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Photo from iStock.

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Asset integrity

Features

ON THE COVER

View from the top. This month's cover features the Oceaneering's Millennium ROV during sea trials in Norway. Read more about Oceaneering's latest intervention tools on page 44.
Photo courtesy of Oceaneering International.

Departments & Columns

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People

Weatherford names Halliburton exec CEO

Weatherford International has appointed Mark McCollum president and CEO of the company, effective this month. McCollum, an executive with over 36 years' experience in the oil and gas industry, most recently served as executive vice president and CFO at rival service company Halliburton.

Mark McCollum

Moho Nord. Photo from Total.

What's Trending

The right track

- Moho Nord comes onstream
- Chevron strikes oil at Anchor appraisal
- Noble approved to drill Leviathan-7

Activity

Mexico finalizes 7 deepwater pacts

Pemex, SENER, CNH and Inpex officials. Photo from SENER.

Mexico's National Hydrocarbons Commission (CNH) finalized seven deepwater Gulf of Mexico contracts, as part of the country's Round 1.4 held last year. The Secretary of Energy Joaquín Coldwell said that the investments associated with the eight blocks awarded in Round 1.4, will amount to US$34 billion dollars.

Undercurrents

Investing in oil's future

In March, the annual CERAWeek conference by IHS Markit rolled into Houston for a five-day stint, attracting all the heads of major oil and gas operators, academics, foreign oil and gas ministers as well as regulatory authorities.

While the mood was optimistic, both on the floor and up at the podium, the message delivered from the oil majors was the same – we've come too far to give up now.

"The ultimate test of our ability to learn is not in the crisis, but in the recovery," said Statoil's CEO Eldar Saetre on CERAWeek's opening day.

"Now is not the time to relax and repeat our own mistakes from the past," he continued. "Now is the time to fundamentally change how we run the industry... in short, seizing the opportunity to strengthen the long-term competitiveness of oil and gas in an increasingly complex energy space."

> **"The ultimate test of our ability to learn is not in the crisis, but in the recovery."**
>
> —Eldar Saetre, CEO, Statoil

Statoil has always been a champion of standardization and, again, Saetre called on the industry to embrace it, as well as simplification and lean manufacturing.

"[Statoil has] reworked solutions, increased efficiency from the reservoir to the market, we have brought down the breakeven prices from our next-generation portfolio to well below US$30/bbl," he said.

BP CEO Bob Dudley offered a similar sentiment, saying that his company won't forget the lessons of the downturn, and advocated for operators to sit down with suppliers to come up with cost-effective solutions. Next month, *OE* will report on how BP used standardization and worked with its suppliers to bring its Thunder Horse South Expansion project, in the deepwater Gulf of Mexico, online 11 months ahead of schedule and 15% under budget.

Another item discussed during CERAWeek was the need to continue to invest in oil and gas projects, particularly offshore.

Saudi Arabia's Minister of Energy, Industry, and Mineral Resources HE Khalid A. Al-Falih expressed dismay about the current lack of investment. "I am concerned that misguided projections of peak demand and stranded petroleum resources may discourage the trillions of dollars in investments needed to underpin essential oil and gas supplies, during the long transformation of our global energy system," he told the CERAWeek audience.

Dudley echoed a similar call to keep investing in new projects and detailed BP's current workload.

"There's US$1.5-2 trillion in investment that has been cancelled or deferred," Dudley said. "We're going to pay a price for that," he warned. "I will tell you [that] BP is not planning on that. We're going to plan as if the price of oil is not moving up for the next five years ($55-60/bbl)." And, whatever price oil ends up being, Dudley said that BP plans to bring on seven major projects this year, with the first one slated for March – just as *OE* goes to press.

"We will bring on more projects than we have in the history of the company, in terms of activity levels," Dudley said. "In 2011, we had about 8 million man hours of activity across the company, and this year we will have 88 million – from projects under construction around the world."

Some of the projects that Dudley mentioned were the massive West Nile Delta, offshore Egypt, and Quad 204, west of Shetland, as well as projects in Trinidad. Dudley said BP has about 25,000 people working on Shah Deniz project and the pipelines offshore Azerbaijan alone.

"These are really important to the company," he reiterated. "These projects were under construction during the downturn, with construction costs coming in well below original cost estimates," he added.

Still, the drill bit will need to spin if the hopper is to be fed and this kind of activity continue. OE

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Ⓐ Anchor pays off for Chevron

Chevron has hit additional oil pay at an appraisal well at its Anchor prospect in the deepwater Gulf of Mexico. The Anchor No. 4 appraisal well encountered approximately 800ft of net oil pay in multiple inboard Lower Tertiary reservoirs. The Anchor discovery is in Green Canyon Block 807, 140mi (225km) off Louisiana in 5180ft (1579m) water depth. Anchor is in the same trend as Big Foot, Jack/St. Malo, and Buckskin/Moccasin.

Ⓑ Pemex talks Trión

Mexico's Pemex expects initial production from its Trión deepwater field to start by 2023.

Two years following first production, the Mexican national company anticipates Trión to reach its production plateau of 120 MMboe/d by 2025. Pemex revealed its plans for the deepwater field in its Q4 2016 financial report.

BHP Billiton Mexico will operate Trión with a 60% participating interest. Total estimated investment throughout the Trión's life is expected to be US$11 billion.

Ⓒ Exxon looks to Liza FID

ExxonMobil hopes to make a final investment decision on its Liza discovery offshore Guyana this year, with first oil expected by 2020, less than five years since its discovery.

A Phase 1 development at Liza, on which front-end engineering and design is underway, would see a floating production project, producing 100,000-120,000 b/d, at US$40/bbl costs, said Exxon CEO Darren Woods. That could rise to 300,000 b/d with a second phase development, which would include another second floating production unit.

Ⓓ Total adds stake off Brazil

France's Total signed a deal with Petrobras for stakes in several Brazilian offshore fields. Petrobras will give Total 22.5% in the Iara concession area, containing the Sururu, Berbigão and Oeste de Atapu fields, which are under unitization with the Entorno de Iara, a transfer of rights area in which Petrobras holds 100% interest in Block BM-S-11. Petrobras will remain as operator with 42.5% interest.

Petrobras will also transfer 35% interest in the Lapa field concession area to Total, in Block BM-S-9, with Total taking operatorship, leaving Petrobras with a 10% interest.

Ⓔ More oil at North Platte

Cobalt International has encountered oil at its North Platte No. 4 appraisal well in the deepwater Gulf of Mexico, with plans to drill a second sidetrack, as the company adds to its estimates of recoverable hydrocarbon resources at the prospect.

Cobalt's North Platte No. 4 appraisal well encountered approximately 650ft of net oil pay, with initial results indicating high quality inboard Lower Tertiary Wilcox reservoirs on the eastern flank of the field. Current estimates of recoverable hydrocarbons at North Platte is now greater than 500 MMboe, according to Cobalt, with the potential to grow larger once water contacts have been established across the entirety of the field. Appraisal operations continue to further analyze the extent of the eastern flank.

Ⓕ Chevron starts up Mafumeria Sul

Chevron started up Mafumeira Sul's the main production facility, offshore Angola.

Mafumeira Sul is 15mi (24km) offshore Cabinda province, in 200ft (60m) of water. It marks the second stage of development.

The project has a design capacity of 150,000 b/d and 350 MMcf/d of natural gas. Ramp-up to full production is expected through 2018.

Chevron operates Mafumeira (39.2) along with partners Sonangol (41%), Total (10%) and Eni (9.8%).

Ⓖ Ophir preps Ayame spud

Ophir Energy said it will spud the Ayame-1X exploration well, offshore Cote d'Ivoire in May 2017, targeting 234 MMbo of gross mean prospective resource. The well will be drilled by Seadrill's *West Saturn*. The well is a stratigraphic prospect testing an extension of a proven petroleum system in the adjacent block and the main risk is trap effectiveness. Ophir CEO Nick Cooper said that Ayame-1X is the firm's first operated deepwater well in almost three years.

Ⓗ Cairn to drill near SNE find

Cairn is getting ready for its next target, offshore Senegal.

The *Stena DrillMAX* will drill the Vega-Regulus (VR-1) well, about 5km to the west of the SNE-1 discovery. VR-1 will assess the Vega-Regulus Aptian exploration target, underlying the SNE field, with mean prospective resource of more than 100 MMbbl, and

an appraisal objective in the SNE field.

I Azinor surveys Partridge

UK explorer Azinor Catalyst completed a site survey ahead of drilling on the Partridge prospect in the Outer Moray Firth in the UK North Sea.

The survey was conducted by Gardline Geosurvey using its MV *Sea Explorer*. Drilling operations are expected later in 2017.

The Partridge prospect is in blocks 14/11, 14/12 and 14/16, adjacent to the Scapa, Claymore and Athena oil fields. The Partridge prospect's pre-drill recoverable volumes have been estimated at 119 MMboe in the mid-case, with an upside case of 260 MMboe. The prospect has a relatively shallow and normally pressured reservoir with an estimated gross well cost of US$8-9 million, Azinor said.

K Lundin tests Edvard Grieg flank

Lundin Petroleum has spud well 16/1-27 on the Edvard Grieg field in the North Sea.

Well 16/1-27, an appraisal well in PL338, is being drilled on the southwestern flank of the field by the *Island Innovator* semisubmersible.

The well is being drilled 3km west of the Edvard Grieg platform and is targeting additional gross resources of up to 30 MMboe. The drilling operation is expected to take approximately 30 days.

Lundin Norway operates PL338 with a 65% interest.

L Energean eyes Montenegro

Energean Oil & Gas signed a US$19 million exploration and production contract with the State of Montenegro for two blocks off the Balkan country's coast.

The concession contract is for Blocks 4219-26 and 4218-30, with a seven-year exploration period. The deal also includes funding for a new 3D seismic survey, geophysical and geological studies, and the drilling of one well.

The two blocks are close to the Montenegrin coast in the vicinity of the town of Bar, at 50-100m water depth. Energean says it plans to begin the 3D seismic acquisition during Q1 2018.

M Next Leviathan well planned

Noble Energy has won approval to drill an additional well, Leviathan-7, at its giant Leviathan project offshore Israel, alongside the Leviathan-5 well. Noble will drill Leviathan-7, a development and production well, with the *Atwood Advantage* ultra-deepwater drillship, "in batch" with the Leviathan-5 well, to streamline and reduce the cost of the drilling of these two wells. The *Atwood Advantage* will first drill Leviathan-7 to a depth of about 2900m below sea level (bsl), then move

J Total starts Moho Nord

Total started production from its Moho Nord deepwater development, 75km offshore Congo, in March. The project, with 100,000 b/d capacity, is the biggest oil development to date in Congo.

The Moho Nord field, part of the Moho Bilondo license, is being developed using 34 wells, 17 tied back to a new, 14,600-tonne tension leg platform, the first for Total in Africa, and 17 to Likouf, a new, 62,000-tonne floating production unit. The oil is processed on Likouf and then exported by pipeline to the Djeno onshore terminal, operated by Total.

Total operates the Moho Nord project with a 53.5% interest. Its partners are Chevron Overseas (Congo) Ltd. (31.5%) and Société Nationale des Pétroles du Congo (15%).

Global E&P Briefs

to Leviathan-5 to drill the well to a final depth of some 5200m bsl, and finally move back to Leviathan-7 to drill the well to a final depth of approximately 5100m bsl.

Leviathan-7 is in the I/14 Leviathan South and I/15 Leviathan North leases, some 120km west of Haifa at 1630m water depth. The well will target pay in the Oligo-Miocene layers.

N Petrobangla signs PSC

Bangladesh's state oil firm Petrobangla has signed a production sharing contract (PSC) with South Korea's Posco Daewoo for deep sea block DS-12 in the Bay of Bengal.

The agreement includes a commitment to carry out 2D and 3D seismic surveys, within the first three years, and then to drill wells in the fourth and fifth years of the PSC.

Posco Daewoo has acreage in neighboring Myanmar, which the firm says is analogous.

O Premier sanctions BIGP

Premier Oil sanctioned the development of the Bison, Iguana and Gajah Puteri (BIGP) fields on Block A in the Natuna Sea offshore Indonesia.

"An invitation to tender for long lead items has been issued and delivery of first gas is targeted for Q3 2019," Premier said in its full-year 2016 results.

Bison and Iguana development concepts have been reported as single well subsea tiebacks to the Pelikan field. Gajah Puteri will also be a subsea tieback, 40km, to the existing Anoa platform.

Premier (28.67%) operates Natuna Sea Block A with partners KUFPEC (33.33%), PTTEP (23%) and Petronas (15%).

P CGG Philippines project completed

French geoscience firm CGG completed its processing of geoscience data on the Carabao multi-client study, acquired offshore the Philippines.

The study integrates more than 8500km of new broadband prestack time-migrated 2D BroadSeis data and complementary marine gravity and magnetic data acquired with the seismic.

The survey connects diverse sedimentary basins across the Philippines from West Palawan (the only currently-producing basin in the country), across the Sulu Sea, to the Philippines Mobile Belt. The survey area is characterized by extensional and compressional tectonic elements and displays positive indications of active petroleum systems.

Q Chevron adds to WA acreage

Supermajor Chevron paid US$2.3 million for a new exploration permit in the Carnarvon Basin, offshore western Australia, in WA-526-P, which will last six years.

"The new permit is in a gas-rich part of the Northern Carnarvon Basin very close to the Gorgon gas project and Pluto LNG, offshore of Western Australia between Onslow and Dampier," said Minister for Resources and Northern Australia Senator Matt Canavan.

Contracts

Wood Group bags Mad Dog work

Wood Group has won two separate contracts related to BP's Mad Dog 2 project to provide engineering services to the deepwater project in the Gulf of Mexico.

Samsung Heavy Industries awarded Wood Group a contract to provide detailed engineering and procurement services for the topsides for BP's Mad Dog Phase 2 floating production unit. The US$80 million contract follows the December 2016 completion of interim agreement period early work, which was valued at $4.5 million.

Additionally, as part of the recently signed global services agreement with BP, Wood Group's Specialist Technical Solutions business picked up a $4.89 million contract for subsea engineering and project management services to the Mad Dog 2 project. That work includes gas lift system interface design, geospatial information system support, subsea controls engineering and geotechnical engineering support.

West Capella lands Cyprus gig

Seadrill has secured a one-well contract with Total for the *West Capella*, offshore Cyprus.

The contract is expected to start in 2H 2017 and backlog, estimated at 50 days, is expected to be approximately US$10 million.

The *West Capella* has recently been upgraded with a managed pressure drilling system, which is expected to be utilized as part of the upcoming work scope.

Amec in Brunei deal

Amec Foster Wheeler won a major contract from Brunei Shell Petroleum (BSP) for the rejuvenation of assets in Brunei. The work includes concept, front-end engineering design, detailed design, construction, completions and commissioning, marine management, fabrication management, procurement, and project management. The contract will run for five years from March 2017, with two one-year options to extend, and includes Brunei Shell Petroleum's oil and gas assets in the South China Sea.

Fugro wins Kenyan survey

Fugro will execute a seabed survey to detect natural leakages of hydrocarbons for Shell-BG Kenya. The seeps survey complements a seismic exploration program that was completed recently offshore Kenya.

Undertaking a four-week campaign of multibeam data acquisition and precise sampling, Fugro will mobilize its specialized survey vessel, *Fugro Discovery*, to Kenya. Seabed sampling will be carried out using a drop corer and multibeam data will be acquired with the latest deepwater high resolution multibeam echo sounder, installed in a newly designed gondola on the vessel hull.

Erin contracts *Pacific Bora*

Erin Energy signed a drilling services contract with Pacific Drilling for use of the *Pacific Bora* drilling rig at its Oyo-9 well on the deepwater Oyo field, offshore Nigeria.

Under the contract, Erin Energy has the option to drill up to two additional wells. The option to extend the contract, if exercised, would be used to drill two of its offshore Nigeria exploration prospects in the prolific Miocene geological zone.

The contract provides for a base operating rate of US$195,000 per day. The rig can be used for both drilling and well completion.

Erin Energy anticipates spudding the Oyo-9 in mid-June and first production from the well to be in September 2017. The Oyo-9 is expected to add an additional 6000-7000 b/d.

March of the Penguins

With Shell's Brent Charlie due to shut down in 2018, the supermajor has had to find a new home for its Penguins cluster subsea tieback. Elaine Maslin outlines the redevelopment plans.

The Penguins cluster, (discovered in 1974 in Blocks 211/13a, 211/14 REST, 211/29F1 in the Northern North Sea) is 150km from the Shetland Islands in 160-170m water depth, and started production in 2003 via Brent Charlie. The Penguins cluster A, B, C, D and E fields were developed in an era where, like today, cost reduction was high on the agenda, meaning subsea meters were not installed on the manifolds and wells were not constructed to enable future intervention work, BP senior production geologist Lucy Ritchie told the Devex conference in Aberdeen last May.

Shell wants to do things differently this time. The field is set to get its own "low-cost" floating production unit – a cylindrical floating production, storage and offloading (FPSO) unit – and four new manifolds for the initial seven new, metering- and intervention-friendly wells on the Penguins fields. This will be from four new drill center manifolds, new pipelines, umbilicals and risers and a new riser base manifold. Existing wells, forming a low-pressure system of the redevelopment (with the new wells being the high-pressure system), will continue to produce via a tie-in to the new FPSO. Four additional wells could also be drilled later, depending on performance from the seven new wells. Oil will be exported by shuttle tanker, with gas exported via a new 16in gas pipeline into the FLAGS (Far North Liquids and Associated Gas System) pipeline, which transports gas to St. Fergus, Scotland. Production has been tentatively planned for 2020.

Further resource could be tapped from an area south of the cluster, subject to the results of an exploration well called Rockhopper.

The upgrade for the field follows a reassessment of the subsurface. Ritchie said that an analysis of the field, which lead to an increased understanding of the geology, showed extra potential in the area spanning the play being tested by Rockhopper to known Triassic and Statfjord reservoirs beneath the upper Jurassic Magnus and middle Jurassic Brent reservoirs currently produced. About 80 MMbbl recoverable is left in the cluster, Ritchie says, and the target is to increase recovery rates from 9-15% today, to 23%.

"Statfjord and Triassic are our largest undeveloped reservoirs in the Penguins cluster and where we see quite a lot of development opportunity," Ritchie says. "We have a number of exploration and appraisal wells that have drilled down into the lower Jurassic Statfjord and cormorant Triassic. We've always found reservoirs and hydrocarbons."

Penguins A currently has two producers on it, both producing oil with no water breakthrough as yet. Two to five additional wells are due to be drilled on A, one testing the free water level.

Penguins C, D and E produce from Brent sandstones. C Block has three producers, all producing oil. D Block, split into North and South blocks, has

Lucy Ritchie. Photo from Devex.

Shell's soon to be decommissioned Brent Charlie platform during a storm in 1988.
Photo from Shell.

one producer on each block, with North producing oil and South producing gas condensate. It is beneath these fields that the Statfjord and Triassic reservoirs lay. In fact, a production well, D3, was drilled to access the Triassic, but they were unable to get the liner down so it didn't produce. Furthermore, there are environmental challenges, including braided fluvial sands.

Surveillance work has also helped the firm realize that Brent sands extend much further than thought, which has given it a new target in the C Block. As a result, Shell will focus its redevelopment plans on the Brent and Triassic with its new wells in the C and D blocks.

The new wells will be tied into metered manifolds, with well completions designed for flexibility for interventions. In addition, drilling will take a phased approach, to gain maximum knowledge, Ritchie says.

For the topsides, Shell had considered a number of alternatives, including redeployment of an existing FPSO, a new conversion or newbuild ship-shaped or cylindrical FPSO, production via BP's Magnus platform (10-21km from the Penguins wells), or continuing to use Brent C, beyond its cessation of production date, which would mean "extensive modifications" to the facility.

In its Environmental Impact Assessment, Shell says, "The new cylindrical FPSO option was selected as the preferred concept, based on there being no technical showstoppers identified, and it being the most suitable within the project timeframe." OE

Sevan's cynlindrical FPSO concept, which is in use at Eni's Goliat field.
Image from Sevan Marine.

Efficiency^3

Tackling costs head on with fresh no-nonsense thinking could prove a boon for struggling subsea developments. Elaine Maslin reports on a project that hopes to achieve just that.

What happens when you get a dozen UK North Sea-based companies, including operators and the supply chain, to work together to find ways to make subsea projects more efficient – and therefore viable?

In short, it's more than 60% cost savings and 120% schedule reduction in certain segments of the subsea scope, and a ~25% cost reduction overall. Furthermore, these are results that could be applied, and were (as a desktop exercise), to two actual North Sea fields with similar savings achieved.

These were the results of the Subsea Standardisation Project (SSP) in 2015, which presented its results late 2016. The aim was to find tangible subsea development project efficiencies to make developments more viable at oil prices less than US$50.

The project, launched under Oil & Gas UK's Efficiency Task Force, has helped both open eyes to different ways of "doing things" and offer operators realistic benchmarking for their subsea projects, says Carla Riddell, asset manager, southern North Sea, for operator Centrica. Indeed, the project has had tangible results, Centrica supplied a subsea tieback development for the SSP to trial its ideas. The results showed nearly 25% potential cost savings.

The Efficiency Task Force's themes.

"As an operator, and for industry, the benefits of an exercise like this are getting that input from outside the business and seeing a fresh way of doing things," Riddell says. What was great about the project was how many people were involved, leading to different ways of doing things, so many view points and not being confined to 'this is how we've always done it.'"

"Capturing the ideas and perspectives from such a diverse group, which included more than 70 people from 31 individual companies, shows what can be achieved when all are working together to drive change and add value," says Richard Hinkley, general manager of projects and future growth, Chevron Upstream Europe. "Having operators, design consultants, manufacturers, fabricators and installation contractors, involved from the start brings added rigor and credibility to the output of the project."

Furthermore, having realistic cost benchmarking, "realizing what the costs are for others and where savings can be made and where you can work the work scope harder," was another benefit, Riddell says.

For Steve Duthie, who took the best part of a year out of his job at Technip to lead the

The Paragon B391 jackup during the drill-stem test at Pegasus West in 2014.
Photo from Centrica.

project: "We needed tangible results to make a difference, or it is just another talking shop."

Putting heads together

The core SSP group comprised of 12 representatives from 10 companies (out of 31, which had offered support, and a total 70 people involved), including operators (from major to North Sea independent), contractors and manufacturers. They formed 12 subgroups, each looking at different facets of the subsea system, such as flexibles or trees, to find cost efficiencies across four areas: codes and standards; processes; alternative methods and technology; and hardware standardization.

The project has sought efficiencies and then developed and tested them through four theoretical subsea projects, a "straw man" exercise, involving a reference case subsea project being benchmarked by operators, and two actual field development projects. The first project, the four theoretical subsea projects (one dynamic riser project, two tiebacks and one bundle project) indicated 15-28% potential savings.

The exercise saw similar potential savings, but highlighted the difference between global and local operator costs. Nine operators (three UKCS-focused) marked-up the reference (base) case, which was broken down into the various subsea system elements, with their preferences, i.e. additional testing or exotic material requirements.

The results were predictable. Global operators added far more specifications and preferences than North Sea-focused players. As an example, the flexibles reference case (for 400m-long and 1000m-long, 8in flexibles, for 200m water depth, and an 80°C / 5000psi operating regime) was £1.6 million, with a 52-week schedule. That cost rose to £2.232 million (a 40% increase) with an 84-week schedule (a 62% increase) for the highest scoring global operator. Meanwhile, the highest cost UKCS operator had put prices up to just £1.712 million.

It was a consistent theme across the various reference case scopes, with pipeline and valve schedules standing out with <120% added, on average, to the schedules on both by the global operators. For UKCS firms, the schedule increase was <14% on pipelines and <40% on valves. Costs for the same products were higher by <22% (pipelines) and <59% (valves) for the global operators, compared to <4% and <17%, respectively for the North Sea-focused operators.

The examples go on. Global operators added <69% cost to the reference case for subsea trees, and <41% in terms of schedule (<15% and <16% for UKCS-focused firms, respectively). For control systems, global operators added <65% to the cost and <47% to the schedule, while UKCS firms added <29% to the cost and <23% to the schedule. "The marking showed how much their own specifications pushed forward schedules," Duthie says.

When all the individual scopes were brought together as a whole, the UKCS operators had added <17% in cost to the reference case, while global operators added <38%. UKCS firms added <26% to the schedule, while global operators added <57%.

Global operators could shave 30% off of the costs if they

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)	76	56	30	3
Deep (500-1500m)	32	20	12	0
Ultradeep (>1500m)	13	12	6	1
Total	121	88	48	4
January 2017	127	114	72	-
date comparison	-6	-26	-24	4

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	14	350	2649
Deep	13	1129	2835
Ultradeep	35	10,783	12,756
United States			
Shallow	6	27	71
Deep	20	1190	1602
Ultradeep	15	2090	1950
West Africa			
Shallow	120	3989	16,739
Deep	29	2640	3950
Ultradeep	13	1761	2518
Total	265	23,959	45,070
(last month)	(266)	(25,028)	(44,430)

Greenfield reserves

2017-21

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Shallow	938	35,785	344,070
(last month)	(967)	37,600)	(355,948)
Deep	136	6605	99,551
(last month)	(149)	(7992)	(107,871)
Ultradeep	74	15,839	46,887
(last month)	(76)	(16,274)	(49,457)
Total	1130	58,229	490,508

Pipelines

(operational and 2017 onwards)

	(km)	(last month)
<8in.		
Operational/ installed	41,694	(41,584)
Planned/ possible	22,230	(22,436)
	63,924	(64,020)
8-16in.		
Operational/ installed	82665	(82,548)
Planned/ possible	47052	(47,396)
	129,717	(129,944)
>16in.		
Operational/ installed	95,091	(94,967)
Planned/ possible	42,903	(43,836)
	137,994	(138,803)

Production systems worldwide

(operational and 2017 onwards)

		(last month)
Floaters		
Operational	309	(306)
Construction/ Conversion	42	(42)
Planned/possible	291	(292)
	642	(640)
Fixed platforms		
Operational	9094	(9107)
Construction/ Conversion	71	(70)
Planned/possible	1302	(1311)
	10,467	(10,488)
Subsea wells		
Operational	5078	(5076)
Develop	312	(280)
Planned/possible	6361	(6390)
	11,751	(11,746)

Global offshore reserves (mmboe) onstream by water depth

	2015	2016	2017	2018	2019	2020	2021
Shallow	21,263.21	32,035.17	32,788.99	11,682.05	12,436.84	17,310.18	22,195.42
(last month)	(21,272.27)	(31,782.40)	(33,260.12)	(12,484.77)	(15,941.97)	(17,366.05)	(20,667.15)
Deep	972.99	1411.48	4786.07	2728.43	2567.19	5175.86	9046.09
(last month)	(972.99)	(1411.48)	(5240.33)	(2799.53)	(3580.31)	(5420.49)	(10,135.39)
Ultradeep	2023.19	3075.34	1671.44	3924.53	3693.78	9609.94	5206.35
(last month)	(2023.19)	(3075.34)	(1789.07)	(3685.74)	(4362.19)	(9760.99)	(5206.35)
Total	24,259.39	36,521.99	39,246.5	18,335.01	18,697.81	32,095.98	36,447.86

Source: InfieldRigs 9 Mar 2017

Rig stats

Worldwide

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	96	59	37	61%
Jackup	403	226	177	56%
Semisub	118	63	55	53%
Tenders	27	14	13	51%
Total	644	362	282	56%

North America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	30	22	8	73%
Jackup	25	7	18	28%
Semisub	10	7	3	70%
Tenders	N/A	N/A	N/A	N/A
Total	65	36	29	55%

Asia Pacific

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	11	3	8	27%
Jackup	119	66	53	55%
Semisub	31	11	20	35%
Tenders	20	11	9	55%
Total	181	91	90	50%

Latin America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	23	17	6	73%
Jackup	51	25	26	49%
Semisub	24	16	8	66%
Tenders	2	1	1	50%
Total	100	59	41	59%

Northwest European Continental Shelf

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	0	1	0%
Jackup	50	30	20	60%
Semisub	39	23	16	58%
Tenders	N/A	N/A	N/A	N/A
Total	90	53	37	58%

Middle East & Caspian Sea

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	2	1	1	50%
Jackup	117	82	35	70%
Semisub	4	3	1	75%
Tenders	N/A	N/A	N/A	N/A
Total	123	86	37	69%

Sub-Saharan Africa

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	18	13	5	72%
Jackup	18	7	11	38%
Semisub	3	1	2	33%
Tenders	5	2	3	40%
Total	44	23	21	52%

Eastern Europe

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	N/A	N/A	N/A	N/A
Jackup	2	0	2	0%
Semisub	N/A	N/A	N/A	N/A
Tenders	N/A	N/A	N/A	N/A
Total	2	0	2	0%

Source: InfieldRigs 9 Mar 2017

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

dropped the likes of sacrificial testing and their own testing regimes, prescription qualification regimes, using exotic materials and demanding full traceability, and issuing project specific specifications (with conflicting information), the SSP project suggests. For UKCS operators to move closer to the reference case cost, they would need to work to industry standards and drop minor modifications, drop defined specification sheets and have functional specifications instead, use readily available materials, drop the requirement for full traceability, use existing qualified procedures and solutions, and accept contractors' standard testing procedures.

Going further

Next, the subgroups went through their respective elements of the system to see where additional efficiencies could be made. Ideas to identify areas of conservatism around flexibles standards ranged from overhauling subsea tree supply scopes (from materials to inspection processes) to adapting industry standards (e.g. API 17J). The subsea tree supply scope project identified 13% cost and 18% schedule savings through changing inspection and test plan regimes, allowing contractors to control their own supplier process and reducing documentation by providing only functional requirements. The API 17J work identified 15% cost and 7% schedule savings, mostly achieved by clients accepting a type-approval certification as pre-qualification, removing the need for third party design reviews.

"API 17J took eight years to revise and it became a very high-requirement document and the feedback was that it was higher than what was needed for the UK North Sea," Duthie says. "Reducing its requirements could result in 15% cost saving."

One of the biggest potential cost reduction areas was in using alternative methods, however, followed by simplifying or making more fit-for-purpose the codes and standards, then processes.

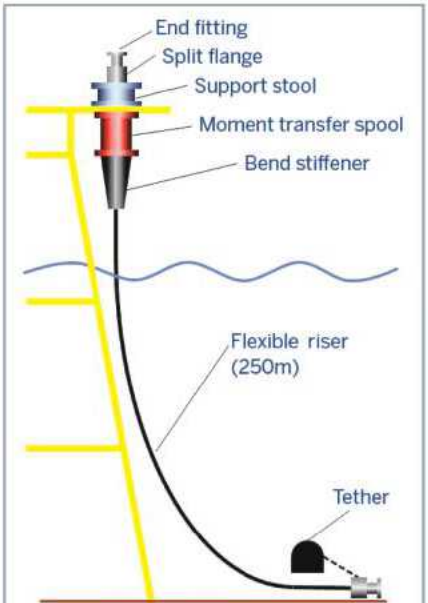
Into the real world

The final project was seeing what efficiencies could be made on two real projects: Centrica's Pegasus West, a potential three-well gas tieback in the southern North Sea, and Chevron's West Wick, a potential 2.7km heavy oil tieback to the Captain platform in the Moray Firth.

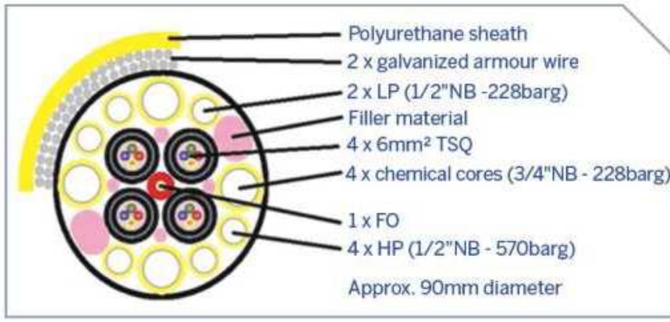
"For Pegasus West, a lot of options were looked at and a lot of screening done," Duthie says. "The results were efficiencies and areas that could be simplified, such as co-mingling at the manifold, simplifying the umbilical, reducing the amount of documentation, and having a standard manufacturing approach."

While actual figures weren't revealed for the project, savings were given as a percentage, which were 20.4-24.7% in total. The biggest impact came from introducing alternative methods and technologies (65.7%), then codes, standards and practices (18.9%).

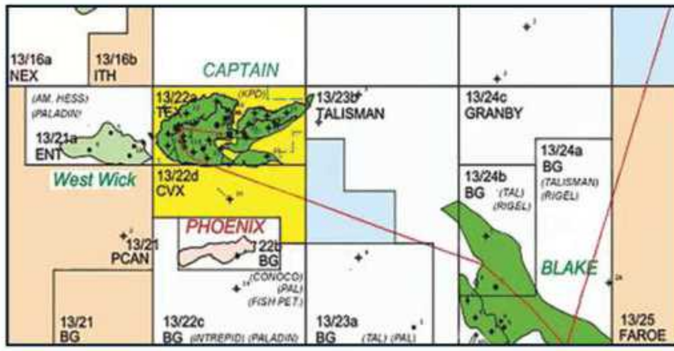
Riddell says that the SSP project was good timing for Pegasus West, which is in concept select (pre-FEED) phase. "We are fortunate having many options on Pegasus West," Riddell says. "But for discoveries like this, it is about working it as hard as possible. We have reworked the subsurface data to give us a more accurate view of what is possible. The SSP came at a perfect time and has allowed us to move ahead on the concept select without having to drill more



Free hanging risers, schematic.
Images from Efficiency Task Force.



West Pegasus umbilical.



West Wick, close to Captain.

wells and appraise for more gas." Centrica will now test the results of the SSP project to increase their confidence in the project.

Efficiencies on West Wick were also based on taking an alternative approach, i.e. using free hanging risers instead of a caisson riser. "This gave a big saving," Duthie says, at 34.14%, and also meant the flexibles scope could be reduced, using pre-qualified designs and not having third party deign reviews, etc. The subsea manifold and umbilicals were also simplified, as at Pegasus West, and some 38.1% savings were made on the project's valve scope by using materials supplied on standard material data sheets, using standard contractor sealing arrangements, cast bodies for gate valves, limiting the number of valve types, using contractor standard sizing factors, using pre-qualified designs, having no welding or material qualification and reducing documentation and inspection requirements.

Savings of 26.27% were made in pipelines through material selection, inspection, qualification and installation efficiencies and the concrete mattress, trenching and rock dumping scopes were also made more fit-for-purpose.

Overall, the saving on West Wick was 24.77% (or £8.19 million) from a £33.9 million scope, mostly through using alternative methods and technologies, accounting for 47.2% saving, followed by efficiencies in codes, standards and specifications at 29.4%, then processes, at 20.4%.

"The review of West Wick suggested savings of up to 25% on the subsea system – about half related to design choices, and the rest from sustainable process improvements," Hinkley says. "We are now in the process of understanding the results and learnings.

"Our project is at a very early stage," Hinkley continues. "We are currently focused on verifying and validating the results from the Subsea Standardisation Project against our own internal engineering standards to fully analyze the findings and potential savings. In addition, we are continuing to analyze the subsurface which, alongside a number of other important work scopes, will be critical to determining the economic viability of this small pool development."

Moving forward

The real test will be if this work now enables these projects – and others – to move forward. Duthie notes that smaller operators will be able to do more, with global players less able to reduce codes and specification requirements, etc. "In real life, we would have more time to go into more detail," Duthie adds. "It will also be pick and mix," i.e. it doesn't have to be all or nothing.

How the benefits of this project can be captured also remains to be seen. It would be nice to have so much input into every project, admits Riddell, but this isn't feasible. "What we need to do is pick the most difficult challenges and get industry together and try to solve these challenges as a group," she says. "We need to use that wider knowledge to try and collectively solve the problems."

"Since we did this work they [the operators] are taking this approach seriously and revisiting everything," Duthie says. But, it takes more than just seeing numbers. "Getting through to development is another matter. There is still a permafrost among the technical authorities."

Future goals

While hardware standardization was a part of the project – and its title – it was felt that this was a longer-term goal. "We need solutions here and now," Duthie says. "A lot of small pools are within tieback range. We don't need (new) technology to develop those, we need to be efficient so investors get a return. Here and now is about simplification and fit-for-purpose. True standardization is modular, plug and play. That's the long-term goal. But in the short-term, commercial sensitivity, IP, etc. make it difficult."

In time, Duthie thinks that subsea equipment for small pools – with more than five-year production lives – will be more like drilling equipment, i.e. hired on a project by project bases and refurbished each time.

Meanwhile, the industry has the results of the SSP – a 18-page set of guidelines available from Oil & Gas UK – with which to play. All involved hope that it helps unlock some of those small pools and bring some much-needed development activity into the basin. OE

Testing high-tech solutions for asset integrity

The impact of asset integrity is hard to quantify, but UK North Sea goals to tackle it, including using robots, are being made clear. Elaine Maslin reports.

With a recent history of low production efficiency, alongside the high-costs related to dealing with asset integrity issues, ways to make inspection easier and reduce corrosion related failures, including using robots, are high on the agenda in the North Sea.

The UK's new Oil & Gas Technology Centre (OGTC), based in Aberdeen, has set asset integrity cost reduction firmly in its sight and this summer will work with operators Chevron and Total to trial new technologies, including a robotic snake arm systems for inspecting inside pressure vessels.

The OGTC, which launched in February (*OE*: March 2017), has three goals, under its Asset Integrity solutions center: reduce inspection costs by 50% by 2021; eliminate all failures by corrosion under insulation (CUI) by 2026; and have no vessel entry for inspection by 2026, by man or drone. Currently, just 10% of operators are using non-intrusive inspection (NII) techniques for the latter, according to Rebecca Allison, asset integrity solutions center manager, for OGTC.

Not all think that the goals are achievable. But, Allison, who previously worked at Lloyd's Register and Aker Solutions, does.

"Our vision is to eliminate the impact of asset integrity on operational uptime by 2026," she says. "I have worked in the industry for over 20 years and the way we have managed asset integrity hasn't really changed over those 20 years.

This is an opportunity to change."

Allison says that these are not just oil and gas issues. "The global cost (of asset integrity) is about £4 trillion. It's £28 billion in the UK. CUI is estimated to cost £300 million/year."

Dave MacKinnon, head of Technology Innovation at Total E&P UK, says that asset integrity is a large cost in the operating environment, especially in the North Sea. "Salt from the seawater, added to hot process pipework and things that are under insulation, make it a challenge to ensure integrity," he says.

"One of the main challenges is to use NII, rather than opening everything up and inspecting it," MacKinnon adds. "[Intrusive inspection] is predominantly a manually intensive program with lots of people to remove insulation or people crawling around taking measurements, so it takes many man hours."

Reducing these hours could improve uptime. Production efficiency fell from 80% to 60% from 2004-2014. Process vessel inspection is a significant contributor to production downtime, during shutdowns, often involving personnel entry into confined spaces and all that entails, from permits, to having specialist personnel and having to shut in production, according to a study by Lockheed Martin, on behalf of industry body Oil & Gas UK, and the Technology Leadership Board. Reducing shutdown time will improve production efficiency.

Paul Jackson, integrity management team leader at ABB, told an OGTC breakfast briefing on NII that typically 85% of equipment has to be shut down and isolated for inspection. Some 95-97% of the cost of inspection is associated with enabling the inspection, he says.

Issues around CUI are just as bad, because it is difficult to

Above and left, the P100 robot "snake arm" robot is due to be trialed in the North Sea this year, as part of efforts to make pressure vessel inspection more efficient.
Photos from OC Robotics.

detect due to the insulation that masks the corrosion problem, sometimes until it is too late. According to the Lockheed report, industry data suggests that 60% of pipe leaks are caused by CUI. It is also estimated that CUI incurs 40-60% of pipe maintenance costs. But, detecting CUI means having to cut into or remove plugs from the insulation, a technique that inevitably relies on the right section being tested to find any hidden corrosion.

Using technology to visualize through the insulation or look inside from the outside using various techniques would be better, MacKinnon says, and using new technology such as robots could also make it more efficient and more accurate.

Vessel inspection

The Lockheed report highlighted possible technologies and techniques that could help in the near-term, for both vessel inspection and CUI. For vessel inspection, the report highlights a low frequency electromagnetic technique, which has moderate cost, low risk and a high maturity score in Lockheed's assessment matrix. The Low Frequency Electromagnetic Technique (LFET) is used to detect defects by passing a low frequency magnetic field through metal plate or pipe. By using several sensors in a LFET scanner, a 3D image of the collected data is produced so that the shape and depth of the defect can be determined.

Full matrix capture (FMC) was also highlighted, albeit being seen as less mature, but having good long-term prospects. FMC is a data acquisition technique that allows for the capture of every possible transmit-receive combination for a given ultrasonic phased array (PA) transducer.

Inspection using PA ultrasonic techniques is now relatively well established, with several advantages over conventional ultrasonic techniques resulting from the ability to steer and focus ultrasonic waves using a single transducer containing multiple probes. By using beam steering and focusing, a single transducer can perform a task which usually requires multiple conventional ultrasonic transducers.

I, Robot

Using robots and remotely operated vehicles was also highlighted, in combination with other sensor technologies, to allow a reduction in the need for manual entry. Indeed, some operators have already been looking at robots, which are an established technology in nuclear and aerospace industries. Ten companies were involved in the Petrobot challenge, including Shell, Chevron and GE Inspection Robotics.

The Petrobot team developed three offline (i.e. empty and clean) pressure vessel inspection robots and one online (i.e. product still in the tank) tank robot to inspect tanks for a range of potential defects such as weld cracks, pitting and wall thinning:

- The FAST platform – a magnetic inspection and cleaning crawler with several tools including visual inspection cameras, ultrasonic and eddy current tools and a laser for 3D point cloud generation.
- The Snake Arm robot – this has a long slender, flexible design to fit through small openings and avoid obstacles. It can carry visual inspection cameras, ultrasonic and eddy current tools.
- The BIKE robot – a small robotic crawler for complex environments within vessels. It can carry visual inspection, ultrasonic and eddy current sensors and laser scanning technology to generate 3D images. It can climb over obstacles.
- The TANK robot – designed to inspect tank floor while product is still inside. It can operate semi-autonomously and uses ultrasonic navigation technology. It can hold visual inspection cameras, magnetic eddy current and ultrasonic thickness tools.

The project has led to the forming of the Sprint Robotics Collaborative, based in the Netherlands and supported by Shell, Chevron, and Statoil.

Following the project, Chevron is now lining up a trial for a snake arm robotic inspection system, the P100 from OC Robotics, to inspect inside pressure vessels on its assets in the North Sea, following onshore trials. This would be a world first. The system is designed to traverse the platform and use its arm, which is manipulated using wire ropes, to inspect inside the workspace, while the system's main drive motors, electronics and control systems are located away from the inspection area.

"Our vision is to eliminate the impact of asset integrity on operational uptime by 2026."

Rebecca Allison,
Asset Integrity Solutions
Center Manager, OGTC.

CUI

For CUI, pulsed eddy current (PEC) techniques offered a good solution, at moderate cost and risk, and has a high maturity score, says Lockheed Martin. PEC works by driving an electromagnetic field though the insulation and into the pipe. Pickup sensors detect variations in the field that are caused by changes in the pipe.

The report notes that there is a "significant industry commitment to product development, marketing and deployment" in this area. Vapor phase corrosion inhibitor was also highlighted, as a preventer rather than detection technique. A vapor phase corrosion inhibitor is a volatile compound and forms a stable bond at the interface of the metal, preventing penetration of corrosive substance to metal surfaces. Despite some concern about the chemical required for the process, it was "worthy of further investigation to prevent the extent and nature of the underlying problem of CUI."

Some of the techniques highlighted for CUI could also be combined with robotic techniques, such as pipe and vessel crawlers, the report suggests. Indeed, any technique that reduces the need for scaffolding would be welcome, it says.

Building on the work of Oil & Gas UK's Efficiency Task Force, and the Lockheed Martin report, the OGTC already has several projects under way. As well as Chevron's plans to trial the P100, Total E&P UK is due to do three trials of mapping techniques for vessels (assessing wall thickness primarily) during a shutdown this year.

In Total's Central Graben Area, mid-2017, the firm will have flotel support for maintenance, inspection and modification work on the Elgin/Franklin facility during a summer shutdown campaign.

Leading up to and during this time, i.e. online and offline, trials using non-intrusive pressure vessel inspection technology, CUI on piping inspection technology, using a PEC system (without removing insulation), and an embedded sensor technology, to monitor specific locations, either where CUI is a risk or where CUI needs monitoring, will be carried out. This will mean online and offline results can be compared.

A number of other technologies, including a tethered robot for vessel entry, could also be tested. Meanwhile, on Total's northern North Sea Alwyn asset, a remote online monitoring system using an acoustic emission (AE) technology, will be trialed.

Not convinced?

Those who are using NII have adopted it heavily. Speaking at the ITF Technology Showcase in Aberdeen early March, Jonathan Copp, technology manager at Chevron Upstream Europe, said Chevron's spending on NII has quadrupled over the past five years and in doing so had eliminated manual entry into pressure vessels, taking that off the shutdown path.*

Jackson says that this also eliminates issues caused by equipment not being put back together properly, after an inspection. An asset integrity lead from another North Sea operating major said that adopting NII was a painful process, even in the second year of doing it, but the big change had come with justifying why vessels needed to be opened, rather than justifying when you shouldn't go in. He said a typical inspection during a turnaround involving isolation, cleaning, flange cleaning, line walking, de-isolation, etc., cost £215,000, compared to a £25-40,000 NII, program, depending on the size of vessel. Instead of inspection being the cause of that higher cost, when entry is required, it is the process team now wanting vessels opened for the work they see needing to be done, following an NII.

However, there are some that have concerns about NII. Some of the concern is conservatism, but also about there being the staff with the skills to use the equipment properly, or if there are risk-based inspection methodologies to support it. Where vessels have complex geometries or equipment inside, there's a question of how comprehensive NII could be.

"You have to understand what type of degradation you have and the capabilities of the non-destructive techniques to test it," said a contractor at the OGTC briefing. Knowing the current condition of the vessel is also important – while a visual inspection might reveal no flaws, grit blasting could reveal a surface like Aero chocolate, said another contractor. The starting place should be what are you looking for and is using NII first going to benefit.

The OGTC has launched an initiative with Swiss group ABB to seek to "demystify the perceived limitations in adopting NII." ABB thinks US$500 million a year could be saved by using NII, through increased production uptime and reduced maintenance costs.

The first phase of this initiative will be a base line survey of operators' use of NII technologies and to identify existing barriers to change. The project will also seek to set out the overall opportunity for UK Continental Shelf operators to reduce costs and increase production by applying such technologies and methodologies across their assets.

"Looking ahead, asset integrity is not just about CUI or vessel inspection," Allison says. "We need to look at remedial side, unmanned aerial vehicles, data visualization, additive manufacturing, laser cladding, 3D printing."

There will also be a piece around data, MacKinnon highlights. "There's a lot of data associated with inspection and if you can start to analyze that data, look at patterns, trend and share that data within industry, you have much better insight into how corrosion or integrity issues form, what patterns you have, and how faults propagate," he says.

The OGTC itself also wants to hear from industry, subject matter experts especially. "We need access to knowledge and experts," Allison says. "Plus test equipment – test pieces as well as test facilities so we can do field trials. We also need help identifying the challenges. Operators cannot really tell us what their budgets are, so there is a bit of work to be done to get that business plan data." OE

**OE has asked for detail on this*

Fighting fatigue

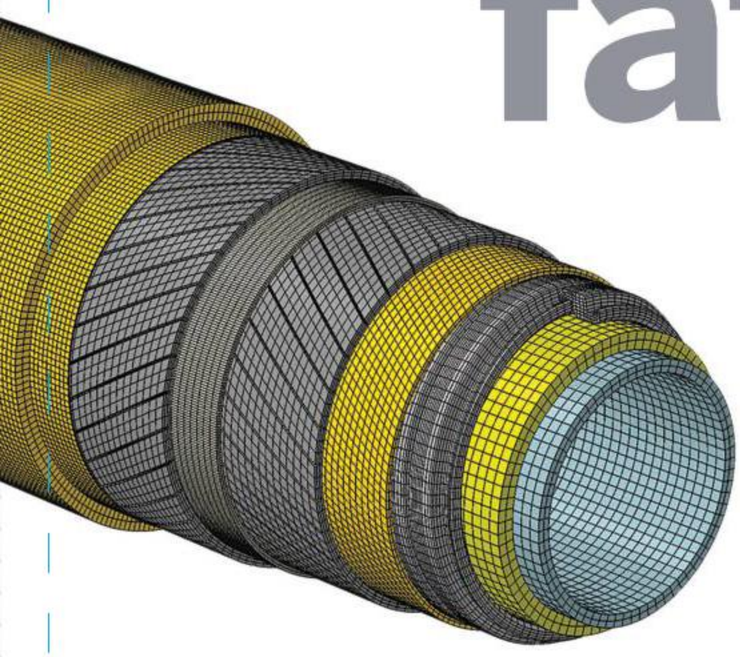


Figure 1: A typical flexible riser composition.
images from Intecsea.

Intecsea's Kirsten Oliver discusses a new flexible riser inspection tool created in partnership with UK-based Innospection.

Understanding the condition of flexible risers as they approach the end of their design life is not a straightforward exercise.

Flexible risers are designed with a discrete design life that includes significant safety factors to compensate for the uncertainties in degradation associated with the complex layer construction associated with tensile armor, pressure armor, inner carcass and outer protective layers.

The key benefits of flexible risers:

- Enabling a permanent connection between floating facilities and subsea infrastructure, where large motions are experienced.
- Cost-effective installation, ability to reel long lengths for transport and handling, and diverless installation, which enables deepwater installations.

However, this means flexible risers are put under complex dynamic stresses during operation, and one of the critical parameters in the design and continued operation is related to failure of the tensile armor wire layers because of fatigue.

When risers are initially designed, they have a significant in-built safety factor driven by the uncertainty in the fatigue life of the tensile armor wire layer. During early life, when the riser operates well within the design limits, basic inspection is carried out in line with a low risk categorization (e.g. DNV RP 206) (see Figure 2). This means there is often very little inspection testing or monitoring carried out.

As the riser approaches the end of its intended design life, this lack of operational integrity data makes life extension a challenge. Understanding the remaining fatigue life of the riser and establishing whether any degradation of the tensile armor wires has occurred has historically been both an analysis and inspection challenge.

Inspection

While there are many non-destructive testing (NDT) inspection tools on the market, they have had their limitations. Figure 3 summaries the comparative techniques.

The Innospection MEC-FIT inspection tool enables degradation (cracking and corrosion) to be detected in up to three layers of armor wire in both flooded and non-flooded annulus conditions. The tool can be deployed by inspection remotely operated vehicle or directly from the facility using a low capacity crane.

A client used MEC-FIT for a UK North Sea Project to inspect from the topside to about -30m on a flexible riser that had damage to the polyethylene outer sheath. The operator decided to assess the wire condition of the main flexible riser and neighboring risers.

Analysis

Finite element analysis (FEA) is the predominant method used to perform structural integrity assessments of complex components under various load combinations. Its application to the simulation of flexible risers is common during the design phase, as well as throughout the asset lifecycle in the form of life extension.

Flexible risers exhibit nonlinear behavior under bending, largely due to the stick/slip interaction between the pipe wall layers. However, capturing the highly nonlinear interactions in a compliant system that can undergo large 3D translations/rotations is currently limited by the computational efficiency of commercial FEA tools.

This limitation has historically precluded flexible risers from being assessed using high fidelity irregular wave fatigue methods, rather necessitating a regular wave approach with increased uncertainty and overarching assumptions. API RP 17B[1], Section 5.7.1 states: "The limitation of the regular wave approach is that the results can be difficult to interpret for systems whose response is strongly dependent on frequency. It is often impossible to determine whether the result is conservative or un-conservative, particularly in the case of flexibles where estimation of the natural periods can contain significant uncertainties."

Intecsea developed a simulation-based approach where nonlinear dynamic substructuring (NDS)[2] is leveraged for efficient computation of the large scale nonlinear simulations. This approach, enabled by a proprietary FEA solver (Flexas), has been fully validated for dropped object simulations[3] and for accurate prediction of detailed local stresses in unbonded flexible risers[4].

The technology uses simplified beam elements, and eliminates the need for additional local model analyses. Instead, the full detailed internal layer geometry is simulated either with global tension/curvature time-history inputs, or directly within the global riser configuration under irregular wave environments to extract wire stress time-histories[5].

The following example demonstrates how the conservatism in fatigue life calculations using regular waves (typical during design phase) can be quantified using an approach incorporating Flexas NDS.

The wire stresses were extracted from the following locations: the cross section under the bend stiffener, the wire corners' inner armors at 16 locations and wire corners' outer armors at 16 locations.

Post-processing of the wire stresses was carried out to generate fatigue spectra for both the irregular and regular wave cases to enable a comparison of wire damage ratios. Analysis demonstrates that the predicted damage from the regular wave cases is in the region of 6-7x greater than for the Flexas simulation based irregular wave cases. This equates to a potential 7x increase in fatigue life using the Flexas approach. Using Flexas irregular wave modeling increases confidence that the fatigue life can be extended for situations where the original design life has been compromised. While the Flexas simulation approach may be considered more accurate, it is specific to configuration and environmental loading and therefore needs to be assessed on a case-by-case basis; this is clearly a significant enhancement on the basic design premise regular wave analysis.

The Flexas approach has the additional benefit that damage can be incorporated into the detailed local model, and therefore any metal loss or cracking detected by the MEC-FIT inspection can be also be modeled. **OE**

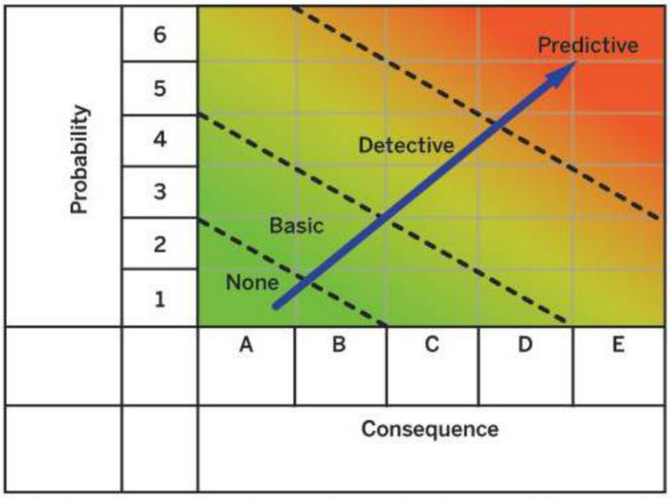


Figure 2: Example of risk-based integrity strategy (DNV RP 206)

***Kirsten Oliver** is the Brownfield and Asset Management Lead at Intecsea. FlexIQ is a strategic alliance between Innospection and Intecsea that enables inspection and computational simulation techniques to be delivered as part of an integrity management framework.*

[1] API Recommended Practice 17B. Recommended Practice for Flexible Pipe.

[2] A Nonlinear Dynamic Substructuring Approach to Global Dynamics of Flexible Riser Systems, Arya Majed and Phil Cooper , ASME 2014, 33rd International Conference on Ocean, Offshore and Arctic Engineering Volume 6B: Pipeline and Riser Technology.

[3] Arya Majed (Intecsea), Antoine Dutertre (Total), iSOPE-2015, International Ocean and Polar Engineering Conference

[4] Michel W Dib, Philip Adrian Cooper, Shankar Bhat, Arya Majed (Intecsea) Offshore Technology Conference May 2013

[5] Majed, A., Cooke, N., Chinello, L. (Intecsea), Gomes, J. (DeepStar), Yiu, F. (Anadarko) and Kusinski, G. (Chevron), "New Generation Computational Capabilities in Nonlinear Dynamic Simulations of Flexible Riser Systems", OTC 2017, Houston, Texas.

Ultrasonic	MAPS-FR	Digital Radiography	MEC-FIT
Pulsed echo ultrasound technique	Electromagnetic stress measurement technique	External radiography technique	Electromagnetic technique (magnetic / eddy current field)
Ext scan under water, slow	Static ext. mounted measurement	Static spot RT shots	Dynamic fast scan
Detect flooding of annulus and thickness of outer tensile armor layer only if flooded	Detect fatigue failure and through cracked wires	Detects cracks, corrosion (limited min wall loss detection), loss of interlock in pressure armor layer	Detection of corrosion (pitting) cracks, wire misalignment in tensile armor later 1 and 2. Loss of interlock in pressure armor layer
Couplant required	No penetration through outer layer	X-ray Computed Tomography Very high resolution single line scan)	No couplant required but requires calibration

Figure 3: Comparison of NDT techniques. Source: Intecsea.

Improving passive **fire protection systems**


Weather erosion of lightweight concrete passive fire protection.
Photos from MMI Engineeering.

UK-based technical consultancy MMI Engineering discusses issues around passive fire protection integrity, and the launch of a new industry network – PFPNet.

Passive fire protection (PFP) materials are designed to mitigate the effects of fire on safety critical systems, reducing the likelihood of escalation.

Examples include PFP coatings, materials and systems; combined fire and thermal insulation systems; insulated and non-insulated fire and blast barriers; penetration seals; and enclosure systems.

But, there was a view that something needed to be done to improve the way that PFP systems are used around the world.

One such misunderstanding encountered by UK-based technical consultancy MMI involved a gas platform's main structural steelwork, which at the time was being protected by deluge pipework (active fire protection).

Such a system could be specified and used to protect against a hydrocarbon pool fire threat on an oil platform. However, deluge has been shown to be an ineffective mitigation measure when protecting items against jet fires, which are a major threat to gas platforms. A correctly specified PFP system would have mitigated the effects of jet fire, rather than rely on a method that had unknowingly compromised both safety and loss prevention.

Occurrences are commonly encountered by MMI's engineers, who are often commissioned to advise on the use of new systems, or repair and remediate older failing systems and materials.

While conferences cover some technical aspects, and manufacturers are developing new systems, there is still confusion and misunderstanding amongst the end users, which is leading to costly and sometimes dangerous mistakes being made on a regular basis.

MMI Engineering has seen at first hand the results of the misuse and misunderstanding of PFP systems and is trying to address this issue. MMI is behind the launch of PFPNet (The Hydrocarbon Passive Fire Protection Network), which has seen broad support from operators, contractors and product and system manufacturers, confirming our view that something needed to be done to improve the way that PFP systems are used around the world.


Fire seal pentration insulation failure.

PFPNet is an independent, subscription-funded body which will focus on educating, training, researching key topics and clarifying points of confusion for those that work with fireproofing materials and systems, thereby improving the quality of PFP applications in hydrocarbon industries.

To ensure that the group works purely in the interests of its members, its activities will be managed through an independent steering committee led by John Dunk, former director of Fire and Insulation products at International Paint. Headed by Dunk, the interim steering committee is made up of individuals from Kaefer, CB&I, BP, UK HSE, The University of Edinburgh, and MMI.

A one-day meeting was held last year in Manchester, UK, which introduced the group to over 70 attendees with diverse hydrocarbon PFP-related backgrounds.

The UK meeting attendees identified themes and topics they felt needed addressing to raise standards. Primarily noted was the absence of fireproofing qualifications, guidance documents, and accreditation scheme, and the real need for external bodies and standards organizations to be on board with addressing such issues. This output led to a scope of work for 2017, which has been documented within a membership proposal that is now with industry.

A similar meeting in Houston was also held. MMI's Dr. Simon Thurlbeck and Graham Boaler introduced PFPNet to several operators, engineering, procurement contractors, manufacturers, fabricators and consultants. Over 50 representatives from companies including Shell, Bechtel, Dow, UL, NACE, Marathon Oil, BP, Jotun Paints, Carboline, PPG, Sherwin-Williams and Promat attended and heard about the key findings from the initial launch in the UK.

PFPNet now has 14 members (Advanced Insulation, Exova, Hempel, UK HSE, Jotun Paints, Perenco, Promat, Sherwin-Williams, Trelleborg, Woodside, Shell, Technip, Alfred Miller Contracting and Esterline), with more expected.

"As a comparatively new entrant to the fire protection market it is essential that we develop our working procedures in accordance with what are the very best practices within the industry," says Simon Daly, Group Oil & Gas Segment Manager at Hempel. "PFPNet will ensure that our advice is based on current thinking through tailored research programs into highlighted industry issues. This will in turn allow us to keep our own knowledge as current as possible."

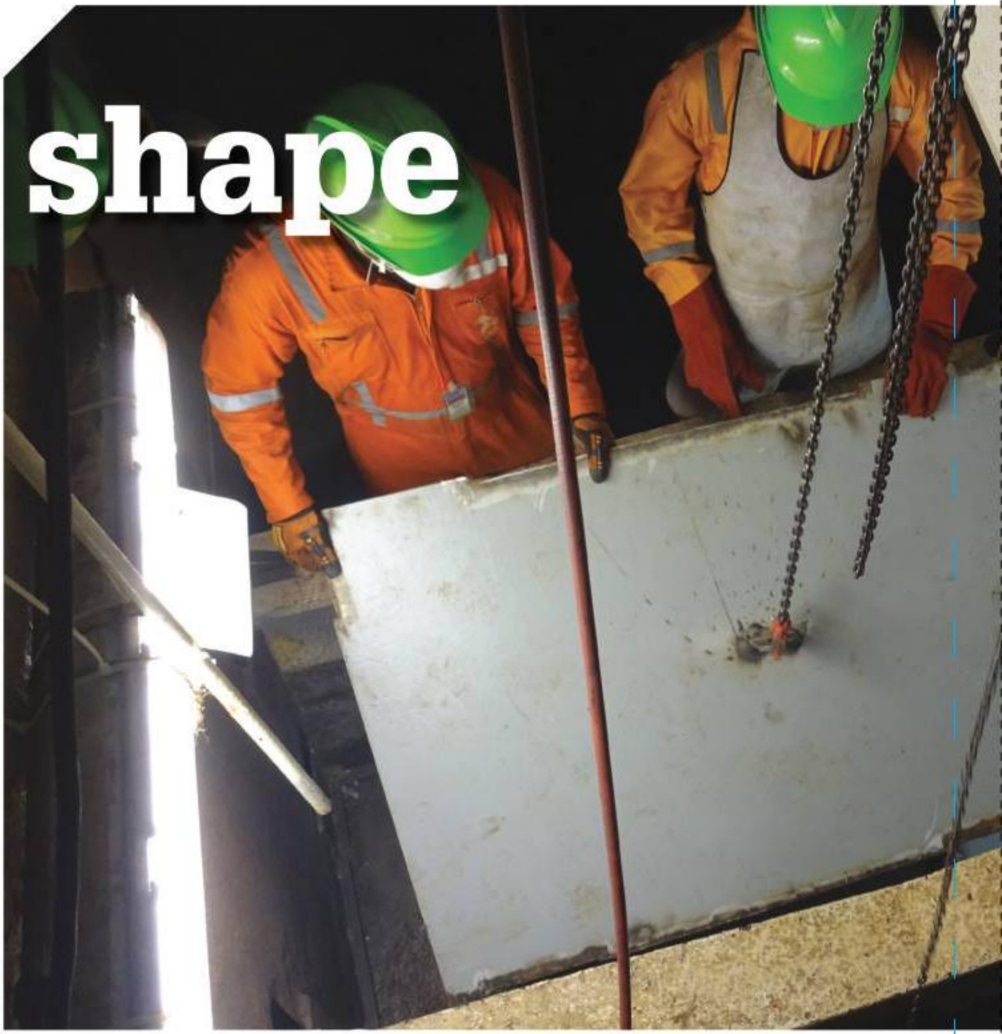
In the long-term, PFPNet's goal is to reduce the errors and costly mistakes that occur with misused PFP systems. Working together with users and suppliers globally, the group's aim is for this collective influence to change the way PFP is specified and applied across the hydrocarbon industry.

For more information go to visit: www.pfpnet.com. OE

Ship shape

Polymer steel composite repairs are becoming a popular solution for worn out plates in the growing floating production vessel fleet. Elaine Maslin reports.

The *FPF3* on station.



Top plate positioning on the *Komi Kribi 1*. Images from Intelligent Engineering.

The industry has been searching for solutions to repair the world's aging 270 floating production units without having to take them off station to a shipyard. UK-based Intelligent Engineering (IE) has one: composite repairs.

Last year, IE carried out below the water line repairs over more than 120sq m of plate on two floating production vessels – ExxonMobil's floating storage and offloading (FSO) vessel *Komi Kribi 1*, stationed off Cameroon, West Africa, and the floating production, storage and offloading (FPSO) vessel *FPF-003*, operated by Petrofac, off Thailand – both while the vessels remained in operation on station.

Furthermore, the firm's composite repair technology has been extended to be used to create an emergency tunnel onboard the newbuild *Glen Lyon* FPSO, which is due to start production west of Shetland on the UK Continental Shelf this year. It's also being used for strengthening helidecks – to handle heavier helicopters – and for upgrading vessels to ice-class – among a string of other applications for which IE's sandwich plate system (SPS) technology has been used.

Polymer sandwich anyone?

SPS plates comprise two metal plates bonded to a solid polyurethane elastomer core. The technology was developed by IE with Germany's BASF supplying the core material. In repair and strengthening applications, perimeter bars and a new steel plate are welded over the thinned metal to create a void into which the elastomer core is pumped. The plates are continuously supported by the core, which fills the cavity, including uneven geometries in the corroded plate. This repair method means existing material doesn't need to be removed – so on a below the water line repair, cofferdams and divers (plus dive support vessel) are not required.

IE first started using SPS in the ro-ro (roll-on, roll-off) ferry market, where decks were thinned beyond classification limits due to repeat wear, and where repairs would then also keep failing. "The unique thing is that it acts in a global manner, adding strength to the whole deck," says Ian Nash, business manager, IE. "From that, we discovered SPS had a lot of advantages over conventional steel. It has high shock absorption, acts as an external barrier, it's a barrier for noise, it's blast and ballistics resistant and fire retardant. We realized SPS could take a good battering and remain flat."

It can also be applied to suit its use. For example, on a ro-ro or FPSO, the plate will be about 8mm-thick. On a bulk carrier, however, where it needs to withstand 10-15-tonne repeat loads, every day, 10mm plate will be used. The core is usually 20mm-thick, but sometimes it is higher, such as when it's being used as a thermal barrier, when it could be 40mm.

The firm has been working in the offshore sector for about 10 years, with work including reinforcing pipe rack decks on semisubmersibles, without disturbing other decks or equipment.

Aging FPSOs

In the FPSO market, there are some older vessels which are starting to need some tender loving care. "It could be that a vessel's steel wasn't as thick as

originally thought or that the maintenance wasn't as good as it could have been," Nash says. For a conventional below the water line repair on an FPSO, a cofferdam would first need to be installed and then divers deployed, Nash says. The time it takes them to do the work could vary. The alternative is to take it off station and tow it to a yard, which operators want to avoid. Instead, Nash says that IE can deploy a 4-5-man squad to do the job, while the vessel remains in production, without the need for divers.

FSO *Komi Kribi 1*

The firm's first below water line repair was in 2013. Last year, the firm did six such repairs. One was on the FSO *Komi Kribi 1*, converted in 1977 from a very large crude carrier and operated by ExxonMobil for Cameroon Oil Transportation Co. 11km offshore.

The vessel had its sea chest, bottom shell and bulkhead reinstated using SPS, with a squad comprising two IE staff (a project manager and an elastomer injection engineer) and six local welders and platers from Cameroon Shipyard and Industrial Engineering. The SPS repairs, comprising a 10mm top plate and 25mm elastomer core, covering 25sq m, and approved by Bureau Veritas, took just under a month, from 30 August to 29 September.

After the *Komi Kribi 1*, some 96sq m of steel across five different areas was reinstated on the *FPF-003*, in Southeast Asia on station at Mubadala's Jasmine oil field in the Gulf of Thailand.

FPF-003

The *FPF-003* is an ABS-classed vessel, built in 1976 and converted in 2005. The repair work, carried out with EM&I and steelworkers Altamar, covered the engine room bilge, engine room side shell, pump room bottom shell, forward cofferdam bottom shell and bulk head and main deck. The work started on 2 October and completed on 3 November, 15 days ahead of schedule, with no disruption to the vessel's day to day operations, despite the multiple complex and space constrained areas to be repaired, resulting in four machine and equipment moves, and atmospheric working temperatures of 35°C.

The *FPF3* team.

The process involves cleaning the corroded steel, with grit or sandblasting, then welding perimeter bars around the area needing reinstating, creating a picture frame. A top plate is added to the bars, creating a cavity. This is leak tested before the polyurethane elastomer, which is brought to the site in its component forms and then mixed at high pressure, is injected. Vent ports in the plate enable it to fill the cavity fully, before setting in a 10-minute exothermic reaction, bonding the plates together.

Everything is measured and tested – humidity, hardness of the polyurethane, and sample tested after 24 hours, Nash says. The cavity is then sealed by welding in the ventilation ports and the repair is complete.

"To do this work conventionally, we would've had to take some serious measures," Nash says. Because the thinned plate is left in place, removal works are avoided. Also, all hot work is done away from the shell of the vessel. Classification rules mean you cannot weld directly to steel that has water on the other side of it, because the weld would cool too quickly and cracks could form, Nash says. Instead, IE uses the hull's strengthening members to weld to, where the plate needs to be added to areas of the hull.

Further ideas

IE has more ideas for where this technique can be used. The work with BP on *Glen Lyon* gave IE an idea for enabling vessels to carry marine gas oil (MGO), in order to meet the 1.1% sulfur emissions regulations. "SPS enables vessels to hold both heavy fuel oil, which is kept at 80-90°C to achieve the required viscosity, and (the more environmentally friendly) MGO, which needs to be kept below 40°C," Nash says. "SPS provides a thermal barrier between the two tanks. This has been successfully installed on a number of vessels for a leading UK oil major. Not only does SPS provides an efficient thermal barrier, it also maximizes available storage space as there is no need for void spaces between the tanks which would require through-life inspection."

It has also been using SPS for side shell protection, instead of fenders, and is offering the solution for ice-class strengthening.

Despite composites not always getting a ready reception, IE appears to be making in-roads. "There was resistance in the early days, because it is a new technology and you have to push through the traditional barriers," Nash says. "Using steel is generally what they wanted in the early days. But, [now] we are an established company with a huge portfolio of projects around the world." **OE**

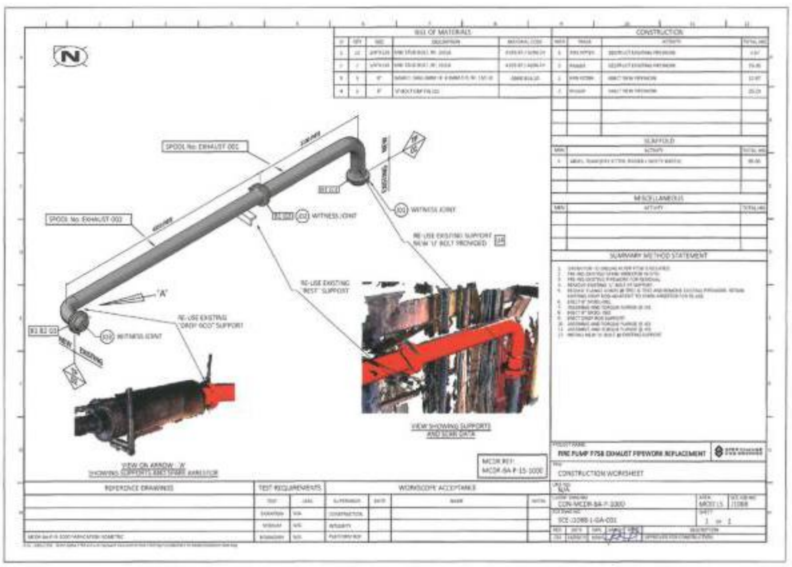
Brownfield – without the bother

Satnam Shoker, of Step Change Engineering, details a new automated, streamlined process, which helps save time during brownfield modification work.

In a mature basin, such as the North Sea, brownfield modifications work on facilities designed up to 40 years ago, but need to continue producing, can be a challenge.

Access to pipework, bed space for inspection personnel, logistics, etc., all add up and can challenge project economics.

What if you could streamline all that work, remove the need for specialist inspection personnel, and use design data auto-generated from handheld infrared (IR) scans, which can then also be quickly converted into engineering drawings for fabricators?



Single sheet work pack. Image from Step Change Engineering.

Aberdeen-based Step Change Engineering is doing just this. The firm has developed an automated, streamlined process for like-for-like and small- to medium-sized modifications. Its workflow covers all stages of a project scope, from work initiation, technical appraisal, conceptual study and detailed design through to procurement, delivery of materials, offshore construction support and closeout.

The system is based on three elements: offshore data capture, using handheld IR scanners; 3D modeling and design work (using the IR data); and then automated deliverables output – i.e. engineering drawings are generated automatically, directly from the design applications, using the firm's software.

This can include various structural and piping design deliverables, including piping isometrics/general arrangements (GAs), perspective GAs, line list, structural GAs, fabrication drawings, bill of materials/material take off (MTO), and a construction worksheet.

For simple scopes, the entire work pack can be produced onto a single A3 construction worksheet containing the MTO, job cards, resource requirements and construction activities. Detailed workflows can also be created in the system, such as client and contractor responsibilities, which can be tailored to suit a client's requirements and procedures.

Using client-owned handheld scanners, on which staff can be easily trained, immediate savings on time and cost can be made, with rope access technicians able to use the devices in hard to get at areas – avoiding the need for scaffolding.

For minor modifications and spools we have confidence in the manufacturer's quoted figure of 0.5% accuracy. Flange offsets and bolt-hole orientation would be measured by traditional methods. Caution should be exercised where less than +/- 1mm accuracy is needed.

Step Change Engineering has been applying this technology in the UK North Sea on several platforms and floating production systems, covering multidiscipline and single discipline modification scopes at concept and front-end engineering and design stages.

Brent Alpha

One such project, for oil major Shell, on the Brent Alpha platform in the UK North Sea, enabled 70% cost savings, using Step Change Engineering's method, compared to a conventional scope.

During early 2015, Step Change Engineering approached Shell with a solution for brownfield modifications, including like-for-like pipework and structural steel replacement, often referred to as repair orders (ROs) or material and corrosion defect reports (MCDRs).

Initially, there was a degree of caution and a series of practical demonstrations and testing were done to prove the technology, including its accuracy and suitability for offshore use.

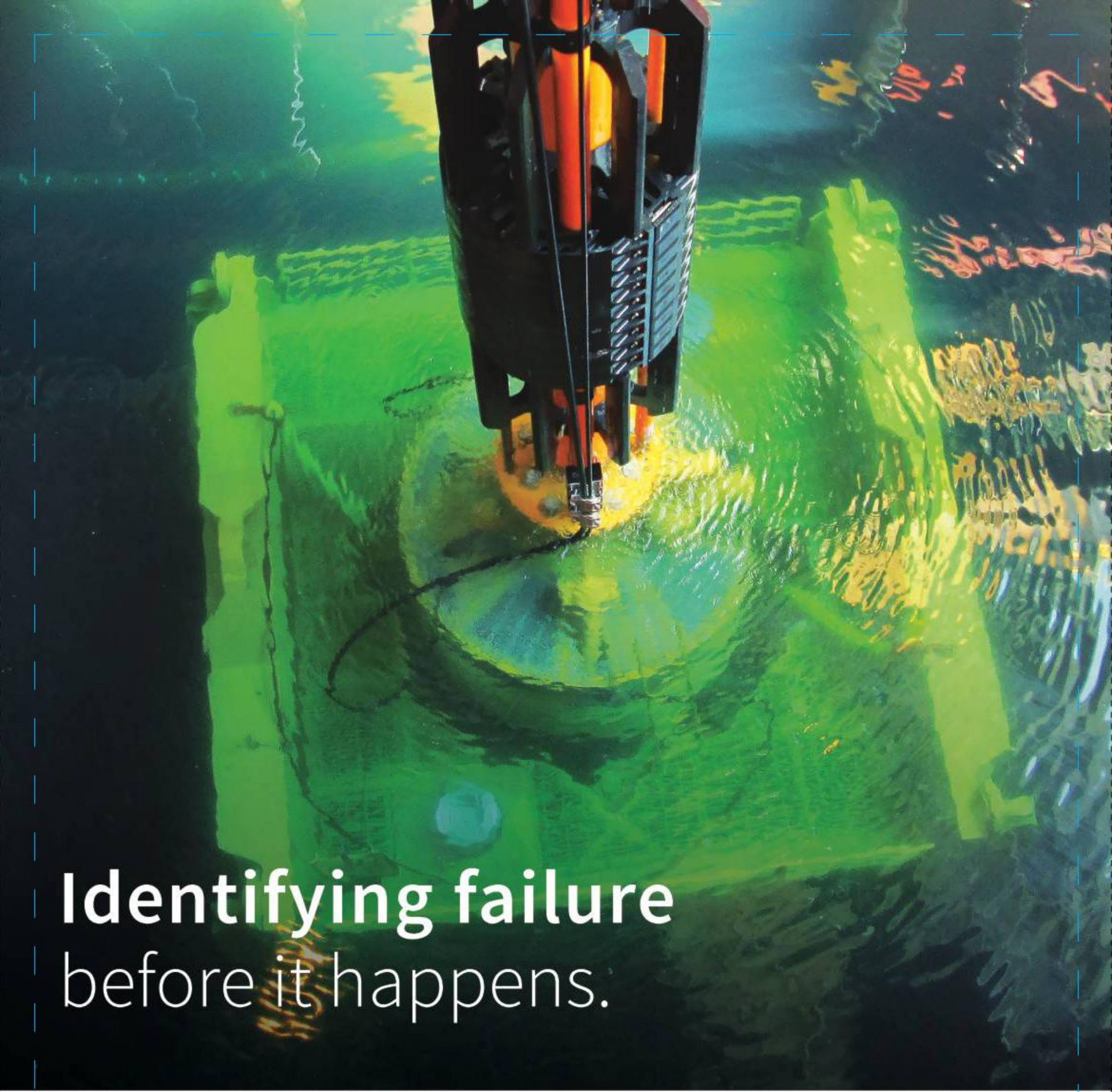
Following successful trials, Shell issued Step Change Engineering with a contract in July 2015 to design and fabricate an existing MCDR scope.

The initial MCDR selected by Shell was to replace an approximately 6m length of a corroded section of pipework in the 6in exhaust line of a diesel engine on one of the Brent Alpha fire pumps. One of the challenges with this scope was that the exhaust pipework was difficult to access and high-up.

Traditional approach

Conventionally, the inaccessibility of the pipework would have required a large scaffold platform to be erected to allow safe access, initially for a piping designer to perform a detailed design survey, and then for the offshore construction team to carry out the necessary destruct/construct scope required to replace the corroded pipework spools.

For this job, which was typical of many



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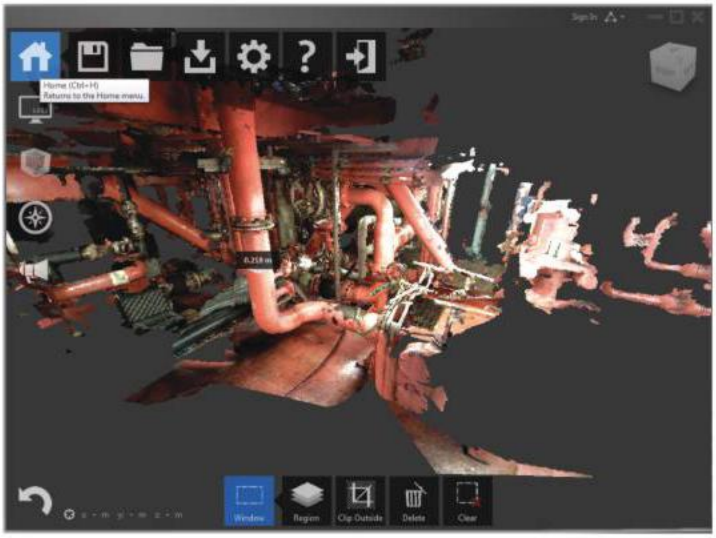
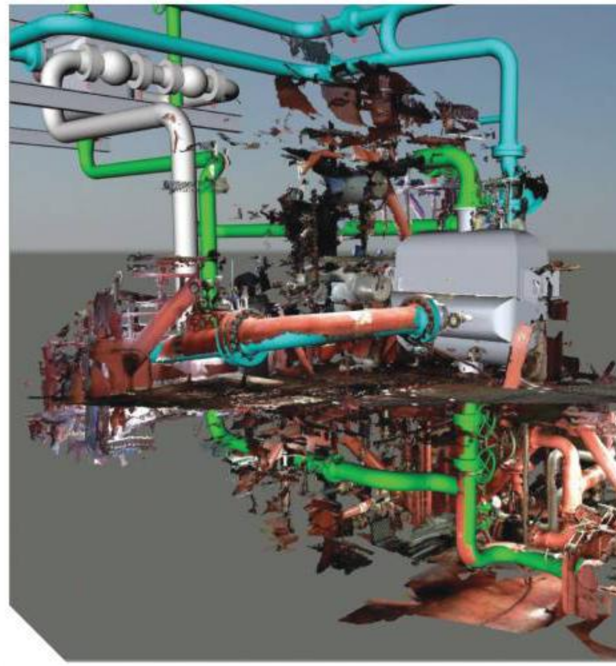




Above: Scan data of cooler inlet pipework imported directly into Autodesk Recap. Right: Screen shot from Navisworks Simulate. Using Navisworks Simulate SCE can save an AutoCAD model to a format that can be read by Navisworks Freedom which is a free 3D viewer.

Images from Step Change Engineering.

brownfield repair/replacement type scopes, such offshore scope elements extend the project schedule and add significant extra cost, particularly in relation to the onshore design and fabrication requirements, which often are a relatively small proportion of the overall cost.

Our approach

Step Change Engineering's workflow allowed an alternative solution to be proposed, i.e. deploying rope access technicians to perform both the design survey and the construction scope. This addressed the main cost/schedule issues by avoiding the requirement for scaffolding and eliminating the need to use a piping designer to perform the survey.

Survey data was captured in less than 30 minutes using a portable hand-held scanner by Shell's rope access technicians, who were trained to use the scanner beforehand and are part of platform's core construction team. The scanned data was emailed to our onshore design team where it was imported into our 3D modeling and design applications suite.

Once the pipework was modeled, further cost and schedule efficiencies were achieved by auto-generating a range of deliverables directly from the model. This took less than four hours, including checking.

For this first MCDR scope, Shell incurred a one-off cost for training the rope access technicians, which Step Change Engineering carried out at its premises. Shell had already purchased a hand-held scanner for use on the Brent platforms and Step Change Engineering simply updated the software and tested the unit to ensure it would be compatible.

Brent Alpha in 1977.

Photo from Shell.

Key benefits

The rapid data capture and auto-generated deliverables resulted in a significantly reduced project schedule. Piping isometric drawings were auto-generated with detailed fabrication information including the necessary piping cut lengths and weld preparation details, which avoided the need for the fabricator to mark-up the drawings (as would be the case traditionally) and further helped to reduce overall delivery time.

Overall, the data capture, design and fabrication scope was completed with materials delivered within approximately 1-2 weeks, compared to an estimated 4-8 weeks doing it the traditional way.

Cost savings exceeded 70% when considering the requirements for scaffolding and dedicated design survey were eliminated from the scope.

Another recent project for Shell included the development of a conceptual design for installing a temporary pig launcher. The study was completed within one week, including the survey time, compared to 4-8 weeks conventionally. Deliverables included a 3D CAD model, construct/destruct piping and instrumentation diagrams, destruct isometrics and a perspective GA with a detailed bill of materials. **OE**

Satnam Shoker *is consultancy director at Step Change Engineering. He has spent more than 27 years working in the oil and gas industry and is a Fellow of the Institution of Chemical Engineers.*

GoM operators set sights on tiebacks

Even though the downturn has changed many operator's initial plans, subsea tiebacks have emerged as the economical way to develop many Gulf of Mexico fields. Karen Boman reports.

The *North Ocean 105* lay vessel. Images from McDermott International.

The global oil price downturn prompted oil and gas operators to delay or cancel plans for offshore field development in the Gulf of Mexico (GoM), including subsea tiebacks.

As a result of the downturn, Rystad Energy expects only nine dedicated subsea tiebacks to start production from 2017-2021, down from 31 dedicated subsea tiebacks to existing fields that came online from 2012-2016. During that time, 43 tiebacks for both existing fields and greenfield floater projects came online, says Fredrik Folmer Ellekjær, project manager, Rystad Energy.

"Capital expenditures for both floaters and tiebacks in the US Gulf of Mexico also declined from 2012-2015 levels of approximately US$20 billion per year to $16 billion in 2016," Ellekjær says. He expects this spending to fall to around $12 billion, then flatten towards 2021.

"We expect spend to increase post 2021 with higher activity levels due to renewed sanctioning activity picking up from 2018 and onwards," Ellekjær adds.

Rystad expects 15 dedicated tieback projects to come online from 2022-2025. However, the commerciality for these projects is more uncertain than those starting production from 2017-2021. Many of these projects have already been sanctioned by operators, Ellekjaer explains.

Subsea tiebacks economics

Going forward, GoM operators will primarily use subsea tiebacks to bring new production online as industry seeks profitability in the "lower for longer" oil price environment. With the exception of the Lower Tertiary play, Wood Mackenzie estimates breakeven prices for GoM subsea tiebacks in the high $20s-$30/bbl (Brent crude). On the other hand, the breakeven price for a standalone facility could range from a high $40/bbl (Brent) to the low $50/bbl range, says Imran Khan, senior manager for Wood Mackenzie's deepwater Gulf of Mexico team.

Subsea tiebacks will comprise 27%, or $2.4 billion, of total GoM capex ($8.7 billion) this year. For 2018, Wood Mackenzie anticipates approximately $2.7 billion in subsea tieback spending out of $11.1 billion in GoM spending. However, Wood Mackenzie expects overall capex spending and subsea tieback spending in the region to decline through 2020 to $10.4 billion and $899 million, respectively. This capex data includes commercial fields only, not fields that might be fast-tracked into development or non-commercial fields that are reclassified as commercial.

Investment is pulled back for many reasons, Khan stated.

"Lower oil prices can make it hard to justify a multi-billion dollar deepwater project when compared to a low-cost onshore project," he explains. "The short lead time also factors into the decision making process in the current environment. Deepwater projects take much longer to develop than onshore projects and in the current environment, short lead times are very important for generating a positive return on investment."

What's next?

Over the next two years, Wood Mackenzie expects three major subsea tieback projects to take place in the GoM. These projects include Shell's Kaikias field, which the supermajor said in late February that it would develop via six subsea wells to Shell's Ursa production hub. Greater efficiencies in Shell's drilling strategy will enable a two-year timeline from sanctioning of Kaikias' first phase to first oil in 2019, and also save the company millions, Khan says.

"What Wood Mackenzie is starting to see now is operators drilling wells with the belief that hydrocarbons will be encountered, and designing the appraisal well so it can be turned into a development well," says Omar Garza, research associate with Wood Mackenzie's deepwater Gulf of Mexico team. "Before even announcing the sanction, Shell already has been drilling development wells and plans to convert appraisal wells to producers. This involves more of a parallel process than seen in the past, when operators drilled a well, then went back to the drawing board to see what kind of development plan made sense."

Anadarko Petroleum's Constellation field is another widely anticipated GoM subsea tieback project. BP, the former operator of Constellation, still maintains an interest in the field. At 50 MMboe, Constellation – formerly called Hopkins – would be too small for BP to develop as an operator.

"But, cash flow remains king [in the oil and gas industry] and everybody needs it," Khan says. "Given the project's relative cheapness, it makes sense for BP to maintain an interest."

In its Q4 2016 earnings report, Anadarko said that it would likely tieback its Warrior exploration well to its Marco Polo facility. Additionally, the company may tieback the Phobos appraisal well to its Lucius facility.

LLOG Exploration's subsea tieback of the Lower Tertiary discovery Buckskin, to what Wood Mackenzie believes will be the Lucius platform, will be another subsea tieback project that industry will follow closely. One reason is that the Lower Tertiary is viewed as a major growth region for the deepwater GoM, but little production data is available for the play. Even as subsea tiebacks,

An aerial view of McDermott's Gulfport, Mississippi, spoolbase, which opened in 2015.

these wells will be pricey, with breakeven prices estimated at around $40/bbl (Brent). The other reason is that LLOG had previously focused on smaller subsea tiebacks or other plays such as the Miocene and Pliocene.

"The industry is interested to see how LLOG, someone with a proven track record in other areas, will fare in the play," Khan says.

To economically justify a standalone development, a field would have to contain around 200 MMboe, Khan says. But, proximity to existing facilities and available processing capacity also would factor into the decision. However, Wood Mackenzie expects facilities to become cheaper due to falling costs and available capacity in fabrication yards. Lower costs could make 150-200 MMboe fields economic now compared with three years ago, Garza says.

Prior to the oil price downturn, operators were talking about pursuing prospects longer from existing infrastructure and in increasingly deeper waters. The trends of longer and deeper subsea tiebacks have halted with the oil price collapse, and Rystad does not anticipate deeper field developments to come online that have not been discovered yet, Ellekjær says.

"We're not going to push the technical boundaries in the next five years in terms of tieback length in the US Gulf of Mexico," Ellekjær says.

The industry's focus on keeping costs low is allowing new subsea production to move forward. In January, BP brought online the Thunder Horse South expansion project 11 months ahead of schedule and $150 million under budget. BP was able to complete the new subsea production system – located approximately 2mi south of the existing Thunder Horse platform – by relying on proven standardized equipment and technology rather than building customized components, the company said in January.

BP also recently sanctioned the second phase of its Mad Dog field development project in the GoM. According to Rystad's estimates, Mad Dog 2 was sanctioned at a breakeven oil price right above $50/bbl. Shenandoah and Vito, the two next floater developments in line in the GoM, are also expected to have breakevens lower than $60/boe.

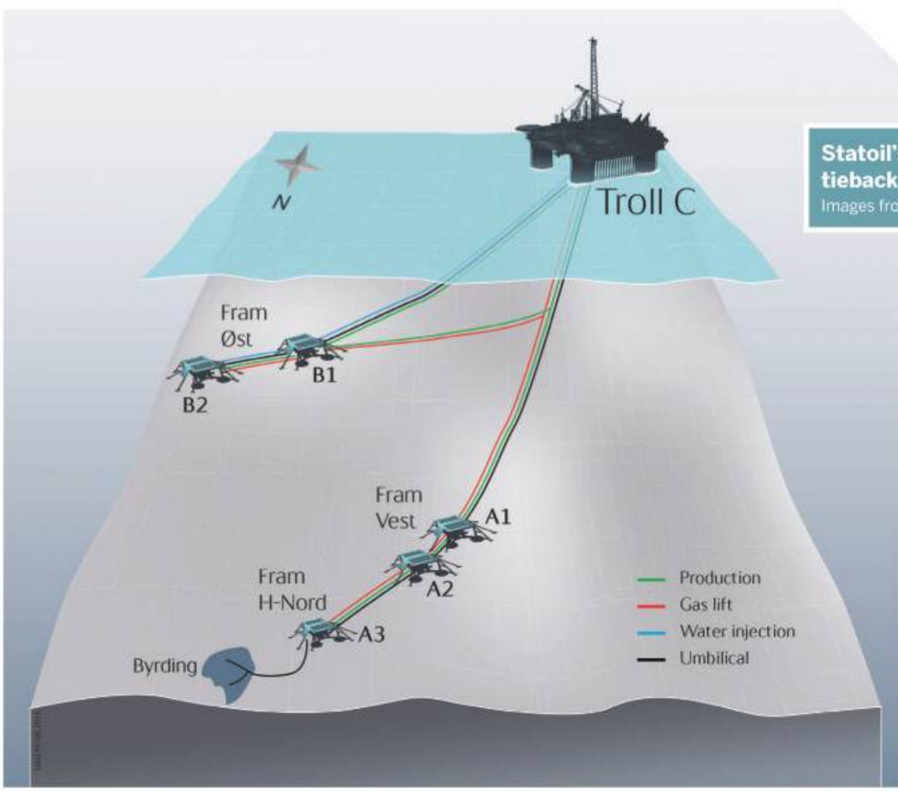
McDermott International also is seeing majors and smaller independents pursuing a few smaller subsea tieback existing infrastructure projects in the GoM, says Scott Munro, vice president of McDermott's Americas, Europe and Africa division. In late 2015, the engineering, procurement and construction firm opened a new spoolbase facility at Gulfport, Mississippi, to support its flex-lay, rigid pipelay vessel *North Ocean (LVNO) 105*.

The *LVNO 105* has worked on smaller subsea tieback projects such as LLOG's Otis field and Anadarko's Caesar/Tonga Phase 2, Munro says.

McDermott's flex lay vessel *North Ocean 102* has worked on several subsea tieback projects in the deepwater GoM, including ExxonMobil's Julia project and Chevron's Jack/St. Malo project. McDermott's *Derrick Barge 50* also has installed equipment packages on existing Gulf facility topsides to accommodate subsea tiebacks, Munro says. OE

Tiebacks by the numbers

With large-scale projects on hold, subsea tiebacks are accounting for 75-80% of sanctioned projects. Will it last? Elaine Maslin shares Wood Mackenzie's view.



Statoil's Bryding tieback layout.
Images from Statoil.

The last 24 months has been about survival, cutting costs and deferring projects, with the goal of bringing down breakevens. Projects that in 2013 had US$80-85/bbl breakeven costs have been brought closer to $65/bbl, using synergies and going back to the drawing board, says James Hall a director at analyst firm Wood Mackenzie.

In fact, the firm has tracked a 40% drop in offshore capex spending since 2014, Hall told the Society of Underwater Technology's (SUT) January Global Market Outlook briefing. But, much of the activity over the past two years is yet to filter through into final investment decisions (FID), with relatively few projects above 50 MMbbl sanctioned in 2016: just Utgard, Dvalin and Trestakk (tiebacks) in Norway, Zohr and Atoll in Egypt, and Greater Enfield in Australia (deepwater subsea tieback), plus KG-DWN (deepwater) off India, and Tangguh Phase 2 (two new platforms), off Indonesia.

In 2017, projects FIDs are expected to focus on greenfield developments in Brazil, East Africa and Russia. But, even with more FIDs in 2017, the benefit will take time to trickle down into the chain, except for those in front-end engineering roles, Hall suggests.

One area that has seen an increase in activity is subsea tiebacks, which could help prop up the subsea, umbilical, risers and flowlines (SURF) market in the short- to medium-term, with many operators opting for cheaper, near-term new production, instead of larger stand-alone projects.

Suppliers and contractors need the work. After a record high 547 subsea tree orders in 2013, just 66 had been ordered by the end of Q3 2016, Hall told the SUT event. The expectation is that by the time the numbers are fully in, the total for 2016 will be just 85 subsea tree orders, he says, outlining Wood Mackenzie research. Things will look better in 2017, at about 100 orders. But, it's still a far cry from 2013 and the industry isn't likely to see those figures again anytime soon, he says.

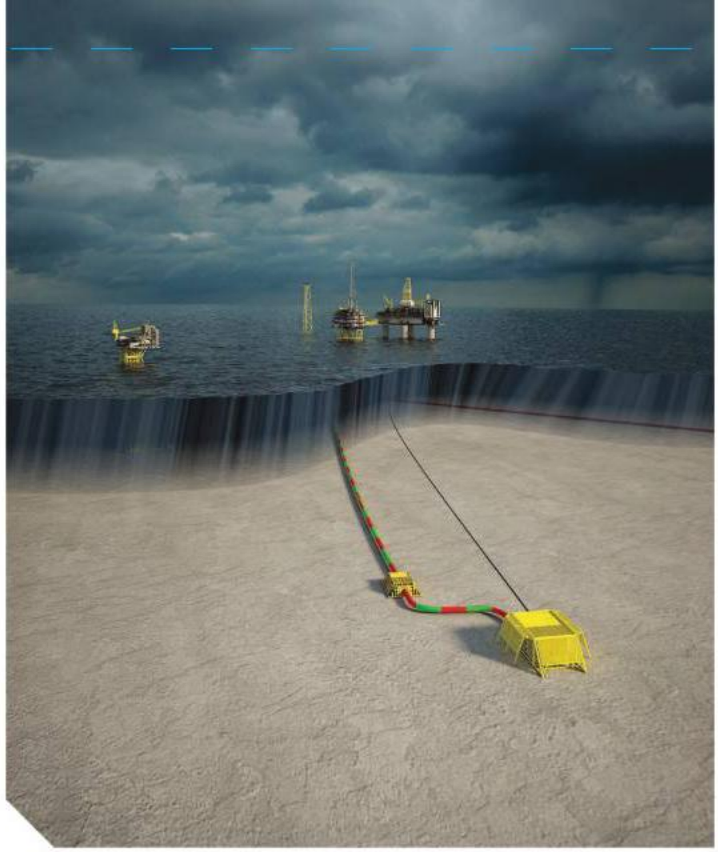
"The proportion of projects driven by tiebacks has increased and continues to increase," however, he says, with 80% of subsea trees ordered destined for tiebacks in 2016 (compared to 52% in 2015, 62% in 2014, and 29% in 2013). But, that is expected to fall to 59% next year, then gradually drop to 51% by 2020. "Our expectation is that the new norm, resetting the former 400/year average, will be closer to 200-250 trees a year in the next 4-5 years (or 150-170 if you take the gloomy view). But, it only takes a couple of projects to bump up those numbers," Hall says.

It is the oil majors – Shell, BP, ExxonMobil – driving most of the tieback activity, Hall says, plus Brazilian national oil firm Petrobras, which is supporting a high proportion of the short-term tieback activity. Other national oil firms, such as Eni and CNPC, are likely to join in as time goes on.

By region, the Middle East will see a small drop in tieback activity, at about -3%, as will Asia, at -8-10%, compared to an average global increase of about 16%, Hall says. Australasia will see the biggest increase, from about 46% of orders to 55%, according to Wood Mackenzie's forecasts.

After a good start in 2017, with the award of Mad Dog 2 subsea production system to OneSubsea (ca. 30 trees), the next largest order is expected to come from Eni, with 20 subsea trees anticipated for the West and East hub project offshore Angola; followed by Premier Oil's Sea Lion in the Falklands, at 14; Hess' Tubular Bells in the Gulf of Mexico, at 10; Total's Zinia (Pazflor Phase 2), at 9, and Rosa (Girri tie-in), at 8. Then, there's Tullow's Mahogany East (7), Hess' Stampede (6), Anadarko's Constellation (6), and BP's Azeri (6).

The rise in tiebacks means a rise in SURF installation work, especially given a 35% increase in the average length of sanctioned tiebacks, expected in 2017. Some 75-80% of projects are being driven by tiebacks, Hall says. Indeed, tree awards in 2016 were 80% driven by tiebacks, he adds.



Statoil's Utgard tieback, an artist's visualization.

But, because of the lack of FID decisions in the past couple of years, that rise in SURF installation work may not come for some time yet, leaving contractors to rely on their ever-dwindling backlogs. "If we don't see FIDs on some projects soon, that backlog will continue to suffer," Hall warns.

Subsea firms shouldn't put all their eggs in the subsea tieback basket either. By the end of the decade, subsea tiebacks are likely to drop to about 50% of new tree orders, Hall says.

"There are swathes of projects out there waiting final investment decision," Hall says. "In our view, it's a waiting game."

Looking at production facilities in general, there could be 20 getting through FID in the next couple of years, based on a breakeven $60/bbl oil price. Most will be floating production facilities, Hall says. Southeast Asia will see many these, followed by the Middle East, where activity would be driven by brownfield developments, as well as East and South Africa, home to large gas projects. **OE**

Keeping station

Elaine Maslin chats with Helix Energy Solutions to find out how the intervention services provider is keeping afloat with new collaborative offerings, and, yes, new vessels entering the market.

Helix's newbuild the *Siem Helix 1*, before its back deck equipment was fitted.
Photos from Helix Energy Solutions.

The downturn's reach has affected many sectors, including the well intervention market. Vessels – some the result of significant investment – have been introduced to the market, only to fall off the radar.

For the stalwarts of the business, they have seen shorter contracts, shorter-term planning (impacting contract visibility) from operators, and plugging and abandonment (P&A) preparation work. Despite seeing some fleet attrition, Helix Energy Solutions Group expects two new vessels to come into operation this year, and another in 2019 (the *Q7000*). It is also set to introduce new equipment designed to help extend the capabilities of the existing and the new vessels to the market, while continuing to drive new techniques and operating philosophies into the market.

"Rates are down, competition is strong, but we had a very full schedule (last year) and are filling up the schedules for the rest of this year," says David Carr, vice president – Commercial, Helix. "Rigs have been coming off contract and competing against us."

But, a combination of efficiencies Helix has made over the last year, risk-sharing work under its Subsea Services Alliance with Schlumberger, and renting intervention riser systems (IRS) to operators who have rig contract over hangs and want to find alternative work for them, has helped Helix stand firm.

Since the downturn hit in 2014, most of the well intervention work in the North Sea and Gulf of Mexico has been a steady blend of P&A preparation work and production enhancement work, Carr says. While the P&A market has a lot more potential, with a growing global well stock, production enhancement work might also be making a return, he says.

"With oil prices above US$50/bbl, we expect to see an increase in production enhancement work. In the North Sea, there is also a much older well stock which needs maintaining or it will reach the end of its production life much sooner," Carr says.

Gulf of Mexico

Helix's two semisubmersibles, the *Q4000* and *Q5000*, have work in the US Gulf of Mexico for the next year, despite facing competition from rigs. This month, in fact, marks the first full year of operations on the *Q5000*. The vessel entered service on contract to BP in Q2 2016, working entirely on intervention. Although IRS-related issues led to a "shaky start" early on, Helix says it has close cooperation with BP and expects continued improved performance.

Helix also recently announced that under its Subsea Services Alliance, it plans to make the *Q4000* available with a full Schlumberger spread as a fully integrated package.

Doing this would have two impacts, Carr says. First, staffing can be cut by up to 30%, reducing replicated staff. Second, operators will benefit from regularly having the same crew return shift after shift, with this consistency and experience adding value to all parties. "That has a tangible impact," Carr says. "It also means fewer helicopters, improved safety and competency, among other benefits."

Helix is also bringing two new vessels into operation this year. The firm has already taken delivery of the chartered *Siem Helix 1*, which, following modifications in a Brazilian yard as part of acceptance with Petrobras, is currently expected to start a four-year contract with the state-oil firm offshore Brazil during Q1. The *Siem Helix 2* is expected to join her on contract to Petrobras later in the year (read more on page 40).

The recently upgraded *Seawell.*

New equipment

As well as new vessels, Helix has new subsea well access equipment scheduled to come into the market this year: a 15,000psi IRS and its ROAM open water abandonment tool, which *OE* featured in December 2016. The IRS, due in the market in Q4, is the same design as the IRS on the *Q4000*, but with higher pressure capacity.

"We see quite a lot of use for this in the Gulf of Mexico," Carr says. "When times were good, there were a number of projects by certain supermajors to build and own equipment of this type. This is expensive and then the operator has the cost of maintaining it. We will be the first to actually have a high-pressure rental system in the market."

The ROAM tool will bring a significant change, Carr says, by allowing 18 3/4in access into the wellbore.

This would open up the use of tools already in the market, such as perforate and circulate, or perf and wash, as it's known tools, but which currently have to be run on drill pipe. "We have proposed a methodology to complete entire upper abandonments with the ROAM tool with one of our units, instead of a full rig using these technologies." There are also a lot of companies looking at ways to do full upper abandonments using plasma or explosives and the like. These could also be deployed from a riserless well intervention unit, he points out.

With ROAM, Helix can also install primary steel caps in abandonment mode, instead of using inflatable devices currently used, which some operators are not entirely comfortable with, he says. The system has several clients interested, is currently undergoing regulatory review with no known issues thus far, and is due to be ready in 2H 2017.

"The combination of the *Q5000* and ROAM tool is interesting," Carr says. "The *Q5000*, like a lot of rigs, has false moon pool underneath the deck, so you can do subsea lower abandonments with the riser access package, then suspend the riser access package subsea, so that you can simultaneously deploy the ROAM tool, without having to retrieve the IRS back to surface. That literally saves you days in running time."

The 15,000psi IRS and ROAM have been built by OneSubsea, which jointly owns the equipment with Helix under the Subsea Services Alliance. This is beneficial to the alliance, Carr says, because it means the original equipment manufacturer has "skin in the game." "It gives us a supply chain we are comfortable with and lets us bring products to market faster."

North Sea

After completing an approximate $90 million refit and upgrade at the Damen yard in Vlissingen in the Netherlands, the *Seawell* (which did its first intervention job in 1987) came back to work in the North Sea last year and has a full schedule for the rest of this year.

While traditionally vessels coming out of a major refit would have teething troubles, the *Seawell* has been performing well and expects to be in operation some 270-300 days this year, nearly all supporting P&A work in the North Sea for various clients, says Steve Nairn, vice president, Helix Well Ops (UK). The *Seawell* was involved in this type of work in the 1990s, but legislation has changed since then, resulting in the call for rigs to do a lot of the work. With the ROAM tool, more can again be done from intervention vessels, Nairn says, de-risking the work the rig still needs to do, i.e. pulling tubing.

New techniques, rather than technology, have indeed been a feature of the North Sea business, led by the *Well Enhancer.*

Last year, the *Well Enhancer* performed the first riser-based coiled tubing (CT) job from a vessel (*OE*: December 2016), for a perforation job on the Pierce field for Shell, and the first deployment of ceramic sand screens from a light well intervention vessel, also for Shell. The CT job received a lot of interest and multiple clients are already expressing interest to use this method for work in the North Sea this summer, Carr says. "We expect to see an increase in that type of activity. Being able to add CT capability into the well without a full rig is quite a game changer."

Earlier this year, the vessel performed a subsea first, running a coiled hose – essentially wireline with a hallow core – to inject chemicals to specific areas of a well.

This year, the *Well Enhancer* will continue its P&A work, with further coiled hosing work potentially in the cards.

Attrition

It's not all been peaches and cream.

At the end of last year, Helix sold the *Helix 534*, a converted drillship. It also does not plan to renew its charter contract with DOF for the *Skandi Constructor.* However, Helix is leaving its kit on the boat and currently plans to jointly market the vessel in Asia Pacific and Africa, under a DOF Subsea business with Helix well intervention capacity. **OE**

Making a step change

Elaine Maslin reports on two new vessels and a semisubmersible from Helix Well Ops due out in 2017-2019, which aim to make a step change in operational efficiency.

Helix Energy Solutions has three new vessels coming into the market, the *Siem Helix 1* and *2* this year and the *Q7000* in 2019. They have all been designed building on Helix's nearly 30 years' experience in the well intervention space – plus a dollop of a northeast England engineering expertise.

Each new unit is being fitted out with a new-design intervention tension frame (ITF), blowout preventer (BOP) storage and maintenance tower, moveable decks and gangway access system.

Together, these will enable Helix to do something significant – i.e. change between coiled tubing and wireline operations without the need to disengage from the wellhead. This is an industry first. Before, a reconfiguration would have been required between operations. Staff will also no longer have to use so-called man-riding winches or cranes to access the equipment for maintenance, making the system safer.

Both moves are set to reduce downtime and increase staff safety. "The ITF is designed to increase efficiency and safety," says David Carr, vice president – Commercial, Helix. "It will take all man riding out of the process and provide a walk-to-work system so staff can get right up close to heave compensated equipment that is bouncing up and down, without having to wear riding belts. It is a real step change in use of technology to increase efficiency and safety in operations."

The 158m-long, 31-beam, DP3, Salt 307 WIV design *Siem Helix 1* and *2* were completed at the Flensburger shipyard in Germany (owned by Siem Industries) in 2016, and will be chartered from Siem Offshore (part of the Siem group). Both will work for Petrobras, under four-year initial term contracts, offshore Brazil, with the *Siem Helix 1* starting operations in Q2 and the *Siem Helix 2* due in service later in the year.

Both vessels have accommodation for up to 150, a Huisman multipurpose tower (MPT) and a 250-tonne, down to 3000m water depth crane. The *Q7000* is being built by Sembcorp Marine's Jurong Shipyard in Singapore and is due in service in 2019. Once complete, the unit will also have a Huisman MPT.

Northeast England engineering firm Osbit designed a string of new systems for all three newbuilds, having been initially awarded the ITF contract in March 2015. Osbit had previously worked with Helix on its *Seawell* refit and designed some other equipment – umbilical guide wire system and ROV launch and recover systems – for the *Q7000*.

"Helix came up with a brief outline of what they wanted," says Steve Binney – Osbit engineer and project owner. "The industry used to have someone on the moving equipment on a man riding crane. It was probably something that started as a one-off but it took a company like Helix to be building new vessels to start thinking about how to move away from that."

Brendon Hayward, Osbit's managing director, says: "In parallel to that, the market is driving people to look for efficiencies and competitive advantage. Because the oil prices have dropped, no one has money, so we need to be more efficient. The whole idea is to make the process safer, better, faster and cheaper. The result is a step change."

Hanging off each vessel's Huisman heave compensated MPT, the ITFs form a tensile connection between the well riser and the vessel's handling equipment during well intervention operations, while also facilitating safe access into the riser. The entire ITF effectively stays stationary as the vessel moves, so that subsea equipment, including the riser, isn't damaged.

In normal run of operations, the riser sections, with subsea stack attached to the bottom, would be built down to 5-10m from the seabed. Then the ITF would be attached, active heave compensation (AHC) mode initiated and the stack connected to the well. The gangway would be connected before going into AHC mode.

To this is added the maintenance tower, with a 120-tonne crane, to build and service the stacks, and pivot for connecting to the ITF while active, and the movable deck, which slides to the

The *Siem Helix 1*'s back deck spread from Osbit. Image from Helix.

well center and from which the iron roughneck and third party equipment can be deployed. Beneath the moveable deck is a well center operations equipment storage space. Both add a level of safe access for operations maintenance that has not existed before, Osbit says, as well as providing working and storage areas, all while not getting in the way of the riser handling cat walk.

The ITF enables Helix to switch between coiled tubing and wireline operations, without detaching from the well, removing the need for tool changeover, and allows for operation in worse weather conditions. Each ITF has three platform access levels, supported by Osbit-supplied BOP maintenance and storage towers and moveable decks. This allows on-board equipment to be moved into its working position quickly and easily via three-plane movement skidding systems, rather than being lifted into position. The systems were also designed to support a full range of third party equipment and can be configured for different tooling options.

Each ITF stands at more than 20m-high and weigh about 100-tonne, with a 600-tonne safe working load and meets EX BSEN13463 standard.

Integrating the systems was an important part of the work, Hayward says. "Often subsea systems can be over looked and don't often work that well together," he says. "In this example, Helix brought us a problem, which we worked with them to solve. But in a position where we can look at all the subsea system integration."

Accommodating and packaging all the necessary equipment subsystems and third party equipment was a challenge. To accomplish this, the ITF's skidding systems were developed. A design that could handle a vast range of third party equipment varying in size, weight and shape was created. 3D design software, used throughout the design, helped ensure there would be no equipment clashes during skidding operations and that equipment could be secured.

While all three ITFs look similar from the outside, and are, the internal will differ on the *Q7000*, with different level platforms, etc. The equipment layout on the *Q7000* will also tend to be more stable, whereas the *Siem Helix 1* and *2* would be more adaptable to meet Petrobras' needs, which meant the design on the *Q7000* could also be more stream-lined, Binney says. But, should the ITFs need to be moved to a different vessel with different internals, they could (and were also designed to be road transportable).

Osbit was also able to work in a unique way with Helix. "We started out with a problem," Hayward says. "We worked from that to find what was feasible and what was the best solution, then optimized that to get the best weight, which is quite rare. Normally someone gives you a weight budget."

This was partly enabled by Helix doing initial design studies with Osbit, to find a rough idea of the weight of the system, then designing the vessels around that weight. "The weight hasn't really varied from the initial front-end engineering studies," Binney says. **OE**

Installing ceramic sand screens

In an industry first, achieved last year, 3M ceramic sand screens were deployed from a light well intervention vessel, Helix's *Well Enhancer*.

Deploying the screens offshore last year.
Photos from 3M.

3M's ceramic sand screen technology.

Sand has long been one of the major challenges for oil and gas operators and service companies as it can seriously limit production.

For the most part, metallic sand screens are used. However, 3M has developed a ceramic sand screen. 3M chose to use ceramics due to their resistance to erosion or corrosion, compared with metal, in harsh downhole environments.

The firm's ceramic sand screen technology's deployment last year, on Shell's Gannet field in the Central North Sea, was the first time the technology was used by a major. It was also the first time one of the ceramic screens has been deployed using a light well intervention vessel (LWIV).

The screens were deployed using e-line, with each screen hung from a high expansion Interwell packer.

One, 40ft section of screen, which comprised six ceramic modules, was deployed on the Gannett well (each ceramic module is about 5ft-long).

The aim of the project was to prove that a cost-effective intervention and installation of ceramic sand control technology was possible, with a viable return on investment. Using a LWIV, rather than a rig, was key.

Using ceramics, which have better long-term wear resistance than metal screens, also helps improve the long-term viability of the well, says Martyn Earl, business development manager, Advanced Materials Division, 3M.

"The ceramic won't erode/corrode whereas as metal will in certain conditions," he says. "We have screens that have been in the ground since 2011 (the first deployment) that are still functioning, to our knowledge."

This quality can add real value, compared to metallic screens, in highly corrosive and erosive environments, such as high-flow wells, high-rate gas wells, and high-pressure and high-temperature (HPHT) wells as well as preventing proppant flowback, Earl says.

The screens are manufactured with a metallic base pipe, with a stack of ceramic rings providing the sand filter mechanism. The rings are technical ceramics, manufactured in 3M's Kempton plant, Germany, from Silicon Carbide.

"The rings are spaced to allow gas/fluids through, but prevent any sand ingress," says Ian Hunter from 3M Oil and Gas, Advanced Materials Division. "The sizing can be changed during manufacture depending on the size and distribution of sand to suit the application."

3M manufactured the first screen in 2011, and has since had 25 installations worldwide to date, including 17 offshore. This number was set to increase throughout February, Hunter says.

The main challenge on Gannett was it had not been done before, Hunter says. "Additionally, there were more space restrictions, more vessel movement, height restrictions on the wireline mast, compared to a rig," he says. "But, in terms of the technology, there is no difference to us deploying from a rig or a vessel, it is just a change in planning. The screens can be deployed via wireline, coil or by a rig pipe, for example, and we have both retrofit and standalone versions available."

The screens were deployed in April 2016 and took about 12 hours to install. "It would take a similar time on a rig due to the wireline deployment," Hunter says. "However, with the LWIV there was less mobilization and demobilization time."

The screens are capable of being run in any well, however, Hunter says that they have significant technical advantages in high flow wells, high rate gas wells, HPHT wells, and for prevention of proppant flowback. Thanks to their longevity, they would offer advantages in such wells subsea, he adds. OE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Wireline wonders

Oceaneering International's acquisition of Blue Ocean Technologies is set to reap returns in terms of new technology. Elaine Maslin reports.

When Oceaneering International bought Blue Ocean Technologies last year, it was a strategic move. Buying the Texas-based firm adds a strong track record of wireline intervention to Oceaneering's own record, including setting deepwater wireline intervention operation records. The move is also set to give Oceaneering the capability to roll out what could be a riserless industry "first" in late 2018.

Blue Ocean was originally set up to perform downed well remediation after hurricanes Katrina and Rita – category 5 storms that hit the Gulf coast states of Texas and Louisiana in 2005. "We couldn't get a rig to kill the wells," says Neil Crawford, now vice president of OceanNext for Oceaneering, and one of the founding members of Blue Ocean. "We had to do it riserless, so we installed flexible lines to the well to do what we needed."


Neil Crawford

Blue Ocean then developed a system for downed wells for work on undamaged wells. The result was the interchangeable riserless intervention system (IRIS), which interfaces with the Xmas tree to allow a wide range of intervention operations, including using e-line, slickline or braided wire; running, setting and pulling tubing and tree plugs; pumping cement plugs; and logging while flowing, perforating and fishing. It incorporates a hydraulic control system, a patented grease injection/sealing system and electric hydraulic controls through an Oceaneering umbilical system.

IRIS can be deployed from a 328ft-long (100m) DP2 vessel of opportunity (through the moon pool or over the side) with a knuckleboom crane, and is rated for 10,000ft (3048m) of water depth and 10,000psi. The system can work on both horizontal and vertical trees.

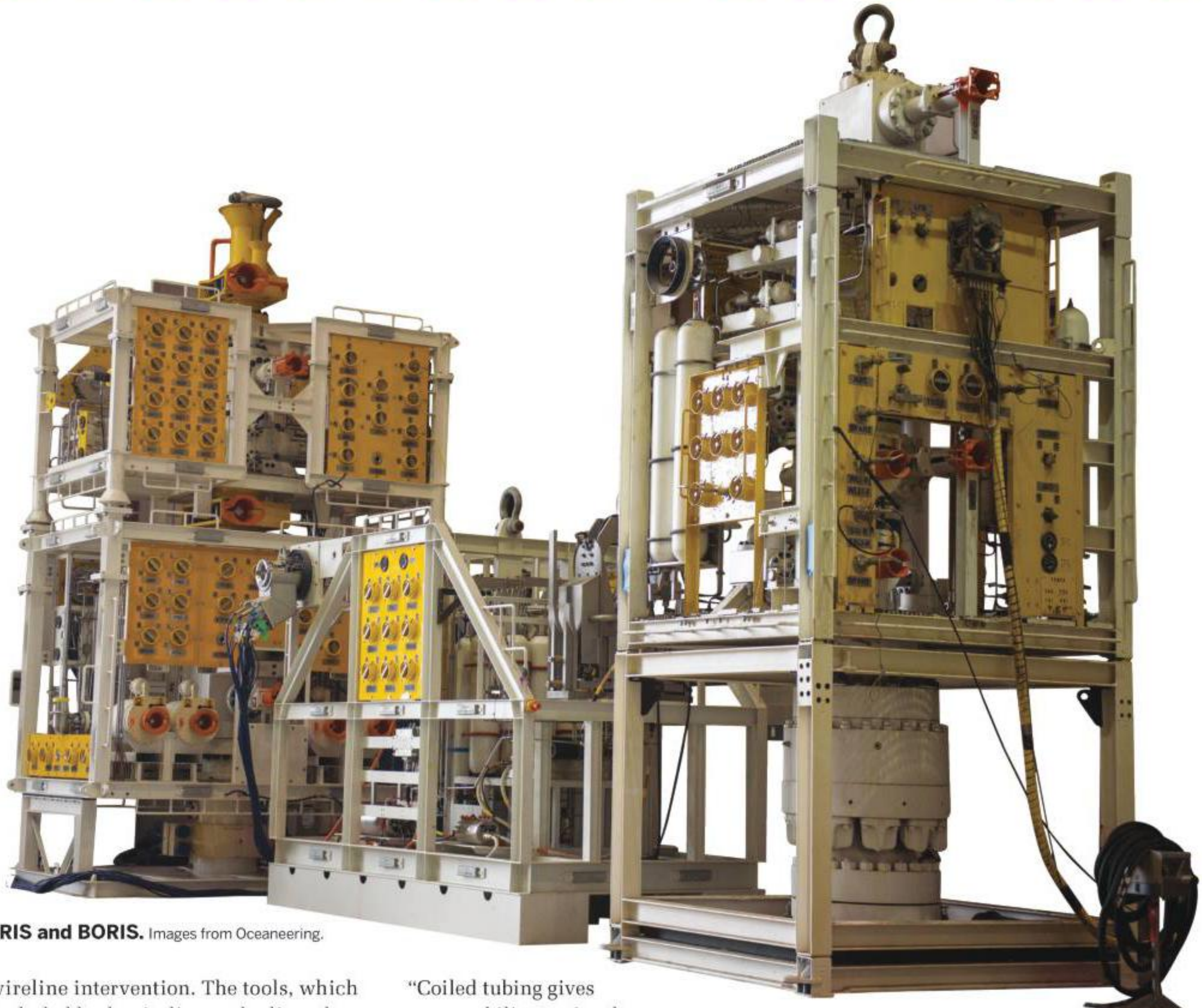
Oceaneering, meanwhile, has a track record of hydrate remediation and rigless well stimulation work. With Blue Ocean, Oceaneering acquired the IRIS, along with wireline capability, and is set to launch the Blue Ocean riserless intervention system (BORIS). This system is similar to IRIS, but its four main barriers – two gate valves (one at the top and one at the bottom) and two rams – are split into two sections, with a connector, so that the smaller (compared to IRIS) 7-1/16in upper section with a ram and gate valve can be removed. The lower 13-5/8in bend capacity section with a 7-1/16in gate valve and ram remains on the well and interfaces with a riser package.

These systems are noteworthy as they are able to work in deepwater and ultra-deepwater, because the grease supply to the pressure control head is subsea, Crawford says. Wireline services in shallower water supply the grease from the surface, but this wouldn't work in deeper waters. On IRIS and BORIS, hydraulic power is used from the surface to hydraulically pressurize the grease subsea.

"Because we are able to put all types of wire through our pressure control head, such as big braided wire all the way to slickline, we are able to deploy tools that others are developing in order to do more in the well," Crawford says. These tools range from the most basic wireline tool to electric tools that can run into the well.

This IRIS system has already proved itself in up to 8200ft (2499m) water depth, where it set a record for the deepest water

Subsea Pressure Control Head.



IRIS and BORIS. Images from Oceaneering.

wireline intervention. The tools, which included both wireline and e-line, then ran a further 8000ft (2438m) downhole, where they performed operations. Blue Ocean has also done a lower abandonment in 6700ft (2042m) water depth.

"It is sometimes easier for us without the riser because we can adjust the pressure in the lubricator as we need to depending on what's going on in the hole," Crawford says. "The key to what we do is the way we supply grease to the grease head, which allows us to transmit grease in deepwater and ultra-deepwater depths."

Riserless coil

But, there's more to come from this technology. With its well control package foundation and subsea line management, Oceaneering now has what it needs to make the step to riserless coiled tubing (CT), Crawford says.

Riserless CT has long been a goal for the industry. "With riserless wireline, there is a set amount of things you can do," says Ben Laura, vice president of Service, Technology & Rentals for Oceaneering. "Coiled tubing gives you an ability to circulate inside the well. If you do a standard stimulation job, you can circulate to the tree. With coil, you can circulate all the way down to the production zone. A second driver is that you can push and pull a lot more than you can with wireline. This opens up more scope. You cannot pull as much as a rig, but CT has advanced to 60–70% of what a rig can do."

But, so far, riserless CT has not been achieved. "No one has really been able to run the coil riserless," Laura says. "Several companies have tried, and there are several patents on ways to use CT in open water without a riser and to properly seal the interface subsea."

Oceaneering will be deploying riserless coil in 2018. However, Laura points out that wireline would still be the core intervention tool, with riserless CT an option for where it was needed. "Ultimately, riserless wireline is getting close to being able to do anything you could do through wireline with a riser," he says.

"This includes setting and pulling plugs," Crawford says. "Opening and closing sleeves – check. Milling – check. Logging – check. Perforating – check. Anything we can do with a wireline unit conventionally, using a riser or from surface, we can do riserless. It's more about building a track record now."

Such a move adds to the argument for using these systems on vessels of opportunity, by enabling mobilization with smaller spreads, minus the risers, Laura adds. These could help reduce costs on the likes of costly plugging and abandonment (P&A) campaigns, which are finally looming in the North Sea.

"P&A work in this area has been talked about for a long time," Crawford says. "The North Sea has some really large P&A campaigns about to kick off, and the capability to do them is exceeded by the amount to do. We will see riserless systems coming into their own. There is no magic bullet to P&A. But there is a large section of P&A that can be done riserless." OE

A clean cut

Cutting and sealing has been combined into a neat package in Interventek's Revolution valve design. Elaine Maslin reports.

A common plea in today's cash-strapped, low investment environment is for technologies that can help make the industry more efficient – or even do more – at a lower cost.

Small technology firms, often set up by ex-operator or ex-major service firm staff who've seen and grabbed the opportunity to do things differently, are not short of offerings.

Interventek Subsea Engineering has developed an intervention system valve – the Revolution Valve – to address the short-comings seen in current systems.

Formed in 2014, the firm's senior staff have spent time at Expro, FMC Technologies, BP, and Weatherford, among others.

The Revolution Valve, which won the Emerging Technology Award in last year's Offshore Achievement Awards (see this year's winners on page 61), is designed to cut slickline, braided cable and coiled tubing during intervention operations, should the need arise, and then, contain well pressure. It can cut intervention media up to and including 2in outer diameter, 0.203in wall thickness, 147 KSI tensile strength coiled tubing. A slim design, through use of a rotary actuator, means it can be used in in-riser and slim-line open water interventions.

Ball valves are predominantly used for this and are often used in series to compensate for their shortcomings, says Gavin Cowie, Interventek's managing director.

Furthermore, moves towards larger bores and higher-pressure environments, and new requirements in API 17G, particularly around fatigue capacity, will only add to those pressures, he says. Interventek has designed a more compact valve that can cut and seal in one movement, while having separate cutting and sealing components to avoid damage to either.

The firm has a license agreement with Hunting, which has already been successfully using the valve in the field. The firm has also made a deal to supply 6.375in 15,000psi in-riser Revolution Valves to Louisiana-based Professional Rental Tools (PRT) to service the Gulf of Mexico.

"The starting point was a recognition that valves in the market place were not suitable," Cowie says. "There were shortcomings with existing technology and these were becoming more apparent as industry increased requirements for larger bores and higher pressure applications." In some cases, this had led to systems being built entirely from expensive exotic alloys, because of the larger bore size, but the same outer restriction, resulting in little wall section to play with.

The existing arrangement has been around a long time, he says. Ball valves, which rotate to create an open bore, or close it off, were used, with the edge of the bore used to cut then contain as it closed, using O-ring type seals.

"Historically ball valves were used, but they are built as containment devices. The process of cutting an intervention medium would damage the seal surface," Cowie says. These valves were OK for 3in, 5000psi bores, but have become challenged with larger bore sizes and higher pressures, as well as issues

An in riser valve assembly, above, and landing string system, right.

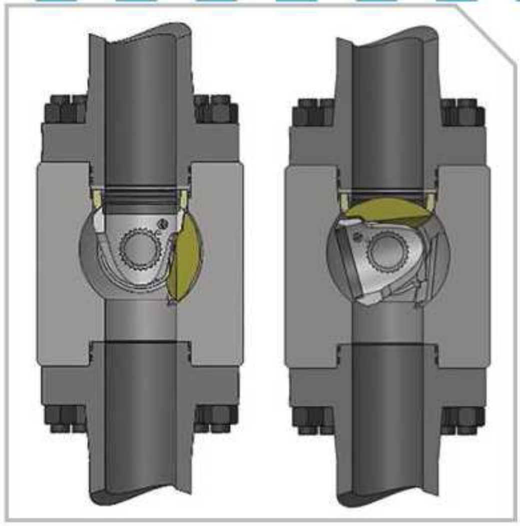
Images from Interventek.

created by higher temperatures and material degradation.

Interventek's valve doesn't contain elastomer seals and uses elements of ball valves and flapper valves in combination, to meet both cutting and containment requirements. It is a ball valve in that it rotates, but the corrosion resistant sealing surfaces are kept clear of the cutting edges until they are safely able to form a seal.

Hydraulic pressure is used to move the valve using a compact fractional turn rotary actuator, shaped to fit within the outer geometry of the tool, but not protrude, so it can be positioned inside a BOP, and allow intervention equipment to run through, but kept away from well fluids and sand, etc. Cowie says that axially-operated actuators are mechanically poorer and less efficient and take up more space. Because Interventek's actuators are on the outside of the valve, they can also be serviced faster and more easily, Cowie says. "You can take it apart with simple hand tools and replace the actuator seals in five minutes," he adds.

Interventek has used SolidWorks for 3D modeling, which enables you to create models which can reflect anything



Left: open valve. Right: closed valve.

you can imagine, Cowie says, something which would have been more difficult in 2D programs. While 3D modeling isn't new, wholescale adoption of a system like SolidWorks is, Cowie says. "That, coupled with an analysis capability, i.e. Ansys, lets you do extensive analysis of stress conditions and load regimes to optimize before manufacturing."

Having manufacturers able to make the components also helps. Elements like the cam grooves, along which the sealing flapper moves on the inner surface of the valve, can be created using spark erosion. This uses a CNC machine to create a carbon electrode negative die, which has a current put through it to burn into the metal. Again, while this technique isn't new, the speed at which it can been done – from 3D modeling to manufacturing – is. Instead of taking 6-12 months to create a ball valve, it is possible to manufacture a Revolution Valve in around 12 weeks.

The firm has its eyes on a couple of markets. The first is in-riser well completion and intervention landing string valves, using a 6 3/8in, 15,000psi version, which can be tailored to suit, for new subsea well developments and heavy intervention from mobile offshore drilling units using a drilling riser or BOP stack. The other is open-water light weight intervention systems, as either an open-water well control valve with compact versions of the valve, or as part of a subsea abandonment tree (a compact lightweight tree-on-tree system for use during well abandonments to allow well access without overstressing the Xmas tree). **OE**

Gaining control

Inflow control valves and in-well fiber-optics have given Nexen far greater visibility of what's going in and out of their reservoirs on the Golden Eagle field. Elaine Maslin reports.

When the Golden Eagle field was discovered in 2007, it was one of the biggest oil discoveries in the UK North Sea, after the huge Buzzard field.

But, with a complex reservoir and some uncertainty over the level of connectivity and aquifer support, careful consideration had to be given over how to develop the field.

Nexen Petroleum UK opted for so-called intelligent well technology, using interval control valves, which allows for different reservoir zones to be opened and closed remotely. The technology, which includes fiber-optic sensing, meant Nexen could reduce the number of wells it needed to drill on Golden Eagle. Using this technology has also given Nexen far more information about its reservoirs than it would have with conventional well completions, reduced intervention requirements and meant the waterflood could be tracked and managed more efficiently.

The field

Golden Eagle is 100km northeast of Aberdeen and was developed using a wellhead and production, utilities and quarters platform, with two subsea tiebacks to date (Peregrine and Solitaire). The development, which came onstream in October 2014, under budget and ahead of schedule, has 19 wells, comprising of 14 producers and five water injectors. All were completed with fiber-optic downhole distributed pressure and temperature monitoring. Most have intelligent completions, i.e. interval control valves (ICVs). The two subsea satellites, north and south drill centers, also have production and injection wells with fiber-optic intelligent completions.

The main reason for using intelligent completions was the reservoir, which is two different formations, Punt and Burns, says Craig Durham, production engineering advisor at Nexen.

The Burns reservoir is the oldest, and underlines the Punt sands – a former meandering riverbed, which makes it quite layered and connected in different ways, Durham says. Burns is a larger area, connected to a large aquifer that gives pressure support, but is not connected to the Punt sands, which rely on water injection to produce.

Managing this scenario would be, "very difficult without intelligent technology, without being able to control flow from separate zones and being able to inject into separate zones. This is why we went for intelligent technology," Durham says. "All the wells were completed with fiber-optic, downhole pressure, temperature and flowrate monitoring for the production wells. Most of our wells are intelligent wells."

Downhole

In the reservoir section in a normal well that requires sand control there would be a production packer, some sand screens, maybe some open hole isolation, Durham says. "In an intelligent well, on the other

Golen Eagle with the Safe Caledonia alongside.
Photo from Nexen.

hand, it is a lot more complicated."

On Golden Eagle, Nexen divided up the sand face section into three separate zones. "We still have a production packer and we still have pressure, temperature and flowrate monitoring at the top, but we also have an interval control valve (ICV) immediately under the first packer," Durham says. "We still have sand screens and open hole isolation. But, then we have a second ICV and second pressure, temperature and flowrate monitoring and so on into the third zone."

The number of zones is limited to three because the ICVs have hydraulic controls; the number of control lines that can physically fit into the tubing hanger and across a completion is limited.

Pressure and temperature data are gathered from the tubing side, but also the annulus, so that if a zone is shut in, engineers know what the reservoir pressure is. The fiber-based distributed temperature sensing system (DTS) runs along the length of the liner string, and provides useful information for inflow performance, because temperature changes at different flow rates in the well. These data supplement information from the single downhole flowrate meter, which only gives a cumulative rate – not what is coming through each zone.

The DTS is especially useful on the water injection wells, because of the geothermal temperature gradient when you shut a well in and get "warm back." The well heats up in quite close proportion to how much water has been injected, Durham says. "Through thermodynamics, heat conductivity etc., we're able to quantify, almost to production logging standards, what the percentage injection is into these zones." This includes subsea wells, where production-logging quality data can be gathered, without having to intervene in the well, in any way.

It's not quite as simple on the production wells, where the temperature trend is not as great and the quality of the DTS resolution is not as good. But, this is being worked on, Durham says. They are also doing temperature transient analysis, using the single point temperature gauges and seeing how temperature changes in proportion to flowrate, which has offered useful information.

ICU ICV

The ICVs themselves can have 10 positions, from fully closed to fully open, making them chokable, which is useful for water injection wells, Durham says, to reduce any thermal fracking effect in the reservoir due to the shock from the cold water coming in, as well as being able to vary how much is injected into each zone.

The ICVs are controlled using SmartWell Master, which allows the operator to select a position at the click of a mouse and SmartWell Master sets out the control sequence to open or close the sleeve. The operator has a screen with just the valve status, while production engineers get all the data they want; pressures, temperatures, flowrates, what flowrate is going through each sleeve, etc., viewed through an integrated visualization and management system.

"Intelligent wells are more expensive compared to a normal well with more rig time and hardware. But, overall, there's lower total capex."
– Craig Durham, Nexen

"We can see temperature on each zone, annulus and tubing side, the pressure drop across the sleeve, the downhole flow meter, what the measured rate is and what the calculated rate is," Durham says. Five different methods are used to estimate what the flowrate should be and it's compared with the downhole meter and shown in green if they're within 5%, to ensure everything is as it should be.

Benefits

A big benefit of the ICVs, with monitoring, is flexibility, Durham says. "In a normal well, if you set an isolation plug to isolate water breakthrough, you isolate production, too, so it's not very efficient. In later life, you might want to take these plugs out to get the last oil out, but they might not be easy to get out," Durham says.

A zone can be shut, and the annulus gauge monitored, and re-opened. "If you are injecting in a well a kilometer away and see the pressure going up, you know you have connectivity. From a reservoir management point of view, there's a huge amount of information that you would never have on a conventional well." Water cut from individual zones can also be ascertained and what injectors are connecting with which producers monitored.

Instead of taking months and using up a 12-man crew for a wireline operation to shut in a zone, the ICV can also be moved in just hours, in theory, although Durham says, in reality, ICV moves are planned a few weeks in advance to ensure that the maximum amount of information is obtained from the move.

Learnings

To date, 19 wells have been drilled on Golden Eagle, four of those are subsea. Some 36 ICVs have been fitted, 10 of those are subsea. The wells contain a total of 14 optical flow meters, three of which are in subsea wells, and 164 fiber-optic sensors.

Just over 100 ICV moves had been made, as of early December 2016. The ICVs are moved every six months as a minimum, to prevent sticking, and to gain opportunistic data. Forty of those moves were in the subsea wells. About 20 pressure build up analyses have been done on individual zones, as well as four water injection distributed temperature surveys and a couple of temperature transience analyses, Durham says.

It's not all been perfect. The ICVs have not been moved, on the first subsea well, due to subsea control line contamination, he says. The fiber-optic sensors also failed on the same well, due to an issue with the wet mate connector. Because different computer systems control the ICVs from the rest of the platform, the interface between the two has sometimes tripped, requiring an engineer call-out to reset. But, this is still much cheaper than sending a 12-man wireline crew out for an intervention to achieve the same result in a conventional well, Durham says.

And, thanks to these tools, 40 different zones on Golden Eagle are being produced from only 19 wells, which has helped reduce the well count, and enabled greater reservoir management, understanding and operation.

"Intelligent wells are more expensive compared to a normal well with more rig time and hardware. But, overall, there's lower total capex because we've completed fewer wells and there's reduced opex as we will not need as many interventions," Durham says.

Nexen Petroleum is owned by China's CNOOC and operates Golden Eagle (36.54% interest) with partners Suncor Energy (26.69%), Maersk Oil (31.56%) and Dyas EOG (4.74%) and Oranje-Nassau Energie (0.46%). OE

AFGlobal's riser gas handling system is integrated with the drilling riser to mitigate the breakout of formation gas and enable an easy transition to MPD. Photo from AFGlobal.

Putting HSE in MPD

There's a growing acceptance of MPD in offshore operations, but are all options being considered? Jerry Lee examines the RFC-HSE variation.

North America was the largest market for managed pressured drilling (MPD) in 2015, due to its extensive use in the Gulf of Mexico (GoM), according to an April 2016 report by research firm MarketsandMarkets. The firm sees the trend continuing to 2021, when it expects the global MPD services market to reach a sizable US$4.6 billion.

The GoM has benefited from MPD technology, but to realize MPD's full potential, all applicable variations must be considered. Constant bottomhole pressure (CBHP) and dual gradient drilling (DGD) have dominated the MPD conversation, due to their ability to drill "undrillable" wells. These methods have done well for pressure sensitive situations. However, the returns flow control variation for health, safety, and the environment (RFC-HSE) may be more applicable. Unlike CBHP and DGD, RFC-HSE is only used with conventional (overbalanced) mud, which means conventional drilling operations can take advantage of MPD benefits.

MPD

Well control methodologies have minimally evolved since the early 1900's, relying solely on hydrostatic pressure [derived from the annular fluid column during static (non-flowing)] condition, and – to a certain extent – annular frictional pressure [derived from a surface resisting flow during dynamic (flowing)] conditions, to keep formation pressures at bay. Normally, when hydrostatic pressure is insufficient, issues arise (e.g. non-productive time, stuck pipe, gas kicks, narrow fracture margins, loss of well, etc.), however, now these issues may be mitigated with MPD.

Rig owned buffer manifold allow for the integration of MPD and Riser Gas Handling systems. Photo from SafeKick.

MPD creates a closed-loop system and enables the driller to manipulate surface back pressure (SBP) to manage the annular hydraulic pressure profile. The minimum equipment required is a rotating control device (RCD), a choke manifold, and at least two drill string non-return valves. Positioned above the blowout preventer (BOP), the RCD can isolate the annulus between the wellbore and pipe, creating a closed-loop system, while allowing the pipe to be rotated and reciprocated. When the annulus is closed, the returning fluid is diverted to the choke manifold at the outlet of the well. The choke can then be adjusted to create and manipulated SBP, giving the driller more precise control over equivalent mud weight (EMW) – the hydrostatic equivalent to the total pressure created in the wellbore.

RFC-HSE

Unlike other variations, RFC-HSE is specifically used to enhance process safety while drilling with conventional fluids. RFC-HSE allows drilling to occur in a closed-loop system; diverts returning fluids to the choke manifold; enables early kick/loss detection; limits the size of kicks/losses; allows the driller to perform dynamic formation integrity tests and leak-off tests; and provides riser gas mitigation capability.

To apply this MPD variation in the GoM, rigs will require the basic MPD equipment mentioned above as well as Coriolis flow meters. For convenience, a programmable logic controlled choke system and associated software, such as SafeKick's SafeVision rig package, will automate the choke system and allow for more precise control of annular pressure, at any depth in the well. In that situation, the choke control software serves as the system's interface, allowing the driller to control the MPD system and model annular conditions. The Coriolis flow meters, located at the inlet and outlet of the system, are sensitive to variations in fluid density and temperature. By inputting data from the Coriolis flow meters into the control software, real-time wellbore analysis and control (including EMW) is enabled.

Process safety

When the RCD is closed, a closed-loop system is created, like a pressure vessel, giving the driller better control over the annular pressure profile than an open-to-atmosphere system would. The closed RCD also diverts the returning fluids to the choke manifold, away from the drill floor where rig hands are working.

If there are changes in mud flowing into or out of the well, the Coriolis flow meter will immediately recognize and display the change: more volume flowing out of the system than in may represent a kick; more volume flowing into the system than out may represent losses. This deviation acts as an early kick/loss indicator, allowing the driller to react to the event quickly and in real-time. In response to the volume flow deviation, the driller would only need to increase the choke pressure – increasing the SBP and EMW – to stop or minimize the kick, or decrease the choke pressure – decreasing the SBP and EMW – to stop or minimize flow into the formation, resulting in a smaller kick or loss size that the crew needs to manage.

In comparison, conventional methods require visible changes in mud tank for kicks/losses to be identified, which would be in barrels, rather than the gallons it would take an MPD system to identify.

Furthermore, because SBP can be manipulated while the system is flowing, dynamic pore pressure tests, dynamic formation integrity tests and leak-off tests can be performed. With these capabilities, the driller can ascertain more information about the well, decreasing uncertainty and risk.

Riser gas mitigation

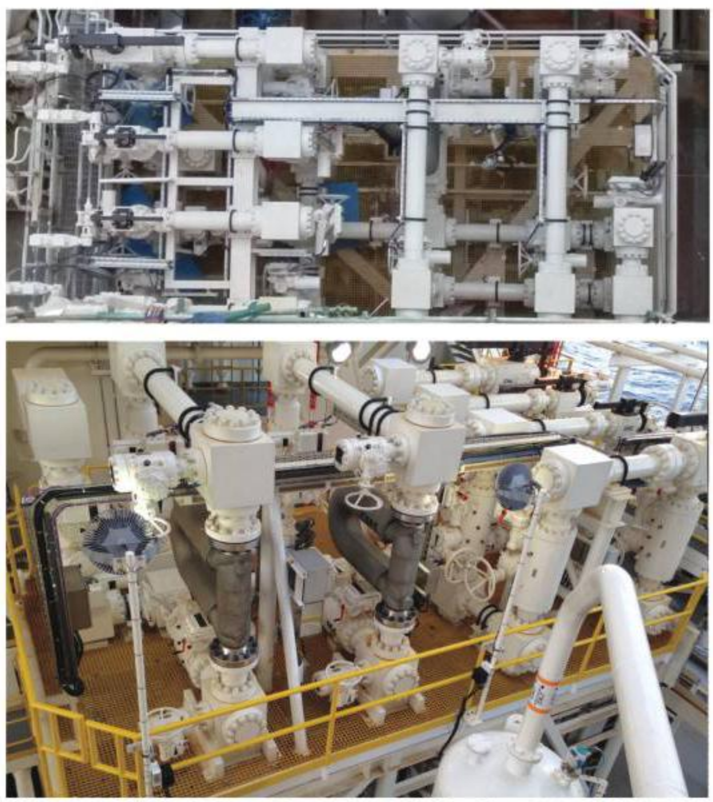
Riser gas can be troubling for any drilling operation using subsea BOPs. If gas gets into the riser, it can quickly come out of solution, expand, and lead to an unloading event, which can cause a blowout, collapse of the riser, or environmental and legal issues, says Bo Anderson, vice president, advanced drilling systems, AFGlobal. However, with a riser gas handling system (RGH) installed in the riser string, the risk can be greatly mitigated.

An RGH system is comprised of a drillstring isolation tool (DSIT), a flowspool, and riser crossover joints.

Integrated into the riser using the crossover joints, the DSIT can close the annulus between the riser and drillstring and redirect the returning fluids through the flowspool. The flowspool, which has two exiting lines, can then divert the flow to the rig's mud gas separator or to a choke, allowing control over the pressure seen at surface. With this system, the driller is given the capability to control the amount of flow from the riser. Additionally, if is sized properly, the RGH is the key component that enables MPD to be deployed on a floating rig, says Mark Mitchell, president, oil and gas, AFGlobal.

"Our riser gas handling system is the essential building block for MPD in deepwater," Mitchell says. "From an equipment standpoint, it gives you the platform to install the RCD, the flowpath needed for MPD, as well as serving the function as a riser gas management tool."

With an RGH installed in the riser, an RCD can be integrated into the riser string, above the DSIT. Then, when the RCD bearings need to be replaced, the DSIT will isolate the RCD and the flowspool will redirect the returning fluid.



Rig owned MPD choke and meter manifolds. Complete with duel 3in and 6in chokes and duel 8in Coriolis meters. Photos from SafeKick.

These necessities not only result in an inherent riser gas mitigation capability, but when combined with the flowmeters, like those used in RFC-HSE MPD, the driller also has a riser gas management tool. With the flowmeters providing early kick detection, influxes can be seen early, allowing the driller to start thinking about and making accommodations for handling them, Anderson says.

"Riser gas management then changes from a reactive solution to a proactive solution," Mitchell adds.

There are additional benefits available with RFC-HSE, such as well breathing identification, ability to circulate out small influxes at drilling flow rates, the ability to monitor tripping operations, mitigation of wellbore instability issues, and the ability to provide managed pressure wellbore strengthening and managed pressure cementing.

BSEE well control rules

New well control rules from the US Bureau of Safety and Environmental Enforcement went into effect July 2016. These rules are intended to increase offshore safety. Although, some rules may inhibit some drilling operations. One such rule, Section 250.414(c), requires the implementation of a 0.5ppg drilling margin – unless the operator can justify deviating from the drilling margin through supplemental data and other documentation – which could result in previously drillable wells becoming "undrillable." However, regulators specifically changed the 0.5ppg margin from static mud weight, to EMW, which seems to invite the use of MPD.

This is good news for US GoM operators, however, because CBHP and DGD operations are still only approved on a case-by-case basis. On the other hand, since RFC-HSE is used to augment conventional drilling programs, it would not require pre-approval, allowing drilling contractors to freely utilize this technique to operate more safely, and potentially use some of the fringe benefits of MPD.

Rigs equipped for RFC-HSE MPD could capitalize on the 0.5ppg EMW drill margin, drilling wells closer to balanced pressure, which improves drilling efficiencies. In addition, if an influx occurs the driller's response could then be based on the real-time information about the mud weight, rather than relying on old pre-drill estimates. Applying SBP would increase EMW above the formation pressure, which would not only stop the influx, but would also allow the actual formation pressure to be determined. **OE**

Southeast Asia

Stepping on the gas

While Southeast Asia has suffered during the downturn, a return to natural gas developments could drive sector activity over the next several years. Steve Hamlen sets out the details.


Shell's Gumusut-Kakap platform operating off the coast of Sabah, Malaysia. Photos from Shell's Flickr.

Southeast Asia's upstream offshore oil and gas sector has been suffering in the low oil price environment and even though it seems that few final investment decisions (FIDs) will be made in the region this year, some developments outside of traditional powerhouses Indonesia and Malaysia are making good progress.

Indonesia and Malaysia hit hard

"In terms of South Asia, there are definitely some countries struggling with the current environment," says Matt Cook, lead analyst for drilling and production forecast at consultants Wood Mackenzie. "Indonesia, in particular, has been hit hard because a lot of the fields there are very mature, requiring secondary and tertiary extraction methods. The country has really struggled with attracting new investment, even before the oil price crash, so it has been compounded because of that."

"Regarding mature fields, Malaysia introduced an EOR [enhanced oil recovery] production sharing contract (PSC) that offered more favorable terms for those higher extraction costs for the lower volumes you would get out of such a field," Cook adds. "This could be something that Indonesia might look to do in the future."

Cook says that the future for Southeast Asia's offshore sector is natural gas. And, indeed, upcoming projects such as Chevron's IDD project and Eni's Jangkrik in Indonesia, as well as the Petronas-operated Kasawari and Rotan floating LNG project offshore Malaysia, are all gas developments.

Gas takes precedence

"The reason behind this is a combination that East Asia and Southeast Asia are very gas and LNG hungry," Cook says. "These gas fields historically have not been tapped into just because the market has not been there for them. Now, there certainly is the market. Japan is a huge importer of LNG, as is South Korea. These markets are on Southeast Asia's doorstep."

"In terms of oil, Indonesia and Malaysia both struggle with it. There have not been major oil discoveries in the region – and there will not be any major oil developments in the next five or six years, for example," Cook says. "Projects like Chevron's West Seno, in deepwater offshore East Kalimantan, Indonesia, were the last wave of oil developments offshore. The last few were Shell's Malikai and Gumusut-Kakap [both off Sabah, Malaysia]. There is nothing of that sort of size coming up for oil in Indonesia or Malaysia – everything seems to be gas-focused."

Myanmar exploration surge

Weak interest in recent licensing rounds and budget cuts are pointing to a bleak year for exploration in Asia-Pacific – with Wood Mackenzie expecting around 50 wells to be drilled this year, which would be a decline of 70% from 2014 levels.

However, Myanmar looks to be emerging as a hot spot this year, amid the forecast drilling downturn. The country opened its doors to foreign investment some years ago and activity is now gathering pace.

Myanmar, which holds some of the last remaining frontier acreage in the mostly mature Southeast Asia plays, could experience increased exploration drilling.

Shell's Malikai tension leg platform, offshore Sabah, Malaysia – the supermajor's first outside of the Gulf of Mexico.

"We expect several wildcat wells to be drilled as several blocks from the hugely successful 2013 bid round are matured through the exploration process. We also expect to see several companies farm down interest in exploration acreage where commitment wells are due to reduce risk and manage budgets," said Wood Mackenzie's APAC Upstream: Five themes to look for in 2017 report.

Myanmar is also set for its first deepwater gas development soon from Woodside's Thalin field, discovered in 2016.

The Australian operator is looking to tieback Thalin to the Shwe field infrastructure. This fast-track development could be onstream by 2019.

"Woodside might have Thalin onstream within a couple of years from now, which – given that it is the first deepwater development in the country – is quite a bullish timeline," Cook says.

Oil not gone just yet

While most developments in the region will indeed be gas projects in the coming years, Shell is looking to exploit an oil field offshore Brunei by a cross-border development with an existing facility off East Malaysia.

The Geronggong field is a proposed tieback to Shell's Gumusut facilities across the border in Malaysian waters. The field is 100km offshore Brunei at a water depth of 1000m (3281ft), making it the deepest field off Brunei and the most remote.

These challenges made Shell (operator, 50%) and the Sultanate of Brunei (50%) consider two development options: a tieback to Gumusut, and a standalone floating production, storage and offloading (FPSO) concept.

Shell currently estimates that Geronggong could produce 25,000-42,000 bo/d. The field also holds some natural gas and condensate.

Shell started production from its deepwater Gumusut-Kakap project offshore Sabah, East Malaysia, in 2012. Once Geronggong was deemed commercial, Shell began favoring the tieback option because it is a cheaper solution and could fast-track development.

M&A potential

With many companies suffering during the downturn, many will be considered as prime candidates for mergers and acquisitions (M&As).

"Asia Pacific's upstream sector holds up to US$40 billion worth of opportunities in 2017, as oil majors continue to divest mature and mid-life assets in the region," according to a recent Wood Mackenzie report.

"BP, Chevron and other majors have divested tail-end assets within the region over recent years, but that trickle looks set to gain volume as larger assets are sold in 2017. Chevron and Shell hold the largest portfolio of legacy assets in the region, and in the latter half of last year signaled their intentions to sell assets in Myanmar, Bangladesh, Thailand, New Zealand and Malaysia, amongst others," the report said.

Prasanth Kakaraparthi, senior upstream research analyst at Wood Mackenzie, says that between 2010-2016, national oil companies (NOCs) were the main buyers in Asia Pacific, acquiring over 2 MMboe of commercial reserves.

"This year we expect to see more buying activity from local independents and private equity-backed players," he says. "Domestic utilities and refiners, Japanese players and Middle-Eastern NOCs looking for growth opportunities are also possible acquirers." OE

Rystad: Indonesia, Vietnam to lead FIDs

Rystad Energy forecasts projects holding 512 MMboe of recoverable liquids and gas resources could potentially reach final investment decisions (FIDs) within Australia and Southeast Asia during 2017.

After 2016's heavy gas binge (88%), 2017 sanctions are assessed to have a slight liquids flavor (58%). Indonesia and Vietnam are expected to lead these regions, accounting for almost 75% of the potential 2017 approvals. Most of the volumes fall within the offshore shelf (up to 125m water depth) segment, though Australia could see more onshore than offshore volumes sanctioned during 2017.

"This would be a significant drop from the 1835 MMboe sanctioned in these regions during 2016, though this trend is skewed by two gas megaprojects – BP's Tangguh expansion in Bintuni Bay of West Papua, Indonesia, and PetroVietnam's Block B-O Mon project offshore Vietnam," says Readul Islam, senior analyst, Rystad Energy.

The two gas projects account for around 75% of the 2016 FIDs in volume terms. The Rystad Energy 2017 FID forecast is the result of balancing project operator/partner/industry expectations versus following recent project news flow to assess candidate projects' chances of attaining 2017 FID.

Despite lower volumes expected to be sanctioned compared to 2016, the count of potential FIDs is higher in 2017. The greater diversity in project sizes could be a boon, particularly to smaller service players.

"Rystad Energy's 2017 FID forecast shows that the Australia & Southeast Asia regions certainly haven't gone into slumber following the price slump. The upside and downside risks to the FID forecast means all stakeholders will be eagerly following the development of 2017 approvals in these regions," Islam says. ▪

Southeast Asia

Natuna under pressure

Steve Hamlen profiles the East Natuna gas field offshore Indonesia.

The huge East Natuna gas field in Indonesia's Natuna Sea is considered to be the largest undeveloped gas prospect offshore Asia.

However, the promise of huge gas reserves must contend with high carbon dioxide (CO_2) content, political treadmills and the severe industry downturn. The development solution – subsea pipeline or an LNG facility – is also undecided, although a pipeline is the current favorite. Then, there is the massive budget of such an undertaking, estimated at anywhere from US$24-40 billion, depending on different sources.

Italy's Agip discovered East Natuna (formerly Natuna D-Alpha) in 1973. The field has 222 Tcf (6.29 Tcm) estimated reserves, of which only 46 Tcf (1.30 Tcm) are recoverable due to the high CO_2 content (72%), according to ExxonMobil. Removing the CO_2 will require advanced technology and significant investment.

Since its discovery, the project has been delayed numerous times. The project's partners [ExxonMobil, 35%), Indonesia's Pertamina (operator, 35%), France's Total (15%) and Thailand's state player PTTEP (15%)], set a gas target of 2020 – but, this was before the price crash of mid-2014, and the aftermath of which makes this target look out of reach.

Oil price stumbling block

"I cannot yet confirm when operation will begin," said IGN Wiratmaja Puja, Indonesia's Ministry of Energy and Mineral

Southeast Asia

Resources Director-General for Oil and Gas, last year. "We hope that it will start before 2030." Giving an honest appraisal, Wiratmaja noted: "East Natuna is a special block, as it has big reserves and high CO_2 content. With current technology and prices, the project is not economical." He said that the project would only be economically developed when the price of oil reached more than a lofty \$100/bbl. That level is some way off, even according to the most optimistic crude price forecasts.

Development options

The main problem is Natuna's high CO_2 content gas, which requires the development of advanced technology to separate and re-inject the CO_2 back into the reservoir. This will make production costs much higher than more conventional gas reserves, let alone shale gas.

Development solutions have been evaluated over the years and the current favorite is a subsea pipeline concept, because it is the most cost-effective way to get gas to market, while an LNG project would hike the costs too much.

One upside of an LNG project is that it would make the gas easier to transport to numerous locations around Indonesia, as well as export further afield. However, although pipelines can only go to a fixed position, the planned and existing pipeline infrastructure in the region would allow the transport of East Natuna gas to Indonesia, Malaysia, Thailand and Singapore.

If the pipeline option is followed, the East Natuna gas field could start producing at 1 Bcf/d (28.33 MMcm/d), with peak output to reach 4 Bcf/d (113.3 MMcm/d), ExxonMobil said. Peak production could last for at least 20 years before it started to decline.

The current estimate for Pertamina to build pipelines for the East Natuna development, including linking the pipelines into the Southeast Asia regional network for export, is about \$24 billion, said Infield Systems, although other estimates from industry analysts suggest this will cost around \$40 billion.

This is a wide gap in estimates, but to give some clarity, capital expenditure on the East Natuna project itself, up to 2022, has been estimated at around \$11.6 billion by Infield Systems.

And, then, there are the costs of CO_2 removal, on which the Global CCS Institute said: "The addition of CO_2 transport and injection facilities to the development of the East Natuna discovery would require additional capital costs of about \$5.975 billion (in 2010 dollars).

"The extra annual operating costs would be approximately \$180 million/yr and the additional decommissioning costs would be about \$1.470 billion incurred after a CO_2 injection period of 75 years."

Geology

The East Natuna structure is a middle-to-late Miocene platform reef carbonate and lies around 200km northeast of Natuna Island in the East Natuna Basin.

The geological composition of East Natuna is, "a large structural stratigraphic hydrocarbon trap and is unique in areal extent and reservoir thickness among the various carbonate traps, which are present in many Southeast Asian basins," said geoscience firm PGS, which completed the acquisition of a high definition MC3D survey on the field area in 2010.

"The data from the seismic survey will enable companies to make detailed reserve assessments, as well as identify the main depositional bodies and producing intervals within the carbonate reservoirs," PGS adds.

"The data from the seismic survey will enable companies to make detailed reserve assessments, as well as identify the main depositional bodies and producing intervals within the carbonate reservoirs."

Learning process

Pertamina has said the ideal form of partnership on East Natuna, with ExxonMobil, Total and PTTEP, would be like that between Norway's Statoil and supermajor BP, which helped Statoil gain knowledge and expertise in deepwater operations.

Pertamina is hoping its partnership for East Natuna will help it gain knowledge and skills that it will be able to apply on other projects in Indonesia, such as the Mahakam Block.

But, fruitful relationships haven't been forthcoming to date. In 2006, Indonesia revoked the East Natuna license from ExxonMobil on the grounds that the US player failed to provide a feasibility study for the proposed development within the time frame of rules set out by a production sharing contract, which was awarded in 1985 and amended in 1995.

Following numerous issues with red tape and lengthy talks with various government departments – as well as upstream watchdog BP Migas (since disbanded and relaunched as SKK Migas) – over the years, the latest partnership still includes ExxonMobil.

The partners remain keen to make progress on this troubled project despite the long list of problems that will surely provide further roadblocks along the way. Given the obstacles to overcome, 2030 may come along all too quickly. **OE**

Southeast Asia

Adding up SE Asia activity

Southeast Asia is expected to receive record levels of offshore investment, fueling the expansion of the region's upstream industry. EIC's Angeline Elias outlines the hotspots.

The top five countries in 2017 leading offshore project activity in the region will be Indonesia, Malaysia, Thailand, Vietnam and the Philippines, according to the EIC's project tracking database, EICDataStream. For the period 2017-21, there are a total of 169 projects proposed or under development in Southeast Asia, worth an estimated US$124 billion (see charts below).

Indonesia

Indonesia's government aims to develop five floating storage and regasification units (FSRUs) in 2017, as part of its plans to improve domestic gas infrastructure and increase utilization of natural gas in its domestic market. The country has two new FSRUs, in Central Java (*FSRU Cilacap*) and West Java (*FSRU Cilamaya*) under development and expected to be operational in 2018 and 2021, respectively. In terms of contracting activity, the Jambaran Tiung Biru-Cendana, Jambu Aye Utara and Ande Ande Lumut offshore developments are all scheduled to award contracts this year.

Malaysia

In Malaysia, Petronas plans to reduce its capex and opex to about $11 billion over the next four years, due to the low crude oil prices. However, there are substantial offshore projects still moving ahead, such as the Bokor Phase III field, which is in the process of developing its central processing platform (CPP) with a contract award expected in 1H 2017.

Another positive development is the new gas discovery in Block SK408, offshore Sarawak, by SapuraKencana Energy, which is estimated to hold multi-TCF of gas. Another project making progress is the Pegaga gas discovery, in Block SK320, again offshore Sarawak, where the invitation to tender for an engineering, procurement, construction, installation and commissioning contract is expected to be issued by Q3 2017.

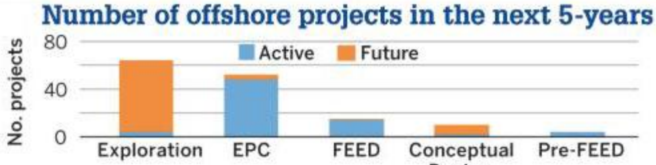
Vietnam and Thailand

Rosneft has started drilling on an exploration well in the Nam Con Son Basin in Vietnam, which has anticipated recoverable reserves of 445 Bcf of natural gas. In Thailand, Chevron has decided to re-evaluate its engineering design for the Ubon field's proposed CPP, which has a final investment decision set for 2018. Carigali-PTT Operating Co. (CPOC) continues to be active in the B-17 Block, in the Gulf of Thailand in the Thailand-Malaysia joint development area, where it is moving ahead with the phase four field, comprising of three wellhead platforms with subsea tie-ins to the existing facilities.

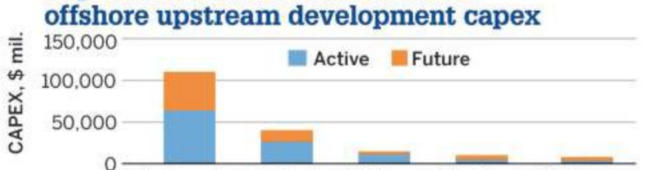
Decommissioning looms

Looking to the future, the decommissioning sector will increase in importance with Brunei, Indonesia, Malaysia and Thailand home to approximately 833 installations that are 20+ years old – the average life expectancy of offshore assets. Malaysia's Petronas and Thailand's PTT Exploration and Production Public Co. have already listed platforms to be decommissioned and feasibility studies are under way. OE

Number of offshore projects in the next 5-years



Top 5 South East Asian countries offshore upstream development capex



Source: EICDataStream

Angeline Elias is regional analyst at the EIC for the Asia Pacific region. She has previously worked for Southeast Asian major oil and gas fabricator, Malaysia Marine and Heavy Engineering.

An overview of OTC 2016's exhibition hall.
Photos from Offshore Technology Conference (OTC).

Preparing for a new (low oil price) world

Melissa Sustaita provides an overview of activities slated for this year's Offshore Technology Conference.

The 2017 Offshore Technology Conference (OTC), the annual four-day event taking over the entire NRG complex in Houston, has crafted its technical program to invite discussion on ways to cope with the new normal.

As one of the world's largest oil and gas conferences, OTC brings together energy leaders and professionals from around the world to discuss the industry's latest technological advances, today's environment, and ideas and strategies on how to adapt.

Technical highlights for the conference include updates on mega projects, such as Shell's Stones and BP's Mad Dog in the Gulf of Mexico, as well as Total's Moho Nord, which came online in mid-March. Other featured topics will include adapting to the low oil price environment; safety and risk management; renewables; and the digital revolution.

On Monday, 1 May, the breakfast sessions at OTC start off with a look at challenges facing operators in the deepwater Gulf of Mexico, entitled "A Fresh Look at the Gulf of Mexico: How Oil and Gas Companies Can Adapt to the New Challenges of Operating Safely and Efficiently in the Deepwater." Other breakfast sessions include a look at new business opportunities in Brazil, and Indonesia. The rest of the day includes profiles on the aforementioned Moho Nord, BP's Mad Dog, and cost-effective solutions for oil and gas.

On Tuesday, 2 May, two technical sessions will be dedicated to Shell's Stones development. Shell and SBM Offshore will discuss the *Turritella*, which is the world's deepest floating produxtion unit, and second FPSO in the Gulf of Mexico. Later that day, Shell will take the stage to go over the Stones project, including FPSO installation work, development, safety, and the subsea, umbilical, riser and flowline systems.

On Wednesday, 3 May, Pemex CEO José Antonio González Anaya will discuss the next five years of the Mexican Energy Reform. Other discussions will cover the UK North Sea with ExxonMobil; Vietnam's plans to open deepwater acreage, featuring PetroVietnam; and Mauritania and Senegal's new offshore gas developments, featuring Kosmos Energy.

On Thursday 4 May, discussions will continue regarding Mexico's deepwater opportunities with Chevron, ExxonMobil, Statoil, BHP Billiton, and Murphy Oil.

OTC will host the Distinguished Achievement Awards Luncheon on Tuesday, 2 May at NRG Center. The conference will recognize John Bomba for individual achievement, the LLOG Exploration – Delta House Project for institutional achievement, Mike Conner for the Heritage Award, and a Special Citation for Art Schroeder.

The d5 event, designed to spark creativity and innovation in the energy industry, will be held at Rice University on Friday 5 May.

Sponsoring organizations for OTC 2017 include: American Institute of Chemical Engineers (AIChE), American Association of Petroleum Geologists (AAPG), American Institute of Mining, Metallurgical, and Petroleum Engineers (AIME), American Society of Civil Engineers (ASCE), American Society of Mechanical Engineers (ASME), Institute of Electrical and Electronics Engineers, Oceanic and Engineering Society (IEEE-OES), Marine Technology Society (MTS), Society of Exploration Geophysicists (SEG), Society for Mining, Metallurgy, and Exploration Inc. (SME), Society of Naval Architects and Marine Engineers (SNAME), Society of Petroleum Engineers (SPE), and The Minerals, Metals, and Materials Society (TMS).

Supporting organizations include: American Association of Drilling Engineers (AADE), American Petroleum Institute (API), Association of Energy Service Companies (AESC), ASTM International, Center for Offshore Safety, Independent Petroleum Association of America (IPAA), Institute of Marine Engineering, Science, and Technology (IMarEST), International Marine Contractors Association (IMCA), International Society of Automation (ISA), National Ocean Industries Association (NOIA), and Research Partnership to Secure Energy for America (RPSEA).

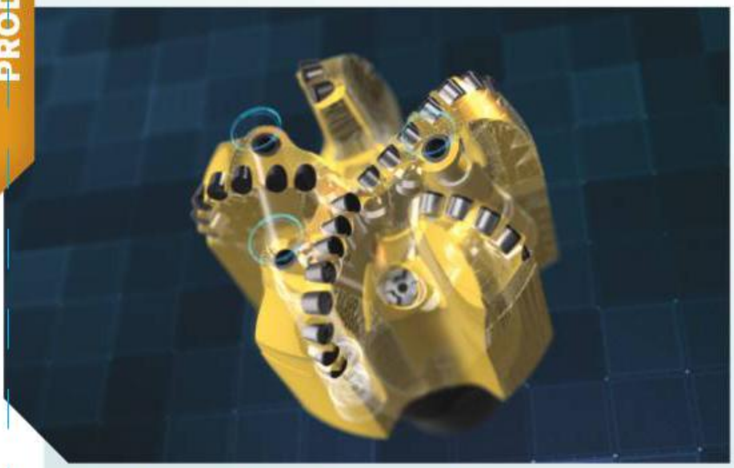
Endorsing organizations include: the International Association of Drilling Contractors (IADC) and Petroluem Equipment & Services Association (PESA).

OTC takes place 1-4 May 2017 at Houston's NRG Park complex. For more information on OTC, including the full conference and events, visit 2017.otcnet.org. OE

OTC 2016 by the numbers:

- **68,000** – The number of attendees OTC attracted (94,700 in 2015, down 28%)
- **120** – The number of countries OTC attendees represented (130 in 2015)
- **2600** – The number of companies that exhibited
- **672,300sq ft** – The amount of sold-out exhibit space in OTC history
- **325** – The number of technical papers presented
- **11** – The number of panel sessions
- **24** – The number of executive keynote speakers
- **13** – The number of technologies recognized for innovation

Solutions



Baker Hughes releases adaptive drillbit

Baker Hughes launched its TerrAdapt adaptive drillbit, which uses self-adjusting depth-of-cut (DOC) control elements to automatically change its aggressiveness based on the formation it is drilling through to mitigate vibrations, stick-slip and impact loading.

A fixed-DOC bit will drill smoothly in some areas, but will perform erratically and inefficiently in others because of vibrations that occur when the bit transitions between different rock types, causing stick-slip, Baker Hughes said. During stick-slip events, the bit's bite becomes too aggressive, causing it to "stick" and stop rotating, while the drillpipe behind it continues to wind up like a spring until the bit releases, or "slips," and begins spinning uncontrollably. These stick-slip events dramatically increase drilling costs by reducing rate of penetration (ROP), and can seriously damage the bit and other expensive mechanical and electrical bottom hole assembly (BHA) components. When this happens, operators have to make extra trips to replace the bit/BHA, or continue to drill with diminished performance.

The TerrAdapt bit incorporates self-adjusting DOC elements that autonomously extend to create an optimal DOC based on the formation, preventing vibrations and stick-slip when the bit transitions between rock types or sections. When the risk of stick-slip has passed, the elements retract, enabling drilling to resume at a maximum ROP. The elements also absorb any sudden shock to the bit face, reducing damage to the TerrAdapt bit's cutters and other BHA hardware and electronics. www.bakerhughes.com

Proserv offers new sampling cylinder

Proserv has developed a new subsea sampling cylinder that can improve the quality of results and reduce risks associated with sample transfer.

Proserv's Subsea Sampling Cylinder (SSC) can be deployed in a subsea environment and capture well properties throughout the lifetime of a field.

Subsea cylinders allow operators to take representative production samples from a subsea system for direct transfer to a laboratory. Proserv's SSC removes the risks associated with handling and transferring samples on the surface, reducing the risk of containment loss and exposure to H_2S/CO_2 which can present a danger to people and the environment.

The Proserv SSC is suitable for severe service applications and has a large 2L sample volume. Cylinders can be used with existing systems or integrated with bespoke subsea sampling systems.

www.proserv.com

Vortex builds ANCHOR BOSS pump

New Zealand's Vortex International offers a new suction anchor pump called

the ANCHOR BOSS, capable of pumping 240cu m/hr of water flow or 15 bar pressure. It also offers data collection with bottom side and topside feedback on pump flow in both directions and pump pressure in both directions during install and removal.

Asset safety has been enhanced with pressure relief valves on both the pressure and suction sides of pumping operation. Real-time data collection in both flow directions, safety features and configurable pumps.

www.vortexdredge.com

InterOcean offers oil spill monitoring service

InterOcean Systems has launched a new offshore oil spill monitoring service called the Slick Sleuth Rig Guard system. The Slick Sleuth Rig Guard

system detects oil on water using optical non-contact sensor technology, which provides users critical early warning for immediate spill response and containment, reducing the risk of fines and cleanup costs. **www.slicksleuth.com**

Trelleborg debuts new elastomer

Trelleborg Sealing Solutions has debuted Isolast J9567, a technically advanced multipurpose perfluoroelastomer compound engineered for acid, water, and steam resistance.

Isolast J9567 provides chemical resistance in a broad range of chemical media at continuous operating temperatures from -10°C to +225°C/+14°F to +437°F. Performance is further enhanced by compression set characteristics, ensuring high elasticity, minimizing the risk of seal failure. It can be used in rotating equipment such as pumps and centrifuges as well as flow regulation/valves. The compound is available in all standard international O-Ring sizes along with custom-engineered solutions and FlexiMold large diameter joint free seals.

www.trelleborg.com

2017 Offshore Achievement Winners named

The Society of Petroleum Engineers (SPE) Aberdeen Section honored 12 companies and individuals at the 2017 Offshore Achievement Awards, held in late March. Oonagh Werngren was presented with the accolade for Significant Contribution.

Werngren was recognized for her work, including her former role as operations director at Oil & Gas UK where she was responsible for establishing several pan-industry projects to increase exploration and production in the UK Continental Shelf. Werngren previously served as president of the Petroleum Exploration Society of Great Britain, one of only two women to hold the position in over 50 years, and has held non-executive director roles for OGIC (the Oil and Gas Innovation Centre) and ITF (the Industry Technology Facilitator), as well as The Girls' Network.

Other winners included JDR Cable Systems, (Export Achievement and Great Large Company), and Enpro Subsea (Great Small Company).

Individually, Marianne McKevitt, of BP, received the Young Professional award, while Sam Lisney, of Petrofac EPS West, was named winner of the Above & Beyond category.

"Once again, the Offshore Achievement Awards has been a great showcase for the strength, creativity and ambition we see in the oil and gas and renewable industries," said Donald Taylor, acting managing director, TAQA Europe. "It is encouraging to see so many companies and individuals taking the time to share their success stories. The winners demonstrate a diverse range of significant achievements, showing just how much the industry is still driving forward, finding innovative solutions and efficiencies."

OE is a media sponsor for the Offshore Achievement Awards.

The 2017 Offshore Achievement Award winners:

Emerging Technology Awards - Sponsored by Nexen – M-FLOW Technologies

Innovator Award - Sponsored by Oil & Gas Innovation Centre – Delphian Ballistics

Safety Innovations Award - Sponsored by Offshore Europe Partnership – Cape plc

Environmental Innovation Award – Exnics

Export Achievement Award – JDR Cable Systems Ltd.

Collaboration Award - Sponsored by Marks & Clerk – Maersk Oil/Amec Foster Wheeler/Bilfinger Salamis

Outstanding Skills Development Program Award - Sponsored by Heriot-Watt University – TAQA

Oonagh Werngren

Young Professional Award - Sponsored by BP – Marianne McKevitt, BP

Above & Beyond Award – Sam Lisney, Petrofac EPS, West

Great Small Company Award - Sponsored by Wood Group – Enpro Subsea

Great Large Company Award – JDR Cable Systems Ltd.

Significant Contribution Award - Sponsored by Aker Solutions – Oonagh Werngren

Wood Group to acquire Amec Foster Wheeler

Wood Group has made a US$2.72 billion (£2.22 billion) offer for rival Amec Foster Wheeler. The takeover bid comes just three years after Amec's 2014, $3.2 billion acquisition of Foster Wheeler. The deal has been agreed to by both companies' boards and is expected to complete in 2H 2017.

Analysts Rystad Energy said that the merger will, "create a clear market leader within the engineering and maintenance, modifications and operations market, with a market share twice as large as its competitors. With a combined workforce of 64,000, it will rank as one of the top 15 oilfield service companies in the world."

Robin Watson and David Kemp, Wood Group's CEO and CFO, respectively, will continue as CEO and CFO of the newly combined company.

Subsea 7 in Seaway Heavy Lifting takeover

Subsea 7 has fully acquired Seaway Heavy Lifting following the purchase of 50% stake from K&S Baltic Offshore, in a move that will increase its position in the renewables, heavy lifting and decommissioning markets.

Subsea 7 signed and completed the US$279 million deal in early March, making the offshore contractor, which operates two world-class heavy lift vessels, and its subsidiaries wholly-owned by Subsea 7. An additional consideration of up to $40 million will be paid in 2021 on the condition that certain performance targets are met, the company said.

Prior to the takeover, Seaway Heavy Lifting was a joint venture company in which Subsea 7 held a 50% interest. Subsea 7 said that consolidating Seaway into the group strengthens the company's position in renewables, heavy lifting and decommissioning services. "These are areas where we expect activity to increase and see potential to grow our market share," says Jean Cahuzac, CEO, Subsea 7.

Boskalis sells all Fugro shares

Dutch maritime services firm Boskalis has sold all of its remaining stake in fellow Dutch engineering and geoscience services firm Fugro. Boskalis went from owning 28.6% stake in Fugro at the end of 2015, to 9.38% in December. Fugro has been fighting to remain independent since Boskalis began buying stock in the company in 2014. In December, Boskalis CEO Peter Berdowski said of the decision to wind down its stake: "[This is] based on the uncertain market conditions, which continue to prevail much longer than anticipated, and on the other hand, also the position of the Fugro management."

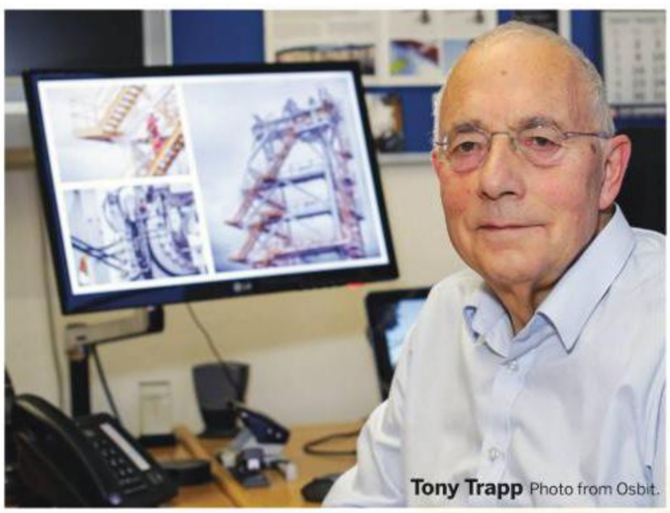
Spotlight

An engineer's engineer

Steve Hamlen catches up with Tony Trapp, executive chairman of Osbit, and subsea industry pioneer who recently won the MBE (Most Excellent Order of the British Empire).

Tony Trapp is a firm believer in the potential of engineers working as a collective. He built his reputation and a string of businesses on that very philosophy – one which has led to him being awarded the Member of the Most Excellent Order of the British Empire (MBE) in the 2017 New Year's Honours.

His latest engineering company's name, Osbit, based in northeast England, is derived from the ethos of 'On Spec, Budget and In Time.' "We are tiny but we can do almost anything that involves engineering," Trapp says.



Tony Trapp Photo from Osbit.

Earthy beginnings

With a true engineer's conviction that his profession can solve any problem, it seems fitting that engineering skills and equipment from one of the world's oldest industries sparked the development of the UK's world-renowned high-tech subsea sector.

"When we started Soil Machine Dynamics (SMD), we were agricultural engineers and we took ploughs and tractors underwater. The idea was that agricultural engineers can do everything as they are people who are trained in mechanical, electrical and civil engineering," Trapp says.

However, all projects require financial foundations and engineering is no different. "We like to design and build things. You can only design and build things if there is money, so you have to look at where the money is flowing," he says. "SMD started when I was doing a PhD. My supervisor was Alan Reece and we were dealing with vibratory cutting. JCB (a construction equipment manufacturer) got interested and [Reece] set the company up with the idea of exploring what we were working on."

Trapp and SMD's Magnus cable plough team.
Photos from Tony Trapp.

North Sea oil

Reece enticed Trapp and Tim Grinsted, all PhDs from Newcastle University, to start SMD. It turned out to be timely; soon after, North Sea oil was discovered and fiber-optics technology was invented.

"Both industries wanted to do a lot of stuff on the seabed and there weren't any experts on underwater earth moving. Very little was known about it. In agricultural engineering, everyone knew everything about earth moving – it had been going on for thousands of years. So, we were well placed. We had soil tanks and we did experiments at Newcastle University's agricultural engineering department," Trapp says.

The engineers converted a JCB mahine into an offshore testing unit. It could be driven along the beach or used in water depths up to 1.5m. The UK government also gave the engineers an £80,000 per year grant, which led to a fruitful meeting when the government sent a grant supervisor who, "just also happened to be head of pipelines for BP."

BP was developing the Magnus field and wanted to bury their pipelines. The field had seven satellite wells and BP wanted a pipe plough semi-mounted onto a tracked seabed vehicle.

"So, we developed our first pipeline plough. Then, they wanted to bury cables so we developed our first cable plough, as well as our first backfill plough – all for BP. We had a very nice arrangement where you could, if you were clever, come up with ideas and patent them, because nobody had worked in this field. So, working for BP, we came to an agreement where BP Ventures owned the patents and we had half of the royalties, which wasn't so well known. So, if anyone wanted to infringe those patents they could discuss that with BP, but we got the royalties."

This research led to interest from Brown & Root – resulting in SMD making its first vessel hauled offshore pipeline plough (PL1).

In 1997, after 19 years, Trapp left SMD and set up The Engineering Business (EB). In 2010, Trapp founded Osbit, which is also owned and run by engineers. Osbit is also a big believer in new talent and has three students from The University of Edinburgh on six-month placements, with potential to be offered to join Osbit as graduates.

"If you put people in the right environment, then they do fantastic things. While customers are the core of our activity, we are actually a powerful training organization; over my 35 to 40 years we have taken on hundreds of graduates," Trapp says.

Trapp in the lab. Photo from Tony Trapp.

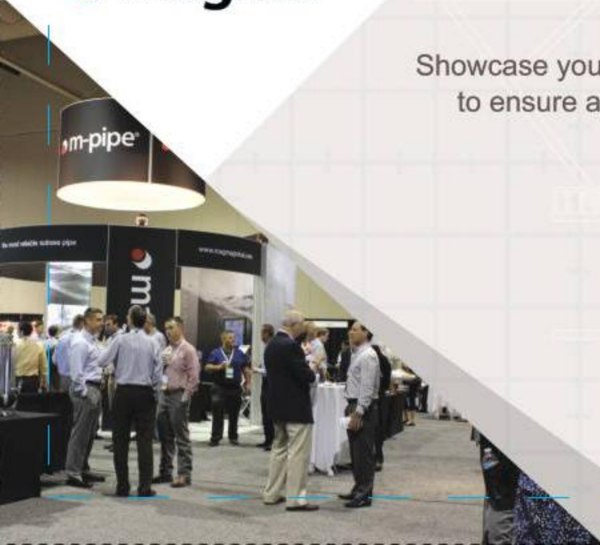
Growth plans

Trapp has gained much business experience, but has always liked to keep his mind open to flexibility.

"I never had a business plan. I do not know how you have a business plan, actually. If you set up a two-year plan, within no time, it will look very different. But, I did have a growth plan. I was 52 when we started EB and we had a 10-year plan. We wanted to build a team of sensible engineers and do interesting stuff that might change the world, have some fun and realize some money," he added.

Osbit has now finished its sixth year, with a solid performance. Indeed, despite the industry downturn, Osbit grew turnover by 33%, to nearly £10 million in the 2015/2016 financial year, thanks to a 51% boost in export activity and 10% rise on UK sales. **OE**

Editorial Index



m-pipe

What's next

Coming up in OE May

Editorial Focus

- **Feature – Global Deepwater Review**
- **EPIC** – Abandonment & Decommissioning
- **Subsea** – Subsea Processing, plus: Risers and Umbilicals
- **Production** – EOR/IOR
- **Drilling** – HPHT
- **Special Report:** Automation (Big Data, Security, Remote Operations)
- **Regional Overview** – Gulf of Mexico

Bonus Distribution

Offshore Technology Conference
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BP's Thunder Horse development in the Gulf of Mexico. Photo from BP.

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