can remove humans from a dangerous spot like the drill floor and do that with a robotic controlled machine, you don’t have humans in pinch points,” Rousseau says.

Remote control also makes operations safer.

“The drill floor equipment used to involve a lot of people working in that industrial area. Now it’s driven from the driller console,” he says.

More and more sensors are being built into drilling rigs and the equipment that goes on them.

“If you put in the right sensors and measurement systems, you have a better idea of the health of that asset,” Rousseau says.

Knowing the health of an asset is vital for condition-based monitoring and makes it possible to move away from the calendar-based monitoring that may require looking at every piece of machinery once a year and tearing it apart at certain intervals.

“The drilling rig is there to drill,” he says. “You want to minimize that nonproductive time, the time you’re not spending drilling that hole or moving onto the next one.”

Sensors can monitor temperature, pressure and vibration among other things. There’s a continuum of digital sophistication, he says, which moves from piecemeal monitoring to real-time monitoring.

“You can get flooded with data and not know what to do with it, or have no data at all. Neither is a particularly good place,” he says.

Big data, analytics and computer modeling can parse incoming data in real time to generate alarms if a machine is out of tolerance.

Smart technologies will go beyond collecting the information in real time so it’s possible to act on. Eventually, he says, the industry will be able to predict problems a month or two ahead of time so the asset manager can plan maintenance before the equipment fails.

The upshot, Rousseau says, is that information from sensors enables decision making “based on data instead of looking at a calendar and saying, ‘I guess it’s time.’ The rig spends more time working and less time doing ancillary tasks of inspecting

Condition-based monitoring using remote and data-centric inspection technologies can keep a drilling rig doing the job it's meant to do: drill.

Source: ABS

and maintaining and documenting."

All that data flying through the air raises the issue of security of offshore drilling data, and a lot of the drilling contractors are thinking hard about cybersecurity to ensure the equipment they procure is cybersafe, he says.

"As you start taking data and transmitting it to shore bases, you have vendors with access and owners with access, there could be vulnerabilities in the system," Rousseau says. "The last thing you want is a data breach that releases sensitive information."

Drilling contractors are often looking for ways to reduce costs, and Rousseau says he's starting to see interest in the North Sea in improving energy efficiency, such as using shore power or wind turbine power to provide electricity to the rig instead of running diesel generators. Doing so could reduce fuel and emissions.

"It's still early days. There's some interest in that, but it hasn't impacted the fleet worldwide," Rousseau says. But he does see the potential for uptake of such solutions. "If they can save money and be green, there could be something in that."

One of the newer trends Rousseau has noticed is the move toward the use of MPD for specific deepwater wells where there is a tight gradient between the fracture pressure and the pore pressure. Seadrill and Transocean are two drilling contractors who are using MPD systems.

"There are several rigs with an MPD system installed, and some are MPD-ready," he says. "It allows you to access holes you might not get to otherwise."

Getting a drilling rig to MPD-ready status requires a risk assessment, pipe routing and scheduling. MPD systems can be retrofitted onto an existing system or designed into a new system.

The industry has steadily moved into increasingly high temperature, high pressure (HTHP) reservoirs, which requires new technologies to be developed and qualified to handle the challenging reservoirs.

The industry is qualifying 20,000 psi technologies, and a 20K system has been designated for a drillship that will be used in the Gulf of Mexico. At the end of 2018, Transocean said it signed a five-year drilling contract with Chevron for one of its two dynamically positioned ultra-deepwater drillships currently under construction at Sembcorp Marine's Jurong shipyard in Singapore. The floater will be the first rated for 20K operations and is expected to start operations in the Gulf of Mexico in the second half of 2021.

"[20K] is a limited area now but it's an exciting area of technology," Rousseau says. "It's a step out from what we've done before."

There have been other changes in rig design as drilling needs and abilities evolve, such as materials and more blowout preventers in a stack, he says. Most rigs have greater derrick capacity than in the past, which allows them to drill deeper.

In the end, drilling contractors are relying on constantly evolving and improving technology to drill the wells.

"They're trying to do the same job, but with a closer eye on getting the job done correctly, quickly and still safely," he says.

PREDICTIVE MAINTENANCE

By Eric Haun

Asset managers leveraging advanced sensor technologies, vast pools of stored and processed data, and real-time analytics are able to foresee—and prevent—costly component failures.

A recent report from Lloyd's Register points out that predictive maintenance has been proven to lead to cost savings of 10% to 40%, yet only 18% of those surveyed in the US oil and gas industry have adopted this approach. But interest and real-world implementation is rising.

As technologies continue to improve and assets in the offshore oil and gas sector become increasingly digitized, predictive maintenance is emerging as a means toward improved operational productivity, efficiency and safety, and the benefits are being seen across the industry.

The adoption of data analytics and digital technologies for asset maintenance and operations can increase production and lower maintenance costs, presenting a value of £1.5 billion ($1.8 billion) annually to the UK continental shelf (UKCS), according to a study published in 2018 by the Oil and Gas Authority, Technology Leadership Board and the Oil & Gas Technology Center.

That same study, which examined the use of data from topsides production and operations equipment, and how it can improve production efficiency and maintenance planning, found that around 110 million barrels of oil equivalent was lost to critical equipment failures on the UKCS in 2017.

Emerson is one of the firms providing predictive maintenance capabilities to help avoid those costly equipment failures and production losses. Under a long-term contract with BP, the US-based company is providing predictive maintenance and operational support services for two of the UK supermajor's operating assets in the inhospitable waters West of Shetland.

Emerson was the main automation contractor for the Glen Lyon floating production, storage and offloading unit (FPSO) and Clair Ridge platform projects, and it secured an additional five-year award to provide ongoing operational support services, remote monitoring and predictive maintenance technologies for both projects.

The Clair Ridge and Glen Lyon solutions rely on Emerson's Plantweb digital ecosystem technologies, software and services, including includes the DeltaV integrated control and safety systems, AMS asset management software as well as measurement and control devices, which deliver real-time production data and analytics to plant personnel. BP is able locally control operations, while remotely monitoring production and asset health from an onshore location.

Digital twin

A key enabler for predictive maintenance is the digital twin, which is essentially a virtual representation of a physical asset. Importantly, digital twins facilitate data driven engineering, production and maintenance decisions.

Aker Solutions is building a complete digital twin of the production system at the Wintershall-Dea-operated Nova field currently being developed as a subsea tieback to the Neptune-operated Gjøa platform in the Norwegian section of the North Sea.

Experts at Aker Solutions' software house ix3 working to create the Nova digital twin recently looked at how live data streaming and condition performance monitoring (CPM) could be added, said Are Føllesdal Tjønn, Head of Software Development for Aker Solutions.

"With live data streaming we can provide visual remote monitoring and status of a subsea control system from any location with internet access, using live pro-

Emerson is providing predictive maintenance services and operational support services to BP at its Clair Ridge platform.

Source: BP

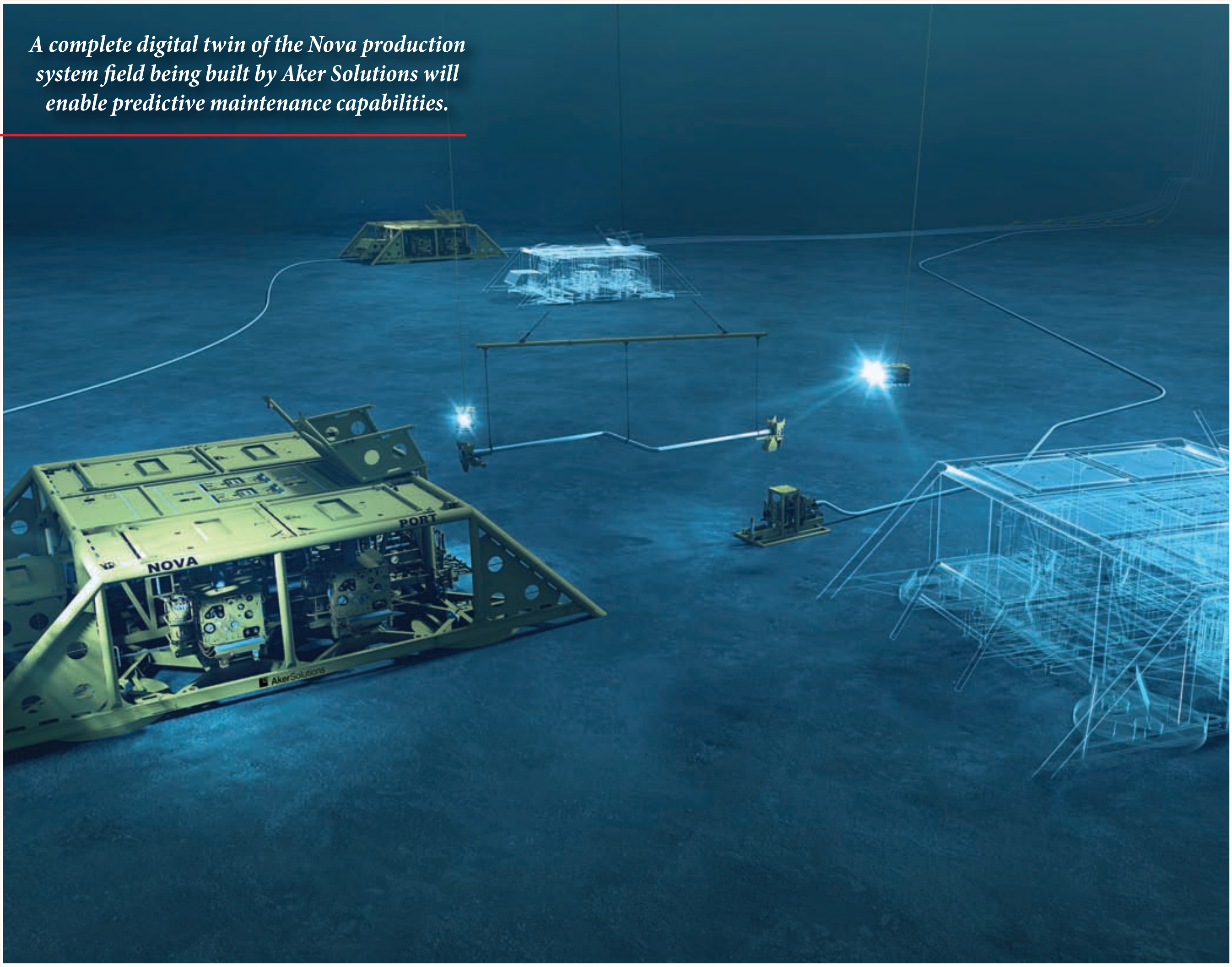
cess data from the Aker Solutions' 'cloud data lake'. This will allow users to verify the current state of a control system as well as support fault finding," Tjønn said.

"We establish a real time data stream from the control system into Aker Solutions' cloud data lake (digital twin), processing the data stream to detect anomalies and create insight about condition and performance, and visualize the data, anomalies and insights in a user-friendly application," he added.

The company's condition monitoring software application Subsense, being implemented with help from fellow Aker company Cognite, enables control system data to be transferred to the cloud so it can reach the subject matter experts and the software programs analyzing it, Tjønn said.

Through the digital twin platform, which Aker Solutions calls Integral, Subsense can be integrated with a wider offering, such as Coabis for inspection data, customers' enterprise solutions and/or a range of third-party packages. Subsense enables users to take advantage of cloud computing services, machine learning models and the ability to combine data from different sources such as maintenance logs and product data, Tjønn said.

"In our world, a failure is typically



A complete digital twin of the Nova production system field being built by Aker Solutions will enable predictive maintenance capabilities.

Source: Aker Solutions

the end result of a chain of events that occur on different subsystems, where data have historically been disparate – in varying formats, with different levels of fidelity. We bring this data together, ‘even’ it out and create insights from the data,” Tjønn said.

“The system is available to operational staff, managers and engineers, at both operator and Aker Solutions, and it typically works in the background providing notifications. Our service team monitor and interface directly with the application to ensure that those notifications that reach the operations room add value and don’t distract from already busy schedules.”

“CPM analytics are typically planned for hydraulic systems, electrical system, communications, electronics, gate valves, chokes and instrumentation,” Tjønn said.

“Applying advanced machine learning, the system learns what normal behavior is, and can highlight potential problems before they turn into faults. It also learns from events across all Aker Solutions-monitored assets, which means knowledge can be shared globally, without sensitive data from each individual field.”

‘Data liberation’

The world’s most advanced oil and gas platforms, such as the highly digitized Ivar Aasen operated by Aker BP in the Norwegian sector of the North Sea, produce more than just hydrocarbons. They also generate and transmit large volumes of data to be interpreted and analyzed.

In 2018, Aker BP entered a “smart service contract” with software firm Cognite and pumps supplier Framo, whereby Cognite liberates and organizes Aker BP’s industrial data to create a digital representation of Ivar Aasen, both retrospectively and in real-time. Aker BP is then able to extract operational data insights to be shared with partners like Framo to use for predictive maintenance.

With access to live and contextualized data, Framo is able to create its own applications to predict the status of its equipment and plan maintenance

Using live and contextualized data from the Ivar Aasen platform, Framo is able to predict the status of its equipment and plan maintenance in advance.

Source: Aker BP

in advance, Trond Petter Abrahamsen, Managing Director of Framo Services AS, said in a statement when the "data liberation contract" with Cognite and Aker BP was announced. "The new system sends intelligent data on our pumps, so we can predict how the pumps will perform in the future," he said.

Another goal of the inititaive is to change the traditional approach to maintenance, Framo said. Continuously flowing live data allows for onshore monitoring of equipment replacing unnecessary scheduled maintenance activities with maintenance when needed.

"While our service agreements previously just defined hourly rates, we will now focus on uptime. This is something completely new for us and has required the design of new smart contracts with Aker BP," Abrahamsen said.

An AI app

Oilfield services company Baker Hughes, a GE company (BHGE) is also advancing its predictive maintenance capabilities. Its joint venture with enterprise artificial intelligence (AI) software provider C3.ai recently launched BHC3 Reliability, an AI application that provides early warning of production downtime and process risk and gives failure prevention recommendations and prescriptive actions.

The generally available app uses deep learning predictive models, natural language processing and machine vision to continuously aggregate data plant-wide sensor networks, enterprise systems, maintenance notes, and piping and instrumentation schematics. Using historical and real-time data from entire systems, AI and machine learning models identify anomalous conditions that lead to equipment failure and process upsets across any number of assets and processes, and then alerts the user to take proactive action.

A BHGE spokesperson told *Offshore Engineer* that the company is currently working with a customer on the implementation of BHC3 Reliability and that a number of other customers have expressed interest.

ROV IN RESIDENCE

Remote operated vehicles (ROV) have become standard workhorses for the offshore industry, providing vital support to underwater operations, from drilling to servicing the latest subsea processing technologies. But, they're now undergoing a transformation.

By Alan MacDonald - Sales Manager - Sonardyne &
Sven Eivind Torkildsen - Sales Manager - Innova

Source: IKM Subsea

The Merlin UCV at IKM's facility in Bryne, near Stavanger, Norway.

Above the surface, 4G telecommunications networks, which spread right across the UK and Norwegian North Seas, have made remote control from onshore a reality. Beneath the surface, "subsea GPS" and communications technologies are making navigation easier, allowing greater degrees of autonomy over longer distances, and enabling harvested data to be transmitted through water without wires. These capabilities free vehicles from the need to be accompanied by a support vessel, offer greater operational flexibility and mean their pilots can stay onshore, increasing safety and quality of life. As resident systems, deployed permanently, or semi-permanently subsea, vehicles can be ready for action, subsea, 24/7, supported from onshore – reducing cost and increasing safety and productivity.

A remote resident journey

IKM Subsea, based in Bryne, not far from Stavanger, Norway, has been taking these technologies onboard, developing and rolling out subsea resident vehicles. IKM's journey towards the resident ROV started in 2007 and saw the company launch a work class ROV, the Merlin WR200, with an in-house designed tether management system (TMS) and launch and recovery systems (LARS), in 2010.

The WR200's large open frame

means it works well in strong currents and makes access for maintenance easy. But, because it's big, it's not always able to access some areas. So, in 2014, IKM Subsea started work on the electric Merlin ultra-compact vehicle (UCV) ROV. Launched in 2015, the Merlin UCV soon became the basis of IKM Subsea's resident ROV, or R-ROV concept, and, in early 2018, the first Merlin UCV, complete with its own subsea cage (or garage) and TMS, was placed on the seabed at Norwegian operator Equinor's Snorre B facility, offshore Norway. It's been there ever since, available 24/7, piloted from on or offshore, on three-month long deployments, between which it undergoes maintenance.

"Some of the challenges to achieving this are technical, such as enabling remote control functionality," says Ments Tore Møller, IKM Subsea's Engineering Manager. This meant moving everything to Ethernet, for example, reducing the number of cables required. "It also meant adapting mechanical parts, such as the manipulators, so that they would need less maintenance. Traditionally, maintenance is weekly. We wanted to go to every three months, when the system would be brought up on deck.

"A key requirement has also been station keeping, to help with certain tasks, when you need the ROV to be stationary, and also path-follow mode, when the ROV can navigate itself, also as a backup mode of operation, if communication is lost, although this doesn't happen often," says Møller.

Key to the Merlin UCV's station keeping and navigational capability is a SPRINT-Nav, Sonardyne's hybrid navigation instrument. IKM got access to the instrument through Norwegian underwater technology provider, Innova, who work closely with UK-based Sonardyne to support its customers in Norway.

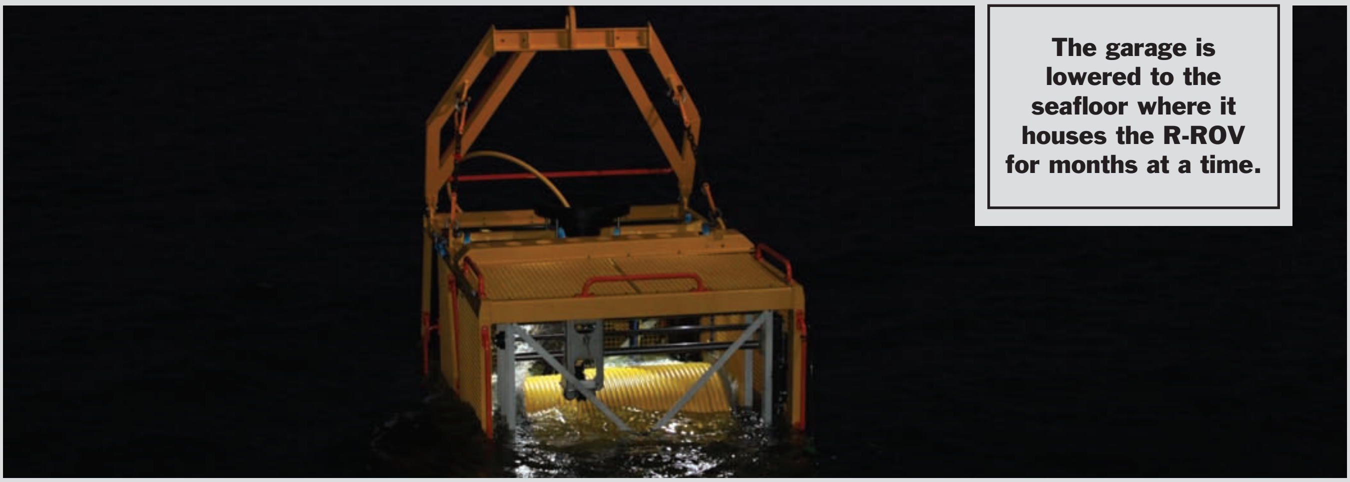
SPRINT-Nav is built around highly robust and accurate Honeywell ring laser gyro (RLG) inertial sensors, in an inertial measurement unit (IMU), tightly coupled with a Sonardyne Syrinx Doppler velocity log (DVL), and an integrated high-performance pressure sensor. Tightly integrating raw sensor data from these sensors at a low level means higher levels of accuracy and reliability are achieved: ROVs can calculate their position for longer with less drift.

SPRINT-Nav is also fast to initialize, with no need for calibration maneuvers before getting to work or during work. This is because it runs two algorithms so that the inertial navigation system (INS) can instantly initialize from the attitude, heading reference system (AHRS) in the IMU. The fast initialization is also made possible by the RLG's very deterministic characteristics, compared with other types of gyros. All of these things are making it a very popular instrument. Its performance and compact form factor also make it ideal for resident ROVs, autonomous underwater vehicles (AUVs) and hybrid vehicles.

Big savings

Having a permanently deployed subsea ROV is a major benefit to operators as it's always there, available, no matter what the weather conditions are, says Møller. "October through to March, many operational days can be wasted due to waiting on weather. Having a permanently deployed vehicle can save many millions of Kroner," he says. IKM Subsea can operate these vehicles in up to 20-meter significant wave height; you couldn't deploy an ROV from the deck in anywhere near that. "Being able to launch from subsea also saves half an hour each time," he adds. "The SPRINT-Nav then initializes in just minutes. The ROV can also be operated from the control room onshore, so there's availability, 24/7."

There are further benefits, including time saving and extended weather window operations during marine riser disconnects and reconnections, says IKM Subsea's Rolleiv Gangstad, who manages IKM Subsea's onshore remote ROV control center in Bryne. "For drilling operations, every time you disconnect – and normally in a season there are about five disconnects – you save 1.35 million Kroner by being there already. To start up wells after a shutdown, normally it's 12 hours if you have an ROV already in the water," he says. "If you don't, it can take 48 hours. That can amount to 38 million Kroner in lost production."



The garage is lowered to the seafloor where it houses the R-ROV for months at a time.

Source: IKM Subsea

Building a track record

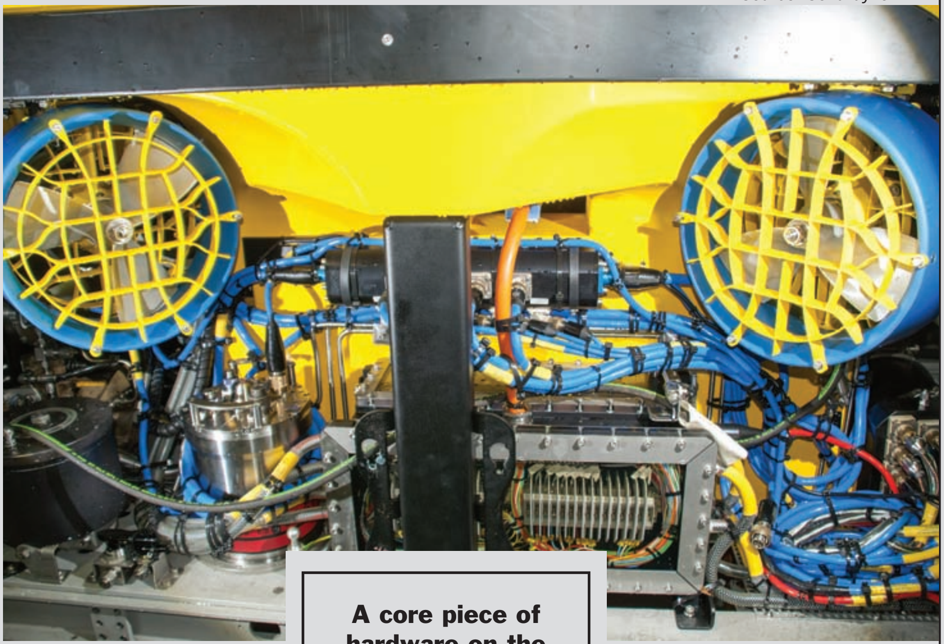
From its onshore control center, IKM Subsea operates ROVs at early adopter Equinor's Snorre B and Visund facilities. At Visund, there's a Tiger observation class ROV and a work class Merlin WR200 ROV.

At Snorre B, there is a work class ROV with a standard "top hat" TMS, that's lowered through the Snorre B moon pool, and the 3,000-meter-rated seabed deployed Merlin UCV R-ROV with SPRINT-Nav. The Merlin UCV is lowered via the platform crane to the one of four pre-created seafloor landing positions inside an "E-Cage". The cage remains connected to the platform, for power and communications, via a tether on a lazy wave buoyancy system. From the cage, the R-ROV deploys on its own TMS, which enables excursions out to 1,000 meters. After three months, the ROV is retrieved to the platform, along with its cage, for maintenance.

Both ROVs at Snorre B (as well as the ROVs at Visund) can be operated from the platform or from onshore via a fiber optic link. The onshore control center currently has two stations, one for Visund and one for Snorre B, although they can be interchanged and both could work on one field at the same time. Two pilots work from the onshore control room 24/7. Offshore, there are also two pilots on each facility – where normally, without the onshore support, there would be three.

At Snorre B, the SPRINT-Nav has been proving itself a very worthwhile investment. For the Merlin UCV R-ROV, IKM Subsea has its own navigation system, which takes in the navigation co-ordinates string from the SPRINT-Nav. This is used alongside a map of the subsea infrastructure. Where with previous systems, positioning had not been accurate or reliable, with SPRINT-Nav, Møller says the pilots have confidence that they know where the ROV is - and the ROV knows where it is. Its station keeping is also working very well and that's thanks to SPRINT-Nav, he says, because it doesn't drift very much.

Source: Sonardyne



A core piece of hardware on the UCV is Sonardyne's SPRINT-Nav hybrid navigation instrument.

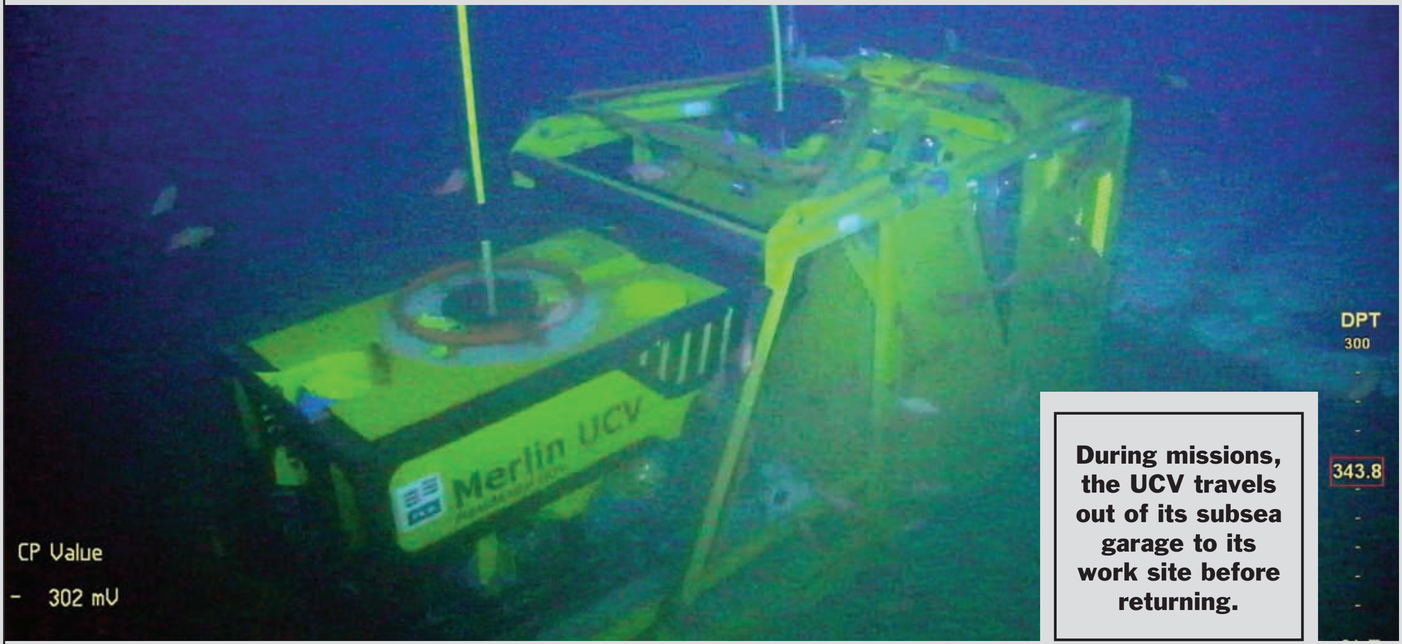
"To be able to have remote control like this, we need station keeping," Møller says. "If we lose communication, we should be able to put it in station keeping mode, so it's just standing there until a local pilot can take over. While that's not something that happens very often, when in the future we use more automatic or automated functions, where the ROV goes by itself, we will need this functionality."

"Others INS' just didn't work," he continues. "The pilots work with other systems and they know, they see, this works better. They see station keeping is better. It's also helpful when we want to do something with the manipulator. At the moment, we just use left manipulator arm (Atlas) for simple work and a Schilling Rig Master arm for fine work. In station keeping mode, we have more flexibility."

The majority of the work done by the Merlin UCV R-ROV is currently drilling and wells related, or opening valves for production, which means that most of the work is within the footprint of the Snorre B facility. Inspection work does see the ROV go out to about 300 meters to inspect where the marine risers are anchored to the seafloor with suction anchors. To navigate out to these, the pilots currently follow the riser along the seafloor. But, in bad visibility, having confidence in a navigation system to get you where you want to be is crucial.

This transformation in the ROV world is just starting. There is more that could be done. Some are looking to remove the tether, because survey work today is limited by the length of the tether from a fixed point. "You could remove the tether, but then you are limited by battery size," Møller points out. "So, we may need different vehicles to do different things." This could be something more like an AUV for survey, supported by SPRINT-Nav for navigation, and resident ROVs, where heavy vehicles with more capabilities are needed. "There are many different ways to do this," adds Møller.

Vehicles could be more flexible by enabling them to change parts subsea using inductive couplers, for example. Without a tether, a system could move from node to node (where it could recharge). Transponders, eg. Sonardyne's Compatts, on the subsea cage would mean that the ROV's return to its standby position in the cage could be



During missions, the UCV travels out of its subsea garage to its work site before returning.

Source: IKM Subsea

automated, supported by anti-collision systems. Sonardyne's BlueComm free space optical modem also allows for live video transmission through the water, which enables live remote control for untethered vehicles.

Another option is a cage with battery packs that could be deployed from a boat to where it's needed and left there to do its work, with communications and control from onshore via a surface buoy and the 4G cellular network. "A vessel may carry four to five ROV systems, it would just be a delivery mechanism," says Møller. Here, station keeping is even more crucial, as in this scenario there's no offshore pilot as a backup.

Other areas that IKM Subsea is looking at include a digital twin of the subsea world. That would create the ideal navigation solution, says Møller. SPRINT-Nav would provide the position alongside a 3D sonar, which could recreate the subsea environment. Furthermore, if communications or the sonar drops out, SPRINT-Nav can continue calculating where the ROV is. A digital twin would also make simulating procedures and training easier and more realistic and reduce time on the real system.

Next steps include more automation. However, this is partly a human challenge. ROV pilots are used to performing these tasks themselves. They're used to being able to see and feel where they need to be in the water and prefer that to relying on a machine. But, change is happening, says Møller, and more will come as tasks can be automated, including using machine vision technologies, eg. you could just message the vehicle and say, "Go to west station #2 and check situation on this valve."

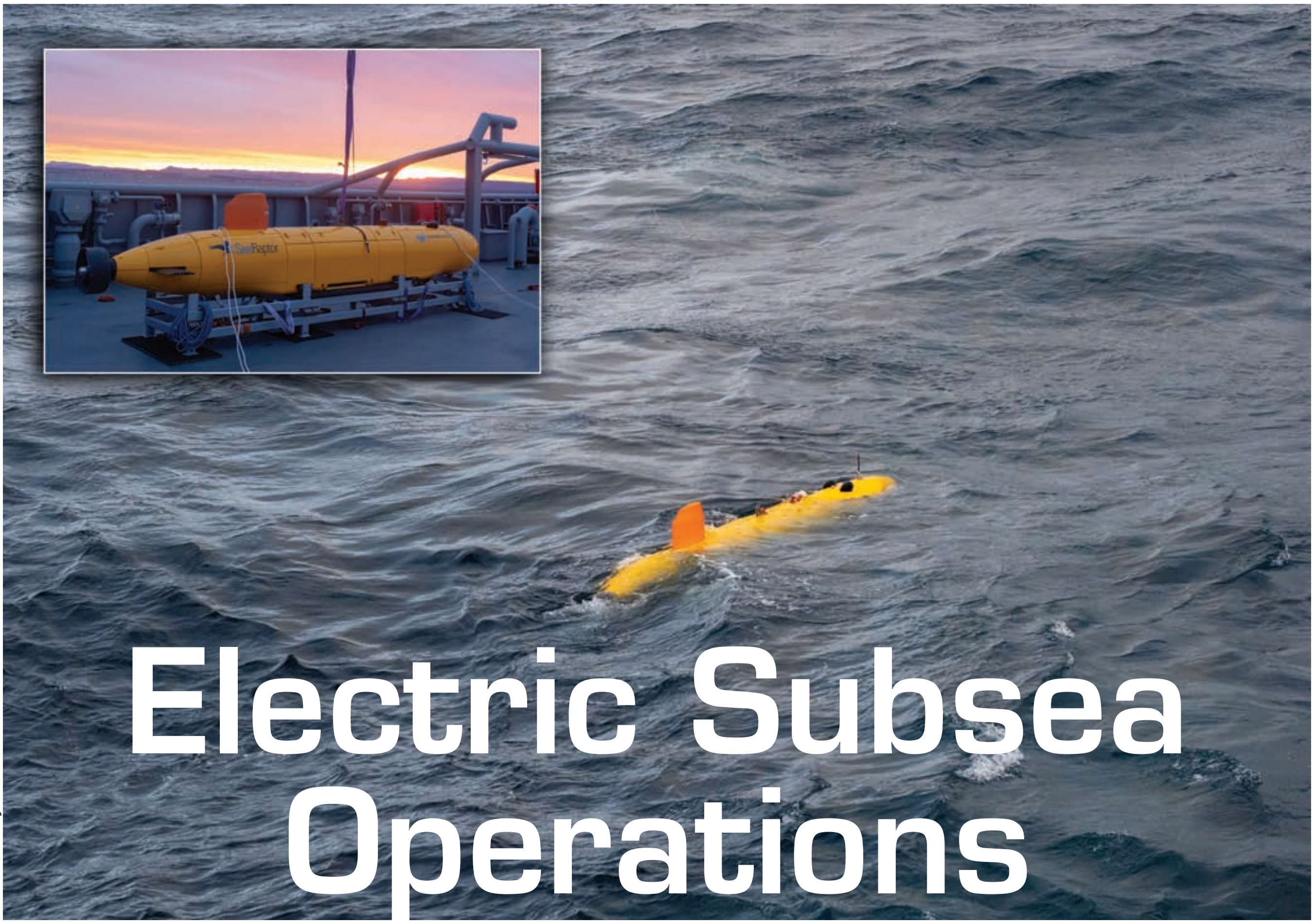
Back at Bryne, where IKM Subsea also builds tests and maintains its ROVs and R-ROVs, two new UCVs are being built for AKOFS Offshore. These will be vessel-deployed systems, both fitted with SPRINT-Navs. Additional remote control stations are also being built and fitted out.

IKM Subsea is also working on an electric manipulator for its electric R-ROV as well as other ways to make these systems more efficient, so that battery life can be extended. This includes an electric TMS, alternative propellers and batteries, and power management systems.

With interest for seabed deployed systems increasing, more such systems will appear in the market and they will evolve, support by navigation and communication technologies.

IKM's Merlin UCV R-ROV in its subsea garage, trailered and ready to be mobilized offshore.

Source: IKM Subsea



Source: Teledyne Marine

Electric Subsea Operations

By Leon Adams - VP Sales, Southwest Electronic Energy

As the offshore oil and gas industry recovers from the downturn, business has focused on operating more efficiently. The transition from hydraulic power to electric power is a part of that equation.

Subsea batteries can safely power subsea operations requirements and save operators cost efficiency through extended battery life and smart status reporting resulting in longer and more reliable mission times. Numerous lithium-ion applications are emerging, such as driving hydraulic pumps and powering autonomous underwater vehicle (AUV) operations.

Batteries may not seem like a natural choice for subsea operations, however, lithium-ion batteries have revolutionized stored power technology. As such, properly designed and engineered batteries can safely be used subsea.

Traditional lead acid batteries are heavy and bulky. Lithium-on batteries, such as Southwest Electronic Energy's line of (SWE) SeaSafe batteries, deliver up to a six-fold lifetime improvement over lead acid batteries at 25% of the size and weight.

SWE SeaSafe batteries powered by large lithium-ion polymer cells are engineered into modules to provide 30 volts at 28 amp hours with other options available. The battery modules are pressure tolerant and able to operate in water depths to 6,000 meters. Multiple SeaSafe battery modules can be linked together to meet the voltage and power needs of various applications. These applications may require periodic high bursts of power, such as controlling a remotely operated vehicle's manipulators, or longer low-draw demands for powering sensors.

When subsea batteries are deployed, monitoring their performance is critical to ensuring that the batteries are operating dependably and sustainability. With SWE SeaSafe II and SeaSafe Direct, condition-based monitoring is built-in with the user-friendly Battery Management System (BMS), patented by SWE. The BMS automatically manages and tracks the safety, reliability, charge and discharge of the batteries and reports technical information at the user's demand. These safe and smart batteries are self-functioning. The reporting software excels over other systems as it provides data on each and every battery module, down to the individual cell voltage level, and in real-time.

In a subsea oil and gas installation, it is necessary to power workover controls, chokes, valves, blowout preventers and well heads, among other equipment. Requirements include electronic control, valve control, electrical drives, primary and backup power, more precision, condition-based monitoring, and long-life sensors. Batteries used in such applications must deliver safety, more capacity, smaller size, less weight, longer life and high reliability with on demand data reporting.

An electric motor for a hydraulic pump may require a high-power surge exceeding 100,000 watts for operations lasting only a matter of minutes. This could serve subsea chemical injection unit and provide subsea local power for hydraulic pressure on demand instead of hydraulic pressure furnished through an expensive umbilical or by bulky accumulators that both get more burdensome and costly the deeper you go in subsea operations.

SWE SeaSafe II and SeaSafe Direct battery modules can provide power solutions as deep as 6,000 meters. Modules can be configured in higher series module strings for higher configured system DC voltage. Parallel strings provide higher current and thus higher power at the configured DC voltage. Battery system reliability is enhanced via redundancy of power available at the system DC voltage because each Diode ORing string can provide standalone power at the DC voltage even if another string goes down. The max current per string will be less than the total current from combined strings, but will still provide the same voltage. Parallel copies of the voltage string can also provide high burst current for high instantaneous power needs. This parallel battery module string inter-connect is facilitated by the SWE SeaSafe Diode ORing Module.

For example, SWE supplied a SeaSafe II Battery system for a subsea electric motor hydraulic pump power drive that required a maximum of 250 kilowatts at peak demand. The system configuration was 17 series string of 37-volt battery modules connected in two parallel strings by Diode ORing Modules, providing 629 volts nominal, 56 amp hour nominal capacity, and 400 amps peak current. This subsea battery system is currently in testing and performing as planned. When released, it promises to be a leader in safe and efficient condition-based monitoring subsea infrastructure.

Multiple SWE SeaSafe II battery systems with 188-kilowatt power each are in production for a subsea chemical injection unit. This battery system will dramatically reduce or eliminate the copper wire demand for the umbilical. The battery packs will deliver sufficient power density to run 120 barrels of MEOH at 1,034 bars and 15,000 psi for six hours.

Subsea robotics, such as AUVs, require longer survey runs, deeper dives, with more simultaneous types of sensor and scanner technology. Pressure tolerant battery packs, such as SWE SeaSafe II and SeaSafe Direct, can provide long-term power needs by eliminating the weight and cost of a pressure vessel for the batteries. The AUV needs to power thrusters, small electric motors for servo control and actuation of manipulators, digital cameras plus the lighting to enhance video and still photos, control processors and interface electronics, sensors and scanners for measurement and feedback of node status information to the control processors. Furthermore, the AUV also needs to power communications systems to issue commands, manually pilot if in hybrid ROV mode, or communicate feedback, whether visually or through data communication.

SeaSafe battery packs can be configured in low count series module strings for low to moderate DC voltage with parallel copies of the voltage string to provide higher capacity of amp hours and redundancy of battery voltage for reliability. Parallel strings can be interconnected on output via the Diode ORing Module for common output to the load. Each Diode ORing string can provide standalone power at the DC voltage even if one goes down. In that case, the max capacity per string will be less than the total capacity from combined strings, but will still provide the required system voltage.

SWE SeaSafe Direct modules power the applications for the Teledyne Marine SeaRaptor, an AUV approximately 5.5 meters long, which includes acoustic modems, ascent and descent weight releases, a black box pinger locator, sub-bottom profiler, multi-beam echosounders, obstacle avoidance multi-beam sonar, Doppler velocity log, current, temperature, depth sensor and onboard processing software.

SeaRaptor has a maximum speed over 4 knots. While its endurance depends on speed and the exact configuration of the AUV, the SeaRaptor can typically survey for 24 hours at 3 knots with a standard configuration. The standard battery configuration comprises 13- to 16-kilowatt-hour lithium-ion rechargeable SWE SeaSafe Direct modules. The vehicle's operating criteria require the batteries to power all of the AUV functions. The ability to change batteries with ease without reconfiguring the SeaRaptor is critical for efficient mission execution.

While the SeaRaptor is in the water, a second set of battery modules can recharge in about 4 hours, thus providing the AUV the capability to quickly change batteries topside and continue its operation flawlessly.

The industry is in the midst of a subsea electric revolution that will see electric robotic vehicles and infrastructure performing underwater tasks. The reason for this is simple: industry experts recognize electric motors and robotics are more efficient and cost effective in subsea applications than hydraulic systems due to advances in technology and miniaturization. Couple that with condition-based monitoring benefits that are inherent in electric systems and then the efficient, safe, and reliable subsea systems of the future will be substantially electric.

Plugging the Cost and Complexity of Environmental Barriers for P&A

By Cherish Bodman - **Operations Coordinator, Coretrax**

Confidently setting an environmental barrier for plugging and abandonment (P&A) operations has traditionally been limited to mechanical bridge plugs and inflatable devices. At a fraction of the cost of conventional tools, Coretrax, the wellbore clean-up and abandonment specialist, is continuing to meet demand for its CX-Enviroplugs as a safer, simpler and more cost-effective alternative for big bore cement plug placement.

Originally designed to act as a simple base for cement, the plug is particularly suited to wells requiring an environmental barrier to prevent the leakage of oil-based mud.

Available in sizes 18-5/8” to 20”, the three-finned tool, which allows self-centralization, now incorporates a compression set elastomer element, enabling pressure testing of up to 1,000psi to be achieved. The design is also able to pass through a smaller wellhead restriction. Manufactured from drillable materials, the device also has a one-way valve and bypass ports across the plug to prevent surging when running in hole.

With a patent pending, eight plugs have so far been run across Norwegian and UK P&A projects in the North Sea. The most recent was completed in the Southern North Sea for Spirit Energy.

The ST-1 platform in the Greater Markham Area of the Southern North Sea, for example, ceased gas production in April 2016. Discovered in 1984, the field extends over license blocks 49/5a and 49/10b on the UKCS and license blocks J3b and J6 on the Dutch continental shelf. Six wells and a single installation are connected via two pipelines to the Markham J6A installation in the Dutch sector, approximately 5.6 kilometers from the ST-1 installation.

Source: Coretrax

Coretrax has been involved in the abandonment of nearly 20 wells for Spirit Energy.

On reaching the end of its economic life, ST-1 was put in warm suspension mode with all wells shut-in and disconnected from the platform pipework. In March 2018, P&A of the wells was performed by the Paragon B391 jack-up and completed in around 100 days.

Coretrax delivered bridge plugs for the permanent abandonment of the wells. In April 2018, a 13-3/8” CX-2 bridge plug was run in well B2. As a permanent cast iron bridge plug, the CX-2 is designed to set with a combination of hydraulic pressure and mechanical pull and boasts a built-in setting mechanism for greater efficiency. The slick OD and large ID of the released running tool minimizes cement disturbance when pulling out of hole. This makes it ideal for cement plug operations.

The bridge plug was made up and run in hole to a setting depth of 232 meters and set by Spirit Energy personnel as per Coretrax procedures. It was then tagged with 10,000lbs and tested to 500psi with a primary release seen upon return to surface.

As part of the batch environmental cap operations on both B2 and B3 wells, the operator also deployed two CX-Enviroplugs for the first time. Here, the disconnect sub was made up to the drill pipe and the plug made up to the string and run in hole. The 13-3/8” casing stump was then tagged at 220 meters and weight set down to set the plug. A ball was dropped from surface to activate the disconnect tool and pressure increased to 2,200psi. As per procedure, a pressure drop was then observed, the disconnect sub sheared, and the plug disconnected. An open-ended stinger is left and cementing was carried out. This resulted in well B2 being fully abandoned.

Using the CX-Enviroplug reduces the cost of big bore cement bases by eliminating the need for bridge plugs or inflates for the environmental cap. In the ST-1 campaign, Coretrax achieved a rig-time saving of approximately 48.7 hours.

Across the ST-1 project, the company also set 10 CX-2 bridge plugs and two CX-Superflows. This is a fully sacrificial combination scraper and brush tool with patented features that can be run with bridge plugs and eliminates the need for a dedicated scraper trip prior to packer or plug setting. By combining scraper blades with a drillable brush it creates a robust and effective solution for the removal of residual cement, scale, small perforation burrs and other foreign debris from the ID of the casing.

Relieving the Pressure of Subsea P&A Activity

By Matt Manning - Engineering Manager, Unity

The temporary abandonment or suspension of a well is a vital early stage of decommissioning whereby the well is isolated using methods such as bridge plugs, cement squeezes and packers. This allows the wellhead and/ or blow out preventer (BOP) to be safely removed. For subsea mudline wells, temporary abandonment (TA) caps are fitted to the hanger system, providing additional well and environmental barriers.

With high costs related to permanent subsea abandonment, suspended wells can often be in-situ for more than 10 years. During this time, it is possible for pressure to build up in the well, corrosion to take place and marine build-up to accumulate.

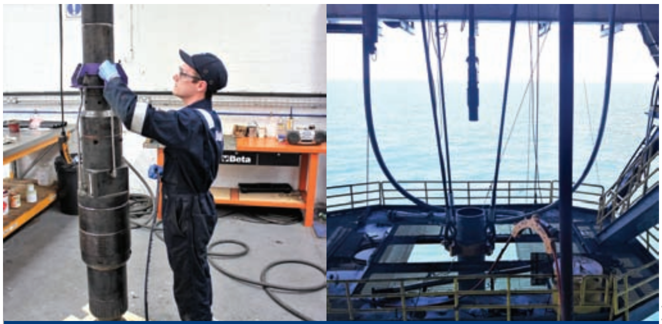
Reentering these suspended wells can be challenging and high risk, particularly as any pressure build up behind the back pressure valve (BPV) of the TA caps cannot usually be measured. Pressures can reach over 4,000psi which creates significant safety concerns, so intervention is normally conducted using a rig with heavyweight well control packages to ensure safety compliances are met. However, this is subject to rig availability and comes with high associated costs – currently around £225,000 ($277,000) per day for deepwater rigs.

Unity, a FrontRow Energy Technology Group company, has developed the Temporary Abandonment Cap Test Tool (TACTT), a new method of pressure testing and venting suspended mudline wells prior to abandonment which contains an integrated well control solution. The technology has returned cost savings for independent operator Spirit Energy for an end of life project in the Southern North Sea.

The TACTT can seal onto any type and size of TA cap, pressure test the seal to ensure well containment, then test and vent pressure from below the TA cap by stabbing the BPV and leaving a reliable secondary seal in place if required. It can be cable deployed from a vessel through open water using a crane and hydraulic umbilical which connects to a control panel at surface. Vessels have greater availability than rigs, can be deployed faster and generally save between 30-50% in costs when compared to rig-based intervention.

The TACTT technology allows operators to understand the amount of pressure accumulation below the TA cap since the last intervention and factor this into their decommissioning plans. If pressure build up continues, and the BPV on the TA cap fails to reseal effectively, the TACTT can leave a secure, secondary seal in place to allow well reentry at a later date.

During the Spirit Energy campaign, the TACTT was deployed from a vessel by crane where it was guided to the mudline well by ROVs and divers, then latched and sealed onto the TA cap. The seal was pressure tested from a surface control unit to ensure effective well containment, before stabbing the BPV of the TA cap and testing the pressure below. This second test verified zero pressure under the TA cap and provided an accurate understanding of the well's condition, allowing the operator to make an informed decision on the next stage of decommissioning. Once zero pressure and well integrity was confirmed, the operator could safely continue with removal of the cap to proceed with P&A operations.



The TACTT can be vessel deployed, creating significant cost savings

Source: Unity

Developed in response to industry demand, the TACTT is able to accurately and reliably pressure test and vent suspended mudline wells behind the TA cap prior to removal. Economic, safety and environmental benefits are particularly realized when deployed across multiple wells in region-wide vessel campaigns to pressure test, survey and prepare for abandonment.

Olav Log, director of drilling and wells at Spirit Energy said, "Unity's TACTT allowed Spirit Energy to successfully abandon two North Sea wells in line with UK government regulations. The tool removed all risk associated with re-entering a suspended well and the ability to deploy by vessel provided significant project savings.

"The TACTT technology was originally designed to our specifications and successfully deployed from a rig in the North Sea in 2014. This latest development allowing for vessel deployment opens up further opportunities."

A recent Oil and Gas Authority report estimates that 45% of all decommissioning expenditure in the UKCS is through P&A of wells. The current cost estimate of decommissioning is £51 billion ($62.8 billion) with the government and industry aiming for an ambitious 35% reduction by 2022.

There is inevitably greater pressure on operators to safely and cost-effectively manage end of life wells in this unavoidable phase of operations.

This provides significant opportunities for the supply chain to evolve and deliver new technologies and methods which tackle and overhaul the key challenges. Research and development investment and adoption of pioneering new technologies is critical.

BP

Methane Detection Drone

A pilot project being run by BP combines advanced sensor technology originally designed by NASA for the Mars Curiosity Rover with a fixed-wing remote piloted air system (RPAS), or drone, to remotely monitor methane emissions from the UK supermajor's offshore assets in the North Sea.

The preprogrammed drone, once airborne, managed itself autonomously, circling the Clair platform at a radius of 550 meters for 90 minutes. The drone traveled a total of more than 185 kilometers, besting the previous UK record of 100 kilometers for the longest commercial drone flight. Throughout the flight, the RPAS live-streamed valuable data collected by the methane sensor.

Following the trial, BP said it will deploy the drone to all of its North Sea assets in 2020, including ETAP and Glen Lyon.

Source: BP

NOV

20K BOP Stacks

Source: NOV

National Oilwell Varco (NOV) announced in June that it has sold two 20,000-psi (20K) blowout preventer (BOP) stacks to offshore drilling contractor Transocean. While others claim to have developed 20K BOPs – designed for use with extremely high-pressure reservoirs and in ultra-deep waters – NOV said it is the first manufacturer to design, engineer and sell such a package. Joe Rovig, President, NOV Rig Technologies, said the sale marks a historic moment for the offshore oil and gas industry. "The introduction of NOV's 20K BOP marks a new era in the exploration and development of high-pressure formations," he said.

According to NOV, Transocean ordered the new equipment for deployment on a 20K well in the Gulf of Mexico in 2021.

Transocean has said it will deploy the first 20K rated drillship, which is currently under construction in Sinagpore, under a five-year drilling contract with Chevron.

A spokesperson from NOV told Offshore Engineer that the 20K stacks are scheduled to be delivered sometime in late 2020.

Schlumberger

TerraSphere

Schlumberger's new high-definition dual-imaging-while-drilling service has been introduced to overcome geomechanics-related challenges and provide geological characterization in real time. TerraSphere applies a logging-while-drilling dual-physics imager for oil-based mud for drilling oil and gas wells. It incorporates electromagnetic and ultrasonic measurements that enable multiple high-resolution borehole images in nonconductive mud. This reveals enhanced details for geological, petrophysical and geomechanical interpretation to uncover subtle variations in the subsurface caused by stratigraphic or structural properties that impact wellbore stability.

More than 30 field trials have been conducted in the Gulf of Mexico, Middle East, North Africa, North Sea and US land.

Source: Schlumberger

Cortez Subsea, AFGlobal
Stinger Deployed Diverless Connector

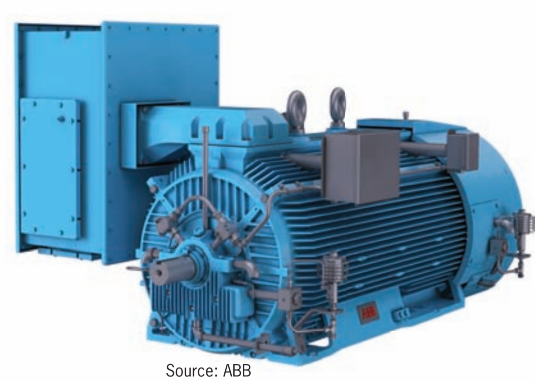
The Stinger Deployed Diverless Connector (SDDC), brought to market by Cortez Subsea and AFGlobal, has been developed to conduct pipeline tie-ins using a remotely operated underwater vehicle (ROV), without welding. When coupled with other installation techniques, the solution can offer cost savings of up to 30%, the developers say.

The solution is driven by the AFGlobal Retlock clamp technology, a two-bolt clamp which has the ability to connect mono and multi-bore. Suitable for vertical and horizontal applications and used for more than 1,600 offshore applications, the technology was customized to form the basis for the SDDC system.

The technology will be deployed offshore Malaysia where Cortez Subsea won a contract with Vestigo Petroleum for pipeline installation in the Berantai field.

Source: Cortez Subsea

ABB
AXR Large AC Motors



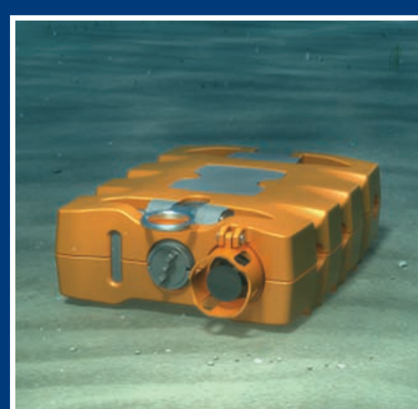
Source: ABB

ABB says its AXR 5000 and 5800 Large AC NEMA motors offer more horsepower per pound than conventional totally enclosed fan cooled motors, but with a smaller frame size in some power ratings. This helps save up to 8 inches in overall length in some cases. The new motors also offer improved cooling; an internal cooling loop circulates air inside the motor, moving heat to the frame, and an external fan blows air over the frame to remove the heat. The main terminal box and auxiliary box can be mounted in several positions. The motors are available with up to an IP56 rating, for protection against contaminates and dust ingress, and they meet American Petroleum Institute 541 and 547 standards.

Sercel
GPR Ocean Bottom Node

CGG's equipment business Sercel, in partnership with BGP, has developed ad deployed a new ocean bottom node (OBN) designed to leverage Sercel's QuietSeis broadband digital sensor technology for reservoir characterization and field development efforts.

GPR features a fully integrated all-in-one compact design that incorporates an optional acoustic transponder to optimize operations and the 3C MEMS and hydrophone to record high-fidelity data, the developers said. The 4C nodes can record seismic data for up to 50 days and down to 1,500 meters water depth. Using a flexible anchoring system, the GPR nodes can be deployed by either remotely operated underwater vehicle (ROV) or node-on-a-rope (NOAR).



Source: Sercel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