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Subsea Tiebacks

A saving grace for the subsea industry

Deepwater Frontiers
New Techology Enablers

Unmanned & Ready
The Future is Now for Remote Unmanned Facilities

Flow Assurance
A Systems Approach to Keep Offshore Wells Producing

VOL. 45 / NO. 2

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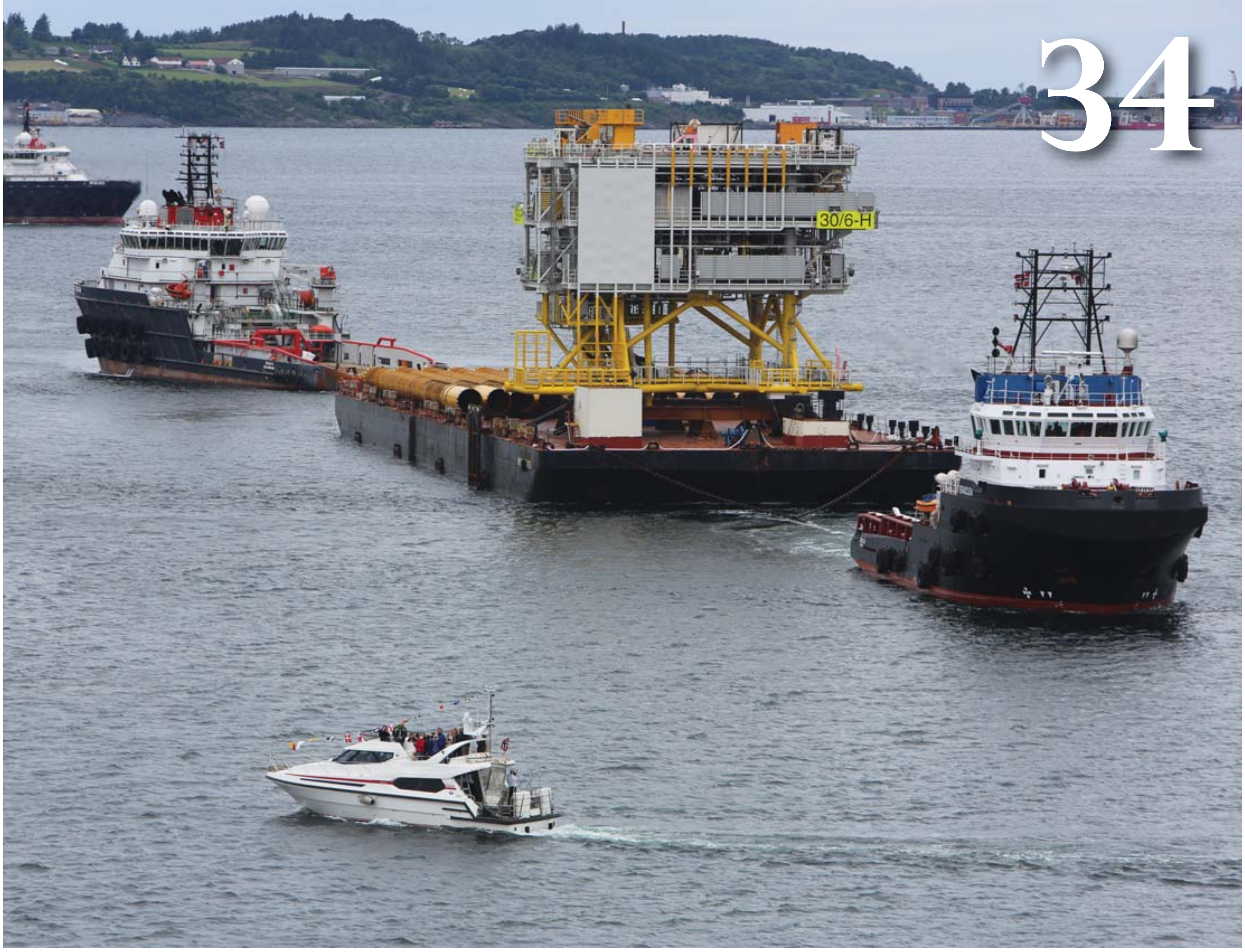
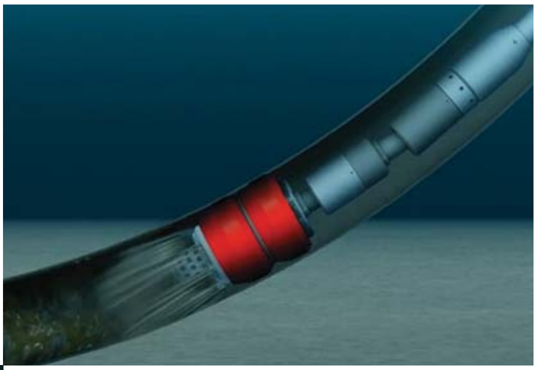
FEATURES



Source: Equinor

ON THE COVER: Subsea tiebacks have been leading the subsea business in the past two years, with vendors, including Baker Hughes, offering new, innovative solutions. **Image Source: Baker Hughes**

FEATURES



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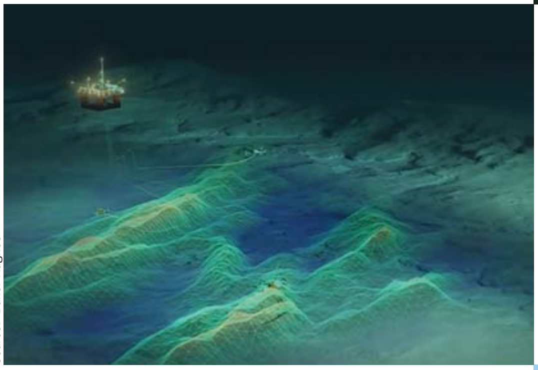

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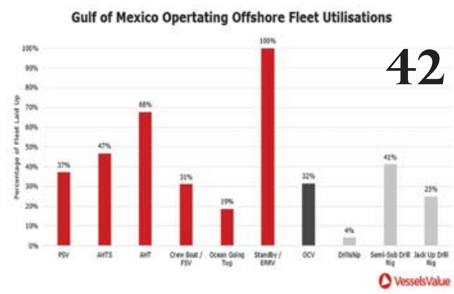
DEPARTMENTS

Source: BSEE



Source: Vessels Value

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BY THE NUMBERS

RIGS

Worldwide

Rig Type	Available	Contracted	Total	Utilization
Drillship	23	66	89	74%
Jackup	113	340	453	75%
Semisub	31	73	104	70%

Africa

Rig Type	Available	Contracted	Total	Utilization
Drillship	2	15	17	88%
Jackup	9	28	37	76%
Semisub	1	3	4	75%

Asia

Rig Type	Available	Contracted	Total	Utilization
Drillship	5	7	12	58%
Jackup	41	109	150	73%
Semisub	11	19	30	63%

Europe

Rig Type	Available	Contracted	Total	Utilization
Drillship	12		12	0%
Jackup	12	38	50	76%
Semisub	11	28	39	72%

Latin America & the Caribbean

Rig Type	Available	Contracted	Total	Utilization
Drillship	3	18	21	86%
Jackup	7	3	10	30%
Semisub	3	7	10	70%

Middle East

Rig Type	Available	Contracted	Total	Utilization
Jackup	24	114	138	83%
Drillship		2	2	100%

North America

Rig Type	Available	Contracted	Total	Utilization
Drillship		23	23	100%
Jackup	17	40	57	70%
Semisub	4	7	11	64%

Oceania

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

Russia & Caspian

Rig Type	Available	Contracted	Total	Utilization
Jackup	3	6	9	67%
Semisub	1	4	5	80%

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 March 2020.
Source: Wood Mackenzie Offshore Rig Tracker

DISCOVERIES & RESERVES

Offshore New Discoveries

Water Depth	2015	2016	2017	2018	2019	2020
Deepwater	25	12	16	15	17	-
Shallow water	85	65	73	49	68	2
Ultra-deepwater	19	16	12	17	17	1
Grand Total	**129**	**93**	**101**	**81**	**102**	**3**

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	551	40,317	20,023
Shallow water	3,220	421,359	145,435
Ultra-deepwater	328	39,870	33,827
Grand Total	**4,099**	**501,547**	**199,285**

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	591	20,389	13,231
Asia	853	17,223	7,473
Europe	796	12,932	14,706
Latin America and the Caribbean	200	6,125	29,863
Middle East	115	89,888	148,472
North America	582	3,172	15,399
Oceania	88	12,325	1,494
Russia and the Caspian	57	8,236	13,745
Grand Total	**3,282**	**170,291**	**244,383**

Onstream and under development.

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

Source: Wood Mackenzie Lens Direct

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MAINTAINING **BALANCE**

First and foremost, I sincerely hope that you, your family, friends and colleagues are all safe during these unprecedented and uncertain times. If you are reading this, I'll assume that perhaps you are viewing it online, from your home or other 'social distanced' workspace, in somewhat of a surreal haze wondering *"what just happened?"* I will not even try to put a pretty spin on the world of offshore oil and gas at the moment, because I don't think even the most seasoned Beltway Spin Doctor is up to the task. For an industry that has endured more than its fair share of ups and downs, early 2020 will serve as a benchmark for geopolitical, business and social studies for a generation to come.

The 'bad news' is apparent and ubiquitous at the moment. I do not have a crystal ball to determine how long this will last, how deep this will cut, but I can say with 99.99% certainty that it will end and sooner than later we will all be back to business. Maybe not business as normal or as we knew it, but business nonetheless.

From even the most dire of times there are always silver linings, good news stories that emerge illustrating how strong will and hard work are a timeless elixir to help heal many wounds. To that end, I and the entire *Offshore Engineer*/ **OEDigital.com** editorial staff are eager to hear from you, to share your stories in pictures, video and words across our print, electronic and social media channels. Many challenges are met with tech or business solution, which has been the hallmark of this industry and has been our privilege to share.

My first disclaimer with this edition is much of the copy was filed before the full effects of COVID-19 was realized. So while some of the market insights presented might seem off-kilter with market conditions on the day you read it, much of the technical information – the hallmark of the *Offshore Engineer* brand since 1975 – is valid and spot-on. **Elaine Maslin** in Aberdeen, **Jennifer Pallanich** in Houston and **William Stoichevski** in Oslo all share with you their signature insightful reporting on deepwater, subsea tiebacks and flow assurance, among others in this edition. We also welcome **Erik Milito**, president of NOIA, who took the time to share his insights on the development of offshore wind, starting on page 46.

"WHILE (GOM) BIDDING DID TAKE A TOUGH HIT, IT COULD HAVE BEEN SUBSTANTIALLY WORSE DUE TO **THE UNPRECEDENTED NEAR-TERM FINANCIAL CONSTRAINTS CREATED BY THE COVID-19 VIRUS AND THE OIL PRICE WAR BETWEEN SAUDI ARABIA AND RUSSIA.** LONG-TERM PROJECTIONS FOR ENERGY DEMAND, INCLUDING OIL AND NATURAL GAS, SHOW STRONG GROWTH FOR THE FORESEEABLE FUTURE. **OFFSHORE PROJECTS ARE UNDERTAKEN WITH THE LONG-TERM OUTLOOK IN MIND."**

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Gulf of Mexico: Which Way Now?

BY JENNIFER PALLANICH

Editor's Note: This feature was written before the full extent of COVID-19 and its impact on global energy markets was fully in focus.

Source: BSEE

Before operations can begin on a new offshore facility, BSEE engineers and inspectors inspect it to ensure the facility meets safety and environmental requirements.

Increasing levels of production and activity in the Gulf of Mexico in 2019 look likely to continue throughout 2020, costs seem to be creeping back up and new HPHT technologies are being developed and deployed.

Even so, the offshore oil and gas industry still faces the uncertainty associated with the energy transition, which can translate into difficulty obtaining capital investments for long-term deepwater projects.

"Despite having been pronounced dead on several occasions, the Gulf of Mexico's daily production rates are the highest they have ever been," Lars Herbst, Bureau of Safety and Environmental Enforcement (BSEE) Gulf of Mexico Region Director, says.

As of early March, 2019 oil production total was 683,681,522 barrels. The increase in production in 2019 led to $2.34 billion in offshore royalty revenue for the US Federal Treasury. According to a US Energy Information Administration report, US Gulf of Mexico oil production will continue to set records through 2020.

"Ongoing BSEE initiatives are supporting these efforts," Herbst says.

Those initiatives include a risk-based inspection protocol that uses data and trend analysis to identify and inspect higher-risk operations and facilities, a risk analysis committee to identify and reduce offshore activity risks to human health and the environment, a vital statistics program to identify areas that need improvement, the BSEE!Safe text messaging service that directly communicates with offshore workers to push out safety alerts and bulletins, the regulatory reform effort to reduce regulatory burden related to the Production Safety Systems Rule and the Well Control Rule without sacrificing safety, and increased information sharing between the bureau and the industry.

The focus of these initiatives is to improve safety perfor-


Source: BSEE

> "Despite having been pronounced dead on several occasions, the Gulf of Mexico's daily production rates are the highest they have ever been."
>
> – **LARS HERBST,** BUREAU OF SAFETY AND ENVIRONMENTAL ENFORCEMENT

mance and environmental stewardship, Herbst adds.

According to William Turner, Vice President – US Gulf of Mexico for Welligence Energy Analytics, a measure of optimism is apparent when it comes to offshore oil and gas activity in the Gulf of Mexico.

"Last year was one of the first positive-looking years. There was a lot of excitement, some building momentum and interest," Turner says. "We're seeing more activity that I think is a result of the excitement building from last year."

And there's more good news, he says.

"We're starting to see evidence that costs bottomed out in 2019. We're seeing increasing rig rates. It's still short-term, but we've seen some indication that costs across the board have bottomed," Turner says. "We're looking for a pretty exciting year."

During down cycles, companies tend to exit regions, so a new company entering a region can signal a turnaround. Petronas has farmed into a field in the Gulf of Mexico.

"In the years prior, we were just seeing exits. Now we're seeing entrances," Turner says. "It supports the theory that it's a strong case in the Gulf of Mexico for getting in at the bottom of the costs and on the foreseeable increase in recovery in commodity prices."

Herbst says operators are taking advantage of existing infrastructure and planning to use more subsea tieback facilities to keep assets at or near full production.

Projects with final investment decisions (FIDs) and subsea tiebacks to existing facilities include Shell's Vicksburg (Appomattox hub) and Power Nap (Olympus hub), BP's Atlantis Phase 3 (Atlantis hub) and Manuel (Na Kika hub) and Thunder Horse South 2 (Thunder Horse hub), Hess Corporation's Esox (Tubular Bells hub), Talos Energy's Bulleit (GC018 platform), and Fieldwood Energy's Orlov/Troika (Bullwinkle platform) and Katmai (Tarantula platform) and Genovesa (Na Kika hub).

Herbst says operators are also focusing more effort on deepwater projects. Several new projects have completed the FID process. Those projects include Hess' ESOX-1, Talos Energy's Bulleit, BP's Atlantis Phase 3 and Manuel, Fieldwood Energy's Orlov and Katmai, Murphy's Khaleesi Mormont and Samurai, and Chevron's high-pressure Anchor.

The new production platforms with FIDs and planned installations with subsea tiebacks include BP's Argos, Shell's Vito, Murphy's King's Quay and Chevron's Anchor.

These new production hubs will add an estimated new processing capacity of 345,000 b/d and 288 mmcf/d of gas be-

Source: Welligence

"Last year was one of the first positive-looking years. There was a lot of excitement."

– **WILLIAM TURNER,**
WELLIGENCE ENERGY ANALYTICS

tween 2021 through 2024, according to BSEE.

"Tangible activity is picking up," Turner says. For examples, he cites the drilling of Chevron's Clingman's Dome, which could tie back to Thunder Hawk, and Equinor's Monument, which is an ultra-high-pressure target. Kosmos has an extensive inventory they are actively drilling, he adds, although a couple have been dry.

Turner says it will be "an interesting race" to see whether Anchor or LLOG's ultra high-pressure Shenandoah project will reach first oil.

"Operators are pursuing high pressure high temperature (HPHT) technology in their efforts to reach more challenging reservoirs in the Gulf," Herbst says. "Although we could see HPHT production in 2023/2024, the timeline for the development of HPHT projects is subject to appropriate technology being available."

In 2019, BSEE released its guidance on HPHT projects in the Gulf of Mexico, which allows for "safer and more environmentally sustainable access to those larger reserves of hydrocarbons being discovered in deepwater," he says. BSEE is "carefully evaluating drilling and other permits that require HPHT equipment."

Many deepwater projects are intended to produce for 25 years or more, but some may be reluctant to invest in a long-term project in the face of what many call the energy transition, during which the world is expected to shift away from fossil-based energy sources to reduce energy-related carbon dioxide emissions.

"There's a question around a 25- or 30-year investment around an oil project and what does oil demand look like in 20 to 30 years. It's long-term uncertainty," Turner says. "We're not sure about the speed at which the energy transition might come and how fast this technology is going to be available. If I go and invest in a 25- or 30-year oil investment, how quickly will I be left holding assets that aren't worth the investment? That timeframe is where the uncertainty is."

And that overall uncertainty can make it difficult for operators to attract investments.

"Companies like Talos and LLOG would like to make meaningful transactions that would meaningfully change their portfolio, but it's difficult to get that capital," Turner says.

Further, investors are more tightly scrutinizing onshore shale plays, and there's the chance that investors may make an apples and oranges comparison with deepwater projects, he says.

"They may paint all of oil and gas with the same brush," he says.

And of course the short-term volatility in prices adds another wrinkle into the uncertainty mix.

Even with all that in the background, Turner says, companies are "optimistic and pushing forward" and the Gulf of Mexico is "fit to compete as much as ever."

One of the reasons is that following a tough four-year downturn, the industry is collaborating more across the board, and are more frequently making partnerships outside of their peer groups, such as Talos and Fieldwood, who have both teamed up with Chevron and BP, and Kosmos pairing up with BP, Turner says.

The industry is also becoming more efficient and standardized, finally, Turner says.

"If you've gone to Offshore Technology Conference and heard the presentations on standardization, well we're finally putting it to work. The industry is finally committed to standardization," he says. The same basic OPTI-X semisubmersible platform that LLOG used for Who Dat and Delta House will potentially be reused for Shenandoah, and is being used for Murphy's King's Quay platform. Additionally, Shell's using the same semisubmersible design for Vito and Whale, he adds.

"The challenge is going to be to hold onto this – the efficient operations, the low costs, the standardization, and the lessons learned," Turner says. "We must not return as an industry to the times of 2014."

Turner echoes what many have said about past downturns: the down cycle can be "a little bit of a blessing in disguise. It gave the industry a reason to get back into shape. The volatile uncertain oil price will keep us on our toes, and it will keep us innovative."

Source all images: GATE Energy

Maintaining flow assurance with a systems approach

Image above: Flow assurance includes prevention, detection and remediation.

BY JENNIFER PALLANICH

Flow assurance can keep offshore wells productive, and it requires successfully preventing or mitigating problems in the reservoir, the subsea flowlines and the topsides equipment.

To prevent flow assurance problems, it's necessary to identify potential issues, then determine how best to resolve those issues. But preventing a problem in one area can have knock-on effects in another. Bringing flow assurance experts onboard early-on during the design phase makes it possible to devise a holistic systems approach to keeping a particular well or field online.

At its most basic, flow assurance is about preventing anything from interrupting the stream of hydrocarbons from moving out of the reservoir through the flowlines and up to the topsides facility. Typical offenders are scaling, paraffins, asphaltenes, hydrates and corrosion. The mix of challenges varies by region, with the Gulf of Mexico having more issues with asphaltenes and hydrates in deeper waters, while the North Sea more commonly has scaling and paraffin issues. Some areas like the North Sea have to grapple with exotic scales, like strontium sulfate.

And finally, as a reservoir produces, its flow assurance issues evolve.

"There's nothing worse than when a producing well stops producing because of some flow assurance-related issue you hadn't seen before," says Karthik Annadorai, executive vice president at GATE Energy. For the E&P company, "it's bad news if they drill a dry hole, but it's worse news when you drill a well, it starts producing and then has to shut in because of flow assurance problems. That can be catastrophic."

Remediation is costly, not just for the cost to carry out the remediation operation, but because of the lost production. Risk mitigation can prevent the need for remediation.

Success with flow assurance requires maintaining the subsurface, subsea system and topsides even as the issues presented in each area evolve as the reservoir produces, he says.

But it doesn't start there.

The most critical intelligence an E&P company can get about what potential flow assurance issues a new reservoir poses will come from the fluids sample. The fluid sample makes it possible to determine how the fluids behave when analyzed along with the reservoir temperature and pressure conditions.

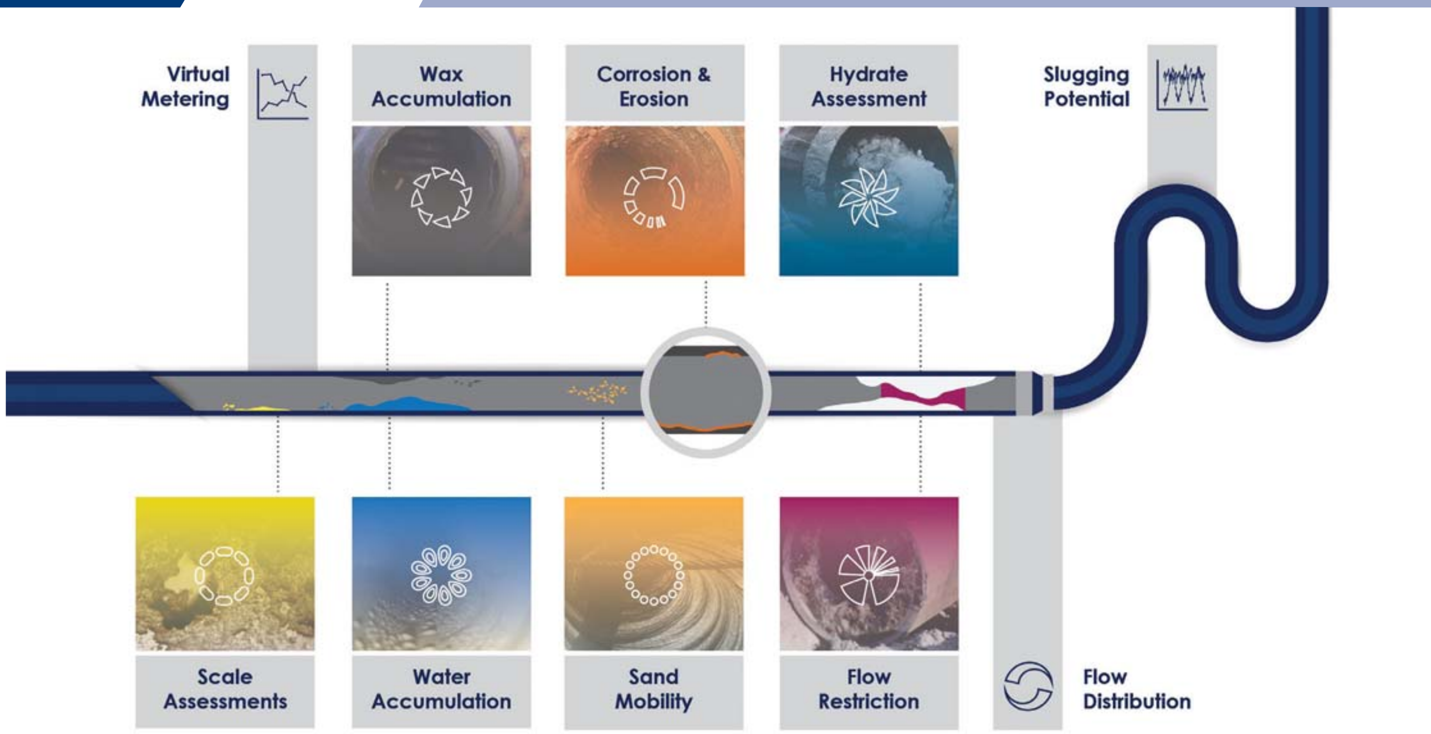
"If you have a bad sample, anything that you test will be bad. Your results will be bad," Annadorai says.

Bad samples happen, he says, when they are taken from the wrong zone or are contaminated. Whether on a bad or good sample, the tests that are carried out will either be on "live" oil or water or "dead" oil or water. Live fluids have been maintained at reservoir pressure, while dead fluids have not. Live fluid samples are more costly to obtain, but both types are needed for the full gamut of testing that drives understanding of the production chemistry.

Sometimes, there's just not enough sample fluid to carry out all the tests needed to create a clear picture of the potential flow assurance challenges, Annadorai says. It can take nearly half a day to obtain live fluid samples, and the spread rate of the drilling rig can become a factor. Ideally, he says, sampling techniques in the future will be vastly improved to reduce the purging time needed to take a pristine reservoir fluids sample.

"One of the biggest complaints is, 'I don't have enough sample, so I can't test,'" he says.

A decision to try to save money during the fluids sampling operation can have cascading effects, particularly if the project becomes



FAST-TRACKING OPERATIONAL DECISIONS

A flow assurance surveillance tool can help an operations engineer shift from reactive mode to proactive mode. One such tool is GATE's Flow Assurance Surveillance Tool (FAST), which is powered by the GATE PRHO simulator, which processes data to offer real-time flags on potential problems. In the past, says Randy Dinata, engineering consultant at GATE LLC, it was typical to "simply overlook, or wait until issues in flow assurance were starting to affect their facilities." But, he adds, "it's easier to remediate a partial blockage compared to a full blockage." The tool was originally developed for an operator in West Africa who had subsea gauges malfunctioning following the field start up. Instead of replacing the gauges, which would have cost millions of dollars, the operator used the simulator to surveil the field and have the ability to make informed decisions based on real-time data during daily operations.

The tool takes the real-time data, processes it, and notes the potential issues along with suggested steps to resolve the potential problem, he says.

"The operator can look at it and say, 'Now I know what to do about this,'" he says.

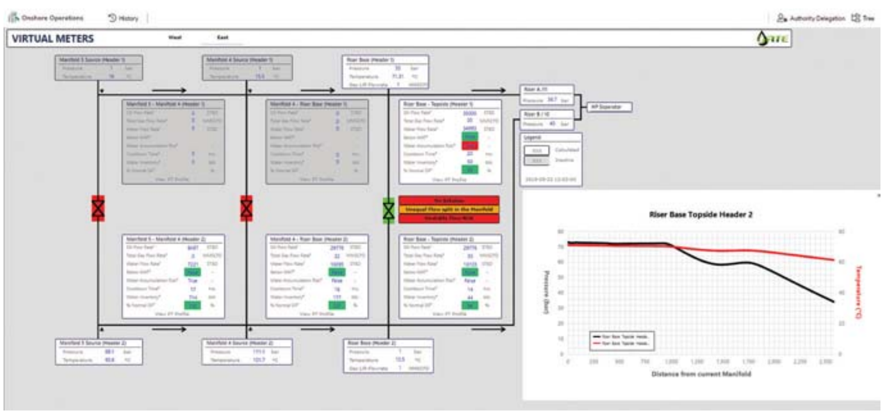
It predicts where there is a potential for slugging, for example, or note how much time a facility has following an unplanned shutdown before hydrates are likely to form. "It tells you you have 12 hours before you could begin to see hydrate risk based on current operating conditions, and here are your options, like injecting methanol at localized water accumulation spots or performing hot oil circulation or preparing for a blowdown," he says. And potential flow assurance problems can manifest a host of symptoms. Figuring those symptoms out requires "playing detective," Dinata says.

"This is a surveillance tool. You get a sense that this may happen in your field and possible causes. To verify it, you'll have to do more in-depth investigation," he says.

For a future iteration of the surveillance tool, Dinata is working on a hybrid model that couples physics-based modeling with data analytics.

"I think they are great tools," he says. "But there are a lot of things physics-based modeling cannot capture. There are a lot of things out in the field that we scientists are not aware of. And with data analytics, if we rely on data too much, if our gauges are not perfect, the data are not perfect and could lead to significant error in the analysis."

A hybrid model that draws on the strengths of a physics-based model and factors in patterns uncovered through data analytics "will give us the ability to predict more accurately," Dinata says.



a multi-billion-dollar facility floating in the deepwater Gulf of Mexico. The end result could be more downtime for the facility due to insufficient sample fluids.

But when enough sample fluid is pristinely collected from the proper zone, it's possible to do the right tests needed to pinpoint potential production chemistry issues and mitigate the issues.

"When you know what the production chemistry looks like, you can find the right chemicals, the right operations environment, the right operability plan," he says. "You identify and understand the problem, and you prepare for it."

But it's not as simple as relying on pressure-volume-temperature analysis or chemical testing or fluids testing or plugging data into thermohydraulic fluid modeling software, he says.

Annadorai says that it's important to treat the subsurface, subsea system and topsides like the interconnected system it is. Flow assurance methods like using hydrate inhibitors impact produced water, he notes. In this way, he says, it's like giving medication to a human. There are side effects, which can ripple throughout the system.

"You have to think about the flow assurance issues, the type of material selected, the operating procedures to design a system to solve the flow assurance issues and how your decision can impact the system," Annadorai says. "What I feel is lacking in the industry is a systems approach to flow assurance."

Cross training between functions like fluids testing and thermohydraulic modeling and materials selection on a daily basis is critical, he says. Having that constant awareness can help an engineer understand those cascading effects, he says. He's heard flow assurance professionals say things like "I had no idea this chemical did that" or "I had no idea that this decision I would have made would have that impact."

He says it's possible to involve the right stakeholders during field design planning. This way, he says, everyone is in the same room, speaking the same language, and incorporating ideas to support the whole production system.

As to what the future holds for flow assurance, Annadorai believes there will be some unknowns and some innovative solutions to solve the issues that crop up with drilling in ever deeper water depths and in higher pressure reservoirs.

"These come with a whole bunch of flow assurance challenges that cannot be solved by old-fashioned solutions developed over the past decades," he says. "There's going to be decades of learning coming up."

SUBSEA: TIEBACKS: PROJECTS AND TECHNOLOGIES

Subsea tiebacks have been the saving grace for the subsea industry. With fast payback, monetizing low hurdle opportunities in operator's portfolios, they've provided work for the supply chain and return on investment for operators – or 66% of recent final investment decisions, ***Elaine Maslin reports.***

It's a trend that's set to continue even as greenfield projects start to return to the mix. Mhairidh Evans, principal analyst, upstream supply chain at Wood Mackenzie, says subsea tiebacks have dominated through 2014-2018.

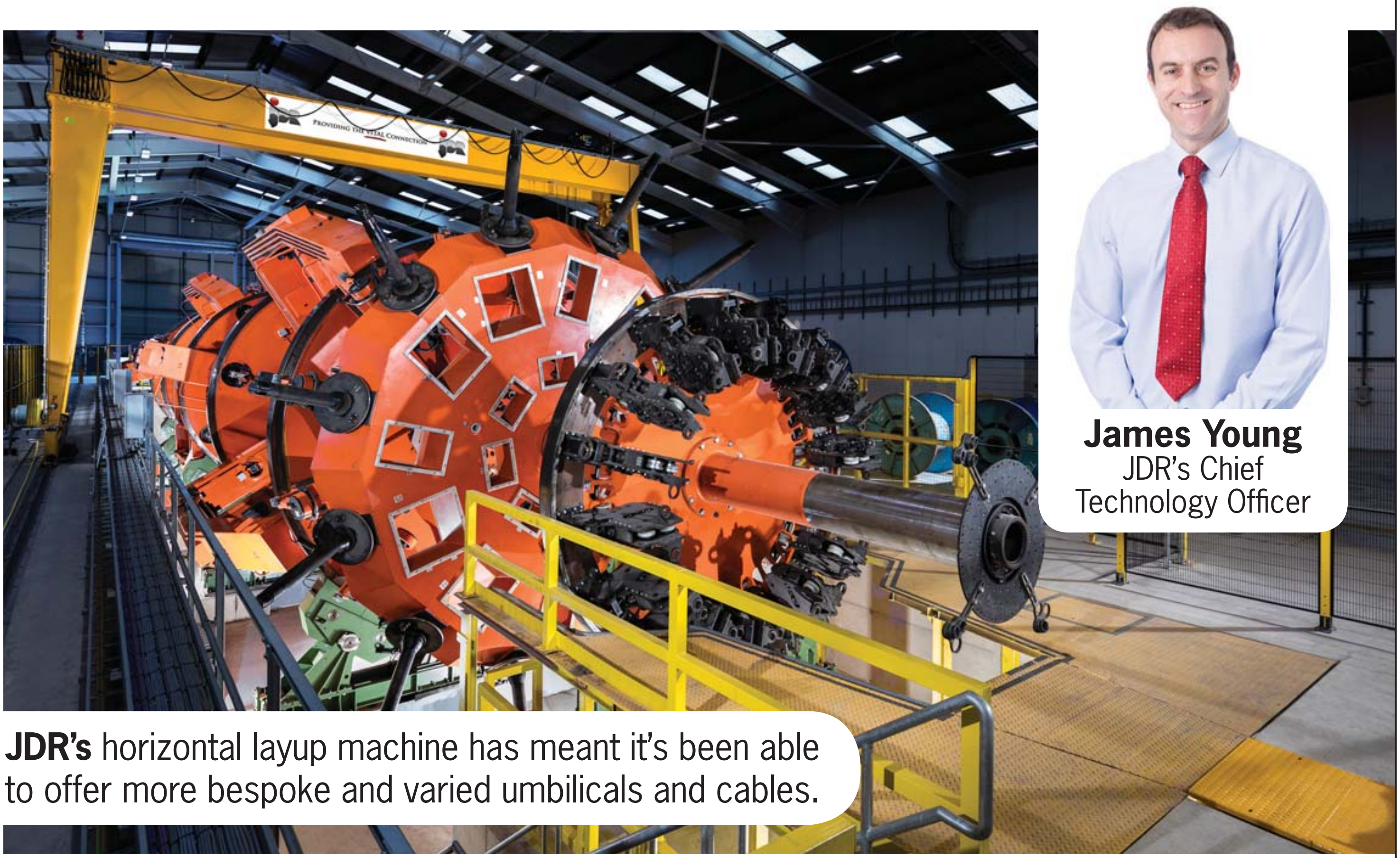
"In the projects sanctioned in that period, only 13 had more than 15 wells associated with them and some of those were tiebacks. Operators pulled in their spending and tiebacks became the development concept of choice, for those pushing on with developments."

The activity was notable in 2018, which saw a return to growth, after a 20-year global low for new contracts in 2016. The North Sea is a big part of the growth. In 2018 and 2019, almost 30% of new subsea wells sanctioned were in the UK and Norway.

Source: Baker Hughes

Baker Hughes: Subsea tiebacks have been leading the subsea business in the past two years, with vendors, including Baker Hughes, offering new solutions.

Source: JDR



James Young
JDR's Chief Technology Officer

JDR's horizontal layup machine has meant it's been able to offer more bespoke and varied umbilicals and cables.

Global awards for subsea trees per year

New projects are also coming, including developments like Mozambique LNG, Sangomar, Barossa, Scarborough and Liza. Despite this, there's not going to be a return to boom years. While Wood Mackenzie expects 2020 to be flat, compared with 2019, indicating a potential for more consolidation in the supply chain, it still predicts 7500km of subsea umbilicals, risers, and flowlines to be installed in 2020-24 – an amount which would stretch from Aberdeen to Houston – as well as 450 new subsea wells. That's just in Europe. Globally, the firm expects 44,000 km of SURF to be installed and 1,500 new subsea wells to start production between 2020-2024. Evans says 60% of all future subsea wells are expected to be tiebacks.

Henning Bjørvik, an analyst in the Oilfield Service team at Rystad Energy with a primary focus on the subsea market, says that in 2022-2023, close to 400 trees are expected to be installed. According to Rystad's analysis, most of these would still be robust at $50/bbl, but not if it dropped to $40/bbl.

A big trend is the success of the integrated contractors – the likes of TechnipFMC, Subsea 7 and OneSubsea's Subsea Integration Alliance, and McDermott and Baker Hughes' alliance, offering SURF and subsea production systems (SPS) in one contract. They've boomed (relatively) globally since Q4 2018. But they've also been raising eyebrows, says Bjørvik.

Some 50% of the subsea tree awards in 2019 were through these integrated contracts and a large number of those were dominated by TechnipFMC, he says.

"Operators are now a bit afraid they've created monsters and it worries players outside of this approach," he says.

With portfolios packed with potential projects, in basins that have existing infrastructure, such as the North Sea and the Gulf of Mexico, operators are also being picky, with easy, fast return projects making the grade, so the more technical projects are not necessarily coming through.

The economics of subsea tiebacks, especially in a relatively mature basin like the Gulf of Mexico, are healthy, says Jonah Margulis, US Country Manager at Aker Solutions.

Operators there are targeting oil and the tieback lengths, water depths, and pressures are continuing to increase, he says, with many now quite comfortable with a 15,000 psi pressure regime and 20,000 psi developments are happening, he says.

But, there's still a fundamental gap in terms of the ask from operators of their technology partners for new technology and a willingness to pay for it or for it to be funded by the service companies themselves, says Evans.

This includes electrification, which is being talked about more and more, and offers a strong value proposition - reliability, safety, and cost reduction, because of the umbilical and topside control simple could be smaller and simpler, says Evans.

"It ticks all the right boxes, but there's still inertia to go down that route," she says. It will come, as will the longer tiebacks that have been discussed, because they're a way to not invest in new facilities.

Here, and in deeper waters, where there's an extra layer of risk aversion, capital constraint is what's hindering investment decisions. The longer-term trajectory is about being more standardized and commoditized, she says.

On the horizon, areas like Australia will come into play, she says, as LNG projects continue to mature and need more backfilling. The, Angola , and potentially Nigeria.

TechnipFMC

Speaking at SPE Offshore Europe in Aberdeen last year, Justin Rounce, TechnipFMC's EVP and CTO, said that tiebacks had been "increasingly important over the last five years and we don't expect that to change".

He estimated that, over the next four years (to 2023) 60-70% of capex would be spent on tiebacks – and potentially more.

"Most customers are asking about tiebacks," he said and if they could be done at up to 30 miles cost effectively it would open huge opportunities, while "60-70 miles would truly game changing."

"We have the technology today to do this, but it has to be more cost effective. If we really want to realize the opportunity we need to be more disruptive," he says.

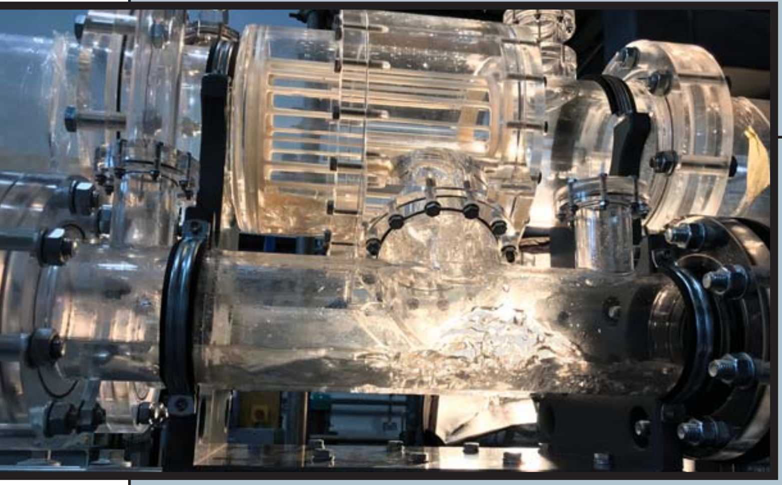
The high-level challenge is flow assurance related, he said, focusing on more cost-effectively maintaining temperature over long distances, and subsea processing. Simple, efficient solutions are needed that are more cost-effective to enable wider adoption, he said, including systems that can boost single wells, such as subsea multiphase pumps for single well tiebacks and the power system that they need, so they don't occupy significant topside space.

"Doing this could really the impact economics of subsea," he said.

Baker Hughes

Baker Hughes has offered its Subsea Connect concept and early engagement in this space, to help reduce costs for subsurface to surface.

It's also offered standardized subsea trees for medium depth projects, the first of which was delivered in 2H last year, as well as its Aptara subsea system concept, which includes lightweight compact tree, modular compact manifolds and pumps, composite flexibles, Source: Lee Thomas, Intecsea



PDG Unit in Testing: *A scale model test of the pseudo dry gas system has been put through its paces.*

TESTING NEW TECHNOLOGIES

A concept that could extend the distance of gas tie-backs to in excess of 150km up to 350km could take another step forward this year. The concept, driven by Lee Thomas, Lead Development Engineer at Intecsea, would involve placing multiple, in-line piggable separators along a long pipeline tieback system in order to remove liquids that condense from the gas during transportation (see OE: May/June 2019). Supported by small, single phase centrifugal pumps, larger pipeline diameters could be used to reduce back pressure – by some 50-180 bar.

Following modelling by Intecsea and the University of Strathclyde in Glasgow and six-inch scale model testing at Cranfield University's flow loop during 2019, Intecsea now hopes to build a pre-production hydrocarbon prototype of the pseudo dry gas (PDG) system concept.

It will use a hydro-mag subsea pump from Norway's FSubsea and a subsea control system. This would be tested at the new NEL facility just south of Glasgow in the UK with simulated hydrocarbons up to 120 bar. This will verify modelling and the scale model testing already done through a joint industry project with the Oil & Gas Technology Center.

After that, Thomas says that the pre-production prototype would be installed on an onshore gas field to run it for three-months for an endurance test. This latest testing is focused on building a consortium of partners in the technology and pursuing a number of funding avenues, which could be approved later this year. These steps would help take the technology to TRL5-6 by 2022, says Thomas.

The system could be used instead of subsea gas compression (or floating compression), which costs more and is based on adding energy to an energy insufficient flow system – based on industry project announcements subsea compression also has a high entry point in regards to gas field size, currently running an average of 12.5 Tcf, he says.

"The core problem with long distance deep-water gas tiebacks is a liquid (multiphase) problem, excessive pressure drop is a symptom of the problem, the further and deeper the tie- back the more excessive this symptom becomes generating highly negative secondary and tertiary order side effects, PDG focuses on addressing the problem rather than the symptoms," says Thomas.

A specific project he's assessed, under the work with the OGTC, is for a west of Shetland gas condensate tieback in the UK sector.

This would be a 200km, 2.5-6.5 Tcf project (first phase-full basin) covering stranded gas fields in 1700m water depth. It would need two pipelines, one larger for gas and a small one for liquid handling (which is eligible for composite materials) with four liquid removal units at stages along the pipe – i.e. about 30, 45, 75, and 90m along the pipe.

Modelling suggested it could add 10 and 6 years to plateau production, compared with a subsea compression solution at 32 and 80 bar respectively and offer 74% recovery, compared with 51% and 61%. CO_2 emissions and economics were also assessed, both favorably.

Areas like the Mediterranean, where significant deepwater gas fields have been discovered, East Africa and Trinidad, as well as Australia, where there are pockets of gas in deep water to neighboring existing infrastructure (<350km) offer significant potential for this technology, says Thomas, who was spoke to OE during this year's Subsea Expo.

and subsea connection systems.

The vision for Aptara tree lead times is 9-11 months, says Romain Chambault, Director Europe - Oilfield Equipment at Baker Hughes GE, with 12-14 months being the current schedule, compared with 24 months in the past. The firm also has a strategic alliance with Microsoft Azure and C3.ai to bring artificial intelligence (AI) to bear. But, Chambault says commercial models, such as incentivized contracts and closer working through alliances, will be what allows the industry to move forward.

JDR

The focus on cost extends to components within the tieback system. James Young, Chief Technology Officer at cables and umbilicals firm JDR, says, "We're seeing big intertest interest in optimizing functions in the umbilical, to make tiebacks more cost effective."

JDR invested in a horizontal laying up machine in 2016, which means it's been able to do more complex umbilicals and cables, with cores mixing up steel tube and thermoplastic hose, depending on operator requirements.

That could be any mix of super duplex, to allow for faster response time, thanks to its lower volumetric expansion or high chemical resistance, thermoplastic, fiber, power of chemical hose, all in one system. This is useful for those wanting to connect into existing infrastructure or to add in water injection, he says.

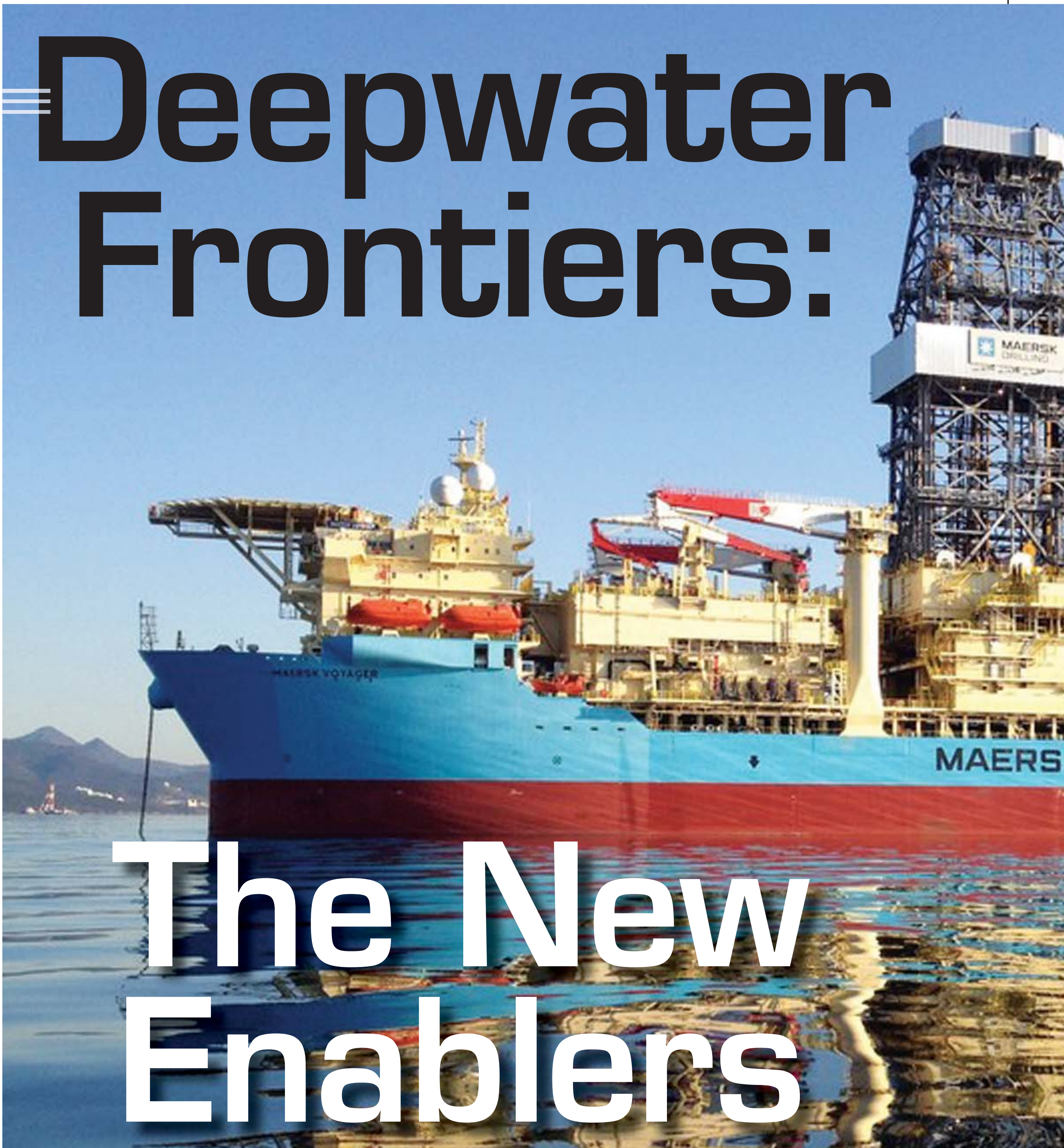
Source: Subsea UK

FAST TRACK SEAGULL

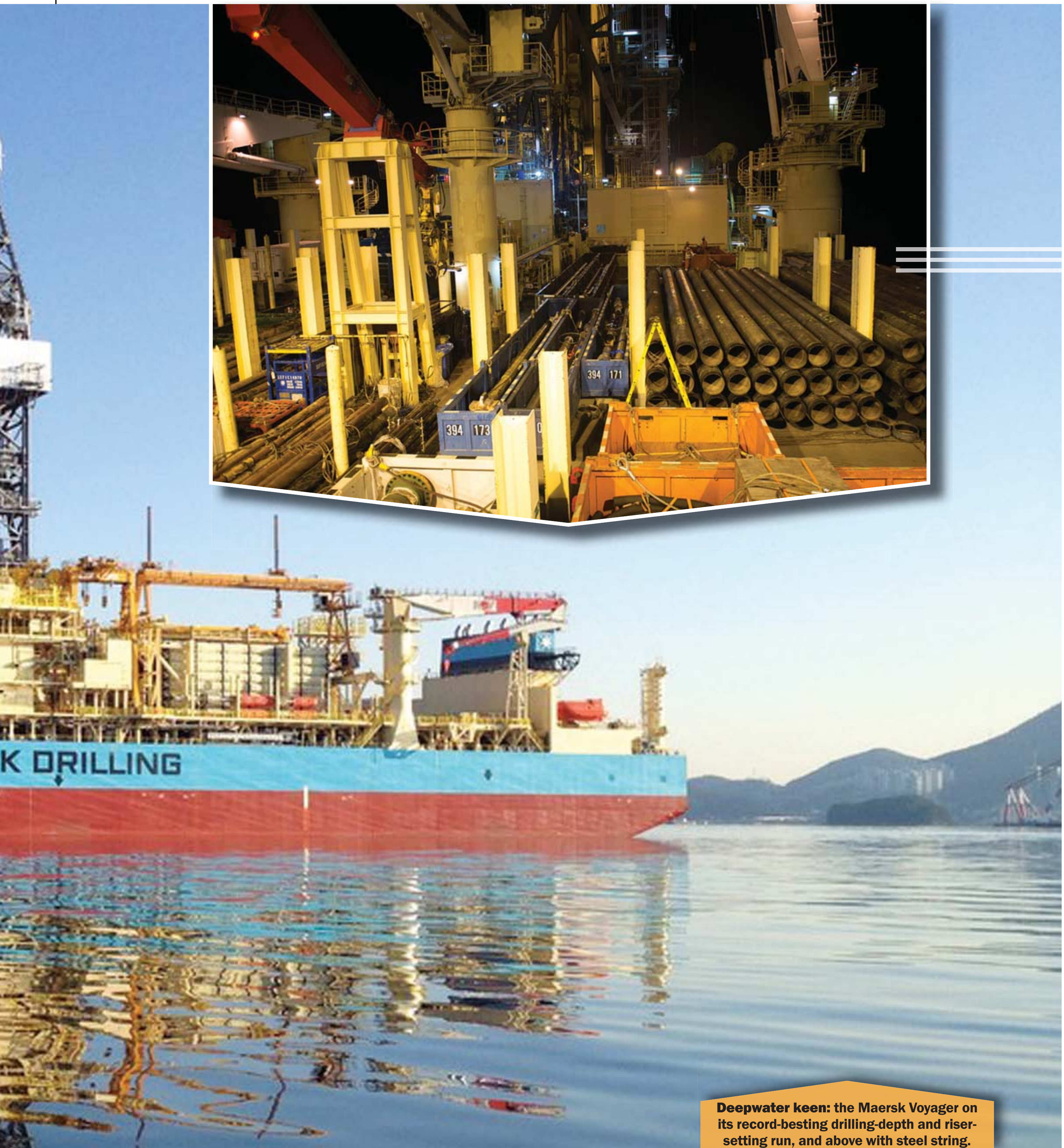
Meeting a license obligation deadline meant Neptune Energy's Seagull project has been under a tight schedule and budget. Neptune decided to acquire the Seagull find from Apache in Q1 2018, closing the deal that August and taking over the reins in Q4 of the same year. It then faced a license commitment to get a field development plan (FDP) approved, this it did by March 2019, with 21 commercial agreements reached and another 40 agreements relating to use of infrastructure and export systems, all just 16 weeks after taking control. The project was outlined by **Alan Muirhead** (pictured left), Director of Projects and Engineering at Neptune Energy during Subsea Expo.

Seagull is a high-pressure, high-temperature field (11,700 psi/160 degrees C), 17km from BP's ETAP (Eastern trough Area Project) project, 230km east of Aberdeen in 95m water depth. The field is projected to hold 50 MMboe gross 2P reserves. Development work started in 2019 with first oil projected for 2021. It will see four wells tied back into ETAP via a new 5km pipeline to the Heren pipeline, via a tie-in skid at the Egret manifold, and then Skua manifold. The project will include a new 17 km control umbilical, direct from ETAP. The achieve the pace to FDP four elements were needed, said Muirhead: capable and competent people, in the supply chain and at the operator; joint venture agreement (with partners BP and JAPEX – for which it was a first project in the UK North Sea); commercial adaptability; and supply chain engagement. "It wasn't about winning every battle, we had to get over the line or we didn't have a license and didn't have a field to develop. It's not winning every point, it's aiming at a target," he said. In terms of supply chain engagement, Neptune used its global alliance agreement with TechnipFMC, with an "open-book, targeted cost collaborative model" based on risk and reward. Pipelines and manifolds are due to be installed this summer and already 6% savings on the budget have been made, said Muirhead, just through the engineering piece. More will come going into installation, he says.

Deepwater Frontiers: The New Enablers



Source: Maersk Drilling



Deepwater keen: the Maersk Voyager on its record-besting drilling-depth and riser-setting run, and above with steel string.

Two kinds of tech making deepwater make sense again

BY WILLIAM STOICHEVSKI

Market reports on new E&P in deepwater suggest skittish but growing operator appetites. Augmenting what is largely a drive for giant oilfields, new digital tech is creating the conditions for targeting smaller fields not normally associated with deepwater and prohibitively expensive at lower commodity prices. ***Offshore Engineer*** has the pleasure of being first to report on digital production technology just out of development and set for commercial launch later in 2020.

OSLO—March, 2009. Morgan Stanley reports oil companies are increasingly shying away from deepwater projects. The credit crunch is threatening to cancel seven million barrels per day in projects.

Fast forward a decade, and deepwater projects are being relied on to meet oil and gas demand that's once more on the rise. As Wood Mackenzie analysists point out, "highly prospective acreage is expensive" and not being let go. Still, the deepwater segment is always first to be written off and last to recover. Tackling deepwater expenses has been difficult. The biggest break for operators has been a fall in rig and OSV day rates since "the downturn". Despite this, the Gulf of Mexico's Permean basin is still a deep-water hive of activity, and ultra-deep offshore West Africa and Brazil are seeing a surge in activity.

To again ply these oil provinces, operators have taken action themselves and nudged the supply chain and research communities in new directions. The fruit of their collaboration in the digital realm are just emerging in Northern Europe.

LedaFlow

Among the cost implications of deepwater production are hydrates, or slugs, the icy clumps in well stream, especially gas, that can foul production at colder, deeper depths.

As hot well stream emerges, the trace water in it can form into slushy bits, and the threat to process plant — and to safety — ensures operators have always spent staggering amounts heating and insulating pipelines and treating throughput to eliminate hydrates or slow them down, something they've gotten really good at doing (by bends in riser, pipe and slug-catcher).

The price of hydrate control and monitoring, however, can be astronomical, as it entails employing flow assurance experts; extra standby equipment; extra pipe and extra loads of monethylene glycol, or MEG, by platform supply vessel. A Kongsberg paper put the savings for optimizing the use of MEG alone at $100,000 per day!

"Very expensive," says Mike Branchflower, former global sales manager for LedaFlow, "a consortium-owned product" in the control of operators ConocoPhillips and Total as well as

research community SINTEF and commercialization partner, Kongsberg Digital. Branchflower has worked in flow assurance (hydrates, sand, scale) for years and is now strategic sales manager for Kongsberg Digital's energy division.

Offshore Engineer is first to publish news on this major breakthrough of cost (management and safety) by the consortium ahead of it launching hydrate monitoring software for the Cloud and a technology suite of related apps later this year. "LedaFlow is the only technology that can calculate slugs and it will be the first to deploy this tech in the cloud. It is a first," Branchflower says.

The new slug monitoring tech is already in the North Sea as part of a pilot to study hydrate interaction with production risers. On land, Shell has commissioned a digital twin of the Nyhamna gas processing plant in Norway that will use LedaFlow monitoring for its slug catcher array. However, the use and availability of LedaFlow to manage hydrates in deepwater is news. The new app will, it is understood, combine LedaFlow hydrate monitoring with riser fatigue modelling software now being tested.

Perplexing to some — especially for its use of blockchain coding language — company multimedia nevertheless reveals how much of the LedaFlow offering is revolutionary for deepwater costs. The savings ought to allow the consideration of smaller deepwater hydrocarbon accumulations, where the drilling of a well alone in the CAPEX stage can cost well over USD 100 million. Relaying OPEX savings early will go a long way toward helping operators decide final investment decisions.

Virtual and tactile: a slug catcher's physical and digitalized representations.

Source: Kongsberg Digital

Conserve inhibitor

Shane McArdle, vice president of production at Kongsberg Digital, says operators today "flood the system" with MEG with little insight as to where or how hydrates are located in the flowline system.

"Usually operators over use MEG to be safe, which is very costly," McArdle says, adding that the real time monitoring tools to be released this year will "fully, computationally track MEG" so operators can tune their usage "while maintaining safe distance from the hydrate formation limit."

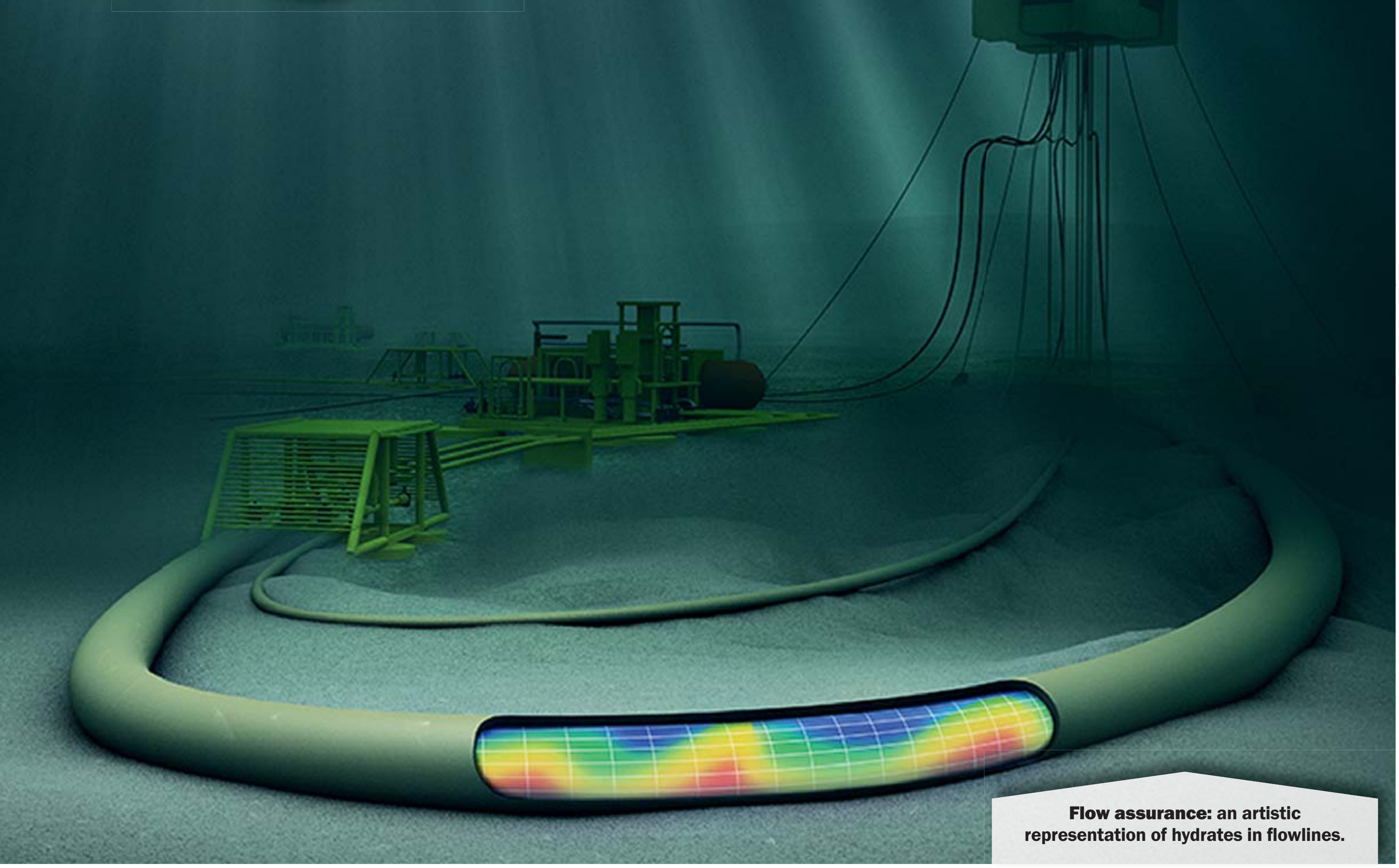
"We see a huge disruptive potential around this technology in the future. The slug capturing app deployed in the cloud is just the start point and is an essential part of our deployed digital twin," says McArdle. It may be the first moving, living part of that digital twin communicated a couple of years back as Kognifai, a cloud platform for supplier apps.

Kongsberg reports savings for using its digital twin in the supply chain — Heerema Marine on operational SIM and survey company benefits — however, deepwater operators will be focused on production management. There's advantage for both, it seems.

"Deploying the solution as an app will help democratize (LedaFlow) and make it available to more cross-disciplinary users. This will drive innovative solutions for the deep offshore industry. We already have seen this happening with the deepwater riser studies showing new results and identifying alternative designs that have not been possible before with existing tools." In the months to come, Branchflower will be keen to tell deepwater operators how LedaFlow, the slug-monitoring tool, really works. In a world where gas has become king, and gas pipelines rely on continuous MEG injection, operators will need to know how they'll save money.

Source: LedaFlow

Localized hydrate readings: fractions of temperature and pressure will help ID precise MEG needs at deepwater installations, especially in gas-lift infrastructure.



Flow assurance: an artistic representation of hydrates in flowlines.

Source: LedaFlow

"There is no hydrate modelling as such in LedaFlow here. What you do is create hydrate formation curves in PVT software and use these in LedaFlow to determine the hydrate margin in terms of pressure and temperature for different inhibitor concentrations," he explains, adding that what's new in LedaFlow is the ability to model hydrate transportation where you form small quantities of hydrate and transport them with the production fluid. "LedaFlow will calculate the mass fraction of hydrates and the viscosity increase of the production fluid. This means you can potentially reduce the amount of hydrate inhibitor required or eliminate altogether."

This "functionality" is already available on the desktop engineering software, LedaFlow Engineering 1D, as well as on online Production Management Systems. It's all usually on-site but is migrating, now, to the MS Azure Cloud and offered as Software as a Service, or SaaS.

Branchflower admits HSE isn't the main focus here. It's savings. "It is about reducing the use of hydrate inhibitors, reducing costs and potentially enabling the development of stranded assets. The typical user is a flow assurance engineer based in an office.

Airborne Oil & Gas

So much for the "virtual". At Ijmuiden, in The Netherlands, the physical make-up of risers and deepwater pipe is changing fast at producer, Airborne Oil & Gas.

With shareholders that include Sumitomo Corp., Subsea 7, Shell, Chevron and Saudi Aramco, this is a company and product with serious cost implications. Many of the challenges of deepwater start at the surface, where vessels and their A-frames, winches and cranes must handle rope, cable, "string" and pipe heavy enough to sink a medium-sized workboat. Lighter rope and cable have been around for years, but the advent of lighter flowlines and pipe, normally steel, has been slow in development.

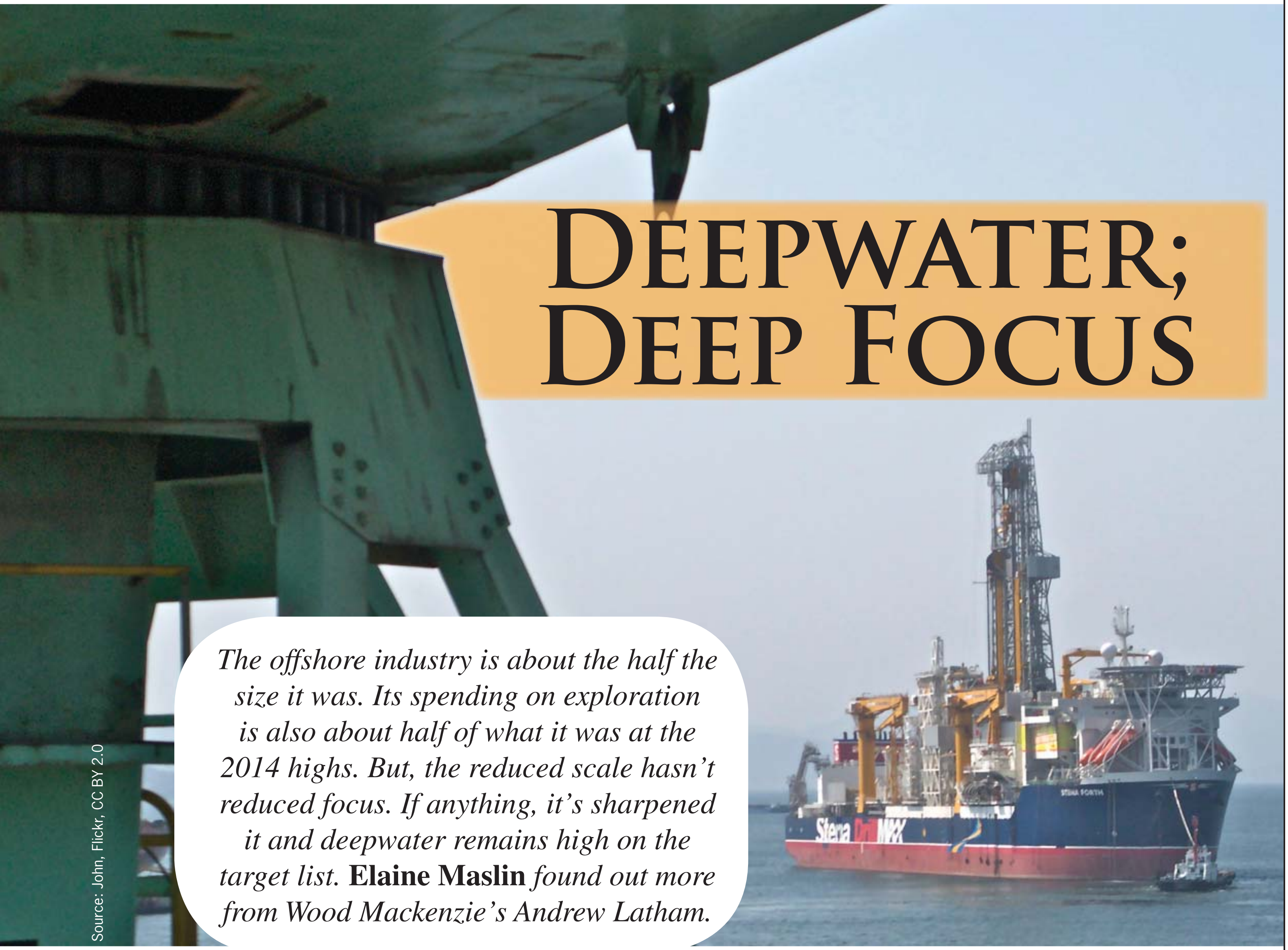
Enter Airborne. Using thermoplastic composite pipe, or TCP, made of an inner liner and outer coat "melt-fused together", this pipe for pipelines, wellheads and risers is easily cut at any point "in a matter of hours", onshore or offshore. Airborne has, since about 2018, qualified one TCP application after another — from pipelines to jumpers and flowlines — but, it's the introduction, now, of its deepwater risers where big-time costs are expected to come down.

Deepwater futures

As of 2018, the company — owned by Sumitomo Corp, Subsea 7, Shell, Chevron and Saudi Aramco — had a solid "track record on all products except the TCP riser". In 2020, however, the Brazilian FPSO market appears to be the target, as company literature looks at the riser array of the FPSO Cidade de Sao Paulo as "a feasible in-place configuration" for its new "plastic" risers.

Savings — where a dynamic riser can be "floated out on low-cost tug" rather than by max-price pipe-lay vessel or rig — is the major Airborne offering to operators and one of the reasons faith has recently been restored in Brazil's prolific pre-salt. The "50-percent lower top-tension" and "70 percent less hanging weight" of a TCP riser helps result in a "30 percent installation costs" cut. Then come the lower pipe, transportation and installation costs. For FPSOs, especially, there's the lower price tag of riser balconies, handling and mooring systems.

So, as the "seventh-generation" rig Maersk Voyager begins its Angola-Namibia campaign to potentially break the Maersk Venturer's world record for drilling depth, there's optimism that more deepwater is within reach even at low commodity prices. The Maersk Venturer's well might one day be completed by TCP flow lines and risers, their well stream monitored by a LedaFlow app.



Source: John, Flickr, CC BY 2.0

Deepwater; Deep Focus

The offshore industry is about the half the size it was. Its spending on exploration is also about half of what it was at the 2014 highs. But, the reduced scale hasn't reduced focus. If anything, it's sharpened it and deepwater remains high on the target list. **Elaine Maslin** *found out more from Wood Mackenzie's Andrew Latham.*

The reduced scale of the industry hasn't reduced interest in exploration, including in deepwater and new basins – provided that there's a sensible route to market for any reserves discovered. These are themes that have been playing out since 2017 and continues, says Andrew Latham, vice president of global exploration at industry analysts Wood Mackenzie, in his annual catch up with us here at OE.

This year, those themes will continue and deepwater is again very much in the mix with wells in deepwater offshore Algeria and Lebanon expected and the industry's deepest water well yet (deferred from last year).

Looking back – 2019 results

These wells will follow what was a year of valuable deepwater discoveries in 2019. Last year saw Guyana's offshore continue to hold the limelight, with ExxonMobil, which has led exploration there, announcing a 2 billion barrel upgrade in reserves in January (2020), mostly from the four discoveries it completed in 2019, says Latham.

It's not all been about Guyana either. Apache's Maka Central-1 well, drilled with the Noble Sam Croft drillship, found light oil and gas condensate in Block 58 off Suriname, estimated at more than 500 million boe. Total also made the gas condensate Brulpadda discovery in Block 11B/12B in the

Image above: The Stena Forth drillship.


Source: Wintershall

Image right: Odfjell's Deepsea Stavanger semi-submersible drilling rig

Outeniqua Basin 175km off South Africa – proving a "world-class gas and oil play", according to Total, in area with similar environments to west of Shetland. The well was drilled in 1,400m water depth using Odfjell's Deepsea Stavanger semi-submersible which is due to return to the area in Q2 this year for 10 months to drill up to three exploration wells.

Other interesting finds included the Orca discovery, says Latham, in 2510m water depth in the BirAllah area, 125 km off Mauritania. It's been estimated to contain 1.5-2 billion boe (or mean gas initially in place/GIIP of 13 Tcf) according to Kosmos, the operator which, along with Marsouin-1 in Block C-8 in 2400m water depth, it says would be enough for the world-scale LNG project.

ExxonMobil also made the Glaucus discovery in 2063m water depth, in Block 10 offshore Cyrus; a multi-Tcf find. Meanwhile, CNOOC made an ultra-deepwater basement gas find, Yongle 8-3, in the Qiongdongnan basin. BHP also made three finds "of interest" offshore Trinidad and Tobago; Tuk, Hi-Hat and Bele. These were in 2102m water depth in the Northern license area and while not massive, they were commercial, with 1-2 Tcf each and nearby infrastructure to tie into.

It's not all rosy. One of the wells on the watch list last year was Chevron's Kingsholm high-pressure, high-temperature (20,000 psi) probe with an estimated 300 million BOE of resource in the US Gulf of Mexico. Little information has been made available about the result. Meanwhile, Eni's Kekra-01 well in the Indus G Block, some 230km offshore Pakistan, drilled Saipem's Saipem 12000 drillship, was a disappointment.

Despite the patches of bad news there's positivity and that's because the sector is profitable, says Latham. "For us to make that call so near to the end of the year, when assessment of the year's success tends to improve over time, is something. Profitability has come roaring back."

Focus remains in 2020

But operators are not getting silly. Budgets are not expected to grow for 2020, if anything, they're 10% or so lower because many companies have really dialled back on their exploration spend, he says. But, "those sticking with it are still drilling and there are a number of high impact wells." These are the majors, not least Total, which again leads the deepwater exploration pack, as it did in 2019, but there are also some national oil companies, including Qatar Petroleum, which is a partner in a number of 2020's significant deepwater exploration wells, as well as players like Kosmos, Cairn and Woodside.

"There's still appetite for frontier exploration," says Latham. "The watch word is commerciality. Five years ago, the philosophy was 'build it and they will come'. Now, there's very much requirement that if a well is successful there's going a reasonable feasibility rate of commercialisation without a long lead time." Part of this is driven by uncertainty, with increasing discussion about energy transition, nearer term projects are preferable. Discoveries also need to compete with the existing portfolio, so they need low cost break evens and big volumes, to bring down the cost curve.

Central & South America

Mexico

It's quite a big year in Mexico, says Latham, with previous years' licensing rounds now being converted into exploration drilling. There are a number of wells scheduled, including Repsol's Polok 1, due to spud in March in 583m water. Other active explorers include Petronas and CNOOC, which are planning the Ameyali well in 1500m water depth in Block 4 in April, then a second later in the year.

Shell, with partner Chevron, is also drilling the Chibu-1 well in the Salinas - Sureste basin in 2760m water depth. Shell also has Max-1, planned for May, at 2500m.

Brazil

It's been quiet in Brazil, on the exploration front, with operators focusing on appraisal. But, this year, there are some wells to watch, with perhaps 10 deepwater wells expected through the year. Shell was due to start drilling Saturno, a billion-barrel prospect, in the Santos Basin in 2700m water depth, starting late May, which could be followed by further wells in 1700-1800m water depth. ExxonMobil will also target an exploration well in the Santos Basin in 2700m depth later in the year, says Latham.

Other notable wells include Monai-1 in the Campos Basin in 2400m water depth, operated by incumbent Petrobras, while Equinor is targeting ES-M-671, in April, in Espirito Santo, in 2500m water depth. Also, BP 's planned Morpho-1 exploration well, in just over 3000m water depth in the Foz do Amazonas Basin, still remains on the 'upcoming' list.

Peru

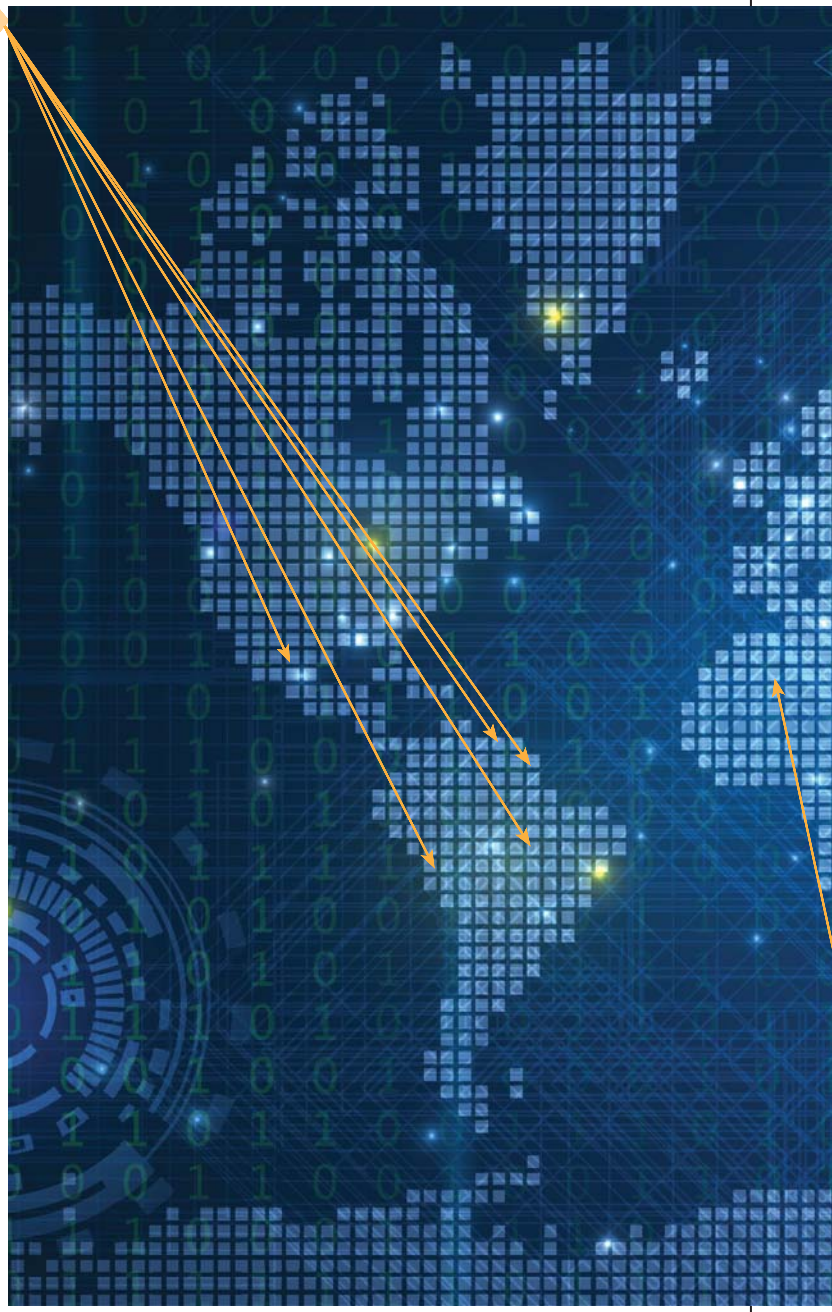
Elsewhere in Latin America, Karoon Energy's Marina-1 well in a pretty big frontier offshore Peru was on the watch list but it's already been deemed non-commercial, following drilling using the Stena Forth drillship earlier this year.

Suriname

Kosmos is set to start drilling on Walker-1, in Block 42 in 2250m water depth, in April 2250m, testing a similar reef feature to the Ranger-1 well in neighbouring Stabroek block in Guyana from 2017.

In Block 58, Apache has followed up its successful Maka Central-1 well from last year, with Sapakara West-1 – drilling was ongoing, going to press. Both wells are in about 1100m water depth.

Petronas might also drill a prospect in 2000m water depth

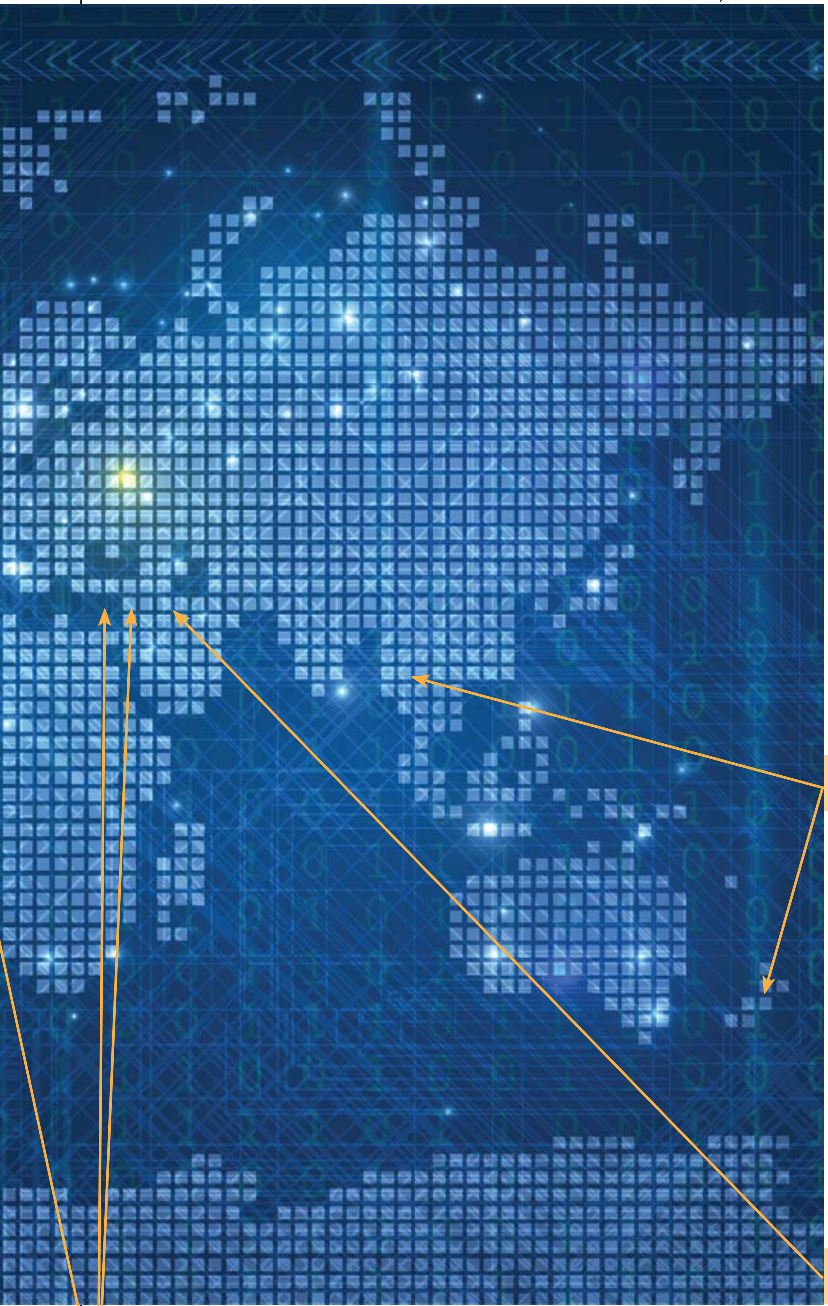


in Block 48, perhaps as soon as April, says Latham. Tullow may also drill the Goliathberg North prospect in 1900m depth in 2H.

Guyana

Guyana remains under focus with two wild cats in the Stabroek Block by ExxonMobile. Uaru was confirmed in January as Exxon's 16th discovery in the block, in 1700m water depth. The Hassa 1 well is next in line, in similar depths. But, more interesting is a well in summer, also by ExxonMobil, in the

Source: © lidiia/AdobeStock



Kaietur Block, called Tanager-1. This will be in 3000m, pushing the drilling depths seen in this country.

North Africa, Med, Middle East

Algeria

Algeria has been promoting its offshore for a long time, but there's been little exploration. Now, Eni is planning the Oaze-1 well in 1400m in partnership with Total and Sonatrac. It's expected to start in July and, if successful, is expected to be something big.

Cyprus

Cyprus has been under the exploration spotlight and it's still interesting, says Latham. There could be 4-5 deep water wells here in 2020. Eni hopes to drill two to three, which could include its second well on Block 6, in 2500m water depth, another on Block 8 later in the year, in about 1000m water depth, and potentially Eratosrhenis, also on Block 8, in 1000m.

Total is set to drill on Block 11 in summer, in 1800m, while Exxon is lined up to drill in Block 10 on the Anthea-1 prospect in 2000m water depth. This is an area that's already ripe for commercialization with more to come, says Latham.

Lebanon

Total started drilling on Lebanon's first offshore well, Byblos-1 in Block 4 in March, using Vantage Drilling's Tungsten Explorer drillship. It's a big gas prospect and could be followed by a second exploration well in Block 9 later this year.

Asia Pacific

Myanmar

Following a spat of discoveries by Woodside, Mynmar fell quiet. Now, Thai firm PTTEP, with Total, is drilling Shwe Nadi-1 in 2000m water depth.

New Zealand

In New Zealand, OMV's Tawhaki well, spudded in January by the COSL Prospector rig, in 1300m water depth in the Great South Basin – a frontier basin – found no hydrocarbons in the target reservoir. OMV then decided to plug and abandon the well.

Other

Azerbaijan

While shallow, in comparison with some of the deepwater wells being drilled globally, BP's 624m water depth Shafag Asiman well is deep for the Caspian Sea, 125 km (78 miles) to the South-East of Baku, Azerbaijan. It's also a huge prospect, potentially containing 5 billion boe of gas condensate. It's already spudded but may take some time to drill, being a 7000m deep well, being drilled using Caspian Drilling Company's Heydar Aliyev semisubmersible drilling rig.

Doing De-manning & Unmanned

Source: Equinor

Increasing moves are being made towards use of remote unmanned facilities. Having unmanned platforms would allow operators to reduce travel and carbon-dioxide (CO2) emissions, as well as raising safety levels by removing the need for permanent personnel offshore. It's also about cost. ***Elaine Maslin takes a look.***


showcase
Pioneering Spirit
Allseas

Source: Aker Solutions

Normally unmanned installations (NUI) aren't new. In the 1970s and 1980s a large number of minimum facility platform designs were adopted in the Gulf of Mexico to exploit marginal fields. Minimum facilities are common in the UK's southern North Sea where shallow water made them economical as satellites to hubs.

However, there's now increasing activity in the unmanned platform space; fixed and floating. Some of this activity was a reaction to rising subsea costs. While subsea offered an unmanned solution, it was becoming increasingly uneconomic, Equinor argued, and instead decided to develop the Oseberg Vestflanken 2 project as an unmanned platform ("wellhead on a stick", as it was called at the time), having made public its concern over the competitiveness of subsea costs.

That led to the remote operated Oseberg H platform, operated from Oseberg central, billed as Norway's first unmanned platform when it started production in 2018 – now called an unmanned wellhead platform (UWP, also trademarked).

A big enabler for that was the growing availability of walk-to-work vessels, initially developed for the offshore wind industry but that have been used in oil and gas, not least after a spate of helicopter crashes that made alternatives attractive, as well as increasing decommissioning work, where extra workers can be housed on flotels and walk across to platforms, embedding these gangway systems into the industry. Use of walk-to-work vessels meant that a helideck and the ancillary equipment needed to service it was no longer needed, reducing costs of the wellhead on a stick.

Aker BP took a similar approach with its Valhall Flank West project, using an unmanned platform, and even hailing its first campaign using a gangway for access from a vessel to facility, for hook up operations, in a press release, although day-to-day

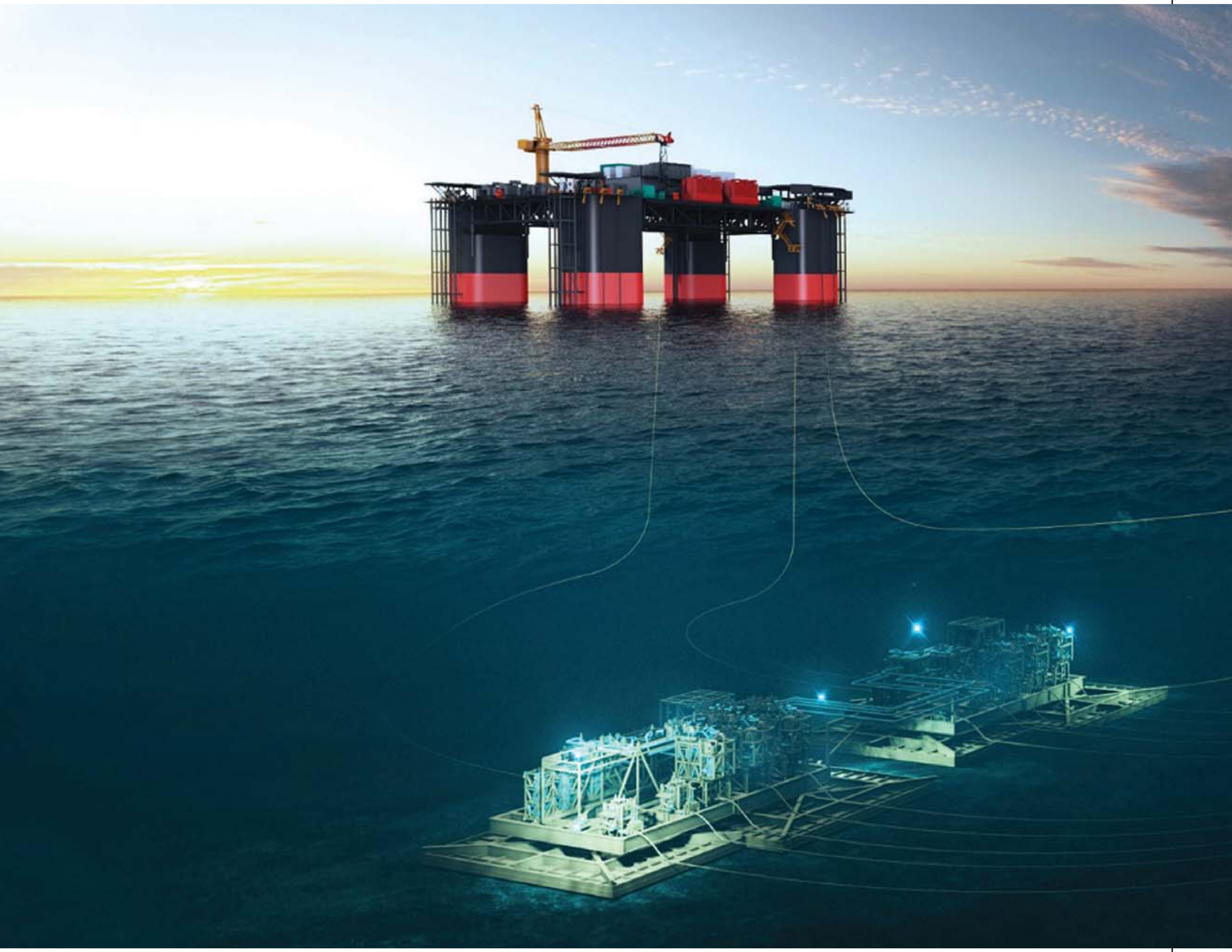
Aker Solutions unmanned FPSO concept.

Valhall Flank West – all electric and unmanned.

transport is via a helideck. It's remotely operated from the Valhall field centre, as are the Hod (Norway's first unmanned platform), Valhall Flank North and Valhall Flank South platforms.

But, unlike the others, the 12-slot, 2220-tonne Valhall Flank West topside – including its crane and lifeboats – is fully electrified, with power from the process and hotel platform at Valhall (although there is diesel supply through an umbilical for coiled tubing operations and well start-up), following conversion to electrification there in 2013 – another "first". Valhall Flank North also has three walk-to-work landings, while still also having a helideck. Aker BP's target is for 50 visits a year, on average, including well intervention operations. A "stretch target" envisions four planned campaign visits a year, not including well intervention.

But, there's a bigger vision. Equinor has a road map towards an unmanned remotely operated factory (ROF), using un-



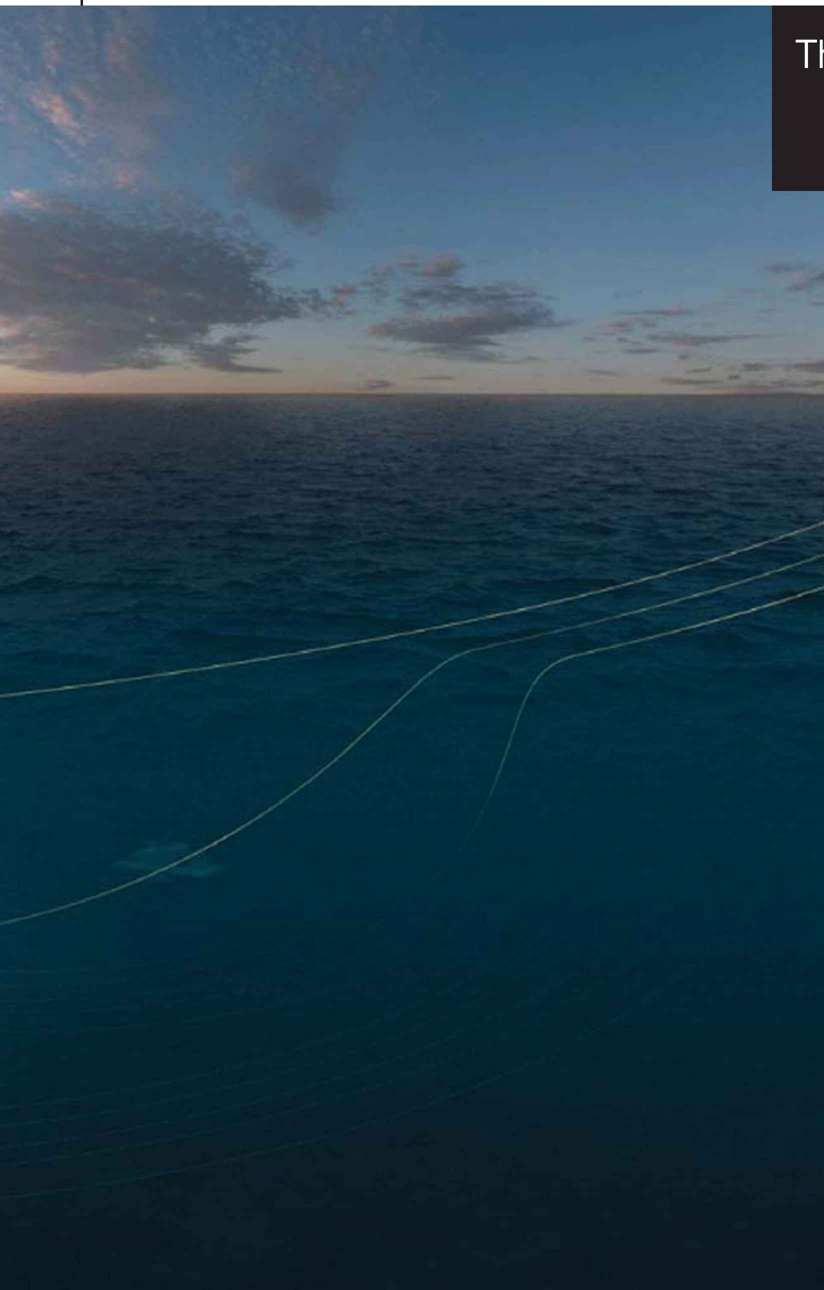
manned wellhead platforms or unmanned production platforms (UWP/UPP). These concepts, working remotely and unmanned, have the potential to save 30% capex and 50% in opex, according to an Equinor presentation from 2018.

Next on Equinor's road map is an unmanned production platform (UPP, trademarked) supported from a host at Krafla/Askja, then a standalone gas/condensate project at Peon. Further down the line, Equinor sees standalone projects in the UK and the Barents Sea, followed by Brazil.

A MINIMAL MINDSET

"A wellhead platform is one thing, another is adding more and more functions; processing, power and control," says Knut Nyborg, EVP and head of Front End, at Aker Solutions. He says having experience delivering unmanned platforms as well as intrinsically unmanned subsea facilities, including the Åsgard subsea compression facility, "which is a truly unmanned process facility", helps.

And, he says most of the technology is in place. "It's about



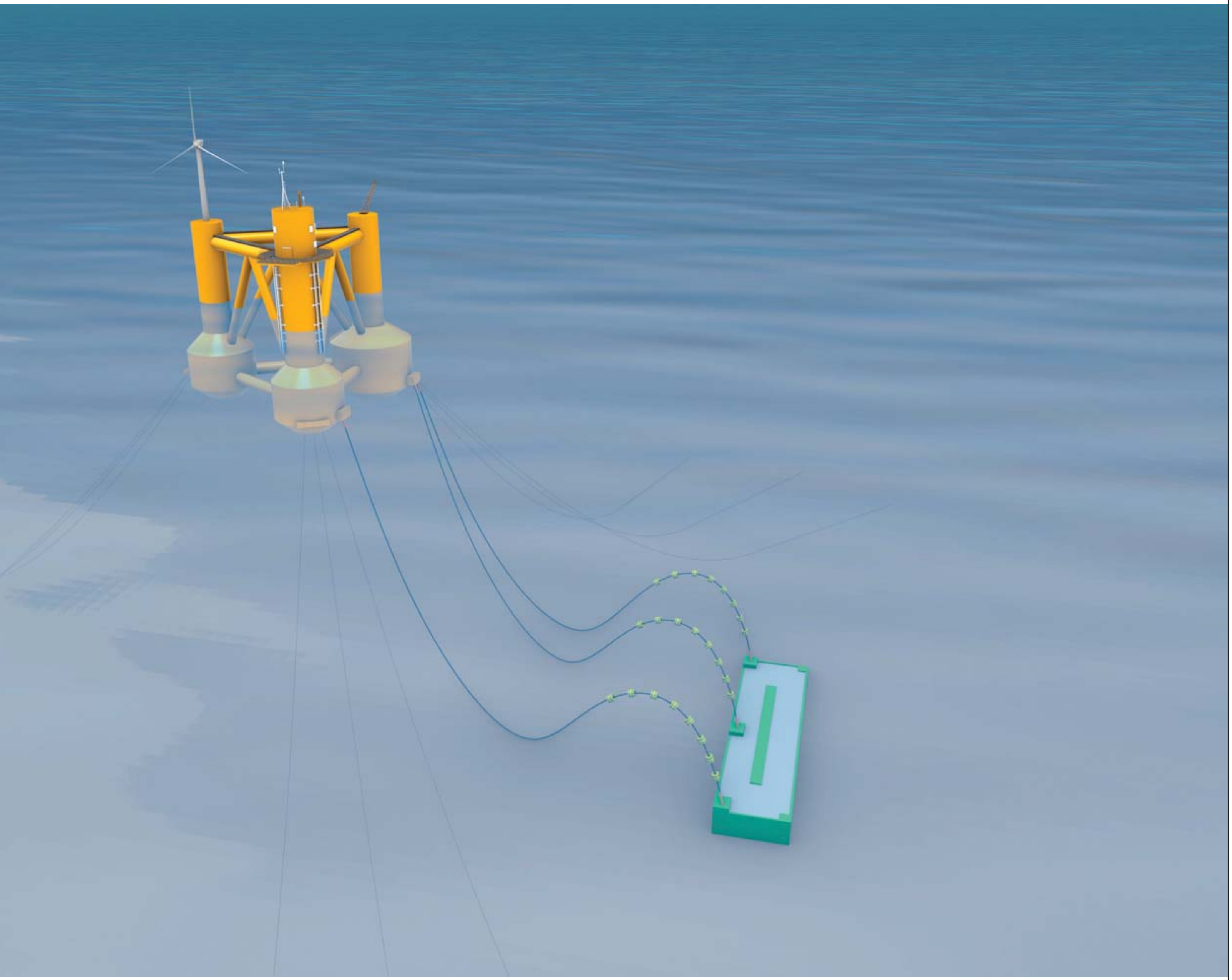
The Jansz-Io subsea compression project supported by power equipment on an unmanned semisubmersible.

It's not just about new platforms. Frames is working with ONEgas - the combined business unit of Shell UK and Shell's Dutch subsidiary Nederlandse Aardolie Maatschappij (NAM) – on converting various manned Dutch North Sea platforms to NUIs or removing functionality from existing platforms to cut maintenance costs using walk to work vessels allowing them to stay on-site longer to complete their programs. Frames says its been helping companies de-man platforms for five years, with service vessels instead of helicopter flights to access facilities.

The main challenge with this work, which is mostly around de-complexing facilities, is to engineer and install highly reliable hydraulic systems which need as little maintenance as possible against a competitive price, says the firm. "It is important to understand that in case of a malfunction you can't simply fly to the platform, you need to be 100% reliable," the firm told OE. "After this de-complexing the regular service activities for an unmanned platform will be stretch over a longer period from one to two years or even longer in the near future."

different mindset. It's about making decisions and challenging regulatory requirements and changing company specifications on the client and contractor side. For unmanned facilities, you need to get rid of everything you don't need. Start with the core functionality. If it's a relatively simple process platform with a separator and pump and compressor this facility shall support pump and compressor and everything else needs to be argued in. it's an 'argue in' methodology'. Then you need to select robust equipment, with inherent reliability and safety to get rid of maintenance."

Åsgard does this by using a compressor design that doesn't need lube oil, they're hermetically sealed and have a magnetic bearing. Topside systems cheaper systems that use open shafts and dry gas seals which are more commoditised and require maintenance. It's a choice. Another key element is going all electric, adds Nyborg, because electric actuators and motors are more reliable than hydraulic and pneumatic ones, but also because they provide much better condition monitoring capability.



Going to press, Kvaerner, which delivered Aker BP's Valhall Flank West platform, was due to deliver a front-end engineering and design (FEED) study to Shell for an unmanned wellhead platform for the Jackdaw project in the UK North Sea. It worked with Leirvik and Rambøll on the project. Aker Solutions, meanwhile, is currently working on Chevron's Jansz-Io project, in Australia. It's a 200 km long step-out subsea compression project, which requires an unmanned power and control station (FCS), based on a semisubmersible, to house electric drives, transformers and breakers etc. for the subsea compressors and pumps. The distance means manning and maintenance are a challenge. There's also not a fleet of vessels as available as in somewhere like the North Sea. So unmanned was a requirement. The biggest challenge here is mostly about mindset, says Nyborg, "taking on board that this is 200km away from the mainland, where there are not many people. It's 200km to any proper facilities. You have to cut surplus and the nice to haves and keep the core things."

Aker is also working on the FEED stage of BP's Cypre project offshore Trinidad; a well head platform that BP is considering replicating in the basin. "The idea is to standardise on the one design and build it," says Nyborg. It will also not have a helideck.

ROBOT REVOLUTION

Total has been perusing developments in robotics that would mean routine inspection and maintenance could be done using robots, limiting even further how often humans would have to visit a plant. The French energy major has been working with German robotics firm Taurob (OE: January 2018), which won Total's Autonomous Robot for Gas and Oil Sites (Argos) challenge, partly sparked by the Elgin-Franklin gas leak in 2012, which could have been easier to deal with using robots on the platform (as it was too dangerous for humans to board).

After winning the competition in 2017, Taurob's further developed the robot and undertook onshore trials at Shetland Gas Plant last year (2019). Earlier this year, Total was due to take over ownership of two versions of these robots with a view to trailing them on the Culzean platform in the North Sea and then a NUI. The end goal is for installations that only need someone on them once a year – or "NUI-1Y", as Total's called it, providing "a new frontier for cost reduction", according to a 2019 OTC paper. Equinor and Saft have partnered with Total on the OGRIP (Offshore Ground Robotics Industrial Pilot) robot project, which aims to develop the "world's first Offshore Work Class Robot (OWCR)".

Others are following. Earlier this year, Aker BP formed a strategic partnership with Cognite, which it part owns, to explore the potential of robotics in the offshore oil and gas platform.

New technologies like this are enabling operators to think differently, from control systems to robots and drones, which have made big in-roads in recent years for inspection work, albeit with a human operator nearby – but that could change. Data monitoring, remote operations, telecommunications – the advent of 4G LTE for example – and robotics are now on the scene and enabling things to be done differently.

Upstream, without a crew

There are also concepts for unmanned floating systems. Various unmanned production buoy concepts have been covered in these pages numerous times before. They've not yet taken off, but some are still hopeful (see panel). Now, engineering firms including TechnipFMC and Aker Solutions are offering new solutions.

A floating UPP is one of the concepts being considered for Peon. The field was discovered in 2005 and has a thin gas column over a large area. In 2012, because of the field's properties, combined with being a long distance to possible host platforms and there being a lack of capacity in the gas transport system, it wasn't deemed economically viable. Now, Equinor has said it's working with Gassco and Neptune Energy to investigate the possibilities of phasing Peon in, into either the Kollsnes processing plant onshore, or to Gjoa field facilities, about 60 km south of Peon, via a floating UPP.

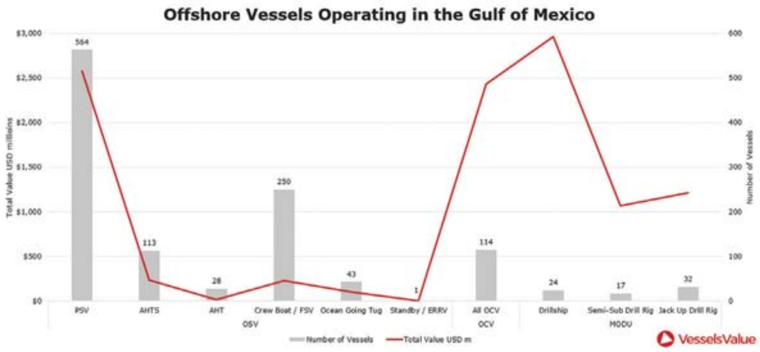
TechnipFMC and its engineering subsidiary Genesis has focused on a minimal unmanned floating substructure for applications including platforms for production, compression, power and wind turbines, using a spar concept. It also looked at alternatives to a spar, such as an extended draft platform (EDP) buoy, which could be used for applications including supporting a low-cost subsea development. Its columns and pontoon are raised, which allows for equipment to be installed in the deck box when it is at ground level or floating in a collapsed configuration. The shape of the deck box also provides sufficient area for processing, power, communications, instrumentation, and material-handling equipment.

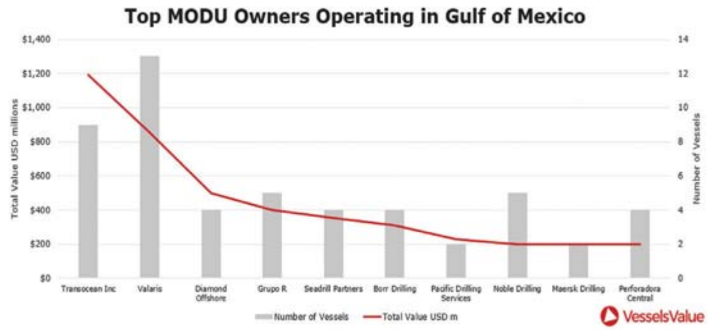
Without people onboard, you can simplify design of the substructure, as the stairs and elevators normally needed to allow people to access the inside of the substructure can be replaced with ladders and ropes that require less space, according to another OTC 2019 SPE paper.

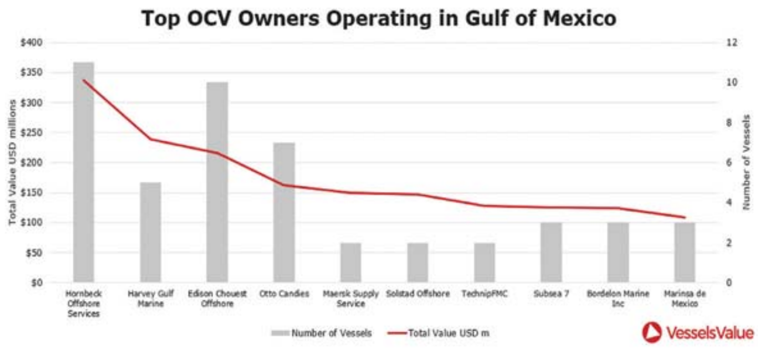
Aker Solutions is also looking at unmanned FPSOs, with remote operation, control and surveillance. That means eliminating quite a lot of functionality, says Nyborg: "no living quarters and preferably also without a helideck, but depends on the location." It also means systems that can sustain shut-in well pressure and live without flaring, as well as being all electric with high reliability equipment. A change in maintenance methodology would also be useful – having self-diagnostic plug and play systems where an entire unit is just switched out instead of needing complex operations, like today's cars, minimising offshore man-hours and not requiring specialists.

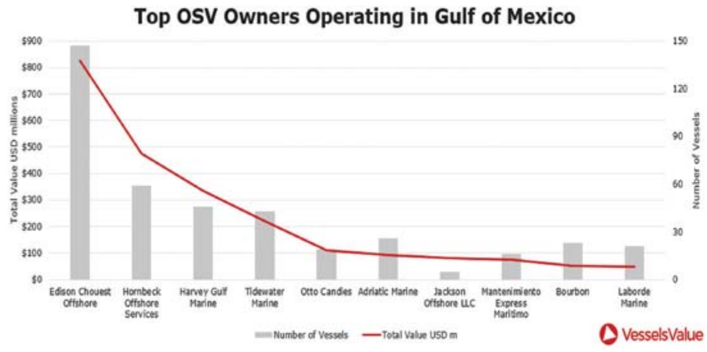
Today, the goal is to design facilities that reduce maintenance and start to require people onboard just 1-2 times a year, says Nyborg. That's a steppingstone for more self-diagnostics and calibration, as well as use of robots, which could also reduce the number of people needed on facilities, from say 80 to just 15. Longer term, could truly unmanned be achievable?

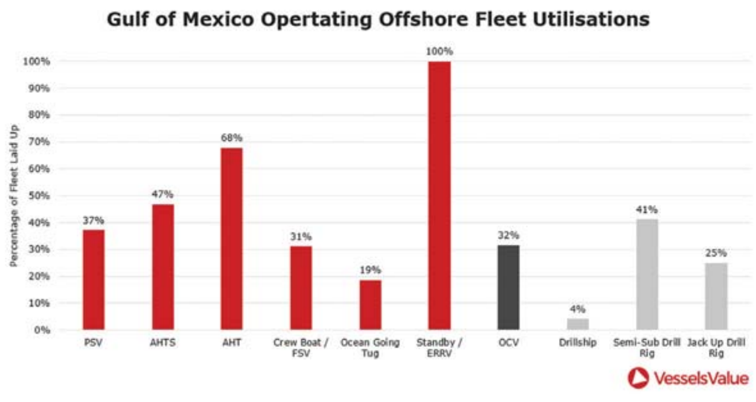
Data & Statistics powered by VesselsValue

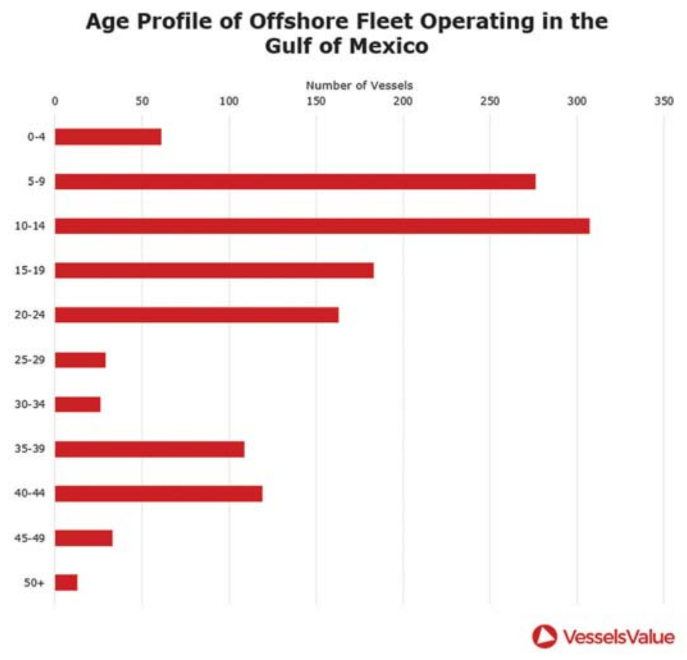












Source: Maridav/AdobeStock

SAFETY FIRST

This product feature was going to be filled with tech and systems aimed at the all important offshore health and safety, a priority irrelevent of the price of oil and gas. Thinking about it, we'd imagined we'd present you systems designed to prevent offshore gas leaks, life saving equipment, fire retardants, accident prevention tools; and some of those are indeed here. However, little did we know that something invented 2800 B.C in Babylon – that we today take for granted and use, apparently occasionally – would top this list – SOAP! You are undoubtedly now well aware the reasoning, as it helps stop the spread of the deadly coronavirus (COVID-19) disease.

According to the World Health Organization, when someone who has COVID-19 coughs or exhales they release droplets of infected fluid. Most of these droplets fall on nearby surfaces and objects - such as desks, tables or telephones. People could catch COVID-19 by touching contaminated surfaces or objects – and then touching their eyes, nose, or mouth – and we do this often, even without realizing. This is why it's important to keep washing hands with soap. Washing kills the virus on your hands, and prevents the spread.

So, while you've probably been bombarded by messages to wash your hands frequently, given the ever increasing number of those who've contracted the virus – here it is again: "Please wash your hands frequently, no matter where your are, offshore or onshore."

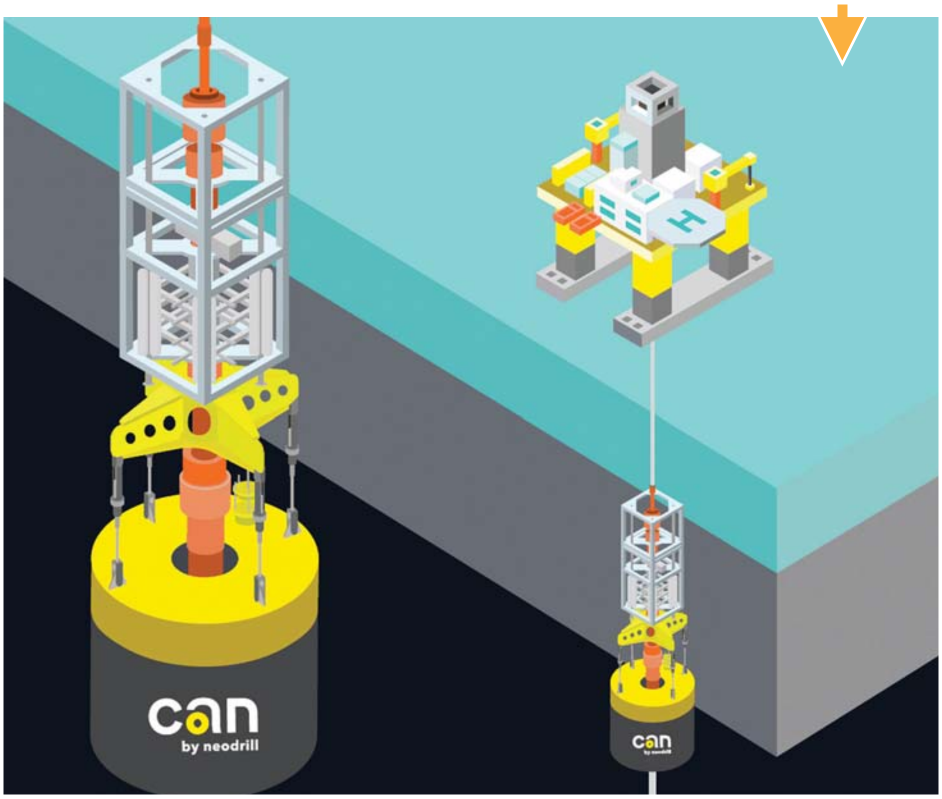
According to the WHO Myth Busters section, the new coronavirus can be transmitted in all areas, including areas with hot and humid weather, as well as in the cold weather. This means offshore facilities can be affected to, as seen in a recent case at an installation in Norway. And no, garlic will not prevent the disease – this is also included in the Myth Busters section.

Also, as WHO has said, and it has been proven with thousands of new cases, if you are standing within one meter of a person with COVID-19, you can catch it by breathing in droplets coughed out or exhaled by them. In other words, COVID-19 spreads in a similar way to flu.

Also, stay tough – as if you can force someone to be tough – as some offshore workers may be forced to stay on their rigs for longer, with the companies adopting measures to stop, or slow down the spread of the virus. Shout-out to those workers! With all the people in self-isolation ashore, we may have a glimpse how you feel when you're out there on your rig in the middle of the ocean, and granted, it could be better, but at least we get to be with our families, and we hope you'll be with yours soon!

Back to our safety systems and products, we didn't think helicopters would end up in the health and safety systems section, but they did. Read on as to how and why.

Neodrill



The Wellhead Saver System (WSS)

The WSS by Neodrill protects the wellhead, conductor and casing from over-stressing by directing the forces from the BOP directly to the well foundation (CAN).

As a result, it is possible to increase the drift off distance limitation of the wellhead system before disconnect, allowing the rig to stay connected to the well in more severe weather conditions, reducing downtime and saving idle rig time costs.

The WSS may be deployed by the drilling rig, with no intervention from the construction vessel. In comparison to the tethered BOP solutions, the WSS avoids handling of additional suction anchors, clump weights or piles.

VIKING Norsafe E-GES

The VIKING Norsafe E-GES is a new all-electric freefall lifeboat, developed in close consultation with DNV GL and the Norwegian Maritime Authority. The lifeboat is powered by 3x25kWh batteries contained in robust, waterproof cases with their own fire extinguishing systems plus an electric motor, gearbox and ventilation system.

The E-GES launches at a higher speed than comparable diesel powered lifeboats, transporting evacuees more quickly away from danger. It also provides maintenance cost savings and offers the remote monitoring capabilities which offshore operators increasingly demand. Other benefits include better onboard comfort due to the absence of exhaust fumes, noise and vibration.

Bristow Helicopter for Covid-19 Case Transport

Offshore helicopter operator Bristow has modified three Sikorsky S92 helicopters to ensure the necessary separation is provided between flight crew, an on-board medic travelling with each flight to provide passenger monitoring support, and passengers with suspected COVID-19. As the aircraft are purpose fit for a search and rescue role, they have a different seating configuration to crew change helicopters, ensuring appropriate separation can be maintained between those on-board.

Numerous preventive barriers are also installed including protective curtains separating the cockpit from the passenger area and airflow systems, while specific entrance and exit points are provided for each of the flight crew, paramedic and passenger to further ensure required distance is maintained.

Each aircraft undergoes a full decontamination process after every flight, assisted by the rugged waterproof seating and a fully waterproof floor which is included in their search and rescue role configuration.

Safe Influx - Automated Well Control

Automated Well Control technology from Safe Influx recognizes an influx while

VIKING Norsafe E-GES

Bristow

Safe Influx

IntelliView

drilling and takes immediate action, efficiently and flawlessly, reducing the influx size substantially and preventing blowouts.

The technology allows continuous monitoring and, once the system detects the influx, it performs a series of operations by taking control of the rig equipment and shut-in the well. The drill string is spaced out, top drive and mud pumps are stopped, and the BOP is closed.

It all occurs without the intervention of the driller; however, they can intervene to stop the automated sequence progressing.

The system comprises in a small unit and HMI touch screen for the driller to configure and operate. Safe Influx is currently working on the development of over 50 additional modules to cover every aspect of well construction and decommissioning operations.

IntelliView Explosion-proof Dual Camera Analytic Sensors (DCAS)

The automated liquid leak detection system developed by IntelliView for offshore well and production platforms enhances operational safety and efficiency by generating immediate notifications. It allows oil and gas operators to visually verify events remotely and respond quickly, leading to lowered HSE, business and reputational risks. The technology also reduces unnecessary travel by providing eyes on the site.

The IIoT solution utilizes an explosion-proof infrared/optical imaging system called the Dual Camera Analytic Sensors (DCAS) with on-site patented/proprietary video artificial intelligence.

The DCAS system offers day/night monitoring of valves and piping using no light source and minimal bandwidth. Live thermal and video feeds are analyzed in real time, enabling leak detection, qualification and alerting (with photo and video) in seconds. Notification options include email, control center, and SCADA network.

PROTECTING THE FUTURE OF **OFFSHORE WIND**

By Erik G. Milito, President, National Ocean Industries Association (NOIA)

The American offshore wind outlook is bright. Regulatory and technological questions regarding offshore wind are clearing up. Atlantic states are offering to purchase more and more gigawatts of wind-produced energy. Wind producers have demonstrated that they are willing to make substantial financial commitments to the industry. With all this progress, however, one cloud stubbornly remans: the Vineyard Wind permitting delay.

Offshore Massachusetts, the 800-megawatt Vineyard Wind is supposed to be the first offshore, utility-scale wind project. In August 2019, the Bureau of Ocean Energy Management (BOEM) announced a delay of the Final Environmental Impact Statement (FEIS). In February 2020, BOEM updated the permitting timeline for Vineyard Wind, saying the FEIS will be out by mid-December 2020.

Delays, especially regulatory delays, are disappointing and worrisome for supporters of any type of project. But for offshore wind supporters, the Vineyard Wind delay doesn't just impact one project or one company. The Vineyard Wind delay could have a ripple effect throughout the entire America offshore wind sector and impact the ability of wind producers

In the U.S. alone, close to $70 billion in capital expenditures by 2030 will be needed, and more than 160,000 direct, indirect or induced jobs could be created by 2050.

© Federico Rostagno/AdobeStock

to provide a new energy source of millions of onshore consumers. The Vineyard Wind delay could create bottlenecks at the East Coasts ports that are tasked with building the offshore wind industry. While companies are spending millions of dollars upgrading and expanding existing East Coast port facilities, there is no one single port that can handle every type of project needed to build an entire offshore wind industry. Wind developers, and their vendors, will utilize a network of East Coast ports to meet their various needs. The complexity of orchestrating such a logistical network, means that if there is a "stacking effect" at one port, there could be ripples of delays at virtually every other East Coast port.

The Bureau of Ocean Energy Management (BOEM), the federal regulator with authority over offshore wind leasing, understands these risks. BOEM delaying Vineyard Wind, shows, almost counterintuitively, how invested the government is in the success of offshore wind. Getting it right is more important than getting it first. This means finalizing an environmental analysis that can be used to support and streamline approvals for vast offshore wind projects that are being planned throughout the Atlantic.

Cape Wind is a warning of what can happen to a new industry. Vineyard Wind was not always supposed to be the first offshore American wind project. Cape Wind owned that distinction. The $2.6 billion project with 130 turbines would eventually power 200,000 along Cape Cod. But onerous regulations and short-sighted litigation can end the hopes of any ascendant industry as fast as any market miscalculation. In 2017, Cape Wind had to pull the plug on its project of Cape Cod after years of, as the New York Times described it, "endless litigation." Round after round of lawsuits drove up costs and established delays and prevented Massachusetts residents from being able to access a new energy source.

Even with the delay, East Coast states are moving ahead with their plans for offshore wind. Six states announced more than 16 gigawatts of new offshore wind targets in 2019 alone. In total, more than 25 gigawatts of offshore wind projects are targeted by Atlantic states.

Furthermore, states are not just theorizing about wind, they are actively awarding wind contacts. In the past year, New York awarded 1.7 gigawatts of offshore wind contracts to two projects; New Jersey gave the green light for a 1.1-gigawatt project; Connecticut signed a 804-megawatt deal; and offshore Virginia, construction began on the first wind farm in federal waters.

States are pushing offshore wind forward, to the benefit of millions of Americans. Close to $70 billion in capital expenditures by 2030 will be needed, and more than 160,000 direct, indirect or induced jobs could be created by 2050. The most recent offshore wind lease auction generated $405 million in Federal revenues. Clearly, there is more hinging on the success of Vineyard Wind and other permits than ever before.

The Trump administration is checking every box to make sure that offshore wind is a success story, and the U.S. Department of the Interior is making sure history does not repeat itself. Realigning the interpretation of the Migratory Bird Treaty Act (MBTA) to meet its statutory intent and reforming the National Environmental Policy Act (NEPA) allow common-sense to prevail and limit the ability of litigation to derail massively important projects that benefit energy consumers while protecting the environment.

But without a firm regulatory foundation to build upon, all the benefits of offshore wind will vanish overnight. The final stroke – getting past the Vineyard Wind permitting hurdles by getting it right – will open the door to an offshore wind industry that will be here for a long, long time.


ABS
LEADING THE WAY IN OFFSHORE PRODUCTION SOLUTIONS
ABS has been helping to enable safe offshore energy production since the earliest days of operations.
In 1975, we provided classification services for the offshore industry's inaugural floating production system. Over the decades, we classed the first floating production, storage and offloading (FPSO) vessel, classed the industry's first semisubmersible production unit, verified the first tension-leg platform (TLP), and classed the first production spar.
Today, ABS is still the classification and verification authority for offshore production units.
Visit ABS at OTC in Booth #1928.
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