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Abandonment & Decommissioning

page 18

Offshore Engineer • November 2017


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FEATURE FOCUS

Abandonment & Decommissioning

Photo from Chris Ledford, Texas Parks and Wildlife Department.

Features

ON THE COVER

End of Life. Shell's Leman BH platform made its way to the Great Yarmouth decommissioning facility to be recycled by Veolia and Peterson. The 1000-tonne topside and the 700-tonne jacket arrived in July 2017. *Photo courtesy of Veolia and Peterson.*

Departments & Columns

ATCOmedia
Atlantic Communications Media

AtComedia
1635 W. Alabama
Houston, Texas 77006-4101, USA
Tel: +1-713-529-1616 | Fax: +1-713-523-2339
email: info@atcomedia.com

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Photo from iStock.

Online Exclusive

Mozambique ready for action

While many natural gas projects in East Africa have seemingly been put on hold during the downturn, Mozambique's prizes have been on simmer. Audrey Leon reports from this year's SPE Offshore Europe.

What's Trending

Sliding home

- Appomattox hull arrives in US Gulf
- Statoil launches Hywind floating wind farm
- First Cambodian field wins FID

Appomattox's hull arriving in Texas. Photo from Shell.

People

Sternadt to head Dresser-Rand

Paulo Ruiz Sternadt has been named CEO of Dresser-Rand, part of Siemens Power and Gas Division. He succeeds Judith Marks.

Undercurrents

The times they are a-changing

Decommissioning has often been called a bow wave – always in sight, but just out of reach. Serious thought is being given to this non-cash generative game now, however.

We've reported on the incredible single lift of the Brent Delta topsides by Allseas' *Pioneering Spirit* this year. Now, much of the work in the maturing North Sea, which is set to lead global decommissioning activity in coming decades, is focusing on plugging and abandonment (P&A).

According to Wood Mackenzie forecasts, over 700 offshore fields are expected to cease production globally in the next five years *(See page 18)*.

Nearly 20% of that activity will be in the UK North Sea. Costs are still hard to predict, not least as we're in the middle of a technology journey when it comes to P&A – a move to rigless P&As could cut 50% of the cost, delegates at the Plug and Abandonment Forum (PAF) Seminar in Stavanger heard last month. This is significant given that estimates suggest P&A cost is on average nearly 50% of the decommissioning bill.

Further progress is being made. PAF chairman Martin Straume said at the 2013 event that it would take 40 years for 15 rigs to P&A all the wells on the Norwegian Continental Shelf (NCS). Just four years later, significant effort has been put into reducing the time (and cost) of well P&A on the NCS.

Technologies have been developed to further reduce the time and cost *(See Hydrawell and Archer's perforating while cementing technologies on pages 28-30)* and yet more are being dreamt up and trialed that could further "change the game." We'll report more on this year's PAF seminar, put on by Norske Olje og Gass, next month (December).

Despite the ongoing pain being felt in the industry since 2014, the technology development in the P&A segment isn't isolated.

Technology changes seem to be happening faster everywhere. This is becoming a cliché, but this is what makes the industry so exciting.

To give an example, robotics is fast becoming a mainstream topic in the industry – and not just through drones and underwater robotics, but for topsides applications. It will be the subject of a week-long series of activities led by the Oil & Gas Technology Centre in Aberdeen. We'll report on this in a future issue.

The Internet of Things (IoT), yet another buzz phrase, and a sometimes baffling one at that, is also making its way into the business. Globally, the number of connected IoT devices worldwide will jump 12% on average annually, from nearly 27 billion in 2017 to 125 billion in 2030, according to IHS Markit.

We'll explore IoT, and, more crucially, the communications infrastructure required offshore to enable it, in *OE*'s December issue. IoT will play a role in robotics, communications infrastructure will play a role in all electric subsea systems, all electric systems – topside and subsea – will play a role in future need (current if you're in Norway) to reduce emissions, NOx and CO_2, from processes.

Which brings us back to decommissioning. As well as looking at faster, cheaper ways to P&A, there are some investigating alternatives to full removal and scrapping of platforms and substructures. *OE* looks at platform reuse and rigs to reefs in our decommissioning focus this month. But, other ideas are emerging, including how active and redundant oil and gas infrastructure could not only coexist with, but support the growth of, offshore wind and balanced energy grids on the Dutch Continental Shelf, by introducing gas to power, power to hydrogen, carbon capture and storage, and interconnecting the whole lot across multiple countries.

The future may still be rather uncertain, but it's far from boring. **OE**

OE

PUBLISHING & MARKETING

Chairman/Publisher
Shaun Wymes
swymes@atcomedia.com

EDITORIAL

Editor/Associate Publisher
Audrey Leon
aleon@atcomedia.com

European Editor
Elaine Maslin
emaslin@atcomedia.com

Senior Editor
Karen Boman
kboman@atcomedia.com

Contributor
Emma Gordon

ART AND PRODUCTION

Bonnie James
Verzell James

CONFERENCES & EVENTS

Conference Director
Jennifer Granda
jgranda@atcomedia.com

PRINT

Quad Graphics, West Allis, Wisconsin, USA

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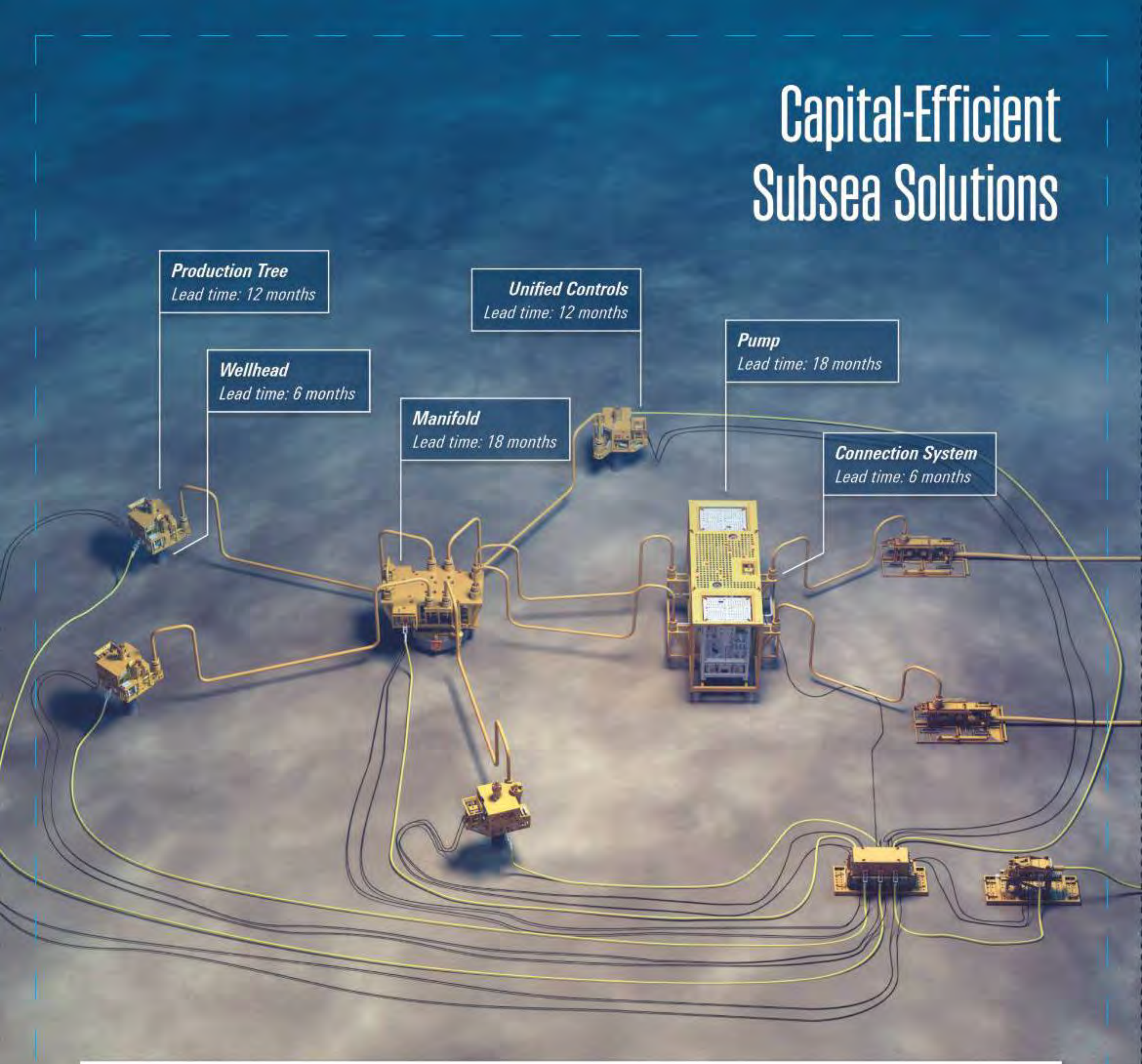

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Global E&P Briefs

A South Timbalier drilling starts

W&T Offshore has started drilling on the ST 224 No. 1 exploration well in the South Timbalier 224 lease in the US Gulf Of Mexico.

Drilling is targeting a large, amplitude supported, high condensate gas ratio exploration prospect in the prolific Bul. 1 trend. The Enterprise 264 jackup rig is drilling the prospect in 170ft water depth. The well has a relatively shallow target depth of 10,800ft (TVD) (11,439ft MD) and is expected to take around 55 days to drill and evaluate.

B Pemex to drill first pre-salt well

Mexico's National Hydrocarbons Commission (CNH) approved Pemex's exploration plans to probe Mexico's first-ever pre-salt well in the Bay of Campeche.

The Yaxxtaab-1 well is in the AE0013-M-Pilar de Akal Kayab-04 area, 95km northwest of Ciudad del Carmen in Campeche state, in Cinturón Akal province, in the Southeast basins.

The well will be in shallow waters of 50m depth, and be drilled to 7800m below sea level, traversing a big layer of salt, CNH said.

C Trinidad OBN seismic planned

FairfieldNodal will begin a large Z700 ocean bottom node (OBN) acquisition project offshore Trinidad in late October.

FairfieldNodal says that OBN is suited to meet the tough environmental conditions in the offshore Trinidad region that make ocean bottom cable or streamer surveys risky.

This acquisition project is expected to take four months to complete.

D Anadarko to explore off Peru

Anadarko Petroleum signed an exploration agreement with the government of Peru to explore 4.7 million acres across three deepwater blocks in the Trujillo Basin offshore Peru.

The exploration phase of the agreement is a typical multi-year, multi-phase agreement for seven years.

During the first two-year phase, Anadarko expects to invest approximately US$5 million to conduct evaluation activities primarily consisting of reprocessing existing seismic data and collecting piston cores from the sea floor to evaluate the potential.

E Appomattox hull reaches Gulf

The hull for Shell's Appomattox facility is now at the Ingleside, Texas shipyard where it will undergo final construction before installation in the deepwater Gulf of Mexico.

Appomattox will add approximately 175,000 boe/d (Shell share) when it reaches peak production, with resources of approximately 650 MMbbl from the Appomattox and Vicksburg fields, and potential to increase in the future through near-field discoveries such as Rydberg.

The platform will tower more than 20 stories above the ocean once fully assembled. It will float in 2255m (7400ft) of water. Appomattox is on track to achieve first oil by the end of this decade.

Appomattox hull. Photo from Shell.

F ExxonMobil makes fifth Guyana find

ExxonMobil has made a fifth oil discovery at the Stabroek block offshore Guyana with at the Turbot-1 well.

ExxonMobil's Guyana subsidiary encountered a 23m (75ft) reservoir of high-quality, oil-bearing sandstone in Turbot-1's primary objective. Turbot-1 lies in the southeastern portion of the Stabroek Block, approximately 50km (30mi) to the southeast of the Liza phase one project.

Drilled by the *Stena Carron* drillship in 1802m (5912ft) of water, the well was safely drilled to 5622m (18,445ft). ExxonMobil plans to drill an additional well on the Turbot discovery next year.

G More seismic shot off Brazil

FairfieldNodal will acquire and process high-resolution 3D marine seismic for the Libra consortium led by Petrobras. The Libra project will use the Z3000 ocean bottom node system.

In the North, Spectrum Geoscience began the Ceara Basin 2D multi-client seismic survey in the Equatorial Margins. The area contains sectors of the 15th licensing round, which is expected to close in Q2 2018. When the survey is completed it will provide a continuous modern long-offset 10K grid from the border with French Guiana to the eastern extent of the Potiguar Basin.

H Brazil's 14th round results

Brazil's 14th Round saw a total of 287 exploration blocks auctioned across nine basins,

with an estimated total of 50 billion bbl in place, both offshore and onshore. The joint venture of Petrobras and ExxonMobil signed the largest bonus of US$701 million (R$2.24 billion) for block C-M-346 in the Campos basin.

The offshore acreage included blocks in Pelotas, Santos, Espírito Santo, Sergipe-Alagoas, and the Campos basins.

In total, 20 companies from eight countries participated in the bid round. Seventeen of them acquired blocks. The signing of contracts is expected to occur in January 2018.

J Chevron approves Captain EOR

Chevron is moving ahead with plans for an enhanced oil recovery (EOR) project using polymer technology on its Captain heavy oil field in the UK North Sea.

The Captain field was discovered in 1977, in Block 13/22a on the edge of the outer Moray Firth (Scotland). The billion-barrel field achieved first production in March 1997 thanks to developments in horizontal drilling and down-hole pumps.

Stage 1 of the EOR project will see the drilling of up to six long-reach horizontal injection wells.

For many years, the field has been under waterflood, which means a lot of effort is put into water production and treatment (some 300,000 b/d of water are produced). However, there is still a lot of bypassed oil, because of the way waterflood results in a "coning" effect in the reservoir.

K More oil at Frigg Gamma Delta

Aker BP found further oil at the Frigg Gamma Delta discovery, in PL442, offshore Norway in the Central North Sea. The appraisal well 25/2-19 S was drilled by the Maersk Interceptor jackup some 12km (7.5mi) northeast of the Frøy field and 200km (124mi) northwest of Stavanger.

The well encountered an oil column of 13.5m in sandstone with good reservoir quality, after drilling to vertical and measured depths of 2212m and 2325m below the sea surface, respectively. The oil/water contact was encountered near 1950m below the sea surface. The well was terminated in the Sele formation from the Palaeocene Age. Prior to appraisal drilling, the Frigg Gamma Delta discovery size was approximately 10 MMcm of recoverable oil, and 2 Bcm of recoverable gas. The well was permanently plugged and abandoned.

L Energean touts Montenegro fields

Mediterranean explorer

I Statoil brings Hywind online

Statoil and partner Masdar's Hywind Scotland project – the world's first floating wind farm – achieved "first power" last month (October). The 30MW wind farm, operated by Statoil, is 25km offshore Peterhead, Scotland, and comprises five, 6MW turbines, at 253m-tall with 154m rotor diameter, and a 30km 33kV export cable. The farm covers about 4sq km in water depths varying between 95-129m.

The onshore operations and maintenance base for Hywind Scotland is in Peterhead, while the operations center is in Great Yarmouth. Linked to the Hywind Scotland project, Statoil and partner Masdar will also install Batwind, a 1MWh Lithium battery storage solution for offshore wind energy. Statoil says battery storage has the potential to mitigate intermittency and optimize output.

Photo: Øyvind Gravås / Woldcam - Statoil ASA

NEWS

Global E&P Briefs

Energean Oil & Gas praised the "untapped potential" of its two blocks offshore Montenegro, which may hold 1.8 Tcf of gas and 144 MMboe of liquids (438 MMboe in total), according to a new report by Netherland Sewell & Associates (NSAI).

Energean owns 100% interest in blocks 4218-30 and 4219-26, which were awarded in March this year. The blocks cover 338sq km in shallow water (50-100m), in the eastern Adriatic Sea, offshore the southwest side of the country. The NSAI report is part of a three-year exploration phase, which includes a 3D seismic survey set to begin Q1 2018 over the two blocks.

M Senegal PSC renewal sought

Independent oil firm African Petroleum has applied to enter a second renewal period at the Senegal Offshore Sud Profond (SOSP) production sharing contract (PSC). The firm is also hoping to swap a commitment to drill a well for a 3D seismic acquisition program from its outstanding first phase commitments.

The renewal would extend the PSC from 2.5 years from December 2017 and would include a commitment to carry out 3D seismic acquisition and processing and one exploration well.

O Tower plans Thali drilling

Tower Resources is taking steps to drill on the shallow water Thali license, offshore Cameroon, in the Rio del Rey basin in the eastern part of the Niger Delta.

The company will conduct reprocessing of the existing 3D seismic data and conduct specific specialist studies such as attribute analysis, including AVO and pore pressure prediction, and coherency cubes on that data; continue with the geological and geophysical interpretations, using that reprocessed data, to refine and high-grade the prospect inventory on the Thali PSC block, to mature the drillable prospects; to investigate rig availability with appropriate technical specifications.

To date, contingent oil-in-place estimated at 39 MMbbl (Pmean, gross) has been discovered on the block.

N Wheatstone starts up

Chevron's Wheatstone LNG project in Western Australia started production in early October.

At full capacity, the Wheatstone Project's two train LNG facility will supply 8.9 MTPA of LNG for export to Asia.

The development comprises onshore facilities at Ashburton North, Western Australia, the Wheatstone platform – the largest offshore gas-processing platform installed in Australia, with a ~37,000-tonne topside – subsea wells and a 225km trunkline from the platform to Ashburton.

In April 2015, Wheatstone made history with Chevron's heaviest topsides floatover and installation onto the steel gravity substructure (SGS). Sitting in 70m water depth, the platform is 225m tall from the base of the SGS to the top of the flare tower and designed to withstand 12 story-high cyclonic waves.

Wheatstone LNG facilities. Photo from Chevron.

P Total inks E&P pact

Total and the National Office of Petroleum of Guinea (ONAP) signed a technical evaluation agreement to study deep and ultra-deep offshore areas off the coast of Guinea Conakry, covering approximately 55,000sq km (21,235sq mi).

Total will have one year to assess the potential of the basin using existing data. At the end of this one-year period, the group will select three licenses to start an exploration program.

The agreement gives Total the opportunity to evaluate a very large area, in an extension of the prolific Mauritania/Senegal basin where it is already active.

Q Ophir signs new EG PSC

Ophir Energy and GEPetrol signed a new production sharing contract (PSC) for Block EG-24 offshore Rio Muni, Equatorial Guinea.

Block EG-24 (formerly Block EG-20 and Block M) is one of 20 exploration areas marketed during the EG Round 2016 licensing round and is to the west of producing fields Ceiba and Okume, covering 3537sq km.

Ophir Energy will operate the block and have 80% interest. GEPetrol will have a 20% stake, with the option to increase this by another 10% if a commercial discovery is made. 2D and 3D seismic data cover large areas of the block.

R Consortium only Lebanon bidder

Acting as a consortium, Eni, Total and Novatek made the only bids in Lebanon's first offshore licensing round. The companies bid on Blocks 4 and 9. Block 4 lies on the shallower side of Lebanon's offshore waters, and is thought to be highly prone to gas. Block 9 is a southern block, thought to be prone to oil.

Five offshore blocks were offered in the bidding round. The bids will be evaluated and a report submitted to the Minister of Energy and Water by 13 November.

S 'Contract of the Century' extended

BP has won a contract extension out to 2049 for the Azeri, Chirag and Gunashli (ACG) oil fields in the deepwaters of the Caspian Sea, offshore Azerbaijan.

Some 3.2 billion bbl have already been produced following some US$33 billion investment in the fields, 120km east of Baku. A further $40 billion could be invested in the next 32 years. The deal was signed between the Azerbaijan government and the State Oil Company of the Republic of Azerbaijan (SOCAR), together with BP, Chevron, INPEX, Statoil, ExxonMobil, TP, ITOCHU and ONGC Videsh.

ACG has eight offshore platforms – six production and two process, gas compression, water injection and utilities platforms. The platforms export oil and gas to the Sangachal Terminal near Baku.

T Woodside fails off Myanmar

Australian explorer Woodside's latest exploration wells offshore Myanmar were non-commercial. The firm's Pyi Tharyar-1 well, in 2449m (8034ft) water depth, in Block A-6, had intersected a thin column of gas saturated sands, which were considered unlikely to be commercially recoverable.

The final well in the campaign, the Khayang Swal-1 well, in 1487m (4878ft) water depth, in Block AD-7, in the Bay of Bengal, intersected water-wet sands in the target interval and was classified as a dry hole.

The prior well, Phi Thit-1, in 2001m (6564ft) water depth, intersected a gross gas column of approximately 65m (213ft). About 36m (118ft) of net gas pay was interpreted within the primary target interval in sandstone reservoirs.

U First Cambodian field win FID

Singapore-based explorer KrisEnergy will proceed with the first phase of its Apsara oil field, the first hydrocarbon project offshore Cambodia.

Phase 1A of the Apsara development, in Cambodia Block A in the Gulf of Thailand, is planned to be a single unmanned minimum facility 24-slot wellhead platform producing to a moored production barge with capacity for 30,000 b/d of fluid with gas, oil and water separation facilities on the vessel. Oil will be sent via a 1.5km pipeline for storage to a permanently moored floating, storage and offloading vessel. The Cambodia Block A contract area covers 3083sq km over the Khmer Basin in the Gulf of Thailand where water depths range 50-80m.

V Manora drilling begins

Mubadala Petroleum has started a three-well drilling program at the Manora oil field in the northern Gulf of Thailand.

The program in the G1/48 concession, using the jackup Atwood Orca, comprises two development wells and an exploration well.

The MNA-18 and MNA-19 infill wells have been planned to develop proved undeveloped reserves and will be drilled to final total depths of 3107m (10,193ft) and 2366m (7762ft), respectively. They will be completed with electric submersible pumps. Drilling is expected to take around 20 days.

The two development wells are expected to increase Manora production performance. The joint venture also intends to drill an exploration well to test the L-Prospect in the Manora production license.

W Chevron, Woodside gain interests

Chevron Australia and its 50:50 partner Woodside Energy have acquired exploration interests in three blocks in the Northern Carnarvon Basin offshore Western Australia.

Blocks WA-528-P, WA-529-P and WA-530-P cover 23,170sq km and are approximately 220km (136mi) northwest of Dampier off the coast of Western Australia.

Through its affiliate, Chevron will be operator with a 50% interest and Woodside Energy will hold the remaining 50% interest.

"Offshore Western Australia is a global focus area for Chevron and these new exploration blocks add to our already significant gas position as the largest resource holder and liquefaction owner," said Chevron Australia Managing Director Nigel Hearne.

Chevron's current projects in the area include Gorgon and Wheatstone.

Contracts

Ophir awards Fortuna EPCIC contract

OneSubsea (a Schlumberger company) and Subsea 7's joint venture Subsea Integration Alliance has won an engineering, procurement, construction, installation and commissioning contract for Ophir Energy's Fortuna floating LNG project offshore West Africa.

The contract scope includes subsea umbilicals, risers and flowlines for the subsea production systems. Planned delivery of first gas is 2020. Work will start on final investment decision, which is due before the end of 2017.

HFG wins NUI work

Independent Oil and Gas (IOG) has signed a letter of intent with Heerema Fabrication Group for front-end engineering and design (FEED), and engineering procurement, construction and installation (EPCI) of up to four normally unmanned installation platforms (NUIs).

The NUIs will be used for IOG's Southern North Sea (SNS) gas project, which consists of the Blythe Hub and Vulcan Satellites Hub developments.

Keppel wins Liza FPSO conversion

SBM Offshore has selected Keppel Shipyard for the conversion of an FPSO meant for ExxonMobil's Liza development offshore Guyana.

The contract is for the conversion of a very large crude carrier into an FPSO, with storage capacity of 1.6 MMbo. The vessel will also have a gas treatment capacity of 170 MMscf/d and a water injection capacity of 200,000 b/d.

The shipyard's work scope includes refurbishment and life extension works, such as the upgrading of living quarters, fabrication and installation of spread mooring systems, as well as the installation and integration of topside modules.

Kvaerner wins CGS installation

Husky Energy has awarded Kvaerner a contract for engineering and marine operations to tow and install the concrete gravity structure (CGS) for the West White Rose Project offshore Canada. The installation is scheduled for Q2 2021.

The Husky West White Rose Project will use a fixed platform – an integrated topside on a concrete gravity base – tied back to the *SeaRose* floating production vessel. The main White Rose field is about 350km (217mi) east of St. John's, Newfoundland and Labrador, on the eastern edge of the Jeanne d'Arc Basin in water depths of about 120m (393ft).

OneSubsea wins Indian supply gig

Reliance Industries has awarded OneSubsea an EPC contract for supply of the subsea production system for the R Cluster (Block KG-D6) project, offshore the east coast of India.

The scope of this project includes trees, subsea manifolds, control system, tie-in system, multiphase meters, intervention tooling and test equipment for the R Cluster field.

The contract also includes installation and commissioning support and life-of-field services. Reliance has the option to award the supply of the subsea production system for additional wells for the satellite fields.

Total efficiency

When Total launched the Laggan-Tormore subsea tieback, West of Shetland, it was always with the long-view, and not just in terms of distance. The investment is starting to pay off. Elaine Maslin reports.

The 143km-long gas pipeline export facilities for Laggan-Tormore, with pre-installed tie-ins points, is no ordinary subsea tieback. As well as being the UK's longest tieback, it created a hub for further development in the area when it came onstream in 2016.

It's already bearing fruit. Total brought the first two tie-ins to the system online ahead of schedule and 30% under budget earlier this year.

First gas had been expected from Edradour in Q4 2017, with Glenlivet expected to come onstream in late 2018. Instead, both were onstream in August this year and Total is already looking at other opportunities in the area.

The advanced schedule and reduced costs were achieved by being careful not to plan or carry out drilling and construction activities in the harsh winter months, and by using much of the same subsea equipment for the latest tiebacks as it did for Laggan-Tormore, as well as the same processes and procedures, tooling and spares, says Kevin Boyne, West of Shetland asset director, Total. The drilling and project teams comprised staff and contractors (where feasible) who already had experience on Laggan-Tormore.

However, it hasn't been a complete replica. The Glenlivet Edradour project saw the first use of seam welded pipe in a control umbilical and the use of thermally sprayed aluminium inside part of the Edradour flowline to help keep it cool, to minimize corrosion due to the CO_2 content of the Edradour production.

"By careful planning, maximizing the use of the summer

The *West Phoenix* semisubmersible drilling rig.
Image from Seadrill.

season and building on lessons learned from Laggan-Tormore, we were able to carry out a cost-efficient, long subsea tie-in to existing subsea infrastructure in more efficient way, significantly reducing both cost and schedule," Boyne says.

Go west

Edradour was discovered in 2010, in 300m water depth, then tested in 2011. The field contains lean gas condensate, with about 5 mol% CO_2. The initial reservoir conditions were about 118°C and 345bar. Glenlivet, in 435m water depth, was discovered in 2009, by DONG Energy (which has since exited the hydrocarbon industry) and is also lean gas condensate, but the initial reservoir conditions were lower at 65°C and 229bar.

Neither fields met Total's investment criteria when assessed on their own merits. But, as a joint development, tied into the pre-installed in-line tees on the Laggan-Tormore system, they became economic.

The Laggan-Tormore export system comprises two, 18in, 143km-long pipelines to the onshore Shetland Gas Plant. It also has an 8in MEG injection line, 2in service line and a control umbilical, and capacity to tie-in 20 wells, eight of which have been used to date, including Glenlivet and Edradour.

For Glenlivet and Edradour, the same manifolds, Xmas trees (FMC Technologies' 10,000psi vertical Xmas trees), pipelines, flowline end terminations, tooling and spare parts as Laggan-Tormore were used, reducing costs, and where possible facilities were shared, i.e. using a single pipeline end manifold for both fields. This ethos resulted in Glenlivet and Edradour comprising two production flowlines, which both tie into the Edradour pipeline end manifold (PLEM). One, 35km-long flowline, ties back two wells from the Glenlivet manifold, and the other, at 17km-long, ties a single well back from Edradour. A single 6in MEG line from the Edradour PLEM serves both fields, with a single umbilical serving both routed from the Laggan manifold.

Boyne says that cooperation with contractors helped. "The project was sanctioned in a high-cost environment," he says. "Total has worked with TechnipFMC to reduce costs. They made savings and passed those on and we had good cooperation in terms of trying to reduce and simplify the scope." This included combining a 6in MEG line with a 2in service line in a single deployment, i.e. piggy back, over the Glenlivet and Edradour lines.

Using new technologies has also brought savings. Using seam welded super duplex tubes on the Glenlivet umbilical (seamless tubes on Edradour) reduced costs. The seam welded process was developed by Vallourec with laser welding technology for longitudinal welding. The process gives pipe higher mechanical properties, with reduced wall thickness, helping to reduce umbilical weight, making handling easier.

Using thermally spayed aluminium inside the pipe also reduced costs. It was needed to help reduce temperature, as there's a link with temperature and corrosion related

Quick stats

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

New discoveries announced

Depth range	2014	2015	2016	2017
Shallow (<500m)	77	58	37	19
Deep (500-1500m)	28	18	11	4
Ultradeep (>1500m)	12	11	9	6
Total	117	87	57	**29**
January 2017	127	114	72	-
date comparison	-10	-27	-15	29

Note: Operators do not announce discovery dates at the time of discovery, so totals for previous years continue to change.

Reserves in the Golden Triangle

by water depth 2017-21

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Brazil			
Shallow	12	287	2333
Deep	10	940	1295
Ultradeep	25	8364	10,673
United States			
Shallow	5	45	89
Deep	19	730	1264
Ultradeep	18	1915	1658
West Africa			
Shallow	111	3656	16,029
Deep	23	2070	3130
Ultradeep	12	1611	2398
Total	223	19,331	36,536
(last month)	[illegible]	(21,819)	(39,231)

Greenfield reserves

2017-21

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Shallow	867	33,464	316,771
(last month)	(875)	(33,435)	(315,810)
Deep	111	5048	64,508
(last month)	(116)	(5193)	(65,828)
Ultradeep	66	13,420	44,392
(last month)	(75)	(15,915)	(46,542)
Total	1044	51,932	425,671

Pipelines

(operational and 2017 onwards)

	(km)	(last month)
<8in.		
Operational/ installed	41,929	(41,907)
Planned/ possible	21,133	(21,339)
	63,062	(63,246)
8-16in.		
Operational/ installed	83,112	(82,901)
Planned/ possible	44,963	(46,481)
	128,075	(129,381)
>16in.		
Operational/ installed	96,974	(96,019)
Planned/ possible	48,815	(50,742)
	145,789	(146,761)

Production systems worldwide

(operational and 2017 onwards)

Floaters		(last month)
Operational	310	(311)
Construction/ Conversion	43	(41)
Planned/possible	277	(289)
	630	(641)
Fixed platforms		
Operational	9068	(9075)
Construction/ Conversion	77	(79)
Planned/possible	1277	(1299)
	10,422	(10,453)
Subsea wells		
Operational	5255	(9075)
Develop	355	(79)
Planned/possible	6062	(1299)
	11,672	(10,453)

Global offshore reserves (mmboe) onstream by water depth

	2015	2016	2017	2018	2019	2020	2021
Shallow	21,400.30	32,101.42	20,879.08	20,068.2	11,983.08	16,758.52	20,970.91
(last month)	(21,385.42)	(32,117.92)	(20,854.43)	(20,164.01)	(12,361.24)	(16,412.81)	(19,213.42)
Deep	960.47	4215.67	2051.08	2580.97	4697.54	4417.34	2655.54
(last month)	(960.47)	(4215.67)	(2051.08)	(2580.97)	(4690.17)	(4753.11)	(2719.83)
Ultradeep	2000.69	3100.14	883.85	4643.35	3621.29	8125.72	4032.24
(last month)	(2000.69)	(3100.14)	(903.85)	(4582.16)	(3642.68)	(9520.31)	(5531.72)
Total	24,361.46	39,417.23	23,814.01	27,292.52	20,301.91	29,301.58	27,658.69

Source: InfieldRigs 6 Oct 2017

Rig stats

Worldwide

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	88	57	31	64%
Jackup	393	236	157	60%
Semisub	105	60	45	57%
Tenders	28	15	13	53%
Total	614	368	246	59%

North America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	29	21	8	72%
Jackup	25	9	16	36%
Semisub	8	5	3	62%
Tenders	N/A	N/A	N/A	N/A
Total	62	35	27	56%

Asia Pacific

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	11	5	6	45%
Jackup	114	71	43	62%
Semisub	30	13	17	43%
Tenders	21	12	9	57%
Total	176	101	75	57%

Latin America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	21	16	5	76%
Jackup	50	27	23	54%
Semisub	21	13	8	61%
Tenders	2	1	1	50%
Total	94	57	37	60%

Northwest European Continental Shelf

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	N/A	N/A	N/A	N/A
Jackup	48	29	19	60%
Semisub	32	21	11	65%
Tenders	N/A	N/A	N/A	N/A
Total	80	50	30	62%

Middle East & Caspian Sea

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	N/A	N/A	N/A	N/A
Jackup	118	80	38	67%
Semisub	4	3	1	75%
Tenders	N/A	N/A	N/A	N/A
Total	122	83	39	68%

Sub-Saharan Africa

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	16	12	4	75%
Jackup	14	8	6	57%
Semisub	1	1	0	100%
Tenders	5	2	3	40%
Total	36	23	13	63%

Eastern Europe

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	1	0	100%
Jackup	1	1	0	100%
Semisub	2	1	1	50%
Tenders	N/A	N/A	N/A	N/A
Total	4	3	1	75%

Source: InfieldRigs 6 Oct 2017

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

to CO_2 corrosion. Typically, a cooling loop is used to bring the temperature down, as well as use of corrosion inhibitor, Boyne says. Using the thermally sprayed aluminium and understanding the thermal impact of rock dumping and how much it could be reduced, by using glass-reinforced plastic covers (with rock dumping either side, instead of on the pipe) helped reduce the need for that additional equipment and chemical use.

Timetable

Compressing the project execution timetable – while trying to avoid the impact of winter weather West of Shetland – also had a huge impact, bringing forward first production by over a year, in the case of Glenlivet, and savings on contingencies that didn't have to be drawn.

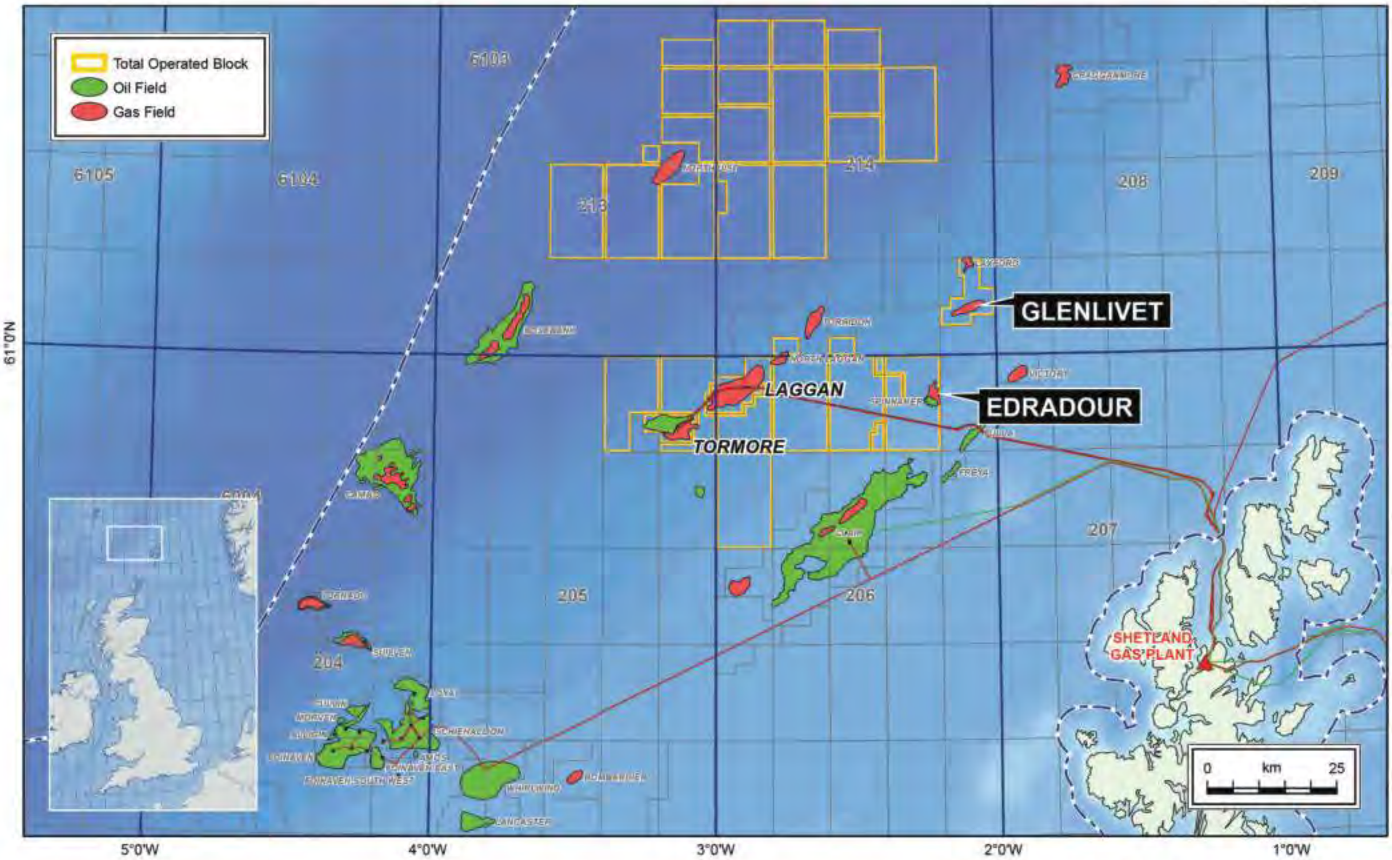
With the Edradour well completed and subsea installation work carried out in 2015-2016, the plan was to install the subsea infrastructure for Glenlivet in 2017, followed by wells completion (two deviated Glenlivet wells drilled in 2015) in 2018.

Total wanted to avoid operating in winter. "In winter you have the jet stream bringing deep lows through the West of Shetland area," Boyne adds, "With high winds and high waves." The conditions make operations, drilling, logistics and installation activities challenging, with a high risk of waiting on weather.

But, attempting to do the drilling and installation campaigns at the same location, in one summer season, was also very challenging. However, having seen the 2015-2016 campaigns go well, with the focus on making the summer seasons (i.e. April to September) as efficient as possible, it was decided to try to advance the Glenlivet schedule.

"We looked again using the learnings from Laggan-Tormore and challenged ourselves to see if we could carry out the well

The *Deep Explorer.* Image from TechnipFMC.



West of Shetland development. Map from Total.

completions on Glenlivet first [in early summer season 2017], then carry out installation work during the remainder of the 2017 summer season," Boyne says. This would allow Glenlivet to start up in October 2017.

Drilling went well, starting early in the season in 2017, and the project vessels were allowed in early, with simultaneous operations procedures in place. At peak SIMOPS (simultaneous operations), the *West Phoenix* semisubmersible drilling rig was doing a Glenlivet upper completion while the *Deep Explorer* was installing flexible spools and rigid jumpers, the Far Superior was doing pre-commissioning of pipelines and the Nordnes doing rock dumping.

Then, by bringing forward commissioning and start-up activities before some of the non-critical path activities (rock dumping and installing protection structures) were completed, Edradour and Glenlivet first production were both brought forward to August.

Detailed planning, good interfaces between drilling, project, operations and commissioning/start-up teams, and careful SIMOPS, to make sure everything was coordinated, were key, Boyne says. Experience within the teams, which had worked on Laggan-Tormore previously, as well as use of contractors who also had experience on Laggan-Tormore (North Atlantic Drilling and TechnipFMC), also helped significantly, Boyne adds.

The same rig, the *West Phoenix*, was used on Edradour and Glenlivet as Laggan-Tormore. But, Total also achieved commercial efficiencies. Total hadn't contracted the rig for the full project, which meant costs fell from around US$450,000/d at the end of Laggan-Tormore to about $145,000/d during the 2017 season, reflecting market rates.

Future tie-ins

With Edradour and Glenlivet now online, Total is looking at what else is in the area. There are a few relatively small discoveries in the area, but also exploration prospectivity, Boyne says, pointing out that, according to the UK Oil and Gas Authority, 17% of the UK Continental Shelf's remaining reserves could be West of Shetland area.

There are also oil fields in the area that could now have an export route for any associated gas. As well as looking at fields in its own portfolio, it's also looking at third party business – tying in other people's assets – and it is participating in the 30th licensing round to add to its acreage.

There's also more potential for testing new technology. Total has said Laggan-Tormore, an electro-hydraulic system, would have been economically viable as an all-electric system. For future tie-ins that stretch beyond the potential for additional electro-hydraulic tie-ins, i.e. beyond around 150km, all electric would be a viable alternative, Boyne says, potentially still using the Laggan-Tormore pipeline system, but with electric controls. **OE**

FURTHER **READING**

French chemistry. Elaine Maslin examines the Laggan-Tormore development. www.oedigital.com/regions/item/12248-french-chemistry

The beginning in nigh. Total assessed an all-electric system for Laggan-Tormore and has been considering subsea compression. www.oedigital.com/regions/item/16029-the-beginning-is-nigh

Decom dollars

More than 700 offshore fields are expected to cease production in the next five years, according to forecasts. Elaine Maslin reports.

Two major events appeared to fire the starting gun for the UK's offshore decommissioning market to take off this year – the single lift removal of the Brent Delta topsides and the piece-meal removal of the Murchison platform.

Yet, while spending is indeed forecast to ramp up over coming years, in the near-term, it's not being driven by these huge facility removals, it's more about the plugging and abandonment (P&A) work and smaller field removals.

Globally, some 700 offshore oil and gas fields are expected to cease production in the next five years, according to Wood Mackenzie, seeing spending on decommissioning increase from US$3.6 billion per year on average, in 2013-17, to $6 billion in 2018-22.

Of the field cessations, about 19% are forecast to be in the UK North Sea, which accounted for 17% of the total in the preceding five years.

The three regions with the most activity globally are the North Sea, Asia Pacific and the US Gulf of Mexico deep water, says Fiona Legate, analyst with Wood Mackenzie. Activity in Asia Pacific has been increasing, she says, while the Gulf of

Making light work of Leman

Veolia and Peterson accepted the first offshore structure into their Great Yarmouth decommissioning facility, the Shell Leman BH platform accommodation block and jacket.

The 1000-tonne topside, used as quarters for staff working on the Leman BT and Leman BK platforms, 62km north of Great Yarmouth, and its 50m-high, 700-tonne jacket arrived in July. Both were delivered by Boskalis, which had contracted Veolia and Peterson for recycling of the 1600-tonne of facilities, following offshore removal and transport.

Boudewijn Versluijs, commercial manager decommissioning, Boskalis, outlined the removal process at a Decom North Sea event in Aberdeen late September. Accessing the platform, in 31m water depth, with an Ampelmann walk to work system, rope access technicians installed scaffolding to aid removal of a staircase from the cellar deck. The platform legs were then cut below the spider deck and the topsides removed using the Taklift 4 floating shearleg barge, with 2200-tonne crane capacity and taken in the hook to Great Yarmouth. There it was placed on upended recycled pipe, so that the stabbing cones and then the rest of the legs could be cut off. It was then transferred to an SPT transporter to be moved from the quayside.

A rigging platform – a stable platform with a crane for lifting cutting gear on, etc., was installed on to the jacket before it could be lifted out. Soil plugs from the piles were also removed and the legs cut -3m below the sea bed inside the jacket leg before the lifting operation, which again used the Taklift 4. Once on the quayside, it was also moved using an SPT transporter before being pre-cut then toppled, ready to be cut up. Photo from Veolia/Peterson.

Mexico work is legacy work, mostly subsea.

The North Sea, the UK specifically, is leading in terms of activity and spending, however, she says. "When you look at offshore decommissioning activity globally, the UK is miles ahead. It is ahead in the number of fields ceasing and decommissioning costs." Some 134 fields are expected to cease over the period 2018-2022, says Wood Mackenzie, although many will not have topsides facilities.

Westwood Energy anticipates the removal of 290 platforms and over 3000 wells in the UK over 2017-2040, at a cost of more than $55 billion.

"When you look at spend, the UK is leading the way," Legate says. "Over the next five years $13 million of spend is predicted, at 40% of the total." To put it another way, spending is set to increase from under $2 billion/yr in 2013 to $8 billion/yr by 2022. "Norway is also quite a big spender going forward, the Netherlands too, but the UK is leading," Legate adds.

Part of the regional activity could be due to cheaper rig rates, she says, accelerating P&A campaigns. In some cases, it could be where a rig is already on hire and it's being used for P&A work instead of exploration or production well drilling. Operators are learning that by running campaigns, they can reduce costs by learning from repeat activity, at 30-40% in some cases, Legate says, depending on the company and the rig, as well as if it's subsea or platform wells.

"From a UK point of view, for years the view has been that decommissioning is going to increase and it's been shifted to the right. But there's definitely been a step change in attitude. The downturn made companies think about it much more." However, in the main, it's been a lot of smaller fields and tiebacks, the Brent Delta removal, with the rest of the Brent facilities to come, and the Murchison platform, being the only larger fixed facilities being decommissioned.

"At $100/bbl, they could keep the smaller fields producing. Now there is no point."

Yet, we're still only at the start of the "bow wave." Only certain yards can receive larger topsides at the moment, but there's not been demand so it hasn't been an issue (although UK decommissioning work going overseas has been a bone of contention). Ports are also investing in facilities so that in future there will be more capacity (*OE*: May 2017, Building Capacity), Legate says. "We are starting to see signs the service sector is getting ready for this activity."

While Norway hasn't seen a high number of field cessations, it has had high decommissioning spending, Legate notes. This is due to "mid-life" decommissioning work, Legate says, i.e. work on the likes of the giant Ekofisk and Valhall fields, which has seen some of the older infrastructure removed, while the fields continue production and also see new facilities installed as part of redevelopment work.

Deepwater Gulf of Mexico has the third highest number of fields ceasing over the last years, and is forecast to be in the same position in the next five years. Some 54 fields are expected to cease production in 2018-22, with spending pegged at $3 billion over that period. These will mostly be small mature fields that have been tied into existing production facilities, Legate says.

Asia Pacific, meanwhile, is likely to account for about $25 billion of spending in 2018-2022, most of which will be in Australia and Indonesia with some in Thailand, Legate concludes. **OE**

FURTHER **READING**

Building capacity www.oedigital.com/drilling/decommissioning/item/15206-building-capacity

As decommissioning gathers pace, the debate around how to make the entire process more efficient – safely – at a reduced cost intensifies. Emma Gordon reports.

Sizing up for decom

Are we thinking big enough, or is the challenge smaller than we think? Certainly, the UK Oil and Gas Authority's (OGA) call this year for industry to reduce its decommissioning costs by at least 35%, from an estimated value of around £60 billion ($80 billion) was described by Steve Phimister, a session moderator at SPE Offshore Europe 2017, as an "ambitious target."

That said, the consensus at this year's SPE Offshore Europe was that the target was achievable — and could even be beaten, if the industry changed its approach — including altering the way operators and the supply chain work together — as well as deploying specialized technology, and encouraging innovation.

"You really can't approach the decommissioning challenge in traditional ways, traditional thinking will get you traditional results," said Phimister, who is upstream director UK & Ireland, Shell. "We really do have to think quite deeply and differently about it, and draw on all the expertise in the industry, take on the issues... find the solutions and smart ways of working together whether in execution strategies or contracting strategies."

CNR International's decommissioning project manager, Roy Aspden, said another important question was how the industry was developing the capability to respond to the sheer size of the decommissioning challenge: around 470 installations will need to be decommissioned over the coming decades in the UK North Sea alone.

Aspden said, from CNR's perspective, "ignorance had fueled collaboration."

"Six years ago, we had zero [decommissioning] capability in the company," Aspeden said. "And [we] faced decommissioning the tallest, deepest, most northerly [installation] in Murchison. So, we needed to build capability pretty quickly.

"Looking back, we intensely took part in conferences, work groups, forums, and stakeholder workshops... to help us inform ourselves and build capability.

"Where are we now," he asked. "Thankfully, we're two years ahead of the original schedule, 15% under budget; 33 wells have been abandoned, and 40,000-tonne removed. What's left is one subsea well to abandon starting next

Time to retire. In August, the Buchan Alpha production vessel arrived in Dales Voe, Lerwick, Shetland, for disposal at Veolia and Peterson's facility. It is believed to be the first major North Sea floating production vessel facility to be disposed of in Scotland. Operated by Repsol Sinopec Resources UK, Buchan Alpha, weighing 12,000-tonnes, was a semisubmersible moored floating production unit. It was built in 1973, as a drilling rig, and converted for production purposes in Stornoway in 1978-80, starting production in 1981, on the Buchan field, in blocks 21/1A and 20/5A. It also produced the nearby Hannay field. Production, which totaled about 148 MMboe, ceased in May 2017. Veolia aims to achieve 98% recycling of the structure. Photo from Veolia/Peterson.

spring: a decent performance on our first outing."

Aspden added that decommissioning is a "fertile ground" for innovation. As an example, he said 3D printed models were "tremendous" for offshore planning and work permitting, saying that "every time a cut was made on the jacket, a little hacksaw came out to make the same cut on the 3D printed model."

Now the operator has set its sights on Ninian Northern facility, with the plan to de-man next year.

"In terms of building capability, our simple strategy is working for us, I think that gives us some kind of confidence that the direction of the cost reduction that OGA has set for industry should be attainable," he said.

Aspden said that a revised contracting approach was particularly effective. Here, the operator described what it wanted to achieve, but did not prescribe the method, sequence or timing: instead leaving those specifics to the supply chain.

Perhaps not surprisingly, that's a view shared by Ronald van Waaijen, vice president, sales and business development, Europe, Heerema Marine Contractors, who said that the industry should not apply the same process used in E&P projects for removal. "Tell us what to do: let the contractor determine how to do it. Don't be shy to share information."

"Accept decommissioning as a task that just has to be done; see the upside in minimizing the pain — it's actually encouraging to manage to reduce the pain — change the approach: different drivers demand a different contractor approach," he added.

Greta Lydecker, managing director, Chevron Upstream Europe, also thinks the 35% target is doable. Lydecker was previously president of Chevron's Environmental Management company, which provides environmental liability, management and decommissioning services for the operator in more than 50 countries worldwide.

Since it was established in 1998, projects have included well, offshore platform and pipeline decommissioning and abandonment, site remediation and cleanup for refineries, service stations and terminals.

"If you can do more in a campaign, you'll find ways to take costs down," Lydecker said. "Maybe that involves not just Chevron doing work, but finding partners who are also in the same mode of [decommissioning] and bringing them together as a campaign."

She said that standardization is key, as is involving the right partner — whether from, for example, the supply chain or a regulator — as early as possible.

Specialized technology, she said, is also critical, citing Chevron's work with Versabar in the US Gulf of Mexico developing a new method for severing subsea structures.

"In 2005-2008, we suffered some of the most severe and significant hurricanes in the Gulf of Mexico. The group faced decommissioning that was not just picking up the jacket and topside, they were having to go down and pick up things that were toppled on the seafloor.... We really weren't keen on putting divers in the water to go down to do that kind of work."

Versabar's "giant claw" tool could go down and pick up these toppled platforms, significantly reducing diver hours, as well as the associated risk. OE

Assessing all options

As the North Sea enters the decommissioning era, should complete removal remain the default option? And what is the impact of the process on North Sea ecosystems? Emma Gordon reports.

The oil and gas industry must address its knowledge gap about the sea life that lives in and around its installations and associated infrastructure, if we are to properly understand the consequences of decommissioning.

That's according to Andrew Guerin, University of Newcastle research associate, who spoke at a Society for Underwater Technology-hosted session at SPE Offshore Europe 2017.

After four decades of production, North Sea decommissioning work has started in earnest and is set to ramp up in the short- to medium-term.

Currently, operators are under a legal obligation to remove all platforms and associated structures from the seabed, with the option to apply for a derogation in certain cases (steel jackets weighing more than 10,000-tonne, gravity-based concrete structures…).

Yet, Guerin says, these structures have become colonized and typically develop highly productive ecosystems including invertebrates, fish, seabirds and other predators. Are there ecological benefits to leaving the installations in place? If removed, what happens to these communities?

The problem in answering that question, he explains, is that a lot of existing knowledge is at a "fairly superficial" level. While we know

A bird hunts fish near an offshore platform. Photo from iStock.

what species live on and around installations, we don't know a lot about their ecology, or indeed how they fit into the wider North Sea marine ecosystem, he says.

"Decommissioning will affect biological systems over different timescales and areas, and it's really quite hard to forecast what the impact of decommissioning will be."

Guerin says there would be little effect on those organisms living and growing on the platform over the short term if the structures remained. However, he said: "It's worth bearing in mind that at some point any infrastructure [still in place] may eventually fail… there may be consequences we may not see immediately."

Partial removal would likely see persistence of sea life on what is left behind, with some loss of habitat and redistribution of certain species.

While complete removal, including anything growing on the platform, would lead to the redistribution of species elsewhere, with reef associated fish — those only found on reefs or similar structures, such as the Wolffish — potentially lost entirely. It would have the benefit that "once everything is removed, there is no scope for further impacts in the future," however.

The impact of partial or complete removal on marine mammals is even more uncertain: "We don't know how these animals do or don't interact with the structures at the moment. It's very difficult to figure out what happens if we remove [them]."

Knowledge of the effect on the wider marine ecosystem is even more porous, particularly if there's a network effect created by structures, acting as islands.

There is work underway to understand these issues, including the Insite Program (*OE*: February 2017).

This research initiative, involving scientists and researchers from across the UK and Europe, is working to assess the impact of man-made structures on marine life, both individually and as a network. The program started in 2015, and are set to run up until the end of this year.

Three of the eight projects focus specifically on connectivity and are run by the Centre for Environment Fisheries and Aquaculture Science (CEFAS), Lowestoft, UK; IMARES, Texel, Netherlands; and the University of Edinburgh's School of Geoscience, Scotland.

Another initiative underway is a Natural Environment Research Council (NERC)-funded joint science industry project, led by the National Oceanography Centre (NOC).

NOC scientist, Daniel Jones, said at the Offshore Europe event that the one-year project — with partners including BP and Shell — started in April, and looks at developing "best practice guidelines" for effective monitoring using the latest generation autonomous systems to provide low-cost, high quality, repeat assessment.

Jones has been involved, too, with the Scientific and Environmental ROV Partnership using Existing Industrial Technology (Serpent) Project, which uses underwater vehicles for deep-sea research during stand-by periods, augmenting these findings with data collected as part of routine offshore work, as well as from existing environmental assessments.

"There is a large requirement for marine monitoring, in all cases [of decommissioning] environmental impact assessments will be needed, and the derogation cases will need more extensive monitoring, potentially for the entirety of their lifetime."

Yet, Jones says, there is no standard approach for assessing the ecological role of structures for these environmental assessments, and current assessments have not led to clear conclusions.

In an environment where infrastructure such as cables and wires can make survey operations complex, and with the considerable scale of decommissioning the industry faces — around 500 installations in the UK Continental Shelf alone — Jones says that autonomous systems can be a "transformative technology," capable of providing a more standardized approach for decommissioning monitoring.

From gliders and observatories, to automated underwater vehicles (AUVs), the project will look at the current approach and how it can be adapted for decommissioning.

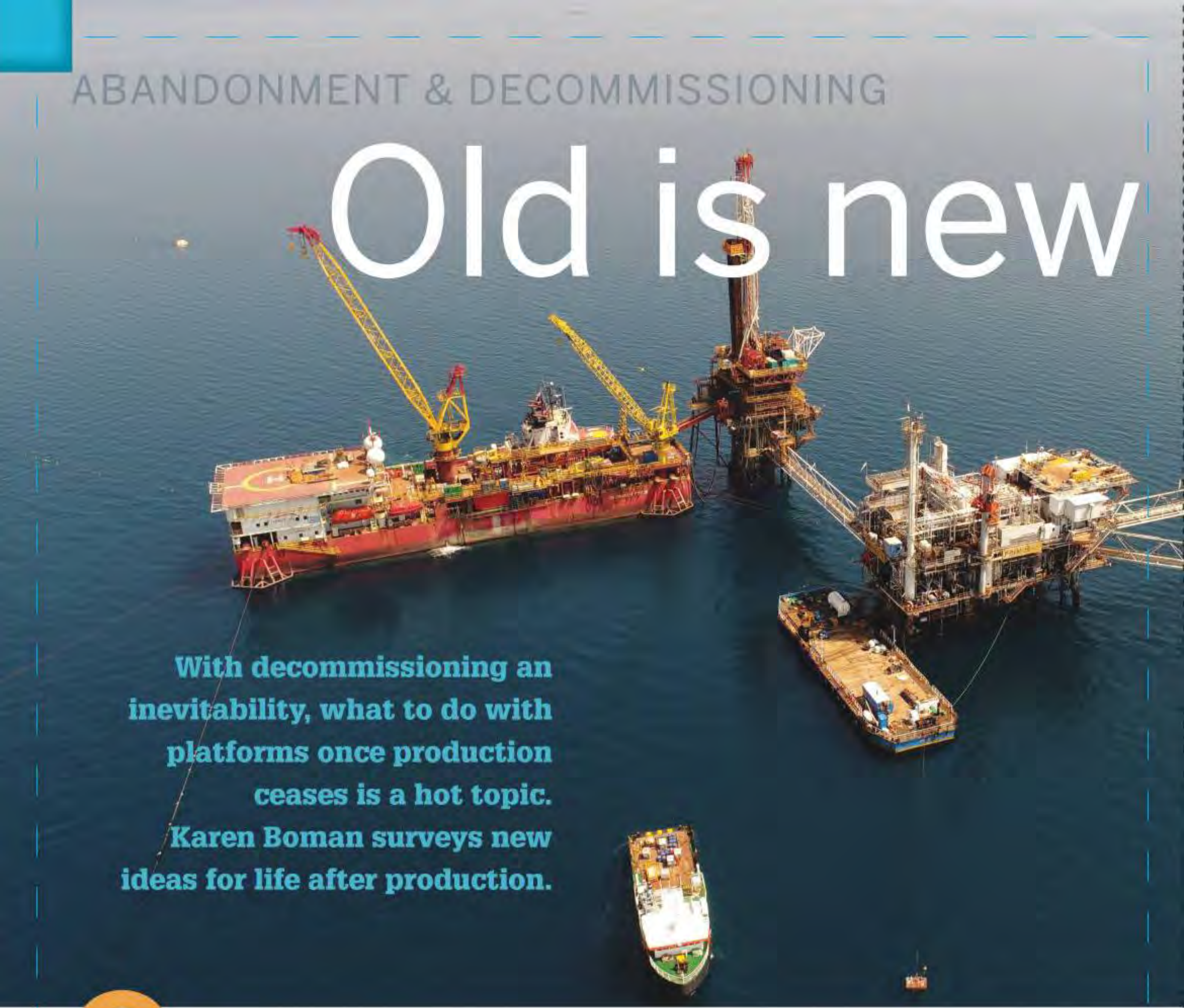
Jones adds that there are a number of relevant applications, including acoustic and visual mapping looking at, for instance, pipelines and cuttings piles on the seafloor; visual assessments to, for example, detect and classify marine life with speed and efficiency, and using sensors on AUVs to assess water quality and carry out wide area pollution assessments.

The ability to augment findings with historical information is crucial, Jones said, adding: "There is a wide variety of existing data … it would be a shame to lose that, so we have to work out how we can mesh the two together." **OE**

FURTHER **READING**

Plenty of fish in the sea
www.oedigital.com/component/k2/item/14617-plenty-of-fish-in-the-sea

Old is new



With decommissioning an inevitability, what to do with platforms once production ceases is a hot topic. Karen Boman surveys new ideas for life after production.

Once upon a time, it seemed that the only thing to do with aging offshore infrastructure was to rip it out. Yet, new ideas, such as leaving structures behind to encourage artificial reef development, or repurposing for education and tourism are under consideration.

Katerina Bounia, associate and co-founder of Athens-based Arch-Interact Architects, has proposed such an idea for the entire Prinos fixed platform infrastructure, in the Gulf of Kavala, offshore Greece. The Prinos platform complex started production in 1981 at a rate of 30,000 bo/d; by 2013, production had declined to 1800 bo/d.

Through Bounia's plan, based on thesis research she conducted at the University of Patras to foster ocean awareness and offer a new paradigm for platform reuse strategies worldwide, the platform complex would not only serve as an artificial reef that would become a home to marine life, but offer educational and research lab facilities, a scuba diving center, and a platform for concerts. The platforms would be renovated and the structural frame preserved though the plan, which would extend the urban network of the city of Kavala offshore.

The proposal would offer a chance for big companies to have a positive impact on the environment, Bounia said during a panel discussion on decommissioning at SPE Offshore Europe 2017 in September.

The scenario for repurposing the Prinos platform structure will remain a scenario, however, as the prospects in the Prinos basin in the Gulf of Kavala still contain over 35 MMbbl of recoverable oil, says Costas Ioannidis, plant manager for Kavala Oil, a subsidiary of Energean Oil & Gas. The main processing platform Delta of the Prinos platform complex (Alpha - Beta - Delta) will remain active as the recipient of the oil and gas produced from the main Prinos field and the surrounding satellite small fields via new small platforms (like the existing Alpha, Beta and Kappa) and new short submarine pipelines.

Recent studies and continuous inspection by DNV GL and maintenance by Kavala's divers also have extended the life of the Prinos platforms to a new total of at least 50 years, Ioannidis says.

Kavala Oil gave Bounia drawings and data of the Prinos offshore platforms for her study as part of the company's policy

again

Prinos offshore complex. Photo from Energean Oil & Gas.

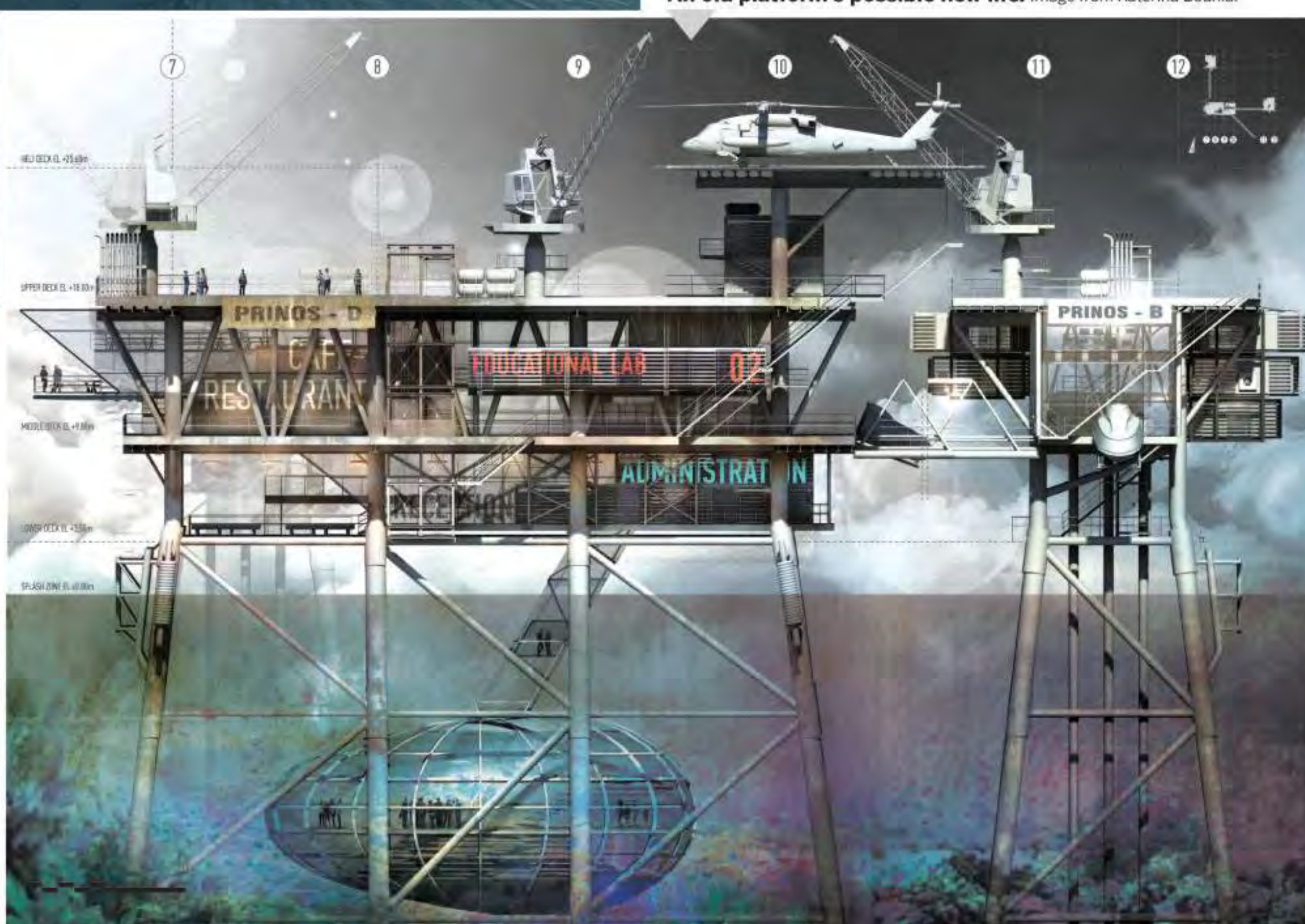
and Ioannidis' personal philosophy of helping students and universities achieve their goals, Ioannidis says. However, "the time to convert the Prinos offshore structures into a casino or some touristic or fishing resort is still far away in the future," Ioannidis says.

Still, new ideas for decommissioning are needed as the global oil and gas industry faces a limited choice of removal processes and equipment for decommissioning. With 307 floaters, more than 9100 platforms, over 5000 subsea wells and thousands of kilometers of pipeline needing removal, the global oil and gas industry is facing a major wave of decommissioning, said Brian Jones, technical director, energy, at London Offshore Consultants UK, during the panel presentation.

The variety of installation types means that no standard fix is available for all offshore infrastructure in need of decommissioning, Jones said. Costs also will vary by region, with the biggest stemming from marine operations. The age and condition of most infrastructure also adds complexity to the removal process. Regulations in different regions also vary; in the North Sea, all platform infrastructure must be removed.

"The reality is that costs will be higher than estimates, which means that more competitive tendering will be required," Jones added.

An old platform's possible new life. Image from Katerina Bounia.



Jones sees some positive movement, with newer vessels such as the *Pioneering Spirit* now available to the market, and cutting methods better than explosives are also now available. One platform removal method, refloat, is not new, but is innovative. However, it does raise the risk of spiraling costs.

Rigs to reefs

The US currently has a program called Rigs to Reefs in place in the Gulf of Mexico to address abandoned fixed platforms. The US Bureau of Safety and Environmental Enforcement (BSEE) created the Rigs to Reefs program in response to public outcry over the loss of marine life that occurred when oil and gas platforms that had existed for years in the Gulf were removed in the mid-1980s.

A fireworm at home on an old rig.
Photo from Chris Ledford, Texas Parks and Wildlife Department.

The high costs of removing shallow water fixed platforms in the Gulf of Mexico has resulted in 1227 idle structures out of 3907 total structures being left idle, Bounia said during her presentation. The Rigs to Reef program has significantly lowered the costs of platform removal by cutting and toppling platform infrastructure onto the ocean floor, where they become reefs for marine life. The program not only has reduced removal costs per platform by US$800,000, or $4 million to date, but created income to help finance marine research. To date, 10% of Gulf of Mexico fixed platforms have been decommissioned through the program.

The growth in fishing activity from oil and gas platforms and support for the effective creation of artificial reefs off coastal states led the US Congress in 1984 to approve the National Fishing Enhancement Act. This legislation created the basis for establishment of a National Artificial Reef Plan and establishment of a reef permitting system.

Since 1985, BSEE has encouraged coastal states with artificial reef plans to repurpose oil and gas platform jackets into artificial reefs. BSEE requires oil and gas companies to decommission and remove oil and gas platforms from the Outer Continental Shelf (OCS) once a lease expires or operations cease. However, a platform can be exempted from these requirements if they qualify for reuse as an artificial reef.

According to BSEE, oil and gas platforms become habitats for marine life shortly after installation. Hundreds of different species of fish flock to these reefs, including red snapper, mackerel and some shark species, which drop in on the reefs at mealtimes. Coral, sponges, bryozoans, and clams are some of the invertebrate life found on the steel piles and jackets, creating the basis for undersea food webs.

All five US Gulf Coast states – Louisiana, Texas, Alabama, Mississippi and Florida – have specific state approved artificial reef programs. Through these programs, oil and gas platforms, concrete structures such as bridges, barges, vessels, and even military tanks, are deployed to serve as artificial reefs.

The majority of oil and gas platforms that have been turned into artificial reefs are located offshore Louisiana and Texas.

Louisiana has recycled 387 oil and gas platforms over the lifetime of its Rigs to Reefs program. These platforms have been deployed at 76 sites across the entire Louisiana coast, in water depths ranging from 102ft to 656ft, says Mike McDonough, Rigs to Reef program manager with the Louisiana Department of Wildlife and Fisheries.

Texas, through its Rigs to Reefs program, has repurposed 151 oil and gas platforms into reefs, which have been placed in at least 80 of 91 reef sites offshore Texas. The reef sites are situated in water depths ranging from 50ft to 925ft, though most are in 200ft to 300ft of water. The sites are scattered offshore the Texas coast, but mostly centered around the Outer Continental Shelf area known as High Island near the Flower Gardens, says Dale Shively, program leader for Texas Parks and Wildlife Department's (TPWD) artificial reef program.

However, the number of platforms recycled into reefs since the 2014 oil price downturn has declined both in Texas and Louisiana. The projects can be expensive; in some cases, it might make more economic sense to scrap the platform, try and extend production life, or sell to a smaller company that can operate it more efficiently.

Over the next 10 years, Shively expects the number of platforms that could be turned into reefs to shrink as oil and gas companies focus on deepwater, or water depths over 1000ft. A debate is now occurring over whether leaving piles and jackets at this depth would serve any purpose. Marine life does exist at 1000ft that would use the infrastructure, but the amount of growth is lower than in 200ft of water, where sunlight can penetrate and foster growth of natural coral reef systems.

Shively says that TPWD also has seen the number of platforms offshore dwindle to less than 300. Once those are gone, TPWD will need other types of materials and a different source of finding to run Texas' Rigs to Reefs program. **OE**

Perfecting PWC

Perforate, wash and cement technologies are offering operators an alternative to milling. Elaine Maslin reports.

When *OE* headlined an article about plugging and abandonment (P&A) "Pain in the annulus" back in 2016, it was with just cause.

Amounting to an estimated 48% of decommissioning costs (according to the UK's Oil and Gas Authority) and with "train wreck" wells costing nearly double-digit million dollar figures, it's an activity that brings in no revenues, just headaches.

There are firms looking to ease the pain, developing the likes of thermite plug solutions and plasma drilling technology. Something less exotic is starting to make in-roads into the P&A space, however: perforate, wash and cement (PWC) tools and methodologies. Norway's Hydrawell was a first mover in the PWC space. The firm's PWC solutions comprise a suite of tools helping to cut well P&A cost, where section milling would have been required, from ca.10-14 days to just two, when run as a one-trip solution.

The firm is assessing options for a rigless version of its latest tool portfolio, to further reduce costs, as well as technologies for barrier verification, without having to redrill the just installed barriers – for re-logging.

The HydraHemera system, cementing.

Who needs section milling?

Morten Myhre, chief technology officer, says the firm, set up initially in 2008, with a restructure in 2010, responded to industry calls, notably from ConocoPhillips in Norway, to do section milling differently, or not at all.

Section milling is normally needed when there's not a verifiable barrier (cement) behind the casing and between the formation (either cement or creeping shale – *OE:* July 2017). This allows a new barrier to be set. According to regulations that barrier must be 50m across two sections, in Norway; or 30m across two sections, in the UK.

Casing milling can mean up to 4-tonne of steel has to be removed from the well for a normal 9-5/8in casing size, says Myhre, who was at Baker Hughes for 18 years before co-founding Hydrawell.

"We have found a technology that has the potential to save a lot of money," he says.

In 2009, the firm developed Hydrawash, for wells with a single annulus. The first launch was in 2010, initially as a two-trip system. The system was rapidly transformed into a single trip system, and comprised a tubing-conveyed perforating (TCP) gun with disconnect, the HydraWash jetting tool, a cement stinger and Hydrawell's Archimedes cementing tool, which helps circulate the cement into the annulus.

After perforations are created, the TCP assembly is dropped and left in the well. A ball drop then initiates the washing process using the HydraWash tool, with rubber cups to direct the flow. A second ball drop disconnects the wash tool, which is left below the perforations to act as a base for the cement, then cement is pumped through the stinger and is rotated through the perforations using the Archimedes tool.

Eliminating section milling – and underreaming operations – means reducing the amount of material having to be removed from the well and preventing BOP (blowout preventer) damage from swarf, etc.

Time is also significantly reduced for a section milling operation on a 50m section from ~10.5 days to three days, Myhre says.

Enter HydraHemera

In 2012, the HydraHemera system was introduced for wells with more than one annulus. With a high-pressure (HP) jetting system, it reduces operational risk and operation time and has now become the default tool for multiple and single casing applications.

A new version of HydraHemera has a TCP gun with auto-disconnect, the new HydraHemera HP jetting tool, an internal cement foundation tool with disconnect, a Hydra spray cementing valve, as well as the Archimedes cement assurance tool.

As with HydraWash, the TCP gun is dropped and left in the well. The internal cement foundation tool is disconnected to form a base, and then a ball drop initiates the washing and circulation with the HydraHemera jetting tool. It has normally 30 ea. 1/8in nozzles on a 2.5ft sub at irregular angles to create high-energy jets of mud – at ~450ft/sec – rotating the tool and washing up and down the perforated section to clean between the casing and the rock.

"It creates a chaotic turbulence of flow, ripping off small solids, and efficiently cleaning the annulus to be cemented," Myhre says. Spacer fluid is then injected and another ball drop diverts flow to the Hydra cementing valve, with four 1/8in nozzles along a 3ft-long sub. This pushes the cement out at (to prevent cement de-hydration in the nozzles), through the perforations, with the aid of the Archimedes tool rotating at up to ±100rpm, and creating pressure below. This all takes about two days, says Myhre. Further, the operation is being optimized by means of CFD modeling and fluid comparison to enable installation of two plugs in 48 hours.

The first dual string job was performed in 2013. Now, 215 single and dual plugs have been installed in total by the firm, 130 with HydraHemera technology.

The tool can also be used for other applications, like well remediation, where excessive annulus pressure is present preventing wells to be producing, or for slot recovery (where the PWC technology is used to secure P&A of existing well bore, prior to side tracking the well).

Traction

The firm has been building its track record. At AkerBP's Valhall field on the Norwegian Continental Shelf (NCS) the use of HydraWell's PWC technology assisted in reducing P&A operations from 118 days at the first well to 20 days at the last well in a 12 well campaign.

In a 2016 presentation to the Norsk olje & gas Plug & Abandonment Forum about the campaign, AkerBP says the average days per well on the campaign were reduced by 45% and costs reduced by an average 35%, or US$210 million in total, with PWC helping achieve those results.

At the same event, ConocoPhillips Norway said that 23 wells on the Ekofisk Alpha field and 15 wells on other platforms in the Greater Ekofisk area were P&A'd with significant time savings, thanks partly to using PWC technology. The Ekofisk Alpha wells alone improved more the 70% in operation days from start to end of project.

Improvement

Hydrawell continues to work on CFD modeling to investigate where the process could be further optimized. "We're analyzing the how efficient we can clean the annulus, by optimizing perforation pattern (perf size, shots per foot, phasing, etc.), and fluid properties vs optimum wash rates. The goal is to have two, 50m plugs installed within 48 hours," says Myhre.

Rigless work is the next challenge,

HydraHemera, washing. Images from Hydrawell.

however. An abandonment job with a drilling rig can take 40-45 days or more, or down to 20-22 days using Hydrawell's PWC technology, says Myhre.

The plan is to do the P&A rigless with the 4, 5 and 7in production tubing still installed inside the (normal) 9-5/8in production casing. This means that the PWC technology operation days will most likely be less the 7-8 workdays per well (i.e. rigless days).

"The plan is to perforate the production tubing and production casing in a dual casing scenario. This is doable, but," says Myhre, "the 'thorn in the side' is the verification of the installed barrier."

Hydrawell is looking at barrier verification first, to find a way to verify the cement barrier, as logging dual annuli casing is impossible with existing logging technology without having to drill out the plugged area for re-logging purposes. Hydrawell is discussing possible solutions with potential partners, which could involve installing pressure and temperature sensors and transducers downhole, which would send data to where it could be collected. OE

Creating a Barricade

Archer has developed the Stronghold Barricade perforating, washing and cementing (PWC) system. It was first used offshore in the North Sea for a major operator in 2009. Since then, 110 jobs have been carried out using the Stronghold Barricade worldwide.

The Barricade washes and cleans the annulus of a perforated casing or liner in a selected formation zone or between casings, then accurately places a permanent barrier. With the addition of the one-trip TCP tubing conveyed perforation (TCP) module, the Barricade system becomes a single-trip perforate, wash and cement solution that gives a solid cement barrier.

Archers says the system can perform up to 2.5 times faster than a typical section milling operation (at ca. 2ft/hr). To give an example, section milling 50m (165 ft) of a 9-5/8in casing inside a 13-3/8in and setting a plug can take up to 148 hours or 6.2 days. Using the Stronghold Barricade system at 50m (168ft) of a 9-58in inside a 13-3/8in concentric casing annulus, and then setting a plug, takes just 60.5 hours, or 2.5 days, says Thore Andre Stokkeland, Archer Oiltools' Product Line Manager for P&A Solutions.

In a PWC job performed for a major operator in the UK, Archer created a rock to rock barrier and isolated pressure from the overburden. The PWC to achieve a 550ft cement plug with a 168ft solid lateral barrier was completed in five hours. The total time from run in hole (RIH) until the tool was at surface was 15.5 hours from a depth of 2431ft. The plug was verified by load and pressure test. A rock-to-rock barrier was achieved in 15.5 hours, which exceeded the customer's expectations and sets a new benchmark in PWC efficiency, Stokkeland says.

"The above-mentioned time and cost savings are a result of eliminating the need for section milling. Milling casing would be challenging due to limited swarf handling capabilities and surface equipment to handle metal swarf, including the need to mill at relatively shallower depth with potential eccentricity challenges due to decentralized casing," Stokkeland says.

Since launching Stronghold Barricade, Archer has engineered a new system that has been added to the Stronghold family of PWC and verification systems. The Fortify system tests and verifies the integrity of the existing annular formation in a well.

It perforates the casing, tests annulus integrity, and verifies this integrity using a unique pressure verification system. It then cements across the perforated area. This system has three major benefits:

1. The integrated unique pressure verification system has a primary and back up temperature and pressure gauge, confirming the annular integrity.
2. Small volume to identify annular integrity, ie. less than three barrels.
3. The solid ballseat and the fluid by-pass system limit the circulation of new mud and reduce the impact of thermal expansion.

The Fortify system delivers the final result of a verified permanent annular barrier. ▪

Archer's Stronghold Barricade system eliminates the need for cutting, pulling and section milling. Photo from Archer.

Going against the flow

Record numbers of marine energy devices are generating record amount of power in Scottish Waters, but the sector has been knocked back in its bid for support. Elaine Maslin reports.

Timing is everything, they say. For the UK marine energy sector, it's proving a challenge.

In many ways, the industry is having one of its best years. The largest number of marine energy devices are in the water, including the first arrays, power production milestones being recorded, and cost reduction potential demonstrated.

Yet, for an emergent, pre-commercial sector, which has had significant support from the EU, the UK's exit from Europe isn't welcome, especially at a time when the UK Government has pulled support for marine renewables, with no contract for difference (CFD) – a support mechanism – offered in the latest round.

With the cost of offshore wind now pegged as low as US$76/MWh (£57/MWh) (the lowest price agreed in the latest CFD for offshore wind), "Westminster thinks it doesn't need any more renewables," one commentator said during Scottish Renewables' Marine Energy Conference in Inverness in September.

With there no longer being a green premium – i.e. you can no longer expect funding or support, just for being "green" – a different argument needs to be made for marine renewables, such as supporting the UK's industrial strategy or community benefits, the conference heard.

One of the challenges the industry has faced, in order to get funding, is to demonstrate an ability to reduce costs. Yet, the tidal industry has just reached the point where it's able to set a baseline, from which it can reduce costs as it builds out, and has reached the stage where it's proving reliable power generation capabilities, says Andrew Scott, CEO of Orkney-based tidal energy firm Scotrenewables.

To put it another way: "They're about to pull away the punch bowl just as the party begins," says Chris Harwood, of Sustainable Marine Energy, a wave energy firm now also offering anchor and mooring technology as a way to diversify (See page 36).

"We are dismayed at the lack of vision on the UK level," Hardwood told the conference. "Over 15 years, there's been a lot of good will and investment and we are starting to see that [improvement] curve, even at raw level generation. Right when (we're) having technical success, [they are] removing investment mechanism for that to keep happening. This is a story we have seen before. In early wind, Germany and Denmark kept [their] policies in place, which means Denmark has people employed [in offshore wind]."

Robert East, UK Development Manager for "open-hole" tidal energy firm OpenHydro, says the challenge is to persuade politicians that the industry is worth backing, by focusing on gross value added and jobs for the UK, alongside continuing to build operational experience and seeking routes to market.

It can be done

It's not all gloom, however. It wasn't that long ago that few would've thought offshore wind could reach £57/MWh. "If they [offshore wind] can do it, it's logical that we can, too," says Andrew Smith, managing director of Glasgow Consultancy Deja Blue (previously head of Scottish Enterprise's Renewable Energy Investment Fund).

Neil Kermode, managing director at the European Marine Energy Centre,

Robert East, OpenHydro.

Sue Barr, OpenHydro. Photos courtesy of Paul Campbell/Highlands and Islands Enterprise.

(EMEC), on Orkney, is also positive and points out that there are more devices in the water than ever this year.

"I don't think I've been at a conference when we have had so many devices in the water," Kermode says. "This is what happens when you stay with the program." The EMEC test site opened in 2004. Since then, it has had 30 devices tested at its sites, from 19 developers across 10 countries.

"The first job was getting something to stay still in the water," Kermode says. "Next was to generate power. And then to generate for longer periods. That's about polishing all the details, so that no single component holds back the program. It's about repetition."

There's plenty of other work ongoing, including looking at different types of materials, coatings, biofouling and corrosion protection, as well as cables and how they behave in water. "It's about how to improve performance of the machines," Kermode says. "Simplify, make them more robust or build heavier. These are the things people are grappling with, looking at where can we economize."

The success of EMEC is borne out by the fact that devices there are producing more electricity than is needed on the island. To make use of the excess power, EMEC has opened a hydrogen plant, which will initially help power visiting ferries via fuel cell, while they're in port, but, ultimately, the hope is that this could provide enough hydrogen to power the ferries around the islands, all from wave and tidal energy.

Cape Sharp Tidal. Photo from OpenHydro.

Atlantis Resources

Atlantis Resources has been paving the way – in both deployment and finding finance (notwithstanding the recent lack of CFD). The firm's MeyGen project in the Pentland Firth achieved a record for monthly production from tidal stream power in August this year, with 700MWh. That was with two Andritz Hydro Hammerfest turbines. A third was reinstalled in late August. Atlantis' own AR1500 turbine was due back in the water at the end of September, taking the MeyGen Phase 1A to its 6MW capacity from the end of Q3.

The firm's Phase 1B (Project Stroma), which has EU funding, was approved last December and will see a further four turbines deployed. The turbines will be provided by Marine Current Turbines (MCT), a company bought by Atlantis from Siemens in 2015, and they will have larger diameter rotors and optimized turbine power ratings. Drilled foundations will also be used, instead of the "material intensive" gravity foundations used in Phase 1A.

Whereas Phase 1A had separate cables to shore for each turbine, Phase 1B is looking at how a single export cable could be used. Wetmate versus drymate connectors are being assessed, as well as learnings from the MCT project at Strangford Lough, Ireland.

Phase 1C would see a further 49 devices installed (73.5MW capacity), starting in 2019, with full power export from 2023. Phases 2 and 3 then have the potential to build out to 398MW capacity.

Despite the firm's success to date, it was critical of the lack of UK funding for marine energy. Atlantis made a bid in the CFD auction round, which forecast a two-thirds reduction in the level of revenue support required for Phase 1C, versus that enjoyed by the first phase of the project. Atlantis also pointed out that there are funds available for further contracts awards, because 40% of the US$285.2 million [£290 million budget] for the recent auction round was not allocated through the competitive process.

Scotrenewables

Scotrenewables has been chalking up milestones with its 2MW SR2000 tidal energy device. The floating, moored structure, which supports two, 16m-diameter rotor, 1MW turbines, with the generators and controls accessible inside

Simon Forest, Nova Innovation.

Andrew Scott, Scotrenewables.


The SR2000 tidal turbine. Photo from Scotrenewables.


SR2000 alongside a multicat. Photo from Scotrenewables.

the floating substructure, via ribs from shore, is being tested at EMEC.

Earlier, the 500-tonne unit, built at Harland & Wolff in Belfast last year, had generated over 18MWh within a continuous 24hr testing period, reaching 40% capacity: "a performance level which matches established offshore wind turbines," says the firm. The device was taken to shore in summer, due to a problem with a cable, but was back generating from 9 August, producing 300MWh over 30 days with a couple of outages – caused by two creel (fish basket) buoys in the rotors. It also achieved 120MW over a seven-day period. It then broke its own record, producing 20MWh in a 24hr period late September.

Scott says the unit is easy to install with small vessels, i.e. multicats. In under 30 minutes one can be installed with 30-tonne bollard pull vessel. An onboard winch enables it to self-install, in 1-1.5m wave height conditions, once the recovery line has been picked up.

Scotrenewables' is looking to improve performance further through the EU-funded Horizon 2020 project, "FloTEC." This will see the rotor blades increased to 20m-diameter and composite materials developed, with project partners EireComposites. Scotrenewables says this alone is projected to increase annual yield from the turbines by more than 50%.

Nova Innovation

In 2016, Nova Innovation built a three, 100kw-device tidal energy array at Bluemull Sound between the islands of Unst and Yell, Shetland. It now has Horizon 2020 funding to extend the array with another three devices and add a smart grid with battery storage. Simon Forrest, the firm's CEO, says the philosophy is about starting small.

The Nova M100 device is described as a flat pack. It took two months to the first device, including cables, substructure, ballast etc. "On the third it took six days," says Forest, "with 70% reduction in cost."

The extension project will look at device spacing, moving the devices around and assessing hydrodynamic forces. An energy storage system will also look at how to curtail production when demand is low, but make more available when demand is high, so that it would in effect create a base load power, in combination with an intermittent producer like offshore wind.

OpenHydro

Sue Barr, external affairs manager, OpenHydro, says: "We are at a critical point. We have to move from technology development to industrial development. If we can show this can be an industry going forward, that could be a strong signal to drive revenue."

OpenHydro has a 2MW, seafloor based (on a tripod gravity base) bi-directional permanent magnet ring motor, 16m-diameter tidal turbine – the so-called open-hole device. It's transported and installed with a purpose built, modular barge. The firm is part of Naval Energies Group (previously DCNS), a majority French state-owned firm.

Having settled on a design, 2014-16 saw the firm focus on a new power convertor, and its control systems. Now it has demonstration projects, i.e. Cape Sharp Tidal (two 2MW devices in Nova Scotia), another two at Paimpol–Bréhat in France, and a single device in the Goto Islands, Japan. Barr says the firm has a 900MW pipeline of projects.

Significantly, the firm is looking at assembly facilities on an industrial scale to reduce costs and has an EU Horizon 2020 grant in place to help this work. It wants to start out with a 25-turbine a year facility, extendable to 50, with the first turbine expected to be delivered off the production line in Q1 2019. A site hasn't been chosen yet.

And the rest

Meanwhile, companies without their own technologies are seeking to develop sites. Ireland-based DP Energy got consent to develop the West Islay Park, a 30MW tidal energy project, which it says could take a range of devices, from seafloor mounted to floating devices.

There's also plenty of other work ongoing. Vicky Coy, project manager marine at the Offshore Renewable Energy Catapult (one of a number of not-for-profit technology "catapults" in the UK), says this time last year the catapult had 30 projects ongoing, with a third on wave and tidal. Now there are fewer, but they're larger and include blade turbulence in the water, a tidal harness, RECODE (a wave energy project), and an involvement in EnFAIT on the Shetland Array with Nova Innovation.

Hayman says the industry is learning by doing. For Kermode, the industry is progressing. "Over the next few years we will see some designs run for longer without intervention. We are also going to see small groups of small arrays, 2, 3, 5 machines, start to happen. It sounds straight forward, but it's not trivial. They've to consider how connect them, how does failure of one affect the others, how intervention on one affects others. Fundamentally, provided there's support from government, we expect to see continued development." OE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Tapping Asia's marine energy market

With waning support for marine energy in the UK, Sustainable Marine Energy decided to head East. Elaine Maslin reports.

Sustainable Marine Energy (SME) set out to be a tidal energy developer, but took a change of tack last year, both in what it was designing and for where. The move has seen the Isle of Wight and Orkney-based firm diversify into producing a new, simpler design for Southeast Asian markets and to start supplying anchoring and mooring solutions to the wider marine markets, including aquaculture.

SME's Plato-O device is a taut-moored, submerged tidal energy unit, which sits beneath the sea surface. It comprises three connected "pontoons," for buoyancy, hosting two SchottelHydro SIT turbines.

Last year, work on a 240kw Plat-O (O for offshore) prototype (with two, SIT 250 turbines) was halted when there was an issue with a cable connection. It was due to be reinstalled at the European Marine Energy Centre (EMEC) at Orkney, Scotland, in September 2016, but, the firm decided to re-think the project, largely due to falling support for marine energy development in the UK.

This led to the development of the Plat-I (I for inshore), a floating (on the surface), trimaran kit-orientated device, which is four-point catenary moored, via a turret, using synthetic or chain mooring lines, with fixed, removeable anchor points. It has been designed for more sheltered sites, compared to those off the likes of Scotland. This is a more conventional design, with a long hull and outriggers, off which four, SIT 250 turbines (providing 248kW) will hang (and can be lowered and raised for work), the benefit of which is accessibility in a dry environment, says Andy Hunt, SME's engineering manager. "It strips out a lot of the complexity and cost, not having to make components water pressure tight and access is easier." Another possible benefit is that the hull could have available payload capacity for other uses, potentially seeing it supporting fishing or other industries, Hunt says.

"There needs to be a realization that the UK market has gone, since the budget last year, with confirmation there was no allocation," SME's Jason Hayman told the Scottish Reneweables' Marine Energy conference in Inverness in September. "Plus, the EU referendum [meaning uncertainty around EU funding]." Meanwhile, areas like the Philippines have 14% predicted growth rates and a lot of "islands hungry for energy," he says. There, wave energy could "compete and add value," he adds.

SME is currently building a Plat-I unit in Peterhead, northeast Scotland, for this market. Once built, it's due go through a 6-8-week sea acceptance test in Connel Sound, near Oban, Scotland. It is then due to be deployed to a demonstration site in Singapore, under a project with Schottel, and Singapore-based firms Envirotek and OceanPixel.

Meanwhile, the firm also decided it could market the anchoring and mooring technology it's developed to hold its tidal energy devices in place, including a rock anchor. As part of its work, the firm has developed the A-ROV (anchoring ROV). It's a seafloor drill, which can be remotely positioned then operated from a vessel, such as a multicat.

This was initially used to operate a screw anchor. SME has since developed Raptor, a rock anchor/bolt. This is a drilled rock anchor, which has an inner stem which drills into the rock, then stops and an outer stem then tappers into the rock, forcing cutting fingers over the lower cone (over the drill bit), reaming the lower taper into the rock. This is then tensioned by pulling the top and bottom tapers together.

With this solution, the firm has already been working with the aquaculture industry, but sees other opportunities. "The ocean economy is growing fast," Hayman says. "We can tap into that."

Last summer, four Raptors were installed at EMEC, in 35m water depth, in less than an hour. Each can take 150-tonne load, with 20cm accuracy positioning, says SME. In March this year, the firm did its first project in aquaculture for a long-line mussel farm. Some 26 screw anchors were installed over four days. The anchors could also be used for navigation buoys, fish cages, feed barges, etc., Hayman says. The firm is working on additional versions of Raptor with higher load capabilities. **OE**

The Plat-I design. Image from Sustainable Marine Energy


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Fixing floaters

Clement Mochet, of Vryhof, discusses ways to bring down the costs associated with floating wind projects.

While costs in fixed offshore wind have more than halved in recent years to reach a zero-subsidy bid by developers (*See panel on page 40*), floating offshore wind still has some way to go.

The opportunities are attractive. Enabling offshore wind development in >40m water depth brings into play more steeply shelved coastlines, otherwise not viable for fixed turbines. According to Bloomberg New Energy Finance (BNEF), there could be as much as 237MW of floating offshore wind capacity installed by 2020, albeit mostly demonstrators and pre-commercial wind farms.

Stevtensioner on the Wikinger wind farm.

The French government is supporting four 25MW arrays for installation in the Mediterranean and Atlantic starting in 2020. However, that the government had to provide a feed-in tariff of $282/MWh (€240/MWh) for 20 years shows how much incentives are still required. Floating wind still needs to cut development costs significantly if it is to move into the mainstream as a viable energy source.

Where can changes be made to reduce costs? Initially, there will be a period of concept rationalization, from the 30+ concepts cited by the Carbon Trust in 2015, to probably three or four floater technologies that will move towards full commercial development, allowing the industry to focus on cost improvement, rather than technical feasibility.

Innovations in other areas, such as higher voltage cables and more cost-effective means of delivering electricity back to shore, will also help reduce capex.

One key of area of cost savings and technology advances will be anchoring and mooring – technology to tether the floating structure to the seabed while withstanding extreme offshore environments. Such technologies comprise up to 20% of the total costs of a floating wind offshore project and in complex deployments and extreme water depths, could be substantially higher.

Winfloat, offshore Portugal.
Photos from Vryhof

The challenges facing mooring and anchoring

It is likely that by the time the first floating wind farms become a commercial reality, they will be hosting 10MW+ turbines (8MW turbines have already been deployed on fixed structures), if not 12-15MW, with ca.200m rotor diameters.

The coupled loads generated by a turbine of this size on the floater could be huge - potentially up to 20,000kN per mooring line – with the units engineered for a lifespan of 25-30 years.

A large part of the cost of the mooring package is the installation costs, at about 50%.

Vryhof's STEVTENSIONER system, used in the oil and gas industry for more than 20 years, would save costs by allowing two opposing anchors to be cross-tensioned simultaneously in constrained areas. A repeated heaving up and slacking of the system in a yo-yo action builds up the load in the mooring chain until the required tension is achieved.

The reduction in the required bollard pull capacity, the use of winches and the ability to use anchors with shorter leads enables operators to use much smaller and cheaper vessels in mooring installations, saving cost.

This system has been used on the WindFloat project. This is a tripod semisub, developed by Principle Power, installed as a pilot in 2011, 5km off the coast of Aguçadoura, Portugal, with a 2MW turbine. WindFloat was the first offshore wind turbine in Portugal, and the first to be installed without any heavy lift vessels or piling equipment at sea.

All final assembly, installation and pre-commissioning of the turbine and substructure took place on land in a controlled environment and the complete system was then wet-towed offshore using simple tug vessels.

As well as supplying the full mooring system solution, including procurement, production follow-up, certification, integration and delivery, Vryhof's cross-tensioning system helped keep installation costs within budget.

Optimizing mooring spreads

However, the offshore industry is not yet used to dealing with high volumes of mooring lines. Getting there implies a significant scale change for all the components of the lines, moving from a project-orientated approach to mass production.

Mass production is considered as one of areas with the highest potential to help reduce costs. Early stage, confidential studies are currently running in cooperation with wind farm developers, floater designers and the mooring industry to assess the positive impacts to be expected.

Another means of reducing costs is through optimal mooring spreads that share anchoring points, rather than traditional single mooring points. The development of floating wind farms with a 'networked' mooring system will mean fewer anchoring points and a streamlined approach to geotechnical site investigations.

The quest for ongoing stability

Another important area is the importance of securing stability in challenging hard soils, such as complex gravelly soils, over-consolidated clays, limestone, or complex cemented soils of carbonite origin. As floating offshore wind expands further offshore, soil conditions are likely to become increasingly prevalent.

Hard soil conditions, however, have traditionally caused significant operational and cost challenges for anchors, with highly developed, multiple and expensive anchoring arrangements required to provide the necessary stability.

There are options entering the market. Vryhof, for example, has recently introduced a new anchor, STEVSHARK REX, based on its geotechnical and modeling expertise and the principles of soil mechanics. The drag embedment type anchor has a holding power of up to 20% more than previous anchors and can be used in all hard soil conditions.

Following testing in the North Sea and the United Arab Emirates, the new anchor recently completed extensive testing in Australian waters in close collaboration with Woodside Energy. The 18-ton anchor with 7.2-tonne ballast was tested in 100m water depth at four different locations, each with their own 'extreme' soil characteristics based around cemented soils of carbonite origin. All the tests were successful with the anchor's geometry and the protruding fluke tips effectively penetrating the hardest rocks.

With future floating wind farms likely to be in relatively complex geological settings where standard anchors may not work as effectively, such anchoring developments are likely to be crucial in the future.

The perfect blend

While mooring and anchoring is only an enabler to some of the exciting new developments in the floating wind power industry today, the focus on innovation and pushing the boundaries will ensure that it plays a crucial role in the viability of marine renewable energy for many years to come. **OE**

***Clément Mochet** is commercial director for Vryhof. Before to joining Vryhof, Mochet was Sales Director and Export Manager at Le Béon Manufacturing. Mochet holds an MSc in mechanical engineering from The National Institute of Applied Sciences (INSA) of Lyon, France, and from the Tampere University of Technology (TUT) in Finland.*

Wind blows, costs fall

Offshore wind has been making headlines for the scale of cost reduction in the industry. Recent contracts for new offshore wind farms in Europe have been agreed pegging the cost of energy from them at as low as US$76.27/MWh (£57.50/MWh)(Hornsea 2 and Moray Offshore).

This is via UK Government issued contracts for difference (CFD), a support mechanism providing project owners a guaranteed price (strike price) for electricity.

In comparison, Westwood Global Energy says the first CFD round saw strike prices averaging $155.20/MWh (£117/MWh). Meanwhile, the CFD award to the Hinkley Point C nuclear project in the UK at $122.70/MWh (£92.50/MWh). Westwood points out that wholesale prices in the UK have ranged between $42.45-66.33/MHW (£32-50/MWh) over the last five years.

Scale, competition, efficiency and reduced costs from the oil and gas sector have helped offshore wind drop its costs, says Westwood Global Energy's Head of Research, Global Oilfield Services, Steve Robertson.

"The UK has established itself at the forefront of offshore wind activity with 5.1GW installed to date," he says. A further 17.2GW of capacity planned for installation over the 2018-2026 period at a cost of $84.55 billion (€72 billion). Including projects at the concept or speculative stages, this could rise to 19.8GW, with capital expenditure over 2018-2026 reaching $91 billion.

"The offshore wind sector has benefited from the increased scale of projects, both in terms of overall capacity and capacity per turbine," Robertson says. "Westwood data indicates that, until recently, turbines of 3-4MW capacity were the norm for most installed projects. Now, projects at the planning phase are typically evaluating turbines of 7-10MW.

Greenpeace, which welcomed the cost reduction, said that by the mid-2020s, turbine capacities are set to reach 15MW. "Furthermore, the sector has seen intense competition and efficiency gains as major engineering and construction firms are lured by the attraction of what are now multi-billion dollar megaprojects," Robertson adds.

Vryhof's Clement Mochet says the economies of scale achieved with huge projects (the He Dreiht offshore wind farm from Germany's EnBW for instance aims at 900MW) and the synergies with other projects nearby have allowed for capex and operations costs optimization.

"A cyclical downturn in the oil and gas industry has helped by putting downward pressure on offshore construction and support assets, a number of which serve both the oil and gas and wind sectors," he adds. Shorter cycle times on offshore wind farms, of two to three years for a build out, also minimizes the risk of cost overrun and sees new technologies adopted more quickly.

"It is not yet clear the extent to which these awards are indicative of a new price paradigm, or if the industry can consistently deliver projects at these levels, but it is a remarkable milestone in the progression of offshore wind to becoming a commercially viable power-generation proposition in its own right," Robertson adds. ▪


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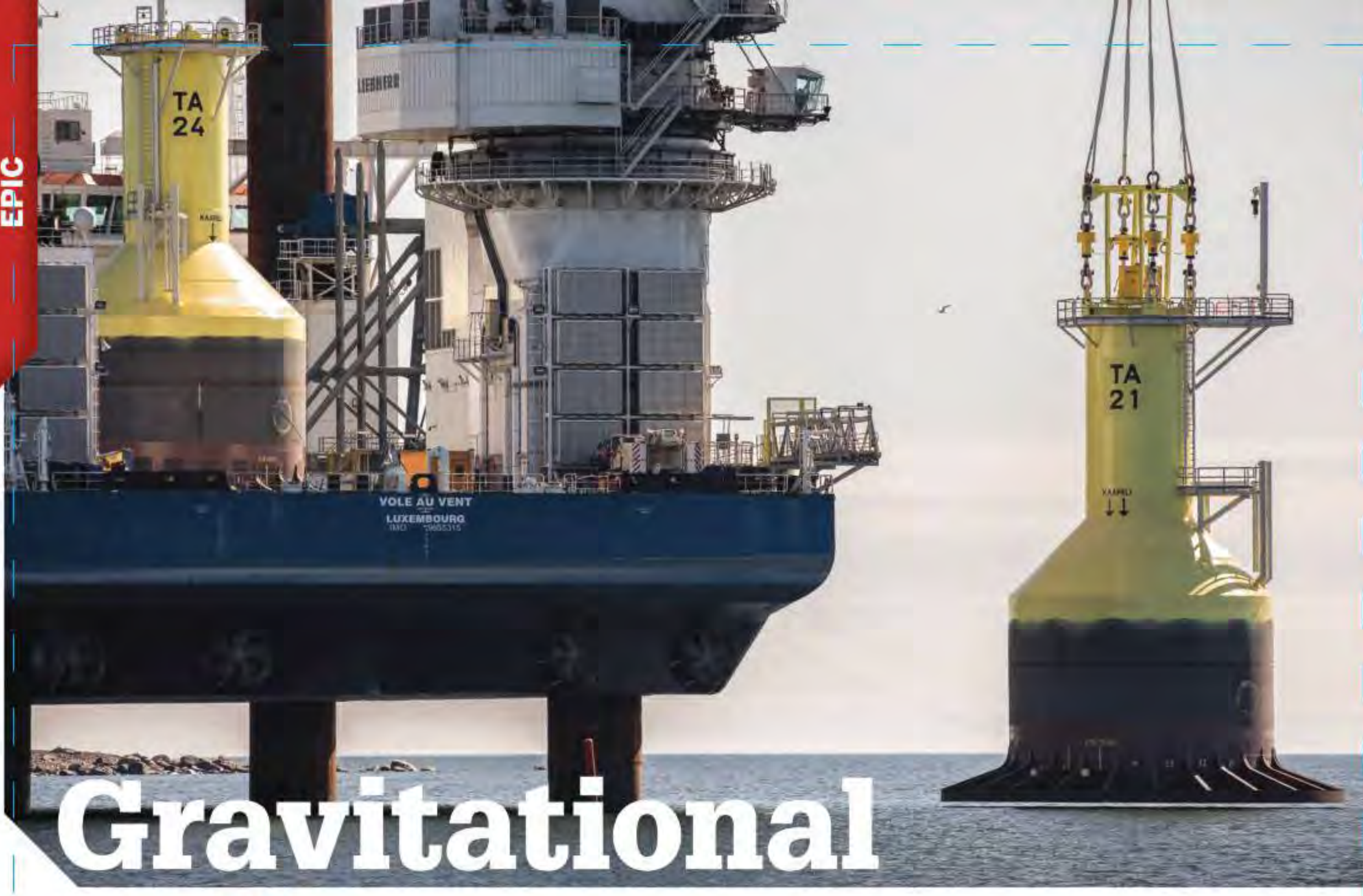


Gravitational pull

Two offshore wind firsts have been achieved this year, both relating to use of gravity-based foundations. Elaine Maslin reports.

While gravity-based wind turbines are not new, they're far from the most common form of foundation for the offshore wind industry.

To date, the most common foundation used for offshore wind turbines has been the monopile. According to trade body Wind Europe's 2016 report, 81% of substructures installed were monopiles, with just 7.5% gravity foundations (the same as in 2015, at 315). The rest were jackets (6.6%), tripods (3.2%) and tripiles (1.9%).

This year, however, has seen two new innovations in the gravity foundation space for offshore wind. At the Blyth Offshore Wind Demonstrator in the UK, gravity-based foundations (GBFs) were built then floated out to site and submerged – a first. Meanwhile, in Finland, GBFs designed for ice-impact have been installed at the Tahkoluoto project.

Tahkoluoto

An offshore wind farm setting out a few global firsts is Tahkoluoto, Finland's first offshore wind farm (not built on an island) – and the first offshore wind farm designed to withstand ice loading.

Tahkoluoto, which was completed this September, is a 10-turbine farm, using Siemens' 4.2MW turbines, on top of GBFs.

What makes Tahkoluoto different is that it's sited 0.5-3km offshore Tahkoluoto, in the Gulf of Bothnia, near Pori, on Finland's west coast, in up to 8-15m water depth.

Finnish waters offer a different challenge to the North Sea, says Xavier De Meulder, marine operations manager, Tahkoluoto Offshore. The country's Baltic Sea coast sees ice flowing down from the north west into its shallow waters. The seafloor is strewn with boulders, beneath which is rock bed interwoven with mud, "making it tricky to install anything," which led to the use of GBFs.

Despite the challenges, project owner Suomen Hyötytuuli Oy is already considering an expansion of the offshore wind farm, with Tahkoluoto 2, adding 100MW after five years, in more like

Jan de Nul's Vole au Vent loading Tahkoluoto wind farm blades. Image from Jan de Nul Group.

Enerpac's Synchoist X-frame.
Images from Suomen Hyötytuuli Oy.

25m water depth, says Toni Sulameri, managing director, Suomen Hyötytuuli.

Suomen Hyötytuuli has taken a stepwise approach to its Baltic wind farm ambitions, however. It started with an initial design for a GBF, which was built and installed in a one-turbine pilot in 2010, with a 2.3MW Siemens turbine, 1.2km offshore in 9m water depth, also at Tahkoluoto.

Designed for ice

The pilot used an ice-strengthened steel shell GBF, based on principles used for ice-class vessels, which is filled with rock for ballast once sited. It has a ring footing and a conical top to withstand ice ridges, which can drift along the coast.

For Tahkoluoto, the same GBF has been used, but optimized and three similar but separate designs created, according to site specific characteristics. These weigh 450-500-tonne, largely due to differences in steel thickness.

The designs were developed to withstand the highest ice conditions, based on meteorological data going back 50 years, says De Meulder, and taking into account wave and wind conditions, as well as subsoil, which all impact how fast the ice moves, and therefore the impact it would then have on the structures.

Unlike traditional wind turbines, where grout is used to position and fix the transition piece in place offshore, the transition pieces on the Tahkoluoto GBFs, built by Technip Offshore Finland, are pre-welded in place before being installed. The main turbine column is then placed on the transition piece.

While it was easier installing the transition piece in the shipyard, however, this means tighter tolerances during installation – the seafloor has to be level, the structure has to be built with tight margins, and the lifting and positioning margins are also tight, says De Meulder.

Preparation and Installation

Work on seabed preparation for Tahkoluoto started in April 2016, to avoid the October-April winter season, and involved digging foundation pits, which were then filled with crushed rock, which was then compacted to create a level seabed.

In June, Jan De Nul Group's Vole au Vent jackup vessel completed the installation of the 10 GBFs. While it might have been a bigger vessel than possibly required, it was the right tool and meant no waiting on weather, says De Meulder. The careful positioning operation was done with the help of Enerpac's Synchoist load positioning system. The system was used below the crane hook during lowering through the splash-zone and positioning on the seabed, to ensure the foundation remained as close to vertical as possible to prevent damage to the levelled seabed surface. The wirelessly operated system, comprising a lifting frame with four SyncHoist, self-contained PLC-controlled, double acting, push-pull hydraulic cylinders at each corner, and diesel hydraulic powerpack with battery back-up, also support the installation of the turbine towers.

The system was able establish the center of gravity for each foundation, on the vessel, just above the water, 3-4m into the splash-zone, and 5cm above the foundation. The first foundation took 12 hours to install, later foundations took eight hours as the installation team became more proficient, Enerpac says.

Each GBF was then filled with ballast and scour protection added over the ring base. The Vole au Vent jackup then installed the turbines – a more routine job, compared to the GBF installation – before demobilizing to work on the Blyth project. Finally, about 14km of a 30kV undersea cable was laid in trenches, which were then backfilled. Because the wind farm is so close to shore, it is connected via four cables to an onshore substation.

Operations

While weather conditions haven't been as bad as they used to be – the last bad

The Vole au Vent vessel.
Image from Jan de Nul Group.

winter for serious ice conditions was in 2011-12, says De Meulder. Changing weather patterns have made weather prediction harder, making day-to-day operations trickier. In winter, especially, operations vessels will have to navigate lumps of ice in the water. Because of this, an aluminum crew transfer vessel is used in summer, but a steel-hull former naval vessel is used for access in winter.

In addition, the boat landing ladder on each GBF has a heating element, to stop ice forming – as happened on the pilot turbine foundation, which meant the ice had to be chipped off to gain access. Now, the four main pillars are heated to prevent icing.

For future projects, Suomen Hyötytuuli will want to bring in more expertise relating to the seabed, says De Meulder. "It's an important element of installing the wind farm. If we don't get the bottom right, then you could lose a lot of time and costs. We were good on this project, but it's just 10. The next part we really have to be careful."

It's likely the GBF design will also be further adapted, in consideration of the larger turbines being used today – up to 8MW, for offshore. But, whether larger or smaller turbines are used is yet to be decided, as it could influence the size of the foundation in such a way that larger vessels are needed, making operations less economical.

Blyth spirit

For Blyth, GBFs were chosen because of the chance to use the float and submerge method, reducing the need to use heavy lift vessels, as well as reducing the impact on the environment from installation operations in other methods (eg. Piling).

Using GBFs also suited the ground conditions, which comprises a thin veneer of gravelly and/or muddy sands, on top of a bedrock, which would make piling very difficult, says operator EDF Energy Renewables.

The wind farm, 6.5km off the Northumberland coast, comprises five, MHI Vestas V164 8.3MW wind turbines (another first, for a GBF) with a total generating capacity of 41.5MW, connected using 66kV rated cables from JDR (another first).

Fully installed, each 60m-high GBF (from seabed to access platform) is made up of more than 1800cu m of concrete and weighs more than 15,000-tonne. All five turbines were installed in late September.

EDF Energy Renewables acquired the rights to develop the project in October 2014, having taken it over from NAREC, now the Offshore Renewable Energy (ORE) Catapult.

Part of the attraction to using GBFs for the project was that, unlike steel foundations, self-buoyant GBFs can be mass-produced locally using conventional civil engineering construction skills. They're thought to be economical in 35-60m water depth, depending on ground and/or environmental conditions.

Blyth Offshore Demonstrator cable works. Photos from EDF Renewables.

Blyth Offshore Demonstrator cable works.

The GBFs comprise a concrete caisson and a steel shaft. Designed and built by Royal BAM Group, the GBFs were constructed in the Neptune Dry Dock on the River Tyne, northeast England, with the shafts fabricated in the Netherlands and shipped to Newcastle to be installed into the caissons. Once complete they were floated down river to the Port of Tyne, where extra ballast was added before being towed offshore to be submerged.

While piling isn't required, the seabed at each foundation location had to be dredged and two layers of different size gravel placed to create a level surface and suitable depth. Once the GBFs were on site, Dutch contractor Strukton Immersion Projects used a specialist vessel to pump sea water into the foundation as ballast to lower it to the prepared sea bed. Once in place, the water ballast was replaced with a sand ballast to keep the foundation on the sea bed.

Once all five GBFs were in position, VBMS laid 66kV inter array and export cables to connect the wind farm to a new substation being constructed at Blyth.

The turbines were than installed using the Vole au Vent jackup. It is anticipated that the turbines will start generating power by the end of the year.

"The project has provided an opportunity to optimize the design of the GBFs by combining two technologies – one that makes the floating concrete structure and the other which uses a monopile steel shaft," says EDF Renewables. "This challenge was overcome successfully with a fully certified design from DNV GL."

As part of the project, the ORE Catapult designed a sensor system in two of the five GBFs. This is the first time that sensors have been installed in a GBF to analyze the performance of the foundations in the challenging conditions to which they are exposed out at sea.

The project was conceived as having maximum of 15 wind turbines across three arrays, with the first five turbines being array 1. However, EDF says: "There are currently no immediate plans to develop the other two arrays, but the option to develop them at a later stage will be kept under review." **OE**

Being sure about flexibles

Nearly 16,000km of unbonded flexible pipe has been supplied to the market – but, how much do we know about its integrity and failure modes? Wood's Ian MacLeod shares recommendations from the Sureflex JIP.

While recognized as an essential technology that enables key operations in a way that fixed pipe cannot, flexible pipes are still seen as a riskier option.

To understand more about the reality of flexible pipe deployments, the Sureflex joint industry project (JIP) was launched in 2015. By creating a global database covering pipeline population, failure and damage statistics, the JIP's aims were to:

- Research the quantities and types of installed flexible pipe
- Improve industry knowledge of flexible pipe integrity management
- Update industry guidance for managing the integrity of unbonded flexible pipes
- Aid personnel responsible for flexible pipe integrity

The JIP's 13 industry members included operators of flexible pipe, manufacturers, certification bodies, and regulatory authorities. Their contribution was supplemented by non-member organizations' experiences.

Research framework

The result is the Sureflex JIP report on Flexible Pipe Integrity Management Guidance & Good Practice. The report shows that, by 2016, 15,750km of unbonded flexible pipe, consisting of 17,500 individual sections, had been supplied – often in harsher conditions than rigid steel piping. The report also shows that the use of flexible pipe for static flowlines accounts for more than 70% of total supplied length and half of pipe sections, while dynamic risers account for about 20% of supplied length and 26% of pipe sections.

Flexible pipe jumpers account for 2.5% of globally installed length and 18% of installed individual sections, due to their shorter lengths.

The JIP combined these numbers with global damage and failure statistics and focused on accurately classifying the severity of the different failure events and to understand the differences between the defects that result in damage or failure, including pipes that have been shut down or replaced, but with no containment loss. This is important as some recent studies have classed all defects or the change-out of a pipe as a failure. Correct categorization of reports allowed the JIP to provide an accurate threat assessment.

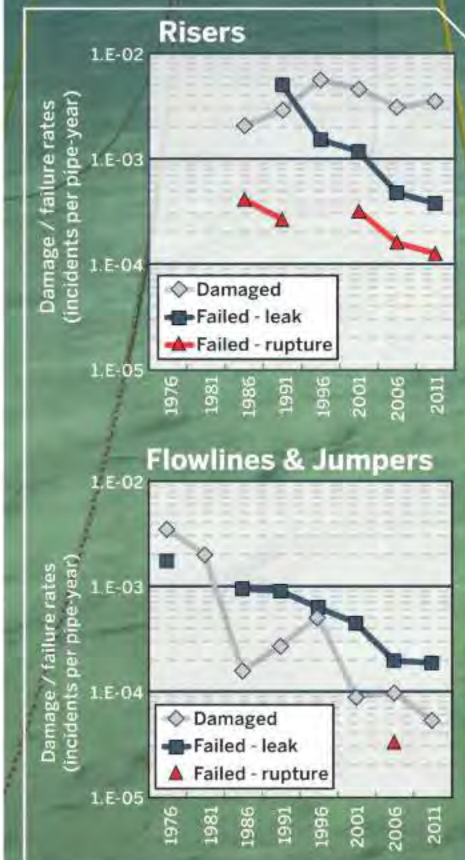
The key categories were:

- Damage: An issue that has degraded the flexible pipe's construction or performance – but may allow continued operation.
- Failure: The loss of the primary containment. Failure is then divided into:
  - Leak: Low-level leakage caused by an IPS defect.
  - Rupture: Bore containment failure due to a defect in the IPS.

The JIP focused on damage and failure during installation and operation of flexible pipe. A limited number of damage or failure events occurred at the factory acceptance testing (FAT) stage. The JIP found these were more likely to be significant events that were rectified prior to delivery. There were also a few damage or failure events at load-out, but these were more likely to require minor repairs.

Findings

The JIP found that the number of catastrophic rupture events is relatively low (five cases reported in the past 10 years).

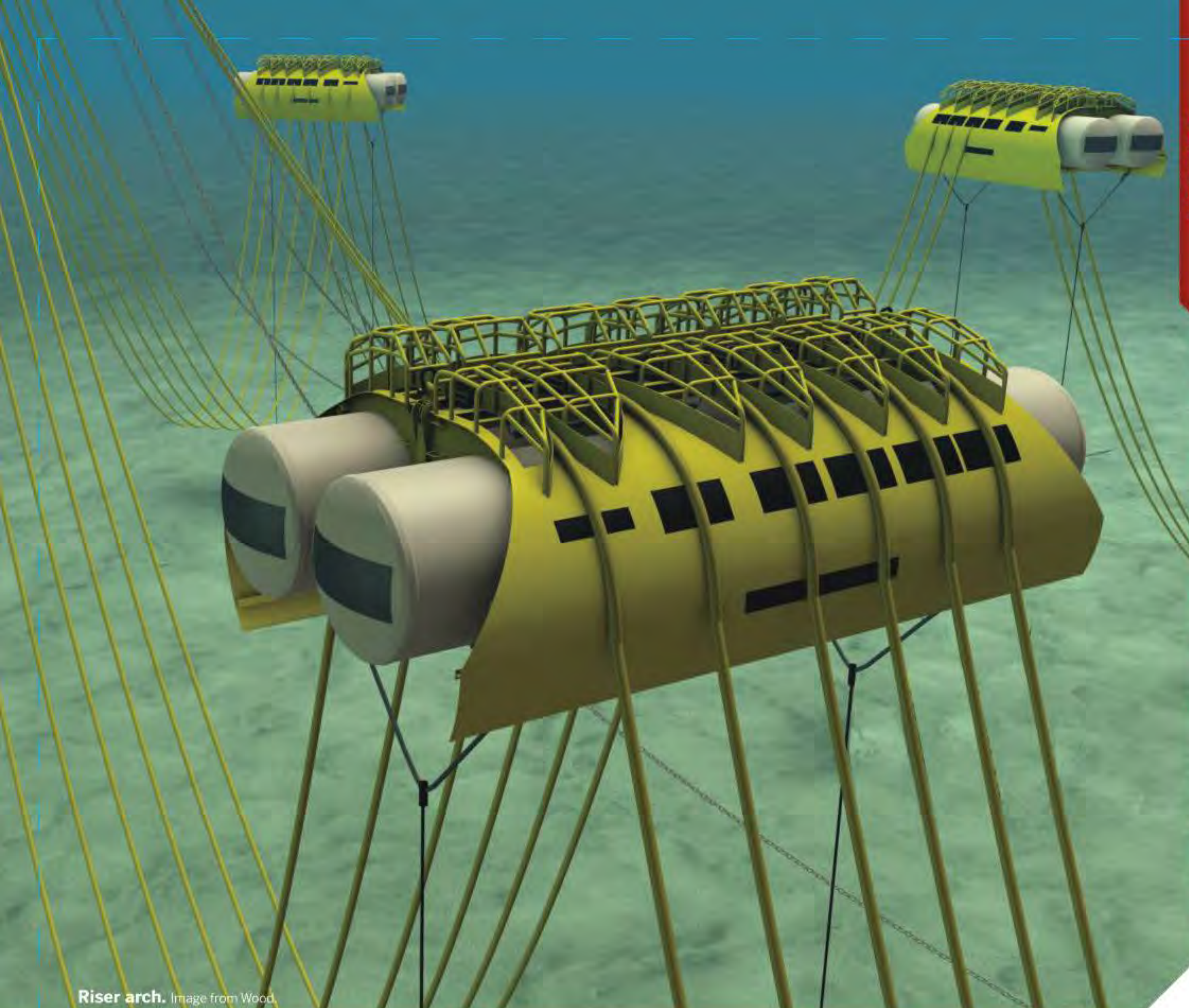


Source: Wood.

Reported incidents are still dominated by annulus flooding or outer sheath damage, accounting for just under 40% of flexible pipe damage and failure. The majority were classified as damage or minor defect with no loss of containment.

Of the 584 incidents reported: 451 were cases of degradation without a leak or rupture; 123 resulted in a leak; and 10 cases resulted in a rupture. Of the 584 incidents, 465 were related to risers and the remaining 119 are attributed to flowlines and jumpers. Looking at these results in more detail, the JIP shows:

- 45% were classed as damage: an anomaly that had degraded the piping but not caused a loss of containment.
- 21% resulted in a containment loss.
- In 16% of cases, the pipe was operating with a minor defect that was unlikely to affect the service-life.
- The two most commonly reported



causes of degradation led to annulus flooding. 212 cases of annulus flooding were reported.

- In a further 15% of cases, pipes had been shut down because of integrity concerns, but damage was not necessarily identified.
- Fewer than 2% of cases resulted in containment loss/rupture. These were primarily caused by:
  - Corrosion
  - Tensile armor wire breakage

Analysis

The safety record of flexible piping is more benign than previously perceived. When its typical deployment is taken into account – notably harsher conditions than those experienced by fixed pipe counterparts and the role it often plays as an enabling technology – the JIP concludes that flexible pipe integrity experience compares favorably with rigid steel pipes. Despite some failures, leaks and ruptures, the industry's experience is that flexible pipes exhibit robustness under abnormal conditions.

Examples of where abnormal loading has resulted in damage include:

- A mooring system failure that led to large displacements of riser bases. Nonetheless, no ruptures were reported and the only loss of containment was caused by a topside rigid spool failure.
- Large dropped objects that impacted flexible pipes. However, the pipes reentered service following re-validation assurance activities.
- A number of mid-water arch failures resulted in multiple risers being dropped on to the seabed or significant abnormal loading. Several of the 'dropped' risers were reinstated.

Despite the relative youth of flexible pipe, the statistics show that even though new failure modes have been observed, the rate of failure has declined since the mid-1990s. Reported damage increases are largely a result of increased monitoring. In addition to the core work of the JIP, a review of independent studies showed that when acknowledging the incident rate per installed pipe, flexible pipe has lower rates of containment loss than rigid pipe.

Future risks

The results are broadly positive. However, previously undocumented failure modes identified in this report include:

- Fatigue failure in the main pipe section
- Carcass tearing
- Smooth bore riser ruptures as a result of reverse permeation in pressurized J-tubes

Flow-induced pulsations can also occur in unbonded flexible pipes. Flexible pipe is only the initiator, but it's important not to underestimate the potential threats to safety.

The oldest flexible pipes were manufactured 42 years ago and 56% of all manufactured flexible pipes were supplied in the last 15 years. Nine in 10 were manufactured in the last 30 years. Operators need to remain vigilant as an increasing proportion of their flexible pipe deployments enter late-life state.

Conclusions

Flexible pipe is a specialist product with distinct differences to rigid steel pipe. Historically, however, flexible pipes have often been inspected, repaired, maintained and assessed by personnel with limited knowledge of flexible pipe technology.

The industry now acknowledges that flexible pipe integrity should be managed by those with demonstrable flexible pipe system competence and experience.

To that end, the JIP report also includes a comprehensive Inspection and Monitoring Technology Review to help operators identify how to mitigate the threats.

The report also acknowledges that many operators have established long track records of applying integrity management techniques detailed in prior JIP reports.

Improvements in materials and design of flexible pipe has led to greater confidence among operators in the effectiveness of their integrity management methods. However, with new threats coming online, the JIP has created a standardized reporting template for flexible pipe damage and failure.

Finally, the report itself makes a number of key recommendations:

1. Operators should consider the guidance concerning the global experience of flexible pipe usage, damage, and failure.

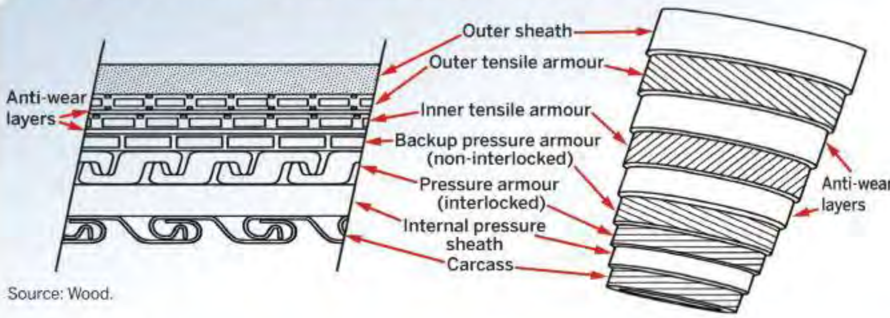
2. Annulus flooding events remain the most prevalent cause of damage to dynamic risers. Dynamic risers are increasingly being designed for flooded conditions. Operators should still make every effort to mitigate any anomalies leading to annulus flooding.

3. Operators should perform risk-based integrity management programs to identify the specific threats to a flexible pipe system.

4. The JIP database should be kept up-to-date to advance understanding. Finally, the JIP recommends using its standardized reporting template for flexible pipe damage and failure.

The report of the Sureflex JIP Flexible Pipe Integrity Management Guidance & Good Practice was published in 2017 and is available on Oil & Gas UK's website. **OE**

Components in an unbonded flexible



Source: Wood.

Ian MacLeod is *engineering manager for integrity management at Wood. MacLeod is the technical lead on the Sureflex JIP report on Flexible Pipe Integrity Management Guidance & Good Practice, and delivered technical paper SPE-186158-MS on the topic at Offshore Europe 2017. He is a Chartered Engineer and a Fellow of the IMechE.*

Population database, total supplied inventory

Pipe type	Total flexible pipes supplied				Average pipe section length
	Sections of pipe		Length		
	(number)	(% of total)	(km)	(% of total)	(meters)
Riser - static	264	1.5%	225.7	1.4%	855
Riser - dynamic	4609	26.3%	3331.2	21.1%	723
Riser (unspecified)	73	0.4%	21.1	0.1%	289
Flowlines	8747	49.8%	11,418.5	72.5%	1305
Jumpers	3144	17.9%	370.2	2.4%	118
Unspecified	712	4.1%	385.1	2.4%	541
Totals (average)	**17,549**	**100.0%**	**15,751.8**	**100.0%**	**898**

Source: Wood.

Largest contributors to flexible pipe damage & failure (by grouped causes)

Rank	Damaged		Failed – Leak		Failed - Rupture	
	Riser	Flowline & jumper	Riser	Flowline & jumper	Riser	Flowline & jumper
1	Rank	Annulus flooding 19 cases, 63%	Internal pressure sheath 29 cases, 46%	Internal pressure sheath 21 cases, 35%	Armours 5 cases, 56%	End fitting 1 case, 100%
2	Ancillary equipment 59 cases, 26%	Global pipe defects 9 cases, 30%	Armours 10 cases, 16%	Armours 20 cases, 33%	Internal pressure sheath 3 cases, 33%	n/a
3	Carcass 29 cases, 13%	= 3 Pigging damage (1 case) Internal pressure sheath (1 case)	Carcass 7 cases, 11%	= 3 End Fitting, 9 cases, 15%, Global pipe defects, 9 cases, 15%	Global pipe defect 1 case, 11%	n/a
Total cases	**197 (85% of damaged risers)**	**30 (100% of damaged flowlines & jumpers)**	**46 (73% of riser leaks)**	**59 (98% of flowline & jumper leaks)**	**9 (100% of riser ruptures)**	**1 (100% of flowline & jumper ruptures)**

Source: Wood.

An Exnics Hot Ring.

Circular energy

Elaine Maslin reports on a new solution aimed at converting heat in subsea pipes into power, and then using that power to measure what's going through those pipes.

"Hot Rings" firm Exnics has its sight set on further offshore trials of its subsea power system after identifying how it could improve output of the system by 60%.

The firm is also developing non-intrusive instrumentation, to be powered by its hot rings technology, which could improve production rates by monitoring flow regimes inside flowlines. The technology would move the firm towards becoming a data services firm, providing insight for operators to optimize flow rates on their fields, in both green and brownfield environments.

The firm, based in Aberdeenshire, had the first trial of its hot ring technology last year on EnQuest's Crathes subsea tieback in the North Sea. The technology is a thermal energy regeneration system, based on rings, fitted with thermoelectric generators (TEGs), which can be clamped around production flowlines. The heat inside the pipe is converted to electricity, which recharges batteries used to power instrumentation.

Stuart Ellison, the firm's director, says learnings from the six-week trial last year, as well as work with Heriot-Watt University in Edinburgh, via the Oil and Gas Innovation Centre, on nano-engineering, has improved the TEGs in the firm's rings, enabling up to 60% increased power output, i.e. from 10w, from a 100°C, production flowline, to 16w, per ring. To generate more power, more rings can be added at a rate of six rings per meter to cover various power needs.

The Talon.
Images from Exnics.

The Hot Rings deployed in last year's North Sea field trial used off the shelf TEGs. These commercially available TEGs are designed to cover a wide range of industrial uses and therefore have a broad range of operational temperatures. Subsea flowlines have a much more defined temperature envelope. By taking control of the TEG design, Exnics has developed a TEG specifically for the subsea flowline application, which is, therefore, much more effective than an off the shelf TEG. It also meant they could determine the geometry of the TEGs and make better use of the available space while also improving the build quality.

In December, the firm won approximately US$200,000 (£150,000) in funding to develop a brownfield version of the Hot Ring technology. This has been dubbed the Talon, as the semicircular Hot Ring components are used as fingers to form a three-fingered claw shape which is installed around a pipe. It could be diver or ROV deployable providing a continuous power supply for an instrument package.

Using the remote power package, Exnics is developing a non-intrusive flow monitoring system based on measuring minute optical variance on the surface of a pipe using a laser and then putting the signal through a machine learning process, patent pending. By doing this, they say they are able determine fluid properties and flow parameters within the pipe.

The firm is working on a project with the Oil & Gas Technology Centre in Aberdeen to develop the technology with the aim of gaining better visibility of commingling fluids in subsea manifolds. Over 500,000 boe/d are commingled blindly in subsea manifolds on UKCS alone.

Initially, Exnics plans to pilot the technology in onshore terminals where pipelines make landfall, using a portable, tripod-mounted system. The firm can use the data collected from the pilots to further train their algorithm ahead of offshore and ultimately subsea trials.

The firm's goal is to develop a monitoring system which the Hot Rings could power under an "edge analytics" philosophy, i.e. where a certain amount of the processing is done at the instrument, so that only the information that is required has to be transmitted, potentially acoustically, where there's no communication system in place to tap into. Not sending all the data would also reduce how much power is needed for transmitting data. The data sent could help platform operators tune the choke setting, gas lift and ESP drive frequency of individual wells in subsea clusters, to help prevent certain wells backing out others, on a field by field basis, for example. The data could then also be used more broadly across a business to track trends such as predicting sand ingress or water cuts, says Ellison. OE

Umbilical assembly ready for load-out. Images from Oceaneering.

Weighing the options

Oceaneering's Joao Melo explains how operators can decide if aged assets can live longer.

Subsea umbilicals are critical components in most subsea oil and gas production infrastructure, connecting topside facilities to subsea equipment and interconnecting them as required. Through these connections, hydraulic and electrical power, electrical/optical signals and chemicals are supplied to the system. While typically designed for 15-25 years' operational life, in many situations the actual field life is longer. This forces operators to assess their options, i.e.:

- Do nothing and accept the risk of a failure during operation;
- Purchase sufficient spares to maintain operation of the existing equipment (not always a viable alternative for umbilicals and some of their failure modes);
- Replace or upgrade parts of the equipment (again, not always a viable alternative for umbilicals and some of their failure modes);
- Replace or upgrade the equipment.

In recent years, Oceaneering has been involved in the assessment of the risks related to a potential decision to extend the life of aged umbilicals for various operators and relating to different fields, applications and environments. The process used for such assessment includes a detailed review of all available information regarding the asset (including design, manufacturing, installation and operational data), the identification of risks based on the analysis of the information available (or the lack of information available) and the assessment of each risk identified, based on its likelihood of occurrence and impact (on safety, the environment, quality or cost).

One common mistake made during these types of studies is to focus on – and to put a majority of resources into – one single area of concern (such as on the most evident or most recent risks identified, based on previous experiences from the individuals involved in the decision-making process). Although this usually addresses real and critical risks, it could, and most certainly will, take focus away from other areas and risks that might ultimately lead to different decisions (such as a decision to replace the asset). In other words, the best practice is to identify and assess all risks before making any decisions and taking action.

Assessing risk

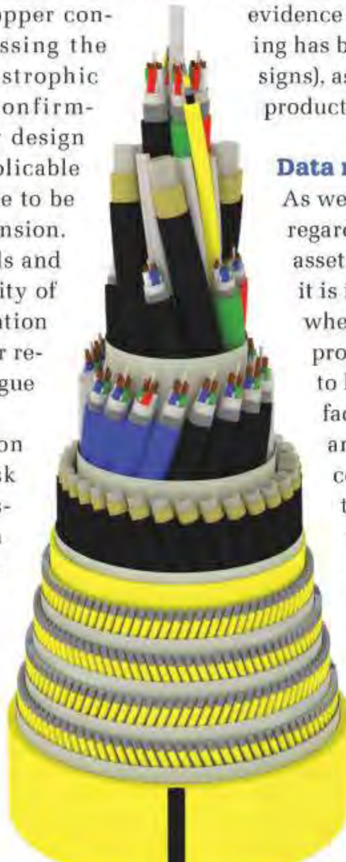
Some of the most common high-risk areas identified in our analysis include:

Compatibility with operational fluids: Particularly with, but not limited to, umbilicals that use thermoplastic hoses as hydraulic conduits, the long-term compatibility between the operational fluids (or combinations of fluids) should be confirmed. It is very likely that different fluids would have been used over the years and may not have been tested against the materials in question – and could, therefore, slowly deteriorate the hydraulic lines' performance, leading to complete loss of functionality. Scenarios where the fluid within a given hose is "unknown" have been reported before, but should (of course) be avoided.

Umbilicals and termination assemblies ready for testing.

Fatigue: This is normally one of the areas of focus for dynamic applications. Concerns regarding the fatigue life of metallic elements of the umbilical (steel wires, tubes and/or copper conductors) include assessing the increased risk of catastrophic failure, along with confirming that the necessary design criteria defined by applicable standards will continue to be met in case of life extension. Advances in design tools and the increased availability of environmental information could also be drivers for re-assessing a product's fatigue performance.

Corrosion: Corrosion is most certainly a risk that will need to be assessed. The effects on unprotected elements including steel tubes, for example, to corrosive environments and the evaluation of cathodic protection systems having a defined design life and may need to be resized accordingly to support a life extension scenario must also be considered.



Typical subsea umbilical with thermoplastic hoses and electric cables.

Other high-risk areas include certain design aspects of ancillary items within the system (often resulting from a lack of evidence that the adequate engineering has been done to validate the designs), as well as the obsolescence of products originally used.

Data management

As we are faced with decisions regarding the life extension of assets (umbilicals, in particular), it is important to identify areas where we should adjust our processes and products today to help those who will be faced with similar questions and challenges in years to come. What can we do today to better support a decision-making process that will take place 20-30 years from now?

The entire risk identification and assessment exercise is based on available information regarding the asset. One thing we are learning is that, despite all the efforts that our industry puts on generating good documentation and traceability, if this information is not maintained and readily accessible when needed, then all such efforts would have been in vain. Data management systems that consolidate all the relevant documentation regarding an asset should be put in place and used across the entire life cycle.

Having accurate information on how a product performs in the field, including what levels of stresses have been imposed on it, would allow companies to compare that information with design models and identify opportunities to extend the product's operational life. Decisions made based on actual data, rather than estimated or theoretical figures, would certainly enable better and less conservative decisions. **OE**

Joao Melo *is a mechanical engineer with over 15 years of industry experience, mostly in the umbilicals, subsea connection, and distribution business. He has held positions in engineering, project management, and technical sales, and now works as the Engineering Manager for Oceaneering - Subsea Distribution Solutions in the UK.*

BP's *Glen Lyon* FPSO, pre-fitted with polymer EOR equipment.
Images from BP.

Improving recovery

Last month, Chevron approved plans for a commercial polymer EOR project on its UK North Sea Captain heavy oil field. Elaine Maslin looks at the broader prospects for EOR projects on the UKCS.

For many fields on the UK Continental Shelf (UKCS) the clock is ticking. The basin has been producing oil and gas for some 50 years and many facilities are reaching the end of their lives.

The average UKCS recovery factor from oil fields is projected to be about 46% at end of field life, which leaves significant potential to be tapped – if enhanced oil recovery (EOR) technology can be harnessed in time.

Use of EOR technology has been on the radar for some time. It was highlighted by the government-industry PILOT project, and then also the 2014 Wood Review – a report that set out what the UK North Sea industry needs to turn itself around and maximize its remaining potential.

Screening by the PILOT work group found a theoretical maximum (unrisked) total 6 billion boe EOR potential on the UKCS. The group's view was that the economic (risked) EOR potential was between 10-20% of the maximum (unrisked) amount, i.e. 600-1200 MMboe. Furthermore, the economic (achievable) EOR potential for the top 20 fields alone equated to 500 MMboe, which is comparable in size to the top 20 new projects that had their field development plans (FDPs) approved over the six-year period from 1998-2013.

The Oil and Gas Authority (OGA), set up on recommendation of the Wood Review, has taken up the mantle, with polymer-based EOR at the top of the agenda. The OGA has set a goal to "drive economic development of 250 MMboe incremental reserves" primarily through polymer EOR over the next decade. Proven offshore operation of low salinity EOR is next on the hit list, followed by a next generation of EOR technologies, such as miscible has injection using CO_2.

In 2014, at $100/bbl, EOR projects were more attractive. However, today's low oil prices have impacted how much cash operators have for these schemes. They come with brownfield modifications costs and the challenge of accessing natural gas or CO_2 for injection.

There are currently just two active EOR schemes in the UK North Sea: a hydrocarbon miscible gas injection scheme at BP's Magnus field and Chevron's polymer EOR scheme on the Captain field (*OE*: May 2017). The Captain EOR project is designed to increase field recovery by injecting polymerized water into the Captain reservoir. The scope of stage 1 of the project includes six new polymer injection wells and brownfield modifications to platform facilities. A final investment decision was made on 20 October 2017. Stage 2 would expand polymer injection to the full field and is dependent on the results from stage 1.

BP is also working to bring its Clair Ridge project online next year, which will see the world's first offshore low salinity EOR scheme (*OE*: June 2014), and other projects are at presanction stages of evaluation, such as BP's polymer project at Quad 204 (*OE*: September 2015) and Statoil's potential polymer flood project on the Mariner heavy oil field (*OE*: May 2017). BP has made a pre-investment in tanks and pumps on the new-build Glen Lyon floating production unit, which came onstream in May, but the project is subject to partner sanction, according to the OGA's EOR Strategy document.

The potential for use of EOR technology for heavy oil recovery has also been seen on Quad 9 (home to the Kraken, Bressay, Bentley, Mariner, Harding and Gryphon fields), meanwhile, the Steam Oil Production Company has been assessing steam flood technology for heavy oil fields in the central North Sea (*OE*: December 2015). Another technique "out there" is thermally active polymer.

As *OE* went to press, the OGA published a report; Polymer Enhanced Oil recovery – Industry lessons learned, supported by BP, Chevron, Shell and Statoil. It says polymer EOR can be economic and that there are there are six fields where there are plans to implement polymer EOR, potentially delivering some 194 million bbl of incremental reserves. This represents an incremental recovery factor of 5%.

It recommends standardizing a suite of experiments that should be consistently applied and available to all, to assess the compatibility and polymer selection to aid screening work.

Dave Puckett, the OGA's senior reservoir engineer, says that, as well as working on existing projects, field development plans are also being screened for their inclusion of EOR technologies.

"The challenge is the capex and opex prices of different EOR technologies," Puckett says. Indeed, a report by petroleum economist Alex Kemp from the University of Aberdeen from 2015 suggested that tax incentives might be needed to encourage EOR projects (*OE*: April 2015).

"In the longer-term, it's our hope CO_2 becomes achievable," Puckett says. "CO_2 is very good for miscible gas injection, but the economics are challenged and we don't have a source of CO_2 at the moment." The OGA is seeking the government's view on carbon capture and storage (CCS) (last year the UK government dropped a significant CCS project). Norwegian plans to shipped captured CO_2 offshore could also improve this situation.

Thermally active polymer could be used as an alternative to workovers, Puckett says, by using a small amount of treatment to block off water cut in a specific area. So-called Bright Water is a form of this technology. Another technology, which is the subject of a joint industry project (JIP) supported by the OGA, is carbonated water, which contains the gas used to makes oil more mobile in water that is injected. "It changes the way the gas is pumped into the pore space," Puckett says. "The CO_2 comes out of the water and into the oil and the oil then becomes lighter and easier to move."

Other JIPs supported by the OGA include a low salinity water injection project at Heriot-Watt University and the Dolphin JIP with France's IFPEN. This project has been running for three years already and is now entering a second phase, looking at the effect of chemical EOR (polymer or surfactant) on the water cycle in the reservoir, i.e. how they behave in flowlines, the reservoir and production equipment. The project has been looking at fields in Brazil and onshore Europe, but the second phase will include a UK North Sea field, too.

Meanwhile, the University of Warwick is involved in a project with SNF to find a way to measure the molecular weight of polymer in a solution.

There are clearly challenges to implementing these technologies, from cost to more practical considerations, including facilities not being designed in the first place to be able to accommodate EOR related equipment. Subsea completions, if not designed similarly, will also be a challenge, Puckett says. Having a good understanding of the subsurface, usually by having performed water flood for a number of years, is also important, he says. If CO_2 EOR is used, it brings with it corrosivity, which will be a challenge.

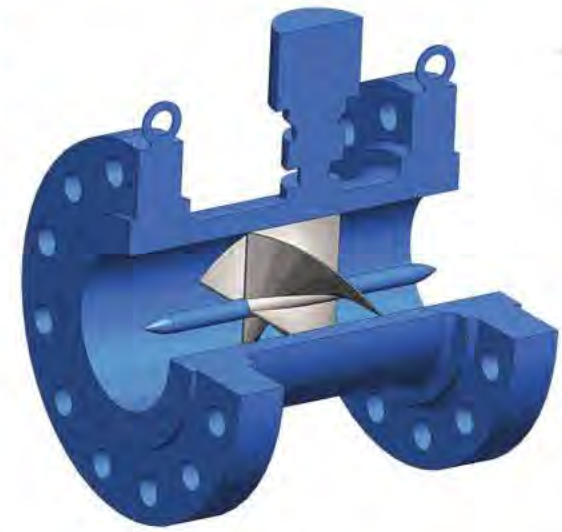
Having said that, BP is going straight into LoSal EOR on its Clair Ridge field, an extension of the producing Clair field, such is its confidence in the technology. This will have the benefit of having dry oil for longer, Puckett says, which in turn reduces H_2S and sulfate scale issues, because clean water has been injected from day one.

But, it's not just about the individual technologies. Combining these technologies could enhance recovery further. To help companies understand the opportunities and challenges, the OGA is putting together a "starter pack," to help others not already involved in assessing EOR technologies understand some of the risks associated with polymer EOR. This was due to be published in summer this year. OE

BP's *Glen Lyon* FPSO.

Improving flow measurement accuracy

Changing production regimes over the life of a field can prove to be a flow measurement challenge. NEL's Neil Bowman looks at the challenges.



A turbine meter.
Image from NEL.

As fields mature, so do their production characteristics. In the North Sea, for example, the maturity of the basin means there is more produced water here than on average globally.

In 2015, some 69% of well stream fluids were produced water, according to the Oil & Gas UK Environmental Report 2016. In 2015, the UKCS generated 2.4 tonnes of produced water per tonne of hydrocarbon. In Norway, this figure is about 2.3 tonnes.

For flow measurement, this can be challenging. Flow measurement is a vital aspect of hydrocarbon production, providing the means for well testing, process monitoring and production optimization, as well as the basis for fiscal and custody transfer measurement of hydrocarbons. Accuracy is paramount as even small measurement errors can amount to significant revenue loss.

Flow meters, like most types of process equipment have fundamental performance limitations making them susceptible to changing field conditions that occur as a reservoir matures. Over time, reservoirs that once produced almost exclusively hydrocarbons can gradually transition to a state where they produce almost exclusively water – in excess of 95% in some cases.

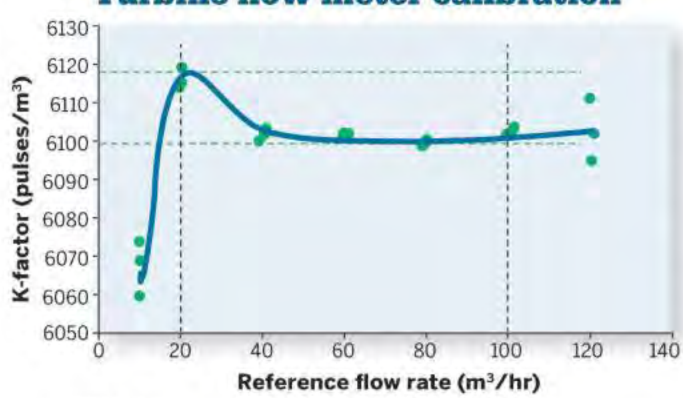
These large shifts in production rates impose a heavy burden on production equipment, which typically have a limited operating envelope and are increasingly pushed to perform under conditions they were not originally designed for.

This impacts flow measurement in a number of ways. Once of the most significant impacts comes from the diminished hydrocarbon production rate forcing meters to operate below their operating or calibrated range.

The range over which a flow meter can effectively operate, known as 'Turndown,' is the ratio of the maximum to minimum flow rate over which the flow meter can perform. This is sometimes also referred to as 'Rangeability.' Different types of flow meter typically have different turndown ranges depending upon their fundamental principle of operation.

Let's consider the humble turbine flow meter as an example. Turbine flow meters, if implemented correctly, can be extremely accurate, and are frequently used in fiscal applications where accuracy is vital. However, like most flow meters, they have a limited turndown and care must be taken in selecting the correct meter or range of meters for a given application. The graph shows a typical calibration curve for a turbine flow meter.

Turbine flow meter calibration



Source: NEL.

Since the flow meter returns a pulse signal, which is proportional to the flow rate, the flow meter is calibrated in terms of the number of pulses per unit volume (K-Factor) of fluid, which flows through the flow meter. Intuitively, we might expect that the relationship between K-Factor and flow rate should be linear, however in reality we can see that this is not the case. The mechanics of the meter mean that there is a limited range of which this relationship is true. Out with these ranges, the behavior of the meter becomes significantly non-linear and more complex, generally resulting in lower accuracy. Flow meters are typically calibrated over this linear and 'predictable' flow range.

All meters exhibit this limitation in one way or another, however, depending upon the principle of operation, some meters have wider turndown than others. Differential pressure meters for instance, such as orifice plates or venturis, have a very low turndown of around 4:1, whereas some modern types such as ultrasonic meters can operate at turndown ranges of 200:1 or higher.

As reservoirs mature, dropping hydrocarbon rates typically force meters to operate at the bottom of their operating range, if not below, whereas produced water systems tend to operate at the high end of their operating range. In some cases, it is possible to characterize the behavior of a device below its defined operating range and thereby extend its capability – so long as the behavior of the device does not become significantly non-linear. In some cases, the only solution will be to either replace the flow meter or redesign the flow measurement system.

In addition to the operating range of the meter, another significant factor is phase contamination. As separation systems are pushed to operate at the extremes of their performance envelope, phase contamination becomes a serious risk. This can result in a mismeasurement of the hydrocarbon produced, but depending upon the meter type, can seriously affect its performance. Electromagnetic water meters for instance are affected by the presence of oil since oil is not conductive, and transit-time ultrasonic meters are seriously affected by the presence of small amounts of a secondary phase. Great care must be taken in understanding the performance limitations of the meter and the conditions in which it operates.

In addition to this, there are a number of other problems that can arise from changing field conditions. These include material erosion caused by increased sand loading, distorted, swirling or asymmetric flow profiles caused by upstream process equipment, or pipework resulting from system modifications and changes in fluid physical properties to name just a few. All of these factors must be monitored as they can have a detrimental effect on meter performance.

Since every application is unique, the solution to this problem is not always straight forward. A number of factors should be considered before selecting a course of action. In particular, accuracy requirements in addition to other relevant technical factors such as fluid properties, ideal turndown, contamination and operating conditions should be reviewed, and economic and human factors should be taken into account. In addition to which, manufacturers and regulators should be consulted and appropriate standards observed. **OE**

Neil Bowman *is a project engineer at NEL, a provider of technical consultancy, research, testing and program management services. He has a Master's degree (MEng) in Aero-Mechanical Engineering from the University of Strathclyde and is a Chartered Engineer and a Member of the Institution of Mechanical Engineers.*

Filling in the gaps

Photo from iStock

While automation has begun to be slowly implemented offshore, it's going to take a full business transformation to get IoT and other technologies fully implemented.

Karen Boman reports.

The industrial Internet of Things (IIoT) could help oil and gas companies make production operations more efficient through new automated practices. Predictive maintenance, for example, can monitor equipment condition, making maintenance decisions more predictive versus rule-based.

IoT is about marrying industrial controls with the business supply chain, says Rob Wade, senior director of Oil & Gas and Utilities for North America with Atos. Ultimately, ending up with a better decision-making process.

Atos and Siemens have teamed up to offer Atos' Codex analytics engine on Siemens' technology platform Mindsphere, to provide IoT solutions for oil and gas customers.

The implementation of IoT in offshore production is not about replacing current technologies, but filling in the gaps, says Dave McCarthy, senior director of products with BSquare. The firm has been working with original equipment manufacturers (OEMs) and producers to make offshore production operations more efficient.

McCarthy says that BSquare has seen deployments in the Gulf of Mexico of SaaS (Software as a Service) IoT solutions to connect devices, allowing the operator to monitor and improve the performance of the parts and equipment it manufactures. Namely, the operator can visualize processed telematics data to rate performance, track historical trends, monitor device health, and make operating system updates to increase overall device and part lifespans and the production window between required maintenance.

Business case

According to Baker Hughes, a GE company (BHGE), offshore oil and gas organizations rack up an average of

Industry is starting to explore Industrial IoT for automation.
Photo from iStock.

US$38 million annually due to unplanned downtime. For the worst performers the negative financial impact can be upwards of $88 million. But, the effective use of digital technologies such as IoT could reduce capital expenditure by as much as 20% and cut upstream operating costs by 3-5%, according to consultancy firm McKinsey & Co.

Even marginal gains in volume have a transformative effect on operational financials, BHGE says. The company estimates that the industrial internet will bring productivity gains amounting to approximately $8.6 trillion for industrial companies during the next decade – more than two times the future value of the consumer internet alone.

However, fewer than 24% of operators describe their maintenance approach as a predictive one based on data and analytics. Over three-quarters either take a reactive or time-based approach, says BHGE. The company found that operators using a predictive, data-based approach experience 36% less unplanned downtime than those with a reactive approach. This can result in $34 million in savings.

Health, safety and environmental issues is another reason oil and gas companies are looking at IoT. Automation means fewer workers are needed on an offshore platform, reducing the risk of safety incidents, Wade says.

Industry initially was slow to adopt IoT, either because they viewed the technology as expensive, or because they preferred existing practices. Now, companies are telling OEMs that they need to understand more of what's going on with their systems, and they can't just walk the platform and check systems manually. To meet this demand, OEMs are retrofitting existing equipment for IoT capabilities, or designing IoT capabilities into new equipment, McCarthy says.

Oil and gas companies also are looking to measure and normalize performance across different equipment. IoT can create a baseline of what desired and optimal performance is, and not just measure variances, but determine what is influencing performance and remediation solutions. "The common scenario is that two pieces of equipment are configured and engineered the same, but get different operational performances. That drives these guys crazy because they want to know how they can get specific results and help different parts of their business," McCarthy says.

Standardization of data format and equipment present challenges in bringing data from multiple sources together. It's not just about equipment data, but additional information such as maintenance schedules, warranty information, and factory equipment configurations. The good news is that software can take data in different languages from different machines and transform it into usable insight, McCarthy adds.

Siemens and Atos are involved in pilot projects with several companies worldwide for IoT in production efficiency, Wade says. "If this was a baseball game, we would be in the third of nine innings," Wade says of the pilot projects. "We still have a way to go."

New business architecture needed

Oil and gas companies will need to rethink their business architecture to take full advantage of the benefits of IoT technology. Resetting architecture requires a new mindset of understanding how Industrial IoT can impact business, said Trond Ellefson, former special advisor for digital transformation and strategy with Statoil, and CEO of Houston-based digital technology firm Invatare.ai, at the Internet of Things Oil and Gas Conference, which took place in September in Houston.

The right business strategy also is needed. "In the early days of IoT, you would see an initiative like this would be assigned either to someone on the operational side, or to an automation engineer, or on the IT side," McCarthy says. As a result, these forays into IoT would become lab experiments that never see the light of day. Now companies are understanding they need a dedicated team to bridge IT and OT, and the right skill sets.

Oil and gas majors, independents, and service providers are doing smart things in terms of digitalization. But they are attacking digitalization from a functional silo perspective, instead of the needed holistic approach, Ellefson said.

"Most of the [oil and gas] companies are focused on solving the artificial lift problem," Ellefson explained. "They are looking at very narrow things, and there is nobody looking at the global perspective of things."

The pace of digital transformation is fast enough that fast companies will eat slow companies, and incremental changes – the historical method used by industry and taught in universities – will not be enough, Ellefson said.

What's holding back IoT?

While IoT can enhance automation, three factors are holding back the implementation of IoT. First is that new technologies and operating methods present increased risk – some real and some perceived – until they are proven and accepted, says Joseph Perino, president and CEO of consulting firm PERTEX.

"Second, while automation is mature, IIoT, along with Big Data and analytics (BD&A) are not, and so the industry is moving slowly," Perino explains.

Third, IIoT + BD&A can impact the organization such that people may feel threatened, Perino says.

"For example, let say with IIoT and BD&A one needs 20% less OT and IT people per asset, and the skills sets of the remaining OT/IT staff must change to learn the new technologies, but a benefit may mean that the asset can add more engineers to analyze and manage the wells and production facilities, thereby resulting in a net benefit to the operator," says Perino. "All this is a big change management challenge, and not everyone wants to tackle this. High oil prices helped companies resist this change but now with $50/bbl oil, it's coming one way or the other."

While companies are starting to explore digital technology, some are having a hard time seeing how IoT can impact their business. Those that are testing the technology are not yet ready to share results. Technical executives also are still having a hard time getting buy-in from upper management, Perino says.

Some fields already have been fully automated via subsea technology in the Barents Sea, offshore Norway. Automation also exists on platforms offshore West Africa and Brazil. But in the Gulf of Mexico, a strong cultural bias still exists in some areas to have a human being on the platform making the final decisions, says Jim Crompton, head of Reflections Data Consulting.

Two years ago, a study conducted by the National Academy of Sciences Transportation and Safety Board found that, while major Gulf of Mexico operators agreed that automation technology works, companies still want a human being making the final decisions and on site when possible. Crompton says this reluctance to completely automate platforms is why few examples of automation in production, other than subsea, are available.

Capable technology is available to fully automate processes, but upstream largely has been a reluctant adopter of full automation. One exception is during hurricane season. When a hurricane blows through, companies can evacuate all their offshore workers before the storm arrives, and production will shut automatically, Crompton says.

The mindset against complete automation will eventually change as the younger generation of workers enters the oil and gas industry, both Crompton and Perino say. The industry will have to change if it wants to attract and retain these workers.

"Millennials don't want to work for what they perceive are technologically backward companies," Perino explains. OE

East & South Africa

A new Qatar?

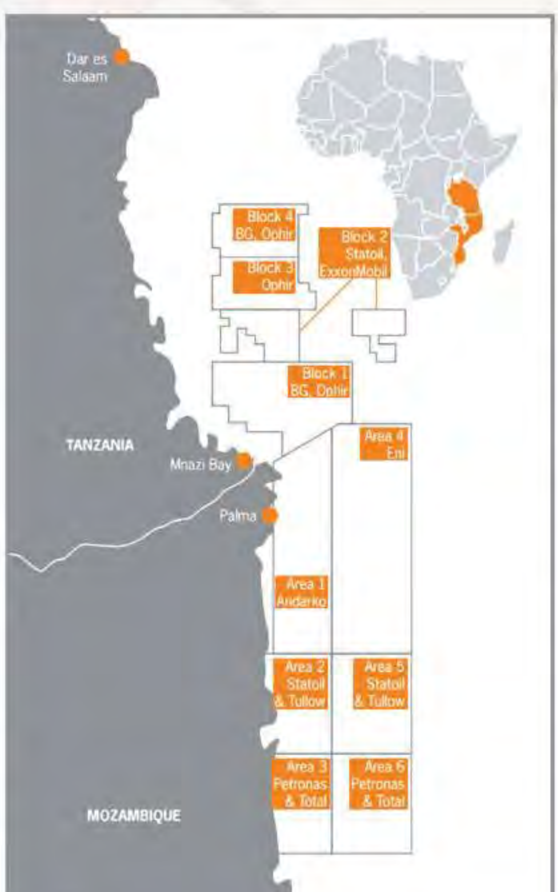
With the entry of ExxonMobil, East Africa has entered the gas business for the long term. Can South Africa catch up? EIC's Andrew Scutter sets the scene.

Over the last decade, recent oil and gas discoveries across East Africa have made the region a key frontier for hydrocarbon exploration. Prospective projects could spell billions of dollars in government revenue which, if managed responsibly, could finance a much-needed overhaul of infrastructure and social services, ultimately transforming the region.

Offshore there have been world-class discoveries of gas made in Tanzania and Mozambique. While it has not yet made the same scale of discoveries as other countries in the region, South Africa is one of the most anticipated hotspots for oil and gas exploration in the continent.

In 2010, BG Group made significant gas finds offshore Tanzania, which took the country's estimated natural gas reserves up to 57 Tcf. The hype which followed these discoveries has tapered off somewhat. The plan, for now, is to construct an LNG plant with a 10 MTPA of gas processing capacity. The plant is scheduled to be up and running by 2025. However, fiscal and regulatory uncertainties, low gas prices and higher exploration and production costs compared to neighboring Mozambique, has led to delays and a loss of momentum in Tanzania.

On the other hand, Mozambique's developments are moving at a much faster pace. Like Tanzania, much of Mozambique's reserves were discovered in the past decade and amount to more than 150 Tcf of natural gas reserves. Anadarko and Eni are the two key players in the country, both having made significant offshore gas discoveries and subsequently proposed major LNG facilities. The Coral FLNG project was the first of these to take final investment decision (FID). In June, Eni announced that a joint venture of TechnipFMC, JGC and Samsung Heavy Industries will be the engineering, procurement and construction (EPC) contractor for the project. Tendering for detailed engineering is also underway for Eni's sizable 10 MTPA onshore LNG facility, which, like Coral, will be fed by gas from the Area 4 gas discoveries.



Map from EIC.

The recent farm-in of ExxonMobil into Eni's Area 4 has made the market much more attractive to potential investors. The supermajor, renowned for planning decades into the future, views Mozambique as the new Qatar.

South Africa

After demonstrating Mozambique and Tanzania's hydrocarbon potential, the industry is now hoping to uncover the potential of South Africa. Many companies, including majors ExxonMobil and Total, have acquired rights to explore offshore South Africa. Recent improvements in exploration technology, coupled with the need for South Africa to diversify its energy mix has seen increased interest in exploration activity, with 20 exploration licenses issued.

The requisites for a successful offshore oil land gas industry differ between East Africa and South Africa. While Mozambique and Tanzania have proven significant reserves, their biggest hindrance is the lack of infrastructure and skilled work force. South Africa, on the other hand, has the basic infrastructure and skills required, but is yet to make major finds. **OE**

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

South African moves

Early September, Statoil completed a deal with ExxonMobil E&P South Africa to acquire a 35% interest in exploration right 12/3/252 Transkei-Algoa.

Operator ExxonMobil retains 40% interest, while Impact Africa holds 25%. The license covers approximately 45,000sq km in water depths up to 3000m.

Statoil also completed a transaction with OK Energy, acquiring 90% interest and operatorship in the exploration right 12/3/257 East Algoa. The remaining 10% interest is held by OK Energy. The license covers approximately 9300sq km.

Statoil entered its first license in South Africa in 2015, acquiring a 35% interest in the ExxonMobil-operated Tugela South exploration right.

Meanwhile, Total E&P South Africa agreed to a contract with Odfjell to drill one well plus one optional well using the 6th generation semisubmersible *Deepsea Stavanger* offshore South Africa, starting between June 2018 and April 2019.

Total operates offshore Block 11B/12B, with 50% interest, 175km offshore in 200-1800m water depth. The block covers about 19,000sq km.

Total also holds a technical cooperation permit (100%, operator) covering 76,000sq km in the Outeniqua Block, in 400-4000m water depth.

Total tried to drill the Brulpadda-1 exploration well in Blocks 11B/12B in late-2014 (a well that was aimed at testing a new deepwater play), but didn't reach total depth due to mechanical issues on the rig. Total had also been lining up drilling on the Paddavissie structure in 11B/12B in 2017. CNR International had previously, when operator of the block, given 3 billion bbl initially in place for Paddavissie. ▪

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a. Total number of copies	20,993	17,895
b. Legitimate paid and/or requested distribution:		
1. Outside county paid/requested mail subscriptions stated on PS Form 3541	12,432	12,463
2. In county paid/requested subscriptions stated on Form 3541	0	0
3. Sales through dealers and carriers, street vendors, counter sales and other paid or requested distribution outside USPS	0	0
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c. Total paid and/or requested circulation	15,899	15,201
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1. Outside county nonrequested copies stated on Form 3541	2,921	1,369
2. In county nonrequested copies stated on Form 3541	0	0
3. Nonrequested copies distributed through the USPS by other classes of mail	0	0
4. Nonrequested copies distributed outside the mail	1,335	820
e. Total nonrequested distribution	4,256	2,189
f. Total distribution	20,155	17,390
g. Copies not distributed	835	505
h. Total	20,990	17,895
i. Percent paid and/or requested circulation	78.9%	87.4%
16. Electronic copy circulation		
a. Requested and paid electronic copies	19,478	20,504
b. Total requested and paid print copies + requested/paid electronic copies	35,377	35,705
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d. Percent paid and/or requested circulation (both print & electronic copies)	89.2%	94.2%

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Audrey Leon, Editor

Date: 09/30/2017

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Solutions


Photo courtesy of Schlumberger.

Schlumberger debuts GROVE IST ball valve

Schlumberger has introduced the GROVE IST integrated seat technology ball valve, which features a patented seat-on-ball design that significantly improves performance over conventional metal-seated ball valves in addition to offering considerable size and weight benefits.

Conventional ball valves tend to become larger in size and weight as oil and gas companies explore harsher environments. Schlumberger says the GROVE IST ball valve overcomes these conditions with its new seat design that provides advanced sealing performance and increased valve life span while minimizing size and weight, enabling customers to reduce total cost of ownership.

The GROVE IST ball valve has undergone an extensive qualification test program that qualifies the full product range to API 6A PR2 for performance, API 6AV1 for slurry testing and API 607/6FA for fire testing. In addition, in-line flow testing validation was performed at an independent, accredited testing facility to further simulate real operating conditions. www.slb.com

Add, Trendsetter develop RWIS Lite

Add Energy and Trendsetter Engineering have developed the Relief Well Injection Spool (RWIS) Lite, designed to reduce the complexity of relief well operations on a global scale when coupled with the original RWIS product. RWIS Lite is a flow spool without controls, allowing operators to install blowout preventers (BOPs) above the spool, greatly reducing the complexity of hooking up kill vessels to the system. This enhancement excludes gate valves, accumulators, ROV panels and a BOP, reducing the complexity of the subsea hardware configuration. In addition, the deployment method is a duplicate of the original set up of the RWIS, so it can be run off a vessel of opportunity or a mobile offshore drilling unit using either a drill pipe or wireline. **www.trendsetterengineering.com**

Archer launches new SPACE services

Archer introduced a new generation of SPACE ultrasound imaging and measurement services, which apply ultrasonic techniques, such as phased-array beam-forming to enable true spatial understanding of the downhole environment.

The service, SPACE Vernier, is designed to maximize well life by measuring the internal and external dimensions of the entire wellbore to generate statistical analysis of localized damage and systemic corrosion. The technology features a no contact design, which eliminates the risk of damage to the well tubing.

As part of the launch, Archer has released a rebrand and technical upgrade of its original SPACE technology. SPACE Focus (formerly Forward Viewer) can now operate in temperatures of up to 135°C and pressures of up to 7250 psi. SPACE Panorama (formerly Azimuthal Viewer) is now suitable for 150°C and 15,000 psi environments and is also available in a 2 1/8in size, making it suitable for a wider range of downhole applications. **www.archerwell.com**

New HPHT coating for subsea choke valves

Hardide Coatings and Master Flo Valve (MFV) developed a new solution to protect high pressure, high temperature (HPHT) subsea choke valves. The companies say the valves are the first of their kind to feature the Hardide-T coating, which can be applied to choke valve stems so they can withstand temperatures up to 400°F and pressures of 20,000 psi.

The coating has been applied to MFV's P4-15K choke valve, which is rated from -20°F to 400°F and 15,000psi, and the P4-20K choke valve, which is rated to the same temperatures but a greater pressure of 20,000psi. They are typically installed on subsea production trees and are used for single/multiphase production or water/chemical/gas injection. There is also an application for use on a capping stack, designed to be deployed in the event of a blowout situation. **www.hardide.com**

End of an era

After nearly 40 years' service, Heerema Marine Contractor's (HMC) heavy lift vessel *Hermod* is due to arrive at a Chinese yard to be recycled this month.

The vessel is being transported by Boskalis' Dockwise Vanguard heavy transport vessel, which is due to arrive at Zhoushan Changhong International Ship Recycling, late November, from Rotterdam.

Designed and constructed in the 1970s, *Hermod* and her sister vessel *Balder* were the first semisubmersible crane vessels of their kind in the offshore construction industry. After delivery by the Japanese Mitsui yard in 1978, *Hermod's* first job was the installation of the Piper A platform on the UK Continental Shelf.

The vessel executed its first project outside the North Sea in Brazil in the mid-1980s, followed by projects in the Gulf of Mexico, Southeast Asia and Africa.

Throughout its career, *Hermod* has worked in more than 25 countries and was involved in several "first-of" installation projects, including:

- *Hermod's* first dual crane topside lift, the L13 platform, in 1986.
- Installation of the first North Sea tension leg platform (TLP) (Hutton) jointly with *Balder* in 1984.
- Installation of the first deepwater foundation piles of the first TLP in the Gulf of Mexico (Auger) in 870m water depth in 1992.
- Installation of the Tombua Landana compliant tower foundation in Angola in 2008, comprising the world's largest single piece foundation piles (2.7m-diameter, 190m-long and weighing 850-tonne each).
- Removal of the first large platform in the UK: North West Hutton in 2008/09.
- The heaviest lift performed by *Hermod* was the Peregrino topside in Brazil in 2010, with a dry weight of 6287-tonne.

Hermod's last project was the installation of a transformer platform on the Borkum Riffgrund 2 wind farm in July this year.

HMC is constructing the world's largest semisubmersible crane vessel *Sleipnir* in Singapore. *Sleipnir* has a two, 10,000-tonne lifting capacity and is due to come into service in 2019.

Sleipnir will be outfitted with a dual fuel propulsion system, whereby in LNG mode, emissions will be substantially reduced. ▪

Hermod in 1979.

***Hermod's* last project: Jacket installation for a transformer platform for the Borkum Riffgrund 2 Windpark in July 2017.** Photos from Heerema Marine Contractors.

Participants sought for hydrates study

A joint industry project led by the University of Western Australia (UWA) and supported by the Industry Technology Facilitator and oil and gas industry partners is welcoming more participants for a 12-month study, 'Hydrate Deposit Growth in Subsea Jumpers (HyJump).' The study seeks to provide the industry with a better understanding of the mechanism of hydrate growth and blockages through development of a new 2in jumper test section on the Hytra flowloop, owned by Commonwealth Scientific and Industrial Research Organisation (CSIRO) and jointly operated by CSIRO and UWA, in Western Australia.

The results may be used to determine how a temporary or permanent reduction in hydrate management chemicals affects the risk of blockage over a variety of restart conditions. Results will also allow assessment of how low dosage hydrate inhibitors can prevent such blockages.

Emerson to acquire Paradigm

St. Louis-based technology and engineering firm Emerson will acquire Paradigm, a provider of oil and gas software solutions, for US$510 million. Paradigm, joined with Emerson's existing Roxar software business, will create a best-in-class, end-to-end exploration and production software portfolio with offerings spanning seismic processing and interpretation to production modeling, Emerson says. Paradigm's technology offerings will enable Emerson to better help oil and gas operators increase efficiency, reduce costs and improve return on investment.

Rovco to join NVIDIA program

UK-based subsea company Rovco has announced plans to take artificial intelligence (AI) to new depths after being selected to join the NVIDIA Inception Program. Designed to nurture start-ups that are revolutionizing industries with advances in AI and data science, the virtual incubator program supports members overcome critical stages of product development, prototyping, and deployment. Being selected by NVIDIA will see Rovco benefit from hardware grants, marketing support and training to aid the development of the firm's range of underwater robotics and subsea inspection techniques.

Editorial Index

What's next

Coming up in OE December

- **Feature –Year in Review**
- EPIC – FLNG
- Subsea – Subsea Technologies
- Production – Reservoir Management
- Drilling & Completions – Drilling Milestones
- Regional Overview – Year in Review

The Johan Sverdrup riser platform jacket being installed by *Thialf*. Photo: Jan Arne Wold/Statoil.

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NORTH AMERICA
Betsy Campbell
Phone: +1 713 874-2212
Mobile: +1 913 908-3102
bcampbell@atcomedia.com

UK/FRANCE/SPAIN/AUSTRIA/GERMANY/SCANDINAVIA/FINLAND
Brenda Homewood
Phone: +44 1622 297 123
Mobile: +44 774 370 4181
bhomewood@atcomedia.com

ITALY
Fabio Potesta
Media Point & Communications
Phone: +39 010 570-4948
Fax: +39 010 553-00885
info@mediapointsrl.it

NETHERLANDS
Arthur Schavemaker
Kenter & Co. BV
Phone: +31 547-275 005
Fax: +31 547-271 831
arthur@kenter.nl

ASIA PACIFIC
Audrey Raj
Phone: +65.9026.4084
araj@atcomedia.com


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