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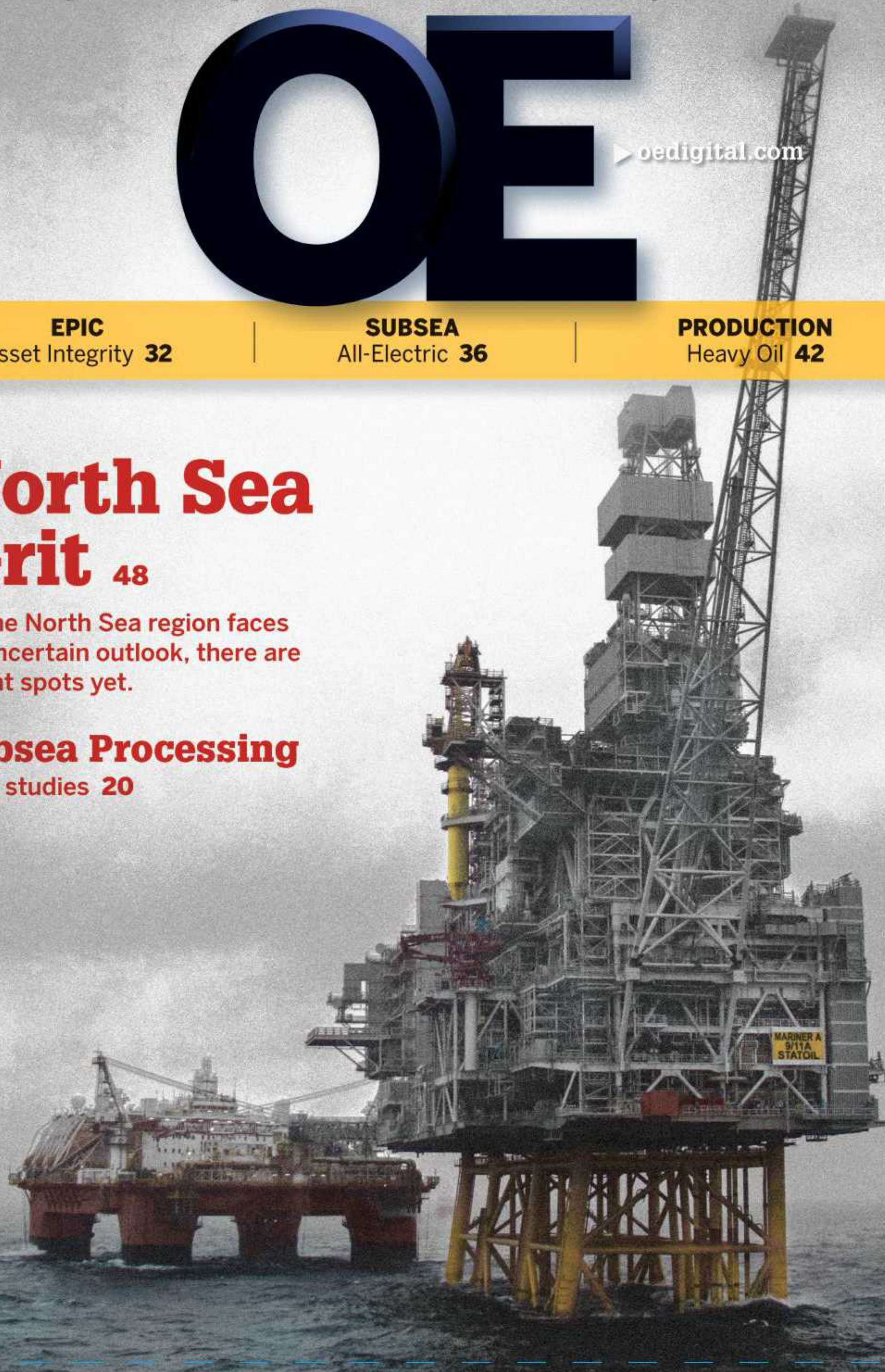

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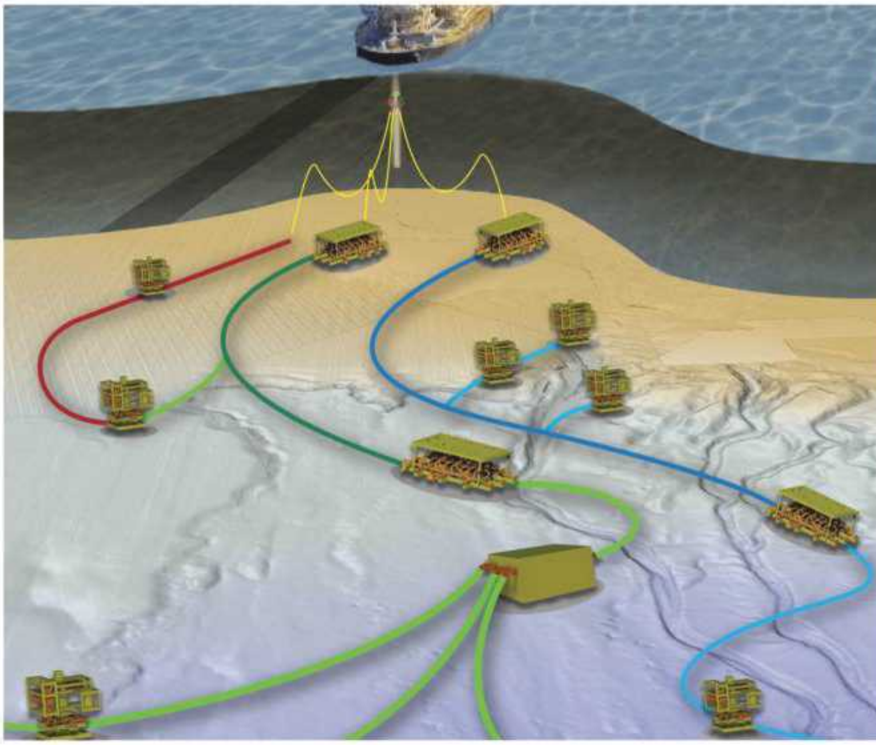

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New players are entering the aging North Sea basin, but there's still ambitions to increase exploration as well push forward with decommissioning. Andrew Scutter, of EIC, gives his view.

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With a new phase in Barents Sea developments on the way, plus strong drilling activity, the region is primed for growth. Espen Erlingsen, of Rystad, explains.

ON THE COVER

Unwavering. *OE* celebrates NW Europe's successes, such as the Mariner platform, now in place following heavy lift operations in July. See page 14 for more. *Photo illustration by OE art staff. Original image from Statoil/Jamie Baikie.*


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Online Exclusive

Pondering further Russian sanctions

As US lawmakers hit Russia with more sanctions, the domestic oil and gas industry is bracing for what potential impacts may come. Karen Boman reports on industry concerns.

What's trending?

Positive outlook

- BP starts up Juniper, Persephone
- Exxon ups Guyana estimates
- Dussafu reaches FID

People

Pacific Drilling CEO steps down

Pacific Drilling CEO Christian J. Beckett has stepped down from his positions as CEO and as a member of the board, after a 10-year tenure. Paul T. Reese, current Executive Vice President and CFO, will take his place.

Undercurrents

Capturing the North Sea legacy

According to latest figures from Oil & Gas UK, annual spending on decommissioning is expected to reach $2.5 billion (£2 billion) in 2017. In the past year, two major platforms have been removed from the basin – Shell's Brent Delta topsides, and most of CNR International's once 250m-high, 50,000-tonne Murchison platform – and the topic is set to be high on the agenda at this months' SPE Offshore Europe, in Aberdeen, which has a new Decommissioning Zone. *[**Ed. note:** OE is the publisher of the official Offshore Europe Show Daily. See us there at stand **3C180**!]*

It is a huge, awe-inspiring piece of work. But, once these facilities are removed, what will be left from which to create a lasting legacy of the economic success and technological innovation that makes the North Sea story one of the greatest in Britain's industrial history? How do we secure and store the records relating to these facilities in order to give future generations an insight into the massive endeavor involved in building, maintaining – and indeed removing – them.

CNR has been working with Capturing the Energy (CTE) to do just this. Murchison, which sat 120mi northeast of Shetland, ceased production in 2014, after more than 30 years and 400 MMbo production. It had a reputation as one of the friendliest places to work in the North Sea.

Now, some 40 boxes of paper documents – including safety cases, offshore diaries and log books, incident reports, and manuals for the platform's original installation – as well as dozens of photos and videos, plus the tens of thousands of drawings compiled as part of the decommissioning project, are all being transferred to the University of Aberdeen's Oil & Gas Archive. For some of it to have made the transition between the three operators that have owned Murchison is quite remarkable in itself.

"Decommissioning is a hugely significant phase when it comes to managing information, as it is the point at which much of it ceases to be in current business use," says Project Officer Joe Chapman. "CTE can preserve valuable records that might otherwise be destroyed. We can also help identify what information you have and how it can be managed more effectively."

Next in line, the Brent Bravo facility, during tow out before coming on stream in 1976. Image from Shell/Capturing the Energy.

OE supports the CTE project, as it seeks to celebrate and preserve the industry. The project is supported by funding from Oil & Gas UK, and it offers free expert advice and support to help companies understand what they should do with the large volumes and various types of information they possess.

To find out more, or get advice on what to do with all the drawings, reports, log books, meeting minutes and other documents relating to no longer producing assets, go to **www.capturing-the-energy.org.uk**. OE

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Global E&P Briefs

A Husky readies West White Rose

Husky Energy is moving ahead with plans for a fixed wellhead platform to develop the West White Rose project offshore Newfoundland and Labrador. Construction of the concrete gravity structure and associated drilling facilities, utilities, support services, and accommodations for personnel, is scheduled to begin Q4 2017. First oil is expected in 2022, with the project anticipated to achieve a gross peak production rate of approximately 75,000 b/d in 2025 as development wells are drilled and brought online.

B W&T to spud South Timbalier 224

W&T Offshore has secured the Enterprise Offshore 264 jackup rig to drill the South Timbalier Block 224 condensate prospect in the US Gulf of Mexico, in Q4, says partner Otto Energy. The prospect is in approximately 170ft of water, and lies within tieback distance to several existing production platforms. W&T has submitted the prospect's initial exploration plan to the US Bureau of Ocean Energy Management. Otto picked up 25% interest in the block back in July this year.

C Zama deep fails

Talos Energy failed to find further volumes after drilling a deeper target on the Zama-1 exploration well, offshore Mexico.

Zama-1 was drilled in 166m water depth, in Block 7 in the Sureste Basin, about 37mi (60km) off Tabasco, in the Mexican Gulf of Mexico, using the *Ensco 8503* semisubmersible. Talos previously said Zama contained an estimated 1.4-2 billion bbl. It has been described as one of the 20 largest shallow water finds in the past 20 years and the first private sector oil discovery in the country.

D ION shoots off Panama

ION Geophysical has begun a new 2D multiclient program offshore Panama, the first seismic survey to be acquired in 30 years. The PanamaSPAN survey will provide the framework to evaluate the hydrocarbon potential of this unexplored area ahead of the anticipated inaugural license round, ION said. Initial deliverables will be available in Q4 2017 and complete interpretation of the data will be available by mid-2018.

E Appomattox hull sets sail

The hull for Shell's Appomattox development set sail from Geoje, South Korea, to Ingleside, Texas, in early August, where construction will be completed. Shell says that the project remains on track to start producing oil by the end of the decade. Located in the Mississippi Canyon area in 7200ft (2195m) of water, the Appomattox development will initially produce from the Appomattox and Vicksburg fields. Shell has reduced project costs by 20% since Appomattox was sanctioned in 2015.

F ExxonMobil ups Payara estimates

ExxonMobil hit additional oil at a Payara appraisal well offshore Guyana, increasing the ultra-deepwater prospect's resources to about 500 MMboe and confirming the second giant field offshore Guyana.

The Payara-2 well encountered 18m (59ft) of high-quality oil-bearing sandstone after being drilled to 5812m (19,068ft) in 2135m (7000ft) water depth.

Payara-2 is about 20km (12mi) northwest of Liza in the Stabroek Block, 130mi offshore. Exxon says that these positive well results increase the estimated gross recoverable resource for the Stabroek Block to between 2.25 billion boe and 2.75 billion boe.

G Tullow Oil readies Araku

Tullow Oil plans to drill the high-impact Araku-1 well offshore Suriname in Q4 2017.

The Araku prospect is in Block 54 and is a large structural trap, which has a resource potential estimated at over 500 MMbbl.

Tullow Oil has hired the *Noble Bob Douglas* to drill the well, and expects Araku-1 to cost US$14 million net.

H Petrobras in Marlim Sul find

Petrobras encountered oil at the Poraquê Alto well, marking the company's first commercial oil discovery in the pre-salt layer of the Marlim Sul area offshore Rio de Janiero state, Brazil.

Poraquê Alto – also known as well 6-MLS-233-RJS – is 115km off the coast of Rio de Janeiro in the Campo de Marlim Sul area, in the Campos pre-salt basin, sitting at 1107m water depth.

The well reached a final depth of 4568m, where Petrobras says that current data indicates carbonate reservoirs with good porosity and permeability characteristics, about 420m deep and 45m thick with oil.

I Kosmos to spud Hippocampe

Kosmos Energy plans to drill the Hippocampe well in Block 8 offshore Mauritania at the end of August. The well is the start of a drilling program targeting high impact wells offshore Mauritania and Senegal.

The Hippocampe well will target Cenomanian and Albian age reservoirs charged by the Valanginian, Neocomian and potentially Albian sources. Both reservoir targets displayed very strong seismic attribute support for hydrocarbons, Kosmos says. The prospect has P-mean resource of over 2 billion boe or 12 Tcf of gas equivalent.

After Hippocampe, Kosmos plans to spud the Lamantin prospect in Q4, and then move to the Requin Tigre prospect in Senegal by year's end.

J Cygnus Bravo onstream

First gas was exported from Cygnus Bravo, a satellite to Engie E&P UK's Cygnus field development in the UK southern North Sea.

Cygnus Bravo is a wellhead platform 7km from Cygnus Alpha, from which gas is exported 150km to Bacton gas terminal, via the Esmond Transmission System. The overall Cygnus complex comprises four platforms and two subsea structures.

Bravo's first gas was delivered from well B5 in one of the platform's 10 well slots, out of 20 across the whole Cygnus complex. A further three Bravo wells are expected to come online with a total of five available in 2018.

L UKCS 30th round expands

The UK's Oil and Gas Authority (OGA) has added seven additional blocks to the 30th Offshore Licensing Round that was announced in late-July.

The new blocks are: 110/5, 110/10, 110/16, 110/18, 113/24, 113/29, and 113/30. The new acreage adds to the 813 blocks or part blocks on offer in mature areas of the UK Continental Shelf (UKCS), covering a total 114,426sq km.

Blocks on offer are in the southern, central and northern North Sea, the West of Shetland and East Irish Sea, featuring a large inventory of prospects and undeveloped discoveries.

Companies will be able to bid on the area come 21 November 2017. Decisions are expected in Q2 2018.

M BP: Zohr online soon

Supermajor BP announced in its Q2 2017 earnings call

K Byrding online

Statoil and its partners have started production from the US$126 million (NOK 1 billion) Byrding field in the Norwegian North Sea. The project cost is down from the original estimate of $440 million (NOK 3.5 billion).

Byrding is an 11 MMboe recoverable field north of the Troll field. The Byrding development includes a two-branch multilateral well drilled from the existing Fram H-Nord subsea template, through which oil and gas are flowing to Troll C.

The multilateral well is around 7km-long and is split in two branches after a few kilometers. After processing on Troll C, the oil is routed in existing pipelines to Mongstad and the gas via Troll A to Kollsnes.

Licensees in Byrding are Statoil Petroleum (70%, operator), Engie E&P Norge

(15%) and Idemitsu Petroleum Norge (15%).

Global E&P Briefs

that the Eni-operated Zohr project, offshore Egypt, is scheduled to be online by year's end. The project was originally scheduled to come online in 2018.

Zohr is in the Mediterranean Sea in the Shorouk concession, about 120mi north of Port Said in some 4900ft water depth. The giant field is estimated to hold approximately 30 Tcf of gas.

Also offshore Egypt, BP said the Atoll field could potentially come online this year.

N BD production starts

Joint operator Husky-CNOOC Madura has started first production from the BD gas field offshore Indonesia. BD, in the Madura Strait at 55m of water, is being produced via an unmanned wellhead platform, a floating production, storage and offloading vessel and four production wells.

The gas field has two wells in production and its gas and condensate sales production is approximately 7200 boe/d. The gas field is expected to reach its designed peak production of about 25,500 boe/d in 2018. Husky-CNOOC Madura operate the production sharing contract for the BD gas field each with 40% interest. Samudra Energy holds the remaining 20%.

O Woodside triples Myanmar success

Woodside marked its third gas discovery offshore Myanmar by intersecting a 65m gross gas column in the Pyi Thit-1 exploration well in Block A-6 in the Southern Rakhine Basin off Myanmar. A 36m net gas pay interval also was interpreted within the primary target sandstone reservoir.

The Pyi Thit-1 well was spudded in June and drilled to a total depth of 4570m. Following drilling, wireline logging confirmed the presence of a gas column through pressure measurements and gas sampling. A drill stem test was performed across a 29m section of the reservoir and flowed at ~50 MMscf/d on a 44/64in choke over 44 hours with strong reservoir pressure support.

The gas discovery at Pyi Thit-1 follows previous finds made by Woodside at the Shwe Yee Htun-1 well in Block A-6, and the Thalin-1A well in Block AD-7.

P Gippsland reprocessing underway

CGG began its Gippsland ReGeneration 3D reprocessing project in Australia's premier Gippsland Basin, offshore southeast Australia.

Historically, imaging the Gippsland Basin's shelf break and numerous submarine channels has proven extremely challenging. CGG says that it will apply its latest high-end technology and workflows, including advanced de-multiple and high-frequency FWI, to delivery "significant" reservoir imaging improvements, to reveal new potential deep reservoir targets and extensively improve understanding of the basin.

To date, the Gippsland Basin has produced over 4 billion bbl and 7 Tcf of gas, sourced from thick coal seams formed during the Paleocene to Eocene, and trapped in late Tertiary, inversion-formed, compressional structures.

Contracts

JV wins West White Rose work

Husky Energy has awarded the partnership of SNC-Lavalin, Dragados Canada, and Pennecon a construction contract for the company's West White Rose Project offshore Newfoundland and Labrador.

The JV will build a concrete gravity structure (CGS) for a fixed drilling platform. The CGS, with an overall height of 145m and base diameter of 122m, will require 76,000cu m of concrete in its construction, which will take place in a purpose built dry dock from 2017 to 2021. Once completed and installed in the White Rose field, the CGS will support a topside module to enable drilling and oil extraction 350km away from the coast of Newfoundland.

Topaz to supply vessels for Dragon

Caspian Sea-focused Dragon Oil has awarded a US$100 million contract to offshore support vessel (OSV) firm Topaz Energy and Marine for use of six vessels.

Topaz will supply Dragon Oil Turkmenistan with five anchor-handlers and one emergency recovery and response vessel. The contract has already started with vessel mobilization and operation ramp-up under way. The contract is scheduled for a five-year term with a two-year option and brings Topaz's market leading revenue backlog above $1.5 billion.

Simmons Edeco to support Maersk

Maersk Oil awarded Simmons Edeco a contract to provide scheduled and unscheduled wellhead maintenance services for all Maersk Oil offshore wells in the Danish North Sea. Simmons Edeco will also refurbish valves and wellhead maintenance equipment, and manage major and consignment stock.

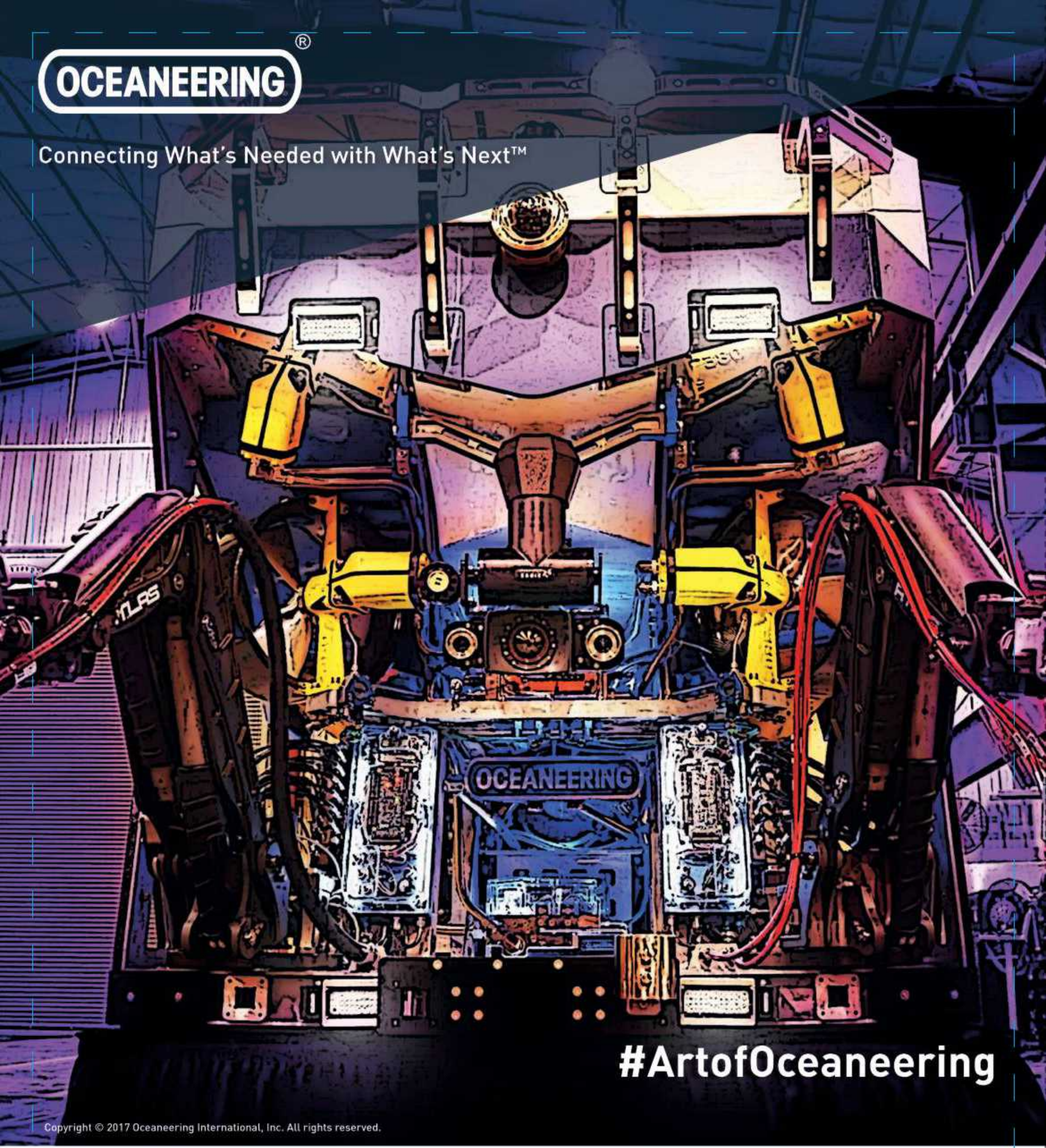
The five-year contract, which began on 1 June 2017, features three one-year options to renew. Simmons Edeco is supporting the contract from its new operations base in Esbjerg, Denmark, home to Maersk Oil's Danish business unit.

Total awards Moho Nord crane gig

Total E&P Congo awarded Sparrows Group and SPIE Oil & Gas Services a crane maintenance contract on the Moho Nord development, offshore West Africa, in the duo's first joint delivery project.

The scope of the work covers maintenance, inspection and testing services on five pedestal cranes on the development's *Likouf* floating production unit and tension leg platform (TLP) over three years.

Scheduled to start in Q3 2017, the project will be managed locally by SPIE, while Sparrows will deliver expert specialist technical personnel.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Progressing Mariner

Offshore heavy lift installation work is complete, and hook-up and commissioning work has started on Statoil's Mariner heavy oil field. Elaine Maslin reports on progress, including work optimizing the field's 100+ wells scope.

Over July, Statoil's US$7 billion Mariner heavy oil development took a major step forward. After travelling across the world on five Dockwise heavy transport vessels, the Mariner A platform's nine modules were installed on the Mariner A jacket using the *Saipem 7000* crane vessel, about 150km east of Shetland on the UK Continental Shelf (UKCS).

The *Safe Boreas* flotel then moved alongside to support some 480 of the up to 750 staff that will be working on the 38,000-tonne platform hook up and commissioning project over the next year or so, leading up to first production in 2H 2018, with storage and offloading by the Mariner B floating storage unit.

Mariner has been a long time coming, says Vidar Nygadr Karlsen, completion manager, who has spent the past two years overseeing the facilities construction in South Korea.

"We say this is the awakening of the giant field," adds Uno Holm Rognli, project director for Statoil.

Mariner was discovered in 1981 and had 18 wells drilled on it already when Statoil took over the Mariner license in 2007. Statoil drilled its first well on the field last year. But, the firm spent a lot of time maturing the development, Rognli says. New seismic, from 2012, played a key role in unlocking the field's reserves, helping Statoil to map their location and extent. "That made it possible to see where the oil was for us to have a good plan to develop the field," he says.

The nature of the sandy, heavy oil reservoir will mean Mariner A will, for many years to come, be an intense factory, with more than 100 wells planned, from a jackup rig, the Noble Lloyd Noble, and a platform-based rig, supported by a well completion and workover deck, on Mariner A.

It's a learning process, Rognli says. One challenge is drilling through the sandy reservoir. Here, Statoil is refining setting depth and mud weights, in order to maintain formation integrity, and will also be looking at casing sizes and completions solutions, Rognli says.

All wells will have electric

Statoil's 38,000-tonne topsides installed.
Photos from Statoil/Jamie Baikie.

Installation work using the Saipem 7000.

submersible pumps (ESPs). Here, Statoil will be applying learnings about the life of ESPs from the Peregrino heavy oil field offshore Brazil (*see page 44*).

The first wells will have gravel packs, but Statoil will be testing where it can emit their use. Similarly, inflow well control will be used on four of the first six wells, with two wells to be left without, so that Statoil is able to compare results. "It's a balance. The more wells we drill the more information we get and then we can make better decisions," Rognli says. "We can switch to autonomous inflow control devices if we believe they can get us more oil. But, we want some production history. We have time to change things and implement new technology."

By the start of the heavy lift campaign, in early July, two wells had been completed and two partly drilled. Another well is expected to be completed before first oil. Statoil is using geosteering and deep resistivity tools, which can help the well path track the roof of the reservoir as close as possible. "That's proven quite successful," Rognli says.

Mariner will produce from two reservoirs, Maureen and Heimdal. Statoil is drilling Maureen first, with Heimdal coming after a year or so. On Heimdal, because less was known about the reservoir, the initial plan was to cover the field with a wells grid, accepting that some wells might miss, like in onshore drilling. "Since we got new seismic, we have a better understanding of the targets and we can do horizontal drilling," Rognli adds. Water management will be another significant factor for Mariner, with water production and injection.

Another nearby project to Mariner, the Bressay heavy oil field, had been due to follow Mariner, but has since been parked. "Bressay [is] even more complicated and difficult than Mariner," Rognli says, of why Statoil put the field on hold. Statoil wants to learn more about Mariner, which has taken on learnings from Grane, in Norway, and Peregrino, in Brazil, before tackling Bressay, he says. "We hope we can do something with Bressay, but we do not know," he says. "We have to look at the concept. We are sort of starting from scratch."

But, there could be more investment in Mariner yet. One of Statoil's three planned exploration wells in the UKCS this year will be in the Mariner area. Statoil is also drilling an appraisal well on southeast Mariner, using the Noble Lloyd Noble jackup. This could help prove up further reserves and may result in more investment.

"The problem with heavy oil is that it is difficult to do a subsea tieback, it would probably have to be a wellhead platform and some sort of processing before being sent back [to Mariner]. We want to drill two wells to see what we have. The potential development of southeast Mariner depends on how much we find."

Production from 3-5 wells is due to start on Mariner in 2H 2018, via the Mariner B floating storage unit, which is already on station. It will both export the oil via a shuttle tanker, but also import diluent, for use mobilizing the heavy Mariner oil.

Once on plateau, the field will produce 55,000 boe/d, with an aim to produce at least 250 MMboe of the 2 billion boe in place over its life time. That could be increased over the life time of the field as new technologies are developed. **OE**

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In-Depth

Lebanon – Ready, set, go?

Lebanon views its potential offshore gas resources as key to meeting its domestic energy demand. However, current conflicts may keep Lebanon's offshore oil and gas industry off the starting block. Karen Boman reports.

Lebanon hopes bidding activity in its first offshore licensing round will result in the nation's first offshore commercial discovery by 2019, Lebanon's Minister of Energy and Water Cesar Abi Khalil told a July roadshow presentation in Houston.

After repeated delays (*OE*: November 2015), caused by political instability, Lebanon finally launched its first offshore oil and gas licensing round this year.

The country needs its own resources to meet domestic demand for electricity production, and to fuel energy-intensive industries such as cement production, Khalil says.

By 2030, Lebanese natural gas demand is expected to range between 0.3 Tcf and 0.5 Tcf/year. While the country's electricity sector and industrial hubs will present short- and medium-term demand for Lebanon, long-term potential exists for natural gas to power Lebanon's commercial institutions, cities, and transportation, Khalil says. Using gas could also reduce Lebanon's electric generation costs and reduce greenhouse gas emissions, he adds.

A total of 51 oil and gas companies are pre-qualified for Lebanon's first offshore bidding round, bids for which are due by 15 September, Khalil says. The 51 companies include those pre-qualified for the planned, but delayed, 2013 bidding round, provided they still meet eligibility standards.

A further 10 submissions were made this year, including two as operators and eight as non-operating companies. These companies include ONGC Videsh as an operator, and Lukoil, Sapurakencana Energy, Sonatrach International Petroleum, Qatar Petroleum International, Petropars Ltd., JSC Novatek, and New Age (African Global Energy), as non-operators.

Lebanon plans to publish the list of bidders on 22 September, and to award blocks on 15 November.

Five offshore blocks – 1, 4, 8, 9 and 10 – are being offered. Lebanon plans to award no more than four blocks in the round, but even if only one block is awarded, the round will still be considered a success, Khalil says. Block 1 is in the far northwest of Lebanon's maritime waters, in 1500m-2000m depth. The block is part of the Cypriot arc in the north, and is highly prone to gas and oil. Block 4 lies on the shallower side of Lebanon's offshore waters, and is highly prone to gas. The three southern blocks, 8, 9 and 10, are prone to oil.

Initial exploration and production agreements (EPA), signed with the Lebanese government, will have an initial five-year exploration phase, which can be extended up to 10 years.

Development projects would be subject to a 25-year production requirement, with a five-year extension option, if additional investments are made. Royalty payments equal to 4% of gas production, and 5-12% for oil production are included in the EPA.

Belief in prospectivity

To date, only a handful of wells have been drilled onshore Lebanon (the last was in 1966), with little success, and no wells have been drilled offshore, says Sarah Haggas, director – Middle East, Energy with IHSMarkit.

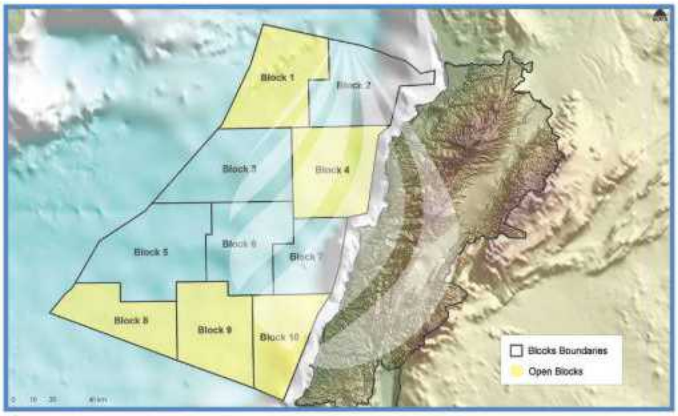
Previously, the Levant Basin had been underexplored due to high costs associated with deepwater exploration and production and lack of offshore infrastructure. Declines in deepwater exploration and production costs and recent large gas discoveries offshore Israel have changed that, Haggas says, driving investment in 2D and 3D seismic data acquisition.

Levant basin natural gas discoveries

Year	Discovery	Operator	Country	Gas Resource Estimate
2009	Tamar	Noble Energy	Israel	10 Tcf
2010	Leviathan	Noble Energy	Israel	22 Tcf
2011	Aphrodite	Noble Energy	Cyprus	4 Tcf
2013	Karish, Tanin	Energean	Israel	2.7 Tcf
2015	Zohr	Eni	Egypt	30 Tcf

Source: Lebanese Petroleum Administration

Image from iStock.



Open blocks for the first licensing round.

Offshore Lebanon offers both proven and new concept exploration plays, said Wissam E. Chbat, chairman of the board and head of geology and geophysics for the LPA, during the Houston road show. Two new play concepts are Late Cretaceous 4-way dip closures, sourced by Jurassic thermogenic source rocks and Oligo-Miocene biogenic gas, and Oligo-Miocene 3-way dip closures and tilted fault blocks, sourced by Oligocene-biogenic gas. In terms of stratigraphic plays available offshore Lebanon, new play concepts include Lower Cretaceous sand pinchouts, sourced by Triassic and Jurassic thermogenic source rocks, and Oligocene and Miocene pinchouts, sourced by Oligo-Miocene biogenic gas.

"The number of companies that have prequalified for the Lebanon reflects the prospectivity of Lebanon's unproven oil industry," Haggas says. This is due to analogs from offshore Israel and the large discoveries there. Until a prospect is drilled off Lebanon, however, it's hard to say how an industry in its infancy will develop, Haggas says.

Most production from the Levant basin has been mainly biogenic, or bacterially generated natural gas, but there is speculation that an oil leg may exist at a deeper depth, Haggas adds. The dynamic of the region could change if operators succeed in producing condensate and oil from the Mediterranean, says Bas Percival, senior analyst with Wood Mackenzie's MENA upstream research team. Some companies such as Noble Energy are testing the deeper Jurassic horizons for oil.

Noble Energy drilled a test well, targeting oil, offshore Israel in 2012, but was not successful due to casing design. Oil prices in 2015 were hurting companies, but Wood Mackenzie thinks that Noble and others will return to take a second look at condensate and oil. Finding oil could draw a whole new set of companies, including American midcaps, but the oil play needs to be proven up, Percival says.

Ready for bidding?

Chbat says that the Lebanese government has taken several steps to increase transparency in the bidding process, including joining Extractive Industries Transparency Initiative, as well as seeking international assistance to develop its bidding round and fiscal terms, Chbat says. But, the process may need fine tuning, given that an offshore round hasn't been done before.

A new petroleum law, with 20% corporate income tax and 10% dividend withholding tax, is due to be ratified in August, he says. It includes various tax exemptions for operators relating to offshore construction, installations and vehicles, as well as goods and equipment.

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)	75	57	35	15
Deep (500-1500m)	30	18	12	2
Ultradeep (>1500m)	12	11	10	4
Total	117	86	57	21
January 2017	127	114	72	-
date comparison	-10	-28	-15	21

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	9	820	1295
Ultradeep	34	11,240	13,256
United States			
Shallow	5	45	89
Deep	21	792	1284
Ultradeep	18	2034	1725
West Africa			
Shallow	110	3524	16,314
Deep	23	2070	3130
Ultradeep	12	1611	2398
Total	232	22,136	39,491
(last month)	(232)	(22,176)	(39,821)

Greenfield reserves

2017-21

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Shallow	875	33,365	320,427
(last month)	(877)	(33,163)	(320,829)
Deep	119	5215	75,778
(last month)	(119)	(5208)	(76,071)
Ultradeep	75	16,415	47,042
(last month)	(76)	(16,155)	(47,097)
Total	1,069	54,995	443,247

Pipelines

(operational and 2017 onwards)

	(km)	(last month)
<8in.		
Operational/installed	41,862	(41,040)
Planned/possible	21,323	(23,302)
	63,184	(64,341)
8-16in.		
Operational/installed	82,442	(81,476)
Planned/possible	46,731	(49,065)
	129,173	(130,542)
>16in.		
Operational/installed	96,182	(94,263)
Planned/possible	46,895	(44,991)
	143,077	(139,254)

Production systems worldwide

(operational and 2017 onwards)

		(last month)
Floaters		
Operational	313	(298)
Construction/Conversion	40	(45)
Planned/possible	286	(295)
	639	(638)
Fixed platforms		
Operational	9019	(9105)
Construction/Conversion	90	(72)
Planned/possible	1305	(1372)
	10,414	(10,549)
Subsea wells		
Operational	5193	(4879)
Develop	326	(374)
Planned/possible	6262	(6425)
	11,781	(11,678)

Global offshore reserves (mmboe) onstream by water depth

	2015	2016	2017	2018	2019	2020	2021
Shallow	21,290.90	32,117.92	21,875.58	19,968.71	12,360.76	16,216.52	19,410.75
(last month)	(21,290.90)	(32,117.92)	(21,897.92)	(20,138.70)	(12,010.12)	(16,123.42)	(19,525.56)
Deep	960.47	4215.67	1198.15	2933.58	2034.93	4753.11	7653.26
(last month)	(960.47)	(4215.67)	(1210.15)	(2921.58)	(2382.10)	(4392.71)	(7711.15)
Ultradeep	2000.69	3100.14	907.60	4828.49	3863.12	9637.94	5531.72
(last month)	(2000.69)	(3100.14)	(1653.94)	(4090.40)	(3847.95)	(9459.94)	(5406.84)
Total	24,252.06	39,433.73	23,981.33	27,730.78	18,258.81	30,607.57	32,595.73

Source: InfieldRigs 07 Aug 2017

Rig stats

Worldwide

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	86	58	28	67%
Jackup	395	236	159	59%
Semisub	109	62	47	56%
Tenders	27	15	12	55%
Total	617	371	246	60%

North America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	28	20	8	71%
Jackup	24	6	18	25%
Semisub	8	6	2	75%
Tenders	N/A	N/A	N/A	N/A
Total	60	32	28	53%

Asia Pacific

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	10	4	6	40%
Jackup	114	73	41	64%
Semisub	29	12	17	41%
Tenders	20	12	8	60%
Total	173	101	72	58%

Latin America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	22	17	5	77%
Jackup	50	27	23	54%
Semisub	24	18	6	75%
Tenders	2	1	1	50%
Total	98	63	35	64%

Northwest European Continental Shelf

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	N/A	N/A	N/A	N/A
Jackup	49	27	22	55%
Semisub	37	20	17	54%
Tenders	N/A	N/A	N/A	N/A
Total	86	47	39	54%

Middle East & Caspian Sea

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	1	0	100%
Jackup	119	81	38	68%
Semisub	3	3	0	100%
Tenders	N/A	N/A	N/A	N/A
Total	123	85	38	69%

Sub-Saharan Africa

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	19	14	5	73%
Jackup	15	8	7	53%
Semisub	3	1	2	33%
Tenders	5	2	3	40%
Total	42	25	17	59%

Eastern Europe

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	N/A	N/A	N/A	N/A
Jackup	1	0	1	0%
Semisub	N/A	N/A	N/A	N/A
Tenders	N/A	N/A	N/A	N/A
Total	1	0	1	0%

Source: InfieldRigs 7 August 2017

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

Risks and challenges

Despite the steps taken to provide clarity and incentives, the political risks facing oil and gas companies in Lebanon still exist, says Firas Modad, with IHSMarkit's political risk team. Lebanon is part of a broader geopolitical competition between the Arab states on the one side and Iran on the other.

The increasing influence of Hezbollah – an Islamist political group operating in Lebanon that has its own health care services and construction arm, autonomy from the Lebanese military and control of access to ports – could pose a risk to foreign oil and gas companies doing business in Lebanon in terms of sanction violations, by interacting with these organizations, Modad says.

Corruption could also affect participation in the country. "You don't have a strong law and order environment and strong legal protections of property rights, which will affect a company's ability to function and operate and follow European and western norms [of business]," Modad says.

A further concern is the boundary dispute between Lebanon and Israel, which revolves around to what angle to the coast the maritime border be demarcated. Initially, only one block of the five offshore blocks being offered was thought to be in the disputed territory; instead, the three most southern blocks lie in this area, Haggas says.

But, Khalil doesn't believe the border dispute between Israel and Lebanon has deterred operators' interest in offshore exploration in Lebanon's southern exclusive economic zone, saying that in particular, operators have expressed interest in the available blocks 8, 9, and 10, along the southern demarcation.

Expectations

The expectation is that gas exports will help Lebanon pay down its high levels of public debt. But, gas production offshore Lebanon isn't expected for another decade, and how Lebanese gas would be exported remains a question. Discussions are underway to construct a pipeline connecting Israel with Europe via Cyprus, Turkey and Greece. But these plans are "very tentative," Percival says.

"Lebanon has a small, limited market for gas, unless they convert all their industrial players and power generation to natural gas," Percival notes.

Excluding Egypt, the Mediterranean region will face a challenge in finding enough market for natural gas. Demand for natural gas in Egypt's domestic market (and lack of domestic supply since the Arab Spring) has surged to the point that the country, previously the world's eighth largest exporter of liquefied natural gas (LNG), is now the fifth largest importer of LNG. As a result, gas found offshore Egypt will be monetized quicker than gas found offshore Israel, Cyprus, and Lebanon.

The "very tentative" Eastern Mediterranean Gas Pipeline, which would transport gas from offshore Cyprus to the Greece mainland via Crete, could serve as an outlet for any gas produced offshore Lebanon, Percival says. Pre-FEED studies for the project are underway and expected to be completed by December. The 1300km offshore pipeline and 600km onshore pipeline would carry an initial 10 Bcm/y of gas from offshore Cyprus and Israel.

But, with gas oversupplied globally, analysts such as Wood Mackenzie don't see a medium-term market for new pre-FID LNG or pipeline projects. OE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Subsea boosting technology recently brought online at Chevron's Jack and St. Malo fields is expected to boost production rates for the next 30 years. Chevron's Chris Hey and Dan Broussard, and OneSubsea's Mads Hjelmeland and Oeyvind Reimers explain.

Accelerating longevity

The subsea boosting system now in place on Chevron's Jack and St. Malo development represents a major industry milestone and a first for Chevron, and is the result of significant collaborative efforts, dedication, and structured technology development. Successful deployments of subsea boosting systems such as this one have encouraged new development activities to expand the envelope of subsea boosting.

The Gulf of Mexico (GOM) Jack and St. Malo fields commenced production in 2014; the naturally high pressures driving production from the fields during the early stages of development are expected to decrease over time. Water depths in both fields are around 7000ft and the reservoirs lie about 5mi below the surface. Key challenges include low permeability, high pressures, high temperatures, as well as water and well depths. OneSubsea, a Schlumberger company, qualified, delivered, and deployed three single-phase subsea boosting systems.

Joint field development

The Jack and St. Malo reservoirs are tight sandstone reservoirs up to 1400ft thick, indicating a vast amount of oil in place. The large volume of oil equivalent reserves in place will be recovered over a lifetime of 30 years. Despite the high initial reservoir pressure, the energy to move fluids to the seabed declines with depleting reservoir pressures, resulting in lower production rates falling off plateau. While various artificial lift methods could be effective, seabed boosting systems were eventually selected, based on the net value added to the project's overall net present value.

A combined development was sanctioned for the two fields that are situated 25mi apart. This joint development strategy required new technology qualification in the deepwater environment due to the challenging reservoirs and the distance between the fields. Jack and St. Malo discoveries are to be developed in multiple stages. Stage 1 involved drilling of 10 wells; four tapping into the Jack reservoir and six tapping into the St. Malo reservoir. The wells at Jack are tied to one subsea manifold, whereas the wells at St. Malo are tied to two daisy-chained subsea manifolds. Three pump stations located downstream of Jack and St. Malo manifolds boost the fluids back toward the semisubmersible floating production unit

Pump module (left photo) and the three pump stations (above) prior to subsea development.
Photos courtesy of Schlumberger.

(FPU) located mid-way between Jack and St. Malo reservoirs through individual 10in pipelines. One combined power and control umbilical was laid from the Jack and St. Malo FPU to each of the two fields, supplying the pump systems with electrical power, communications, control fluid, and barrier fluid.

The use of subsea pumps downstream of the manifolds is expected to provide a significant increase in the oil recovery factor and the best return on investment of the evaluated artificial lift options. This is achieved as the wells are producing at lower wellhead pressure (WHP), which is enabled by the differential pressure generated by the subsea pumping systems.

Qualifying critical technology

The seabed pumping systems for the Jack and St. Malo fields were installed at a depth of around 7000ft with tiebacks of roughly 13mi. To comply with high shut-in pressure, deepwater, and tieback distance qualification efforts were needed with respect to the 13,000psi design pressure, the 3MW electrical motor, and the high-pressure subsea pumps.

Due to the water depth, a two-year technology qualification program was initiated to qualify all components to Jack and St. Malo specifications and to allow Chevron to gain confidence that the subsea pump system would deliver the expected results under challenging conditions such as significant step-out distances and high shut-in pressures.

There was a firm requirement that the pump system qualification be finished in order to comply with the installation schedule and campaign of the overall production system. The subsea boosting systems were installed and commissioned at the same time as the overall subsea facilities. The three pump stations were tied into the production system and initial natural production was routed through these pump stations. The subsea pumps were installed at the same time and placed in wet storage to wait for the reservoir pressures to deplete.

The technology qualification efforts took two years and were related to the subsea pump itself and the subsea transformer, including various subcomponent qualifications. A FEED study was conducted at the same time that included a complete boosting study prior to the final investment decision.

Project specifications called for the subsea pumps to generate a high differential pressure at 60,000 b/d capacity in large water depths in order to boost the fluids back to the FPU. An electrical motor with 3MW was qualified along with new pump and motor housings rated to 13,000psi design pressure. Also, a novel system was qualified to control the barrier fluid pressure subsea. A subsea barrier fluid regulation pod with directional control valves in tandem with subsea accumulators was applied in order to compensate for pressure transients during pump operation and transients. A 40-hour endurance test was performed as part of the pump performance test program.

Pump systems

Each pump system is comprised of a bypass line to allow for natural production as well as the pump module itself and a recirculation line with a retrievable control valve to allow for recirculation of fluids to remedy turndown flow rates. The pump systems also include all required process valves, instrumentation, and process connectors to safely operate the systems. The systems are equipped with hot stab connections and chemical injection points. In addition to the installed subsea equipment, two spare pump modules and a spare transformer module were contracted.

Two pump stations (one submerged in test pit with pump module and transformer module installed) during system integration testing prior to final delivery. Another pump module is shown next to the pump station.

The pumps are powered by adjustable speed drive (ASD) systems located topside at the host platform via an integrated power and control umbilical. The systems are operated through subsea control modules and the control system communicates with the subsea equipment through high-speed fiber.

The subsea pumps started continuous operation in 2016 to maintain desired production. Based on this success and numerous other deployments of subsea boosting technology, new development activities have been kicked off to expand the technology envelope.

Additional development phases

A second stage development planned for Jack and St. Malo call for drilling new wells and supporting infrastructure. Over the project's 30-year lifetime it is expected that the preferred artificial lift method will change. An expanded design of the subsea boosting system has already been developed. Initially single-phase fluids will be produced through the pumps as the inlet pressure to the pump system will be above the bubble point pressure. As the reservoir pressure depletes, it is anticipated that the pump system will be operating below the bubble point pressure, allowing for multiphase flow to enter the pump system; future connectors are in place as part of the initial design. These allow for installation of a multiphase pump upstream of the single-phase pump system for stage two, or alternatively, deployment of a high-boost multiphase pump.

Pushing boundaries of subsea boosting

Since the very first deployment of a subsea boosting system in 1994 in the North Sea Draugen field at 885ft with a tieback of 3.7mi, the technical boundaries for subsea boosting have been extended, making remote deepwater assets economically viable. Based on market demand and the increasing complexity trend associated with undeveloped reservoirs, extensive qualification programs have been in place for subsea pumping systems, and experience has taken subsea boosting technology into harsher, more challenging environments.

Subsea boosting at the seabed enables the wells to produce at a lower WHP, which in turn increases production rates from the wells. In the case of the Jack and St. Malo fields, the reduction in pump inlet pressure, as well as the increase in pump discharge pressure, is generated by the single-phase pumps using centrifugal impellers. Now online, the pumps are expected to boost production rates from these two fields for the next 30 years.

New subsea boosting technology development activities now being implemented based on successful implementation of the technology include higher differential pressures as well as design pressures and smart auxiliary solutions. An example of such boundary expansions for subsea boosting also include the first 15,000psi system to be installed in the GOM Stones field at a water depth of 9500ft.

Emphasis is being placed on maintaining compact design and reliability of subsea boosting systems while applying proven technology components to keep solutions cost efficient, as being witnessed by Chevron in their first implementation of subsea boosting technology to accelerate longevity in the Jack and St. Malo fields.

The inherent benefits of subsea boosting systems for field developments, and in particular subsea tiebacks, represent significant upside compared to conventional developments, based on accelerated and improved recovery in addition to reduced investment costs as important parameters. OE

Reference

This paper, OTC 27800-MS: Qualification and Deployment of the World's First High Pressure Subsea Boosting System for the Jack/St. Malo Field Development, originally appeared at the Offshore Technology Conference held in Houston, Texas, USA, 1–4 May 2017.

Chris Hey *holds an MSc in subsea engineering & underwater technology from the University of Portsmouth, UK, and is*

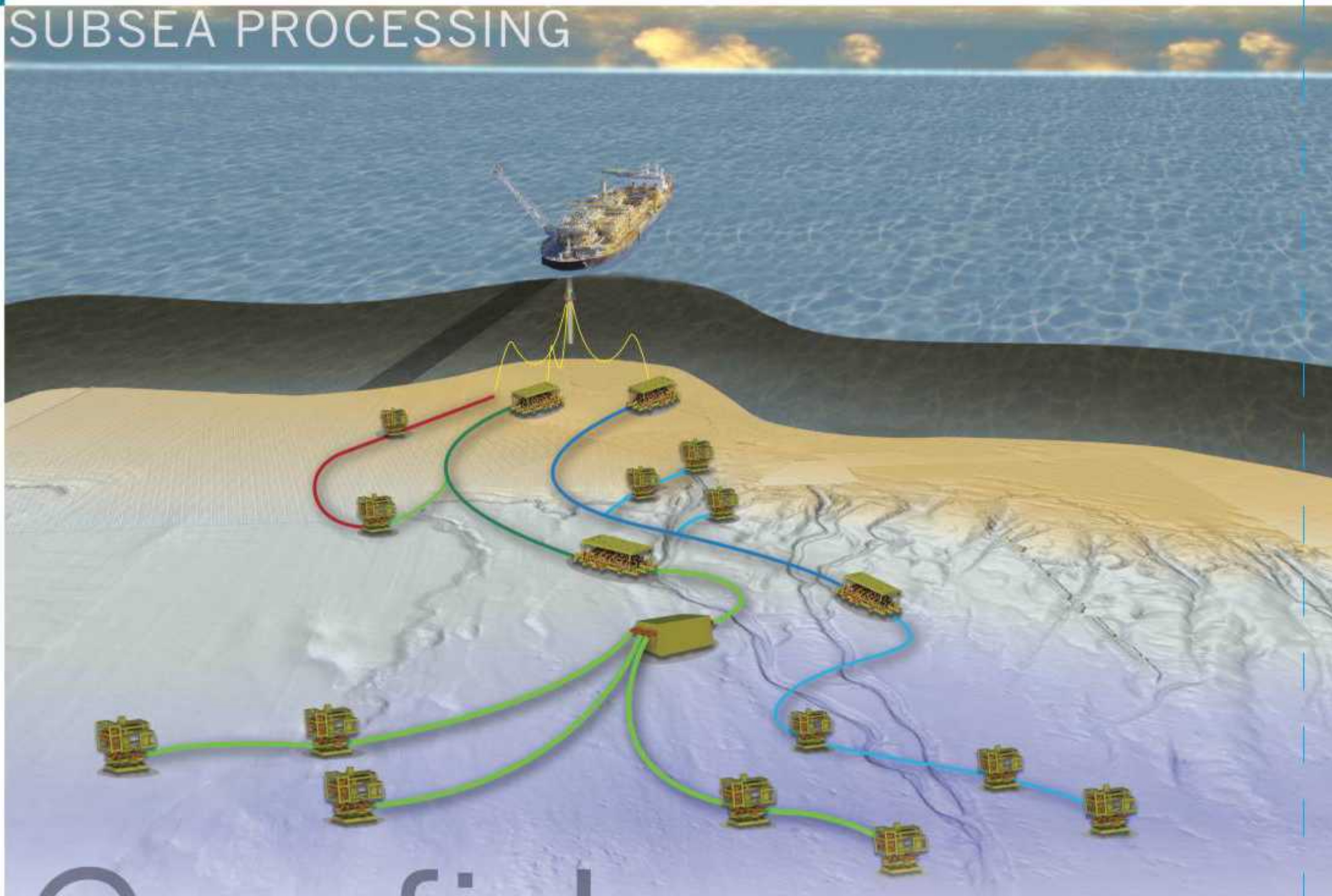
currently in the position of Subsea Compression Manager with Chevron Energy Technology Company (ETC) in Houston where he is working with OneSubsea in Bergen to deliver the next generation subsea wet gas compressor. Chris has held key positions on a number of Chevron's major capital subsea projects worldwide which required the development of new technology, these include Jack & St Malo and Tahiti in the Gulf of Mexico, Malampaya in the Philippines and Captain Area B in the North Sea. Prior to joining Chevron in 1989 Chris worked for Cameron in Aberdeen as an offshore installation engineer.

***Daniel Broussard** holds a BS and MS in mechanical engineering from Texas A&M University, and currently works a Subsea Pump Engineer for Chevron. Working for both Texaco and Chevron since 1991, Daniel has served as technical lead engineer in multiple multiphase pump field deployments to enhance reservoir recovery at field locations in the Gulf of Mexico, Trinidad and Venezuela.*

***Mads Hjelmeland** is the global sales director, subsea processing, at OneSubsea, a Schlumberger company. Responsibilities include managing early engagement and market initiatives as well as strategic business and technology development efforts within the subsea processing domain. Prior to joining*

OneSubsea in 2014, Hjelmeland worked with Murphy Oil in Malaysia, where he was manager of subsea projects, which included development project planning and execution across Murphy's Malaysian deepwater portfolio. Prior to joining Murphy, Hjelmeland worked for OneSubsea, where he held a variety of positions in Norway, the Middle East, and Asia. His work scope focused on subsea processing technologies, with emphasis on subsea boosting and wet gas compression technologies. Hjelmeland holds a Master's in science degree in marine technology from the Norwegian University of Science and Technology.

***Oeyvind Reimers** is a senior system engineer for OneSubsea, a Schlumberger company; he is involved in early customer engagement with focus on identifying potential boosting assets and defining applicable pump and compressor systems. After joining OneSubsea in 2010, Reimers worked as a flow assurance engineer on EPC projects and on subsea pumping and compression technologies. Focus areas include dynamic and steady-state simulations, process system design, and general flow assurance issues, as well as new technology development. Reimers holds a Master's in science degree in process technology from the Norwegian University of Science and Technology.*



Confidence boost

Subsea boosting is helping to push otherwise uneconomic subsea projects over the line. Elaine Maslin reports on two tiebacks benefiting from a bit of boost – including the industry's longest deepwater subsea multiphase boosting tieback.

It's a common refrain – there are many known and mapped resources ready to be tapped. But, because of distance from host facilities, flow assurance concerns, and topside constraints, these potential developments are often left on the shelf.

Operators and vendors have been working hard to find solutions and subsea boosting is proving to be one. Australia's Woodside is using subsea boosting to help make its Greater Enfield project fly, while Murphy Oil is using the same to boost and enable future tie-ins on its deepwater Dalmatian project in the US Gulf of Mexico. Both use high-boost multiphase pumping systems from OneSubsea, a Schlumberger company, and both projects were presented at the Underwater Technology Conference (UTC) in Bergen in June. "Subsea pumping is a mature technology," says Arill Småland Hagland, senior systems engineer, OneSubsea, with more than three million hours operational experience. OneSubsea has more than 100 pump units in its portfolio – adding up to more than 200MW of subsea power.

Many projects use the multiphase high-boost design, which is the result of a joint industry project launched with a number of oil majors in 2007. It aimed to increase boosting capabilities, to significantly more than 50bar achieved previously. It also makes use of balance pistons, which help counteract the axial force of the impellers in the pump. It is field proven on projects including Barracuda in Brazil, and Total's Girassol and Moho projects off West Africa.

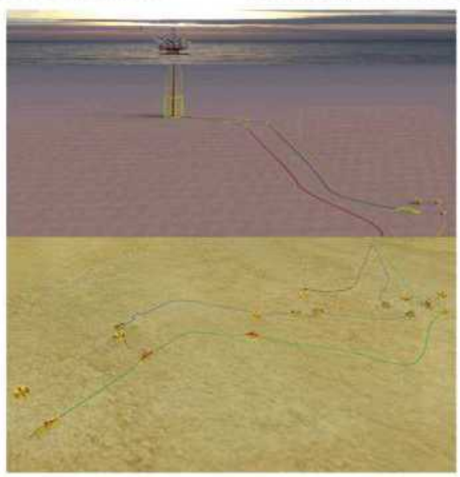
Woodside's Greater Enfield project.
Image from Woodside.

With the help of efforts to standardize these systems – and the processes involved in deploying them – subsea boosting is becoming an economic enabler, Hagland says. "There's been a perception that subsea boosting is very expensive," Hagland says. "We have spent time over the last few years trying to reduce cost based on this solution." This has included a standardization program on the technology and system solutions, but also on how to execute projects, and how to run projects internally." Indeed, Murphy's Dalmatian project, which will have a multiphase high-boost pump installed in 2018, is the result of all of this," he says.

Dalmatian

Murphy Oil's Dalmatian field is in DeSoto Canyon, 260km from New Orleans, in the US Gulf of Mexico. The project, a daisy chained development tied into Chevron's Petronius compliant tower, which sits in 550m water depth. Dalmatian was developed in two phases. The first, Phase 1, is a 35km, pipe-in-pipe oil well tieback and a 38km gas well tieback, with a common, 14-tube umbilical, in 1770m water depth. Phase 1 came onstream in 2014.

Phase 2 added an 18km pipe-in-pipe extension in 1980m water depth, taking the entire system out to 51km from Petronius. Phase 2 came onstream in 2015. Now, the firm is looking to add a subsea multiphase boosting system to the field, based at the end of the initial 35km step-out, making it the industry's longest deepwater subsea multiphase boosting tieback. As well as adding boosting to the development, this could enable further opportunities in the area, said Mike Clarke, project manager, Murphy Oil, at UTC.



Murphy Oil's Dalmatian field layout.
Image from Murphy Oil.

Dalmatian was a marginal development, Clarke says. But, "working with the vendor, with a unique contracting strategy, in the current climate we were able to make something like this work."

Challenges on Dalmatian Phase 2 include flow assurance over 51km, and having to cycle the wells, because they're competing to get into the system, and the need for depletion drive with a limited aquifer support. Clarke says that Murphy looked at a couple of enhanced oil recovery options, including water injection and artificial lift. But, there were concerns over water injection continuity within the reservoir. "At the end of the day, it was deemed that the lowest reservoir risk was to install a pump," Clarke says. "By reducing back pressure, we get a nice bump in production, resolve flow assurance issues and improve the recovery quite dramatically."

The OneSubsea high-boost pump system will be installed where the 35km step-out is now, which will enable it to serve the latest step-out, as well as enable the development of other nearby targets.

To make the project work, however, an increase in the voltage of the high boost pump's motor was needed, to eliminate the need for subsea transformers and high voltage subsea wet-mate connectors. A qualification program for the higher voltage motor was completed June 2016.

"Such an approach, based on the same standard design on all electric pumps to date, significantly reduces hardware scope and complexity of the system," Hagland says. There was just a minor adjustment of the windings to fit the increased voltage rating. "We believe this is game-changer for long step-outs," says Hagland, who adds that the pump could work for projects at 55-65km step-out and still supply 2MW of power.

Part of the approach was changing the contracting strategy. Murphy went for an integrated subsea engineering, procurement, construction, installation and commissioning (EPIC), Clarke says. "We are not telling the market what we want, we're letting them come to us with the solution. The bid package was a functional, fit-for-purpose specification." This approach will also reduce the schedule to first oil by three months, thanks to reducing supplier interfaces, he says.

The contract was awarded to the Subsea Integration Alliance, which was formed in July 2015 between OneSubsea, Schlumberger, and Subsea 7. The contract is for the multiphase boosting system, including topside and subsea controls, and a 35km integrated power and control umbilical. Execution will be in under two years and the payment structure is backend loaded, making payments closer to when production comes online.

Greater Enfield

Woodside Energy and its partners made the decision to invest US$1.9 billion in the Greater Enfield development in June this year. It's been a long time coming.

Woodside CEO Peter Coleman said the decision to go ahead was thanks to "breakthroughs in the development concept, technology and contracting. Leveraging the latest technologies and using existing FPSO (floating production, storage and offloading) infrastructure... allows us to accelerate the development of previously stranded resources." Development costs on the project, expected to come onstream mid-2019, are $28/bbl, according to Reuters.

Greater Enfield is 60km off Exmouth in Western Australia in 340-850m water depth. The development is targeting 69 MMboe from the Laverda Canyon, Norton over Laverda and Cimatti oil fields via six subsea production wells and six water injections wells. The wells, in 340-850m water depth, will be tied back 31km to the *Ngujima-Yin* FPSO, which currently produces the Vincent field.

However, to maintain production assurance, subsea multiphase pumps would be needed in the Laverda area gas lift in the Cimatti area and water injection pressure support for both Laverda and Cimatti areas. The subsea pumps are a key enabler for long subsea tiebacks and are required to be high-boost capable of generating differential pressure over 100bar, said Tim Nallipogu, Woodside subsea pumping lead at UTC.

The *Ngujima-Yin* FPSO vessel. Image from Woodside.

The Vincent field already has multiphase pumps, which were installed in 2008. These provided confidence in the multiphase pumping technology. Going from conventional boosting to high-boost (two and a half times the boost capacity of the existing pumps) was not seen as a major step-change. However, the long subsea tieback did pose challenges around topside constraints on the *Ngujima-Yin*.

The *Ngujima-Yin*, commissioned in 2008, has governed the design for the Greater Enfield subsea pumping system, Nallipogu says. The FPSO has a disconnectable turret mooring system, with the swivel system designed for a short ~4km Vincent field tieback. It has 7.2kV high voltage slip rings, which would mean subsea transformers and 30kV wet-mate connectors would be needed to support the high-boost system needed for the Laverda area, some 31km from the FPSO.

Woodside in conjunction with the pump system supplier took a change of tack. "We looked to upgrade the slip rings from 7.2kV to 12kV, and upgrade the multiphase pump motor from 6.6-10kV, which would eliminate the need for subsea transformers (transmission voltage at 12kV) and 30kV wet-mate connectors," Nallipogu says. This simplified the power system and helped increase the motor rating from 2.4-2.6MW.

This approach still faced challenges, however. One being upgrading the slip rings and the second qualifying a higher voltage subsea pump motor. The *Ngujima-Yin* is due for a shipyard visit, as part of some planned refurbishment work on the swivel, during which the high voltage slip ring upgrade could be performed, however. A qualification program for a 10.5kV high voltage motor for Greater Enfield application (the turret disconnect connectors are qualified for 12kV maximum voltage, limiting any further increase in voltage) was completed with the pump system supplier between September 2015-June 2016.

The subsea pump system will be serviced by an integrated power and control umbilical. There will also be a water injection pipeline system for pressure support for Cimatti and Laverda Canyon. Hydrate management will be via a "risk-based approach." The potential to form hydrates exists later in field life, but not in quantities that would cause blockage, Nallipogu says.

"Greater Enfield has been a challenging field," Nallipogu says. "It has been in the portfolio for some time, but has not got across the line. The long tieback to [an existing] FPSO reduced the development cost and the high boost pumping system was a key enabler. In addition, the power distribution system could be simplified with qualification of the high voltage motor technology and upgrade of the slip rings during the shipyard campaign."

OneSubsea was awarded the engineering, procurement and construction contract, totaling some $300 million. It covers the supply of the subsea production system and the dual multiphase boosting system for Greater Enfield. This will include six horizontal SpoolTree subsea trees, six horizontal trees for the water injection system, six multiphase meters, the high-boost dual pump station with high voltage motors, umbilical, topside, subsea controls and distribution, intervention and workover control systems, landing string, and installation and commissioning services.

Technip was awarded the contract covering project management, design, engineering, procurement, installation and pre-commissioning of carbon steel production flowline, carbon steel water injection flowline, flexible risers and flowlines totalling 82.2km; 38.9km of umbilicals (dynamic and static); subsea structures and valves; and the multi-phase pump system transport and installation.

The flexible pipes will be manufactured in Asiaflex Products, Technip's manufacturing plant in Tanjung Langsat, Johor, Malaysia, the umbilicals will be supplied by Technip Umbilicals' facility in Newcastle, UK. The offshore installation will be using several vessels from Technip's fleet and is scheduled for completion in 2018. **OE**

New kid on the block

Elaine Maslin reports on a new pump under development that could be the next step in subsea multiphase boosting.

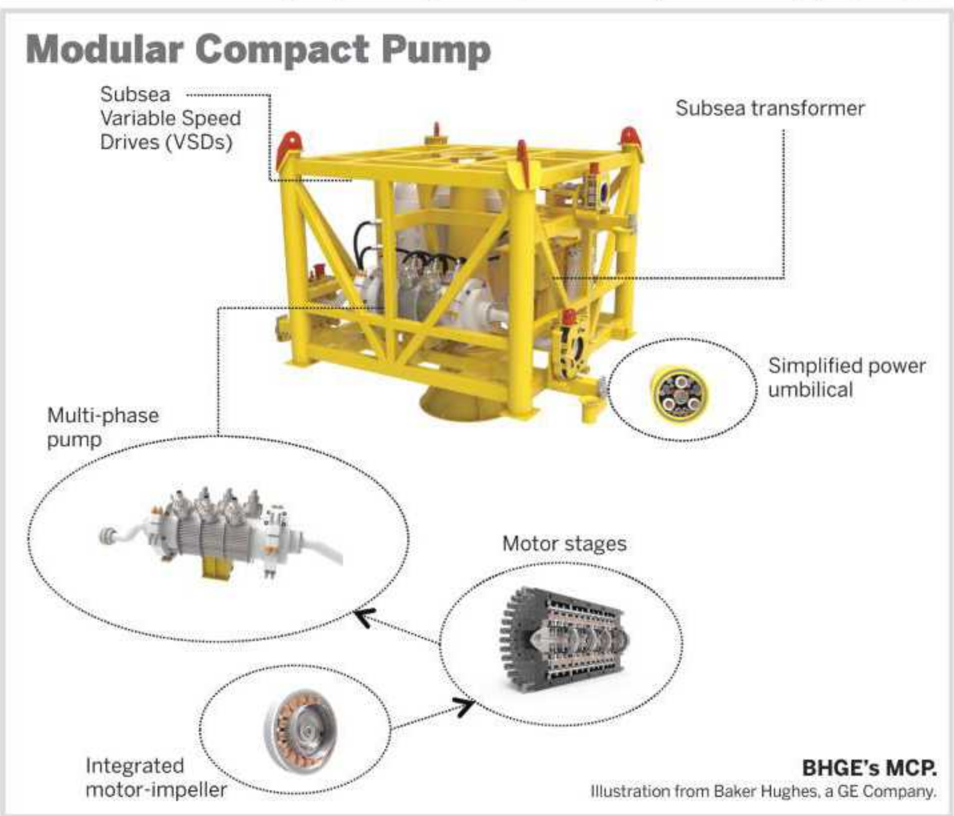
Testing started this summer on a new subsea pump being developed by Baker Hughes, a GE company (BHGE). It's no ordinary pump. It has no barrier fluid, for a start, reducing the complexity of umbilicals and reducing topside support requirements. The impellers rotate around a static central shaft, avoiding rotor dynamic issues associated with conventional pumps.

It could be the next step in subsea multiphase boosting, a space in which new technology is needed, according to Pierre-Jean Bibet, rotating machinery department, expert in pumping systems, Total E&P. Speaking at the Underwater Technology Conference (UTC) in Bergen this June, he said the uses for multiphase pumps have been expanding, including transportation of fluids to a floating production system, to increase production from reserves by lowering wellhead pressure and producing viscous fluids.

The future potential is significant, but for new projects to come on, the biggest challenge is the Delta P (differential pressure), he says. "The issue is the higher power requirement to generate more head (pressure), which means higher speed and more head per stage. With existing designs, you can generate Delta P of 210bar at 60% gas volume fraction (GVF), which is almost the starting point for long tiebacks and deepwater projects. We need cost effective multiphase systems for ultra-deepwater and long tiebacks."

But, barrier fluid is a weak point, resulting in complex umbilicals and complex barrier fluid control, Bibet says. Dealing with pressure gradients during transient periods is also a challenge.

BHGE hopes to have tackled these issues with its Modular Compact Pump (MCP). It presented the concept at UTC. The pump is being developed under a joint industry project (JIP)



BHGE's MCP.
Illustration from Baker Hughes, a GE Company.

Aslaug Melbø, engineering manager, subsea systems, BHGE, speaking at UTC Bergen. Photo from UTC.

with Statoil, Chevron, Shell and Total, plus US$2 million (NOK17 million) funding from the Norwegian Demo 2000 fund for the JIP's Phases 2 and 3, running from this autumn.

Because of how it's been designed, it will be smaller than a standard subsea pump, by about half, says Alisdair McDonald, business leader, Subsea Power & Processing at BHGE.

BHGE is looking to develop modules of four independently controllable stages, with each impeller equipped with its own variable speed drive (VSD), enabling a greater flexibility in operating envelope over field life. The modules could then be stacked depending on process needs and built up into larger systems.

"In a conventional life of field scenario, you have to rebundle a pump system to accommodate life of field conditions," McDonald says. "With ours, you just change the speed of the individual modules, which you can do on the fly."

"It's about performance and maximizing head," Aslaug Melbø, engineering manager, subsea systems, BHGE, told UTC. "It can be placed inside an existing structure, like a four-slot template, or in a separate structure. It is scalable. Because we add the same modules several times you can build the pump and get a very high differential pressure or reduce the number of stages and get a compact pump. It opens up a whole new operating range than what we have today."

Melbø says that system cost could be 20-37% less than current pumps and, with no hydraulics to deal with, it would fit well into the all-electric strategy. McDonald says that a version of the MCP, the same size as a 3-4MW pump on the market today, would be able to pack 6MW – to give an idea of the higher power density. The smallest version envisioned would be a 1-2MW pump, which could be small enough to put on a Xmas tree, McDonald says, where it could also have the potential to act as a choke.

A three-stage prototype has been built and is being tested, with a variety of gas volume fractions, at BHGE's facility in Bari, Italy, over summer. This is Phase 1 of the JIP. Phase 2 will start in the fall and run for about 18 months.

The next phase will focus on qualifying some of the key components, including the axial and radial process lubricated bearings, made from polycrystalline diamond bearings, a form of synthetic diamond. A process loop has already been built and testing of the bearings has started, including throwing "tonnes of sand" at them, and running them almost dry, to see how they perform. Phase 3 will see a full-scale pump built and qualified to TRL4. A complete unit is expected to be ready by 2020.

BHGE is also involved in DNV GL's subsea boosting JIP, which is looking to standardize subsea boosting, in the hope this will reduce costs and increase adoption. **OE**

Gullfaks umbilicals challenge

Statoil's Gullfaks subsea compression project came under the microscope at the Underwater Technology Conference (UTC) in Bergen, Norway – namely, the challenge it faced with a leak in a combined power and control umbilical.

The Gullfaks subsea compression project came onstream in October 2015. The project comprises two, 5MW subsea wet gas compressors.

Fiber optic communications, compressor power, low voltage power, barrier fluid, and MEG are supplied from one, 16km-long common power and control umbilical from the Gullfaks C platform and the compressor station.

Shortly after start-up, pressure was lost on one of the fluid lines in the combined power and control umbilical. The compressors were removed and the umbilical was retrieved and was found to have leakages on three of the seven super duplex steel tubes in the umbilical.

Analysis carried out by manufacturer Nexans found that the failure mechanism was corrosion related to the influence from the power circuits (AC corrosion). This had been because parts of the steel tubes were unsheathed.

UTC was told that the power core, one of 20 elements in the umbilical, generates heat and can induce currents in the other metallic elements in the core. Those grounded at both ends of the cable will have a voltage that builds up. Further, harmonics in the system increase the voltage.

Where there is bare (unsheathed) steel, corrosion can start, as the sheathing acts as both corrosion protection but also as electrical insulation. The higher the voltage, the quicker the corrosion could start.

While testing helped show the reason for the fault – the bare steel corroding – the presenters said more work needs to be done to understand the mechanism and so to be able to define requirements for tubing with sheaths, including joints. Asked how the steel had been exposed in order that it could corrode, the presenters gave no explanation, however.

Two new umbilicals have now been produced and were installed in May. The compressors were due to be installed this summer with compressor re-start slated for August, as *OE* went to press. ▪

FURTHER **READING**

Take a dive into Gullfaks' subsea wet gas compression technology.
http://ow.ly/7aCJ30egwKn

Seawater Springs

Springs, how it might look subsea.
Image from Saipem.

Seawater injection is one of the jigsaw pieces making up the subsea processing puzzle. Elaine Maslin reports on Saipem's Springs technology.

Italian contractor Saipem has been working on a subsea seawater injection technology for the last 10 years and it's now ready to industrialize it, with first commercial use targeted for 2019.

Stephane Anres, innovation & technology development, technical area coordinator – subsea systems, Saipem, told the Underwater Technology Conference in Bergen about the technology.

"Most of us believe subsea systems will play a large role in subsea production," he said. "This is why Saipem, 10 years ago, started to develop its own systems, including seawater treatment."

Having seawater treatment reduces the need for topsides space and or modifications, Anres says. "It just needs a power and control unit." This also ties into the all-electric vision operators, including Total, are targeting. In fact, Saipem, along with Total and water treatment specialist Veolia, have jointly qualified the technology.

This technology is called Springs, standing for "subsea process and injection gear for seawater." Its role is sulfate removal for satellite fields more than 10km from a floating production (FPSO) unit and existing fields without the need for major FPSO modifications, i.e. just a subsea power and control unit is needed topside, not a full seawater treatment facility, Anres says. Removing the sulfate prevents scale formation and reservoir souring.

"Seawater is crucial to treat before injection because it contains barium and calcium and could cause souring," Anres says. "If it's not removed, sulfates come out as scale."

The system would be able to handle 10,000-80,000 b/d of seawater, he says. Seawater intake would be about 100m above the Springs unit, which would comprise a pumping module, umbilical, instrumentation and control, a pre-filtration module for solids, and a membrane module, plus chemical storage – the chemicals are used to mitigate/reduce fouling of the filtration membrane. It's all modular, Anres says.

The membrane module contains nano-filtration membranes. The concentrated sulfate brine produced by the unit is removed using a dedicated reject line for disposal to sea. Desulfated water is re-injected for pressure support. The chemical unit would be periodically refilled (max, once per year) with non-oxidizing biocide to maintain anti-fouling, which would be batch dosed according to project requirement.

The membrane has been qualified to 3000m water depth. In laboratory testing, the membrane was tested to 4° C. It was then incorporated into a subsea test unit, which was taken offshore Congo in 2014 for trials in 600m water depth from the *Alima* floating production unit. Test results were water samples with sulfate content always lower than the 40mg/l specification, Anres says. No plugging was experienced with the inlet screen and there was no issue with pre-filtration treatment, he says. Since then, Saipem has been updating and optimizing the system, based on the test results.

The first commercial use is anticipated in 2019, Anres says. "The main qualification tasks have been completed. We have started industrialization of the system, defining and securing the supply chain. We have entered several partnerships with different suppliers, for example Siemens on the subsea control system."

For commercial sites, the existing subsea test unit could be deployed to optimize the design of a particular field's unit, Anres says. OE

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Asset integrity wrapped up

Engineered composite wraps are becoming the solution of choice for dealing with corrosion issues in the North Sea on an increasing range of offshore pipework and structures. Elaine Maslin reports.

The trouble with metal and water is that they don't get along. The same goes for metal and corrosive fluids. There's a lot of corrosion on oil and gas facilities in the North Sea, many of which were installed decades ago when it wasn't expected they would still be operating today. As a result, there's an increasing amount of composite repair wraps used to temporarily, and even permanently, repair damaged areas, from service lines to caissons and structural members.

With the long-term integrity of engineered composite repairs somewhat unknown, the UK's Health and Safety Executive (HSE) launched a shared research project.

Wrap it up

Composite repairs started to make their presence felt in the early 2000s, and indeed, in 2001, the HSE produced guidelines on use of composites for repairs. However, it took until 2015 for an ISO standard to be drawn up and there's no validated inspection method for checking bonds. Composite repairs were initially used as a temporary solution on service lines through to the next shutdown. The use has also increased dramatically (in the words of the HSE) as well as the types of repair and the the length of time for which they're expected to be used. In some cases, where a facility is near the end of its life, repairs will be expected to last until decommissioning.

Epoxy, used to bond the materials, has also been developed for use in or under water, which means engineered composite repairs are now also being used on caissons, applied by trained divers, which otherwise might need to be replaced, as well as structural members, decks, blast walls, bulk heads and more.

Caisson repair using Technowrap Splashzone. Photos from ICR.

These repairs have proved very good to date, says David Johnson, of HSE, but there are failures. More knowledge is needed about their long-term integrity, given the "steady proliferation" in their use, the length of time that they're being used, as well as their use on more safety critical applications.

"Engineered composite repairs play an important role for aging assets," he told the Topsides UK conference in Aberdeen earlier this year, including for structural repairs, such as helidecks or gas turbine struts, and I-beams. "We are [also] starting to see people wanting to use these repairs for 5-10 years," he says. "We have started to see some failures, generally short-term. Are there any long-term modes we are not aware of at the moment? What is our understanding of repair lifetime?"

Engineered composite can have 2-20-year design lives, says Gareth Urukalo, composite repair senior technical engineer, at Walker Technical, an ICR Integrity company. Initially, many were designated as temporary repairs, but because the HSE wanted a design life so that they and operators could better assess repairs, or mark points at which repairs needed assessing, specific design lives were developed.

"They wanted to stop repairs sitting on pipework forever," says Simon Frost, composite repair technical director, Walker. This would mean a plan could be put in place to manage the repairs, which are often between 5-20mm thick, including revalidating or replacing them at the end of their life.

The advantage of an engineered composite repair is the ability to repair complex geometries and essentially manufacturing a part in situ, instead of using clamps or other mechanical means, or welding – or evening replacing an entire pipe spool. There are different variants of engineered composite repairs, which comprise various layers of glass fiber or carbon fabric impregnated with a type of resin, typically epoxy, and applied directly to a prepared substrate. Depending on what the repair needs to do – i.e. withstand internal pressure or bending moments – glass fiber or carbon fiber is used and in some cases, both. Glass fiber is useful for areas of corroded substrate because it has more adhesive properties, where carbon fiber has more strength, Urukalo says.

Urukalo says that Walker uses epoxy because of its adhesive properties and chemical resistance to most fluids seen offshore. The firm uses various resins for different applications, depending whether they will get wet, the temperature of the environment or application in which it is being used, or if going to be subject to impacts, in which case rubber material might be used.

Johnson adds that there's a variation in duty holder approach to use of composite repairs, with some using them on hydrocarbon lines, and others not. One example, composites were used to repair a 30in gas export header, which was deemed impractical to replace. Some 18 repairs were done over 130m of the pipeline. The project, described as a "Rolls Royce job" by Johnson, was carried out in close cooperation with the HSE.

For the HSE, such repairs should only be done as a temporary measure and only as a permanent solution if a replacement to what it is repairing cannot be sourced. HSE says that safety critical elements should be replaced like for like.

Recently, Walker Technical applied its engineered composite wrap technology to I-beams on a stair tower offshore, as well as to areas of caisson underwater, which first required a live leak seal before the wrap could be applied.

There is a standard for such repairs, ISO 24817, which covers the entire repair system, i.e. the composite laminate, surface preparation, and filler.

But, Johnson says, the quality of installation depends on the competency and proficiency of the person doing it. "Human performance is key. There are clear ramifications when it comes down to the competency of the people doing the job. You can qualify this in a lab, but you have to replicate that out on plant."

There are two main failure modes, interfacial delamination, usually caused by inadequate surface preparation, and media coming through thickness, which is rarer, it implies a clamp has not been isolated properly and affected the cure of the resin. Failures usually occur quickly (minutes, days or weeks), following the repair, and tend to be a benign leak before being a break.

Another issue is corrosion protection continuity, i.e. where surface has been prepared but then not reprotected where it hasn't be recovered by the repair, leaving bare carbon steel open to corrode.

Following a repair, Johnson says that steps should be taken to monitor it, i.e. taking photos to create a baseline for inspection and updating P&IDs (piping and instrumentation diagram/drawing), as well as ongoing integrity management work. This should then feed in to decommissioning work, i.e. understanding when the asset life is ending.


A 48in discharge caisson with large number of defects over a vertical length of 23m.

"Part of the problem is what happens to the pipework itself," Frost says. While the repair might not fail, "we have to make an assumption about the wall thickness or the size of the hole [once it is covered up]." I.e. it's not necessarily the life of the composite, it's the life left of the pipe underneath.

Inspection regimes – how and when to inspect – should also be considered. Visual inspection is still the most commonly used inspection mode and is used to identify continuity of protection, dry fibers, or exposed or damaged fibers, or the repair starting to life, which could be the bond failing.

But, new techniques are also being used to inspect composite engineered repairs, including pulsed eddy current, radiography, and sensors embedded between the repair and substrate, which can be used to give thickness measurements, and dynamic response spectroscopy, and microwaves. Walker has been working with Sonomatic in this area, to monitor the steel underneath repairs.

However, none have been fully validated as a method for validating the bond, Johnson says. A full assessment of existing techniques is set to be part of the shared research project. One of its five work packages will cover inspection techniques and will result in a report detailing the strengths, limitations and resolution of currently available inspection techniques along with an overview of operational experience/perspective to date. There will also be a report setting out the results of tests to failure of specimen trials.

The shared research project is due to run for 24 months and will include gathering and then testing actual repairs, which have been brought back from installations. Those involved in the project include North Sea operators Total, Nexen, ConocoPhillips, TAQA, and Shell, as well as nuclear firm Sellafield, gas pipeline operator the National Grid, and EDF, from the power industry, highlighting the interest from other sectors in this type of repair work.

The five work packages are: quality assurance and integrity management; inspection and the criticality of defects; in-service performance; fire performance; and a repair installer proficiency scheme. OE

Repairing Lomond

Following a planned inspection program, it was identified that the C8 18in Caisson on Shell's Lomond platform in the North Sea had sustained external corrosion, resulting in a through-wall defect and a 4in spool requiring replacement as it was no longer functioning as per its design.

To avoid a dropped object situation, Shell worked with ICR's composite engineering team on an engineered composite repair solution to re-instate the caisson with a 15-year design life. The work required one Technowrap rope access technician working in the splashzone to apply a 14-layer repair, overwrapping two metal plates with the ca. length of 2.20m. ICR's Technowrap LT (low temp) resin system and structural strengthening cloth was used to reinstate the structural integrity of the caisson and provide pressure retention to any through wall defects.

ICR's carbon fiber repair system, Technowrap SRS, was used to accommodate the huge wave loading. During surface preparation, the caisson holed in two areas, 75mm from the end of the bottom landing zone. ICR and Shell reviewed the issue and agreed to increase the repair size in line with the engineered design calculations.

Shell plates were installed and profiled prior to the 14-layer wrap installation being applied. The repair was completed with a design life of 15 years.

Delays were experienced due to adverse weather conditions and the surface preparation grit blasting was slow due to the paint thickness. A long tarpaulin sleeve was also required to divert water coming from the 4in line and isolate the repair area.

The work avoided a potential dropped object and was more cost effective than replacing the caisson, avoiding shutdown. ▪

Project specs and conditions

Design pressure (bar)	1 bar
Design temperature (°C)	40°C
Repair lifetime (years)	15 years
Axial load (kN)	46
Bending moment (kNm)	100.5
Shear load (kN)	148.5
Surface preparation	Grit Blasting

Daniel Abicht. Image from UTC Bergen.

The beginning is nigh

With a need to find more cost-effective solutions, for more complex systems, converging with the big data era, could it be time for the all-electric subsea system?

Elaine Maslin reports.

Going all-electric on subsea systems appears to offer many benefits. You can have simpler umbilicals without hydraulic lines, for one, which in turn removes the need for topsides hydraulic support systems and eliminates the risk of leaks to the environment. More flexible subsea architectures can be installed and more accurate control over, and knowledge of, subsea and downhole equipment can be achieved.

In the past, technology readiness, high oil prices, the costs of such systems and a reluctance to try new technology, have perhaps hindered progress. But, the picture is changing rapidly. System suppliers are edging closer towards qualifying subsea power distribution technologies. Vendors are further proving their all-electric equipment, and operators are continuing moves into areas (deepwater, long stepouts) and technologies where electric control would be beneficial.

Could it finally be time for all-electric? Operators believe so. French oil major Total, which began using the first fully electric subsea Xmas tree last year, says it has "a firm belief on all-electric systems."

Daniel Abicht, leading advisor subsea control systems, Statoil, says that all-electric hits nearly everything on the Norwegian major's technology strategy. This is no longer a subsea controls topic, it's a system topic, he told the Underwater Technology Conference (UTC) in Bergen earlier this year.

All-electric can reduce CO_2 footprints, eliminate the risk of hydraulic fluid leakage, reduce logistics and exposure to equipment under pressure, and enables a degree of automation – as well as advanced condition monitoring, which couldn't be achieved otherwise. "Digitalization requires a higher degree of automation. To achieve a high degree of automation subsea is only achievable by going all-electric and this is even more applicable for subsea processing applications," he says.

Statoil's chief engineer subsea, Rune Mode Ramberg, adds another dimension – imagine being able to have an IP address for each subsea valve. This offers a huge difference in accuracy. Going all-electric also offers flexibility, plug and play capability and simplicity, says Einar Winther-Larssen, product manager, All-Electric, Aker Solutions.

All-electric could also achieve cost savings. In an Offshore Technology Conference (OTC) Houston 2017 paper, Abicht says all-electric subsea production systems provided capex savings of 7-14%, not counting the removal of the associated topside equipment and opex savings. A similar project by Total identified up to 13% total capex savings on an existing project.

Moving on

Traditionally, hydraulics were used to control subsea valves. Electro-hydraulic systems were introduced to overcome the slow response time and issues over scalability with hydraulic only systems. Electro-hydraulic systems are limited in terms of future tiebacks, long stepouts, deepwater applications, and add topside complexity. This means costly and complex Xmas tree control systems, which have arduous system startup and shutdown processes, Abicht says.

"The next step in technology development is to eliminate hydraulics... driven by performance needs, water depth increases and environmental constraints," says a 2017 OTC paper by Johansen et al., from TechnipFMC.

Increases in subsea sophistication, such as chemical dosing, pumping, separation, and gas compression also add to the drivers, and indeed, in some cases, such as for fast modulated process valves, electric actuation is an "absolute need," it says. Furthermore, the increasing emergence of resident remote operated vehicle (ROV) type technologies will also enable the "next generation inspection, maintenance and repair systems," in all-electric fields.

First actuation

Electric actuation is already well established. Statoil has had electric actuation since 2001, and has 8.5 million hours operational experience in non-safety critical applications, all using a spring return. There are 800,000 hours accumulated running time on electric Xmas trees across the industry, Abicht says. Statoil's Åsgard subsea gas compression system has 79 actuators in operation and is an all-electric system.

TechnipFMC installed its first electric systems 15 years ago, 165 of their electric actuators have been installed since, and 8 million hours of operation have been accumulated in electric systems provided by TechnipFMC over that time, says Johansen et al.

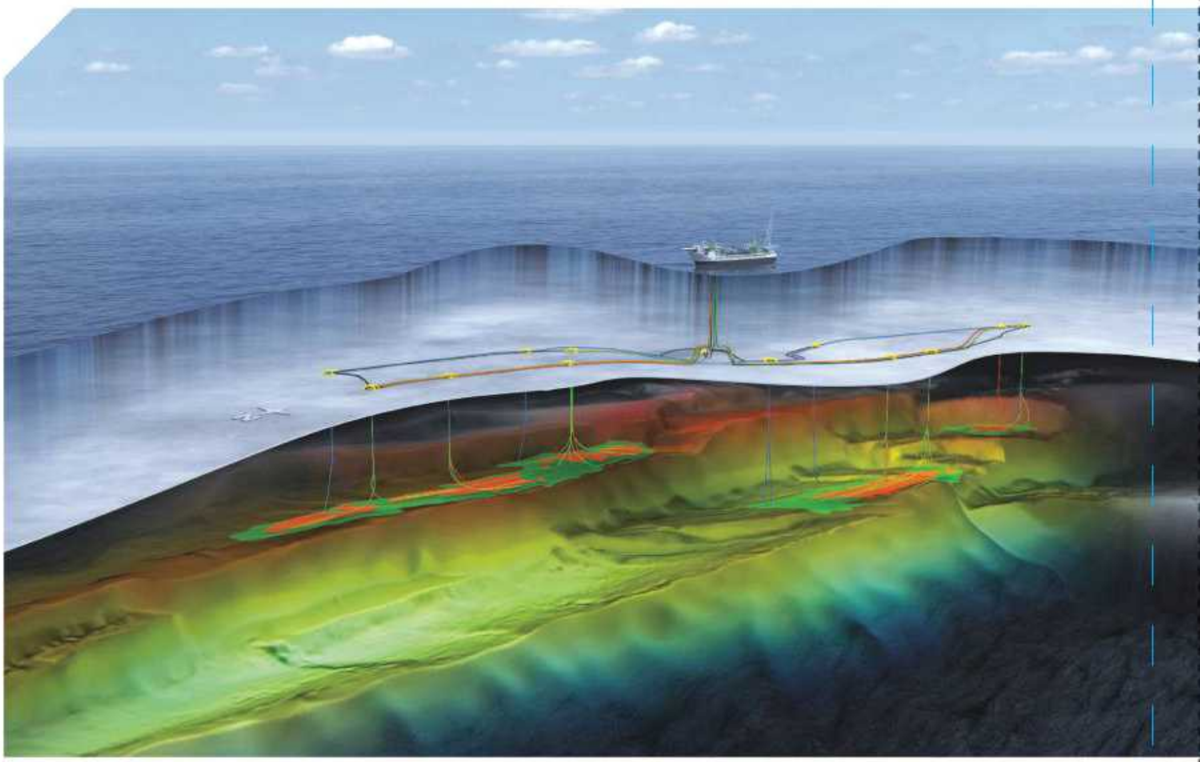
Statoil want to start qualification an all-electric Xmas tree system in 2017-18, then adding a subsea safety valve in 2018-19. A stepping stone for the latter could be a subsea hydraulic power unit, Abicht says. Other items are also requiring qualification, specifically those on safety critical subsea applications, such as well barrier valves.

The first e-tree

Last year, Total launched the first all-electric subsea Xmas tree, including downhole subsea safety valve (DHSV), in the Netherlands (*OE*: September 2016) on the 18km stepout K5F-3 well in 44m water depth. Two earlier wells on K5F have had all-electric trees since 2008 – also firsts – but a hydraulic DHSV. The latest components were qualified to 3000m water depth, making it a deepwater-ready technology. The system uses Schlumberger-owned OneSubsea's latest generation CameronDC subsea Xmas tree and controls technology and a Halliburton electric downhole safety valve (eDHSV).

To test the impact of going all-electric on a subsea development, Total performed a study on its Laggan-Tormore subsea tieback – the UK's longest subsea tieback. The project, 143km from shore, in 610m water depth, came onstream with an electronic-hydraulic control system in 2016. Total looked at what difference it would have made if it had used a DC current and fiber optic (DC/FO) cable, for power and control, and all-electric subsea trees, with revised subsea control architectures, on the field. DC/FO has been proposed for the Johan Castberg development offshore Norway, with Statoil working with Alcatel Submarine Networks (*OE*: August 2016).

While a separate line would be needed to supply injection chemicals (Statoil and others are looking at subsea chemical storage), using such a system could achieve savings of 8-11% on the combined subsea umbilicals, risers and flowlines package, or 4-5% on the whole project capex, according to a 2017 OTC paper by Pimentel et al., from Total.



Statoil's Johan Castberg project, which could feature a DC/FO system. Image from Statoil/Kåre Spanne.

Switching out continuous MEG injection with continuous anti-agglomerant accumulation chemicals, via a dedicated line, increased savings to 20-25%, 10-13% of the total capex, according to Pimentel et al.

Stripping out cost

According to TechnipFMC, savings would be made by removing the costs associated with hydraulic control systems, from the design phase through manufacturing, testing, installation and commissioning and finally maintenance and hydraulic fluid consumption.

Abicht points out that there's around 150m of small bore tubing on a Xmas tree. On the manifold, there's 300-350m. "It's not only the metal, but the process behind that. Welding, inspection, documentation," he says. Removing all this metal also reduces Xmas tree weight and footprint, making installation easier.

A new architecture

Removing a hydraulic control system also opens possibilities for alternative controls architecture. An all-electric system could have "intelligent nodes" in the subsea system, favoring the distribution of control, says Pimentel et al. Having decentralized nodes would have two benefits, it says: a smarter and simpler electrical distribution, with the removal of additional electrical flying leads, and a better communications schema, using a ring connection topology (where devices are connected in a ring and data is sent around the ring until it reaches its destination). "Both effects will equally help in the overall system availability by reducing the number of connections and increasing the network fault protection," the paper authors say.

Adopting decentralized control architecture with intelligent actuators, reduces cost, while electric actuators in a centralized system increases cost, according to a comparative study done by Aker Solutions, Winther-Larssen says. Current control architecture is designed how it is because it's easier to install control hydraulics that way, he says. Removing the hydraulics enables simplified distributed subsea control modules, retrievable electric actuators, with and without failsafe spring, at roughly the same size.

One challenge with all-electric systems is their monitoring and control, Total says.

"The response time between fault detection and the corrective action for a subsea power system is required to be faster than a subsea production or even a subsea processing system," according to Pimentel et al.

"For instance, if a fault is detected in the subsea step-down transformer, the topside protection system should be notified on a fast and direct communication link to ensure that the topside circuit breaker can be opened within time to protect the transformer. Therefore, the performance requirement for data sampling of a subsea power automation system is in the range of a few milliseconds, whereas a range of 100 milliseconds to 1 second is acceptable for a subsea processing system, and a few seconds may suffice for a subsea production system," say Pimentel et al. Fiber optic helps in this respect.

The K5F-3 subsea all-electric Xmas tree from OneSubsea. Photo from TEP NL.

Power distribution

One of the building blocks for all-electric is power distribution. Pressure compensated power equipment is expected to be available in the market soon, "which may have the impact to change the game of subsea production and processing systems," says Pimentel et al.

Indeed, Siemens, GE Oil & Gas and ABB are all working on subsea power distribution technologies. GE Oil & Gas qualified a system, as part of its work on Shell's Ormen Lange subsea compression step out proposal, last year (*OE*: August 2016).

GE Oil & Gas' system is based on marinized power components (variable speed drives, and transformers), which have been marinized in one-atmosphere containers for use on the seafloor.

ABB is working on a US$100 million joint industry project, signed in 2013, based on components in pressure balanced oil-filled containers. The project it looking to qualify an up to 100MW system for up to 3000m water depth and 600km step out. Full system testing is due in 2018, in shallow water. Siemens was planning a system integration test of its system, also in oil-filled containers, and full load testing in water this year (*OE*: August 2016). Early August, Siemens announced that Eni had joined its joint industry project, alongside Exxon, Chevron and Statoil.

New system, new mindset

For all-electric to be achieved, there's a mindset to overcome, however, Abicht says. "We have big organizations and all-electric has always been in some sort of research and development bubble. Hence, close and multi-discipline collaboration across the various business units is required."

Meanwhile, existing requirements for controls, Xmas trees, and subsea production systems are often circled around established (hydraulic) solutions rather than functions. This provides a challenge regarding implementation of new technology. Moving away from a hydraulic system that people have confidence is also a challenge, Winter-Larssen says. But, he adds: "We have come to a point where we believe we can make competitive electric system compared to hydraulic."

It's coming. "We know all the major operators are assessing all-electric and it is the same in supply chain. Everyone has a strategy in place," Abicht says. "That's something we didn't have 10 years ago." **OE**

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1. *Real Application of Electric Controls Technology to Subsea Systems: Success, Learnings and Recommendations. OTC Houston 2017. OTC-27657-MS. Johansen et al., TechnipFMC.*

2. *Seamlessly Integrated Subsea All-Electric Systems: Laggan-Tormore as a Case Study. OTC Houston. OTC-27588-MS. Pimentel, J. et al, Total.*

Under compression

French major Total has been considering its late-life compression options for the Laggan-Tormore step out in the UK North Sea. The development, a 143km tieback to shore, came onstream in 2016, via two subsea manifolds with slots for up to six trees in each and the potential to tie in third party infrastructure.

Subsea compression could be used later in life to boost production from Laggan-Tormore and help produce gas from third party fields tying into the Laggan-Tormore system.

Total thinks that it would need up to 7MW of power for each compression units on the field, supplied via a 143km subsea AC power umbilical, at 63kV, with a separate barrier fluid line for the motor-pump mechanical seals.

The details were outlined in an OTC Houston 2017 paper by Juliano Pimentel, Rory Mackenzie, Edouard Thibaut, and Frederic Garnaud, Total. ▪

A TechnipFMC iEPCI vision.
Image from TechnipFMC.

An iEPCI philosophy

Undeveloped pools in the North Sea and elsewhere could make it over the line with TechnipFMC's iEPCI approach to subsea tiebacks. Elaine Maslin reports.

Moving away from a bespoke approach to oilfield development has been seen as one of the ways the industry could reduce costs following the downturn's start in late 2014.

TechnipFMC has been applying such thinking to subsea tiebacks on the Norwegian Continental Shelf (NCS).

"There are a lot of undeveloped fields in the North Sea that are not economical with traditional solutions," said Dag Jostein Klever, global technical manager iEPCI Satellite Systems, TechnipFMC, at the Underwater Technology Conference (UTC) in Bergen, Norway. "According to analysis, there are approximately 180 undeveloped fields on the [NCS]; 54 of those are less than 20km from host facilities and have up to 30 MMboe. None are high-pressure, high-temperature."

TechnipFMC has developed a system to tap a "sweet spot" among these fields. This would be projects with up to three well satellites, at less than 20km stepout, and water deeper than 125m, where fields are non-high-pressure, high-temperature, and contain more than >30mmbbl in-place.

The system is part of TechnipFMC's iEPCI (integrated EPCI) concept, which has been developed through a design to cost approach, where the total cost of a project – including installation, operations cost, and abandonment cost – is analyzed and the appropriate building blocks are selected. Subsea umbilicals, risers and flowlines (SURF) and subsea production system (SPS) building blocks are vendor-based specification and pre-engineered solutions. The installation ethos is such that a solution can be installed and ready to produce through one single vessel campaign, without disturbing the drilling rig.

Such a solution would be a mid-point between fields accessible by deviated drilling or standalone projects, Klever says. By also looking at possible reuse of the equipment, for fields with 3-7 years' drainage life, the proposition could be even more beneficial – although this would mean a change is necessary to maintenance philosophies to enable reliable, predictable reusable equipment, Klever says.

Dag Jostein Klever

"We have focused on optimizing the solution for installation," Klever says. "Pre-engineered solutions and installations plans reduces delivery time."

As a basis for design, for a 5km, 500m water depth project, a low footprint over-trawlable structure would be used, and could be installed in one campaign (along with the Xmas tree and subsea umbilicals and trenched flowlines) from one vessel, with rental tooling on board. It would use a conventional, 5in, 10,000psi configurable vertical Xmas tree, with a basic circular retrievable choke, with functionality to be added for specific applications.

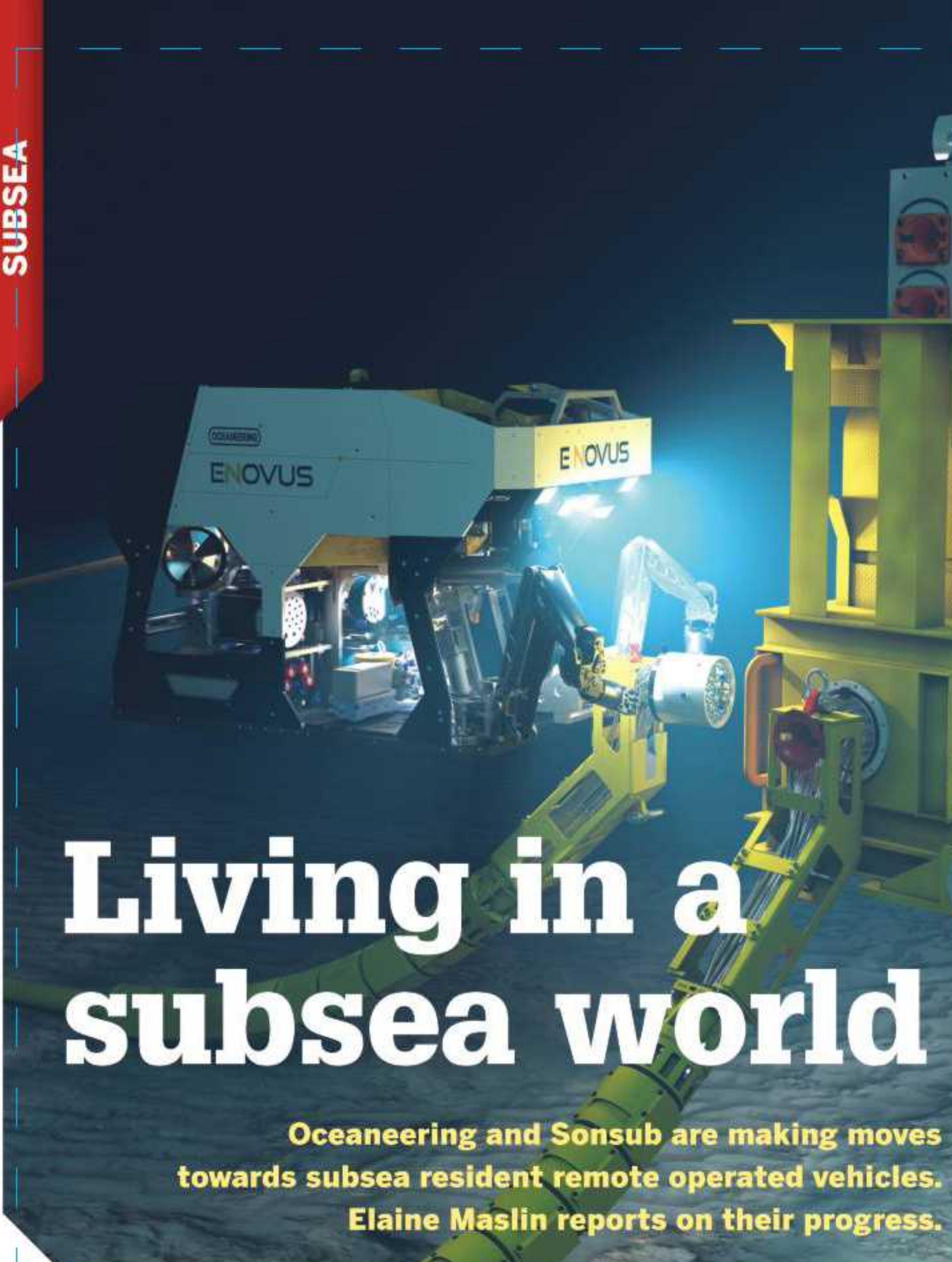
It would have an electro-hydraulic system controlled via a 5km steel tube umbilical and a 6in flexible control line, with a UCON H8 connector integrated into the design. For hydrate formation prevention, continuous injection of inhibitors would be required, so the umbilical is designed for a rate of 1500cu m/hr injection. "That, with decompression (for long-lasting shutdowns), is the basic philosophy for the design," Klever says.

To reduce rig scope, Xmas tree installation would be from a vessel on a wire, using a work class ROV for communications and pressure testing, and then well opening by manipulating the pump open well barriers. This could typically remove seven rig days and add three vessel days, Klever says.

Such an approach would reduce project execution from 41 months for a traditional approach (SPS 24 months, SURF delivery 30 months), to 20 months with the iEPCI approach (SPS plus SURF).

"We see the potential to reduce cost by more than 30% compared to the industry standards for satellite solution," Klever says. "We are now working with clients how to reduce costs further."

In a parallel study, opportunities in Asia Pacific were considered, including a three-well tieback with a leased FPSO. "We are now looking at all regions, looking what the key drivers and similarities are globally," Klever says. "That would allow us to use solutions across the regions." OE



Living in a subsea world

Oceaneering and Sonsub are making moves towards subsea resident remote operated vehicles. Elaine Maslin reports on their progress.

The eNovus ROV illustrated.
Image from Oceaneering.

The move towards increased subsea processing on the seafloor is seen as a driver for producing resident subsea robots.

While many people have been focused on developing a subsea resident vehicle, which would reduce the need for support vessels, Saipem's Sonsub business has been developing a strategy based on a fleet, which it calls the Hydrone platform, to perform life of field subsea services.

Hydrone R, a resident vehicle, is the core of the fleet. But, alongside Hydrone R are other vehicles, both resident and semi-resident, as well as a work class remote operated vehicle (ROV), to be operated by a multipurpose support vessel (MCV). The firm's Innovator 2.0 work class ROV is already in operation. A version of the Hydrone R, which Sonsub wants to be able to operate in tethered, untethered and autonomous underwater vehicle (AUV) mode, is expected to begin tests next year.

"In the future, we will see a completely different way of providing services at sea; active local heating, Springs (*see page 30*), Spoolsep, Multipipe, heated pipe-in-pipe," says Francesco Cavallini, commercial and tendering manager, Sonsub, mentioning some subsea processing technologies Saipem is developing. "Life of field subsea [services] will be critical to make such projects sustainable." But these activities are currently reliant on the use of an MSV, he says. With resident vehicles, there is an opportunity to be more proactive, or even predictive, and perform immediate interventions in the event of need.

The Hydrone fleet

The Hydrone fleet comprises the fully resident Hydrone R, Hydrone W (a work class semi-resident ROV) and Hydrone S (an advanced survey and inspection unit). They can be supported, when required, by Saipem's new heavy duty work class ROV, Innovator 2.0, based off a support vessel with a crane. Hydrone R and Hydrone S would be docked subsea with a common subsea garage, which would also house various tooling skids, as well as recharging facilities.

Sonsub's objective is to have Hydrone R in the water next year and fully operating for demonstration. The Hydrone R is described as a modular subsea resident and reconfigurable intervention ROV, integrated within the field. It would be able to move between different garages, according to mission requirements. It would also be open to third-party component integration, says Giovanni Massari, a Saipem project manager.

The unit would be controlled from a floating production vessel or from shore in tethered or untethered mode, or in AUV (also untethered) mode, when travelling between different stations, or performing a pipeline inspection. It would be available for use in emergencies, to "see" what is happening and intervene, if necessary. It would also have a "menu" of automated missions, which could be selected remotely by operators onshore and implemented autonomously by the Hydrone-R.

Massari believes that there will be an evolution in this technology, but that the resident ROV will be able to perform normal ROV duties. A number of technologies will need qualifying, he says, including long endurance capability, artificial intelligence, subsea batteries and recharging, as well as remote manipulation, subsea Wi-Fi, specific investigation and intervention tools.

For these technologies to take hold, Massari says that there is a need to promote a standard for resident subsea robot interfaces (between the base and subsea production systems and between base and vehicle). The API RP17H revision will include some recommendations for AUV/ROV interfaces on subsea production systems. "Standardization is a must," he says.

For Massari, greenfields should also be designed to accommodate these technologies, in order to maximize their potential.

"The number of functions they could perform could be increased through proper design of greenfield systems," he says.

Remote reality

Statoil and Oceaneering have taken the resident remotely operated vehicle (ROV) concept a step further.

Under a contract with Statoil, Oceaneering deployed a "cage"-based ROV on the Troll field, in the Norwegian North Sea, using control from shore via a 4G LTE offshore broadband network.

The cage was fitted with battery packs, to power the ROV, and connected to a data buoy, which enabled communication to an onshore control center in Stavanger. The deployment, under Statoil's E-ROV project, is the latest in a series of steps Oceaneering has taken in remote piloting.

The company first remotely piloted a Nexxus work class ROV, operated off the MSV *Olympic Intervention IV*, in the Gulf of Mexico, via a satellite link, in 2015. Satellite links have medium bandwidth and medium latency, which add lag to communication rates, according to a presentation by Arve Iversen, ROV Operations Manager, Oceaneering, at UTC Bergen. LTE, however, a 4G version of which is used on the Norwegian Continental Shelf, has medium bandwidth, but low latency, reducing lag.

Last year, Oceaneering again tested remote piloting from the *Songa Endurance* semisubmersible drilling rig using a Magnum 183 work class ROV and the Telenor 4G LTE broadband network. The ROV performed a number of tasks from the semisub on the Troll field, offshore Norway, with onshore control in Stavanger, in December 2016. Tasks included stabbing an HP-cap high-pressure seal test line with a dummy stab, laying down and raising a riser connector support frame, and cleaning a section of template hatch structure.

Data were transmitted in 58ms, and video in 200-400ms. Bandwidth was 0.2 Mbits/s for data and 2 x 2 Mbits/s for video. This will improve as networks improve and even as 5G networks are introduced, Iversen says. In 2020, 5G is coming. Then, the latency will be reduced by 90% again, and it will be "really, really good," said Pål Atle Solheimsnes, leading advisor for subsea intervention and diving at Statoil, at Subsea Valley in Olso, Norway, in April. "We can use it on all subsea production systems in the North Sea." (*OE*: June 2017)

However, Statoil wanted to go further for its E-ROV concept. This is a fully standalone and battery-powered work class ROV system remotely piloted from onshore via surface 4G LTE data and a communication buoy.

Oceaneering was awarded a contract in January 2017, using its eNovus electric work class ROV, stationed in a subsea garage (cage, tether management system, and battery packs), using battery power to operate, and with onshore communication and control via the 4G LTE data buoy. It was deployed using a Statoil-operated inspection, maintenance and repair (IMR) vessel at the Troll field.

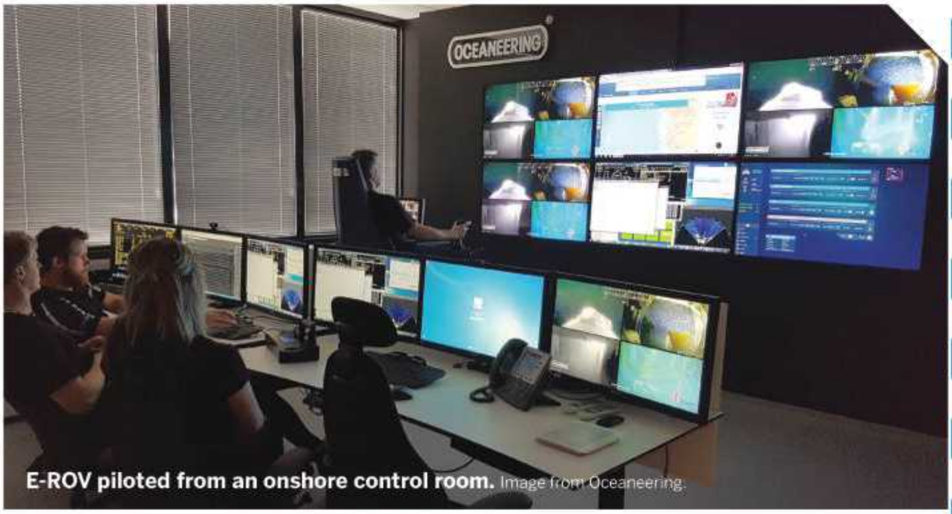
The battery packs were 120-kWh capacity with 100kWh on the cage and 20kWh on the vehicle.

Iversen says that the vehicle would be able to sit in standby "sleep mode" mode for more than six months, or standby "awake mode," with systems off, for 10 days. It would be able to perform stationary observation work for four days, slow-moving inspection work for 40 hours, travel at 1knot for 24 hours, or do left and right manipulator work for 17 hours. Solheimsnes says that the battery pack could be scalable and updated as battery technology improves.

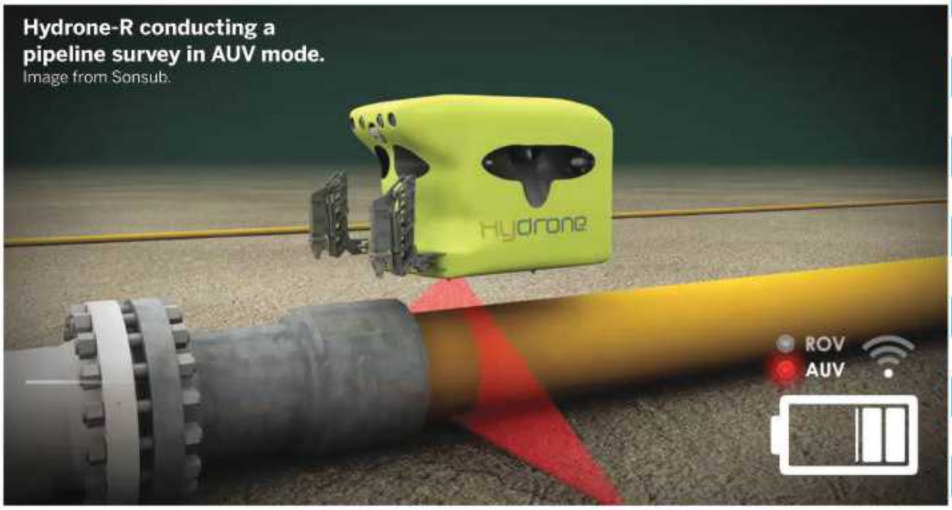
Techniques helping to improve remote operations include advanced adaptive video compression, automated ROV control (such as hands-free piloting and advanced station keeping), and automated manipulator control, using the likes of 3D visual object recognition and automated hot-stabbing, Iversen says.

Options for use of this technology include remote support from other offshore locations, multi-vessel operations, and the resident ROV.

There are a couple of deployment concepts for the E-ROV, one involving the *Seven Viking* IMR vessel, with several E-ROV skids on board, almost doing a "milk round," deploying the skids via its moon pool to the seabed. Another has the *Normand Ocean* deploying one skid, going off to do other jobs, and returning to collect the E-ROV when it has completed its work. OE



E-ROV piloted from an onshore control room. Image from Oceaneering.



Hydrone-R conducting a pipeline survey in AUV mode. Image from Sonsub.

Getting heavy

Elaine Maslin surveys some of the heavy oil field developments in the UK Continental Shelf, plus some of the technology aimed at unlocking it.

Heavy oil is making an impact on the UK Continental Shelf. This year, EnQuest's Kraken heavy oilfield came on stream east of Shetland. Meanwhile, Statoil's Mariner US$7 billion fixed facility heavy oil development is taking shape in the same region (*see page 14*).

Relative to existing North Sea heavy oil fields that are already in production, such as Chevron's Captain field, at API 19.5°, these are heavy fields and there's a reason they're only just being developed (based on investment decisions made before 2014).

A look at a list the world's heaviest offshore oil fields offers a telling tale. According to data from industry analysts Wood Mackenzie, a large chunk of the heaviest oil fields discovered offshore to date have not been developed. Those that are being developed have been waiting some time for the technology to be ready to drain them.

This is because heavy oil is heavy work. Heavy oil is measured by its API gravity. The smaller the number, the more viscous the oil, ranging from a thick oil to something more like marmite. Development, offshore, almost always means the need for downhole pumps and diluent injection, and, as in Mariner, heavy well count (100+). Other technologies to aid recovery of this thick liquid are being considered.

The UK's heavy oil fields

Tudor Rose, an undeveloped UK North Sea field, is one of the five heaviest discovered offshore oilfields, at API 8.5°, according to Wood Mackenzie. It was deemed "sub-economic even at very high oil prices," by MOL Group in a license relinquishment report last year.

The next heaviest known oil discovery on the UK Continental Shelf (UKCS) is Statoil's Bressay at API 10.8° (at number 14 in the global rankings). It was once seen as a sister development to the Mariner oil field, but is currently "parked" pending Statoil gaining more experience on Mariner. Associated gas from Bressay had initially been eyed for use for power on EnQuest's Kraken development.

Xcite Energy had been trying to finance the development of Bentley (16 in the global rankings), also on the UKCS. Bentley was discovered back in 1977, and its API is 11°. To put this in context, says Joao Conde, a production assurance specialist at Aberdeen based Infinity Oilfield Services, Bentley oil is a little like marmite.

The liquidators of heavy oil explorer Xcite Energy have sold the firm to a group of its bondholders, called Whalsay Energy, for US$1. Xcite had hoped to submit its development plan, including use of dual electric submersible pumps (ESPs) and diluent, before then end of 2016, before falling into liquidation, having failed to refinance. Former ConocoPhillips UK and Talisman UK senior executive Paul Warwick is listed as one of Whalsay's directors, as of 4 July.

Mariner, discovered in 1981, meanwhile is API 13° and contains some 2 billion boe, just a fraction of which will be produced, due to the nature of the oil. Statoil's Peregrino field, another heavy oilfield produced via an FPSO, offshore Brazil, is API 14.5° (*see page 44*). Statoil is considering polymer flood on Mariner, but not until it has completed trials of the technology on Peregrino, which itself follows a trial on the firm's Heidrun field in Norway (*OE:* May 2017).

EnQuest's Kraken is API 14°. The field, 125km east of Shetland, or 350km northeast of Aberdeen, is due to comprise a total 25 horizontal wells (14 for production and 11 for injection), with gravel packs and hydraulic submersible pumps (HPSs) in the producers. They are being produced via Bumi Armada's *Armada Kraken* floating production, storage and offloading (FPSO) vessel. The pumps, ClydeUnion-branded hydraulic submersible pumps (HSPs), manufactured in Glasgow, Scotland, were supplied by SPX.

The Kraken field, discovered in 1985, spread over 42km at a depth of 1300m below sea level, is expected to hold 128 MMboe of gross 2P reserves. Late June, 13 wells had been drilled and completed to date, comprising seven producers and six injectors.

Liquid properties

One of the problems is that this viscous liquid has properties that can change depending on its environment, i.e. pressure and temperature, as well as how much water is produced with it, which influences emulsion forming, making it harder to move and handle in separate phases, Conde says.

HSPs or ESPs are used, which require power, and diluent injection can be done, increasing process and import requirements, says Niki Chambers, production assurance specialist at Infinity. Water separation and handling, especially in a brownfield scenario, being able to blend oils, and managing unplanned shut downs are further challenges. Chambers says fluid monitoring will become more

EnQuests' Kraken heavy oil floating production vessel.
Image from EnQuest.

important, yet many flow meters aren't good with heavy oils.

Despite the challenges, there's a lot of heavy oil out there and there are those who see an opportunity, including the UK's regulator, the Oil and Gas Authority (OGA).

According to a Society of Petroleum Engineers Distinguished Lecturer Program presentation by retired Shell executive Johan van Dorp, there's 10 trillion stock tank oil in place resources in the world, with current global heavy production is about 10 MMb/d, with 2 MMb/d from thermal (steam based) production.

The OGA sees heavy oil as an opportunity. "The recent success of the Kraken heavy oil field coming onstream shows what can be done. Indeed, the OGA believes that Kraken, and the Statoil Mariner field, have the potential to open up additional heavy oil opportunities in the North Sea," the OGA told *OE*. It is focusing on promoting new technologies and technology sharing, and the formulation of area plans to capitalize on nearby infrastructure to help promote heavy oil development, with the Quad 9 area in the North Sea seen as a key area of potential.

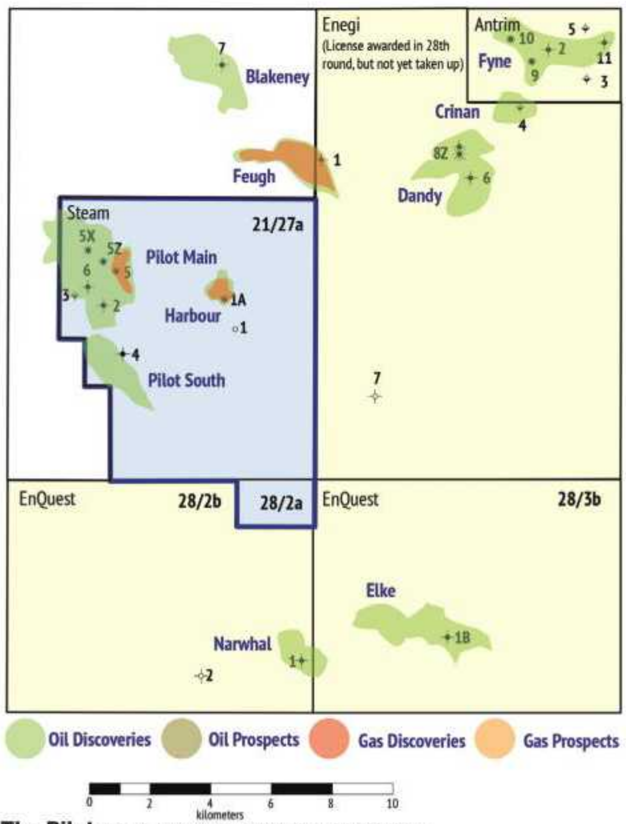
But, the OGA cautions that current oil prices do pose a challenge, "so sharing technologies and identifying the most cost-effective ways to investigate and tap heavy oil potential will be even more crucial in the short term."

Of the some 360 discovered but unsanctioned small pools (fields under 50 MMbbl) on the UK Continental Shelf, many are heavy oil, Chambers says. Technology, such as HSPs, enhanced oil recovery (EOR) techniques like polymer, or steam flood, mostly used onshore, are some of the options which could help improve recovery rates, she says.

Steam and other alternatives

UK based independent, the Steam Oil Company, holds a northern North Sea license containing the Pilot field, which it hopes to develop using steam injection – something few, to date, have tried offshore (*OE*: December 2015). Pilot, a discovery with API 12-18°, and the nearby Pilot South and Harbour fields, contain 272 MMbbl proved plus probable oil in place, says the company. While recovery rates using traditional technology would be low and uneconomic, steam flood would offer much higher recovery rates – up to 60% – thinks the company. And it says it wouldn't be that difficult, because the reservoirs are quite shallow.

Still, the challenges of producing and injecting steam offshore are significant. Another firm thinks it might have an alternative.



The Pilot area. Image from The Steam Oil Company.

Working with the University of Strathclyde, Glasgow, Aberdeen-based Cavitas, founded in 2015, has created a device which can be deployed downhole to generate heat fluid within injection and production wells.

The thermal heavy oil recovery (Thor) system uses a rotor within a housing to heat fluid or steam inside the wellbore of injection wells and can be used as a bypass fluid heater.

The Cavitas device would be a sealed unit and filled with a high temperature fluid (oil). This fluid would be heated by the rotation of the rotor and in do so it would heat the external body of the device. It would be powered by a suitable motor (electric or hydraulic). Injection water flowing past the device would be heated by thermal conduction, resulting in hot water/steam being injected into the reservoir, lowering oil viscosity, increasing mobility and avoiding the losses associated with conventional topside thermal EOR.

For a production well, a Cavitas generator would be incorporated into a downhole artificial lift device, such as an ESP or HSP). It would "fit seamlessly" within the completion and draw rotational power from the HSP/ESP. There, it would act in the same way as the device used for injection, this time heating production fluid as it passed over the device, prior to its entry into the HSP/ESP, lowering viscosity and increasing production.

Traditionally, steam flood using gas/oil powered boilers is used for heavy oil production onshore. Due to size and intensity of this activity, it's not been used offshore. "We won't have the output of the massive steam plants, but because our device is efficient and the losses are downhole anyway it doesn't need the same output," Cavitas says. "Our research in conjunctions with a UK Heavy Oil operator has shown that even small injection rates of heated fluid/steam (c.500-3000 b/d) can have a huge production upside."

Onshore, efforts are looking into using liquid or condensing solvents, to shift heavy oil (including as a way to make steam flood assisted gravity drainage more efficient), but also electrical heating. Both of these are being demonstrated, says van Dorp. The latter – electrical heating – includes formation heating, in various forms, including; using a heating element down hole (thermal condition, like Cavitas); using electrodes in separate holes to conduct current and make heat; induction downhole; and high-frequency radio frequency. **OE**

FURTHER **READING**

The North Sea gets steamy
www.oedigital.com/component/k2/item/10991-the-north-sea-gets-steamy

Sticky business
www.oedigital.com/component/k2/item/15228-sticky-business

Teekay's *Petrojarl I* FPSO will be used on the Atlanta field offshore Brazil.
Photo from Teekay.

Heavy opportunities

There is plenty of heavy oil to get out of the ground in Mexico, Brazil and Indonesia. Karen Boman surveys the work underway.

With oil prices still trading around the US$50/bbl mark, finding efficient technologies that allow heavy oil to be extracted with fewer wells, or at a lower drilling cost in less time, may become a gamechanger for developing offshore heavy oil fields, says Adrian Lara, analyst with GlobalData. Quite often, recovery is defined by the number of wells drilled, as oil with higher viscosity flows much slower than a conventional one and may not respond easily to the primary recovery methods.

New technologies will have to address the challenges of offshore heavy oil fields, including flow assurance, which is one of the main challenges of offshore heavy oil fields, Lara says. Appropriate measures should be taken to prevent formation of hydrates, and emulsions when in contact with water as it may worsen electric submersible pumps' (ESP) efficiency. All of this will affect the well's productivity and lower the recovery.

Another challenge associated with heavy oil production is the water breakthrough. Oil with higher viscosity has lower mobility compared to the water, so the latter just channels through towards the producers. Once the breakthrough occurs, it is very difficult to recover the unswept oil in the near well area, unless enhanced oil recovery techniques, like polymers, are used.

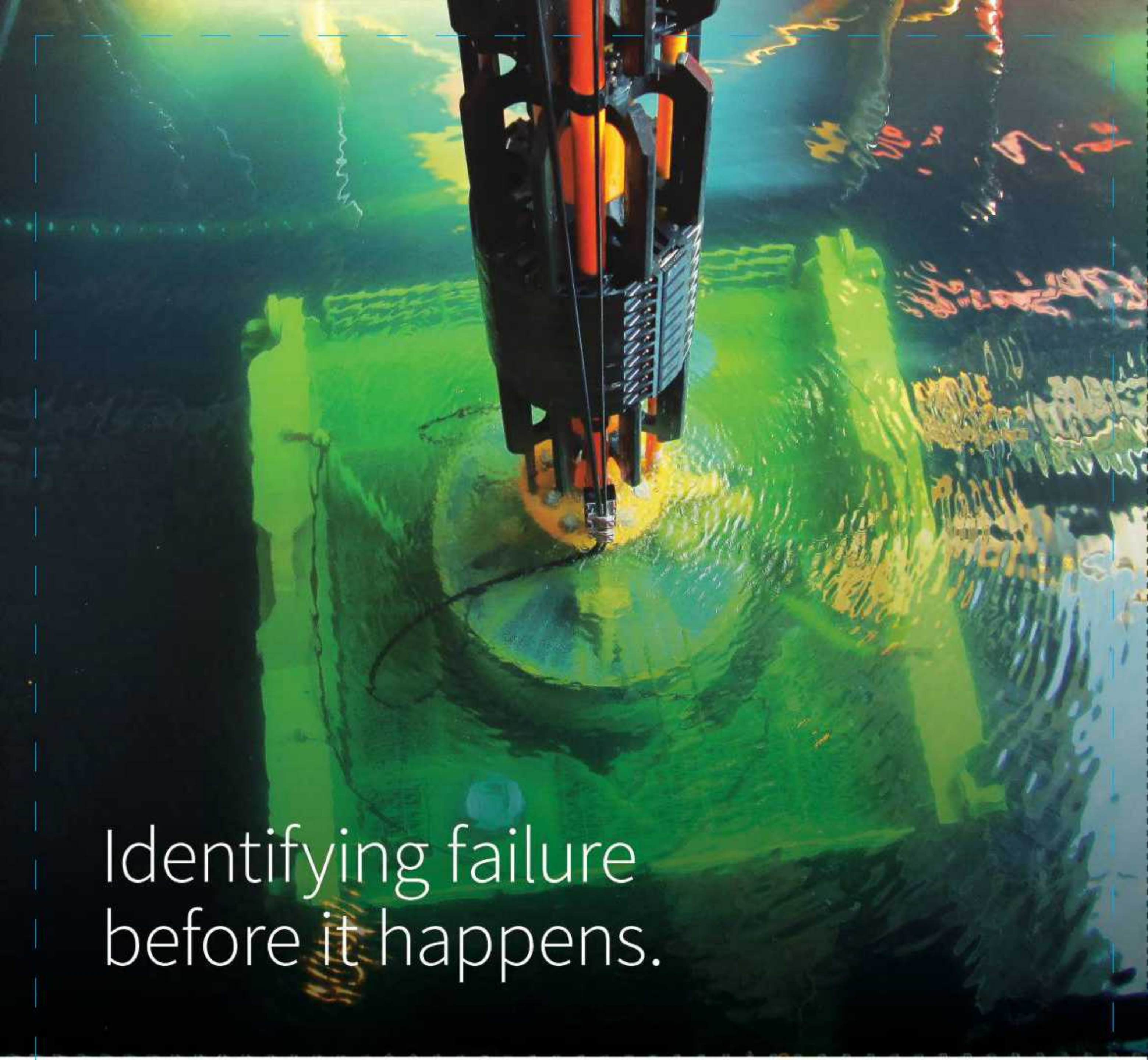
"One important thing to consider is how to keep the oil flowing as soon as it reaches the seabed of deepwater fields as temperature there is usually lower," Lara says.

He cites the Atlanta heavy oil deepwater field in the offshore Brazil as an example. Operator QGEP decided to properly insulate all the production lines. In the wellbore, ESPs with gas lift are usually used to allow the oil to reach the wellhead. Another option here is to add a diluent/condensate/light oil to increase the mobility of the fluid in the well, Lara says.

Many wells in the offshore Brazil are equipped with inflow control devices to distribute the water production more evenly along the wellbore. This allows can prolong the production with lower water cut, Lara adds.

"Normally these schemes include any actions to keep the oil flowing towards the producing wells. Due to higher viscosity of oil, such fields require either stronger aquifer support or water injection strategy to create needed drawdown pressures, or injection of gas/solvent to bring the oil viscosity down," Lara says. "Other technologies that involve heating of the reservoir in-situ, could be used onshore, but may not be applicable to the offshore fields due to difficulties associated with constructing the facilities."

Statoil's Peregrino heavy oil field, discovered in Brazil's offshore Campos Basin in 1994, has been producing via the *Peregrino* FPSO and two wellhead platforms since 2011. A third wellhead platform is currently being constructed (see panel). To reach Peregrino's API 14° heavy oil deposits approximately 2300m below the seabed, Statoil used the horizontal drilling techniques it applied to its Grane heavy oil field in the North Sea. Some 30 long horizontal multilateral wells with open hole gravel pack and screens made it possible to reach and produce from a wider area of the reservoir, Lara says.



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Additional production from increased sweep efficiency allowed them to reduce overall development costs and bring down the breakeven oil price for the project.

"Fortunately, many offshore heavy oil fields in Brazil have good permeability that offset bad quality of oil and make the development of such reservoirs more attractive from the economical perspective," he says.

Statoil also used ESPs, inflow control devices and autonomous inflow control devices to enhance recovery from the Peregrino field. Using ESPs allowed Statoil to heat the oil to 130–150°C in the wellhead platform.

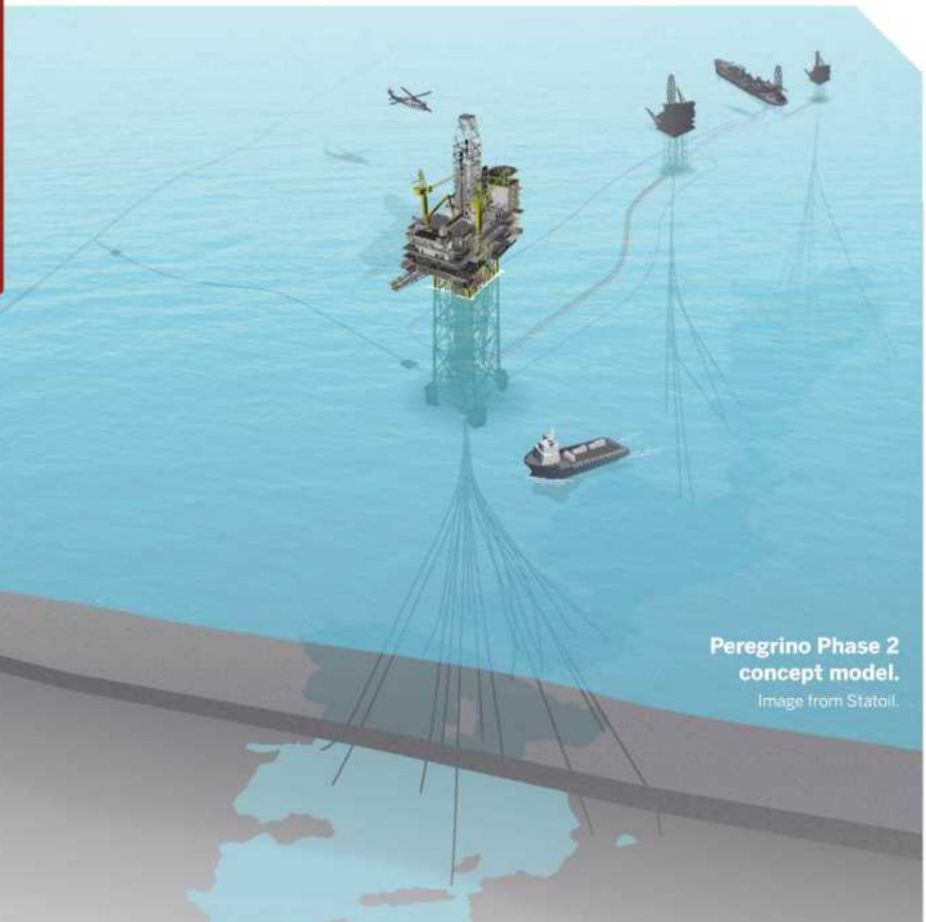
Outlook for heavy oil

The 2014 oil price downturn has stalled development of a number of oil fields, including Atlanta (API 14°) and Siri (API 12.5° according to news agency Estado), offshore Brazil, Lara says.

First oil from Atlanta is now expected by the end of 2017, according to QGEP, just four years after the project's development plan was approved by Brazilian regulators ANP in 2013. The Siri field, an extra-heavy oil in the deepwater of Brazil, has also seen delays, Lara said.

Indonesia's Ande Ande Lumt (API 15.5°) heavy oil field is in pre-final investment decision evaluation and has been somewhat stalled over the last few years due not only to lower crude prices, but due to cost overruns, Lara says. Located offshore Indonesia in the West Natuna Sea, Ande Ande Lumut was expected to be sanctioned in 2013, but cost and price changes have hindered development. The project is still under planning and evaluation, with the addition of deeper reserves having helped raise expectations for possible investment sanction in 2018.

Australia-based AWE, which holds 50% interest in Ande Ande Lumut, said work continues to optimize plans for the field in light of positive results from the AAL-4XST1 appraisal well, with a focus on assessing G sand resources. Laboratory work to assess feasibility of co-mingled production of K sand and G sand oil was looking positive, and no significant changes to the FPSO processing infrastructure were anticipated, AWE said in its March 2017 quarterly report. AWE said the operator has temporarily delayed



Peregrino Phase 2 concept model.
Image from Statoil.

Peregrino II set for 2020

The Peregrino field is Statoil's largest project in Brazil. The field sits in the southwest portion of the Campos Basin, in the BM-C-7 block, 85km offshore Rio de Janeiro. Statoil operates Peregrino with 60% interest alongside partner Sinochem (40%).

Peregrino, according to Statoil, contains estimated reserves of 300-600 MMbbl of recoverable oil and an API gravity of 14°. Statoil says this is the second heaviest oil to be produced in Brazil.

Production began on the field in April 2011, and reached a plateau of 100,000 b/d in 2013. The field is connected to an FPSO via outflow lines and electrical umbilicals. There are 40 production wells and 8 water injection wells currently planned.

Statoil submitted its development plans for phase two of the field in 2015. At the time, the Norwegian major said that the project will comprise a new wellhead platform and drilling rig (Platform C) and adds approximately 250 MMbbl in recoverable resources to Peregrino field. Statoil expected, in 2015, that investment will be around US$3.5 billion. Phase II first production is expected by end of 2020.

Phase II will enhance Peregrino production by increasing the number of production wells by 21, consisting of 15 oil producers and six water injectors, to be drilled from the new well head platform C, which will sit in 120m water depth. The well will tap a new area called Peregrino Southwest, which Statoil says is not currently reachable by the existent platforms A and B.

In November this year, construction is due to start Heerema Fabrication Group's yard in Vlissingen, the Netherlands, on the jacket for the Peregrino II development.

The eight-legged Peregrino jacket, which will be about 135m tall, have a footprint of 66m x 53m and will weigh 9300-tonne (excluding 12 piles), will serve as foundation for the topside, including drilling and process facilities, utilities, power generation, living quarters and a helideck, with a design operational weight of 25,000-tonne facility. The jacket is also designed for storage of fresh drill water with caissons for submerged pumps connected to such storage tanks, Heerema said in May.

Statoil awarded Apply Leirvik a $48 million (NOK 400 million) contract for the delivery of the five-story living quarters module, with delivery due in Q3 2019. ▪

starting Stage 2 commercial tenders to allow time to quantify the size of the G sand resource and integrate these potential positive changes to the plan of development.

The development of offshore heavy oil fields has not halted altogether, however. Offshore eastern Canada, ExxonMobil expects its Hebron heavy oil project to come online by year-end. Hebron is in the Jeanne d'Arc Basin, 350km southeast of St. John's, in 93m of water. Discovered in 1980, it is expected to contain 700MMbbl of recoverable resources, and is the province's fourth offshore oil project. The complete Hebron platform was towed to field and positioned on the seabed on the Hebron field at Grand Banks in mid-June 2017, according to Norwegian engineering services company Kvaerner, who through its joint venture Kiewit-Kvaerner Contractors, built the gravity-based structure and led the installation process.

The *Peregrino* FPSO at the Peregrino Field offshore Brazil. Photo from Statoil.

Mexican heavy oil awaits

With Pemex's announcement of its new farm-out strategy earlier this summer, the oil and gas industry might start to see heavy oil projects there receive their financial investment decisions. Pemex announced that it would include the heavy oil Ayin-Batsil complex, comprising four fields – Ayin, Alux, Batsil, and Makech – in its upcoming farm-out calendar.

Last month (August), *OE* detailed the fields available for farm-out. The Ayin-Batsil area offers more than 359 MMboe of undeveloped 3P reserves, mostly heavy oil, in shallow water, with multiple fields to develop, said Pemex E&P Director General Gustavo Hernandez in Houston this July. Hernandez added that Alux and Makech could potentially be developed at subsea tiebacks to Ayin and Batsil. The area already has infrastructure in place – the Litoral-A central processing platform, which is 24km from Ayin-Batsil and 50km from shore.

"A new operator will benefit from the proximity to shore (less than 50km), making the transportation of the produced crude relatively economical," Lara says. "Also, the existence of some infrastructure built by Pemex could create a new dynamic in the Campeche Basin." **OE**

Northwest Europe

An uncertain outlook

Production is increasing in the UK North Sea as investments made up to 2014 come onstream. But what's next? Elaine Maslin takes a look.

The Culzean development jacket was installed in July. Image from Maersk Oil.

Investment made in the boom years leading up to 2014 has been playing out in the UK North Sea this year, resulting in increased production in the basin.

BP's huge Quad 204 floating production, storage and offloading (FPSO) redevelopment project, West of Shetland, came onstream in May, closely followed by EnQuest's Kraken heavy field development – another FPSO project – in June. Premier Oil's Catcher FPSO development and the Western Isles FPSO, operated by Dana Petroleum, are expected to follow suit.

More will follow, with Statoil's Mariner heavy oil development, as well as Maersk Oil's high-pressure, high-temperature Culzean development taking shape– both fixed facility developments due onstream in 2018 and 2019, respectively. The result is increasing UK Continental Shelf (UKCS) production. Yet, all but one of these projects (Culzean) were sanctioned in 2012-2014. Since then, fewer projects have been sanctioned.

In 2012, not including field addenda, there were 21 offshore field consents, but that tapered off to 10 in 2013, and seven in 2014. In 2015, it only just five: EnQuest's Scolty and Crathes oilfield tiebacks, Total's Glenlivet and Edradour condensate subsea tiebacks, and Culzean. In 2016, just one project was sanctioned (a historic low): BP's Arundel tieback. Similarly, so far, only one project has been sanctioned in 2017, Statoil's Utgard development, a tieback, which straddles the border with Norway.

A modest hopper

"The first half of this year hasn't been as good as you would expect," says Theo Bull, UK upstream oil and gas analyst at Wood Mackenzie. But, there is some light at the end of the tunnel. Three more projects are expected to reach final investment decision this year, Bull says, on a base case estimate. He expects those fields to be Hurricane Energy's Lancaster early production system (*OE:* September 2015), West of Shetland, Independent Oil & Gas' Vulcan Satellites project (*OE:* August 2017), in the southern North Sea, and Alpha Petroleum's Cheviot development. Shell's Penguins redevelopment (*OE:* April 2017) and Zennor Petroleum's Finlaggan discovery development are possible "wild cards" for 2017.

If you include Norway, which has had three project sanctions in the year to date, one brownfield and two subsea, there's a modest number of projects, Bull says. "By the end of this year, we expect seven projects to be sanctioned (three in the UK, three in Norway and one in the Netherlands), amounting to 670 MMbo or US$8 billion in capex. That's a reasonably positive story," Bull says. In comparison, there were 2400 MMboe sanctioned in 2015 (515 MMboe not including Johan Sverdrup) across five fields, totaling $21 billion capex, and 560 MMboe sanctioned in 2016, across 11 fields, totaling $5.5 billion capex.

"Looking further ahead, we expect up to six greenfield FIDs in the UK in 2018, with Premier Oil's Tolmount the most significant. However, the majority of the remaining projects expected to reach sanction are reasonably small scale," Bull adds.

BP is still assessing further phases of its Clair field, West of

Shetland, while Chevron is still crunching the numbers on what would be a large FPSO development at Rosebank, but Wood Mackenzie doesn't expect this to reach FID until 2019.

Chevron said that it expects to issue invitations to bid for the Rosebank FPSO later this year –having cancelled a previous contract.

Recently, commentary by Westwood Global Energy Group suggests that, even with OPEC cuts being held, the pain could continue beyond 2018, as increased supply – the result of the record spending levels in up to 2014 – brings more oil to market.

Silver linings

However, speak with the UK Oil & Gas Authority (OGA) and it seems there's more about which to be positive.

"We are currently looking at about 16 field development plans including addenda during 2017, with currently an additional 10 in 2018," says Gunther Newcombe, the OGA's director of operations. "Not all of them are big, but they are incremental and will potentially add an additional 250,000 b/d to future production, as well as some much-needed contracts for the supply chain."

Indeed, a recent report by the International Energy Agency said conventional producers are globally now focusing on smaller, more near-term investments, and it has been suggested that this could also mean the industry is more able to hold back from going into another cost escalation cycle.

BP *Glen Lyon* FPSO, which came onstream earlier this year. Image from BP.

Following the OGA's 2017 report on North Sea projects, which highlighted budget and schedule overruns, and lessons learned, huge strides have been made in project delivery, Newcombe says. "This year, EnQuest's Kraken development came onstream significantly under budget [$2.5 billion vs $3.2 billion at the time it was sanctioned] and Maersk Oil's Culzean project is currently on time and budget."

Exploration is how the hopper is filled and UKCS exploration drilling remains low. But, there have been high success rates among the wells that have been drilled, Newcombe says. "Last year, 26 exploration and appraisal wells were drilled (13 each), with 460 MMboe delineated, at $0.87/bbl, with a high, one in two success rate, Newcombe says. This year, approximately 28 wells are expected with the key aspect being quality not quantity."

There is some interesting exploration in the North Sea coming up, Bull says, including the highly anticipated Korpfjell prospect (in the Barents Sea) and the Verbier prospect in the Moray Firth of the UK North Sea.

The hope is that there's more to come, following some £40 million government funding spent on broadband seismic over underexplored areas of the UKCS. This has been made available to industry, alongside a host of existing well and other data.

Known, but untapped, discoveries are also under focus. Some 150 data bases, and other data, were made available ahead of the 30th licensing round, which looks to relicense these fields. Projects like the Vulcan Satellites show these fields do offer opportunities, Bull says. The 30th round is anticipated to be the largest round ever, according Paul Warwick, an industry veteran, who was speaking in Aberdeen last month.

Another possible resource is tight gas, which the OGA recently launched a study into, focusing on the southern North Sea.

"The Southern North Sea tight gas play holds over 2 Tcf in discovered, but undeveloped accumulations," says Dave Moseley, manager - Reports, NW Europe at research group, Westwood Global Energy Group. And there is further potential in undrilled exploration prospects and infill drilling opportunities, which could increase estimates to 3.8 Tcf, according to the OGA. But, Moseley warns, most developments are reliant on current infrastructure remaining open for business.

Some are already active. BP, which retained interests in the Carboniferous play when it sold out of the southern gas basin in 2012, is now drilling an exploration program south of the Ravenspurn field, targeting a new tight gas play in the Namurian.

"This was encouragingly sidetracked with a development leg in June," Moseley says. "If the several-hundred Bcf predrill potential can be realized this may help extend the life of Ravenspurn, which is currently expected to reach cessation of production in around 2021. However, even in the event of success, discoveries like this remain the exception rather than the norm in a basin of this maturity."

Another initiative, to encourage more collaboration, through area plans, could also reap more production, Newcombe says. "The area planning approach is really critical. In the central Graben, we can see, value can be improved by up to 50% if we can get more collaboration and optimize the use of current infrastructure," he says. Similarly, there's a significant volume of gas West of Shetland that is currently stranded and could be unlocked if companies worked together.

Last but not least, technology also has a role to play, Newcombe says, both deploying it faster but also more broadly across the basin.

The OGA has been gathering technology plans from the operators and it is looking where technology could be used more broadly than it currently is, from geosteering to using flexibles instead of rigid pipes. Pilot projects, such as testing a thermite plug, for well barrier placement, are being encouraged. The thermite plug concept is due to be tested onshore in the UK this October, under a project with the Oil & Gas Technology Centre. But, it's also been looking at research and development, an area which has suffered from low investment, says Newcombe, who suggests tax breaks might be able to help encourage activity in this space.

Ultimately, however, he says the basin needs transformational change: "There's a lot of good stuff happening, but it's too slow. Collaboration will make the big difference." OE

Northwest Europe

Port of call

Aerial view of the Port of Blyth.
Image from Port of Blyth.

Once a major port for coal export, northeast England's Port of Blyth is becoming a growing hub for offshore industries. Elaine Maslin reports.

Aberdeen and Great Yarmouth have for a long time become key hubs for the UK's offshore oil and gas industry, with one predominantly supporting the oil basin and the other the southern gas basin.

But, there's some 350mi between the two cities – or 531mi by road. Port of Blyth, which conveniently sits about half way between Aberdeen and Great Yarmouth, hopes to fill the gap, serving the offshore industry, including the ever-growing offshore wind industry, not least the Round 3 offshore wind farms (those further offshore than existing sites, such as Dogger Bank, that will need marine support).

It's already been attracting businesses, including Royal IHC, which moved its IHC Mission Equipment business to the site in January. Others include Global Marine and engineering firm Osbit, as well as contractors, including DeepOcean, Fugro and Canyon Offshore. It's also home to one of the world's leading turbine testing facilities, the ORE (offshore renewable energy) Catapult, previously known as Narec (New and Renewable Energy Centre) – the world's longest wind farm blade is being tested there. And, just 5.7km offshore, the EDF Blyth Offshore Demonstrator Wind Farm is being built, starting with five, 8.3MW turbines (the biggest installed to date), mounted on gravity-based foundations, which were built on the Tyne in Newcastle by BAM Nuttall.

And, this is just the start. This year, Energy Central was launched, working with investment agency ARCH, to bring together several sites at Blyth together. It is supported by Enterprise Zone status, which offers financial incentives, and is hoping to attract decommissioning, offshore wind, and fabrication activities, as well as mobilization and demobilization for new and existing oil and gas fields.

Nearly US$40 million (£30 million) of government funding has already been pledged, with $33.5 million (£26 million) of that to be used for Northumberland Energy Park Phase 1, a 36ha site, which will include a 9m depth, jackup ready, 10-tonne/sq m deepwater quay. A further two phases of the Northumberland Energy Park are proposed.

"We are trying to build up a supply chain cluster," says port CEO Martin Lawlor, "so everyone has access to the usual range of services they might want – welding, rigging, fabrication, lifting, and flexible labor."

Lawler points out that labor is 30% cheaper at Port of Blyth than in Aberdeen. This would make the port suitable to mobilization and demobilization activities. "GE Oil & Gas already has reel storage at the site, Royal IHC now has manufacturing and assembly facilities. Then there's ORE Catapult, Osbit, TSG Marine, Oil Spill Response, lifting equipment firm Lift-Rite, engineering firm Jacobs, and Hainsford Energy." More are on their way, Lawler says.

The port, once predominantly used for shipping coal, already has crane capacity up to 500-tonne, and 10-tonne/sq m quayside loading capacity, with 1.5km of berth down to 9.5m draft. It has 50ha of sites with deepwater quay access, and a further 200ha with near access. This could be an opportunity for offshore wind construction or an original equipment manufacturer, Lawler says. The port is also a home from home for

Newcastle University and hosts an offshore training facility.

The port has many sites, including the Bates Terminal/ Wimbourne Quay site, which is being turned into one 15ha site with a heavy lift berth, able to host 180m-long and up to 7.6m draft vessels, and is currently base for construction of the EDF demonstrator. EDF is building an operations and maintenance base at the port's South Harbour.

Battleship Wharf, a dry bulk terminal with a rail link, has 9.5m draft and can host 200m-long vessels. This could be a future site for oil and gas decommissioning activities, Lawler says. The port has been permitted a draft license for its plan to develop the site as a decommissioning facility able to accept up to 50,000-tonne/year of marine structures for recovery, reuse of disposal. There's also a former power station site, which has funding agreed for remediation works to turn it into a 200ha site.

Royal IHC

One of the new tenants at Blyth is Royal IHC. The firm moved on 7 January 2016, to Port of Blyth South Harbour – a move which included some 10,000-tonnes of equipment.

It was all done without affecting production, says Alan Conway, construction manager at Royal IHC. The firm makes equipment ranging from J-lay towers to defense equipment and all through the 5S lean manufacturing principles – i.e. "sort, set in order, shine, standardize, sustain."

Conway likes the fact that in the area there are fabricators, welders, rigging and electrical and mechanical people available for projects. He says this will make it attractive to offshore construction firms when they need to come in to get equipment repaired or modified for specific projects. This has been happening, with the result that some are making it their dedicated port. To support such events, Conway says maintenance and refurbishment agreements can be made, too. "This is one of the best kept secrets out there. There is so much potential. This is just the beginning," he says.

IHC has 10,000sq m factory space and up to 11,000sq m externally at the site. The firm uses the port's LR430 crane, with 124-tonne capacity and 24m reach, but also a roll-on, roll-off quay, which means, for the likes of massive 2500-tonne J-Lay towers it builds, a crane will not be needed for load out.

At Port of Blyth, the firm also makes Reel-lay towers, launch and recovery systems, A-frames, and other engineered solutions. This includes the award winning self-leveling Hi-Traq subsea trencher (*OE:* May 2014). Earlier this year, the first production machine, a four-tracked subsea cable trenching vehicle, was commissioned at Port of Blyth ready for land trials then quayside testing and finally testing offshore. The vehicle, developed to work in up to 1000m water depth, weighing over 50-tonne, and with a tungsten tipped cutter "to cut through the most arduous sea beds," is due to be added to the firm's rental fleet.

Osbit

If the Port of Blyth's approach is about flexibility, then so is one of its South Harbour tenants, Osbit, which took a unit at Port of Blyth in 2015. This was initially to build two intervention tension frames (ITFs) for Helix with parts related to the same order – towers and decks built at WD Close on the Tyne. But, the firm, which has delivered everything from cable handling systems and subsea docking systems for AUVs to offshore access systems in the past year, has been growing. At the end of the initial contract for the space, Osbit signed a contract to take the 1140sq m space with 15-tonne cranage for another three years and is investing in the site.

"More and more people are moving this way," says Brendon Hayward, Managing Director, Osbit, partly helped by the port's flexibility and support. "We intend to use the port as a strategic hub from which to expand Osbit, using our resources to continue to deliver innovative projects on time, while driving down the cost of wind and oil and gas operations."

Last year and this year, the firm delivered two intervention tension frames (ITFs) to Helix Well Ops for the *Siem Helix I* and *II* vessels (*OE*: July 2017). A further system for Helix's *Q7000* has also been delivered. Earlier this year, Osbit delivered a hybrid monopile cleaning tool to Van Oord (*see page 58 for more*).

Meanwhile, for Ecosse Subsea Systems (ESS), Osbit is developing a water-jetting tool that aims to double trench production rates in seabed trenching operations for ESS' SCARJet subsea vehicle.

ORE Catapult

The ORE Catapult is a publicly funded technology innovation and research center for advancing wind, wave and tidal energy. Since it was set up in 2002, originally as (Narec),

IHC's Hi-Traq. Image from Royal IHC.

A gangway supplied by Osbit to jackup vessel operator Seajacks in July. Image from Osbit.

Northwest Europe

before merging with ORE Catapult in 2014, the organization has built an enviable set of open-access test facilities, including 50m and 100m blade testing, 3MW tidal turbine nacelle testing, and 15MW wind turbine nacelle testing. It also has an offshore anemometry platform, which is helping to validate floating lidars, and the 7MW Levenouth demonstration turbine, of which a digital twin has been created for sensor and system development. The center also has a turbine benchmarking platform, looking at 94% of installed UK capacity performance, which it hopes to roll out across Europe.

Earlier this year, at 88m-long, the largest built in the world arrived at the center to be tested. The blade, called the XL Blade, has been built by Adwen for the firm's new 8MW offshore wind turbine. Once testing is completed by year's end, the blade will be used on a prototype turbine currently being installed at a test site in Germany.

Many small- to medium-sized enterprises use the facility, including Gonsys, Invisotech, tidal energy technology firm Nova Innovation, Edinburgh-based wind turbine blade technology firm ACT Blade, cable firm JDR and tidal energy developer Atlantis Resources.

Work includes projects with the America's Cup sail rig designers to see how their designs can be used for offshore wind turbines and looking at new types of generators, instead of using rare earths from China. The center is also looking at floating foundations and different substructures.

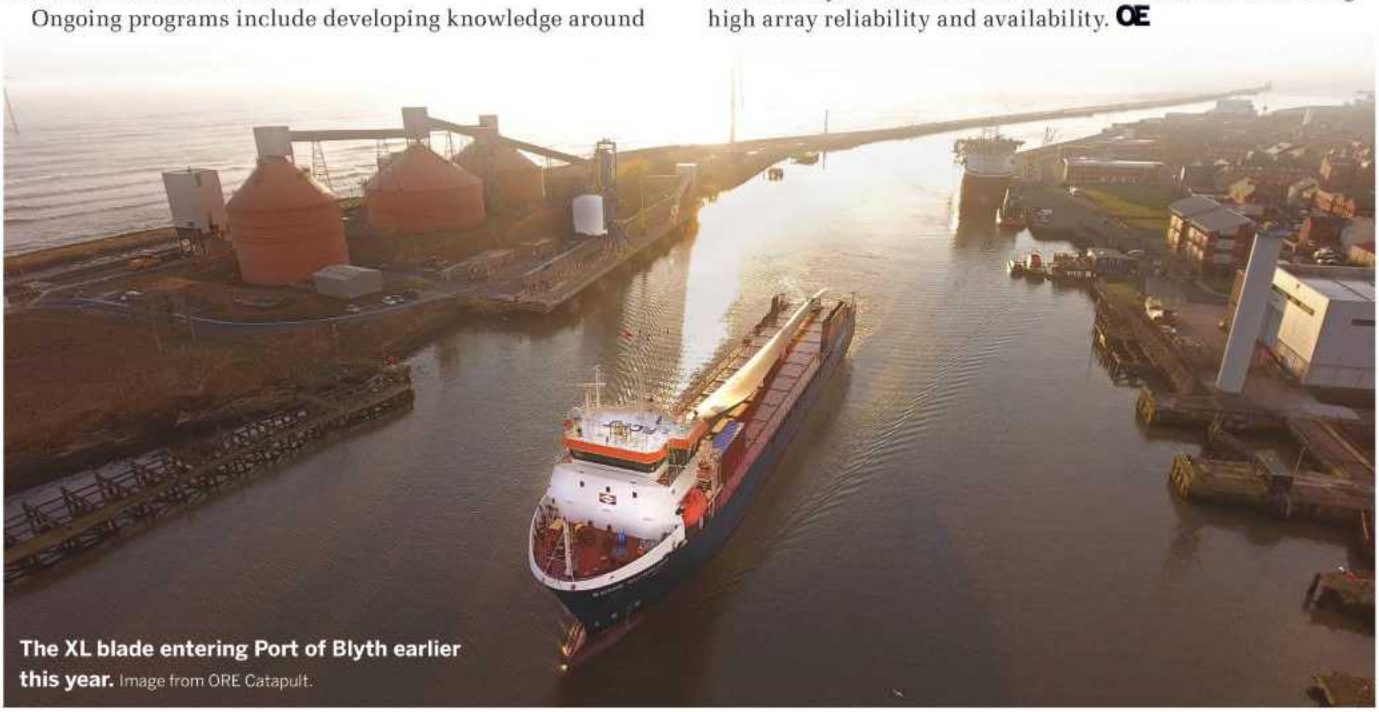
"A few years ago, the industry's viability was in doubt, but industry has gone a long way to answer those doubts," says Chris Hill, lead the innovation program and project teams, ORE Catapult. "There's been a 32% reduction in costs over the last five years. Much of this is to do with larger turbines, but also increased competition, low cost of capital. And there is more cost reduction to come."

Ongoing programs include developing knowledge around blades, drive trains, electric infrastructure, and operations and maintenance – including alternative ways to access turbines. There's a blade leading edge erosion project, to address issues with erosion from salt and sea water, which is seen as a significant issue for the industry. A new test rig to help understand the fundamental issues in this area opened for use in July.

"It's not just about preventing it, but also repairing it as well, accessing the blades and how to fix issues and what impact will there be on the other two blades," says Kirsten Dyer, senior materials research engineer, ORE Catapult. Another new facility will be a bearing test rig, to test current bearings. It will be operational this year. A 15MW drive train test facility will also be commissioned this year.

Alongside the new equipment, there are several new projects, including a five-year, \$3 million (£2.3 million) research partnership with the University of Bristol, called the Wind Blade Research Hub (WBRH). It is investigating how to build more efficient blades to enable turbine capacity to reach 13-15MW by 2025 by studying blade materials and manufacturing technology, blade integrity and performance. With ScottishPower Renewables (SPR), ORE Catapult has a program, the first project of which is a foundation fabrication feasibility study, to review efficiency opportunities in foundation fabrication.

ORE Catapult is also active in wave and tidal energy development and this year became part of a new European tidal energy project called Enabling Future Arrays in Tidal (EnFAIT). Working with Nova Innovation and other organizations, the project, running from July 2017 this year until June 2022, was awarded EU Horizon 2020 funding to help increase the commercial viability of tidal power by extending the Bluemull Sound array, off Shetland, to six turbines and demonstrating high array reliability and availability. OE



The XL blade entering Port of Blyth earlier this year. Image from ORE Catapult.

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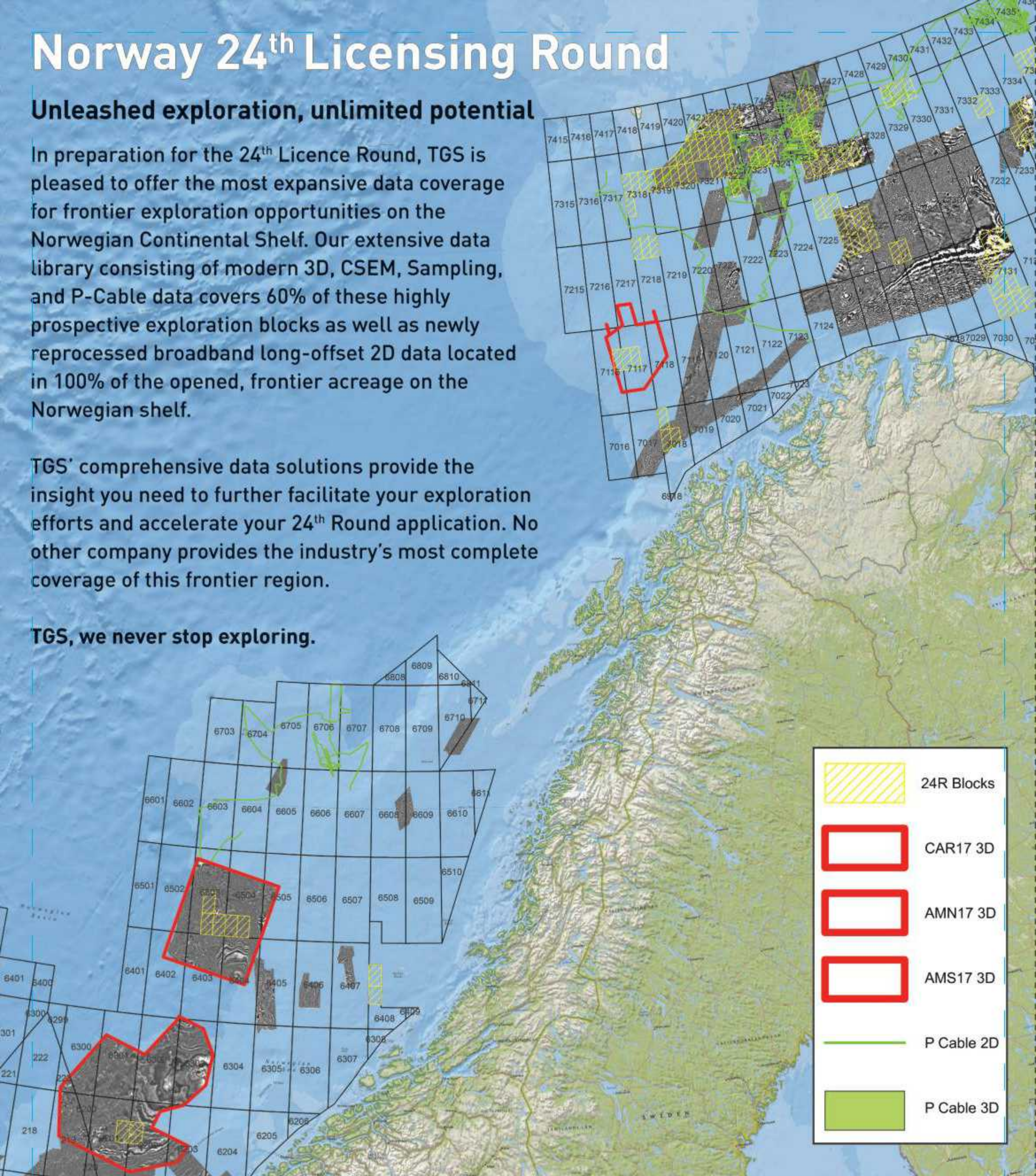

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Northwest Europe

A new production paradigm

New players are entering the aging North Sea basin, but there's still ambitions to increase exploration as well push forward with decommissioning. Andrew Scutter, of EIC, gives his view.

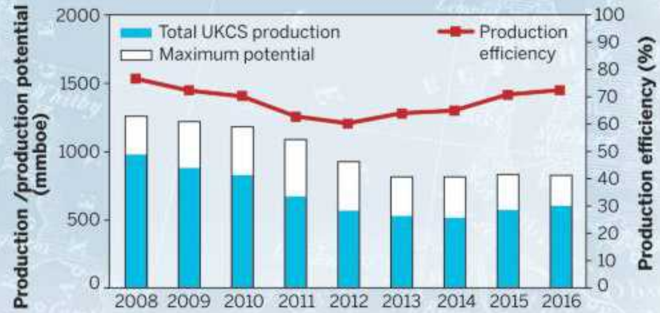
While the North Sea is one of the most developed oil and gas basins in the world, it still has huge potential with an estimated 20 billion boe yet to be extracted. It is hoped that a recent surge in North Sea deals, driven by private equity money, will inspire other investors to spend more in the aging basin.

Chrysaor's US$4 billion acquisition of Shell's North Sea fields earlier this year was the most significant of these investments, making it the largest independent operator in the North Sea. Other private equity interest in the North Sea has come from investors such as INEOS, Neptune and Siccar Point.

New discoveries in the North Sea have been rare of late, however, the UK's Oil and Gas Authority (OGA) is determined to revitalize exploration by completing major seismic surveys in unexplored areas such as the Mid North Sea High in the Central North Sea. The ambitious target of 50 exploration and appraisal wells per year by 2021 will undoubtedly lead to an increase in offshore activity. The 29th Licensing Round was deemed a great success in opening up the frontier areas of Rockall and the Mid North Sea High. Statoil won five licenses as operator with BP partnering. The interest from such majors is a promising sign for the future of North Sea exploration.

Currently, there is a huge push to get the most out of currently operational assets, which will increase demand in the operations and maintenance market. Production efficiency on the UK Continental Shelf (UKCS) has risen for a fourth consecutive year, to 73%, according to figures released by the OGA. This represents an additional production of 12 MMboe compared to 2015.

UKCS production efficiency and production



Source: the OGA

Decom challenge

Being a mature basin, with an average asset age of 26 years, it is predicted that the UKCS is on the brink of high levels of decommissioning activity. This year, decommissioning begun on the iconic Brent oilfield. The removal of the Brent Delta's topsides was completed using Allseas' single lift vessel *Pioneering Spirit*; the remaining platforms will follow. It is expected that about 120 fields will cease production in the next five years, 51 being in the Southern North Sea. UKCS decommissioning expenditure could reach up to US$2 billion/yr and a total of $17 billion is expected to be spent by 2025. About 50% of the spend will be concentrated in the Central North Sea.

The future of the North Sea industry will see small, lean independent operators exploiting operated fields and marginal non-operated opportunities, with the super majors seeking out large-scale finds as well as continuing to exploit their remaining assets. Undoubtedly challenges remain, but with half a century of production behind it, and a new production paradigm emerging, the UK oil and gas industry is confident that the North Sea still has a lot more to offer operators, suppliers and contractors. 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.*

Northwest Europe

Barents spotlight

The Snøhvit gas field produces back to the Hammerfest LNG plant at Melkøya.
Photo from Statoil/ Harald Pettersen.

With a new phase in Barents Sea developments on the way, plus strong drilling activity, the region is primed for growth. Espen Erlingsen, of Rystad, explains.

The Norwegian sector of the Barents Sea is one of the key development areas for offshore Europe. Recent oil discoveries have proven the commerciality of this province and Rystad Energy expects investments and production to grow over the coming years.

After being on a downward trend for more than 10 years, Western European production started to grow again in 2014. Since then, the production has increased every year and, for 2017, the total liquid production is expected to reach 3.3 MMb/d, up 400,000 b/d from 2013. Over the next 10 years, Rystad Energy expects that the production will continue to increase and surpass 3.5 MMb+/d in 2025. Figure 1 shows that the main growth is expected to come from the Norwegian part of the Barents Sea.

For a long time, the Barents Sea was a gas province with production coming from the Snøhvit field. Snøhvit, discovered in the early 1980s, was the first Barents Sea discovery. Due to the remote location of the gas and the difficulties to get it to market, almost 30 years passed before this field started commercial production in 2007. Production from the field is exported as LNG and there were problems with the liquefaction train, which kept production low for several years. The troubling past seems to be behind the project and, in 2016, the field achieved the highest production to date, exporting around 4.5 million tons of LNG.

The first oil producing field in the Barents Sea was Goliat. The Eni-operated field includes 200 MMboe (100% oil) of resources and is developed via a floating production, storage and offloading (FPSO). Goliat came online in March

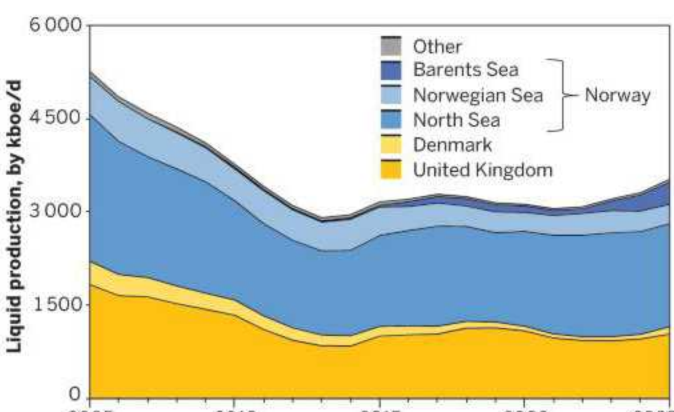


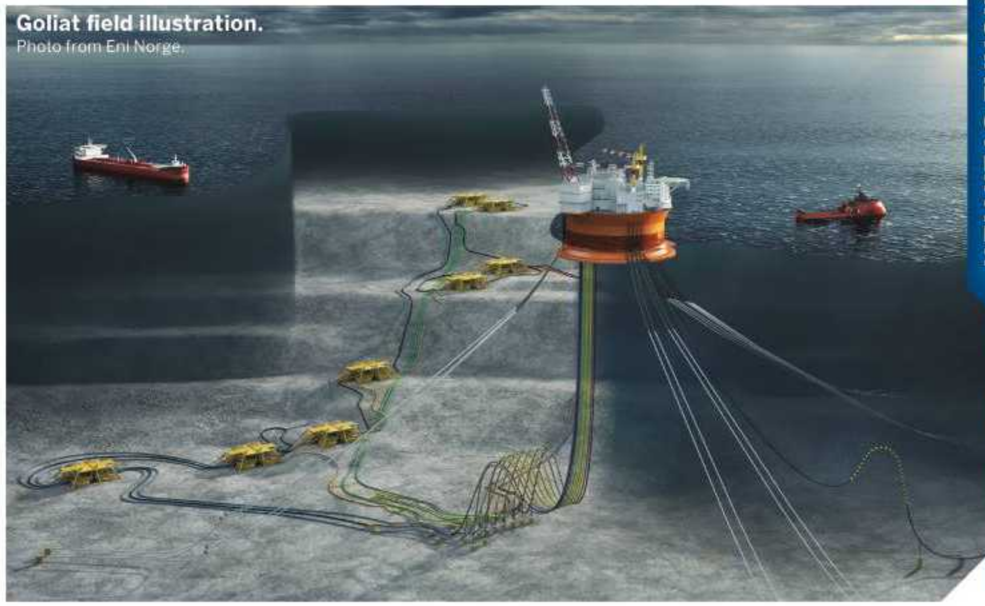
Figure 1: Trend and forecast total Offshore Western Europe liquid production by country, kboe/d.
Source: Rystad Energy UCube

Project	Life Cycle Category	Operator	Facility Category	Remaining Resources (million bbl)	Breakeven Oil Price* (US$/bbl)
Snohvit	Producing	Statoil	Subsea	1,772	28
Johan Castberg	Discovery	Statoil	FPSO	621	33
Alta/ Gohta	Discovery	Lundin	FPSO	400	58
Wisting	Discovery	OMV	FPSO	355	54
Goliat	Producing	Eni	FPSO	203	18

Key Barents Sea projects
Source: Rystad Energy UCube.
*The breakeven price is forward looking, excluding historical costs

2016, after being delayed for several years and incurring over 50% costs overruns.

Statoil's Johan Castberg will likely be the next Barents Sea development. This field was discovered in 2011, and consists of two primary reservoirs called Skrugard and Havis. Initially Statoil, the operator, planned to develop the discovery with a tension leg platform (TLP) connected to an onshore terminal. After the discovery of Castberg, Statoil initiated an exploration campaign in the close proximately of the field. The purpose was to find additional resources and improve the economics of the TLP development solution. The campaign was unsuccessful and in combination with the falling oil price, the partners changed the development concept to an FPSO. The new development concept and current low unit prices have reduced the breakeven price from US$80 to $33/bbl.


Goliat field illustration.
Photo from Eni Norge.

In 2013, two new discoveries were made. OMV discovered Wisting Central, while Lundin discovered Gohta. Combined, the total discovered resources for 2013 was just below 0.5 billion boe, making the Barents Sea the province in Norway with the highest discovered resources in 2013. Additional resources were discovered around each of these fields in 2014, with Wisting and Alta/Gohta being two new potential development projects in the province.

As discoveries have proven to be commercial and new areas opened in the Barents Sea, there has been an increase in exploration activity. From 2011-2016, eight exploration wells were drilled on average per year in the Barents Sea. In 2017, this activity is expected to increase to around 17 exploration wells. The most active drillers in 2017 will be Lundin, Statoil and Eni.

The most exciting prospect in 2017 is the Korpfjell prospect. The Statoil-operated license lies in the formerly disputed Central Barents Sea. This structure is about 39km and 415km, respectively, from the Russian and Norwegian mainlands. The predrilled resource estimate is 2.2 billion bbl.

When adding up all of the potential developments in the Barents Sea, production is estimated to grow considerably. The first growth phase will be in 2016-2018, as Goliat production ramps up. Figure 3 shows historical and forecast production for this province. The next growth phase will be in the beginning of the next decade. With the anticipated startup of Castberg, Wisting and Alta/Gohta, total Barents Sea production may go above 0.5 MMboe/d – about three times higher than current production. The growth in production will be driven by oil, due to the latest discoveries being oil discoveries. However, to achieve this production growth, substantial investment is needed. Historically, annual investment for the Barents Sea has been just below $2 billion. After 2020, this is expected to reach close to $5 billion. Most of this spending will be on subsea equipment, rigs and FPSO construction.

In total, the Barents Sea investments are expected to make up 20% of the total Western Europe offshore investments by the start of the next decade. This is considerably higher than the current share and illustrates how important Barents Sea will be for Western Europe. **OE**

Espen Erlingsen is a partner and leader of the E&P team at Rystad Energy. His areas of expertise include company and acreage valuation, breakeven price analysis and international petroleum fiscal regimes. Before becoming a partner, Erlingsen was the lead NCS analyst at Rystad Energy.

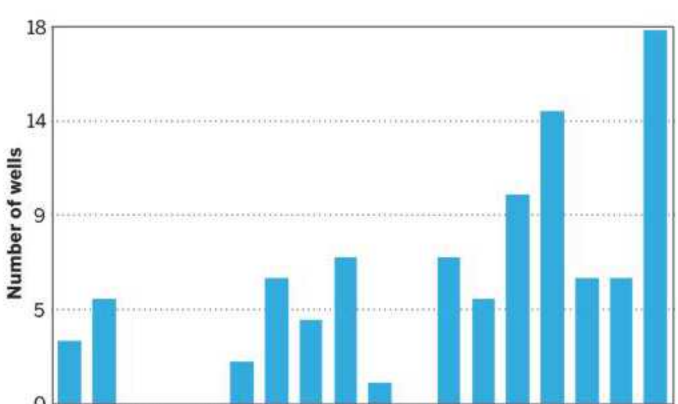


Figure 2: Number of exploration wells (wild cats and appraisal) in the Norwegian part of Barents Sea from 2000-2017.
Source: Rystad Energy UCube.

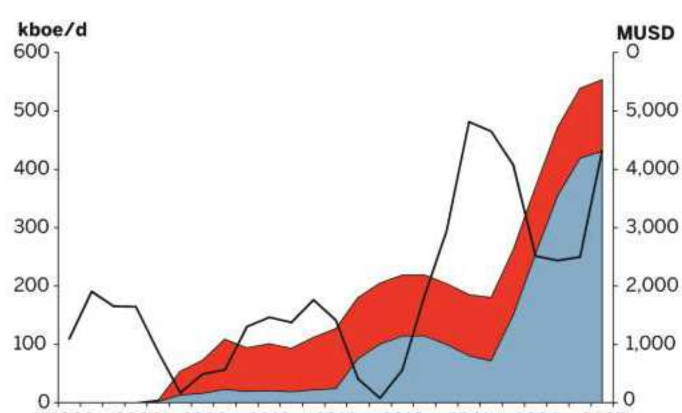


Figure 3: Historical and forecast production (LHS) and investment (RHS) for the Norwegian Barents Sea.
Source: Rystad Energy UCube.

Solutions

Osbit delivers new monopile cleaning tool

UK-based offshore engineering and technology firm Osbit delivered an innovative hybrid monopile cleaning tool to Van Oord, designed to support the efficient installation of offshore wind turbine foundations.

The hybrid marine growth cleaning tool is currently supporting a project at the Walney 3 & 4 offshore wind farm in the Irish Sea, where Van Oord is charged with installing 87 monopiles for DONG Energy. The system has been delivered to a strict 12-week schedule, to ensure the installation program can begin on time.

The tool offers combined monopile cleaning, anode cage lifting and installation down to 30m water depth, along with monopile survey and measurement capabilities.

To ensure the monopiles are sufficiently prepared for grouting and the installation of the transition pieces, Osbit's tool uses a suite of 10 rotating cleaning heads to prepare the monopile surface to fit the transition piece. The system's cleaning heads are adaptable, to enable effective cleaning of the tapered monopiles, which have an increasing diameter of 6-8m. Previously, each of these tasks would require the use of individual systems, which would increase the duration and complexity of the installation program.

Osbit's system was designed in collaboration with Van Oord, at its offices in Riding Mill, Northumberland and manufactured in the northeast of England.

"We are committed to creating ingenious solutions to improve operational efficiencies in the offshore wind sector; in this project, Osbit has succeeded in developing an innovative system moulded to suit our operational requirements, which has been delivered within a challenging time-scale," said Adriaan van Oord, Operations Manager from Van Oord Offshore Wind. **www.osbit.com**

First Subsea demos cable protection system

First Subsea completed an open water demonstration of a new cable protection system (CPS) for offshore wind farms. The CPS protects subsea power cables as they transition from the seabed into the wind turbine structure.

The First Subsea CPS is being deployed on Hornsea Project One, in the North Sea off the coast of England. It offers a quicker installation and reduced risk of cable fatigue compared to traditional systems. Based on proven technology used for the protection of umbilicals and risers in the oil and gas industry, the CPS provides simple, non-destructive disconnection via remotely operated vehicle (ROV).

The open water CPS demonstration took place at Rovtech Solutions' Underwater Test Facilities in Barrow-in-Furness, and consisted of: assembly dockside, deployment subsea and pull-in into a mock-up wind turbine structure and disconnection by ROV. The test facilities allowed the demonstration to take place in open water as close to offshore conditions as possible, incorporating challenges such as poor visibility and seabed interference, while still being accessible and visible from the dockside.

www.firstsubsea.com

New jetting tool launched

Global subsea excavation specialist James Fisher Subsea Excavation (JFSE), introduced a centrally-located

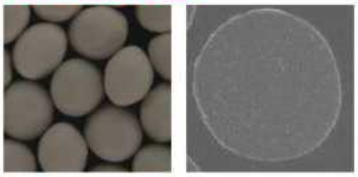
jetting systems to its mass/controlled flow excavation (M/CFE) equipment spreads.

The high velocity water jet facilitates the excavation of soils previously considered too dense to excavate using traditional mass/controlled flow techniques.

Moving away from customary designs that place jets at the side of M/CFE tools, JFSE's tool dramatically reduces velocity degradation. JFSE says that the jets will improve efficiency where additional tooling was required to complete a project due to the density of the

soils thereby helping to lower costs for clients. They will also decrease operational time on a number of excavations.
www.jfsubseaexcavation.com

Carbo's KRYPTOSPHERE hits milestone



Carbo Ceramics' KRYPTOSPHERE HD is now in use by all major E&Ps operating in the Gulf of Mexico, for deep, high stress wells.

KRYPTOSPHERE HD is an ultra-conductive, high strength ceramic proppant, initially engineered to solve the production and completion challenges for Gulf of Mexico Lower Tertiary development, where wells can experience a closure stress range from 12,000 to 20,000psi. In addition, KRYPTOSPHERE is more resistant to cyclic loading and acids and significantly less erosive on frac pumps and downhole tools. These benefits translate into increased completion tool life, reduced rig downtime and overall cost-savings for the E&P operator.
www.carboceramics.com

Varel, Uni partner on drillbit

Varel UK has signed a collaborative project with the University of Aberdeen to design and develop a new drillbit, which addresses the unique challenges of drilling in Resonance Enhanced Drilling (RED) mode.

RED has been developed at the University of Aberdeen from research by applied dynamics Professor Marian Wiercigroch, based on theoretical mechanics.

The technique, which uses high frequency, to create resonances and to generate a controllable zone at the bit, improving significantly rate of penetration and reducing bit wear, as well as stress on the bit, has its roots in theoretical dynamics and fracture mechanics.

"There is a need to develop a new faster, cheaper way of drilling new offshore frontier fields that contain sections with chert or fractured granite/conglomerates," said Jason Marchant, Varel UK District Manager North Sea. "Together with OGIC (the Oil & Gas Innovation Centre, which will support the project with funding) and the University of Aberdeen, we've been examining a new concept that will ultimately result in the creation of a new hybrid drill bit with duel cutting mechanisms that will help overcome the challenges and result in a much more efficient and economical drilling process." www.ogic.co.uk

Activity

New P&A entrant

A new entrant to the North Sea subsea well abandonment market has been launched, with goals to attract US$263 million (£200 million) in investment and create 400 new jobs.

Well-Safe Solutions wants to offer a cost-effective, "one-stop shop" well abandonment service – from front-end engineering to project execution – through a campaign approach, supported by a fleet of its own dedicated plugging and abandonment (P&A) vessels.

The firm has already acquired another business, Intervention Project Management, whose managing director, Phil Milton, has been appointed CEO of Well-Safe.

Industry executives Alasdair Locke and Mark Patterson are major investors in the firm, which also has Paul Warwick on board. Warwick was formerly executive director for Repsol, executive vice president for Talisman Energy and regional president of ConocoPhillips.

Well-Safe is looking to acquire assets to carry out well abandonment work, including a semisubmersible rig, a jackup and a light-weight intervention vessel. •

Phil Milton, CEO of Well-Safe Solutions and Mark Patterson, executive director.

ABIS supports Gran Canaria offshore base

Aberdeen-based ABIS Holdings Energy Services signed an agency agreement to support the development and operation of an offshore supply base on the Spanish island of Gran Canaria.

The UK-based energy services provider will act as the agent for Gran Canaria Subsea and Offshore Base (GCSB), an organization that operates in the Port of Arinaga.

The site includes 20 acres (90,000sq m) of laydown and storage facilities and is inside the Canary Special Zone (ZEC), is tariff free and incorporates corporate tax levels of just 4%.

The base offers a suite of services to support the marine industry with repairs, refurbishments and general maintenance while also being in the center of Atlantic.

NXG invests $2.6 million

Aberdeen-based NXG Drilling Services has invested more than US$2.6 million (£2 million) in two new operations. The business, launched at the start of 2017, has moved from its Aberdeen offices to 30,000sq ft premises at Altens Industrial Estate, adding to operations NXG has set up in Holland and the Middle East.

NXG has also agreed a lease on a three-acre site for a welding, machine shop and "make-and-break" facility within the IOS Longside Supply Base, near Peterhead, north of Aberdeen.

The investment follows the acquisition of tools and equipment from Hunting Equipment Management Services earlier this year.

NXG says it now has contracts in place with all the major service companies and, as a result, operates in more than 50 countries. The company is on track to record turnover of $5.2 million (£4 million) by the end of the year. The firm currently employs 15 people but is looking to add a further 18 before the end of the year.

Partnering with in-country oil service firms, NXG supplies a range

DeepOcean acquires Searov

DeepOcean acquired French company Searov Offshore and has expanded its presence in West Africa.

Searov, established in 2008, is a remotely operated vehicle (ROV) service provider with a strong focus on West Africa. The company owns and operates 10 ROVs from its operating bases in Pointe Noire, Congo, and Port Gentil, Gabon. Searov has a track record of delivering inspection, maintenance and repair and construction support services to a variety of international oil companies in West Africa.

of bottom-hole assembly equipment including stabilizers, subs, drill collars, hole openers and reamers. In addition, the business also has a large stock of non-magnetic tools. The firm also has a research and development arm, OILSCO Technologies, which can deliver a range of solutions for drilling operations.

Yokogawa acquires Techinvent

Yokogawa has acquired Techinvent and its FluidCom technology, which won the ONS 2016 Innovation Award (SME).

FluidCom was developed to obtain a controlled and efficient use of production chemicals and to optimize the oil and gas production, through reliable and accurate chemical dosage.

FluidCom, which was approved for use by Statoil in 2015, before being made available to the market, is a fully automatic chemical injection controller that by its patented technology enables significant capex and opex savings for its users.

Petronas opens Mexico City office

Following its wins offshore Mexico, Malaysia's national oil company Petronas announced it will open a new office in Mexico City in Q3 2017 to manage its new prospects.

"I am pleased with our new partnership with Ecopetrol and I am confident this will bring together our capabilities and expertise for a successful collaboration in the Mexico waters," said Petronas Executive Vice President & Chief Executive Officer, Upstream, Datuk Anuar Taib.

Progress Rail acquires Applied Ultrasonics

Progress Rail, a Caterpillar company, has acquired Applied Ultrasonics, enabling the company to offer ultrasonic impact technology (UIT), which helps strengthen investments in heavy equipment, asset management and infrastructure. The Ultrasonic Peening device uses ultrasonic energy coupled with mechanical impacts to make metal structures and components last longer, extending asset life and increasing reliability. For the oil & gas industry, UIT proved integral in the 15-year extension of a deepwater drilling rig that was at the end of its certified life.

Spotlight

Moving the needle

Elaine Maslin caught up with new Oceaneering CEO Rod Larson, at this year's Underwater Technology Conference, and discovered his commitment to keep pushing the boundaries of what is currently possible.

Rod Larson. Photos courtesy of Oceaneering.

Rod Larson has only been on the job for a few months, but he is already tackling some of the industry's biggest questions, from making deepwater operations competitive to getting ready for the next big technology innovation.

Despite taking on the role of president and CEO at Oceaneering during oil and gas' toughest downturn yet, he's undaunted. The industry has always been able to push the boundary, he says. This year, Oceaneering, for example, started operating one of its offshore-based electric remotely operated vehicles (ROVs) from onshore, in Norway (*see page 40*).

"I don't ever remember people thinking we won't ever go the next step," he says. "Never 'this is the deepest we will go.' It has been and will always be 'what's next?' That's still very alive and well. At Oceaneering, we aim to do things differently, creatively, and smarter to safely and cost-effectively solve our customers' toughest challenges."

And, while the oil industry may take a back seat and be a little slow when it comes to some technology adoption, "the things we do are unbelievable," he says.

Larson, who is married with two sons, took Oceaneering's top job in May, having served as the firm's president and COO before that. He started his career in wireline operations at Western Atlas, later acquired by Baker Hughes (now a GE company). He earned a Bachelor of Science in electrical and electronic engineering from North Dakota State University in 1990.

Larson spent 22 years at Baker Hughes working his way through the ranks. In 2007, he earned a MBA from Rice University. At Baker Hughes, he became involved in deepwater development, working in operations in the Gulf of Mexico, before rising to president for Latin America. In 2012, he joined Oceaneering, serving as COO.

It's perhaps a long way from the farm where he was brought up in North Dakota, an area where many Scandinavian immigrants landed – hence his surname. He was making his career choices at a time when the first video games and computers were hitting the streets and electrical engineers were in demand, he says. "The only way to mess it up was to go into the oil field," he jokes. He had gone to an oil firm for a practice job interview. "I loved the mix of technology," he says, and a job that saw him performing electric downhole surveys off the back of a truck, "a farm boy battling the elements."

A lot has happened since then. While not directly involved, Larson watched the industry battle the Macondo disaster in the Gulf of Mexico, an incident which saw 11 people killed and shook the industry to its core. "Macondo was a major event," he says. "For me, it was a pivotal year in what we had to do and to look at what we had to get right. Oceaneering supplied 150 pieces of hardware, from design to being water-ready, in six weeks. Baker and other offshore providers, at the time, were doing similar work."

Today, the challenge is the economic environment. With surplus oil in the short- to medium-term, the challenge is to reduce costs, to compete with the likes of shale. The contractors have a key role to play, Larson says. "The challenge we have is being competitive with other sources of oil and gas. It's not as fun as making it bigger, it's just a different problem to solve.

"The question is, can we go back to US$20-30/bbl oil for decades and make a living? That's where we started. The deepwater industry was largely born in a sub-$40/bbl world. I have no doubt the industry can and will thrive once again," Larson says.

Reducing time to deliver solutions is also important, he says. "It gives the operator a greater ability to understand what the demand curves will be in the determined time frame." He cites standardization and reducing the amount of non-recurrent engineering as ways to help reduce costs. Standardization in umbilicals could improve manufacturing throughput in what has traditionally been stop-start, and therefore inefficient, operation.

Technology is also high on the agenda at Oceaneering, a business which also works in the aerospace and theme park industries. One of the firm's recent flagship projects is its remotely piloted E-ROV, or all-electric ROV. Last year, a work class ROV deployed from the *Songa Endurance* semisubmersible drilling rig was remotely piloted from an operations center in Stavanger. This year, an eNovus work class ROV, this time supported by a 4G LTE data buoy and its own battery power, is being piloted from shore, also offshore Norway. It is stationed in a cage, with a tether management system, and is also fitted with automated control technology.

"The E-ROV is an enabling technology," Larson says. It paves the way for the likes of working in remote harsh environments and without surface facilities—i.e. surface production facilities or a support vessel— alongside the likes of all-electric subsea systems and power distribution. Having the infrastructure— 4G LTE— in place in a region driving advances into harsher, colder environments, such as

The Millennium Plus ROV at Oceaneering's manufacturing center in Morgan City.

the Barents Sea, has helped. "A lot of what we have done is an interim step to complete de-manning," he says. "If we don't take that interim step, it's going to take such an incredible investment to take that tool in one leap."

Meanwhile, Oceaneering is doing work around automation for the theme park industry—such as trackless amusement park rides—and autonomous vehicles to work side by side with humans in factories. Some of that technology, including machine vision and machine learning, as well as artificial intelligence and virtual reality, is being applied to hybrid ROVs and autonomous underwater vehicles, to improve efficiency and vehicle intelligence. Oceaneering is also working on vessel tracking, understanding where all the vessels are in a given location and predicting future movements.

Keeping up with the increasing pace of change of technology is key, Larson says. "For us to see what the subsea industry is going to look like in 5-10 years is a tall order," he says. "We know it changes faster and faster and becomes a lot less predictable. You have to watch your peripheral vision to see what's going to happen." This means keeping up with the likes of machine learning, data analytics, and automation—areas which are becoming more powerful in their ability to affect change in the industry, he says. "Gaining expertise in those enables you to be a disruptor or at least keep up. You can be prepared, or become a Kodak or Blockbuster."

For Larson, it's also about "stretching the company's wings," in a way that can affect some change. This includes employing technology from Microsoft for big data, working with customers to interface with technologies from outside the oil field, and helping customers integrate with the likes of GE Predix. "It's a new mindset that this next generation live in, where these services are not tools, they're an extension of how they live and work," Larson says.

But, it's not technology for technology's sake, he says. "All the technology in the world is fantastic, but, if you cannot put it to work effectively, it's not worth anything." OE

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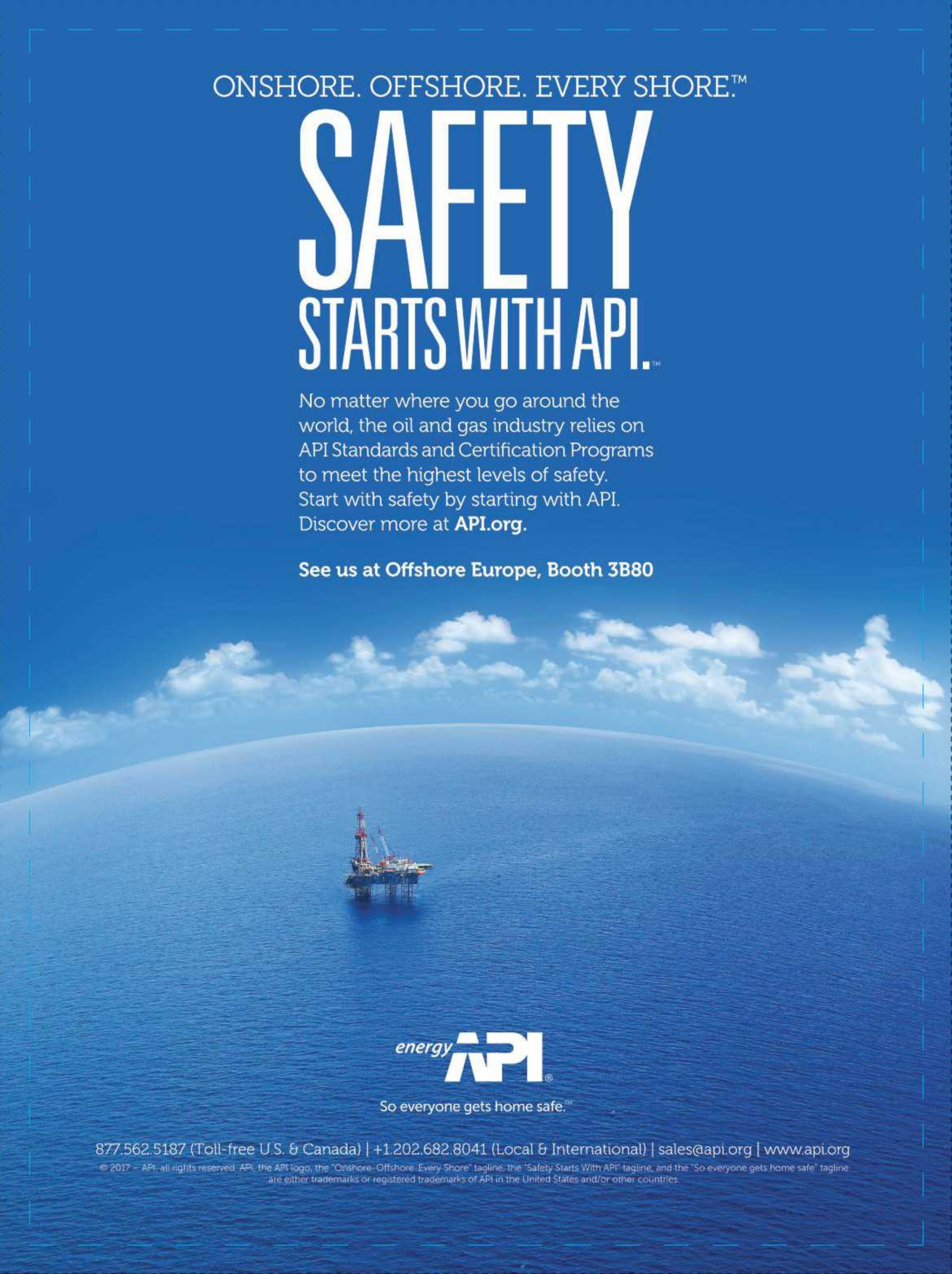
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