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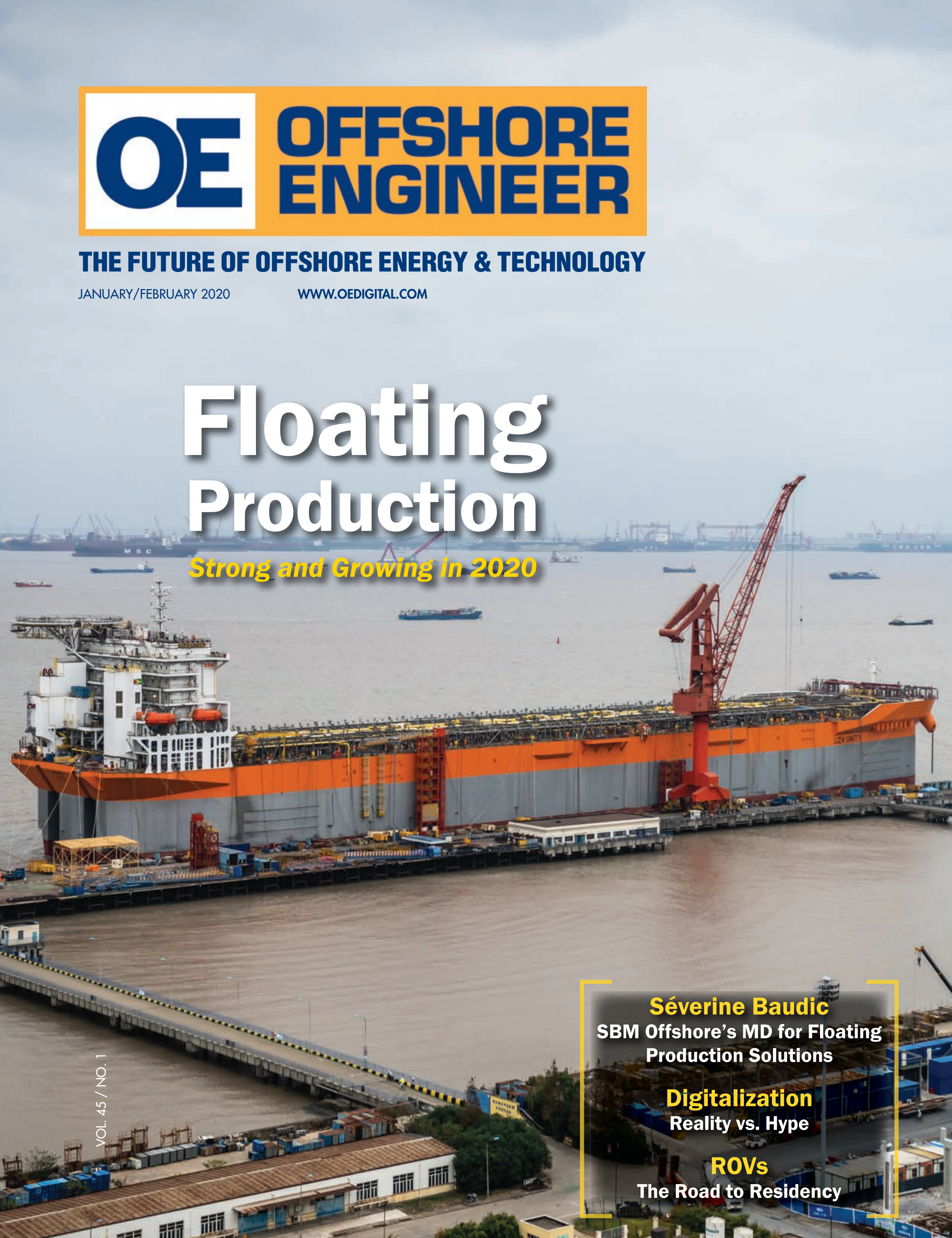

Floating Production

Strong and Growing in 2020

VOL. 45 / NO. 1

Séverine Baudic
SBM Offshore's MD for Floating Production Solutions

Digitalization
Reality vs. Hype

ROVs
The Road to Residency

JANUARY/FEBRUARY 2020
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FEATURES

Source: SBM

ON THE COVER: The market for FPSOs is strong and growing. **Séverine Baudic**, SBM Offshore's Managing Director for Floating Production Solutions, discusses market drivers and SBM's standardized Fast4Ward offering. Source: SBM

F E A T U R E S

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BY THE NUMBERS

RIGS

Worldwide

Rig Type	*Available*	*Contracted*	*Total*	*Utilization*
Drillship	23	66	89	74%
Jackup	114	339	453	75%
Semisub	42	64	106	60%

Africa

Rig Type	*Available*	*Contracted*	*Total*	*Utilization*
Drillship	2	14	16	88%
Jackup	8	28	36	78%
Semisub	1	3	4	75%

Asia

Rig Type	*Available*	*Contracted*	*Total*	*Utilization*
Drillship	5	7	12	58%
Jackup	43	108	151	72%
Semisub	18	11	29	38%

Europe

Rig Type	*Available*	*Contracted*	*Total*	*Utilization*
Drillship	13	0	13	0%
Jackup	12	38	50	76%
Semisub	12	27	39	69%

Latin America & the Caribbean

Rig Type	*Available*	*Contracted*	*Total*	*Utilization*
Drillship	3	19	22	86%
Jackup	7	3	10	30%
Semisub	5	5	10	50%

Middle East

Rig Type	*Available*	*Contracted*	*Total*	*Utilization*
Jackup	24	117	141	83%
Drillship	0	2	2	100%

North America

Rig Type	*Available*	*Contracted*	*Total*	*Utilization*
Drillship	0	22	22	100%
Jackup	17	37	54	69%
Semisub	4	9	13	69%

Oceania

Rig Type	*Available*	*Contracted*	*Total*	*Utilization*
Drillship	0	1	1	100%
Jackup	0	2	2	100%
Semisub	0	5	5	100%

Russia & Caspian

Rig Type	*Available*	*Contracted*	*Total*	*Utilization*
Jackup	3	6	9	67%
Semisub	2	4	6	67%

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 January 30, 2020.
Source: Wood Mackenzie Offshore Rig Tracker

DISCOVERIES & RESERVES

Offshore New Discoveries

Water Depth	*2015*	*2016*	*2017*	*2018*	*2019*
Deepwater	25	12	16	13	14
Shallow water	85	66	72	46	40
Ultra-deepwater	19	16	12	17	13
Grand Total	**129**	**94**	**100**	**76**	**67**

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	549	39,894	19,781
Shallow water	3,193	270,937	103,342
Ultra-deepwater	329	37,452	32,056
Grand Total	**4,071**	**348,283**	**155,179**

Contingent, good technical, probable development.

The total proven and probably (2P) reserves which are deemed recoverable from the reservoir.

Offshore Onstream & Under Development Remaining Reserves

	Water Depth of fields	*Number reserves liquids mbl*	*Recoverable reserves gas mboe*
Africa	615	20,535	12,852
Asia	870	16,734	7,278
Europe	828	12,719	14,282
Latin America & the Caribbean	205	6,174	30,341
Middle East	124	90,714	146,409
North America	587	3,060	14,975
Oceania	98	12,495	1,573
Russia and the Caspian	58	7,892	12,130
Grand Total	**3,385**	**170,324**	**239,840**

Onstream and under development.

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

Source: Wood Mackenzie

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Stoichevski

FLOATING **GOLD**

Strong growth. When, exactly, was the last time that you heard "strong growth" and offshore energy uttered in the same breath? That is exactly what you will find in the floating production sector, which is covered in full in this first 2020 edition of *Offshore Engineer*. **William Stoichevski**, our reporting lead based in Oslo who has decades of offshore energy reporting experience, takes center stage this month with his *"FPSOs: The New Business Model"* report starting on page 32. William reports that there are 21 FPSOs on order, and unlike a year ago, these — and not floating liquefied natural gas — are the real story. Driven by a decent price for oil, this buoyant market is kept strong by new players, new business models and the realization that FPSOs can cost less than new, jacketed oilfield development.

The backbone of William's floating production reporting comes courtesy of **Jim McCaul** of IMA/World Energy Reports, who offers his own insightful numerical take on the business starting on page 15. As you know, there are a plethora of "expert" analytical reports available today, and the number of "experts" seems to grow exponentially annually. I have known Jim, personally and professionally, for nearly 30 years, and I can say unequivocally that you would be hard pressed to find anyone, anywhere that follows the floating production market closer or longer, with data and analysis stretching back more than 40 years to 1978.

> **"THE FPSO MARKET IS BACK . . . REACHING LEVELS THAT THE INDUSTRY HAD PREVIOUSLY IN THE PERIOD 2010-2014."**
>
> SÉVERINE BAUDIC
> SBM OFFSHORE

Adding personality and a face to our FPSO coverage is **Eric Haun**, courtesy of his interview with **Séverine Baudic**, SBM Offshore's Managing Director for Floating Production Solutions, starting on page 19. Séverine discusses strategic initiatives and tech innovations helping the company to secure contracts for some of the world's most complex deepwater projects. Central to this is SBM's standardized Fast4Ward offering.

These are interesting times in the offshore energy sector, as a confluence of geopolitical events – from trade wars to 'green energy' movements to pop-up global health scares (ie. coronavirus) – all conspire to make your jobs more challenging.

However, despite all the outside noise, real and manufactured, proven engineered solutions that help to deliver energy from the offshore environment – oil, gas and renewables – safely, efficiently and reliably remains the cornerstone of what you do, and what we report in *Offshore Engineer*.

Happy New Year to all! As we look to another busy and prosperous year, I welcome you to reach out if you have an insightful and interesting story to share.

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$13 BILLION+ OFFSHORE WIND DECOMMISSIONING BILL

By Elaine Maslin

The UK's offshore wind industry will need to lean on oil and gas expertise to help decommission wind farms as more than 3 gigawatts (GW) of offshore wind power reaches the end of its design life by 2034, an industry decommissioning conference heard in November.

The cost of removing the installed base, as at 2017, could be about $5.2 billion, says John Warrender, chief executive of industry membership group Decom North Sea, told the Offshore Decommissioning Conference in St Andrews, Scotland.

What's more, by 2030, if goals to install more than 30GW of offshore wind power by 2030 are met, the prize for decommissioning the UK's installed offshore wind base could be in excess of $13 billion, he told the conference.

"Offshore wind decommissioning is going to ramp up very quickly," Axel Laval, Asset Manager, The Crown Estate, said, speaking at the same event. The first two UK wind turbines, at Blyth, in England, have already been removed. By 2034, close to 3GW of power will reach the

Vindeby, the world's first offshore wind farm, was decommissioned by DONG Energy, now Orsted, in 2016.

end of its design life, Laval says. That amounts to 1,000 turbines to be removed.

However, just as offshore oil and gas decommissioning costs have been riddled with uncertainty (although that's now improving), offshore wind decommissioning costs currently vary hugely. The challenge for offshore wind is that this creates uncertainty around the cost of energy for ongoing and future wind farms, says Laval. "It's difficult to lower the cost of energy if you don't know the cost of removing it," he says.

Estimates are about $105,000 - $342,000 per megawatt (MW), he says. The total liability, for the installed base as at 2017, has been estimated at $2.38 billion. Given the wide range of cost estimates per megawatt, that means – to decommission the installed base as at 2017 – the numbers could be between $1.67 - $4.75 billion range, he says.

Laval says there are currently 2,225 turbines installed in the UK North Sea amounting to 9,953MW of offshore wind. If the goal to reach 30GW of offshore wind power in the UK by 2030 is met, there could be some 5,000 turbines.

That amounts to about 200,000 metric tons of composites, mostly in the blades, that will need to go to landfill at the end of its life. In addition, there would be 1.3 metric tons of steel in the foundations and towers, 100,000 metric tons of copper in the export and array cables, and 50,000 metric tons of lead in export cables, said Laval.

With 30GW installed, there would be some 600,000 metric tons of composites to be removed at the end of life, 5 million metric tons of steel and 300,000 metric tons of copper. While the composites would cost $78.3 million to land fill, the steel and copper would recover scrap value at about $1.35 million each.

Here, there are opportunities, especially around recycling all that steel, says Laval. Recycled steel versus virgin steel production would see a 74% energy saving, he says. For aluminum there's a 95% saving. Some 1.5 metric tons of iron ore is needed to produce every metric ton of virgin steel, he points out, as well as 0.5-ton of coke. In the process of producing virgin steel, a lot of CO2 emissions are also emitted – which could be reduced by 86% by recycling steel instead.

"There's no sense reinventing the wheel," adds Laval. "The industry that is closest to what we (in offshore wind) do is oil and gas. So we need a supply chain from oil and gas to help (offshore wind) operators reduce the cost of offshore wind decommissioning."

Source: Orsted

Big data or big hype?

The size of the prize of so-called digitalization technologies is enormous. How much is reality and how much is hype?

By Elaine Maslin

UK-based analyst firm Wood Mackenzie asked this very question. The results are perhaps not that surprising.

Speaking at Offshore Europe, last year, Martin Kelly, VP of Wood Mackenzie's corporate research group, outlined the results. For the purposes of their research, digitalization, he said, encompasses all digital technology including artificial intelligence (AI).

"Size of prize is enormous; (improved) HSE (health safety and environment), cost saving and value increases in assets and companies," he says. Wood Mackenzie has, in an October 2019 report, estimated $40 billion could be saved in operating costs in the upstream (on and offshore) industry – per year (of a total $356 billion in 2018).

"But, how much of this is talk, how much is noise versus results being delivered? We think there's a lot of hype; a lot of proof of concept and trial. What are companies doing? They are talking about it."

Wood Mackenzie has been tracking mentions of digitalization in company earnings and analyst calls. Kelly says 2016-17 was an inflexion point, with the number of super majors talking about digitalization in earnings close and management days taking a significant jump, dominated by BP and Shell, initially, with Equinor and Total joining in to a large degree in 2018 and then ExxonMobil becoming more vocal in 2019. "And we expect more than last year," says Kelly.

He gives examples, such as Suncor talking about data and data cleansing, activities that will take a while to follow through, and Chevron talking about the potential of digital being enormous, but not putting number on it. "There are few specifics on the benefits," says Kelly.

One that has offered some detail is Norway's Aker BP, that calls itself a technology company that happens to produce oil. Aker BP says its reduced time spent on routine operations by around 75%, cutting forecast 2020 OPEX by about 15% or $150 million, says Wood Mackenzie's report. When it comes to the project development side, it's less easy to get fast results, however.

Indeed, a large focus of what's being done at the moment is in operations, "where there are myriad work processes where industry can deploy technology to deliver work in more effective, cheaper, safer ways, and get real-time feedback loops," he says. "You can make a change and get results instantly."

But, overall there are very few examples digital technology being disclosed openly, says Kelly. "We think it's because the industry is finding digital transformation at scale harder than they first thought. We are seeing some proof of concept, but it's not coming through at scale yet. The industry has set that use of digital as a priority. At senior level digital is being talked about as strategic.


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"INDUSTRY IS ONLY USING 3-5% OF ALL DATA IT HAS AT ITS DISPOSAL. *THERE'S ALMOST TOO MUCH DATA AND THAT CAUSES LACK OF FOCUS; THEY'RE NOT SURE WHERE TO SPEND AND THEIR MONEY ON THE DATA FRONT.* **BECAUSE OF THAT, WE NOT SEEING SUCCESSFUL TRIALS AT SCALE."**

"Industry is only using 3-5% of all data it has at its disposal. There's almost too much data and that causes lack of focus; they're not sure where to spend and their money on the data front. Because of that, we not seeing successful trials at scale. Cultural buy-in, the buy-in to really make this change happen is still question mark."

Indeed, speaking at the same event, Justin Rounce, EVP and CTO at TechnipFMC, says, "One of problems I have is the big data challenge. It's hard to do." While someone like YouTube handles unbelievable amounts of data, "their data challenge is completely different to anything we face," says Rounce. "They get about 300 hours of video uploaded every minute." While there are companies like Microsoft, Amazon, and Google that provide the infrastructure to load and manage data, it's still not easy for oil and gas. "We have challenges around different standards and types of data and a significant volume of unstructured data."

There are opportunities, however, he says. AI and machine learning lend themselves well to unstructured data. Progress is being made in subsurface modeling and also in drilling and field development, helping to push learnings from offset wells into future planned wells.

There are also off-the-shelf technologies available. Predictive analytics at component and system levels can be used, to see when to maintain equipment – or, equally as important, when you don't need to – and to better understand flow assurance, production optimization and to prevent problems.

Another area of opportunity is the digital twin, he says. But, just as lack of standardization in documentation and records has led to unstructured data and different digital twins are being created, he points out, which will cause problems when it comes to future interoperability or scalability, he says. "So, how about an open system where system data from different sources can be pulled in and interface with as many standards as possible? Time will tell."

There are positive steps. The UK's regulator, the Oil & Gas Authority, produced a Digital Strategy 2020-2025, late last year, aiming to embed "digital excellence". The move was welcomed by Oil & Gas UK, an industry body, which said "effective use of data and digital tools will be critical to unlocking a safe and competitive oil and gas industry working to realize its full potential."

But, as has been found, with UKOilandGasData, a well and seismic data sharing platform built by Oil & Gas UK's CDA (Comon Data Access) subsidiary, which provided the foundations on which the OGA's UK National Data Repository was built, the hardest bit is getting operators to submit data in a common format that is also able to be machine readable and therefore digitally accessible. The OGA's latest initiative will hope to change that.

Mapping in the Cloud

How cloud-based computing is transforming subsea survey

Digitalization has revolutionized the world, and hydrographic survey techniques are no exception. While advances in mechanical design have enabled the survey of increasingly remote locations, electronics and digital processing techniques have dramatically increased resolution. Where once a few spot soundings were considered enough to make a chart, today's survey vessels generate vast amounts of data to give unprecedented detail.

Detail is good, but data in these quantities needs careful management if it is not to become overwhelming. Modern sounders, such as Kongsberg's EM range, can produce data at a rate of more than 1 gigabyte (GB) per minute – too much to economically transmit ashore in real time, and impractical to store locally in raw form. Fortunately, real-time processing can greatly reduce the burden for transmission or storage.

Although most surveys are carefully planned, it's of great benefit to be able to analyze the data while the equipment is at sea, enabling unusual results to be verified and survey gaps to be revisited. Called Mapping Cloud, it is underpinned by Kognifai, which is Kongsberg Digital's solution for an open, cloud-based environment.

Collaboration via the cloud

The purpose of Kognifai, which is based on Microsoft's Azure cloud computing platform, is to support collaboration and knowledge-sharing between and within organizations, and to assist academia and the public in developing a broader understanding of the world around us. A good example of how Kognifai and Mapping Cloud are already facilitating this is the Frisk Oslofjord project.

Kognifai is an open, standard platform, designed to make it easy for developers to create applications. In addition, Kongsberg Digital offer several software development kits (SDK) to assist in application development. These contain edge connectors, 3D tools, application framework support, authentication and authorization systems, dashboard wid-

Source: Kongsberg

gets, database solutions, routing and queue support features.

As an open platform, the range of applications supported by Kognifai is diverse. Recent organizations to join Kognifai include the UK Met Office, Finnish maritime communications technology developer KNL Networks and cyber-security experts KPMG

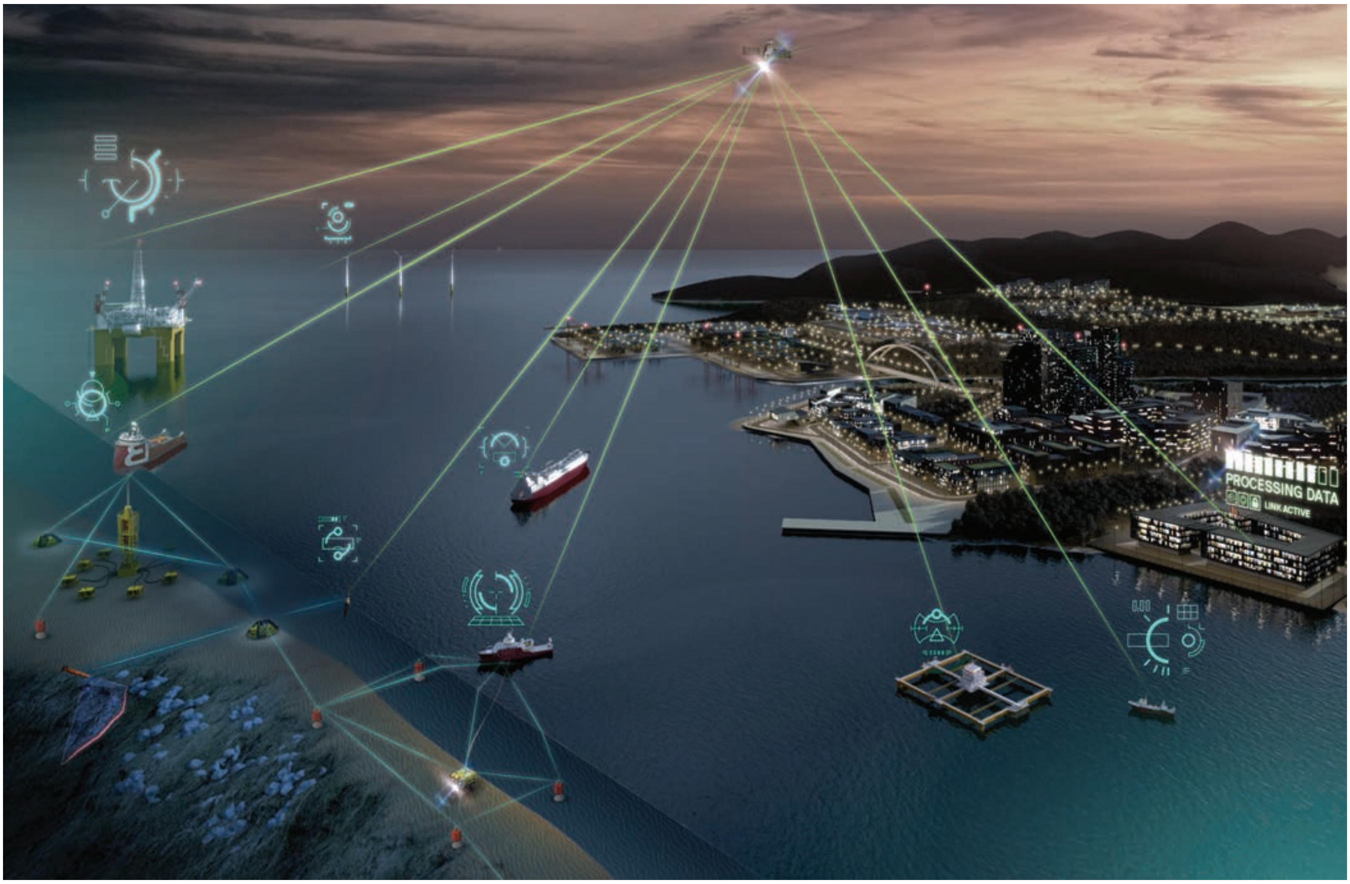
The scope for data generation and, more importantly, sharing and collaboration on such a platform is immense. Kongsberg currently has a footprint on more than 30,000 ships; as an example, the company's Division for Vessel and Fleet Performance has more than 1,000 ships from Europe, Asia and the US using Kognifai, making it possible for ship owners to monitor the status of their assets from any web browser in any location.

The cloud also offers almost infinite capacity for storage. Kognifai allows large data sets to be stored, which remain exclusive to the user unless they grant access to others. This can be done on an individual or group basis and on a permanent or time-limited basis. If they are prepared to grant more general access, large datasets facilitate machine learning, allowing Kognifai to generate additional future value for its users.

Making the most of storage

Mapping Cloud is a joint concept developed by Kongsberg Digital and Kongsberg Maritime's Subsea business. Capable of accepting input from a range of different sources including cameras, multibeam echosounders and temperature sensors, it is built on Kognifai and targets the survey industry. The first application to be released within Mapping Cloud is Storage, designed with an interface similar to other PC-based file managers to make it intuitive to use. However, there are a few differences which tailor its functionality for the data-intense, collaborative world of modern hydrography.

- **Data upload.** Storage has cloud connectors, which can be installed on ships to automatically



Source: Kongsberg

push data to the cloud. It also facilitates data upload from other sources, such as an office PC.

- **Data sharing.** Other Kognifai users, if they have been granted access, can read, process, supplement and modify data. This removes the need for sending physical media or setting up ftp servers.

- **Archiving.** Storage offers the facility to archive data at lower cost. A feature of Microsoft Azure, data can be ‘hot’ or ‘cold’. ‘Hot’ data can be accessed instantly, but once the data is finished with or not expected to be required for some time, it can be put into ‘cold’ storage. This is essentially an archive, and less expensive than keeping data in ‘hot’ storage.

The ability to automatically gather and aggregate data from diverse sources in a single, globally accessible location facilitates efficiency in survey applications.

Taking a remote view

Advanced sonar systems, such as Kongsberg’s EM sounders, can perform significant real-time processing, thus limiting the amount of data it is necessary to store or transmit. The amount and type of processing carried out is configurable, and Mapping Cloud facilitates doing so remotely.

This allows the operator to ensure that only necessary data is uploaded to Mapping Cloud Storage, and to tailor the system to the available communication bandwidth. This becomes valuable when unmanned surface vessels (USV) are used. A single mother ship can have control of a fleet of these craft, which allows large areas to be surveyed by a small team, in areas which might otherwise be inaccessible. USVs are often also used in support of autonomous underwater vehicles (AUVs), with the potential to extend survey depths to 6,000 meters.

A local wireless system may be used to transfer data between vessels in the fleet. It can then be processed further on the mother ship before upload to Mapping Cloud via a shore link, which is likely to be higher bandwidth and less expensive than satcom.

Once the data is in the cloud, the end user for the survey can monitor the progress and quality of the survey, allowing for immediate feedback.

FLOATING PRODUCTION: *THE REBOUND CONTINUES*

Jim McCaul – IMA/World Energy Reports

Activity in the deepwater sector took a huge hit in the second half of last decade as a result of a global oil demand/supply imbalance, downturn in oil prices, hiatus in Petrobras production floater orders and large industry cutbacks in upstream spending. The downturn was the worst to ever hit the offshore sector. Orders for new equipment dried up, backlog fell and many suppliers were forced to cut personnel, while others were forced out of business. But the downturn has bottomed, and orders for production floaters are on the uptick, a large portfolio of new projects are in the planning stage and underlying market conditions are favorable to deepwater investment decisions.

Exhibit 1: **Floating Production Units Installed, On Order and Available** (As of 1/1/20)

Type Floater	Total	Installed	On Order	Available
FPSO	221	178	22	21
Barge	9	8	1	0
Semi	46	37	6	3
Spar	21	21	0	0
TLP	28	28	0	0
All Units	**325**	**272**	**29**	**24**

Source: IMA/World Energy Reports Database

GROWING NUMBER OF PRODUCTION FLOATERS

The number of floating production systems in operation has steadily increased since startup of the first production floater in the mid-1970s. Ten years were needed to reach 15 units in operation. By the end of the second decade more than 50 units were in operation. At the end of the third decade the number had grown to around 170 units in service. Now there are just under 300 production floaters in service or available – and another 29 on order (Exhibit 1).

But growth in production units has not escaped the long-term S-curve pattern typical of all industries. Growth in number of production floaters has slowed as field decommissioning offset new project starts. From 2005-2009, the number of floating production, storage and offloading units (FPSO) and floating production units (FPU) in operation or available grew 39%. From 2010-14 growth was 19% – and from 2015-19 the number of units grew 3%.

THE 10-YEAR TREND IN ORDERS

Contracts for 123 production floaters have been placed over the past 10 years – an average of around 12 units annually. FPSOs accounted for 97 of the contracts, and FPUs for 26 contracts. Included in the FPU contracts were 12 production semis, six tension-leg platforms (TLP), five spars and three barges. A high of 27 contracts was reached in 2010 when Petrobras ordered the hulls for eight serial FPSOs (two were subsequently canceled, one later rebid). The low was in 2016 when no orders were placed.

Orders returned in 2017 as the oil market recovered, and over the past three years 32 production floaters have been ordered, including 25 FPSOs and seven FPUs.

FPSO orders since 2017 include nine large units for use by Petrobras in Brazil (seven) and by ExxonMobil in Guyana (two). Not counted in the FPSO total are two speculative FPSO hulls ordered by SBM in December 2019 – they will be included when a field contract is executed. In 2020 there has been one FPSO order as of mid-January. The seven FPU contracts since 2017 include six production semis and a small production barge. No production spars or TLPs have been ordered over the past five years. The latest spar order was in 2012. The last TLP order was in 2013.

PRODUCTION FLOATERS NOW BEING BUILT

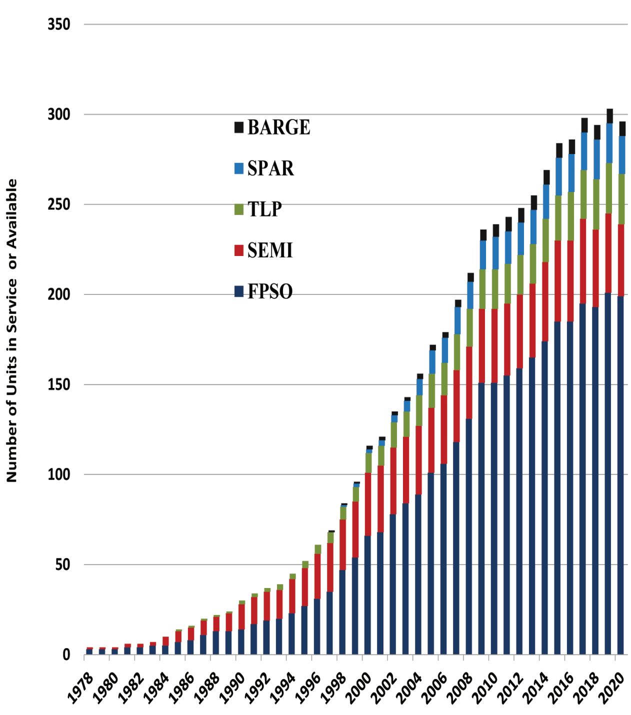
Included among the 29 production floaters now being built are 22 FPSOs, six production semis and a production barge. A third of these units are well into the construction program, with production start planned in 2020/21. Two-thirds are more recent contracts where construction is at an earlier stage and production start is planned in 2022/24.

Seven (32%) of the 22 FPSOs being built are for use offshore Brazil. The rest are for use offshore West Africa (three), Guyana (two), Northern Europe (two), India (two) – and Mexico, Israel, China and Australia (one unit each). The remaining two FPSOs are speculative hulls that at the moment have no field assignment – but are likely to be used on future contracts in Guyana or Brazil.

Thirteen of the FPSOs are being built on new hulls. Nine are conversions or upgrades to existing units. China is clearly the major location for FPSO construction and conversions. Eighteen of the 22 FPSOs on order are partially or fully contracted to Chinese yards. Singapore has retained second position, with three orders. One FPSO contract has been placed in Korea. Topsides plant fabrication and integration is spread over a variety of contractors in Asia, Europe and Brazil.

Five of the six production semis now being built are destined for use in the Gulf of Mexico. The remaining unit is for use offshore China. Construction of these semis is divided among builders in Korea, China and Singapore – each location having two production semi contracts. Some topside fabrication and integration is being performed in the US.

Exhibit 2: **Growth in Floating Production Systems over 40 Years** (Installed and available units as of beginning January each year; excludes FLNGs and FSRUs)



Source: IMA/World Energy Reports Database

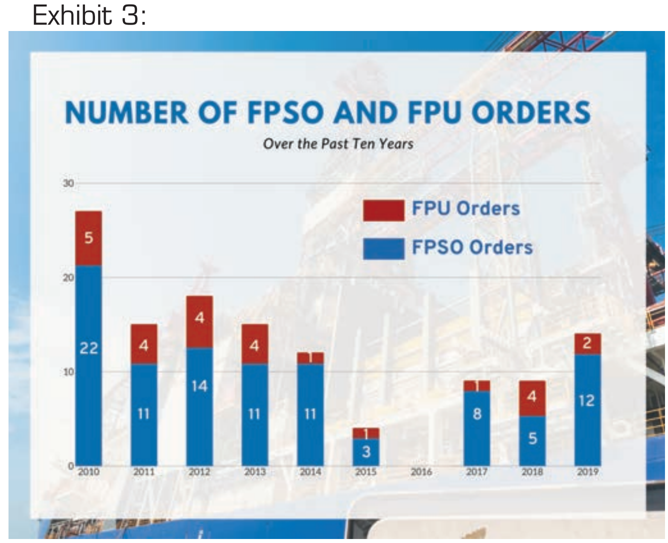
PROJECTS IN THE PLANNING STAGE

We have been tracking 130 projects in the planning stage that are likely to require a production floater for development. They include 118 projects where an FPSO is the likely production solution, 12 where a production semi is likely to be required. Brazil is the dominant location for future production floater requirements – with 38 projects in the planning queue. Other major locations with floater projects in the planning stage are Africa (30 projects), Southeast Asiea (16 projects), Northern Europe (12 projects) and the Mexico/US Gulf of Mexico (10 projects).

Some of the projects are near term, some further out. Of the total, eight projects are at the bidding or contract negotiation stage. Another 10 are in the near term investment queue and eight are in front-end engineering design (FEED) stage. Another 79 projects are further out in the planning stage – either in development concept definition (45), exploration and appraisal (25), priority prospect (seven) or commercial framework negotiation (two).

The remaining 25 projects in the planning queue are

Exhibit 3:



Source: IMA/World Energy Reports Database stalled. Some are stalled due to economics. Some are awaiting field partner or agreement on field commercial terms. Others are stalled by government opposition, field rights issues, operator failure or sanctions that prevent the project moving forward (Exhibit 4).

FIVE YEAR OUTLOOK FOR CONTRACTS

While 130 FPSO/FPU projects are at various stages of development planning, underlying market conditions will influence if and when individual projects move forward to the investment commitment and placement of a floater construction contract.

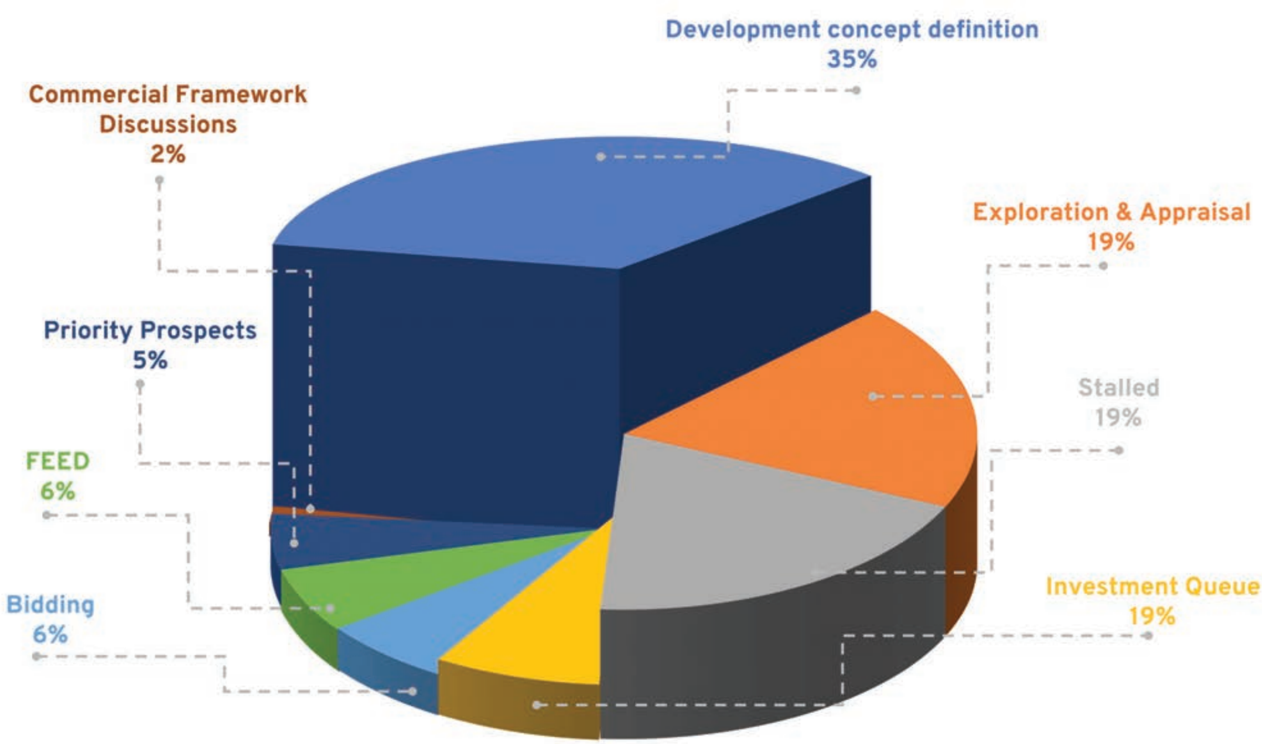
IMA/WER each year looks in detail at conditions likely to exist in the deepwater market over the following five years. Here's how we see the market situation between 2020 and 2024.

In the (mostly) positive category are:

- Future demand growth – Oil demand is likely to grow 0.9 to 1.3% annually through the 2020s, then taper off in the 2030/50 timeframe, perhaps eventually peak in the second half of the century.

> **"BASED ON OUR ANALYSIS OF FUTURE MARKET CONDITIONS, WE ARE FORECASTING ORDERS FOR 41 TO 56 FPSOS AND 8 TO 12 FPUS BETWEEN 2020 AND 2024.** *THE CONSTRUCTION CONTRACTS ARE EXPECTED TO GENERATE EXPENDITURES OF $56 TO $77 BILLION. BRAZIL IS EXPECTED TO ACCOUNT FOR 30 TO 40% OF THE FPSO ORDERS OVER THE NEXT FIVE YEARS."*

Exhibit 4: **Stage of Development of 130 FPSO/FPU Projects in the Planning Queue**
(as of 1/1/20; Excludes FLNG, FSRU and FSO Projects)



Source: IMA/World Energy Reports Database

- Deepwater future supply role – Deepwater production now accounts for approximately 10% of global oil supply and we expect it will continue to provide 8 to 12% of world oil supply over the next 20+ years.
- Supply disruption risk – Global supply of oil and natural gas is fragile and the possibility of major supply disruptions very real; the disruption threat incentivizes investment in deepwater development as a supply security cushion.
- Oil prices – We expect Brent crude to trade in the $55 to $65 price range over the next five years, gradually increasing to $70 to $75 through 2035 in our most likely scenario.
- Deepwater/shale competiveness – While tight/shale rock development remains the major competitor to deepwater investment, productivity gains are slowing, creating upward pressure on tight/shale rock break-even price.
- Cost of capital for deepwater exploration and production (E&P) – The deepwater sector remains attractive to banks, hedge funds and others, and financing is readily available for production floaters backed by long-term lease with substantive counterparty.
- Access to Brazilian deepwater resources – The government has been opening foreign investment opportunities in Brazilian offshore resources and has relaxed some local content requirements.

In the (mostly) negative category are

- Engineering, procurement and construction (EPC) contractor constraints – Capacity of major FPSO leasing contractors to simultaneously perform multiple large FPSO EPC+ lease contracts could constrain the near term pace of FPSO projects. E.g., Modec now has seven large FPSO contracts at various stages of completion. Modec has never had a backlog this large – execution of which will test the depth of the company's project management capabilities.
- Upstream investment constraints – Capital spending on upstream projects continues to be weak as oil companies emphasize "fiscal discipline" and set-aside available cash for dividends, stock buybacks.

In the unknown category are

- Black swans – Negative and positive unexpected events impacting activity in the deepwater sector will undoubtedly occur over the next five years. They have in the past – e.g., 2010 Macondo oil spill.

Based on our analysis of future market conditions, we are forecasting orders for 41 to 56 FPSOs and eight to 12 FPUs between 2020 and 2024. The construction contracts are expected to generate expenditures of $56 to $77 billion. Brazil is expected to account for 30% to 40% of the FPSO orders over the next five years. Africa is expected to be the second largest source of FPSO activity, with around 25% of the orders. Next in line are Northern Europe and Southeast Asia/China, each with around 10%.

We expect that 20% to 25% of FSPO projects over the next five years will involve use of a redeployed FPSO. Assuming the most likely forecast scenario, we expect 10 to 13 FPSO projects will entail redeployments. FPU orders over the next five years will be principally, if not wholly, comprised of production semis. Most will be for projects in the US Gulf of Mexico or offshore Australia.

No TLP and few spar projects are currently visible.

FLOATING PRODUCTION: THE NEXT CHAPTER

*The market for floating production, storage and offloading units (FPSO) is heating up. **Séverine Baudic**, SBM Offshore's Managing Director for Floating Production Solutions, weighs in on the strategic initiatives and technological innovations helping the company to secure contracts for some of the world's most complex deepwater projects. When it comes to reducing lead times and adding value, SBM's standardized Fast4Ward offering has been key.*

BY ERIC HAUN

"The FPSO market is back with nine FPSOs awarded this year [as of mid-December 2019], reaching levels that the industry had previously in the period 2010-2014," Baudic said. "We expect similar numbers in the years ahead."

But for SBM Offshore – and even the offshore industry in general – it's been a long and winding road from the depths of the downturn to the much-improved market situation that exists today.

"The period from 2014 to 2018 was testing for our business," Baudic said. "The 2014 oil price drop meant that many projects were canceled or delayed, with SBM Offshore affected as much as its peers and other oilfield services companies."

And for SBM Offshore in particular, Baudic noted there was the "aggravating factor" of "legacy issues" that prevented the Dutch floater specialist from bidding for business in the all-important Brazilian market.

SBM decided its best option was to tighten up and plot for the future. "In this difficult period, SBM Offshore strategically focused on closing legacy issues, restructuring its cost base while preserving core expertise, and building transformation programs to tackle the inherent volatility of our market, as well as in preparation for future growth," Baudic said.

During this time, the company also went to work developing what would become its Fast4Ward FPSO concept combining a newbuild, multipurpose hull with several standardized topsides modules to shorten lead times and increase capacity limits.

"Fast forward" to present day: optimism is returning to the deepwater market, and with the dust now settled in Brazil, SBM Offshore's strategy and concept are paying off. "In 2019, we began a new chapter. We closed the legacy issues, we regained access to Brazil and the FPSO market conditions are, overall, positive."

The next generation

"The FPSO product has gone through a series of changes over the years, and we define these changes as 'generations'. The third generation FPSOs that we recently delivered in Brazil had topsides weights that reached the limit of what we can safely put on a converted tanker, so we knew that we had to think differently for the next generation."

In addition to greater capacity, the market also sought shortened lead times to help de-risk high-cost and complex deepwater floater projects. Fast4Ward is the result of these customer demands, Baudic said. "The next generation FPSO has been developed, and it is able to carry much high-


CSSC
上海外高桥造船有限公司

Source: SBM Offshore

"THE FPSO MARKET IS BACK WITH NINE FPSOS AWARDED *[AS OF MID-DECEMBER 2019], REACHING LEVELS THAT THE INDUSTRY HAD PREVIOUSLY IN THE PERIOD 2010-2014."*

SÉVERINE BAUDIC
MANAGING DIRECTOR, FLOATING PRODUCTION SOLUTIONS, SBM OFFSHORE

Source: SBM Offshore

er topside weights and is a more standardized product."

When comparing a newbuild Fast4Ward FPSO to a conventional tanker conversion, Baudic said performance and greater production capacity are the main drivers. "The Fast4Ward hull design offers up to 250,000 barrels of oil per day (bopd), which is a significant step change. To date our largest conversion FPSOs have a production capacity of 150,000 bopd."

SBM Offshore orders the standardized Fast4Ward floater hulls on speculation, before a contract is secured. Later, the customer will choose between internal turret, external turret or spread moored configurations, and select from SBM's range of generic and bespoke topsides modules based on client and project requirements. Having construction already underway ahead of contract signing shortens lead times, and ultimately reduces time to first oil. "The Fast4Ward program standardizes floating production systems as much as possible, with knock-on savings in the procurement and construction phases, resulting in a reduction in delivery time of between six and 12 months," Baudic said.

But, for the "design one, build many" concept to work most effectively, early engagement with customers while laying the groundwork for Fast4Ward was essential, Baudic said. With a better idea of client challenges and future needs, SBM Offshore was able to fine-tune its designs and achieve higher levels of standardization.

"With regards to the hull, the level of standardization we have reached on ongoing projects is remarkably high. Very little modifications have been required. This is evidence that our standard design works and is embraced by the major players. Of course, the risers interface remains specific to each project as it depends on the subsea layout and the offshore installation contractor. However, our design is modular enough to accommodate those specifics with minimum impact to the hull.

"On topsides, we are also reaching a high level of standardization for all utility modules, which tend to repeat from one project to another, such as power generation, electrical room, seawater treatment or water injection modules. For the process modules, we standardize what can be standardized, i.e. the module architecture (the footprint, floor elevations, etc.), the position of main equipment on the module, and the definition of the equipment, to leverage standardization of our supply chain as well. We have entered a virtuous cycle of standardization where new modules are developed to fit operators' new requirements and are included in our catalogue of solutions. They can then be used on other FPSOs for other field developments."

Source: SBM Offshore

"An important factor in fully reaping the benefits of standardization is basing the FPSO design on SBM Offshore specifications (GTS). Our customers are familiar and confident with our GTS. They also understand that it is in their interest to minimize any additional requirements."

Markets and orders

"With Fast4Ward, we can offer high capacity and complex, newbuild FPSOs to the market and this is where we see the most potential, particularly for large FPSOs," Baudic said.

"The Fast4Ward hull design is optimized to cover what we see as being the largest FPSO markets: Brazil, Guyana and West Africa. It can take up to 50,000 tons of topsides (operating weight, i.e. with all fluids inside). It is designed for projects up to 3,000 meters water depth and to cover ocean conditions in the South Atlantic. Fast4Ward hulls can also be tailored to suit other geographical areas if needed.

SBM, which ordered its first Fast4Ward hull on speculation from Shanghai Waigaoqiao Shipbuilding (SWS) in China in 2017, received a contract for the unit from ExxonMobil in 2018. The 220,000 bopd floater, now named Liza Unity, recently made its way from China to Singapore for topsides integration ahead of planned startup offshore Guyana in 2022.

A second Fast4Ward FPSO is being built by China Merchants Heavy Industry (CMHI) – again, ordered on spec – and has been contracted to Petrobras for the Mero field offshore Brazil. A third unit is under construction at SWS and destined for the ExxonMobil-operated Payara field offshore Guyana.

In December 2019, SBM ordered another pair of Fast4Ward hulls (one each from SWS and CMHI). Development is progressing while customer and destination are to-be-determined.

"We do expect that Fast4Ward as a whole, i.e. the hull, the topsides and mooring solutions, will meet a greater breadth of customer needs, because we are developing our catalogues and covering more requirements, but also because operators are seeing the benefits of standardization," Baudic said.

"That being said, it is important to understand that Fast4Ward stan-

dardization principles also apply to conversion projects. Our topsides and mooring catalogue can be used for conversions and the same design philosophies and ways of working are employed. We are experts in conversion and we want to remain the leaders in this segment."

"In addition, we are building on our strengths and expertise, we continue to offer solutions in the medium to large conversion-type FPSOs and we are incorporating the principles of Fast4Ward to add value to our conversion FPSOs.

"With this portfolio, we expect that 80% of the FPSO prospects coming to the market in the next few years will be accessible to SBM Offshore. With the disciplined and selective approach previously mentioned, we are confident that we can be awarded 2+ FPSOs per year."

"Brazil is clearly a key target market, with many of the expected global FPSO awards over the next 10 years, Baudic said. "SBM Offshore's strategy is to be selective in its bids and take part in the ones that it sees a clear opportunity to add value, specially focusing on the more complex end of the FPSO spectrum.

"The key success factors for SBM Offshore will be to leverage its Fast4Ward program – which applies to both newbuilds and conversions – and leverage its long experience in Brazil of providing lasting solutions that will facilitate timely delivery and reliable operations for the years to come."

Connecting completions

SureCONNECT system subassembly with Premier feedthrough packer, SureVIEW CoreBright fiber, and pressure/temperature gauges being picked up prior to running-in-hole with the lower completion during an install West of Shetland. This marked the world's first multi-trip completion installation with fullbore fiber-optic capability.

Source: Baker Hughes

Forewarned is forearmed, an adage that is particularly true when it comes to deepwater drilling. Offshore drillers are increasingly relying on existing and new downhole data technologies to make real-time decisions and keep operations safe, writes **Jennifer Pallanich**.

Multi-trip completions in offshore wells have long left operators in the dark about what was happening in the pay zone. Modular technology that connects hydraulics, electric and fiber optics between the upper and lower completions delivers reservoir performance data in real-time.

Complex offshore and subsea wells often rely on multi-trip completion designs to ensure the completion assembly reaches depth without damaging the reservoir. The drawback of this approach is that it has, until recently, made it impossible to run fiber, electric and hydraulic lines that reach the lower completion, which is the part that is in contact with the reservoir.

Thomas Scott, global product line director for intelligent production systems and reservoir information at Baker Hughes, says the industry has been operating with insufficient data since the 1970s, leaving operators unable to tell how efficiently they were draining an asset.

In answer to this problem, Baker Hughes developed a downhole intelligent wet-mate system that enables real-time production monitoring and control of the completion system across the entire wellbore in multi-trip completions. The SureCONNECT enables connection and re-connection of the upper completion components with the lower completion. The system uses a modular approach to connect the hydraulics, the electrics that power traditional monitoring systems such as quartz-based pressure temperature gauges and in-well flow control valves, along with fiber optics with one system design.

"The SureCONNECT system as a whole is a tool that allows us to run multiple trips in the completion," Scott says. "This system allows operators to complete wells in ways they never thought possible."

The system makes available "real-time data that we understand and makes it actionable. It's not just feeding out data, but what does it mean from a reservoir perspective? What can I do to get more value?" Scott says the system "enables monitoring and control in the lower completion. For the first time in the industry, we've enabled every well to have this level of monitoring."

Source: Baker Hughes

"WE MODELED THESE THINGS IN THE PAST, AND NOW WE'RE ACTUALLY MEASURING THESE THINGS. IT TAKES THE GUESS WORK OUT OF THIS."

– THOMAS SCOTT, GLOBAL PRODUCT LINE DIRECTOR FOR INTELLIGENT PRODUCTION SYSTEMS AND RESERVOIR INFORMATION AT BAKER HUGHES

Because the installation is permanent, it provides information about changing reservoir conditions over the life of the well. The SureCONNECT system also allows workover operations to be completed without retrieving the lower completion, such as installation or retrieval of an electrical submersible pump or repairing a safety valve, which decreases rig time, safety risks and equipment costs.

At its heart, Scott says, the system is intended to help operators derive more value out of their assets while enabling efficiency and more remote control of operations. It does this through data.

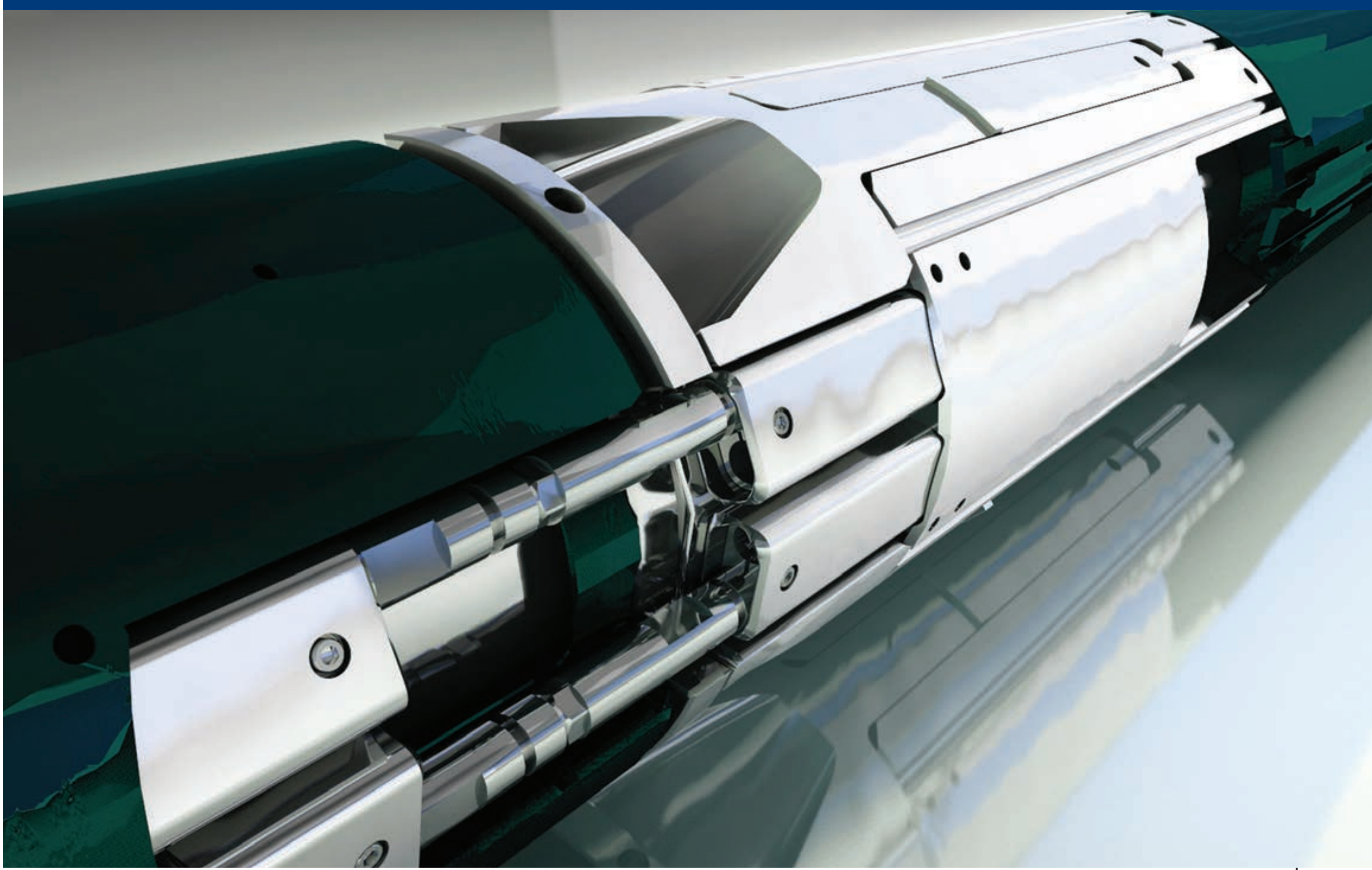
Fiber optic technology provides real-time data about the reservoir through distributed measurement along the length of the fiber. Scott says the fiber optics can simultaneously acquire distributed acoustic sensing (DAS) and distributed temperature sensing (DTS) along with point pressure and reservoir strain data. All this data makes it possible to detect where sands are coming from and where and which fluids are being produced or injected. It can also monitor equipment health such as valve shifting quality for safety valves and inflow control valves, detect flow anomalies such as leaks and other wellbore integrity issues, conduct vertical seismic profiling to map the reservoir properties and fluid boundaries over time, and enable compaction monitoring through a combination of acoustic and strain sensing.

"We modeled these things in the past, and now we're actually measuring these things. It takes the guess work out of it," Scott says. "It's a lot richer data set through fiber optics than you get when compared to electric. Fiber optics as a whole has started to deliver more value in recent years."

And while that level of data has long been desired, for years it wasn't possible, partly because of the difficulty in mating fiber optics about the width of a human hair in the lower completion with fiber optics in the upper completion a mile under the earth, he says.

The breakthrough, he says, came with SureCONNECT. He likens the wet-mate connection to plugging in an electrical cord from the upper completion into an electrical wall socket in the lower completion. The lower connection system is landed with the lower completion. The upper connection system, run with the upper completion, includes a cleaning sequence that removes well debris. This system also facilitates alignment of the connector as the as-

The SureCONNECT system offers a modular approach, connecting hydraulic, electronic and/or fiber with one system design, further driving reliability and consistency across applications.



sembly is mated with its lower counterpart.

The modular system includes five channels that can be customized based on how the completion engineer wants to complete the well. Each channel supports two hydraulic lines, one electric line or one six-fiber line. The electric connectors make traditional monitoring devices like pressure and temperature gauges and electric choking valves possible in the lower connection while hydraulic actuations can help mitigate scale or asphaltene buildup through chemical injection.

"This gives extra flexibility to put monitoring and control tools in the lower completion that haven't been possible before. It gives more segmentation and control of the completion," Scott says.

The data available through SureCONNECT enables operators to make more remote decisions, which minimizes the need for transporting experts offshore. Because the system is compatible with other downhole technologies used to shut off zones and optimize production, it creates standardization across intelligent completion designs, the company says.


Source: Baker Hughes

The gathered data is processed at the surface and turned into actionable, data-driven solutions, according to Baker Hughes. One such action might be shutting off water and gas-dominant zones through remotely actuated sliding sleeves to optimize production in real time.

In addition to allowing the downhole connection of electric, hydraulic, and fiber-optic lines in multi-trip completions, SureCONNECT makes flow profiling, fullbore well monitoring and control possible, according to the company.

Connecting at Clair Ridge

BP has deployed SureCONNECT in its operated offshore Clair Ridge field West of Shetland. This was the world's first multi-trip completion installation with full-bore fiber-optic capability. During the deployment, six optical fibers were mated between the upper and lower completions. BP will use the data gathered in parallel with conventional well surveillance data to provide a better understanding of fracture performance in real time.

Clair Ridge is the second phase of development of the Clair field, which was discovered in 1977 and holds more than 7 billion barrels of oil in place. Clair Ridge features a highly fractured reservoir with some areas that produce quite a lot and other that don't. Clair Ridge, which achieved first oil in late 2018, targets 640 million barrels of recoverable oil reserves.

"The wells there are complex. They're very deviated, with tortuous paths," Scott says. "To efficiently produce this reservoir, they need to know what's happening in the reservoir."

He says the use of SureCONNECT in the Clair Ridge field has made it possible to "see value almost instantaneously" by making it possible to "detect where water is coming from and take appropriate actions to handle that water. They are producing from a highly fractured reservoir in a way that wouldn't have been possible without the SureCONNECT technology."

Scott calls the development of SureCONNECT a two-decade journey and says BP and Shell have been key partners in fine-tuning the system.

"We deployed various aspects of it over the years," he says.

One of those was a fiber-optic only version that was installed at Shell's Mars A field in the deepwater Gulf of Mexico in 2012. The electric connector was deployed in Brazil in 2003, and the hydraulic connector in 1998 in the UK.

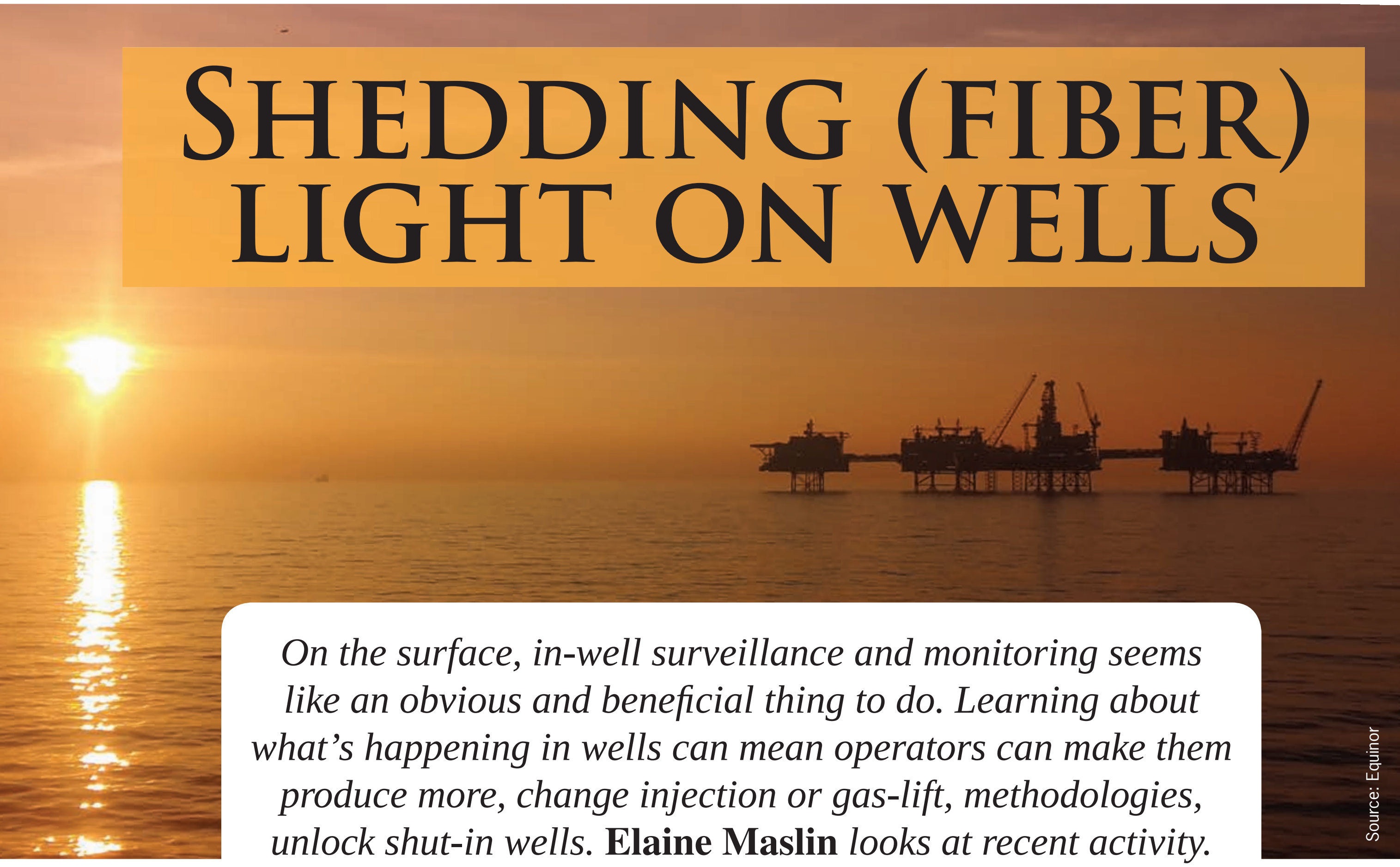
The full commercialization of the modular version capable of accommodating and mating fiber optics, hydraulics and electric came in 2019.

"The critical piece was how could we get to a place where we could do this reliably," Scott says. "It's more than just the tool itself. It's the process and project management process."

All those pieces combine in SureCONNECT to make it possible to do more with less, Scott says. This fits in with the industry's drive for efficiency across the board, he adds.

"This unlocks a whole new level of efficiency that gets us to the point where we can talk about autonomous control," he says. "They can unlock more assets and profitability over the life of the well."

Shedding (Fiber) Light on Wells



On the surface, in-well surveillance and monitoring seems like an obvious and beneficial thing to do. Learning about what's happening in wells can mean operators can make them produce more, change injection or gas-lift, methodologies, unlock shut-in wells. **Elaine Maslin** *looks at recent activity.*

The range of tools and the capabilities of those tools have been improving year-on-year with the data they're able to gather growing fast. From listening to what's happening or monitoring the temperature in a well, they can infer, for example, the exact location of water breakthrough, if a valve has shut or not or even the type and quantity of fluids flowing through a well. If anything, more data can be created by these technologies than operators currently know what to do with.

Some of these technologies were outlined at the SPE's Inwell Surveillance and Monitoring seminar in Aberdeen, UK, late last year. But, so was a paradox; very little surveillance is being done in the UK North Sea despite the available technologies.

The Oil & Gas Authority's (OGA) Glenn Brown pointed to figures from 2018, which showed that of 550 well intervention activities across the UK's 2200 well stock, just 58 were for surveillance (in 2017 the total number of interventions was 627). The numbers might not tell the whole story; surveillance using tools pre-installed in the well isn't counted because it's not an intervention or well access activity. Nevertheless, Michael Hannan, formerly of the OGA, points to knowing of three wells in the North Sea with permanently installed fiber optic monitoring technology (other monitoring technologies are available).

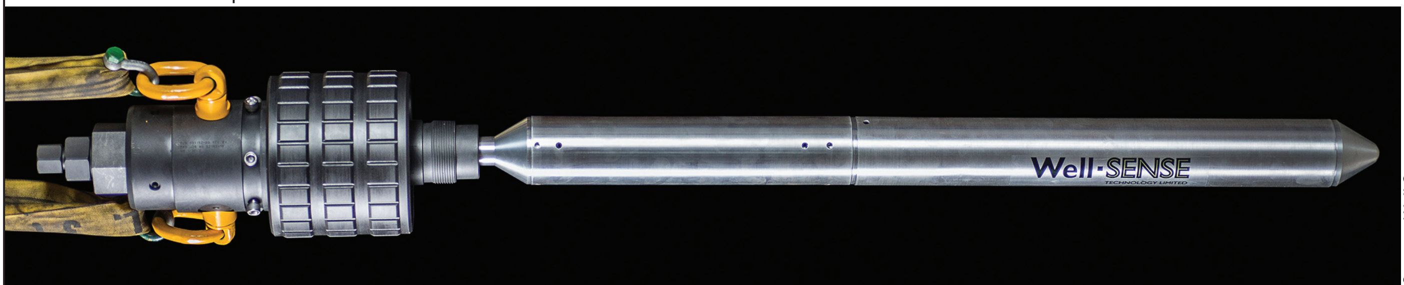
"We are in a really poor place," says Brown. "We have nearly 2,500 active wells and last year less than 60 in-well surveillance activities. Our perspective is that this feels wrong.

"If a well is fully instrumented, with electric submersible pumps and it's being tested every couple of weeks, zero is probably fine. But a lot of fields don't have that. It's about understanding the opportunity and moving forward. I'd expect 20% surveillance rates. Why would you not do that? It's low hanging fruit. We are scratching our heads. Why are we not doing more of this?"

The lack of surveillance is perhaps one of the reasons that the number of shut-in wells in 2018 remains exactly the same as in 2017 – at 30% of the total. No one is look-

Image above: Equinor has been using fiber optics on its Johan Sverdrup and is planning to use it on Martin Linge wells.

A Well-Sense FLI probe and launcher.



Source: Well-Sense

ing in these wells to see what can be done to restore them.

A part of the problem is incentives, says Simon Strombeg, subsurface manager at EnQuest. One metric that should be an incentive, production efficiency (PE), is actually disincentivising this work, he says. PE has been seen to improve, from 60% in 2012 to 74-75% in 2017-2018 (still short of an 80% target). But, "The production efficiency figure for the North Sea is not real," says Strombeg. "It's driven by a need for a metric. But, if I say we have 92% production efficiency, my CEO thinks I have 92% of what is available optimized and producing. In reality, that's not true. I think most people looking at capacity and putting production over it." Instead, he says is should be what proportion of the economic limit. "If it is, I can be honest about locked in potential," he says. "That means I've got opportunity I should be chasing. That means my manager should be interested in that locked in potential."

Strombeg has a "choke model" to look at this opportunity more positively. It looks at what's possible on the current status, what's possible with additional work and what's uneconomic with the current technology, based on current production, current capacity and the economic limit, across the production stream, from the reservoir to wells to gathering systems and so on. "It all starts with surveillance," he says, as this drives everything, but surveillance is then needed across every piece of the production chain.

"The OGA should rethink the PE benchmark so it becomes a tool to drive investment, not a tool for managing directors to shoot against so they can meet stewardship targets," Strombeg says. Other incentives would also be helpful, as would collaborating across fields to scale up operations, and simplifying assets which, built for fields producing 100,000 barrels of oil equivalent per day (boe/d) now support just 5,000.

Well-Sense

Operators are not short of technologies to try. Founded in the recent downturn, Aberdeen tech firm Well-Sense has developed FiberLine Intervention (FLI), a sacrificial fiber optic sensing technology for well surveillance. It's dropped into a well (at up to 60-degree deviation) and spools out fiber as it goes. Once at the foot of the well the fiber then detects various things – i.e. sound (distributed acoustic sensing/DAS) and temperature (distributed temperature sensing/DTS), depending what's wanted – and that data is transmitted to surface in real time.

Multiple fibers can be spooled out at the same time for different data gathering purposes, such as pressure and temperature, casing collar location, etc. When the operation is done, the system is allowed to remain downhole where it disintegrates.

The first round of offshore deployments of the technology were undertaken in 2019 performing DTS and DAS operations. The latest generation offers hold up and resistivity measurements, says Well-Sense's Craig Feherty. These data can be used to detect leaks, do injection profiling, gas lift diagnostics, vertical seismic and microseismic, and directional survey, so they know what direction the tool has gone for depth correlation. To add to confidence of tool depth, it also has an optical domain reflectometer on it, which is also sacrificial.

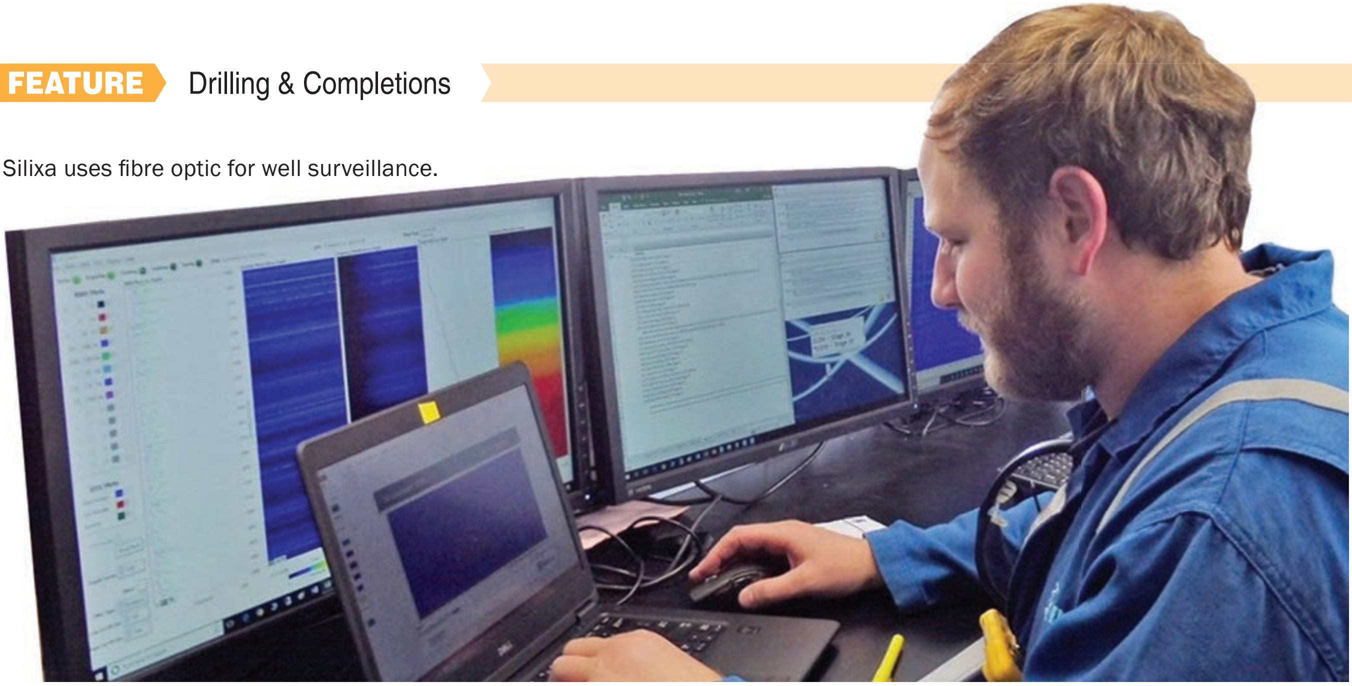
Well-Sense's on- and offshore track record now covers detecting leaks in the North Sea and Malaysia, injection profiling and gas lift diagnostics in Malaysia and vertical seismic in the US.

"The amazing thing about distributed measurement is the sensitivity they are able to pick up," says Feherty. "More important, you are able to look real time across the whole length (of the fiber in the well). Wireline is lengthy (to do) and you have to get to the right point at the right time. With distributed measurement, we are looking at everything at the right time, in real-time and that's powerful, being able to do surveys quickly and identify where issues are."

Silixa

Silixa makes fiber optic sensing systems for permanent downhole installations and for cable interventions by wireline or slickline. Combining DAS and DTS can be power-

Silixa uses fibre optic for well surveillance.

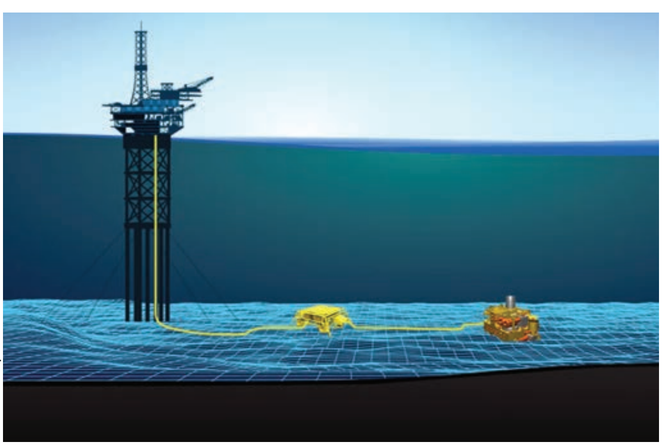


Source: Silixa

ful, enabling quantifiable data, says Silixa's Vero Mahue. Fiber can be used for wellbore leak detection, production and injection profiling and for seismic data acquisition she says, alongside other downhole measurement applications. Silixa's Carina system, using engineered Constellation fiber, is able to detect sound 20 decibels (dB) below DAS based on standard fibers, making it sensitive to even small leaks in a wellbore. By also measuring speed of sound with the fiber and applying Doppler-shift analysis, a flow velocity profile of the whole well can be derived, she says, offering quantifiable information, not just qualitative. By measuring speed of sound, it can also determine what's flowing through the well and gas/oil interfaces – liquid or gas (as sound travels faster through liquid than gas).

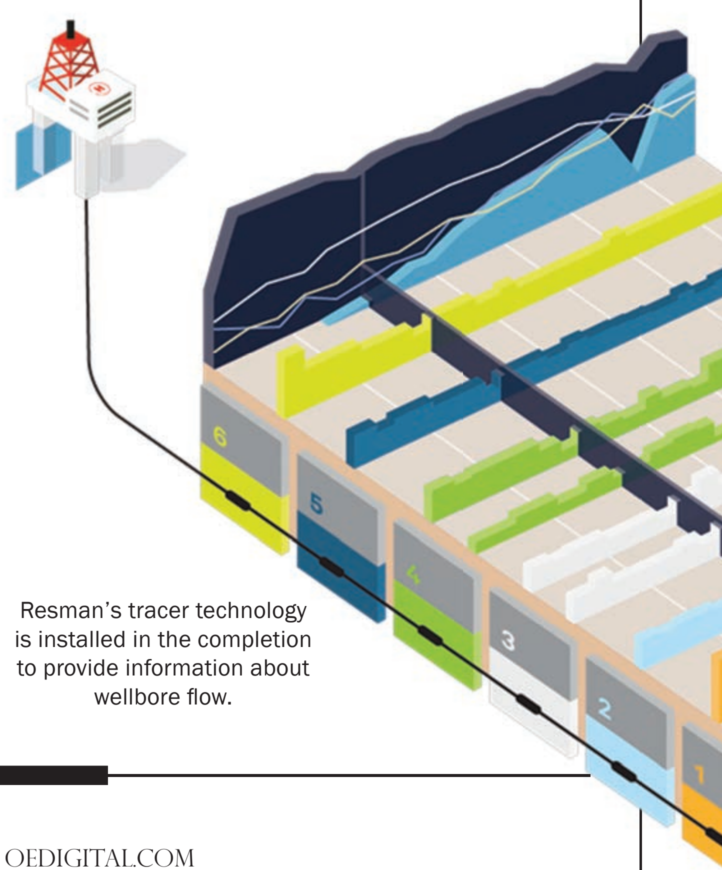
OptaSense

OptaSense, a QinetiQ company, has been deploying fiber optic DAS technology to gather permanent flow, seismic and vertical seismic profile (VSP) data for clients. It's cheaper than using ocean bottom nodes (OBN) as well as offering a permanent broadband sensor downhole for time-lapse surveys with which you can measure other processes in the well, such as the impact of water floods, gas lift or inflow control valves, says J.Andres Chavarria, from OptaSense. "The beauty of fiber is you get to see the entire dynamic across the entire well," he says. "Fiber is sensitive to acoustics and temperature; DAS is very accurate with fine spatial resolution. When you couple that to flow velocity measurements for each injection point, we start to build a model of how reservoir production is im-



Source: OptaSense

OptaSense has been deploying fiber optic DAS tech to gather permanent flow, seismic and vertical seismic profile (VSP) data.



Resman's tracer technology is installed in the completion to provide information about wellbore flow.

pacted depending on the completion design."

It can even detect a small magnitude earthquake, which could be useful if an operator needs to show it didn't come from their field.

Chavarria says the technology has been used offshore including wells with 1-kilometer (km) water depth in the US Gulf of Mexico to test completion zones and verify a production model, by building production profiles across the entire reservoir with different zones flowing.

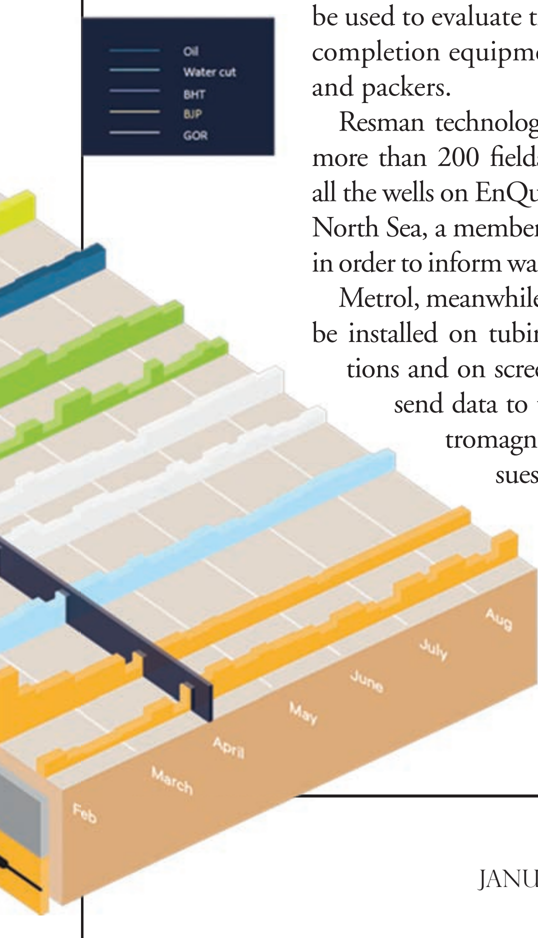
"The next frontier is subsea wells," he says. "How far can you reach with these systems, through a long umbilical?" The significance of this is the challenge of maintaining the integrity of the data flowing through the fiber as it goes through various connectors, including wetmate connections, before reaching an interrogation box. OptaSense has acquired seismic data for this setup using a 25km umbilical, with a 5km-long active section in the well and 30,000 channels simultaneously.

Resman Tracers

Norway's Resman developed a tracer technology that's installed in the completion. When production fluids are sampled, the operator will know exactly where down the well it comes from. They are designed to release when in contact with specific fluids, such as water, to identify the location within a well where a water breakthrough event happens, says Edurne Elguezabal. Their detection can also be used to evaluate the integrity of the well completion equipment, like valves, sleeves and packers.

Resman technology has been installed in more than 200 fields worldwide, including all the wells on EnQuest's Kraken field in the North Sea, a member of the audience noted, in order to inform water injection operations.

Metrol, meanwhile, offers sensors that can be installed on tubing, outside of completions and on screens that wirelessly then send data to the wellhead with electromagnetic signals, avoiding issues with wet mate connectors, during drilling operations providing localized data across sections that's otherwise hard to get.



Source: Jan Arne Wold, Woldcam / Equinor

Richard Tøndel, from energy firm Equinor, says the company has more than 50 wells with permanent deployed fiber optic systems. These are all above the production packer, not in the production zone and are mostly used for transmitting data from downhole sensors. Newer installations, will have fiber systems that enable both data transfer and distributed sensing, he says. This includes, eight wells on the giant Johan Sverdrup field, which came onstream in October 2019, again, down to the production packer. However, that's also changing.

"During 2020, we hope to install our first fiber cable in the reservoir section (at Johan Sverdrup), and we aim for fiber optic installations in subsea wells from 2022," says Tøndel. From 2020, some wells on Martin Linge will also have fiber for monitoring and data.

"We believe fiber optics can be used to improve the well integrity monitoring, as well as increase your knowledge about how production and injection happens in the well," says Tøndel. "The value is compelling. Observations can be made when something happens in the well, in adjacent wells or even from long distances. When you close and open a valve, you can hear it. Permanent fiber optic installations will give you an ability to acquire data without disturbing production. You get higher repeatability and a possibility to observe more subtle changes." Equinor has been testing DTS and DAS since 2010, Tøndel says. In the last two years, Equinor has also been experimenting with real-time DAS continuously in a well, to learn how to do real time data transfer and analysis and visualization. One of the main challenges is handling the potential huge amount of data and how to move, organize and process this. Equinor is currently developing a system on Johan Sverdrup based on open source technology, says Tøndel. Equinor also plans to integrate use of the downhole fiber optic cables with the permanent reservoir monitoring system that is being installed on the field, by listening in on the planned seismic acquisitions that take place every year.

FPSOs: The New

Source: Teekay Offshore

Business Models

BY WILLIAM STOICHEVSKI

As New Year 2020 unfolds, there are 21 floating production, storage and offloading units (FPSO) on order, and unlike a year ago, these — and not floating liquefied natural gas (FLNG) — are the unheralded story. Driven by a decent price for oil, this buoyant market is kept strong by new players, new business models and the now solid realization that FPSOs can cost less than new, jacketed oilfield development. Most of all, nations are again asking industry to concentrate capital and rein in remote-area wealth.

The national oil companies (NOC) are back. In the World Energy Reports Forecast of Floating Production Systems, an industry authority, China's and Brazil's floaters figure prominently. The new year dawned with pronouncements in Rio (and in Beijing and other capitals).

"Petrobras announced a plan for 13 new FPSOs to enter service over the next five years, and said 13 aging floating production units will be retired over the same period," says the WER forecast's author, Jim McCaul. Long an industry consultant, he confirms that a Chinese group has also brought floating production finance to El Salvador in December and to Cyprus for 2020.

CNOOC, in fact, is placing three of its own floaters – the Hai Yang Shi You FPSO, a floating storage and offloading unit (FSO) of the same name and the Ligshui 17/2 semi-submersible – between 2020 and 2021. Lingshui 17-2 represents a NOC bringing technology to the fore, and letting it inspire a new business model for the South China Sea. Its newly procured riser pull-in system from Cargotech denotes the use of a semi-sub in typhoon-prone deepwater (up to 1,560 meters). "The Lingshui 17-2 gas field is CNOOC's first own R&D deepwater project," MacGregor VP of Offshore Solutions, Hoeye Hoeyesen affirms. The pull-in systems will clear the way for CNOOC (and partners Shell and Husky) to tap the northern part of Qiongdongnan Basin on the western continental shelf of the northern South China Sea.

CNOOC wasn't the only "BRIC" champion letting technology inspire a business model. Petrobras, the forecast confirms, will use its own new Hi-Sep technology to lower the gas-to-oil ratio in the production riser of the Mero 3 FPSO. The who's who of FPSO contractors – Bluewater, MISC, Modec, SBM, Teekay and Yinson – were made aware that Petrobras wanted to use its own new technology on the project in a first for NOCs.

NOCs' tech

As with CNOOC at Lingshui, the Petrobras plan is also to separate-out liquids from gas: Mero 3 is a former very large crude carrier (VLCC) that'll produce up to 180,000 barrels of oil per day of oil (bpd); 420 million cubic feet per day of gas (MMscfd) and 250,000 bpd of water for injection. As WER reports, Petrobras intends to install four large FPSOs on Mero this decade.

CNOOC is also partner at Mero and now Petrobras is reportedly considering a floating gas hub "to collect and export (associate) gas to shore", much like Lingshui. In all, Petrobras says it is spending $84 billion to 2023, including $68.8 billion on exploration and production. The Mero FPSOs are part of it.

The life-extended SBM Offshore FPSO, Liza Destiny.

McCaul says that 2020 will see a lot of FPSO activity, but South America – including Guayana, where ExxonMobil's procurement kickoff for a fourth big FPSO is due – will see the lion's share of contracting activity. "Most activity will be in Brazil where Petrobras is likely to initiate five large FPSO procurements over the next 12 to 18 months. Equinor will also likely initiate its Carcara project."

While Australia saw 2019's most complex floater launch (FLNG Prelude), McCaul says the Carcara FPSO seems to have the biggest complexity of contracts expected to be seen in 2020, at least in terms of near-term planning stages. "There's nothing coming up that's like the Prelude FLNG contract," he adds.

Equinor paid $379 million for 10% more of Carcara's BM-S-8 block in Brazil's Santos basin, a plot it had owned as operator in mid-2018. Equinor and partners ExxonMobil and Galp need as much as of the Carcara area's Block BM-S-8 and Carcará North as possible for the FPSO project to begin reining in the 2 billion boe said to be in-place. First oil is slotted for 2023/2024.

Source: SBM Offshore

"We consider West Africa — where numerous offshore oil and gas fields have been discovered in recent years — as one of our most important core regions, and this contract award should geographically reinforce our business portfolio…"

Tech alliances

On January 10, 2020, as we compiled this report, Tokyo-based FPSO-enabler, Modec, was announcing a building and technology alliance that will bring about Senegal's first-ever FPSO.

NOC Petrosen (the Senegal National Oil Company) will join a partnership that includes Woodside's African business, but it'll be Modec supplying the FPSO for the Sangomar Field Development Phase 1 in the deepwater off Senegal.

"A FEED and an Asian yard" – once a criticism – is today a successful business model, with Modec awarded the front-end engineering design contract for the FPSO and now the FPSO purchase contract in the final investment decision (FID) for Sangomar. The FPSO will deploy 100 kilometers (km) south of Dakar, and is expected to be the country's first offshore oil development. Scheduled for delivery in early 2023, the vessel will be moored in about 780 meters of water by an external turret mooring system supplied by Sofec, a Modec business. The FPSO will be capable of processing 100,000 bpd, 130 MMscfd of gas and 145,000 barrels of water injection per day, as well as storage for 1,300,000 barrels of crude.

"We consider West Africa – where numerous offshore oil and gas fields have been discovered in recent years – as one of our most important core regions, and this contract award should geographically reinforce our business portfolio," Modec chief exec, Yuji Kozai, is quoted as saying. Modec has now operated three FPSOs in Ghana and Côte d'Ivoire and has supplied seven other floaters to Angola, Cameroon, Equatorial Guinea, Gabon and Nigeria.

Ultra-deep model

Sangomar is a nice recovery for Modec after a Mexican EPCI project saw the company write-down $73 million. "They got burned on their FPSO contract in Mexico," notes McCaul, adding that other contractors could be hard-pressed to manage contract execution under local-content strictures.

Year 2019 started slowly for Modec, but in the final three months, its four-company, ultra-deepwater technology pact was being exported again en masse, this time to Brazil. A $36.5 million loss in September was eclipsed by year-end by full-year revenues of $2 billion. A deepwater business model was emerging based on "the four companies" – Modec, Mitsui & Co., MOL and Marubeni Corp. – purchasing and chartering FPSOs for named fields. By November 2019, new orders worth over $3 billion – as much as all its previous new orders of the past four years combined – had accrued. Finally, too, construction milestone payments were helping out.

Then, in November, the heads of the four companies agreed that the first three would invest in long-term FPSO

Kindred spirits:
Representatives of Barra Energia (left) and Equinor penning a Santos Basin farm-in deal to pave the way for the Carcara FPSO.
Source: Equinor

A way forward:
SBM Offshore's versatile FAST4Ward hull design.
Source: SBM Offshore

chartering just like Modec was already doing for the Buzios field off Brazil.

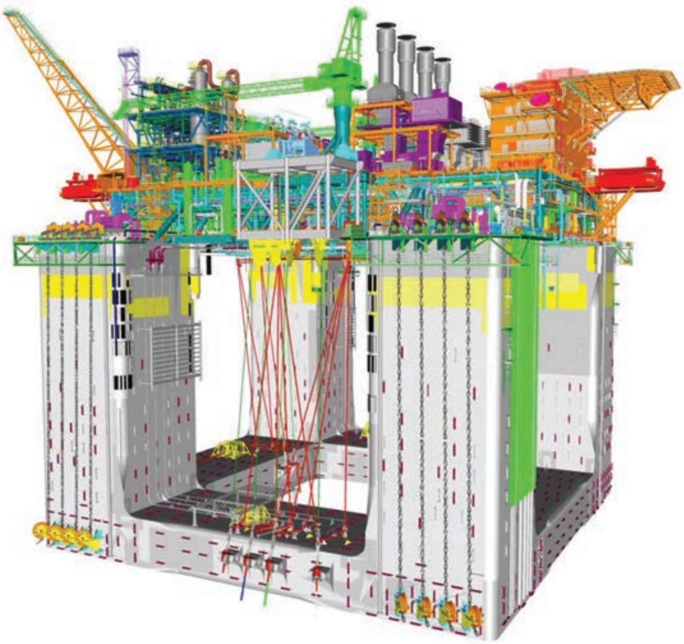
"The Norwegian model"

Tighter still, Mitsui, MOL and Marubeni are to invest in Buzios5 MV32, a Dutch company established by Modec. MV32 has entered into a 21-year charter agreement with Petrobras for the deployment of another FPSO. The deal mimics, to some extent, the convoluted pattern of Norwegian floater ownership, where a rig is the physical expression of a business entity named after it and absorbing all its risk.

The new-model, four-company FPSO will be named FPSO Almirante Barroso MV32 and will be deployed at the Búzios field in the giant pre-salt part of the Santos Basin, 180 km from Rio de Janeiro off the southeast coast of Brazil. The FPSO will be moored in 1,900 meters of water by year-end 2022. It's the seventh time the four companies have collaborated to operate an FPSO in Brazil, but their chartering business now seems more focused and less risky.

FPSO Almirante Barroso will have enough capacity to produce 150,000 bpd from its relatively safe location in the South Atlantic's doldrums. It will have gas production capacity of 212 MMscfd and storage of 1.4 million barrels to round out the project.

NOC variant:
CNOOC's semisub Lingzhou. Source: Cargotech



Revitalization or life-extension

Modec has also been contracted for the Petrobras Marlim revitalization project, part of that 13-FPSO Brazilian renewal McCaul identifies

FPSO revitalization or renewal is code for field-development or life-extension. This new business model for Petrobras is in-line with what's happening elsewhere, including the North Sea, where re-appraising an FPSO for longer life – via tieback or connection to jacketed infrastructure – makes for speedier, less expensive field development.

Brazil's renewal, however, involves new FPSOs, and these are helping vindicate the market's new business models, including SBM Offshore's Fast4Ward hull program. SBM has historically kept yards in Singapore and the Middle East busy building hulls and production turrets. But Fast4Ward is a new business strategy. While you see it in the Japanese four-company model, SBM has been doing it awhile. Now, Chinese Shanghai Waigaoqiao Shipbuilding and Offshore and China Merchants Industry Holdings have started building SBM Offshore's first three hulls earmarked for fields.

Those hulls highlight, too, the FPSO company, or per-vessel JV entity. In mid-December, SBM shed 35% of its shares in the FPSO Sepetiba to make room for Mitsubishi Corp. and Nippon Kavushiki Kaisha. "Special purpose companies related to the lease and operation of FPSO Sepetiba" means all parties will occasionally visit Amsterdam.

In this way, however, Petrobras gets another Mero field FPSO, with MC, NYK and SBM Offshore along in low-risk companies. FPSO Sepetiba is due out in 2022.

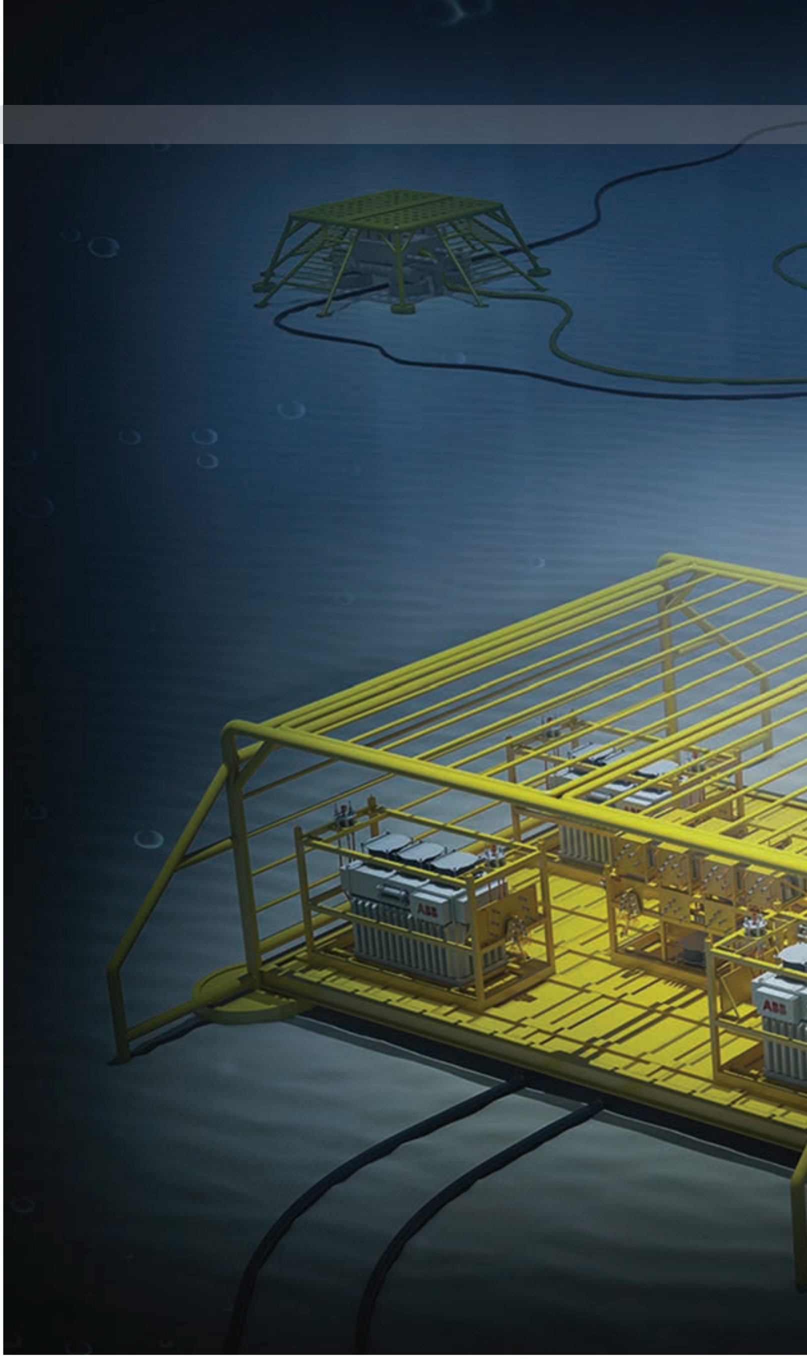
New players

And there may be new players. "What makes the coming year unique is the question of whether the primary FPSO contractors will have the interest to bid realistically for these contracts, given their current backlog," says McCaul. That could mean more write-downs, new business models and the spreading of more risk.

Teekay Offshore, for one, is outwardly wanting to sell FPSOs while building shuttle tankers and upgrading its FPSO fleet. When we check in, Teekay is hiring nine new staff – in Trondheim – where it'll also be bringing in Canadian white-collar people.

Chris Brett, Teekay Offshore Production president, tells ***Offshore Engineer***, "Teekay Offshore is strengthening the organization with key FPSO core competence roles to deliver on our future strategy and ambition." He says the Canadians will help the company "operate on a standalone basis". So, another FPSO business model might yet emerge out of Norway.

POWERING the Seabed



In November 2019 ABB announced the commercial availability of its new subsea power distribution and conversion technology system. Jointly developed with Equinor, Chevron and Total, the tech aims to see the majority of the world's offshore hydrocarbon resources harvested via the use of subsea electrification.

BY TOM MULLIGAN

Environmental regulatory pressures and market realities have conspired to help offshore oil and gas operators conceive a clearer vision for a safer, more energy-efficient, cost-effective and environmentally benign future, both for its mature basins and new, remote, deep water frontiers alike.

To help the industry achieve these goals, ABB, in a $100 million research, design and development joint industry project (JIP) initiated in 2013 with partners Equinor, Chevron and Total, has designed, developed and tested a new subsea medium-voltage power distribution and conversion system that enables all production operations to be moved to the seabed, making a critical last step to realizing the dream of a true subsea facility.

In November 2019 ABB announced the commercial availability of the new subsea power system having completed a 3,000-hour shallow-water test at a sheltered harbor in Vaasa, Finland, that it says demonstrated the validity of the technology. This means that the majority of the world's offshore hydrocarbon resources can be harvested through the use of subsea electrification.

SUBSEA VS. TOPSIDE

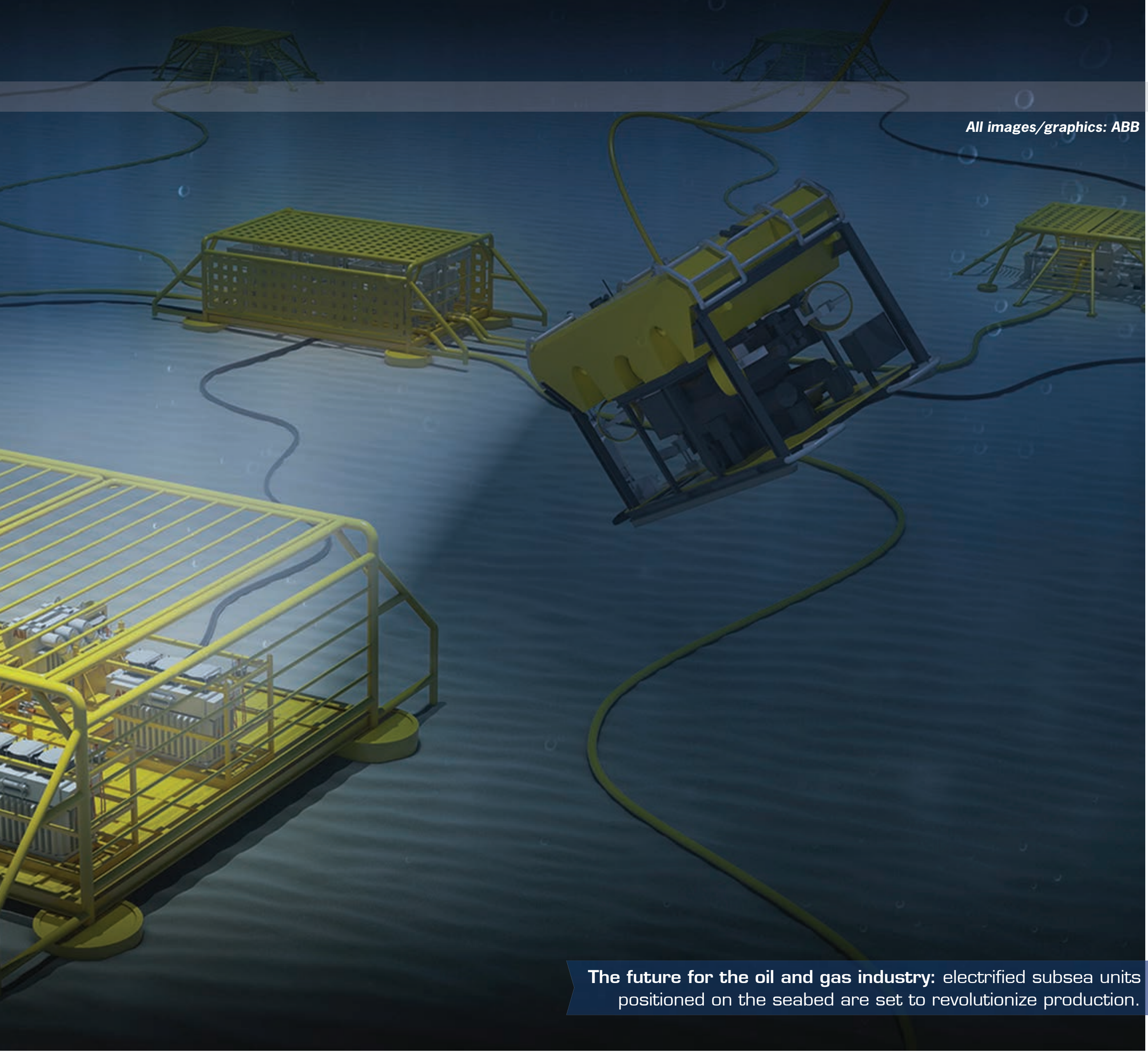
Conventional topside offshore hydrocarbon production systems are typically housed on large, manned floating or fixed structures that are expensive to operate and where space for housing power and control equipment is often constrained.

In addition, costly dedicated power and electro-hydraulic umbilical cables are required for each power user on the seabed, creating a topology that is expensive, hard to adapt to new configurations, and restricted in its ability to support digitalization initiatives due to limited bandwidth.

Most of today's structures use gas turbines for local power generation, with consequent emissions impacting the environment. Other disadvantages are the exposure of humans to risk and the requirement for constant maintenance and logistics support in addition to the costs of building and operating these energy-inefficient units.

To overcome these problems, over the years oil and gas

All images/graphics: ABB



The future for the oil and gas industry: electrified subsea units positioned on the seabed are set to revolutionize production.

companies have attempted to install production infrastructure on the seabed in order to benefit from greater production efficiency and greatly reduced environmental impact. However, early subsea power distribution systems suffered from the drawback of limited tie-back distances, which were restricted to less than 150 kilometers (km).

In contrast, the results of the JIP between ABB and its partners show that, for the first time worldwide, energy companies will be able to access a reliable supply of up to 100 megawatts of power over distances of up to 600 km and down to depths of 3,000 meters, where ambient pressures are in excess of 300 atmospheres. Power can be supplied through a single cable that can be used for up to 30 years, thereby making oil and gas production in distant and deep ocean environments a reality.

"This milestone marks an outstanding achievement and is the culmination point of an inspirational technology development achieved through tremendous dedication, expertise and perseverance. It is the result of intensive collaboration by over 200 scientists from ABB, Equinor, Total and Chevron in a multi-year joint effort," said Dr. Peter Terwiesch, President of the Industrial Automation business of ABB.

ELECTRIFICATION OF SUBSEA COMPONENTS

The research and development work undertaken in the JIP has resulted in subsea components and systems from actuators to pumps and compressors increasingly being electrified, thereby helping to increase system availability and control and reduce component size, cost and energy intensity, as well as remove personnel from a high-risk environment through the use of remote and unmanned operations. ABB says that by introducing technology that can distribute subsea power over long distances and down to great depths to reach subsea production systems, the full possibilities of this technology can be realized and adds that, based on a specific development case, the new system could offer capital expenditure savings of more than $500 million by linking eight power-consuming units such as pumps and compressors through a single cable over a distance of 200 km from other infrastructure.

In addition, the supply of power to such units on the seabed can significantly reduce power consumption, resulting in substantial energy savings and much lower carbon emissions compared with using shore-based systems. The technology can be driven by any power source, including wind and hydro power. A further benefit of the subsea technology is reduced operational risk and increased safety, as fewer offshore staff are required for operations and the benefits of digitalization and autonomy can be exploited.

"Moving the entire oil and gas production facility to the seabed is no longer a dream," said Dr. Terwiesch. "Remotely operated, increasingly autonomous subsea facilities powered by lower-carbon energy are more likely to become a reality as we transition towards a new energy future."

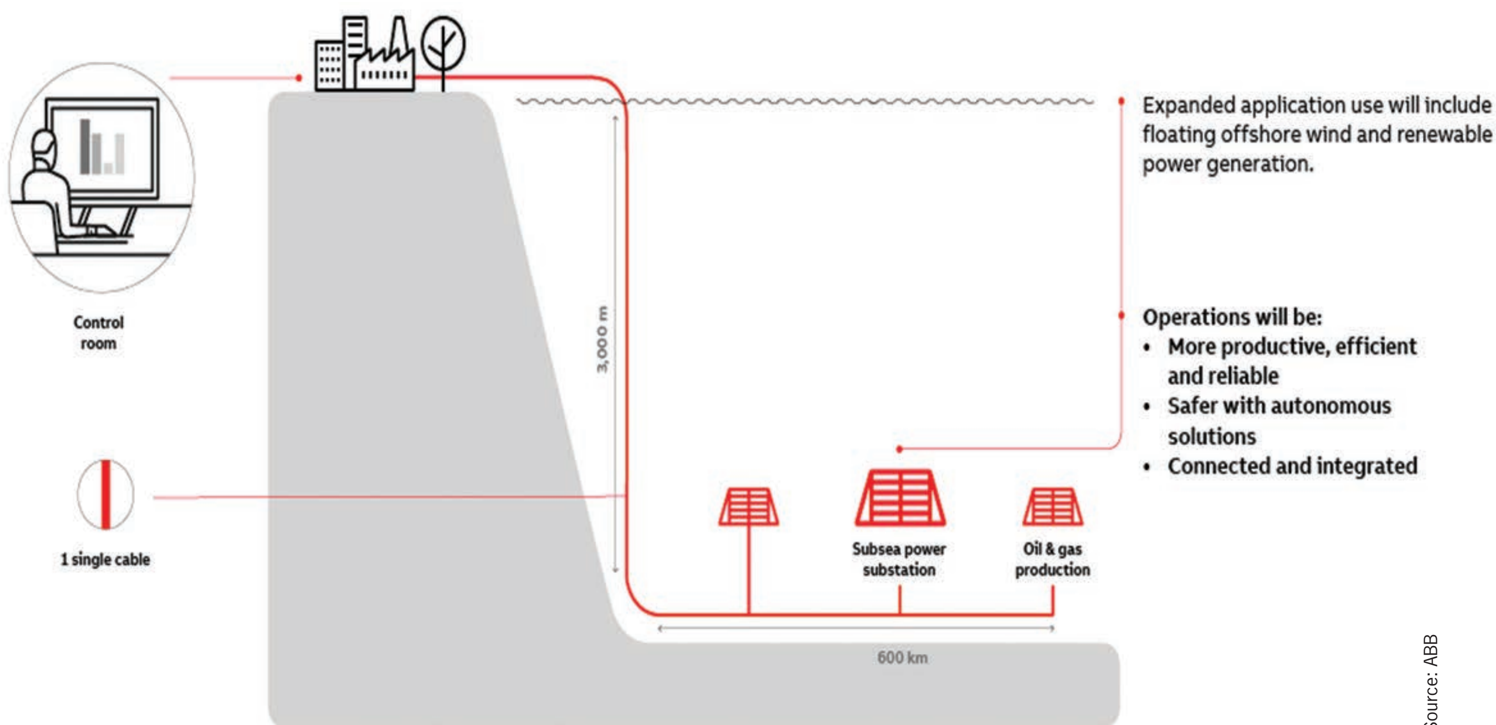
VIABLE TECH, COMMERCIAL POTENTIAL

Prior to the JIP and the 3,000-hour shallow-water test at Vaasa, only the transmission cable and subsea step-down transformer were proven to operate underwater. However, following the completion of the JIP, ABB's subsea power distribution and conversion system now comprises a step-down transformer, medium-voltage variable speed drives (VSD), medium-voltage (MV) switchgear, control and low-voltage (LV) power distribution, and power electronics and control systems supported with 230/400 V.

The expertise behind each of the component parts of the subsea power distribution and conversion system were drawn from various ABB facilities around the world.

"Our success in reaching this stage is a testament to the deep domain experience of our teams, with a passion and dedication to delivering a game-changer for the industry," stated Kevin Kosisko, Senior Vice President and Head of Energy Industries at ABB. "Full subsea electrification has been a long-time coming. It's not easy, but we've done it. Oil and gas companies now have access to technology that will completely transform how they operate."

A critical area of focus during the JIP was ensuring that the system would be modular, flexible and open. It also needed to meet reliability and availability targets higher than those for topside applications. ABB decided that the project would deploy solutions largely based on existing technologies, to



Source: ABB

help ensure reliability, and that quality control and obsolescence strategies were well established from the outset. This approach also meant that integration with existing topside hardware systems and software would be straightforward and that all failures should be mitigated by design improvement or change rather than by adding simple 'ruggedizing' steps.

To ensure compact and reliable solutions, ABB enclosed the VSDs and MV switchgear in oil-filled, pressure-compensated tanks with each component iteratively honed in a stepwise approach, thus optimizing product assemblies and reducing the number of components and functions to ensure redundancy and high system reliability. In addition, to ensure that electronics and power components could operate in a pressure-tolerant environment and within a dielectric oil, component screening and selection, material compatibility, material interface aspects and thermal performance of components were set at optimum levels.

The electronics and control modules are flexible and modular in design to allow for different sizes to enable easy accommodation within the system. Communications and control are Ethernet-based for ease of interfacing with the rest of the subsea system and high-speed fiber-optic communications enables responsive remote operations.

REALISTIC TESTING

As the resulting power distribution and control system is made up from several hundred unique critical components operating under various stress conditions, a clear and pragmatic testing structure was put in place in order to learn the behaviors and limits of different designs, thus helping to mitigate the risk of failure before prequalifying for full-scale prototypes. Therefore, starting with simulation and

In 2017, ABB's variable speed drive underwent a 168-hour shallow-water test and met all of the performance criteria required to pass it. All other components of the ABB system were also proven to operate efficiently under water.

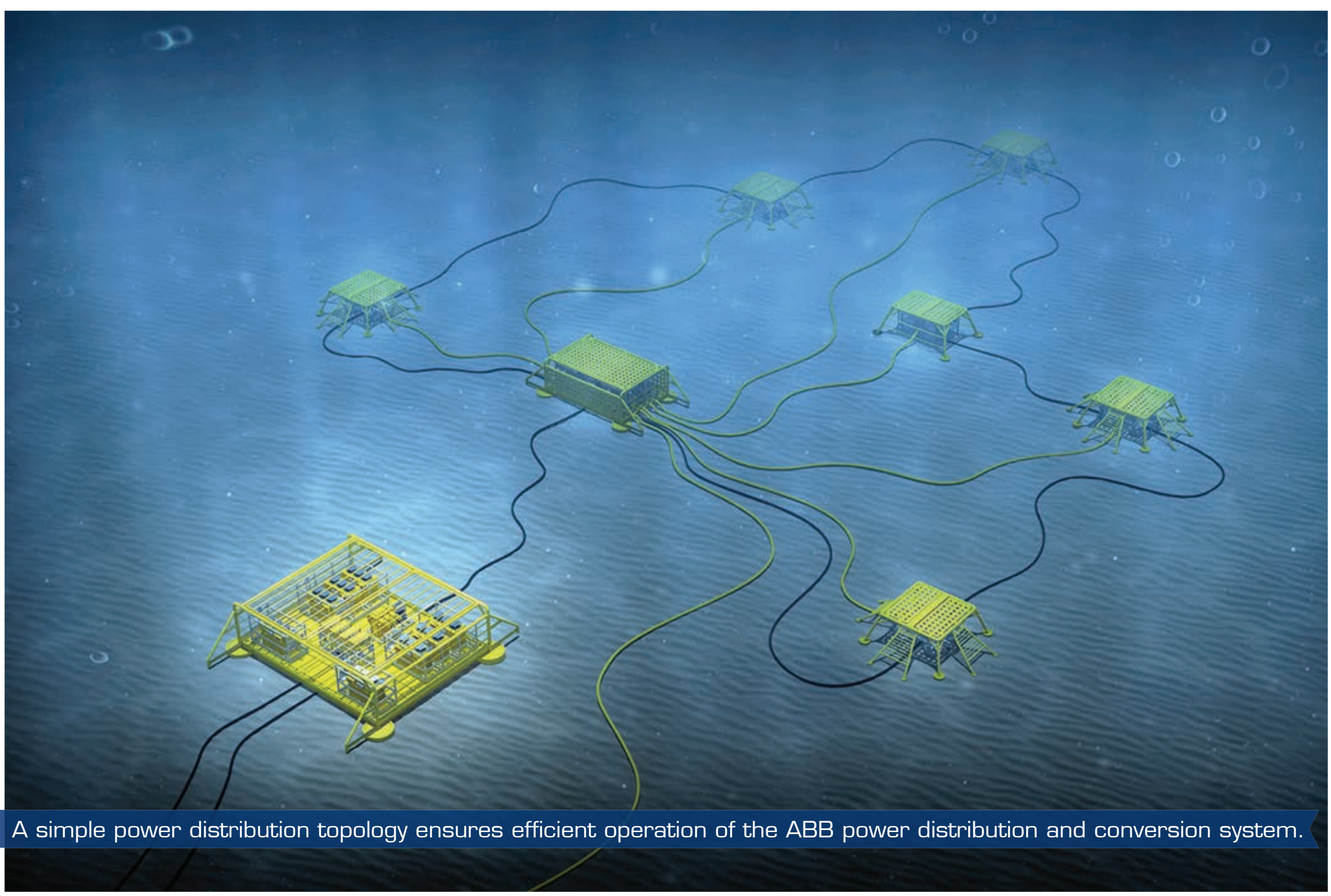
laboratory tests, materials, components, sub-assemblies and assemblies were subjected to realistic stress levels in accordance with lifecycle profiles before the final full-system 3,000-hour shallow water test was carried out.

All tests were carried out in accordance with API 17F Standard for Subsea Production Control Systems and included temperature, vibration, pressure and accelerated lifetime. The development f the project development followed the recommendations and technology readiness level (TRL) defined in DNV RP-A203, which provides a systematic approach to ensure that the technology functions reliably and within the specified limits.

BENEFITS TO INDUSTRY

The successful testing of the ABB system has a number of implications for the oil and gas sectors. The use of the system means that the operating lifespan of an existing facility can be extended through more cost-efficient tie-ins, requiring minimal topside modifications. In addition, future developments can be phased in and easily adapted through an inherently more flexible system topology. With full production systems installed subsea, long tiebacks no longer need multiple power cables or complex umbilicals and in addition, electrically powered solutions enable around-the-clock visibility of system performance. By using ABB Ability, the company's digital platform, more precise control and advanced remote analytics can be performed, these digital solutions delivering ABB's deep domain expertise from device to edge to cloud, thus benefiting oil and gas industry customers. Jeremy Cutler, Head of Total's Energy Research & Development Center in Stavanger, Norway, said

"This disruptive, transformative technology opens up unexplored areas, and the power of the collaboration, which started with a clear definition of the scope of the work and combined the best talents in a fresh design from the bottom up, resulted in a 'subsea factory' concept employing green power from shore to subsea maximizing the exploitation of potential subsea resources. Partnerships are not new in the oil and gas sector – we compete in many areas but we also collaborate – and in a big project like this the different parties can share the risk and share the rewards. An unmanned subsea factory facility provides many benefits, with clean offshore power, more efficient use of energy and reduced carbon emissions."



A simple power distribution topology ensures efficient operation of the ABB power distribution and conversion system.

Source: Olav Bruset

A road to residency

The last 12 months has seen a long-envisioned concept in field resident subsea finally make it mainstream. The idea now features in talks by chief technology officers at major industry events, instead of just being the focus of a smaller subsea side events. But will the road ahead be bumpy?

BY ELAINE MASLIN

Potential rivals. The Sabertooth and Freedom, on show at Tau.

While new subsea resident drone technologies are now being proven, demonstrated and the first contracts awarded, it's still far from clear what the actual commercial future will be.

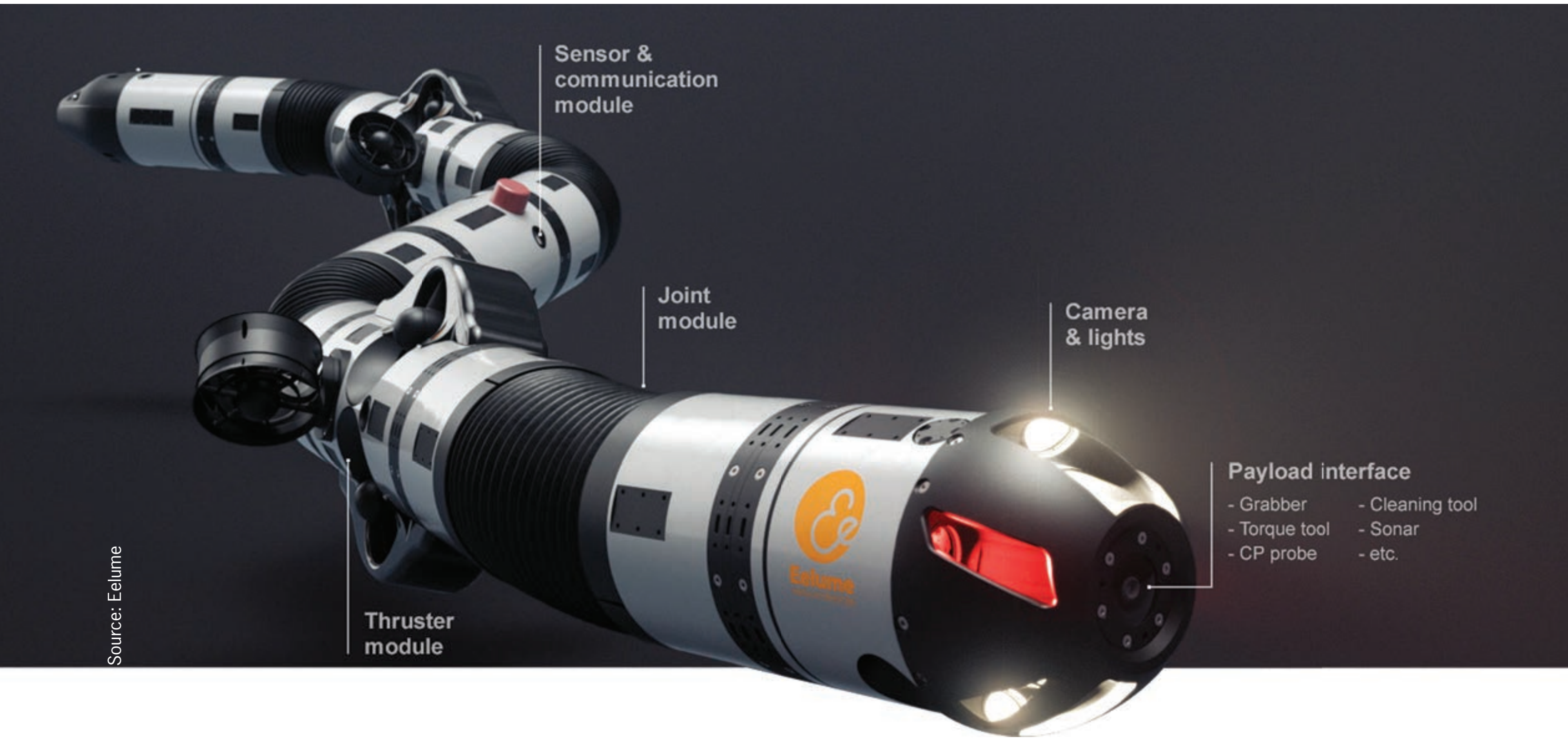
The idea is attractive; having subsea robots permanently based subsea, reducing the need for people and expensive vessels offshore and the emissions that involves. According to Oceaneering, yearly CO2 emissions of an remotely operated underwater vehicle (ROV) vessel are about 25,500 metric tons. Dropping off one of its E-ROVs on a temporary mission would cut that to 3,600 metric tons. Using a permanently deployed vehicle, such as its Freedom vehicle, would cut it to 500 metric tons. It's also perhaps inevitable as executives look across their businesses for opportunities to modernize and make efficiencies through digitalization, automation and remote operations. For Equinor, this is an enabler for subsea factories. For others, it's about time ROVs came into the 21st century. TechnipFMC CTO Justin Rounce, for example, told Offshore Europe that ROV technology hasn't changed in decades. It's time to start using technologies like computer vision in this arena, he says.

Steps have been made. Remote control of ROV systems is already being done. i-tech 7, a Subsea 7 company, has control centers in Norway and the UK, as do other companies including Fugro, Oceaneering and IKM Subsea.

Vendors have also made huge strides in developing new vehicle systems for what seems like a hungry market. Last year saw subsea electric robotics firm Saab Seaeye demonstrate its Sabertooth autonomous underwater vehicle (AUV) perform inductive charging and communication on Equinor's subsea docking station (SDS) – something the Norwegian operator hopes will help encourage take up of this technology, allowing vendors to focus on the vehicle development, if everyone agrees to use the same docking design (Equinor has been working with the Subsea Wireless Group, i.e. SWiG, and Deepstar, on wireless and mechanical standards for these).

Standardization could open up the possibility to provide an Uber AUV – or on-demand subsea robotics – service. Pål Atle Solheimsnes, Leading Advisor Subsea Intervention, Diving and Pipeline Repair, told Offshore Europe, "The plan with the UiD (underwater intervention drone) is that it should be an Uber service. We want to share with other licenses, 1, 2, 3, that service a whole area. We just have to first test them out and get the docking station in place and then we will offer that service. That's part of the big plan." Chevron's John Brian made a similar comment at the same event. "What about UiD Uber? Basin-wide, companies invest in resident robots that everyone can then pull up on their app and see which are available?"

So what has been done? There's lots of work going into



Source: Eelume

having robots for permanent subsea service. US subsea services and technology firm Oceaneering has been ploughing work into its Freedom vehicle, a scale version of which has been used for intensive software development in Norway and was then also demonstrated performing docking on the SDS, using acoustics, visual markers and machine vision, and the magnetic field of an inductive connector to home in to the docking plate. Offshore trials of a full-scale vehicle on a UK pipeline inspection project are expected this year before it goes into commercial operation. Meanwhile, Saipem, has been working hard on its HyDrone series of vehicles, one of which is set to be deployed at Equinor's Njord field under a commercial contract this year. Another firm, Subsea 7, has its autonomous inspection vehicle (AIV), which has performed a structured inspection of a subsea tree in "complete autonomous mode", having navigated there on its own.

Much – but not all – of this activity has been spurred on by Equinor, which paid for SDS to be built, with one installed at a test site off Trondheim, one due at the Åsgard field, to test a tethered version of another concept – Eelume, built by a Trondheim based company – and the third being used for testing by Saipem ahead of its deployment. The firm is understood to be looking at having seven on the Snorre expansion project in order to install resident drones. Rune Aase, VP at Equinor, told a drone demonstration event, organized by Stinger AS, a specialist subsea technology firm, in Norway last year, that other fields are being considered for UiDs, including Johan Sverdrup, Johan Castberg and Bay du Nord. "Then there are all the brownfields that should be supported by some drones and we need to look into how we're going to do that."

For this to happen, infrastructure needs to be in place – such as power networks, to recharge vehicles – and subsea equipment needs to be vehicle friendly. Looking ahead, to a world where different vendor vehicles can dock in different docking stations, how will how they connect into different data and control networks be managed? This is something Jan Christian Torvestad, from Equinor, has been considering.

"If I have a cell phone with Norwegian subscription I can still travel to America and use it, even if the service is provider not there – we have agreements. With a standardized docking station, I can get power, and communication and then a service provider making sure that if a drone docking on an Equinor docking station is connected to the correct control room," he says. "If it goes to a Shell docking station, will it still get the same control room? The service IT and architecture in the background needs to be considered. It's part of the puzzle. It could be an equivalent of a SIM card, proving who connects, and then a dynamic flow of data to where it needs to go; the cloud, control room, operator, etc."

Early days for drone docking automation, at the Tau demo event.

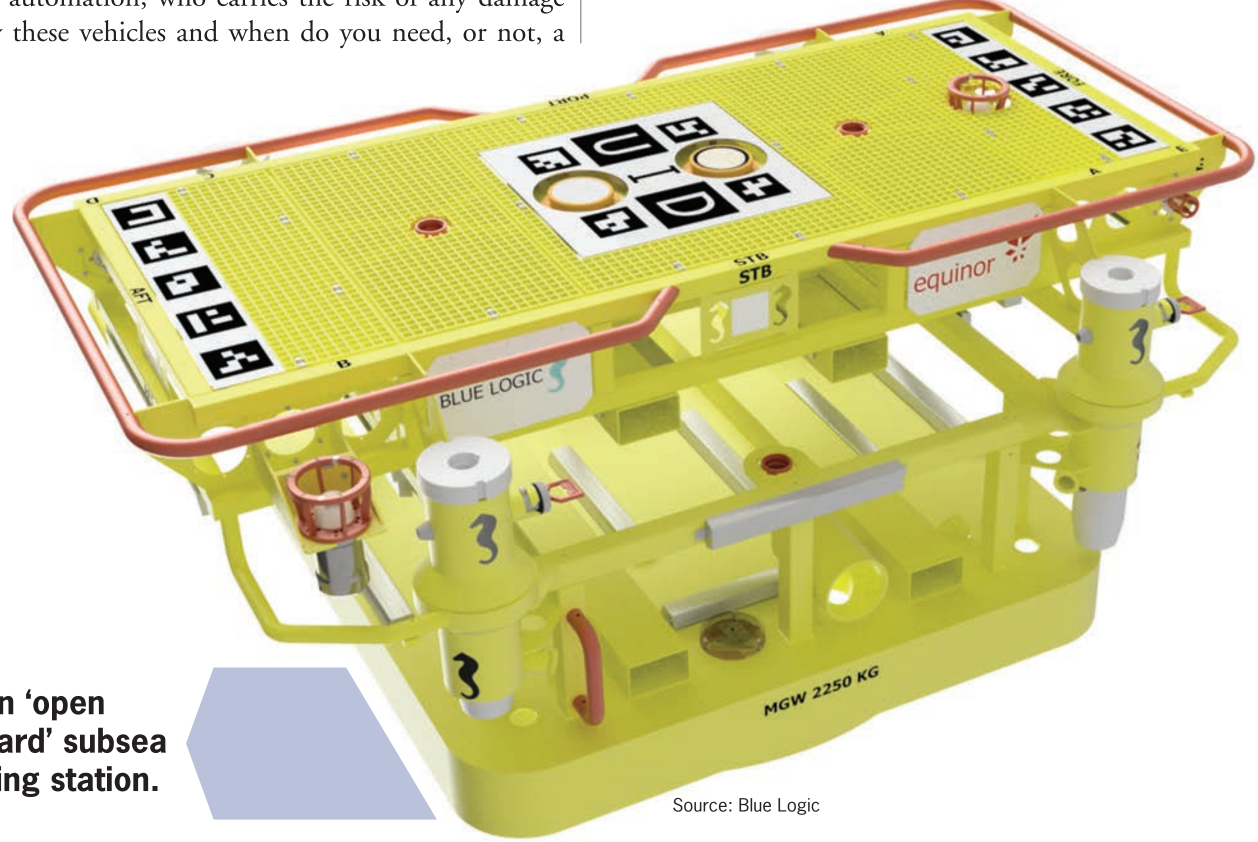
Source: Rolf Nygaard

How do you then prioritize bandwidth and ensure data security? How does this work commercially; there may even be fees for a vehicle to dock and charge at different docking stations, he suggests. Answer these questions and "then you can have the Uber AUV and high utilization because you can switch from one mission to another and between companies," says Torvestad. "Just imagine if we have sufficient number of operators one the NCS (using drones) where we get a critical mass and manage standardisation mechanically, electrically and in IT." That's assuming that everyone is happy to go along with the same standardised docking stations.

Even then, will the commercial models work? Success of this concept could result in some significant changes in how subsea operations are done. "We are on the edge of some really big changes in our industry," said Stephen Gray, CEO at UK based ROV services firm ROVOP, during Subsea UK's Underwater Robotics conference in Aberdeen. Gray suggests that the change will reflect a change that's already happened in other industries, such as telecommunications (think mobile phones and what happened to Nokia when Apple came out of nowhere).

Which leaves further questions. Jim Jamieson, Strategy and Technology, Development Manager i-Tech 7, commented at the Underwater Robotics event that, with increasing automation, who carries the risk of any damage done by these vehicles and when do you need, or not, a human in the loop? Steffan Lindsø, Director of Emerging Technology, Europe, at Oceaneering, told the same event, "It's not technology development that's lagging behind, it's the commercial development to exploit it. The struggle is finding commercial value." Some fields might not be dense enough for a resident system to make sense. But, when you look at maps of fields in an area there is density but the fields are run by many different operators, he says. "This would make a lot of sense if it was shared with everyone," he says. For inspecting dense offshore wind farm infrastructure, it could also make sense, he says. But, "mindsets needs to change on how to do things and cost drivers."

There are also other approaches that could be taken. While Rounce was keen to promote the advancement of subsea vehicles, his company has also been embedding robotics – or more specifically mechatronics – into subsea infrastructure. In August 2018, TechnipFMC, which took over manipulator and ROV manufacturer Schilling Robotics through its acquisition of FMC Technologies in 2017, installed a compact robotic manifold in Brazilian four slot water alternating gas manifold. A robotic arm was later installed. It can operate 30 valves (that would otherwise each need an actuator) and can do 30,000 cycles, says Rounce. The robotic arm was operated for four to five months with-



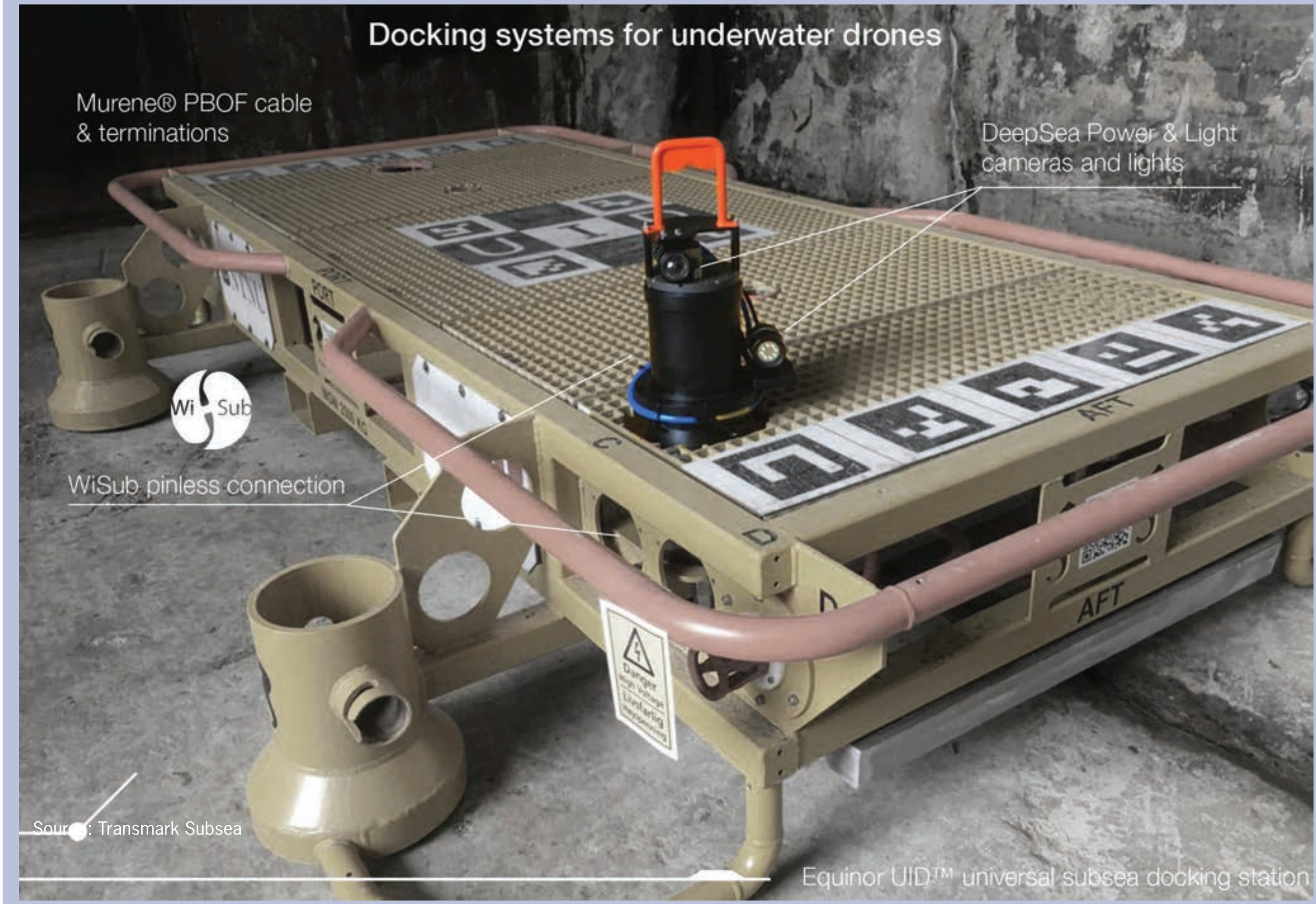
An 'open standard' subsea docking station.

Source: Blue Logic

out issue and was then retrieved to measure the impact of a long-term deployment in then subsea environment. It was due to be reinstalled later in 2019. A second manifold is also being installed. "I think we are only scratching the surface of opportunities in these areas," says Rounce.

That would open up another take on the resident robotics theme. Which concept – even amount the resident systems, vehicles and even docking stations – wins out is yet to be seen. While Equinor has promoted its vision, other operators have not been so vocal. The risk is that they come out with different requirements and that no single vehicle meets the requirements of a single operator. Which would limit the market. "It would be interesting to see in 10 years if anyone was right," says Lindsø. Indeed.

Making connections



Source: Transmark Subsea

Norway's **Transmark Subsea**, which bought Bergen based **WiSub** last year, developed the Torden 3kW pinless power and communication connector, with a flat transducer style, for use on resident vehicle or UiD docking stations. Its development, which includes some gap tolerance, was started under a joint industry project involving Equinor and resident vehicle manufacturers. 3kW is seen to meet the needs of resident vehicles, including when working with DCFO power systems (combined DC power, fibre optic communications cable systems Equinor has been looking at).

The firm also has Fonn system, a 250W system, and Maelstrom, at 1,000 W. Last year, prior to being acquired, WiSub and Transmark delivered product to **Equinor** for its docking stations. The company hopes to win the contract to build seven docking stations for the planned Snorre expansion project.

Thinking out of the box

Source: SMD

All electric systems are starting to free companies from the traditional strict form factors that ROVs traditionally take. With a more flexible modular harness, vehicles can be built from standardized building blocks.

Saab Seaeye has been making noises in this direction, using the smarts it's been developing for the Sabertooth for new electric vehicles.

Another firm looking to enter the resident vehicle space is **SMD**. Last year it launched its Quantum EV ROV. While the Quantum EV ROV made the headlines, what SMD launched was a technology suite, rather than a single ROV, based on an open-electric framework for whatever shape vehicle is required and that can be adapted for a variety of tethered or untethered operations.

Mark Collins, SMD's Director for Remote and Autonomous Technologies, said four years' work has gone into the design, which will be available as a product in 2020 – but will also to be used as a harness for other form factor systems, such as AUVs because of its modularity.

Key was going all-electric, using an in-house designed 25kW DC electric propulsion system, to make it more environmentally friendly but also more energy efficient, compared with hydraulically powered systems, says Collins. This includes a new thruster, based on an enclosed magnetic gear box with only two moving parts, and a new HV DC transmission system. That means smaller diameter umbilicals can be used and down to 6,000 meters, providing power to a 680-volt ring main DC system, that allows plug and play systems.

It's been designed to operate tethered or untethered with a battery as a resident system or deployed from manned or unmanned vessels. And, the design aims to allow easy build-in of future technologies, such as developments in artificial intelligence.

Collins says the EV will have 20% more thrust and 50% fewer moving parts, compared to hydraulic systems. It's also 20% more compact and 20% lighter, so it can be operated from smaller vessels. A hydraulic power unit has been developed for using hydraulic tools – until all-electric tooling is developed – using the new DC thruster motors and new hydraulic control units. When electric tools do come, they will be able to be stored on the vehicle in the space freed up by removing hydraulics, instead of having to add skids.

"The technology is a family of industrialized building blocks for subsea machines," says Collins. "These are scalable and can be brought together to form different machines. We created a Work Class ROV using the technology for the initial launch, but that is because it is familiar. We could have easily created a underwater intervention drone or another type of vehicle."

Subsea Supercharging

Source: Teledyne

Teledyne has developed a fuel cell-based "Subsea Supercharger" to provide remote power for subsea resident vehicles – or anything else that needs power on the seabed. The company has been making fuel cells for years, and while it can make many different types for the plethora of subsea vehicles out there, the company thought it would also be neat to have one that many vehicles can use, Dr. Thomas Valdez, Teledyne, Manager, Chemical Engineering, told a Society of Underwater Technology meeting in Aberdeen. "Most customers don't want a surface system, they want to put vehicle down and have a system it can go and charge at," said Valdez. These technologies – resident vehicles – are still fairly nascent, so Teledyne's looked at other applications, such as where subsea systems might need additional power – where there're brownfield needs for power for injection or boosting or issues around failed umbilicals, said Valdez.

Valdez is an electrochemist who's worked in space for last 25 years, on power systems like the radioisotope thermoelectric generator (RTG) that's on Mars Rovers. But, while RTGs work well in space, they require use of plutonium. So, for subsea, Teledyne's focused on a proton exchange membrane (PEM) fuel cell – a technology others have also developed for use with larger unmanned underwater vehicles.

In a PEM fuel cell, hydrogen and oxygen fed to a polymer membrane electrolyte, and platinum-based electrodes, to generate power with heat and water as a by-product. "The technology been around since the 1950s, but has been expensive so it's not taken off," says Valdez. "It's starting to happen with big systems, such as trains, but not personal transport." A variation of this technology is an ejector driven reactor (EDR) fuel cell. This has no moving parts, instead using a change in fuel cell pressure, during the power production process, to allow reactant circulation and water byproduct water removal. A subsea version able to provide 8 kWhr output comes enclosed in a pressure vessel with a water expulsion system – the only new component for subsea use – as it needs to work at 5 psig. The unit, which was last in Stavanger (where Teledyne hopes to find trials) weighs 1.2 ton and incorporates Teledyne wet mate connectors and a Teledyne Benthos acoustic modem. Valdez said the units, providing greater than 1 MWhr of power, within the size of a 20-foot ISO container, are hot swappable, for refueling up to 30 times each before they need to be rebuilt; instead of refueling them subsea, they can just be swapped out. The test unit has been through vibration testing, full failure mode and effects analysis, in -20 to 70 deg C, and simulated testing at 1,000 m at 1,500 psi. Teledyne's next step would be to qualify down to 1,000 and potentially 2,000 meters.

Break it Down

The decommissioning market is making a comeback, with new fields of opportunity, and challenges, opening. TSB Offshore President Will Speck shares insights on the path ahead.

BY JENNIFER PALLANICH

With the decommissioning market slowly recovering, TSB Offshore is looking to 2020 to be a year of growth and expansion for both the market and the company.

The decommissioning market is growing, but it's difficult for a number of reasons. Chief among those reasons is the fact that there is no revenue to the operator associated with removing aged equipment from an offshore field combined with decommissioning's role as the largest liability on an operator's balance sheet. Further complicating the issue is that inadequate details about an asset or well can lead to surprises during the decommissioning process, and those surprises usually increase the project's cost. Yet a third is evolving market needs, thanks partly to a variety of regulations in place in other parts of the world and partly to the industry's march into ever deeper water, which results in different types of infrastructure that must be decommissioned.

TSB Offshore, with headquarters in The Woodlands, Texas, sees these challenges as growth opportunities, and the company's new president, Will Speck, is enthusiastic about the potential to increase the company's operations around the world.

"Things are recovering slowly," says Speck, who's been with TSB Offshore for seven years. "The last couple of years we had a fairly steady market."

According to the US Bureau of Safety and Environmental Enforcement (BSEE), 137 structures were removed from the Gulf of Mexico Outer Continental Shelf (OCS) in 2018, while 79 were removed in 2019. Due to the aging of infrastructure in increasingly deeper waters, Speck expects deepwater decommissioning activity, along with related deepwater reefing, to rise in the coming years.

That will create a potential learning curve as the industry works out the best way to remove aged tension leg platforms (TLPs), compliant towers, and spars. Additionally, updated decommissioning regulations addressing the challenges of deepwater decommissioning activities will be required.

"Those are starting to be lined up for decommissioning, and we've only seen a handful removed so far," Speck says. "We will see innovations, new methodologies and technologies (for decommissioning) that we hope will drive costs down."

In a typical decommissioning scenario for a fixed platform, the topsides are removed to shore for re-use or recycling, while the substructure is severed 15 feet below the mudline

Source: G.P. Schmahl, the NOAA Flower Garden Banks National Marine Sanctuary

> "Deepwater reefing is coming into vogue"
>
> **Will Speck**
> *TSB Offshore President*

Source: Jennifer Pallanich

and taken to shore for recycling or refurbishment. In some cases, however, an operator can apply for part of the substructure to remain as an artificial reef through the National Artificial Reef Plan. Good candidate platforms are those that are complex, stable, durable and clean, according to BSEE, while those that have toppled due to structure failure are not.

"Deepwater reefing is coming into vogue," Speck adds, noting that leaving more of the structure behind during decommissioning activities creates more biohabitat that allows a larger variety of marine life to grow in the area.

INCREASING DEMAND

Decommissioning activities are also expected to increase along the US West Coast where that infrastructure is reaching the end of its service life. What complicates that market, Speck observes, is the difficulty in mobilizing vessels to the region to carry out the activity. Any vessel will likely come from Asia or the Gulf of Mexico via the Panama Canal. As a result, he says, it is possible multiple Pacific OCS operators might cooperate in sharing vessel assets to reduce the overall mobilization burden.

Elsewhere in the world, Malaysia is starting decommissioning activities and Thailand's decommissioning pace is picking up, he says. The level of activity offshore both Australia and Brazil are likely to be similar, he adds, although each has its own challenges. For instance, Australia's geography imposes logistics challenges almost akin to the US's West Coast, he says, because vessels often have to mobilize from the other side of the island or from Singapore. Brazil, on the other hand, is continuing to develop its decommissioning regulations, he says.

"As they streamline their processes, Brazil will be a market to watch," Speck says.

West Africa is another region where regulations are firming up, he adds.

"This is going to push the decommissioning planning, which is important," he says. He says some West African countries like Equatorial Guinea, Angola, Ghana and Gabon are starting to look at decommissioning from the outset of a new field's development. "That's an excellent improvement."

And a new decommissioning market is also opening up: offshore windfarms.

With the first generation of windfarms starting to age out, Jay Boudoin, TSB Offshore's director of client relations, believes the company will have to opportunity to participate in those decommissioning efforts as well.

LIABILITIES AND CHALLENGES

While it is necessary to decommission assets once they've reached the end of their useful life, Speck says, operators don't want to spend any more on the operation than necessary.

"Decommissioning is a zero-profit effort," Speck says. "The more money you spend, the more money you spend. You're not getting anything in return."

As Boudoin puts it, decommissioning is the operator's largest liability on the balance sheet.

"Having an accurate snapshot of that is very important" for the operators as well as their auditors, certified public attorneys and equity investors, Boudoin says.

One client wanted a full understanding of their decommissioning liabilities in the Gulf of Mexico, where there were more than 20 platforms, 60 pipelines and 200 wells.

"We reduced their total liability estimate by more than $150 million," Speck says.

One of TSB Offshore's roles is to help operators determine how much and when to spend on decommissioning and help potential asset buyers understand the decommissioning liabilities they may be taking on with the purchase.

But sometimes even after an asset is sold, decommissioning liabilities can "boomerang" back to a previous owner, Speck says. This can happen if an asset owner folds, in which case BSEE will work its way up the chain of title seeking a previous owner to take responsibility for a liability thought to be shed years before.

Speck cites a recent case where a pipeline was abandoned in place in the 1990s, but the area was recently identified as having desirable sediment resources. As a result, BSEE notified the former owner the pipeline must now be removed entirely.

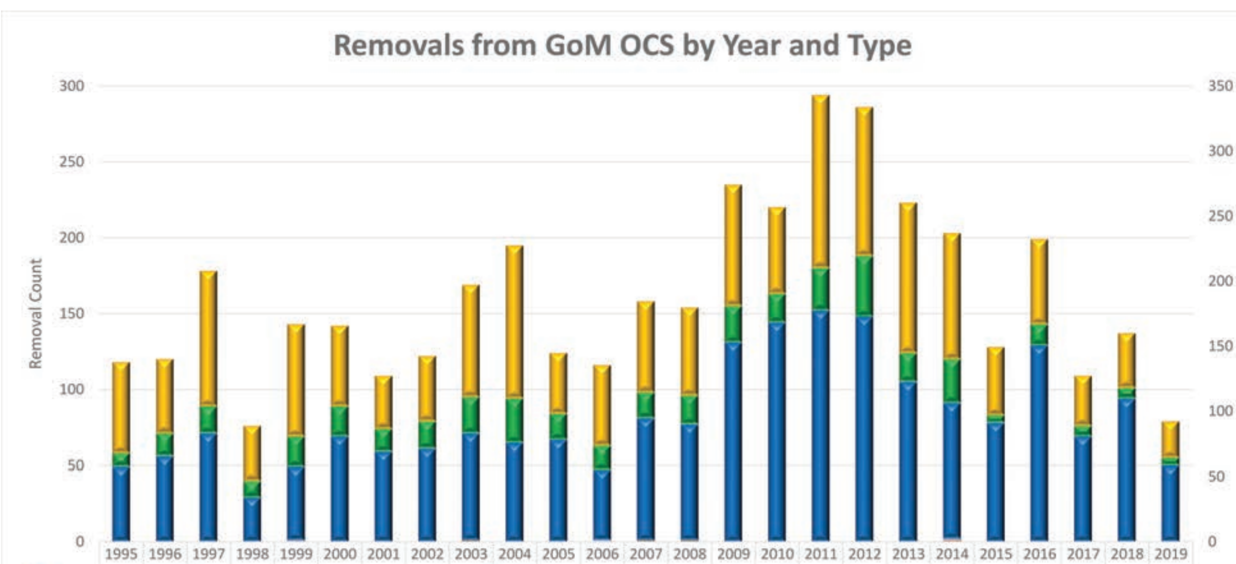
THE POWER OF GOOD DATA

"With decommissioning, there are a large number of unknowns," Speck says.

One of the best ways to minimize costs for decommissioning is minimize those unknowns by maintaining quality data about the assets. Over the years, he says, he's worked on projects where files have been inattentively kept or worse, misplaced or damaged in floods.

"The quality of the information will directly impact the efficiency of the operation," Speck says.

TSB Offshore relies on its Platform Abandonment Estimating System (PAES) software to perform fast, repeatable and detailed decommissioning cost estimates. PAES was developed more than 30 years ago so it has gone through



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WP	9	15	18	11	20	20	15	18	24	29	17	16	17	19	24	19	28	40	19	29	5	14	7	7	5
FIXED	49	56	71	29	48	69	59	61	70	65	67	46	80	76	131	144	152	148	105	89	78	129	69	94	50
CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
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SEMI	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0
SPAR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0
MOPU	0	0	0	0	0	0	0	0	1	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0
FPSO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	118	120	178	76	143	142	109	122	169	195	124	116	158	154	235	220	294	286	223	203	128	199	109	137	79

Source: Generated by TSB Offshore based on BSEE data many iterations and updates as the industry innovated into ever deeper waters. PAES helps with concept selection and assessing multiple removal scenarios.

"We have about 30 years of data and various methodologies," Boudoin says.

Being able to plan contingencies makes it possible to minimize cost escalations.

"Surprises are when the costs explode," Speck says.

He recalls one project where executing an abrasive cut on a piling took three times longer than expected because the wall thickness was much greater than records indicated.

"It was like the difference between a hollow Easter bunny and a solid one," Boudoin says.

Speck believes abrasive cutting will continue to expand as a choice technology instead of explosives. Diamond wire is becoming more efficient with smaller profiles, and it can be run via remotely operated vehicle (ROV) to remove portions of a structure.

On the cementing side, he says, resins are gaining acceptance for well plug and abandonments. In places where cement is setting, any slow gas bubbles will channel through that cement, which means there is no real barrier for pressure containment. But, he says, by topping the cement with resin, even if gas bubbles through the cement, the resin encapsulates the gas. The resin gives the cement time to cure.

"Resins can be a great option, especially for downers or bubblers."

Downers are structures or wells that were damaged due to age, impact or storm effects. Bubblers are abandoned wells that develop a containment leak, allowing gas to bubble from the abandoned well.

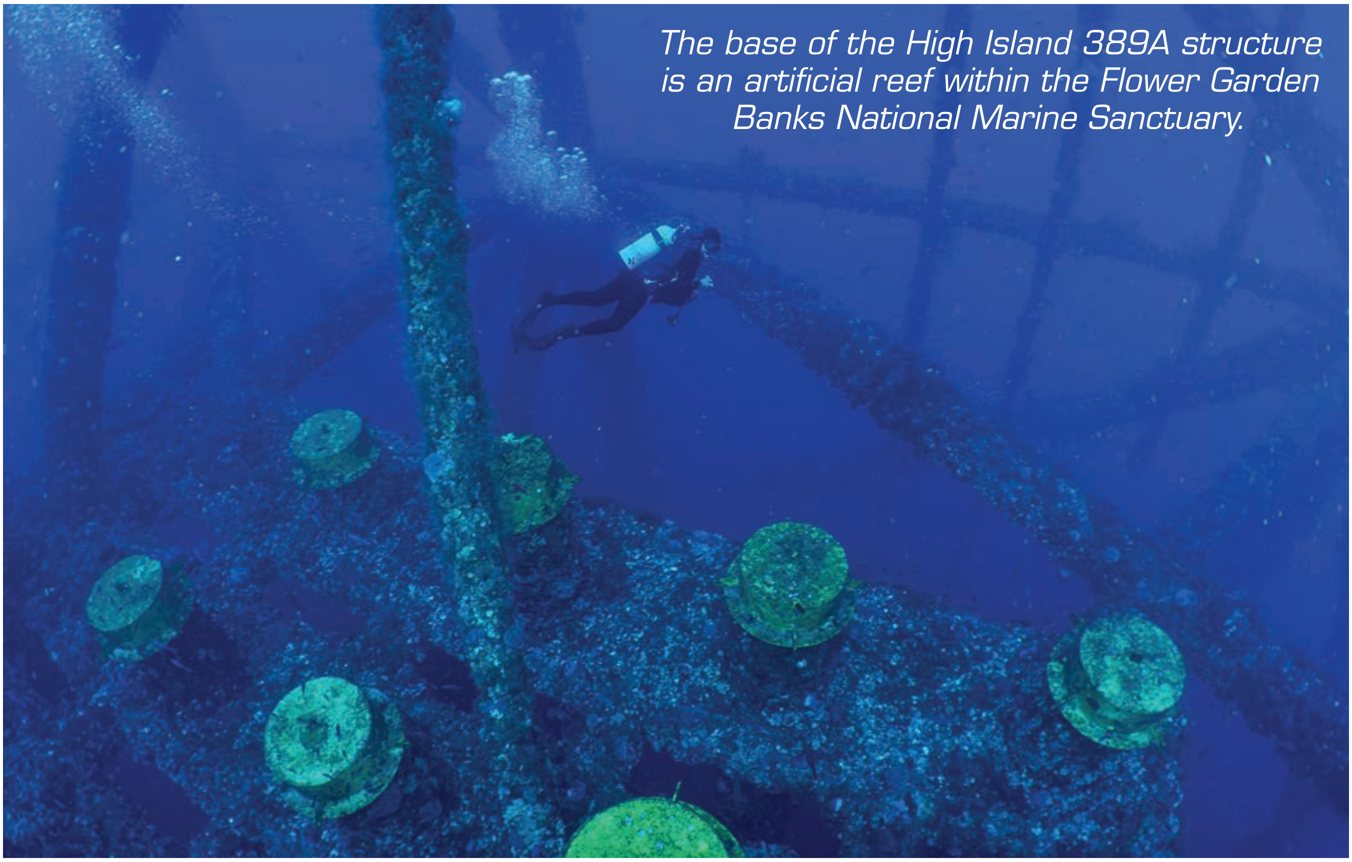
TIME FOR GROWTH

Speck, who holds a mechanical engineering degree and is a licensed professional engineer, has worked in field operations, project management and operations management with Schlumberger, GE Wellstream and TSB Offshore. He was previously TSB Offshore's director of operations.

"We're looking to expand our services, especially overseas," Speck says. In 2019, about a third of the company's work was overseas.

One of the areas of growth that excites Speck is the ability to assist countries and regulatory bodies codify regulations and processes. The company conducts decommissioning workshops around the world, and aims to grow its land-based decommissioning activities for LNG facilities, production facilities, land assets and fields.

"We're focusing on being lean and efficient," Speck says.



The base of the High Island 389A structure is an artificial reef within the Flower Garden Banks National Marine Sanctuary.

Source: G.P. Schmahl, the NOAA Flower Garden Banks National Marine Sanctuary

Source: © Kruwt/AdobeStock

CORROSION Detect & Protect

According to an article in *New Scientist* dated May 22, 1993, Ken Fischer, described as a sailing enthusiast who had gotten tired of scraping barnacles from the bottom of his boat, had an *"A-HA"* moment while eating a meal topped with Tabasco hot sauce.

He suspected the sea creatures might not like the hot sauce, and he hoped it would keep them off the bottom of his boat if he mixed hot peppers into his boat paint. The experiment seemingly worked, and he reportedly filed Pepper Paint, Hot Bottom, and Barnacle Ban trademarks.

Anyone who works on, in or under salt water appreciates the need to properly protect its assets, vessels and structures. According to NACE the global cost of corrosion is estimated to be $2.5 trillion. Using available corrosion control practices, it is estimated that savings of between 15% and 35% of the cost of corrosion could be realized, according to NACE. Here we presents some interesting products and recent developments.

BASF

BASF's Master Builders Solutions launched MasterProtect 9000. It promises the product is the first coating system which ensures 25 years of maintenance-free protection for offshore and marine structures. The coating system is based on a hard wearing high-build hydrophobic PU membrane which provides extremely effective protection for two main critical areas of the offshore structure: the splash zone and the submerged part of the foundations.

Carboline

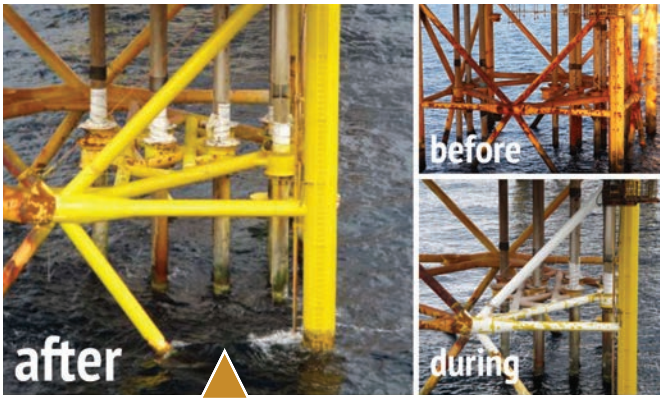
Carboline Carboguard 690 GF is a high performance, glass-flake filled, epoxy coating that displays excellent resistance to water, and saltwater exposures. This coating exhibits outstanding moisture tolerance during application, low-temperature cure capability (down to 20°F (-6°C)), and swift cure response for a quick return to service. Glass flake reinforcement enhances film strength, impact resistance, and corrosion protection properties.

Suitable on a variety of surfaces, including structural steel, piping, pilings, ships, offshore structures and other equipment exposed to industrial or marine environments.

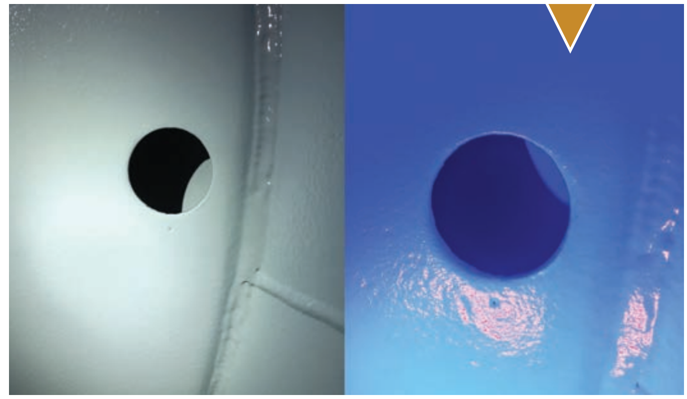
Sherwin-Williams

Nova-Plate 360 tank lining from Sherwin-Williams Protective & Marine helps offshore operators keep high-temperature, high-pressure tanks in service longer to reduce costs. That includes keeping tanks online longer between repairs, as well as enabling

Carboline



Sherwin Williams



Carboline Carboguard 690 GF is a high performance, glass-flake filled, epoxy coating that displays excellent resistance to water, and saltwater exposures.

Sherwin Williams (top right) areas of insufficient coating thickness appear pink when shining an eye-safe ultraviolet light on the applied coatings.

Eddifi Lyft is an inspection tool for identifying corrosion under insulation (CUI).

Eddify Technologies

faster coating applications so tanks can return to service within 24 hours after maintenance. With excellent chemical resistance, the high-solids, flake-reinforced, novolac-based tank lining protects the interiors of steel tanks and vessels from aggressive chemicals stored and processed at high temperatures and high pressures. Nova-Plate 360 is also PTFE-enhanced, which eases tank cleaning processes to reduce asset downtime.

To ensure complete lining applications, applicators can add Opti-Chek Optically Activated Pigments (OAP) to Nova-Plate 360.

Hempel

Hempel has an innovative technology to challenge anti-corrosive coatings trademarked Avantguard. Based on activated zinc epoxy technology Avantguard products deliver excellent anti-corrosion properties for prolonged asset protection.

AkzoNobel

AkzoNobel teamed with RoyalPhillips' to develop a fouling prevention technology which uses ultraviolet light-emitting diodes (UV-LED). It will integrate UV light-emitting diodes in a protective coating scheme which will allow for the UV light to be emitted from the coating surface, providing the total prevention of biofouling accumulation on the surface of the protected area. Initially, the focus will be on applications for ships, yachts and offshore assets.

Cathwell

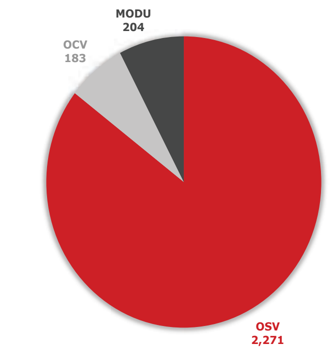
It's not just coatings that protect offshore support vessel hulls. It's electricity too. Impressed current cathodic protection (ICCP) systems use an external power source to impose protective current. This makes it possible to protect any submerged structure, regardless of size and current requirement, by using long-life anodes and appropriately sized power supplies, Cathwell explains. The most important feature of an ICCP system is the ability to continuously monitor the level of protection and adapt to the current required to avoid corrosion.

Eddyfi

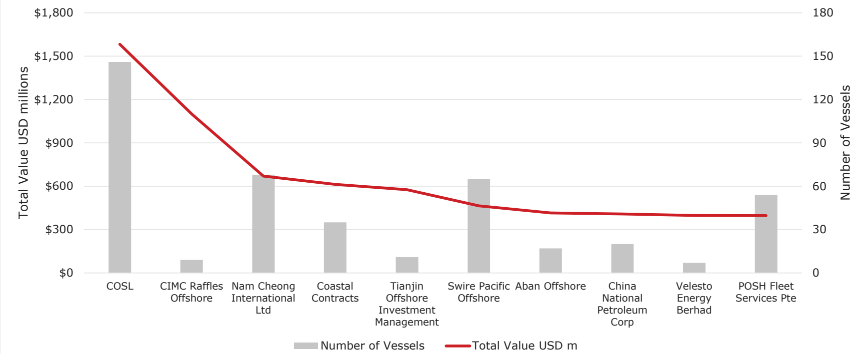
Eddyfi Lyft is an inspection tool for identifying corrosion under insulation (CUI). The Eddyfi Technologies' solution can be used to measure corrosion and wall thickness on insulated pipes without removing insulation. It's suitable for use on a number of materials including metal, aluminum, stainless steel, and galvanized steel weather jackets, to provide real-time C-scan imaging, wall thickness measurements and fast data acquisition (up to 15 readings per second).

Data & Statistics powered by VesselsValue

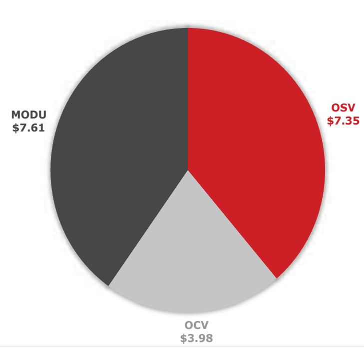
Asian and Australian Offshore Fleet
Number of Vessels
(source: VesselsValue)



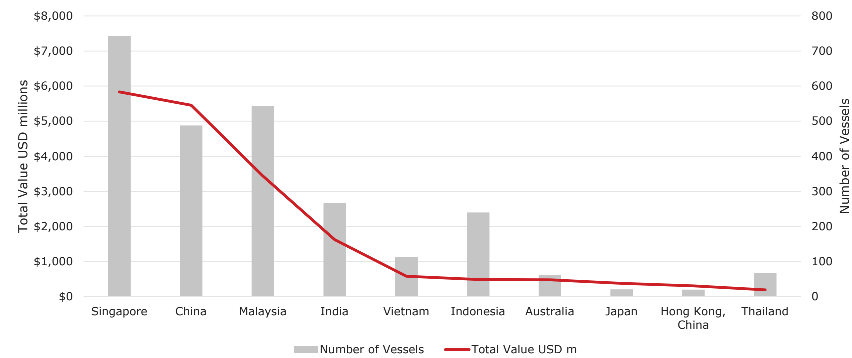
Top Owner Companies in Asia and Australasia
(source: VesselsValue)



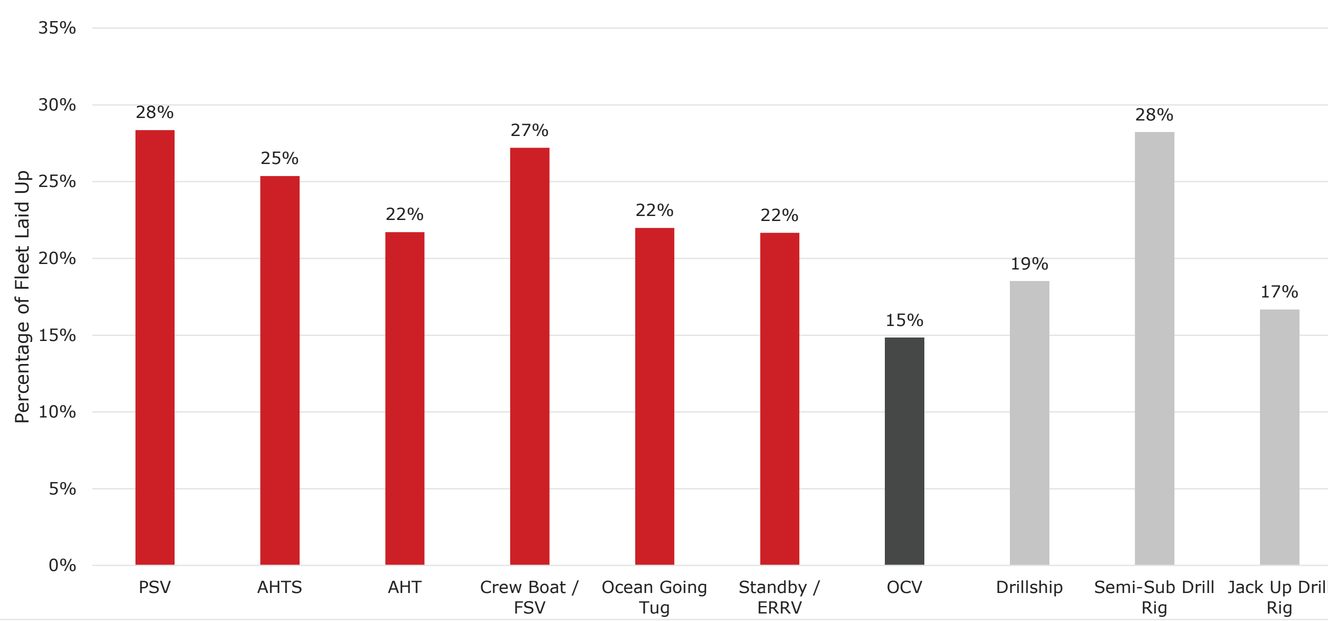
Asian and Australian Offshore Fleet
Value (USD billions)
(source: VesselsValue)



Top Owner Nations in Asia and Australasia
(source: VesselsValue)

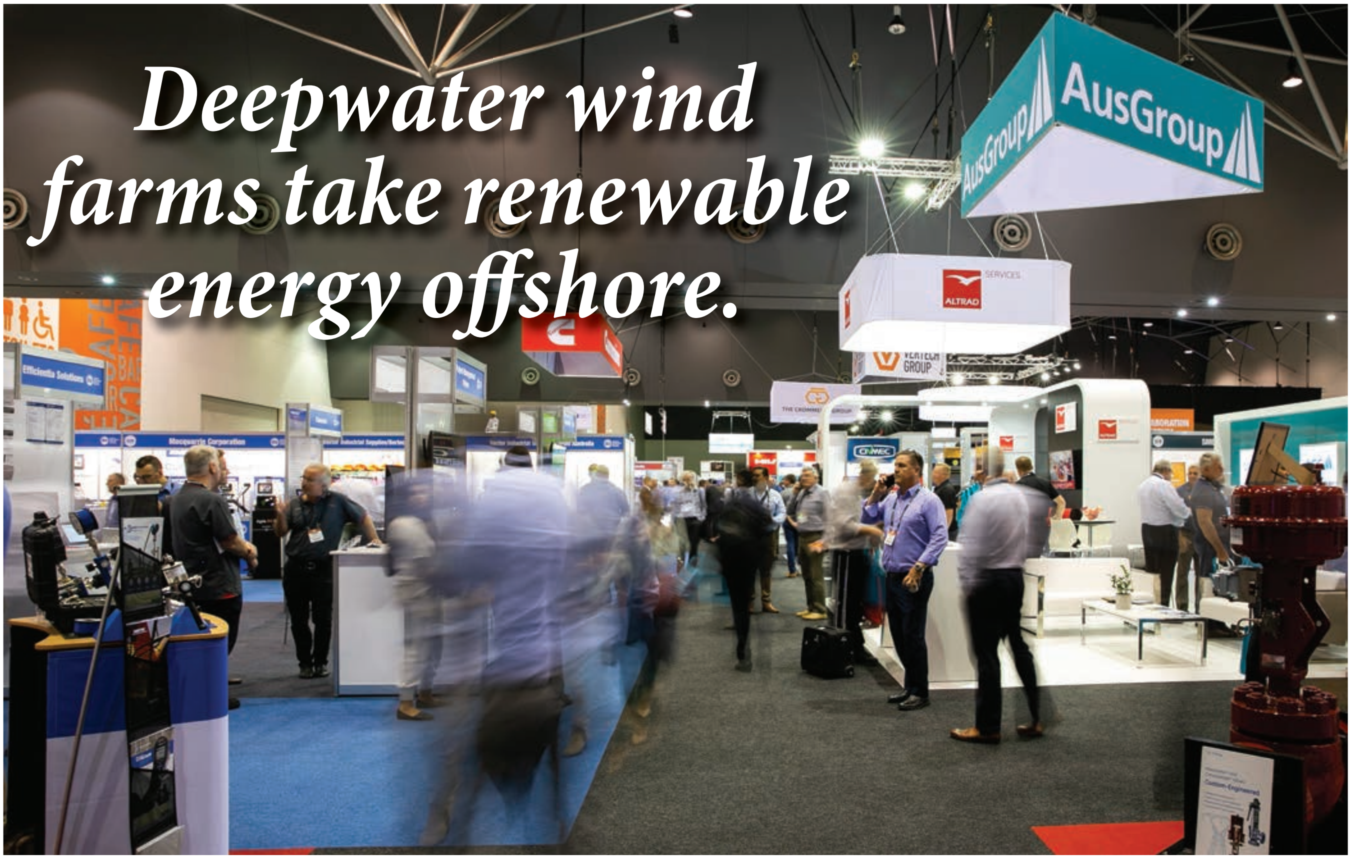


Asia and Australia Opertating Offshore Fleet Utilisations
(source: VesselsValue)



AOG 2020

Deepwater wind farms take renewable energy offshore.



Source: AOG

The global offshore industry is diversifying from oil and gas into renewables as cutting-edge technology and research has facilitated the installation of wind farms in deep water.

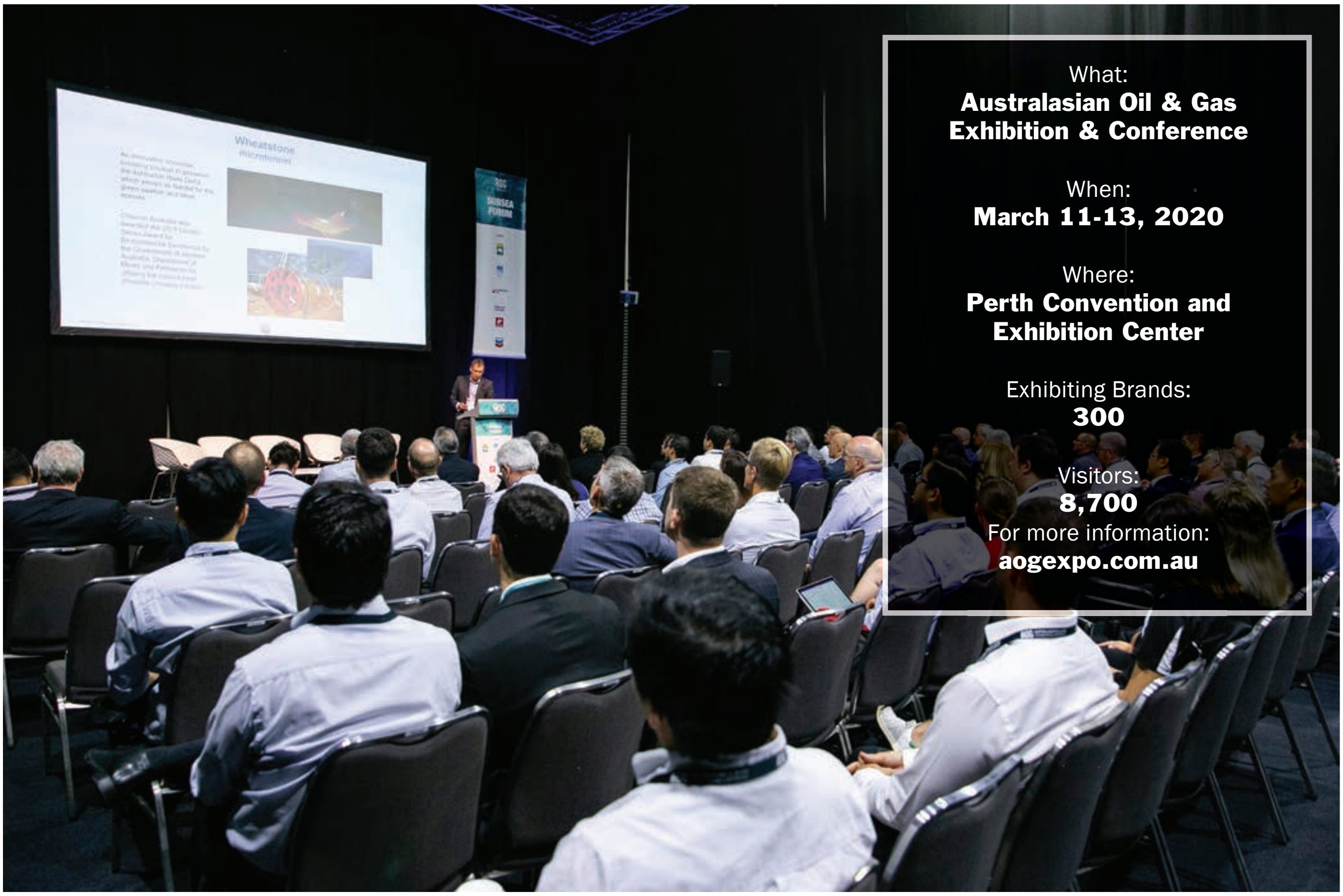
This year's Australasian Oil and Gas Exhibition and Conference is set to hear from Dr. Daniel Veen, one of the Australian experts developing globally significant software capable of integrating the systems which underpin giant offshore wind turbines installed at depths greater than 60 meters (m).

Global offshore wind power is projected to grow 15-fold over the next two decades. In December last year the biggest floating turbine in the world, located off the coast of Portugal, started transmitting electricity to the grid in what was described as a

Source: AOG

milestone for the industry.

Most offshore wind turbines are on fixed foundations at less than 60m depth. In the case of the Portugal and about a dozen other trial sites, giant floating turbines have been installed at



up to 100m by tethering them to the seabed. Each turbine can successfully generate up to 8.4 megawatts (MW) each. GE Renewable Energy now has a 12MW turbine at 220m rotor size to be installed off the coast of France.

"I don't think we've reached the maximum size for these turbines yet. Simulations show they can get bigger, more efficient and more sophisticated," Dr Veen said ahead of the conference.

"There are no deepwater turbines in Australia at the moment but a fixed windfarm off the coast of Gippsland in Victoria is being explored by Star of the South. What I find interesting is the push for this technology isn't coming from governments, it's coming from industry – particularly in China and Europe."

"As an industry, we are working toward offshore wind farms of a scale that will diversify the offshore industry into renewables. Wind is more reliable out to sea, and the ability to build and install these wind turbines is becoming more cost-effective," Dr Veen said.

"Power is transmitted back to shore via subsea power lines, and while there is a risk there, we already rely on undersea cables for a range of technology, including Australia's connection to the internet."

At Bentley, Dr. Veen is part of an international team based in seven different time zones and three continents developing software for hydrodynamic floating systems. He is also Bentley's representative on a project led by the American International Energy Agency, known as OC6.

"Wind turbines in the ocean on floating structures are quite complex. We need to simulate the impact of wind loading on the turbine, how the structure moves in the ocean and how those movements stress the mooring lines into the seabed," Dr Veen said.

"It's a complex system and we are taking the existing software that designs floating systems offshore and enabling it to integrate with other specialist structural and aeroelastic design software to allow an analysis of the whole integrated system."

Dr. Veen is the Associate Product Manager, MOSES, Bentley Systems and will be presenting on Marine Renewable Energy as part of the Knowledge Forum at AOG2020.

Register free now to hear Daniel speak at AOG 2020: **https://bit.ly/2Rq03pH**

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February 11-13, 2020
Aberdeen, UK
www.subseaexpo.com

FPSO Europe Congress
February 18-19, 2020
London, UK
www.fpsonetwork.com

Australasian Oil & Gas
March 11-13, 2020
Perth, Australia
www.aogexpo.com.au

SPE/ICoTA Well Intervention
March 25-25, 2020
The Woodlands, US
www.spe-events.org

OTC Asia
March 24-27, 2020
Kuala Lumpur, Malaysia
2020.otcasia.org

Eastern Mediterranean Offshore Conf.
April 8-10, 2020
Nicosia, Cyprus
http://www.emc-cyprus.com

Offshore Technology Conference
May 4-7, 2020
Houston, US
2020.otcnet.org

Global Petroleum Show
June 9-11, 2020
Calgary, Canada
www.globalpetroleumshow.com

Underwater Technology Conference
June 16-18, 2020
Bergen, Norway
www.utc.no

Subsea Well Intervention Symposium
August 11-13, 2020
Galveston, US
www.spe.org/events/calendar

ONS
August 31-September 3, 2020
Stavanger, Norway
www.ons.no

Gastech
September 8-10, 2020
Tampines, Singapore
www.gastechevent.com

ATCE
October 5-7, 2020
Denver, US
www.atce.org

OilComm
October 14-15, 2020
Houston, US
www.oilcomm.com

ADIPEC
November 9-12, 2020
Abu Dhabi, UAE
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OE OFFSHORE ENGINEER

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Production
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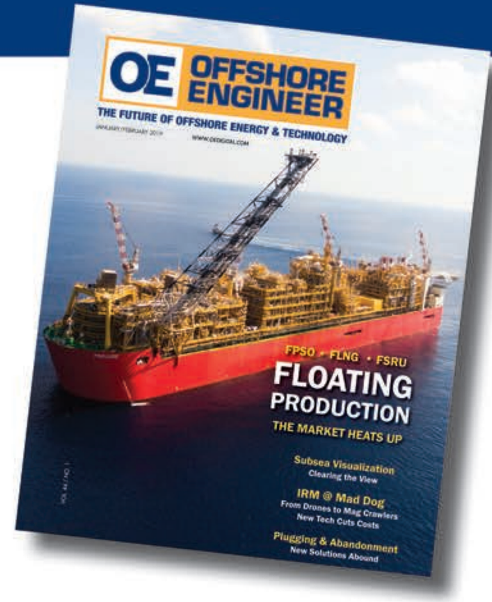

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