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Inside the Numbers @ Dogger Bank

OSVs
Why Don't More get Scrapped?

P&A
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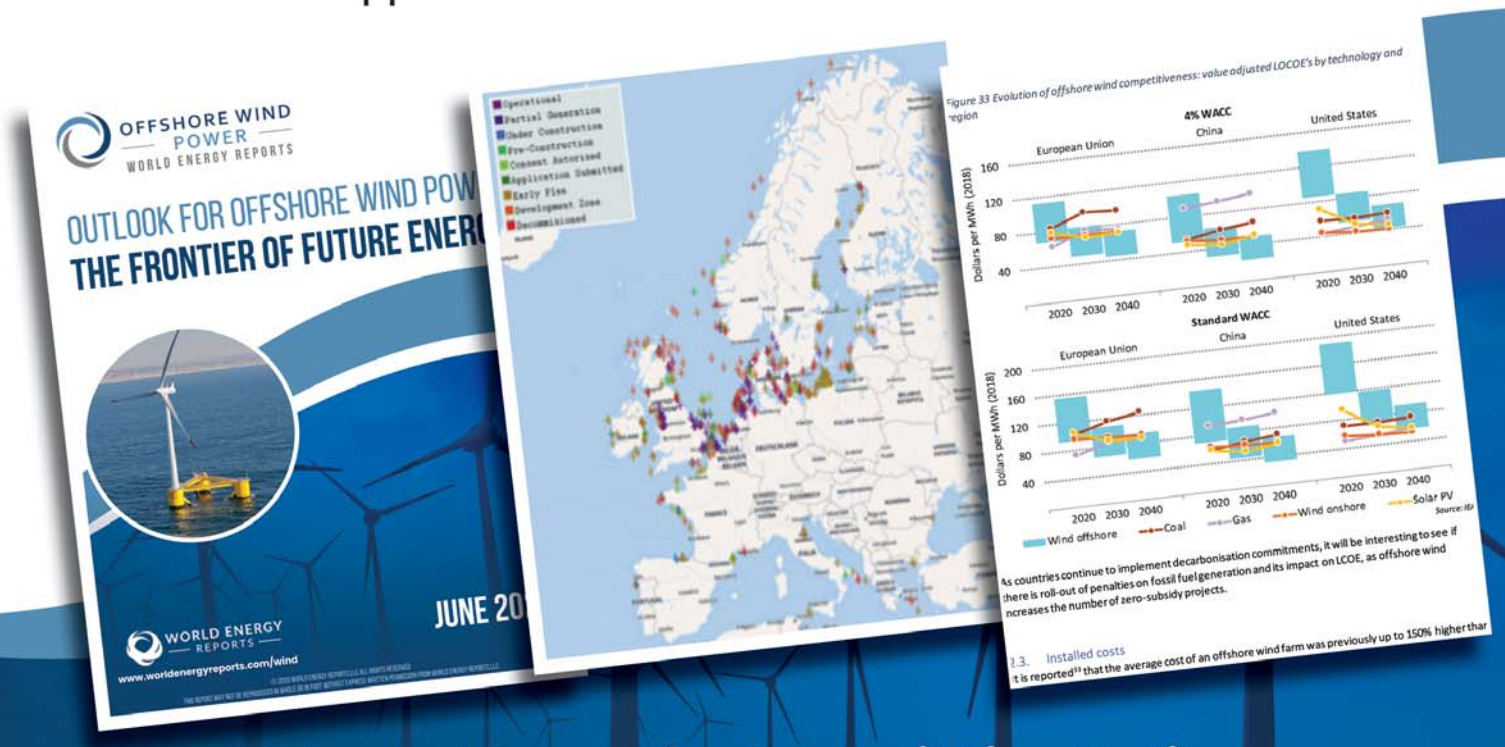

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FEATURES

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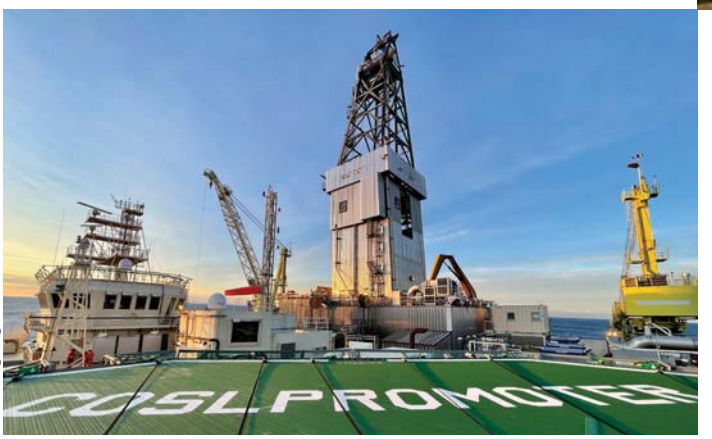

Source: Kongsberg

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BY THE NUMBERS

RIGS

Worldwide

Rig Type	Available	Contracted	Total	Utilization
Drillship	23	48	71	68%
Jackup	157	288	445	65%
Semisub	29	50	79	63%

Africa

Rig Type	Available	Contracted	Total	Utilization
Drillship	1	7	6	88%
Jackup	25	12	37	32%
Semisub				

Asia

Rig Type	Available	Contracted	Total	Utilization
Drillship	5	5	10	50%
Jackup	50	94	144	65%
Semisub	13	10	23	43%

Europe

Rig Type	Available	Contracted	Total	Utilization
Drillship	4	2	6	33%
Jackup	19	28	47	60%
Semisub	9	20	29	69%

Latin America & the Caribbean

Rig Type	Available	Contracted	Total	Utilization
Drillship	4	17	21	81%
Jackup	2	3	5	60%
Semisub	2	9	11	82%

Middle East

Rig Type	Available	Contracted	Total	Utilization
Jackup	31	113	144	78%
Drillship	1		1	0%

North America

Rig Type	Available	Contracted	Total	Utilization
Drillship	6	16	22	73%
Jackup	25	31	56	55%
Semisub	2	5	7	71%

Oceania

Rig Type	Available	Contracted	Total	Utilization
Drillship		1	1	100%
Jackup	1	1	2	50%
Semisub	1	2	3	67%

Russia & Caspian

Rig Type	Available	Contracted	Total	Utilization
Jackup	5	6	11	55%
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 January 2021.
Source: Wood Mackenzie Offshore Rig Tracker

DISCOVERIES & RESERVES

Offshore New Discoveries

Water Depth	2015	2016	2017	2018	2019	2020	2021
Deepwater	25	12	16	16	19	13	1
Shallow water	85	66	74	51	79	33	1
Ultra-deepwater	19	16	12	17	18	5	1
Grand Total	**129**	**94**	**102**	**84**	**116**	**51**	**3**

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

Offshore Undeveloped Recoverable Reserves

Water Depth	Number of fields	Recoverable reserves gas mboe	Recoverable reserves liquids mbl
Deepwater	557	42,133	21,443
Shallow water	3,226	428,248	144,213
Ultra-deepwater	328	41,393	26,720
Grand Total	**4,111**	**511,774**	**192,375**

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	Remaining reserves gas mboe	Remaining reserves liquids mbl
Africa	613	19,665	12,156
Asia	864	16,048	7,596
Europe	762	12,183	13,524
Latin America and the Caribbean	198	5,873	37,443
Middle East	127	71,250	145,781
North America	547	2,996	13,836
Oceania	86	11,336	1,359
Russia and the Caspian	58	13,889	13,848
Grand Total	**3,255**	**153,240**	**245,542**

Onstream and under development.

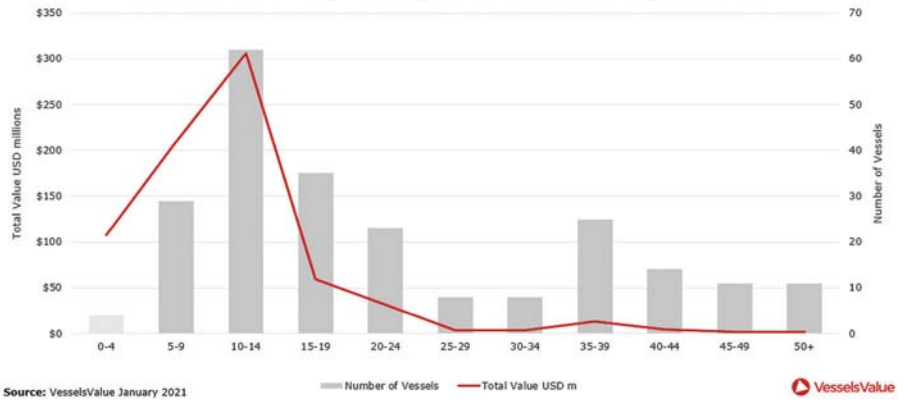
The portion of commercially recoverable 2P reserves yet to be recovered from the reservoir.

Source: Wood Mackenzie Lens Direct

REGION IN FOCUS
MEDITERRANEAN

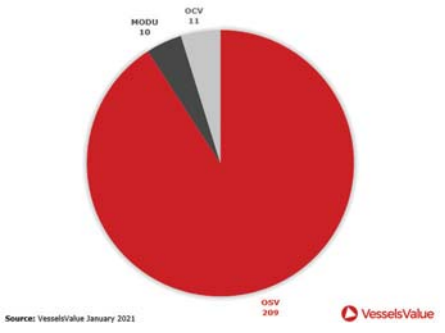
Data & Statistics powered by VesselsValue January 2021

Mediteranean Operating Offshore Fleet Age Profile



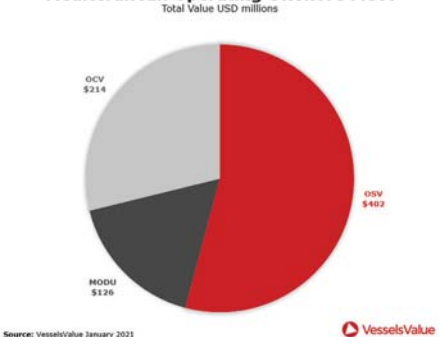
Mediteranean Operating Offshore Fleet

Number of Vessels

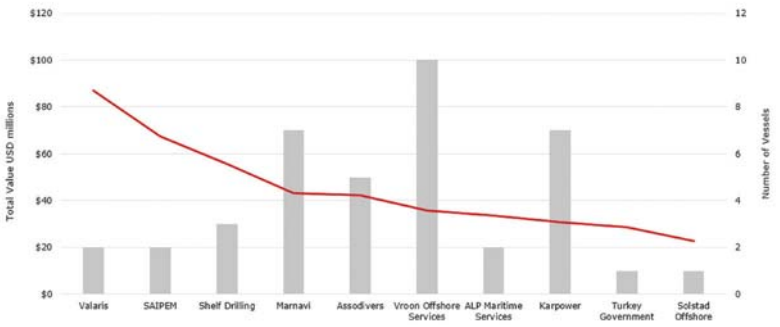


Mediteranean Operating Offshore Fleet

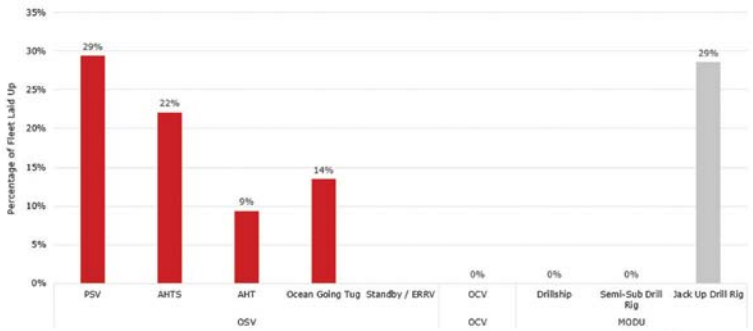
Total Value USD millions



Top Offshore Companies Operating in the Mediteranean



Mediteranean Operating Offshore Fleet Utilisations



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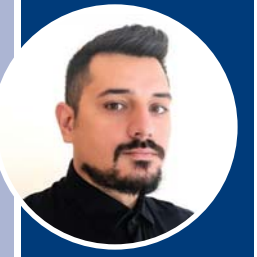
Mulligan


Maslin


Pallanich


Soma


Tomic

THE ONLY CONSTANT IS CHANGE

To me it is somewhat surreal to realize that we are closing in on nearly a full year of having the COVID-19 pandemic dominate our personal and business lives in a fashion that I never thought possible outside of a Hollywood movie set. As of this writing in early February 2021 the *Offshore Engineer* team is still working 'remotely', and personally I have not stepped foot in our Manhattan headquarters since early March 2020. (To be perfectly candid, we were always 'mobile and global', so working from wherever we happen to be is not particularly new for us.) The pandemic, a global societal and political mandate for emission reduction and energy transition, and a new U.S. Administration which has predictably pumped the brakes on traditional oil and gas offshore exploration, have all conspired to make 2021 look hauntingly familiar to 2020 for many of you reading these pages, in print and online.

Our cover feature this month on the trajectory of the FPSO market is hardly a 'good news' story, as it is precisely this sector, these projects – deepwater, long-range, capital intensive – that are currently 'out of favor' – to be kind – with their return to favor TBD. But while they are down, they certainly are not out, and according to the most recently report from **Jim McCaul** and World Energy Reports/IMA there are, as of January 2021, 110 projects in the planning stage that require an FPSO as a production system. You would be hard pressed to find anyone on the planet who has an accrued knowledge and data set on the FPSO market than Jim McCaul, who was a pioneer of sorts in this niche's coverage starting back in the early 1990s and continuing today, daily. The full report on the sector, with insights on the organizations that will fund its future, starts on page 18.

When we started producing *Offshore Engineer* in our publishing house in late 2018, I plotted a course to cover in earnest the burgeoning offshore renewables market, a stance that was met with some resistance and questions as *OE* was an "oil and gas" book. My position then, and increasingly emboldened now, is that our coverage mandate was literally "Offshore Engineer", coverage in-the-round of the planning, construction, installation, lifecycle maintenance, and eventual removal of all types of engineered projects and fields in one of the harshest and unforgiving places of the planet: on top of and below our seas and oceans. As the offshore wind market considers to gain considerable steam in the U.S., particularly in my region, the Northeast U.S., it has the potential to lift not only the offshore energy sector, but also the maritime, subsea, ports and logistics sector, or the entirety of our coverage across our print and electronic publishing sectors. Our traditional oil and gas coverage will always be a mainstay, but increasingly you will see more pages, print and electronic, dedicated to the fast-maturing offshore wind as well as the less mature markets, such as wave and tidal energy. Particularly with the emergence of Floating Wind, I think you'll see that many of the technologies and techniques born in offshore oil and gas will translate well into these new sectors.

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DOGGER BANK

OFFSHORE WIND FARM FINANCING

Offshore wind farms are getting bigger, and none will be bigger (for now) than Dogger Bank in the UK North Sea.

By Bartolomej Tomic

Source: GIEK

Dogger Bank, a wind farm site in the UK North Sea consisting of three phases A, B, and C, will cumulatively be the world's largest offshore wind farm, once in operation a couple of years from now.

Fittingly, being the world's largest, the wind farm will feature the world's largest wind turbines, GE's 13MW Haliade-X for the A&B phases, and 14MW for the C phase.

What is more, the project, owned by Equinor, SSE, and recently Eni (A&B phases) has recently struck another "world's largest." The largest offshore wind project financing to date globally.

The total senior debt facilities across the two phases are $6.4 billion, plus ancillary facilities of around $935.8 million.

The final group of lenders, comprising 29 banks and three export credit agencies, includes experienced lenders in the sector along with relationship lenders of both SSE and Equinor. One of them is the Norwegian Export Credit Guarantee Agency GIEK.

Take note, while the Norwegian companies, such as Equinor, own offshore wind farms internationally, they have yet to build one at home. Worth noting, the construction of an offshore wind farm – a floating one at that – has recently started

Source: GIEK

Pernille Østensjø,

Head of GIEK's clean technologies team

in Norway, too.

However, while the Norwegian domestic offshore wind industry has yet to take off, GIEK is working hard on helping Norwegian businesses score more offshore wind work abroad.

Offshore Engineer TV's Greg Trauthwein virtually "sat down" with Pernille Østensjø, head of GIEK's clean technologies team, and Ivar Rekve, head of energy and industry, to learn more about GIEK's role in financing the Dogger Bank, the ripple effect on Norwegian suppliers, their take on the overall offshore industry, as well as on the growth of the offshore wind industry, and GIEK's plans for the future.

Østensjø explains that GIEK bases its participation on Norwegian export contracts, meaning they're promoting the use of Norwegian companies, such as Aibel and Offshore Heavy Transport which have secured contracts to deliver goods and install wind turbine foundations for the giant Dogger Bank project.

"Based upon the contracts that Dogger Bank signed up with Aibel delivering the HVDC platforms and Offshore Heavy Transport, delivering services for transportation and installational foundations with the custom-built vessel Alfa Lift, we participated. And we're guaranteeing 300 million British pounds for these two projects," Østensjø says.

And we would, Østensjø adds, like to follow our Norwegian exporters into new markets, that be either in Asia or in other European countries.

"Our ultimate goal is of course that Norwegian deliveries will be chosen in front of other countries' deliveries. That's our ultimate goal," Østensjø says.

While the appetite for financing the offshore wind sector seems big, what is the situation with the traditional oil and gas markets?

GIEK's head of energy and industry head of energy and industry Ivar Rekve sees a shift.

He says: "Of course we have a large portfolio within [the oil and gas] sector, but what we're seeing now is that the capital in this sector is gone. There was no demand for new projects. And there were a lot of ships, a lot of equipment in the markets that is... Well, not with high demand. So we see the shift in the industry, we see the shift in the projects, and we see the shifting of capital towards renewable energy. And we are really pleased to being able to support this shift, to be able to support the financing of the Norwegian exporters and their contracts with the buyers abroad."

But what about the offshore oil and gas industry's future? Will it ever return to where it was before? What role can Norwegian companies play in floating wind? Where else in the world has GIEK invested, offshore wind-wise? Learn all that and more in our full interview below.

OETV

Watch the interview @ https://www.youtube.com/watch?v=zMqy9oRxJ6Q&feature=emb_logo

Source: GIEK

Source: GIEK

Ivar Rekve,

Head of GIEK's energy and industry

GEOTHERMAL ENERGY: A NEW LIFE FOR OLD OFFSHORE OIL WELLS?

Old offshore oil wells could be turned into geothermal energy producers under a plan by a new consortium.

By Elaine Maslin

Old offshore oil wells could be turned into geothermal energy producers under a plan by a new consortium. The group, The Aquarius North Sea Geothermal Consortium, is "actively" working with North Sea operators to see if old wells could be used to generate geothermal energy for existing platforms. But a future goal is greenfield geothermal exploration.

Kirsten Pasturel, CEO of ZeGen Energy, says there's huge potential with some mature oil fields producing over 100,000 barrels of water per day, at temperatures hot enough to generate power.

"The potential is huge when you look at the amount of water produced on the UK Continental Shelf, previous academic studies suggest some fields in the UK could produce 10-20MW of power based on their produced water volumes," says Pasturel, who has been doing a study with the Oil & Gas Technology Centre (OGTC) in Aberdeen on the feasibility of the idea.

"When wells are no longer economical for oil production, they could be repurposed for geothermal energy instead of just being shut-in," she says.

Using geothermal energy for power could then lower offshore operators' emissions and costs by reducing reliance on carbon-emitting gas turbines.

"Generating power from geothermal energy is nothing new, and technology exists to do this from low-temperature fluids, but we need to understand the opportunity and value to the UKCS; Can geothermal power be used to replace that supplied by a 5MW or 10MW gas turbine?"

The offshore well portfolio is varied, so solutions will take some engineering and puzzling out.

The other companies in the consortium are dCarbonX, also founded in 2020, and Danish well management firm Ross DK.

There could even be the opportunity to drill new wells, just for water production, suggests

Gillian White, Subsurface Solution Centre manager at the OGTC. But she says that legal and regulatory frameworks for this are also part of the OGTC study.

Another challenge – outside of the scope of the study, which is focusing on energy production for use offshore – would be to get that energy to shore economically, if enough is generated so that it can be exported. That might mean integration with offshore renewable energy systems, says Pasturel, where it could offer a baseload. The study is set to map out the potential across the North Sea and look at available technologies in the market for use offshore.

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Why Don't OSVs Get Scrapped?

The OSV sector will be reliant on a hitherto unseen amount of scrapping to balance the market, writes ***Gregory Brown****, Associate Director – Offshore, Maritime Strategies International*

Source: STOCKSTUDIO/AdobeStock

There is a consensus that an OSV market recovery will only be driven a supply side rationalization. As well as a lack of newbuild activity, that rationalization will have to include unprecedented levels of scrapping in a market which has historically witnessed only limited levels of attrition.

That limited level of attrition has several deep-seated roots, most notably weak scrap values, a fragmented supply chain, and low idle costs (~<$1,000/day). These fundamentals are unlikely to change. Scrap prices are likely to remain weak, the fleet will remain fragmented, and OSVs will continue to be unattractive for scrap yards.

However, our base case assumes that nearly 400 AHT(S) and around 300 PSVs will leave the market between 2021 and 2025, at an average of 74 and 61 vessels per year, respectively – nearly trebling the average scrapping levels between 2000 and 2020.

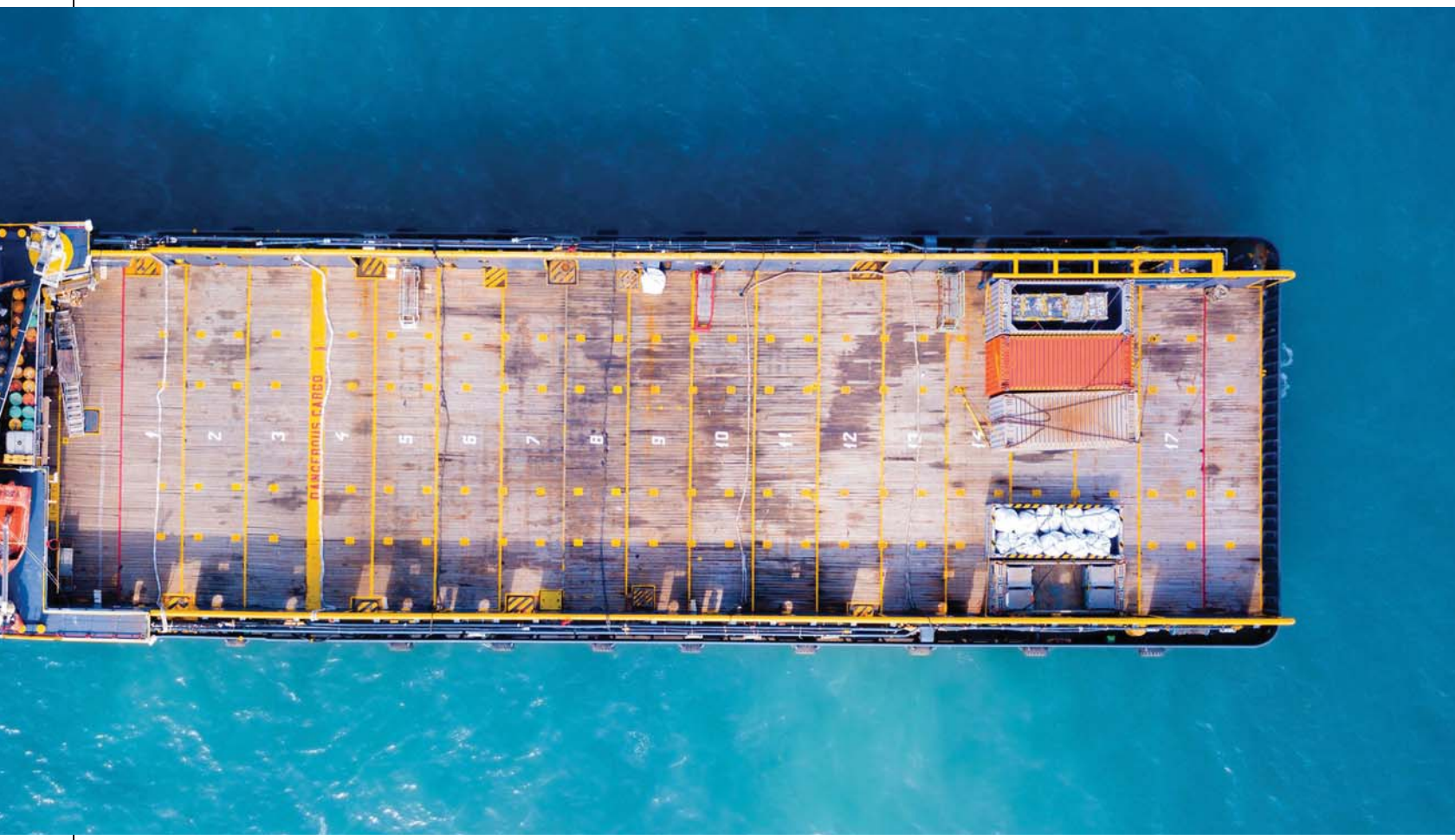
Rather than a fundamental change to the scrapping market, those numbers are underpinned by a changing end-user market that will, in our view, increasingly render older vessels uncompetitive for offshore work.

LONG TAIL OF OWNERSHIP

One of the reasons why so few OSVs are scrapped is the nature of the supply chain. The fleet is fragmented. There are more than 1,000 operators in the market, with the top 20 accounting for just 25% of the total supply. The drilling fleet, where scrapping levels are notably higher, is far more concentrated.

There are fewer than 200 operators, with the top 20 accounting for more than half of marketed supply. This concentration makes fleet-wide rationalization decisions considerably more straightforward as it becomes far easier to arrive at a consensus amongst a smaller quorum of interests. In comparison, the OSV space has a long tail of stakeholders, more than half of which have just one vessel. Decisions made by the likes of Bourbon and Tidewater at the top may have limited impacts on those smaller, regional players at the bottom.

Consolidation would almost certainly help the sector achieve greater capital discipline and potentially prop up scrapping levels. However, while Tidewater, Maersk, Vroon, and many others adopt wholesale restructurings to their fleets and sell more ships, not all assets are heading into the hands of recyclers. Tidewater's



recent sales have seen the likes of the Hanks Tide and Dulaca Tide sold to Baltic Marine and Hudson Offshore, respectively. DOF sold the Skandi Giant to Hai Duong in August 2020, while in June of the same year, Maersk sold the Maersk Advancer and Maersk Asserter to Karadeniz. These vessels, and many others continue to trade, lengthening the wagging tail still further.

Kim Heng has also been an aggressive buyer of tonnage from distressed sellers in the downturn. Its subsidiary, Bridgewater Offshore acquired four ships from the collapsed Teraseas business, including the Salvanguard and Salvigilant for an en bloc $4.8m price. Bridgewater also purchased the Salveritas and Salviceroy for $5.2m combined. The business has a stated intention to "invest for the future in cycle positioning so as to take advantage of buying distressed assets at significant bargains with the right value."

With the presence of such players in the market hopes for a bout of consolidation in the space look to be forlorn.

LESS ATTRACTIVE TO RECYCLERS

Yet another reason underpinning the lack of recycling activity in the OSV space is their relative attractiveness, and lack thereof, to recycling yards in comparison to alternatives in the shape of large, cheap drilling rigs and merchant vessels.

That attractiveness is reflected in the relatively low scrap prices achieved for AHT(S) and PSV vessels. Fundamentally, OSVs are significantly smaller and contain less valuable parts than drilling rigs or merchant vessels. This disincentivizes scrapping. Indeed, the scrap price of OSVs in Northern Europe is arguably negative.

Assuming a theoretical scrap price of $300/ldt, the average OSV scrapped between 2010-20 would be worth just $461,000 to a recycling yard, arguably lower than the repositioning costs associated with transporting a vessel. This stands in marked contrast to the ~$3-4m value of scrapped tankers, bulkers and containers removed over the same period.

AGE REQUIREMENTS AND CABOTAGE REGULATIONS

The fundamentals behind the lack of OSV scrapping are not going to change. The vessels will remain relatively unat-

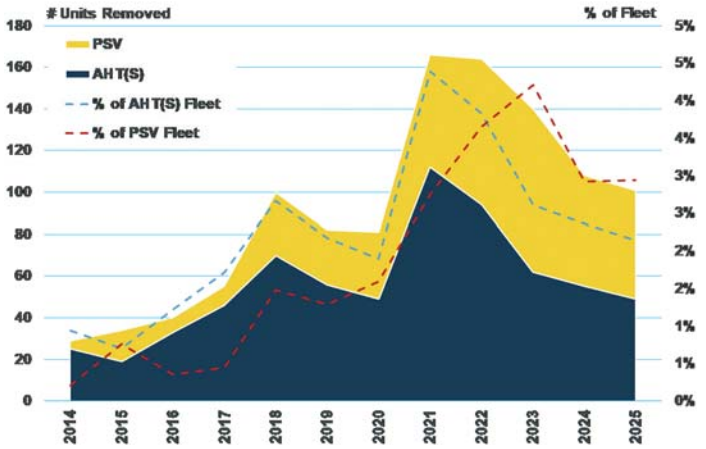
tractive to recycling yards, and the ownership profile will still be fragmented. Optically, it may be surprising to see that our base case vessel supply forecasts include a hitherto unprecedented amount of removals from the fleet. We forecast 421 AHT(S) and 339 PSVs to be removed from the fleet between 2020 and 2025 – suggesting that, on average, 3% of the OSV fleet will become obsolete each year.

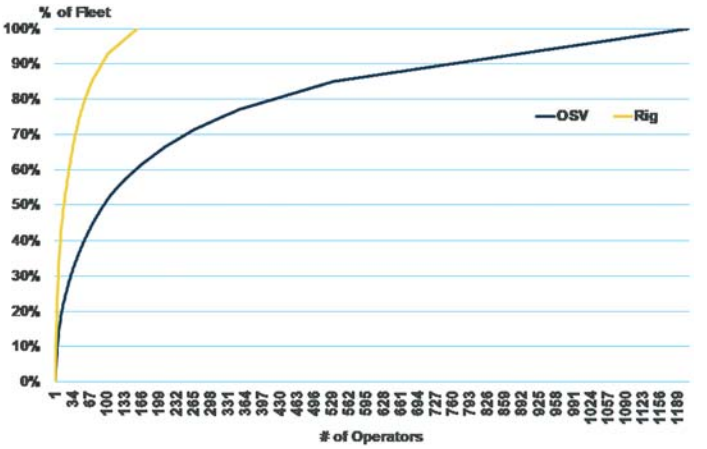
If the fundamentals behind the scrapping market are not going to change, those removals will have to be driven by outside influences. Specifically, our forecast is predicated on older vessels becoming increasingly uncompetitive in the offshore space. In Northern Europe, for example, vessels older than 15 years of age will struggle to secure utilization and will eventually fall out of the market.

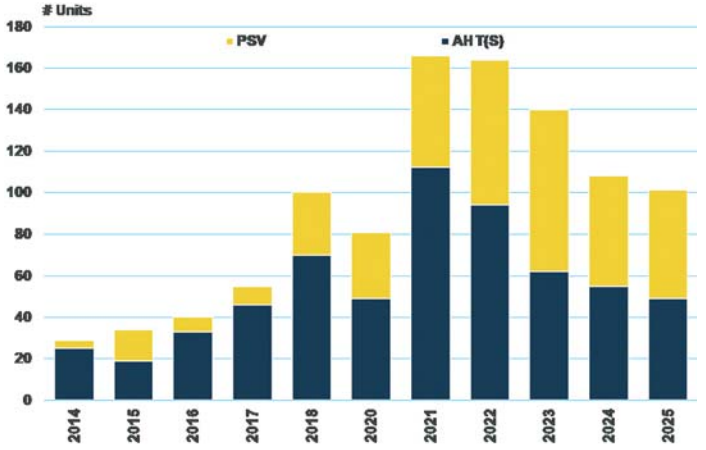
Those older vessels would typically remobilize to the Far East or Middle East Gulf. The physical process of repositioning is relatively straightforward and costs between $0.1-0.3m per vessel depending on the mode of transport, weather, etc. However, the process of securing work for those vessels has become increasingly complex. Barriers to entry have increased along with greater local content (IKTVA, ICV, Tawtween, etc.), and owners are required to establish local entities and partnerships. Even then, foreign assets will be increasingly marginalized against local tonnage.

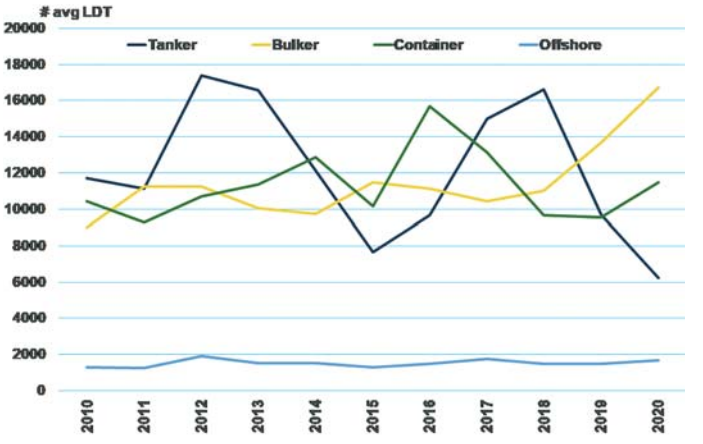
Meanwhile, stricter age requirements are serving to limit the competitiveness of older assets. ADNOC will no longer take on vessels greater than 20 years of age. Aramco will not take vessels greater than 23 years of age, and ONGC has lowered its upper age limit from 24 years in 2013/14 to 21. Acting in parallel with those age requirements is the continued shift towards vessels with lower emissions. In Norway, all vessels on longer-term contracts for Equinor in 2021 (~20 vessels) have, or will have a battery and a shore-power based system in 2021. Such modifications are unlikely to be made to older vessels.

The diminishing commercial prospects of those older vessels should drive their retrenchment from the fleet, helping to balance the market and drive an improvement in utilization, and eventually, earnings.









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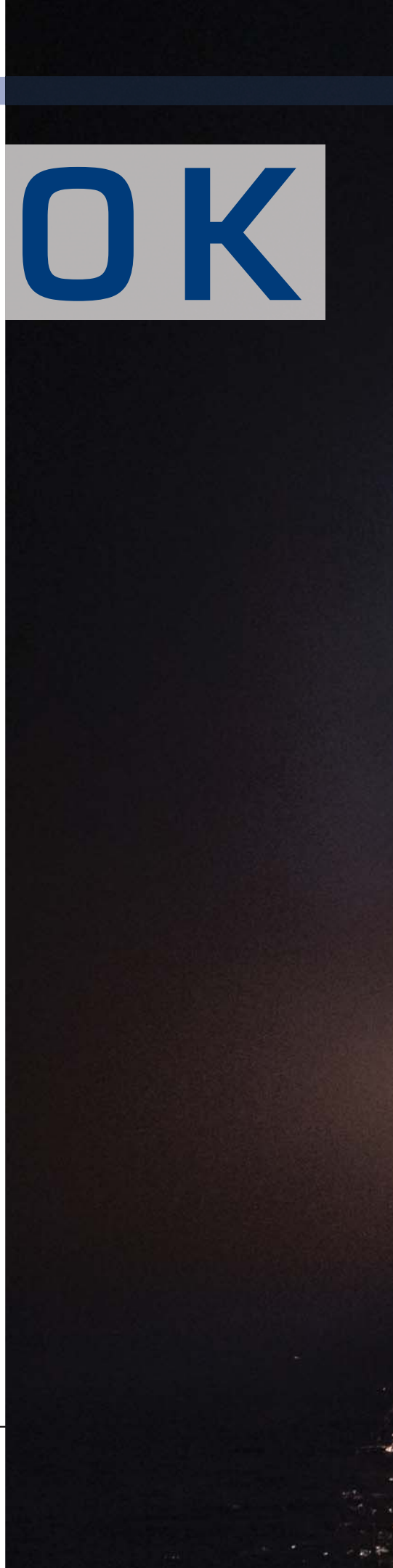
OUTLOOK FOR FPSO ORDERS OVER THE NEXT FIVE YEARS

AS OF MID-JANUARY 2021, THERE WERE 110 PROJECTS IN THE PLANNING STAGE THAT COULD REQUIRE AN FPSO AS A PRODUCTION SYSTEM.

By Jim McCaul, IMA/WER



Source: Simon Peter/Adobe Stock

COVID-19 will continue to skew the floating production systems market for the coming 24 months, while buying power for a large portion of FPSO contracts will be centered in Brazil and Guyana/Suriname. These two areas are expected to account for more than 60% of the FPSO contracts awarded between 2021 and 2025.

These are the findings shared in a recent floating production outlook report produced by International Maritime Associates (IMA) and World Energy Reports (WER).

The 100+ page report examines business conditions likely to drive investment decisions in deepwater development over the next five years and forecasts the number and timing of orders for floating production systems through 2025.

FPSO Overview

According to WER database, 220 floating production storage and offloading vessels (FPSOs) are now in operation, on order, or available. They account for 68% of the total oil/gas production floater inventory.

While all FPSOs are intended to produce, store and offload oil on offshore fields, each is designed and outfitted for use on a specific field. The result is a diverse inventory of FPSOs – with vast differences in plant processing capability, oil storage volume, mooring system design and construction cost.

Some FPSOs are small units with <20,000 b/d oil processing plants; some are mega units capable of processing 250,000 b/d. While most are ship-shaped, a few have cylindrical hulls. Some are fitted with external or internal turrets to weathervane; others are spread-moored.

Some are designed to permanently remain on field, some to be quickly disconnected.

The cost of building an FPSO ranges from $200 million to $3 billion, depending on production plant capacity, design life, local content requirement, operating environment, and other factors.

FPSOs have a number of important advantages over other production systems. The most important is their field storage capability, which allows production in locations economically inaccessible to pipeline infrastructure. Among other advantages: water depth is not a constrain, they can operate in environments ranging from benign to harsh, FPSOs can be modified and redeployed following field depletion and leasing of FPSOs has evolved into an industry-accepted procurement practice to transfer financing burden, con¬struction risk, residual value risk and operational responsibility from the field operator to a contractor.

But there are disadvantages, too. Subsea tiebacks associated with FPSOs generally bring higher well maintenance costs. Redeploying an FPSO is not as easy as it may appear -- each field is different, typically requiring major modifications to

Floating Oil/Gas Production Units Installed, On Order, and Available

(As of November 2020 – excludes floating LNG and storage units)

Type Unit	Total	Installed	On Order	Available
FPSO	220	175	20	25
Barge	9	9	0	0
Semi	46	37	6	3
Spar	21	21	0	0
TLP	28	28	0	0
All Oil/Gas Units	324	270	26	28

Source: WER Database

Ownership of FPSOs as of November 2020

	In Service	Available	On Order	Total
Field Operators	104	5	8	117
Leasing Contractors	71	20	12	103
Total	175	25	20	220

Source: WER Database

Trend in Number of FPSOs in Service or Available

As of End Year	Number of FPSOs	Growth Index *(2011 = 100)*
2011	159	100
2012	165	104
2013	174	109
2014	185	116
2015	185	116
2016	195	123
2017	193	121
2018	201	126
2019	198	125
2020	200	126
2021 (projected)	196-200	123-126

Source: WER Database

More than 90% of FPSOs now in service are located in six major regions. Brazil accounts for 29%, West Africa 24%, SE Asia 15%, Northern Europe 13%, China 7% and Australia 5%. The remaining 7% are spread over the Gulf of Mexico, Eastern Canada, SW Asia, and the Mediterranean.

the topsides plant and mooring system.

More than 90% of FPSOs now in service are located in six major regions. Brazil accounts for 29%, West Africa 24%, SE Asia 15%, Northern Europe 13%, China 7%, and Australia 5%. The remaining 7% are spread over the Gulf of Mexico, Eastern Canada, SW Asia, and the Mediterranean.

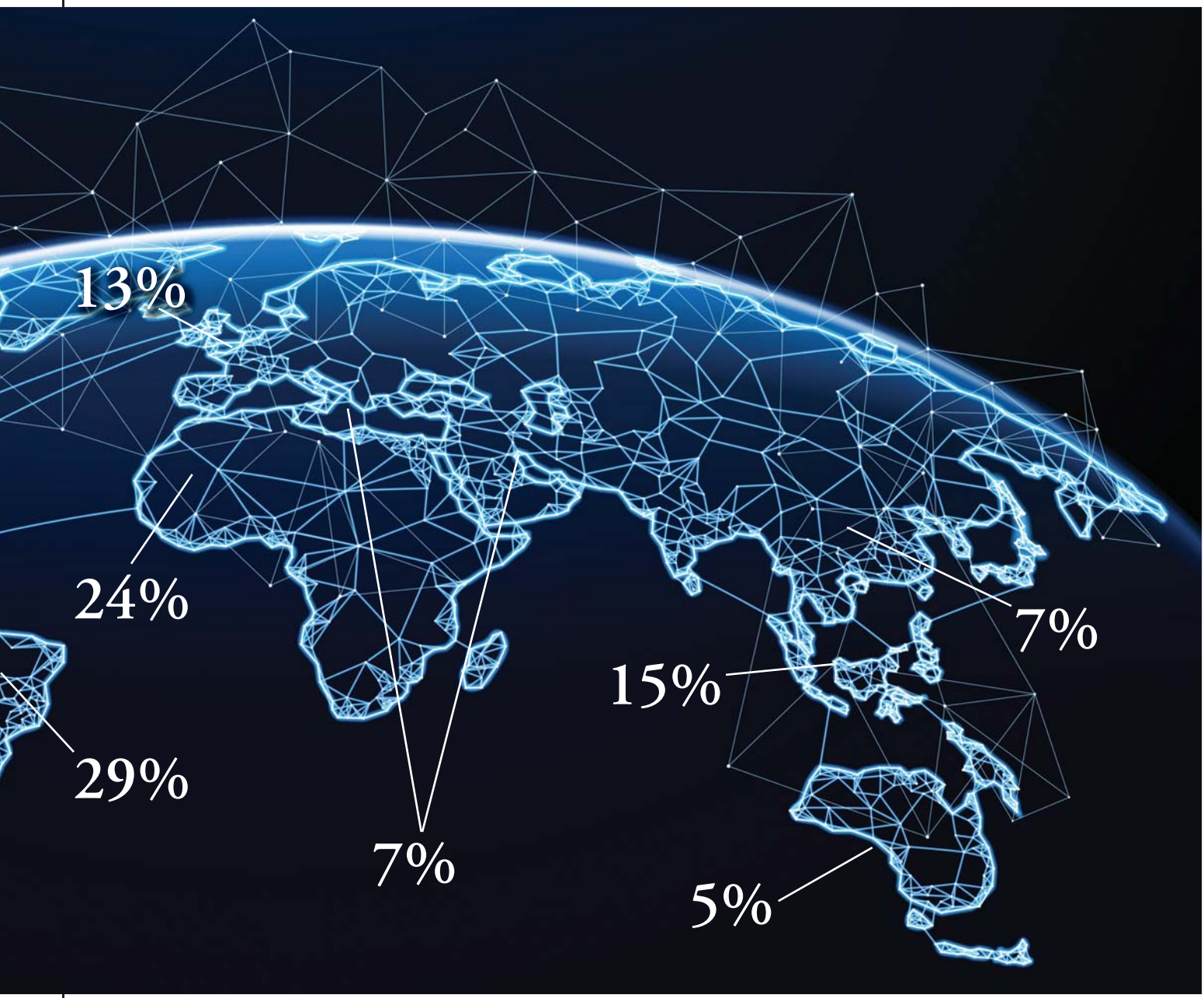
Ownership of FPSOs is almost evenly split between field operators and leasing contractors. Field operators own 53% of the total inventory; leasing contractors own the remaining 47%.

Petrobras is the clear heavyweight in the FPSO sector. Counting both owned and leased units, Petrobras has 49 FPSOs under its control – 22% of the FPSO inventory. Other major field operators utilizing FPSOs are CNOOC (13 units), ExxonMobil (12), Total (9) and Shell (8).

Major FPSO contractors are SBM, Modec, and BW Offshore. These three companies control 22% of the FPSO inventory.

Growth in FPSO Inventory

The number of FPSOs in operation or available for deployment has grown by 26% over the past 10 years - from 159 units at end-2011 to 200 units at end-2020. This reflects the



Source: © TAW4/AdobeStock

net result of delivery of new FPSOs and scrapping of aging units over the ten-year period.

Expansion of the FPSO fleet has been tapering off, and the inventory of existing units has likely now peaked around 200 units. Taking into account units on order for delivery this year less FPSO removals in 2021 due to anticipated field closures, we expect FPSOs in service or available to number between 196 and 200 units at end-2021.

While another 14 FPSOs are scheduled for delivery between 2022 and 2024, the scrapping figure during the same period will likely be higher, causing the number of FPSOs in service or available to begin to slowly decline over the next two or three years. While the number of FPSOs will decline, processing capability of the overall FPSO inventory will continue to expand as incoming larger units replace smaller aging FPSOs being removed from service.

Orders for FPSOs

Contracts for 79 FPSOs were placed between 2011 and 2020, an average of just under eight FPSOs ordered annually. There has been big variation around this average – with orders ranging from a high of 14 contracts in 2014 to no contracts in

2016. Contracts for four FPSOs were placed in 2020 – three for Brazil, one for Senegal.

All told, 64 of the 79 FPSO contracts (81%) over the past ten years entailed construction or conversion of first time FPSOs. These FPSOs have not previously operated as production units. Another 15 contracts (19%) involved redeployment of an existing FPSO to a new field. Typically the redeployment contract involves major modification of the process plant and mooring system, plus general upgrade to the entire unit.

FPSOs Now Being Built

Twenty FPSOs are currently on order. Six are in the final stage of completion, with delivery scheduled over the next 12 months. Seven are scheduled for completion in 2022. Seven more are in the early stage of construction with delivery planned in 2023/24.

Eight (40%) of the FPSOs on order are being built for use offshore Brazil. The others are destined for Guyana (2), India (2), Mauritania/Senegal (2), UK/Norway (2), Israel (1), and Mexico (1). Two more orders are speculative FPSO hulls likely to be used on projects in Brazil or Guyana.

China is the dominant location for FPSO construction and conversion. Seventeen of the 20 FPSOs on order are partially or fully contracted to Chinese yards. Singapore has retained the second position, with at least partial involvement in 2 of the 20 orders. Korean yards – which had been a powerful force in this market sector – have only one FPSO contract in progress. Topsides plant fabrication and integration is spread over a variety of contractors in SE Asia, Northern Europe and Brazil.

Planned FPSO Projects

As of mid-January 2021, there were 110 projects in the planning stage that could require an FPSO as a production system. Around 38% of FPSO projects in the planning stage are located in Brazil, some of which require multiple FPSOs. Africa is in second place, with 24% of planned FPSO projects. Nigeria and Angola account for two-thirds of the African projects. Other major locations are SE Asia, Northern Europe, Guyana/Suriname and Australia.

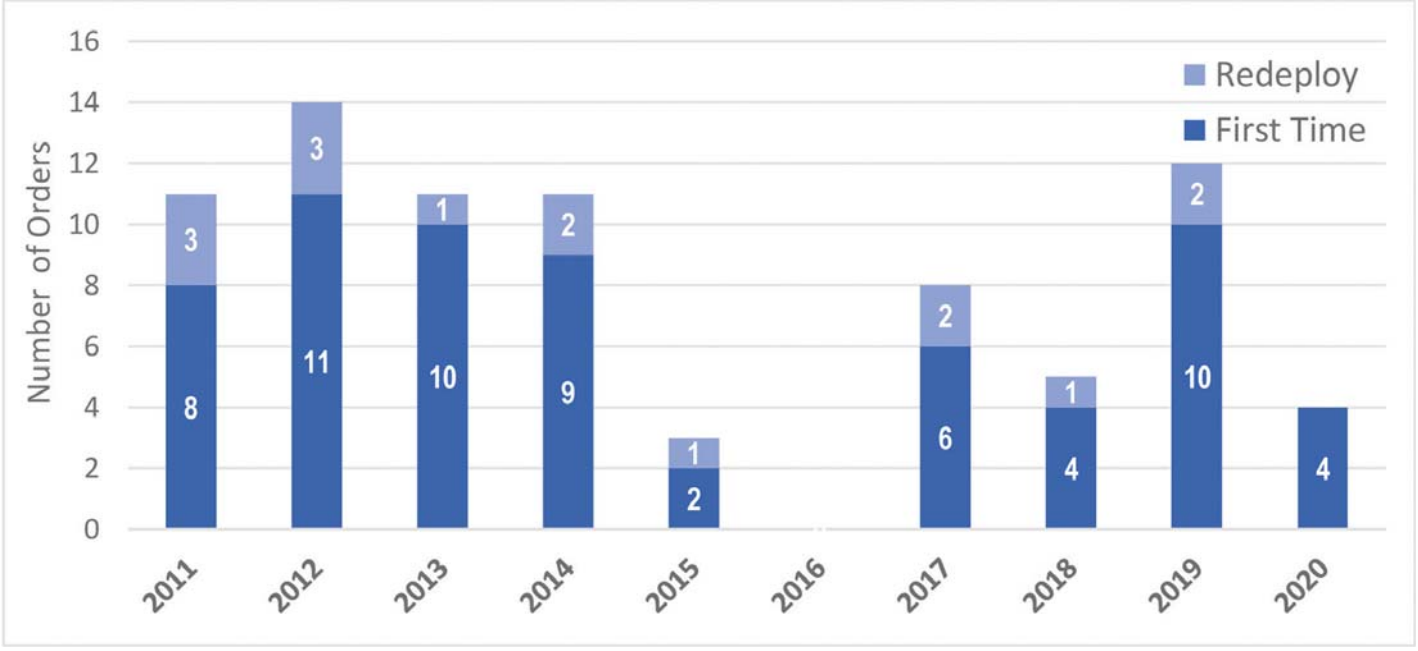
Details for all FPSO projects in the planning queue are provided in the WER online database, information that is kept up to date on a daily basis.

Projected Orders for FPSOs

A bottom-up methodology was used to forecast the number of FPSO orders. We examined each FPSO project in the planning queue to determine its probability to proceed to an investment decision by end-2025. The forecast takes into account future oil prices, capex budgets, deepwater competitiveness and other underlying business drivers in each of three market scenarios – as well as each project's status, barriers to proceeding, size and quality of reserves, operator financial strength and capex allocation strategy and other factors.

Depending on the future business scenario we expect orders for 23 to 48 FPSOs over the next five years. Our most likely forecast is 37 FPSO orders. This figure is 28% higher than the

Number of FPSOs Ordered over the Past Ten Years



Source: WER Database

number of orders placed over the past five years, during which 29 FPSOs were ordered -- but 26% lower than the number of orders during 2011/15, when 50 FPSOs were contracted.

Orders for FPSOs will be skewed toward the later years in the five-year forecast period – reflecting the expected continuing impact of the COVID-19 over at least the next two years. Buying power for a large portion of FPSO contracts will be centered in Brazil and Guyana/Suriname. These two areas are expected to account for more than 60% of the FPSO contracts awarded between 2021 and 2025. The remaining 40% of FPSO contracts will be with customers in SEA/China, Africa, No Europe, Australia and other areas.

Based on experience of the past ten years, we expect around 20% of future FPSO projects will involve use of a redeployed unit – and the number of FPSO contracts forecast in our most likely market scenario will generate a requirement for 8 FPSO redeployments over the next five years.

This redeployment requirement will not absorb all of the FPSO looking for new fields. Currently, 25 FPSOs are in layup. Of the units in layup, 14 appear possibly suited for redeployment. Including FPSOs now off field and FPSOs that will likely end production by the end of 2025, there will be somewhere between 25 to 35 FPSOs available for redeployment during the forecast period – at least 3X the number of likely contract possibilities.

Capex associated with FPSO orders over the next five years is projected to total $56 billion in the most likely scenario -- an average capex of $11.2 billion per year.

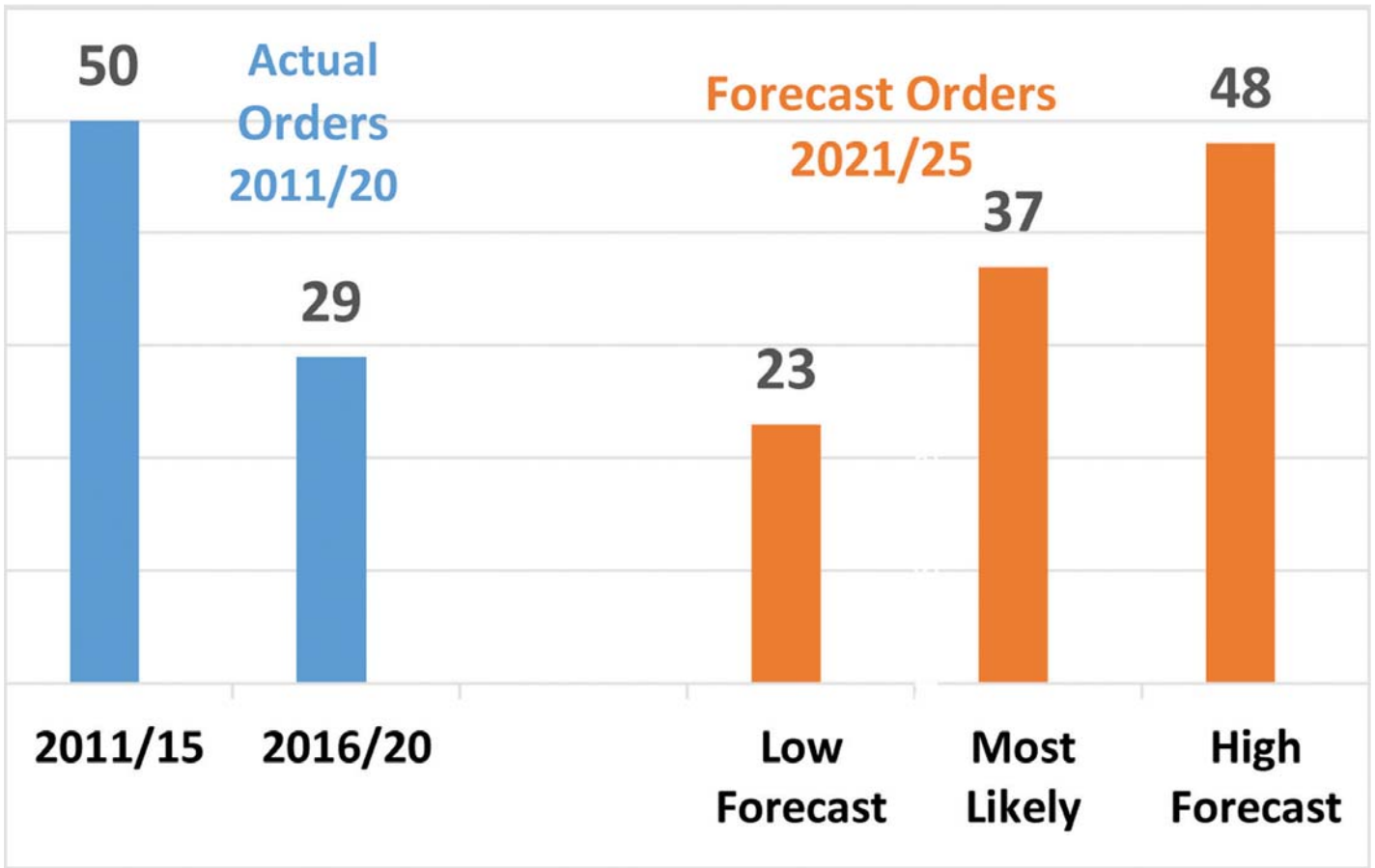
Details for all FPSO projects in the planning stage and our assessment of which specific projects will likely lead to an EPC contract over the next five years are provided in our forecast report.

OETV

Watch the interview @
bit.ly/3jEhWP0

For more information about the floating production report and online database, please visit www.worldenergyreports.com or contact Bailey Simpson in the USA at +1 832 289-5646.

2021/25 FPSO Orders Forecast Compared to Past Contracting Pace



Source: WER 2021 Market Forecast

PLUGGING

Source: BiSN

BiSN's 15,382kg (33,911lbs) P&A tool was deployed in a 30-in casing in a well on Aker BP's Valhall field in the Norwegian North Sea.

THE HOLE

Sitting at 49% of the total cost of decommissioning, wells plugging and abandonment (P&A) has long been high on the hit-list on the decommissioning cost reduction agenda. It's a task that has no returns on the cost to do it, and activity is increasing. ***Elaine Maslin*** *looks at some of the latest technologies aiming to reduce that cost.*

Well decommissioning activity outstripped exploration, appraisal, and development activity combined on the UK Continental Shelf for the fourth year running, Kenny McAllister, section chair of the Society of Petroleum Engineers (SPE) in Aberdeen pointed out to the Offshore Decommissioning Conference, held online late November, citing data from Oil & Gas UK's latest Decommissioning Insight Report.

As activity rises, technology companies are also gaining more traction with their concepts for alternative barriers to permanently seal wells. One of those is Aberdeen based isol8. Last year, the company, set up in 2017, qualified its metallurgically bonded-alloy barrier technology in an offshore trial. Isol8 now has 7-10 on and offshore projects lined up for 2021. Others, including BiSN and Norway's WellStrøm, are also making significant inroads.

Isol8'ing wells

The drive to create new barriers materials is largely to reduce reliance on rigs for offshore operations. "The big cost saving for well P&A is avoiding the need to pull tubulars," said Andrew Louden, founder of iSol8. "The holy grail is for phase one zonal isolation, phase two intermediate isolation, and the environmental cap to be deployed without the need for a rig." This is particularly valuable for subsea wells which can cost $10 million per well, he says.

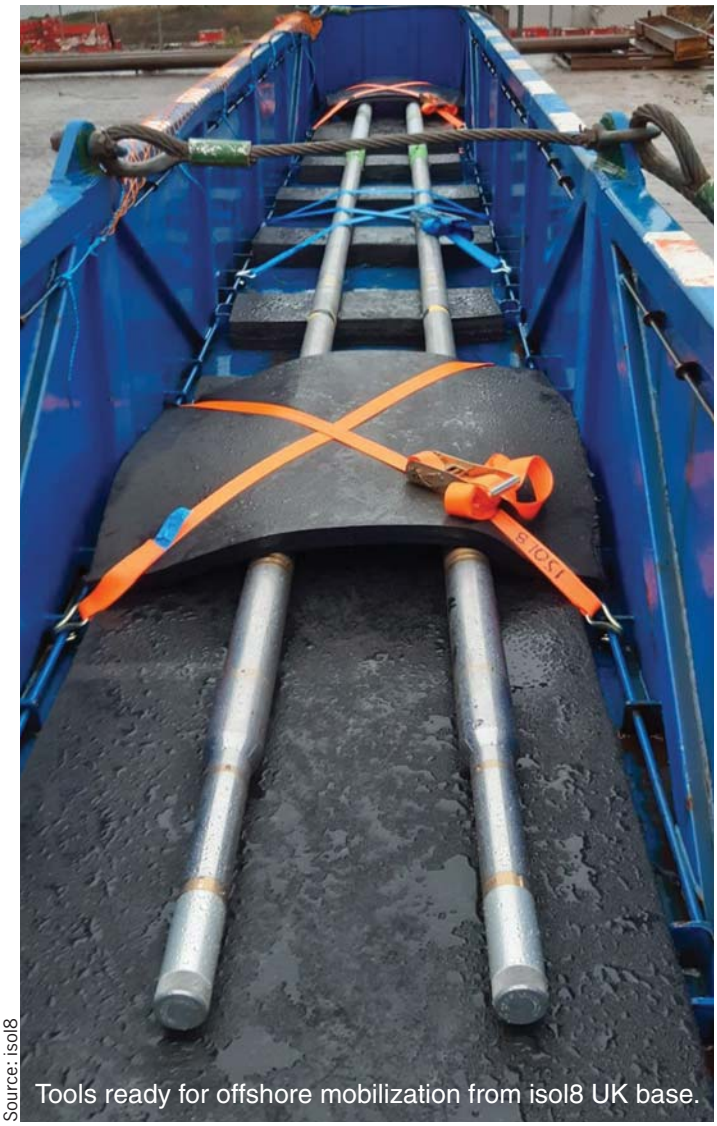
Isol8's goal is to create a metallurgical bond with steel with the highest sheer bond strength and life expectancy in the industry, says Louden. The company uses alloys, bismuth, and non-bismuth based, that are melted in the well using a thermite heating system to create a barrier with a metallurgical bond with the steel or expands against the in-situ cement and/or geological rock to create a barrier.

The metallurgical bonding between the steel and alloy creates a kind of sub-aquatic soldering, says Louden, so there's higher shear bond strength than simply relying on friction to create a tight seal. That also means less alloy is needed in shorter lengths than the unbonded bismuth-based seal alternatives, he says. The entire system, called Fusion, is adaptable to meet well-specific conditions. The same 3 ½ inch tool string size can be used in a wide variety of well geometries and can be deployed through tubing on wireline or slickline.

Last September, a 5-inch Fusion barrier was qualified at isol8's facility in the US. The following month, a Fusion barrier was deployed down to 10,765ft on a 3 ½ inch tool string in a 110°C 30-degree deviated well for Repsol Sinopec Resources' UK on their Fulmar field, – its first offshore trial. There, 1m of alloy above the thermite heater was deployed on e-line and, once it was set, the world's first bonded-alloy barrier was tested with pressure from above and below.

The bridge linked North Sea Fulmar Alpha platforms are about 217 miles east of Dundee and were installed in 1981 with first oil in 1982.

isol8 is now preparing for 7-10 projects this year with multiple operators and for a range of different well geometry applications. The next will be onshore; again a 3 ½ inch tool



Source: isol8

Tools ready for offshore mobilization from isol8 UK base.

Source: Rawwater

Setting up the test rig; left to right: Andy Moore (Rawwater), Adam Thomas (Rawwater) and Wellstrøm CEO, Gert Rege.

string but this time forming a 7-inch barrier. After that, isol8 is going to isolate a 7-inch perforated well out to the 8 ¼ inch rock in their first subsea well application. This is a water shut off project, to seal beyond the 7-inch casing and isolate a lower zone from an upper zone. The next North Sea project will then be a 3 ½ tool to form a bonded-alloy barrier inside4-½ tubing and the 9 5/8-inch annulus.

As well as using a solid thermite heater, isol8 also fluidizes thermite to fill the wellbore. For the 4-½ by 9 5/8-inch annulus P&A project, for example, instead of a solid thermite heater, isol8 will fluidize the thermite to create a platform through the perforated annulus on to which the alloy can set to form an ultra-high expansion seal. But Louden says that whilst isol8's technology can be used as an alternative to cement, he expects that alloy-based plugs will be used to form hybrid P&A barriers in combination with competent cement.

BiSN breaks own records

UK-based BiSN, which works with thermite to melt bismuth-based alloys into plugs, has also been hitting milestones. The firm surpassed its record for the largest bismuth plug with a 15,382kg (33,911lbs) P&A tool deployed in a 30-inch casing in a well on Aker BP's Valhall field in the Norwegian North Sea, 290km south of Stavanger – equivalent to the size of 11 cars, the firm highlighted. Its previous record was a 4,695kg (10,351lbs) tool inside an 18 5/8-inch casing on the same field in 2018. The latest plug, based on BiSN's Wel-lok M2M technology, was an environmental plug, set in September last year. The weight required the use of special lifting cradles to be able to lift the tool, measuring

56ft long, says CEO Paul Carragher.

It was the first in a 40 plus tool campaign providing gas tight environmental barriers on Valhall wells – where compaction and seabed subsidence are known issues. Tool sizes to be run on the project include 13-3/8 inch out to a 20 annulus, 18 5/8 inch out to 24 inch, and 20 inch out to 30 inch on wells, which are section milled before the tool is run.

The company, in which BP is a co-investor through BP Ventures, says it has now deployed its bismuth solution more than 180 times with no emittance of gases once placed. 2020 was a big year, with 103 tools run, compared with 50 in 2019 and 17 in 2018, as the company's technology has been adopted and not just for P&A. Recent projects include a seal through two strings (9 5/13 inch out to 13 3/8 inch then 20 inch) offshore California, which had been section milled, in case of lack of integrity in the cement behind the casing. On a new well, in Denver, the bismuth alloy solution was used to create a gas-tight annulus to prevent annular gas migration. The bismuth alloy could be deployed over just 6ft in a "surgical way" exactly where the issue is instead of needing 100ft of cement, says Carragher. This includes deployment via e-line, slick line, coil or drill pipe, he adds. Coming up is a campaign from a light well intervention vessel offshore Angola for BP, part of a follow-on campaign BiSN was involved in previously. This will see the tools run subsea using ROVs.

While section milling is still done, BiSN is looking at an alternative based on using liquidized thermite. BiSN normally uses thermite as a heating element. But the liquidized version will be pumped through perforations and ignited to effectively melt out casing sections, including control lines, etc., ready for BiSN's regular plugging tools to be run or just to aid pulling the casing. This will be able to be done through multiple casings, says Carragher. In fact, the company recently tested the tool on a mock-up to melt through 2 7/8 inch then 7 inch and then through a 9 5/8-inch casing, with just 25 kg of thermite, says Carragher.

An electrically heated WellStrøm

Also working with bismuth alloy is Norwegian consortium WellStrøm. Unlike others, WellStrøm is using an electrical heater to melt its bismuth downhole. Formed last year, the consortium brings together Norwegian company Aarbakke Innovation's downhole electrical heater technology and well intervention techniques, consultancy K2 Oilfield Services' perforating and P&A expertise, and UK-based Rawwater Engineering Company's bismuth alloy knowledge (OE: October 2019).

Source: BiSN

Late last year, the company performed system integration trials of its technology, placing and melting a bismuth alloy using a cable deployed downhole electrical heating technology from Aarbakke. This was in 9 5/8 inch within 13/3/8 inch casing, with a cement-filled annulus. To show milling operations could be avoided, Wellstrøm, together with Core Laboratories, achieved a controlled shattering of the cement annulus ready for the application of molten bismuth. It was pressure tested during placement and is now back at Well-Strøm headquarters for testing to ISO14319. WellStrøm says the sealing concept is based on a 3,000-year-life seal design already qualified by Bureau Veritas to DNV-RP-203, ISO 14310 (VO).

The trials follow a two-year program to deliver 7-inch alloy plugs for deployment in the North Sea, rated to 6,000 psi differential pressure at 60 cm (2inch) in length. This included developing the formulation of the metal seals, supported by Innovate UK. To establish mechanical properties and creep behavior under service pressure and temperature conditions, Rawwater worked with the University of Aberdeen, through an Oil & Gas Innovation Centre (OGIC)-funded partnership. The result is a suite of alloys for onshore, offshore and subsea P&A in downhole conditions from 70 – 90°C and 140 – 160°C.

Rawwater managing director Professor Robert Eden says

Source: Rawwater

Source: isol8

he's "convinced of the superior capabilities of bismuth as a cost-effective alternative for sealing well abandonments and resealing failed abandonments that were previously plugged using cement. Thanks to the extensive system integration trials that have taken place through the Wellstrøm consortium, there is now also the means to deploy bismuth alloy seals in a totally controllable way."

Next for WellStrøm is a program, supported by Demo 2000 funding from the Research Council of Norway, which will lead to a field applicable tool system.

Interwell Cannseal too

Operating in a similar space and also subject to corporate activity is Interwell. Also based in Norway, Interwell, which has been developing thermite tools to burn through well sections, recently acquired Cannseal, a Norwegian technology company that has developed a proprietary annular isolation technology based on a tailored epoxy recipe. This is to provide a sealant into the annulus at pre-defined locations, to help seal off micro annuli, or also leaking production packers, for example, to re-establish well integrity. A form of its CannSeal epoxy is currently being developed for permanent P&A operations when injected into the cement micro/macro annulus.

REVERSING THE FLOW – repurposing wells for CCS?

2020 is a year that'll be remembered for many reasons. COVID aside, it's been a turning point for the offshore industry, one where net-zero solutions have been top of the agenda, including within well abandonment. **Elaine Maslin takes a look.**

Industry and regulators have been looking at whether wells can be repurposed for carbon capture and storage (CCS). There are some big numbers. Some 350 to 1200 gigatons of CO2 will need to be captured and stored this century, according to the World Economic Forum. Operators are signing up, with a string of major projects announced, and starting to look at the details, including the potential to reuse existing wells.

Margaret Copland, senior wells and technical manager at the Oil & Gas Authority (OGA), told the Offshore Decommissioning Conference late last year that there are a number of significant questions about this possibility. Operators need to assess storage sites, produce a development plan and apply for a storage permit to the OGA. Part of this work includes looking at the integrity of existing wells to see if there's any leak potential. "The first problem is a lack of data," Copland told the event, co-run by Oil & Gas UK and Decom North Sea. "Original drilling data is frequently not available for wells drilling today."

The UK National Data Repository has a lot of data in it, but only it's where it's available. The ideal scenario is there's information about existing wells in end of well reporting, detailing how their cement plugs were verified. But often it's not the case. This makes it hard to know whether they will create a leak path for CO2. The wells weren't abandoned with reuse for CO2 storage in mind and, "the jury is still out on Portland cement (used for plugging wells) and how it will stand an attack from CO2," says Copland.

CO2 has to be injected at specific pressures which means that phase change can take place and very low temperatures, down to -50 degrees, can be experienced, she adds, so the design of wells, including subsurface safety valves, subsea infrastructure, pipelines and topsides need to take this into account. Another concern could be around CO2's corrosivity and the impact on Portland cement, that's traditionally used in well construction. Laboratory tests have proven Portland cement to be suitable, but what about an old highly deviated that wasn't designed for CCS and has a sidetrack and micro annuli.

Andrew Duguid, of Advanced Resources International, says carbonic acid, created when CO2 dissolves in water, will eat Portland cement. But, he says, the cement isn't very permeable, so there's not a worry about it moving through the cement. "Micro annuli could be an issue; the cement formation interface or casing cement interface are where we're going to see flow moving through the well."

Andrew Louden, founder of barrier technology firm iSol8, says, "We know CO2 has an impact on cement, so repurposing for CCS presents some real and well documented risks," including the cement rock interface, the cement casing interface and eccentricity and channels, and also the thermo-mechanical aspects of the cement from when it was put in place and throughout its service. "Some of these you can't see with any evaluation tool," adds Duguid, so you need multiple evaluation tools to get a full picture.

It may also be that hydrocarbon production wells just aren't suitable, because they're not in the right location for an injection point, says Copland. Side-tracking existing wells could be an option, which could allow for some of these issues to be dealt with, she says. There are projects looking at these issues. REX-CO2, for example, is a €3.3 million project evaluating the use of existing wells for CO2 storage, as well as creating tools to evaluate wells and model to predict any potential leakage.

What's more, there might actually not be that great a need. Copland says that a lot of work has been done on the UKCS where about 560 subsurface stores, formations, aquifers, that could be used have been "semi-identified." "But we're not going to need huge numbers to take care of the CO2 that the UKCS needs to," she says. There's 78 gigatons of storage capacity, or more than 100 years' worth, she says, and only something like 6-15 projects. So how many wells would need to be reused?

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Subsea Connector Delivers Cost Savings, Improves Safety for Critical Service Environments

TESTING UNDER EXTREME CONDITIONS PROVES THE RELIABILITY OF INNOVATIVE SUBSEA CONNECTOR DESIGN

By Scott Elisor, Dril-Quip

Market conditions have painted the oil and gas industry into a corner, where cost containment is critical to survival. At the same time, the industry is pushing the limits of system performance as exploration and development move into increasingly harsh and more demanding environments. In many cases, areas of operation are characterized by high fatigue and severe bending in shallow water, and high-pressure/high-temperature (HPHT) deepwater conditions, all of which can affect the integrity of subsea systems. The need to adapt to the demands of complex offshore field developments continues to raise the bar for performance at a time when E&P companies can ill afford costly downtime or unforeseen safety incidents.

Reliability is vital for subsea systems because the cost associated with replacing worn components can have serious repercussions, interrupting operations and negatively impacting project economics. Now, more than ever, offshore companies need solutions that improve performance, minimize nonproductive time (NPT) and decrease maintenance costs.

COMPREHENDING CONNECTOR CHALLENGES

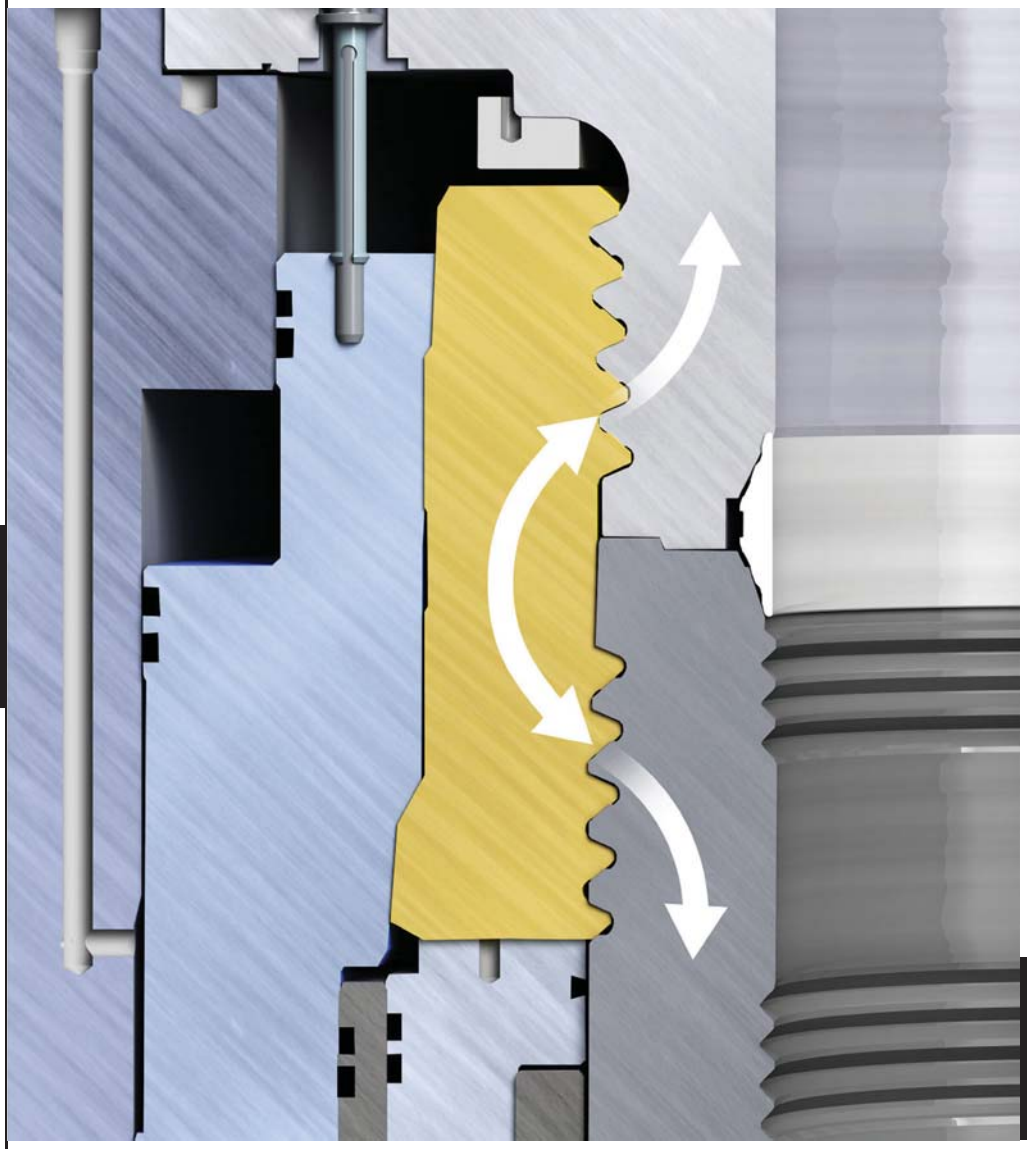
Results from research carried out separately by Statoil (now Equinor) in Norway and the Bureau of Safety and Environmental Enforcement in the U.S. exposed a critical weakness in the wellhead profile design. Findings revealed that the BOP connector, in some cases, exhausted fatigue life in as few as 12 days during drilling. The bolts at the top of traditional connectors were found to be one of the most significant design weaknesses. These bolts bear most of the load in the system and are susceptible to embrittlement and hydrogen-induced stress corrosion cracking. Failures – the consequence of a design that places the bolts in the primary load path where they can experience cyclic fatigue loading – have occurred in connectors commonly used in the industry.

Improving system safety meant creating a connector without these weaknesses and testing it to confirm its performance in high-fatigue, high-bending conditions, and HPHT environments.

A BETTER SOLUTION

The Dril-Quip engineering team evaluated traditional connectors and applied their understanding of the vulnerabilities to define design requirements for a new wellhead connector that could accommodate stresses in the load path caused by rig mechanics, ocean currents, vortex-induced vibration, and high-pressure environments.

The result was the DXe connector, which, when combined with the DXe profile, delivers superior fatigue resistance and versatility that allows it to be configured easily for both the



The design of the DXe connector removes bolts from the load path, reducing wear, extending field life, and improving operational safety.

Source: Dril-Quip

high-fatigue DXe profile and the H4 profile. The design removes bolts from the load path, so the connector experiences loads only when latched and unlatched from the wellhead. The novel connector design features a locking wellhead profile with a self-aligning, slim gasket and can be used as a BOP, subsea tree, or riser tieback connector.

TESTING THE MERIT OF THE DESIGN

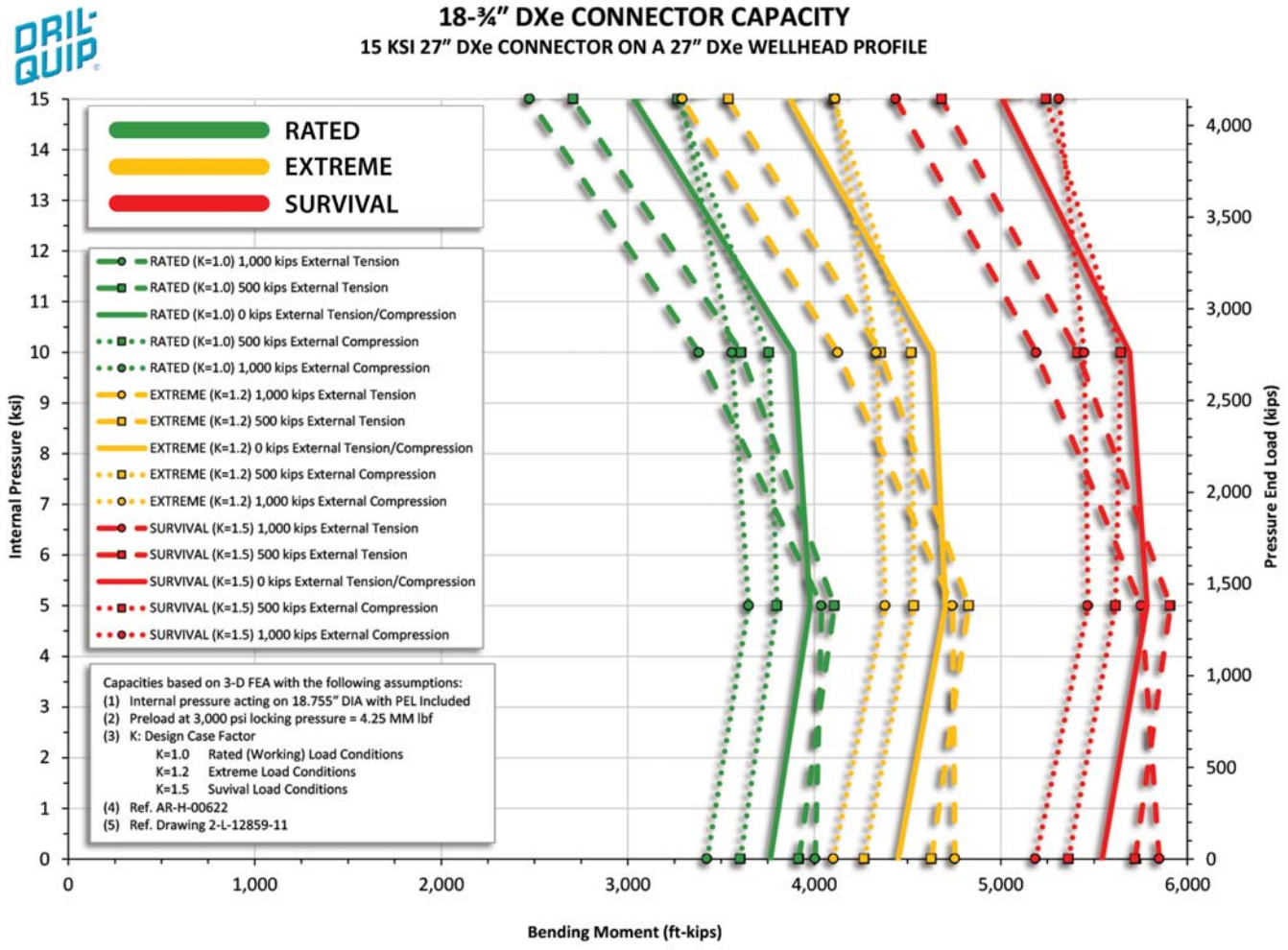
The locking profile is the primary mechanical interface between the hydraulic connector and associated mandrel. Many hydraulic connectors in use today were designed for much less severe environments and shallower water depths; however, present work environments generally expose connectors to higher pressures and temperatures and greater static and cyclic loads. Meanwhile, the systems are expected to perform consistently for a longer field life than was originally anticipated. Fatigue performance under these challenging conditions is crucial to continued, safe operations, and that means test criteria must reflect current harsh environments and anticipated future conditions.

Believing it is only a matter of time before API TR7 becomes a requirement for connectors, the team made the determination to test the DXe connector to API 17TR7 as well as API 16A standards. Both standards require validation testing and confirmation of design margins for normal, extreme, and survival capacities.

The connector was tested as a full-scale assembly at normal, extreme, and survival ratings based on as-tested material properties. Each test series included exposure to internal pressures from 0 psi to 20,000 psi working pressure of the connector in intervals of 5,000 psi, along with axial loads of +(-) 1MM lbf of tension. The DXe connector went beyond the 13MM ft-lb

DXe wellhead connector underwent qualification testing at the Dril-Quip facility in Houston. No other connector in the industry is proven to both API 16A and API 17 TR7 and offers the configurability and fatigue life of the DXe connector.

All images: Dril-Quip

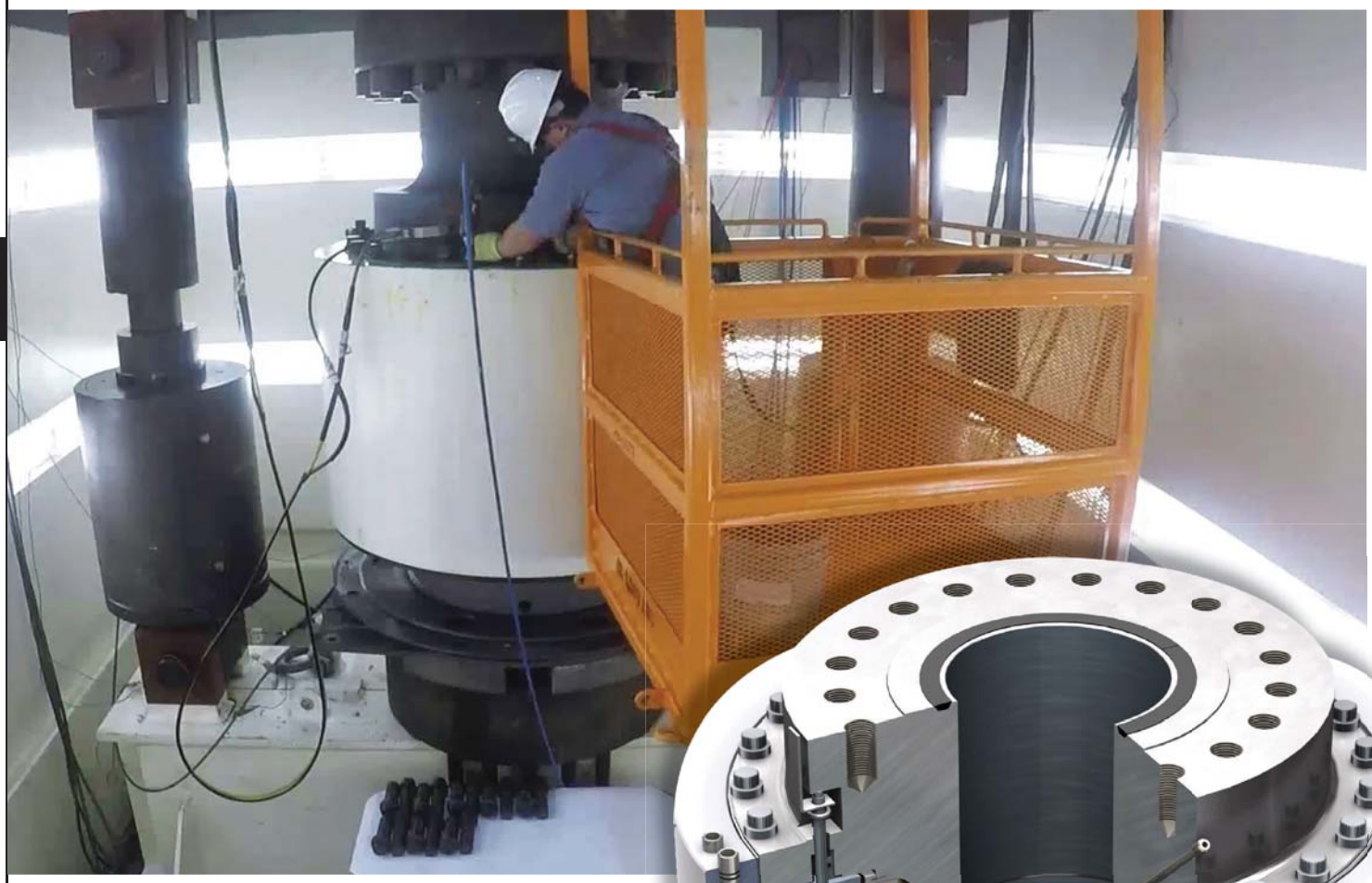


bending required during the survival load tests and exhibited zero damage as required by API 17TR7.

For fatigue testing, a complete 18¾-inch wellhead system with DXe profile and wellhead connector was assembled, including the wellhead and wellhead connector. The full assembly was placed into a resonant bending test fixture and cycled until the desired fatigue life was achieved. During four months of continuous testing, the system was subjected to more than 90 million cycles, with an applied bending moment of 1,500,000 ft-lbf.

When it was disassembled following testing, there were no cracks in or on the connector components or the wellhead or wellhead profile. The fatigue performance far surpassed industry needs and proved the wellhead system and connector can handle the most severe cyclic loads.

A separate "No Bolts" test, in which all the bolts were removed from the connector, was performed to API 16A requirements for bending, tension, and compression. For this test, the connector was fitted with strain and pressure gauges



Source: DrilQuip

and tested at its full rated working pressure of 20,000 psi in the bore. Through 21 load tests, performed with a load exceeding 8 million ft-lb of bending, the integrity of the system remained intact with no leaks recorded.

PROVEN PERFORMANCE AND VERSATILITY

Combined, these tests constitute the highest-level connector testing carried out by the industry to date. The results prove that the DXe connector can perform reliably in shallow-water service, where severe bending and high-fatigue HPHT conditions must be met, as well as in hyper-deep water (20,000 ft/6,096 m) applications, where the system must withstand sustained pressure to 20 ksi. No other connector in the industry is proven to both API 16A and API 17 TR7 and offers the configurability and fatigue life of the DXe connector. The designed-in ability to adapt to traditional wellhead mandrel profiles currently in service extends the connector's potential to improve safety and project economics across the board.

The DXe wellhead connector improves reliability in critical service applications.

COVID-19 Mitigation on Rigs & Ships

***STEVE LYKINS**, PRESIDENT, MAKO INDUSTRIES, DISCUSSES THE CASE FOR INVESTING IN PURADIGM COVID-19 MITIGATION AND MONITORING TECHNOLOGY ONBOARD OFFSHORE RIGS AND SHIPS.*

By Greg Trauthwein

The creation of Mako Industries, a subsidiary of Mako Oilfield Services, is proof that every storm cloud has a silver lining. "Mako Industries is an interesting company that was spawned as a result of Mako Oilfield pivoting as a result of the downturn in early 2020 and Q1 2020," said Steve Lykins, President, Mako Industries. "We had a substantial force of highly qualified technicians on the oil field side transition into our industrial division, which focuses on HVAC and electrical installations and, with the addition of Puradigm, COVID-19 mitigation and monitoring" in landside facilities, as well as on offshore rigs and ship.

WHAT IS PURADIGM?

Mako Industries is an authorized reseller and installer of Puradigm, a technology which according to Lykins and documentation from the manufacturer, can eliminate the threat of COVID-19, both airborne and on surfaces. Puradigm's Active Technology creates High Energy Clusters (HEC) and Bi-Polar Ion Oxidizers that seek out and destroy dangerous pathogens in the air, as well as on surfaces. Puradigm is verified to kill up to 99.99% of the below pathogens in laboratory and real-world testing: viruses, bacteria, mold fungus, VOC's, mildew and odors.

"Puradigm Technology is one of the most validated COVID mitigation technologies in the market today," said Lykins. Through a process called photocatalytic oxidation, UV light bounces off of a coated metal material, in this case, a proprietary honeycomb designed for Puradigm, generating and dispersing high energy clusters and oxidizers. High energy clusters attach in the air to airborne pathogens, bacteria and viruses, as well as treat surfaces, too.

"So we attack air and surfaces for not only certainly viruses and bacteria, but also mold, VOCs, these other airborne contaminants," said Lykins. "This technology has been validated through the University of Florida via a test back in July (2020). We're excited that a lot of our customers, particularly in the offshore arena can be able to have some level of protection."

MITIGATION & MONITORING

While many may not envision an HVAC system at the forefront of the digitalization revolution, COVID-19 has flipped the script on this, too, as virus mitigation is just one part of the puzzle. Continuous monitoring of facilities is a second but equally important piece to ensure 24/7 vigilance, and in this regard Mako Industries offers the Airthinx Air Quality Management System, a system that leans on AI to optimize the health of indoor spaces.

The Airthinx solution includes:

- **Power Sensors** – combined with digital signal processing to ensure continuous and accurate measurements.
- **Standalone Connectivity** – An independent & self-sufficient connected system that uses 3G/4G, Wi-Fi, Bluetooth, and mesh to connect the device to the cloud without requiring a local network in a plug and play fashion.
- **Scalable** – Works right out of the box.
- **Using AI** – Using Artificial Intelligence and deep learning, the data analytics engine can identify and classify events such as fire, smoking and mold detection.

"We have a technology called Airthinx. which is an active

monitoring system that continuously monitors air quality," said Lykins. "Even though it does not monitor COVID, per se, it monitors the size of airborne particulate that resembles bacteria and COVID, so you get an indication if you have an event in a particular area."

An important part of the monitoring package is not simply to detect and address anomalies, but also the data is stored, providing a historical snapshot of the air quality onboard a rig or ship during a given time period. "It's an important process to be able to have not only the mitigation tool with Puradigm but have the Airthinx monitoring to go along with it," said Lykins.

TIME, POWER, SPACE

Space and power on offshore rigs and ships are valuable turf, and Mako Industries connection to the offshore market make it well-suited to take care that the Puradigm system dominates neither. "Predominantly, we either have wall-mounted units or units that are installed in the HVAC system," said Lykins. "Either way, these are 'out-of-the-way' technologies that do not interfere with any type of operation, that integrates directly into the ship ventilation system or into each confined space." Power-wise, too, is "very simple" according to Lykins: "It's 120 volts with a 12-volt transformer and has a very low average draw."

To get the system up and running "we run about one to two weeks for design review, followed by installation," said Lykins. "We have our technicians which can go out and perform the installation or maintenance services on the technology for the life of the system. The energy source has about a one year lifespan on the cell. Depending on which technology we apply, HEPA filters are integrated into some of the units, which need changed-out." While pricing is specific to each project based on a number of factors, in general it is $.12/.15 per square foot for air purification depending on the Bio load and ceiling heights; and $.08 per square foot for monitoring.

While Lykins and his team were working through multiple bids in the offshore and maritime markets at the time of the interview, one recent, high-profile land-based installation was inside the Texas State Capitol. "With our distributor partner Eagle disinfectant, we have been installing the system at the Texas state capital, which is a very large complex," said Lykins. "We're protecting well over 2 million cubic feet of air and purifying that air to protect our lawmakers in the state of Texas. We see that as kind of the gold standard for the state of Texas just to be able to provide that installation for Puradigm."

OETV

Watch the interview @
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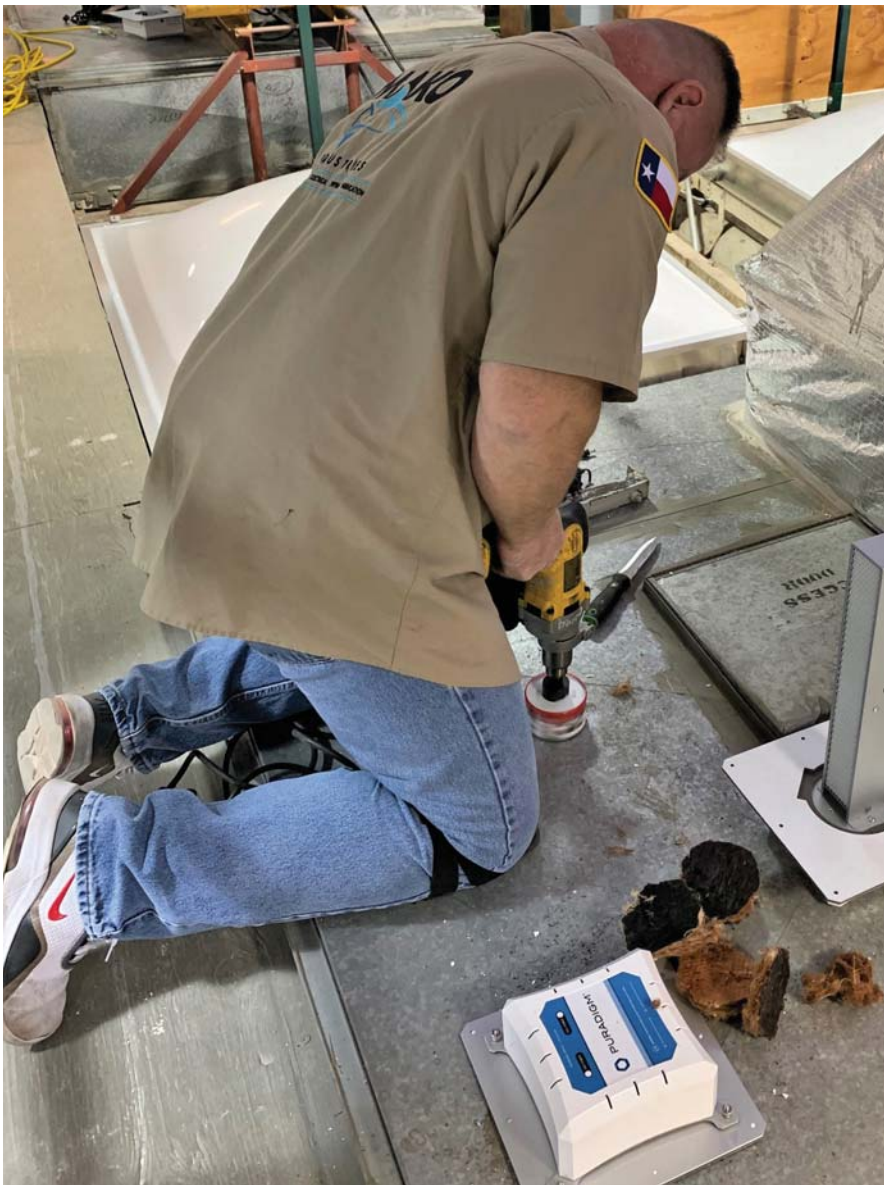

Source: Mako Industries

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Collaborative solutions for more efficient, greener drilling operations

All images: KONGSBERG

How teamwork between COSL Drilling and key suppliers KONGSBERG and NOV has improved on previously record low emissions to deliver fuel and environmental savings of more than 25%.

By Morten Firing, Operations Manager,
Global Customer Support Offshore & LNG, Kongsberg Maritime

In 2020, after several years of developing energy-efficient drilling operations, a team at COSL Drilling Europe AS launched a major project to save energy on COSL rigs operating on the Norwegian shelf in the North Sea. This 'Energy Control' project aimed to reduce greenhouse gas emissions and at the same time pursue other benefits, such as reductions in maintenance costs and fuel usage for engines and generators.

"By reducing the environmental footprint of COSL Drilling Europe and at the same time safely reducing our operational costs, we hope to create a win-win situation for both our business and the environment," explains Torfinn Kalstø, project leader for COSL Drilling Europe.

The drilling operation on a rig is a complex combination of safety and operational critical energy consumers. COSL invited Kongsberg and drilling specialists NOV to work together to achieve these goals. Both companies already had individual solutions to improve power consumption and generation efficiency: Kongsberg could provide smarter ways to control energy production, and NOV could optimize the use of the

available energy. Integrating these technologies has provided a holistic solution, now deployed on board the semi-submersible drilling rigs COSLPromoter and COSLInnovator, which achieves far greater energy savings than could be attained by focusing on a single area.

Learning from the past

The challenge was significant, as COSLPromoter and COSLInnovator already claimed record low emissions for a 6th generation harsh environment semi-submersible DP3 rig. Historical data provided the key to the savings delivered by both NOV and Kongsberg. The rigs are both powered by six Wärtsila Vasa 12V32 diesel generators developing 4,800kW each. These previously ran all the time during drilling operations, but analysis showed that full capacity was rarely used. NOV examined historical data for parameters such as rig movement, hook load, and the number of generators, and delivered a software update based on this information to optimize energy utilization for large consumers.

Figures for estimated maximum power consumption drawn from this historical data were sent to the team at Kongsberg, who, based on these estimates, developed advanced, targeted solutions to control energy production and distribution on board. The net result allowed them to shut down – on average – three of the six diesel engines. COSL can now deliver full DP3 drilling operation with fuel consumption of less than 20 tonnes per day, and – as COSLPromoter and COSLInnovator are certified to operate in 2 split mode for DP3 and Posmoor/anchor operations – the possibility exists to deliver even greater efficiency and sustainability by running on just two generators.

To service the needs of the rig, the remaining generators work at higher loads, which is highly beneficial to the diesel engines, with more efficient fuel consumption and reduced carbon build-up. This has a positive knock-on effect in terms of both working environment, noise, and reducing required maintenance.

Reducing the number of running generators and increasing the efficiency of operation of the remaining units produces dramatic savings both in costs and emissions. Annual fuel consumption is cut by approximately 2,300 tonnes, CO2 emissions by 7,300 tonnes and NOx by 125 tonnes, representing an overall saving in both fuel and emissions of more than 25%.

The project is approved and supported by the NOx Fund, a Norwegian Government initiative for reducing NOx emissions.

Predicting the future

While the additional generators remain available for use in adverse conditions, the aim of the Kongsberg/NOV solution is to avoid using them when not required. Kongsberg Maritime helps to achieve this by improving how efficiently the installed thrusters are used via a dynamic load prediction strategy, built on the company's decades of experience in Dynamic Positioning (DP). Just as a driver might accelerate a car as they approach a steep hill in order to avoid making a reactive response which consumes more fuel, Kongsberg's patented system anticipates thruster requirements to virtually eliminate spikes in demand, similar to a peak shaving application.

Measurable success

To quantify the savings delivered, Kongsberg uses an Information Management System (K-IMS) that collects performance data from the rig and uploads it to the cloud, allowing information to be viewed in a dashboard environment and

The Kongsberg Integrated control system keeps the vessel's position, monitors and controls vessel functions and actively distributes energy across onboard consumers.

improvements verified against benchmark data. This allows a range of performance parameters to be monitored and new potential areas for improvement identified. COSL is currently in the process of using the K-IMS data to establish an onshore operation center at the COSL Drilling Europe main office in Stavanger. This facility, which will closely follow the results and climate contribution, will help to ensure that COSL is – and continues to be – a sustainable partner in the future energy sector. COSL will now be able to safely carry out a large part of its drilling operations while running with a minimum number of diesel engines. At the same time, reserves are quickly available if circumstances such as weather and wind change. This intelligent, 'best-of-both-worlds' solution has only been made possible through collaboration and is set to provide a model for future operations.

"For COSL," says Torfinn, "it is very satisfying to work with suppliers who achieve such great results in our quest to continuously improve our operations together. In this case, we created improvements without installing new equipment that in itself may incur a negative effect on the environmental balance – instead, we have only installed new sensors and improved software and interfaces between the equipment on board. This has meant that installation time has been minimal. Before, the focus was on reducing consumption for economic reasons. We are now changing our focus to reduce our environmental footprint, but we are increasingly finding that it also results in reduced costs and increased efficiency in our operation."

Are the Potential Incidents a result of 'Old School' Safety Leadership?

Despite the general perception of 2020 as an "annus horribilis", there were also some optimistic safety trends with injury frequency relatively low.

By Dr Torkel Soma, Senior Partner at Sayfr

Based on industry statistics, several companies are expected to set an all-time low record in Lost Time Injury Frequency (LTIF) and Total Recordable Injury Frequency (TRIF). Even so there are still too many high potential incidents . Some say that the underlying causes of several of these high potential incidents were cost-cutting and delayed maintenance, enhanced by low oil prices and COVID-19. But there are alternative explanations. A biased focus on minor incidents and rigid control can easily be prioritized at the expense of preventing far worse major incidents. Without insight and due care, it is easy to go down the wrong path. This article outlines some of the challenges and possibilities for guidance in this difficult terrain. The Norwegian Petroleum Safety Authority (PSA) is tasked with investigating potential and actual major incidents. Its investigations into the recent 2020 incidents are not yet completed. However, a review of 68 investigations identifying more than 140 failures (deviations from what is expected, desired, or required) demonstrates some clear patterns.

The failures which involve how the personnel actually do their work (red) are far more frequent than the structural "non"-human systems they have in place to prevent major incidents (blue).

The largest single failure identified is "Risk management in planning and execution", which was found in more than a quarter of the incidents. In contrast, maintenance has played a key role in only nine of these investigations. Although the recent high potential incidents may involve more maintenance issues, the major takeaway from these investigations is that behavioral failures have greater improvement potential.

Injuries & Major Incidents

The relationship between injuries (High-Frequency, Low-Consequence (HFLC) and major incidents (Low-Frequency, High-Consequence (LFHC) involves several misconceptions and conflicting interests. The investigations into two major incidents, the Texas City explosion in 2005 and Macondo in 2010, concluded that the management had a biased focus on injuries such as LTIF at the expense of major accident risks. Injuries and other HFLC incidents are usually triggered by single failures and the injured person is normally the one who makes the mistake. Innocent parties are seldom exposed.

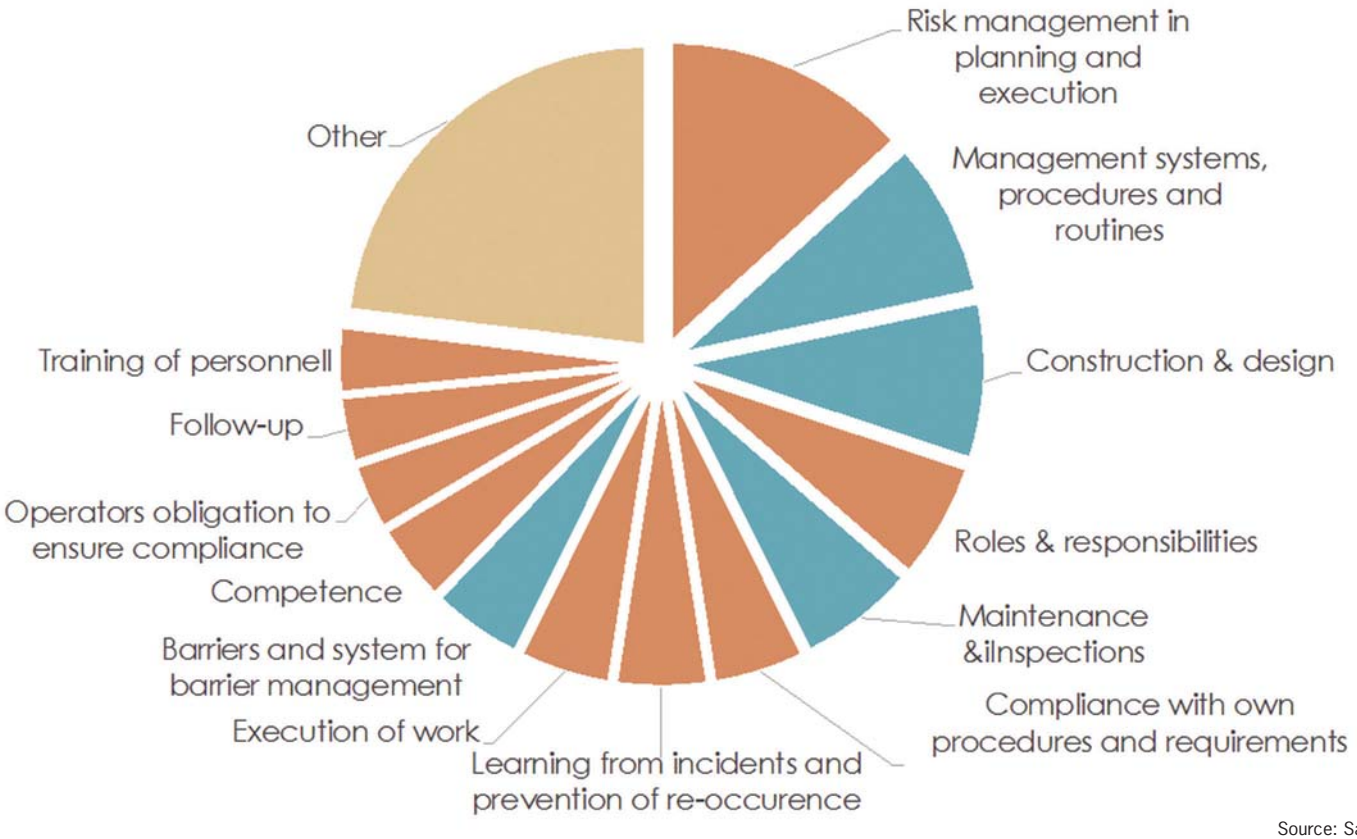
Major incidents, on the other hand, have different characteristics involving multiple failures, several of which are caused by persons in different departments and at various levels in the organization. The failures are often unaddressed over time until an unfavorable situation results in major losses that frequently involve innocent persons.

These incidents are therefore often referred to as organizational accidents. Because of the difference in the nature of injuries and major incidents, there is a need to be more aware of, and up to date on, the various strategies to prevent these incidents from happening.

Different Safety Strategies

In other industries, a biased focus on structural interventions and transactional implementation results in a doubling of the frequency of major incidents while the injury frequency is halved. This emphasizes the need to more thoroughly evaluate how injuries and major incidents can effectively be prevented. The first distinction should be between structural- and behavioral interventions. Structural interventions, such as requirements for the use of personal protective equipment (PPE), can be used to prevent injuries. Similarly, barrier management system is a structural approach to prevent LFHC incidents.

The second distinction is between various ways of implementing changes. There are several different ways, but for simplicity let us consider the two most relevant, which are the transactional and transformational leadership approaches.



Source: Sayfr

A transactional implementation tends to focus on supervision, responsibilities, rewards, sanctions and authority. The underlying driver is to "control" the implementation process. In effect, it uses power to change behavior, often under the mantra: what is measured gets done. An alternative to a transactional approach is the transformational leadership approach.

Transformational leaders aspire to the "change" itself over "control". Transformational leadership wants to build ownership of the change, motivate for goal achievement, inspire innovation, and show concern for the employees' welfare. Several studies demonstrate that a transformational leadership approach is more effective in achieving sustainable behavioral change.

Keys to Safety Improvement

So, back to the distinction between injuries and major incidents. Because of the characteristics of individual injury accidents (HFLC) described above, it is obvious that a transactional approach may have some effect on compliance with procedures and other requirements. For example, if you require people to use personal protective equipment (PPE), the injury frequency will decline. If you supervise everybody and sanction the ones that do not use proper PPE, the HFLC statistics will probably continue to improve.

In the energy industry, which has potentially high operational risks and decades of experience, there is a foundation of accepted construction and regulation in place. Hence, as the PSA investigations reveal, the need for additional "structure" is not that evident in the prevention of major incidents (LFHC). A socially safe working environment based on trust, care, and openness is required to allow people to share their own mistakes and address failures caused by their colleagues or even managers. If people believe they will be fired for speaking up, they will keep their mouths shut.

Trust, care, and openness cannot simply be required (like the wearing of PPE). On the contrary, this kind of environment is something that managers and leaders must create. Hence, there is an evident need for behavioral interventions combined with a transformational leadership approach.

Temptation of the 'Quick Fix'

With a strong public focus on sustainability and transparency, all energy companies are committed to continuously improve their safety performance. Injuries and other high-frequency low-consequence incidents can be a substantial problem and are easy to monitor due because they occur more often than major incidents. Companies that fall behind on improvements must expect negative attention from investors,

media and the public.

One tempting "quick fix" to improve the injury frequency is to implement structural interventions through a transactional approach; write a new rule and simply require people to comply. Because this approach has long traditions, it is referred to as the "old school" approach. A transformational approach requires more cross-organizational collaboration between the safety department (which "owns" the problem), the HR department (which "owns" the people) and day-to-day operations (which "own" the managers and priorities). Furthermore, their often involves more advanced implementation. Bottom-up engagement ensures that the employees have ownership and understanding of the change. The top-down implementation through the "chain of command" ensures that the changes are welcomed.

Old School Safety Management Can Fuel Cover Ups

Many energy companies unconsciously rely too much on structural interventions and/or transactional implementation. For example, to speed up reporting it is common to require a certain number of observations or near-miss reports per employee or installation per month. Other examples are behaviour-based safety and barrier management, which are often implemented using a transactional approach.

When people are forced into a change without buy-in, engagement, and motivation, the change can easily turn into a compliance exercise without ownership and critical thinking. The end result is that complying with the requirement or expectation tends to be more important than the underlying purpose and intention.

The reporting of lost time injuries is one example of under-reporting due to both the internal and external transparency regarding these incidents. Some typical strategies that stimulate the under-reporting of lost time injuries are listed below:

- Bend the definition: creatively find any simple task that makes it possible for the injured person to continue working.
- Suppress reporting: suppress the reporting of injuries by using indicators such as "days since last LTI" or "7 years without reported LTI".
- Swapping: define the location of the injury to be outside the workplace or outside working hours or change the project that the injured person is working on.
- Simple under-reporting: simply violate the requirement to report an injury unless it is impossible to conceal.

Embrace Transformational Leadership

With few exceptions, the failures leading to major incidents are known before the incident takes place. This underlines the need to build a culture in which people dare to speak up and where they listen to each other. Transformational implementation is effective in maturing trust, care, and openness in the organization, resulting in a 50-80% drop in major incident risk. These are significant improvements, but there are other benefits as well. A more mature culture also has an impact on the serious injury frequency, which is reduced by a factor of 40-65%. Employees who have the buy-in and understanding take greater care of themselves and their colleagues.

So, when somebody asks if they should focus on major incidents or personal injuries, it is simply the wrong question. The most effective approach is to address both of them with a common transformational safety program.

	Injuries /High-Frequency Low - Consequence (HFLC)	Major Incidents /Low-Frequency High-Consequence (LFHC)
Causes	Single Cause	Multiple causes
Time	Short time	Several days - up to years
Victims	Often the person who causes the failure	Often innocent people
Structural Intervention (example)	PPE requirement	Barrier management system
Behavioural Intervention (example)	Behavioral-based safety	Risk management in execution
Transactional Implementation	Some effect	No (or negative) effect
Transformational Implementation	Large effect	Large effect

Source: Sayfr

1 Examples of 2020 incidents are fires and explosions (Marathon, ExxonMobil, Equinor, Astron and Engen), blowouts (Assam/Baghjan (India) and Orenburg (Russia)) LNG process plant problems (Equinor and Petronas) and rig problems due to heavy weather (Seadrill/Lundin and Petronas Carigali).


Morris


Kragseth


Rød


Stewart


Durrant


Rose


Crawford


Laheij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Bull


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Vassbotn

Danish drilling contractor Maersk Drilling appointed **Christine Morris** as the new Chief Financial Office.

Vår Energi's CEO **Kristin F. Kragseth** in December 2020 said she'd leave the company for her new role as CEO of Petoro, a Norwegian government-owned oil and gas firm. Vår Energi said it had appointed **Torger Rød** as the company's new CEO, to take over from Kragseth. Rød has spent the last 22 years working with Equinor (formerly Statoil) in Norway

Ashtead Technology in January appointed **Ingrid Stewart** as a chief financial officer.

Premier Oil's CEO **Tony Durrant** stepped down from the Board of Directors and from his CEO position in December 2020, ahead of the company's expected merger with rival Chrysaor. Finance Director **Richard Rose** will serve as the Interim Chief Executive from January 1, 2021, until the completion of the proposed merger.

Oslo-listed drilling contractor Borr Drilling appointed **Magnus Vaaler** as its new CFO, replacing **Christoph Bausch** with effect from December 28, 2020.

Oil firm Ithaca Energy said in January it had appointed **David Crawford** as chief financial officer, taking over the role from predecessor **Graham Forbes** who would be leaving Ithaca, effective February 1.

Singapore-based marine and offshore pump manufacturer Hamworthy Pumps named **Hans Christiaan Laheij**, 48, as its new CEO, effective January 15, 2021.

Håkan Agnevall took over as CEO of the Finnish marine equipment maker Wärtsilä on February 1, 2021.

Gilmore, a U.S.-based flow control solutions provider for the oil and gas industry, in January appointed D**avid Nemetz** as its new CEO. The company is a subsidiary of Aberdeen-headquartered Proserv

Stephen Bull, Equinor's senior vice president responsible for offshore wind operations in the North Sea, will leave the company this summer and will join the Norwegian offshore services firm Aker Solutions. **Øystein Michelsen** will fill up the Bull's position at Equinor, and has been appointed acting senior vice president North Sea in New Energy Solutions in Equinor.

Great Lakes Dredge & Dock, a U.S.-based dredging services giant, appointed **Eleni Beyko** as senior vice president offshore wind – a strategic growth area for the company.

UK-based Global Energy Group in January appointed **Tim Cornelius** as Group Chief Executive.

Simec Atlantis appointed **Graham Reid** as the new Chief Executive Officer and a Director. He was most recently CEO of RES Americas.

Knut Vassbotn will lead deep Wind Offshore, a newly established offshore wind operator in Norway, as CEO. On February 1, Deep Wind Offshore announced the appointment of **Hans Petter Øvrevik** as its Chief Commercial Officer (CCO).

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