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Global Deepwater Review 22

Offshore Engineer • May 2017


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The Thunder Horse platform. Photo from BP

FEATURE FOCUS

Global Deepwater Review

Features

EPIC

SUBSEA

ON THE COVER

Under the sea. This month's issue, which provides in-depth sector reports to provide a complete Global Deepwater Review, features on the cover the ROV control room aboard the Thunder Horse platform, the South Expansion project is profiled on page 88. *Cover image courtesy of BP.*

Features (continued)

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What's Trending

Work picks up

- BP picks SLB, Subsea 7 for Mad Dog 2
- Statoil to develop wind farm off New York
- TechnipFMC picked for Shell's Kaikias

Activity

NEL invests in subsea center of excellence

A new US$19.9 million (£16 million) Center of Excellence for subsea development will be established in East Kilbride, Scotland and will be led by TÜV SÜD Ltd. (NEL), a provider of research and development, consultancy and testing to the international oil and gas industry.

People

Stone Energy's Welch to chair NOIA

The National Ocean Industries Association (NOIA) board of directors has elected David H. Welch as chairman for the upcoming 2017-2018 term. Welch, Stone Energy president and CEO, becomes the first producer to serve as chairman at NOIA.

Undercurrents

Mexico's undeniable potential

Mexico, when it launched its energy reform efforts, was a victim of bad luck – opening its sector for the first time in over seven decades just as one of the worst – if not the worst – downturns hit the global oil and gas sector like a punch to the gut.

But, Mexico has been able to weather the storm, and keep interest in the country's underexplored shallow and frontier deep water areas simmering in time for the industry to start investing again.

At IHS CERAWeek in Houston, in early March, Juan Carlos Zepeda, president commissioner of Mexican regulator CNH (National Hydrocarbons Commission) rattled off impressive statistics: **71%** of the 55 areas up for lease in the country's Round 1 (four separate rounds) bid round were awarded, yielding **39** contracts that made commitments for **22** exploration wells, and **49** new oil companies have been created (both small- and mid-sized) due to the energy reform. **US$6 billion** in capex is expected to be invested over the next five years. **$810 million** (as of March) in revenue has been made through sales of seismic data from the geological and geophysical companies. And, this is just the beginning. Round 2 bidding is scheduled to kick off next month [June].

"The most reliable indicator... is how much the oil industry is spending to acquiring and reprocessing data," says CNH's Juan Carlos Zepeda.

"The most reliable leading indicator of what is going on... is how much the oil industry is spending acquiring and reprocessing data. That's hard data; hard money that is highly correlated to their commitment," Zepeda said. He added that the information industry in Mexico is a booming one, and called attention to the more than 100 years of oil information that CNH made available through the National Data Repository.

Norwegian oil major Statoil, along with its consortium partners BP and Total, picked up two blocks in Mexico's Saline Basin during the country's deepwater round in December. *OE* spoke with Helge Hove Haldorsen, Director General of Statoil Mexico, based in Mexico City, to get the company's thoughts on Mexico's growing energy sector, and parallels between Statoil's journey as a national oil company and Pemex's own road to come.

Haldorsen called this period, post-energy reform, "Mexico's big opportunity." Of Mexico's prospects, Haldorsen said: "Mexico has a significant yet-to-find potential offshore, particularly in the more frontier deepwater areas. Most of the Mexican deepwater is either underexplored or not explored at all, which of course from an exploration perspective is very exciting." See the full interview on page 92.

There will be more to come offshore Mexico and *OE* will keep you up-to-date as it happens.

OE also hosted its 23rd annual Petroleum Exhibition & Conference of Mexico (PECOM) in Villahermosa, this March. The event attracted 125 exhibitors, visitors from over 40 countries, and had some 6000 attendees. Come and be a part of this emerging petroleum province and join us at next year's PECOM, from 13-15 March 2018.

Global Deepwater Review

As always, *OE*'s May issue strives to take the pulse of the global deepwater industry.

This year, that thread expands throughout the issue, including our robust subsea section, which highlights advances in subsea separation technologies as well as subsea riser development and monitoring. OE

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Global E&P Briefs

Ⓐ Jeanne d'Arc bidding opens

The Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) issued a call for bids in the Jeanne d'Arc region offshore Newfoundland and Labrador.

Call for Bids NL17-CFB01 (Jeanne d'Arc Region) consist of three parcels and a total of 317,407 hectares. Interested parties will have until November 2017 to submit sealed bids. The minimum bid for the parcels offered is US$7.5 million (CAD $10 million) in work commitments.

Ⓑ US lease sale 247 a success

US lease sale 247, held in late March, had 28 companies vying for 163 tracts in the Central Planning Area of the Outer Continental Shelf, bringing in nearly US$275 million in high bids.

The US Bureau of Ocean Energy Management (BOEM) offered 9118 unleased blocks, 3-230mi offshore Louisiana, Mississippi, and Alabama, in water depths ranging from 9-11,115ft.

Shell made the highest bid for a block, $24 million for Atwater Valley 64. Total won Garden Banks 1006, which received the most bids, for $12.6 million.

Other high bidders included: Statoil for Walker Ridge 55 at $21 million; Hess for Green Canyon 287 at $18 million; Chevron for Green Canyon 642 at $11 million.

Ⓒ Exxon hits Snoek pay

ExxonMobil made a third discovery offshore Guyana at the Snoek well in the southern portion of the Stabroek Block, close to the huge Liza find.

Exxon found more than 82ft (25m) of high-quality, oil-bearing sandstone reservoirs. The well was drilled by the *Stena Carron* drillship to 16,978ft at 5128ft water depth in mid-March.

Drilling at Snoek targeted similar aged reservoirs as encountered in previous discoveries at Liza and Payara.

Ⓔ Dominican Republic asks for seismic

Dominican Republic's Ministry of Energy and Mines (MEM) issued a call for a high-resolution 2D offshore seismic campaign to determine the hydrocarbon potential of the country's sedimentary basins. The survey covers the San Pedro de Macorís, Ocoa Bay, and the exclusive economic zone and the country's territorial waters in general.

Ⓓ Amoca-2 pays off for Eni

Italy's Eni found oil in multiple reservoirs at the Amoca-2 well, offshore Mexico. The well reached a total depth of approximately 3500m, encountering approximately 110m of net oil pay from several good-quality Pliocene reservoir sandstones, of which 65m were discovered in a deeper, previously undrilled horizon, Eni says. The well confirmed the presence of 18° API oil in the shallower formations, while the newly discovered deeper sandstones contain high quality light oil.

Amoca-2 is the first in a four-well campaign at Amoca, which sits in the shallow waters of the Bay of Campeche, in Area 1, 200km west of Ciudad del Carmen, at 25m water depth. Eni says it will continue its Area 1 drilling campaign with the Amoca-3 well, followed by the Miztón-2 and Tecoalli-2 delineation wells, which will be drilled in 2017 to appraise existing discoveries as well as targeting new undrilled pools. ▪

Ⓕ Eni surveys Porcupine

Eni and its partner Providence Resources agreed to underwrite and license 1800sq km of new multi-client 3D seismic data over FEL 3/04, in the southern Porcupine Basin, off Ireland.

The main objective is to understand the hydrocarbon potential of the undrilled Lower Cretaceous Dunquin South carbonate exploration prospect. Other objectives include obtaining new data related to exploration well 44/23-1 in the adjacent Dunquin North carbonate prospect and assessing the nature and hydrocarbon potential of the approximate 700sq km Dunquin Ridge, which underlies both Dunquin carbonate build-ups, which was not penetrated by the previous well.

FEL 3/04 is situated in about 1500m water depth and is some 200km off the southwest coast of Ireland. CGG will conduct and mobilize the *Oceanic Caspian* for the data acquisition program.

Ⓖ Maersk marks first oil from Flyndre

Maersk Oil's Flyndre oil field, which straddles the UK and Norwegian North Sea boundaries, achieved first production in late March.

The Flyndre field is 293km

southeast of Aberdeen in blocks 30/13 and 30/14 and 325km west-southwest of Stavanger in Norwegian block 1/5 (PL018C). Production is expected to peak around 10,000 b/d, with the field expected to produce until at least 2023.

The field is a 25km single well subsea tieback to the Repsol Sinopec-operated Clyde platform, from which oil is then exported via the Fulmar platform, also operated by Repsol, then on to Teesside via the Norpipe system.

H Dvalin PDO gets greenlight

Norway's Ministry of Petroleum and Energy approved German operator DEA's development plan for the US$1.2 billion (NOK 10 billion) Dvalin field in the Norwegian Sea, with production set for 2020.

Dvalin will be developed with a four-well subsea template, tied back to the Heidrun platform. At Heidrun, the gas will be partly processed in a new module, before the gas is transported via the new Polarled pipeline, going to the Nyhamna onshore gas terminal.

Dvalin is in PL435, Blocks 6507/7/9 and 6507/8 in the Norwegian Sea, about 15km northwest of Heidrun and 290km from Nyhamna in Mid-Norway.

Recoverable resources are estimated to be some 18.2 Bcm of natural gas from two reservoirs.

J Rosnet drills Khatangsky well

Rosneft started drilling the Tsentralno-Olginskaya-1 well, the northern-most well at the Russian Arctic shelf, in the Khatangsky license area.

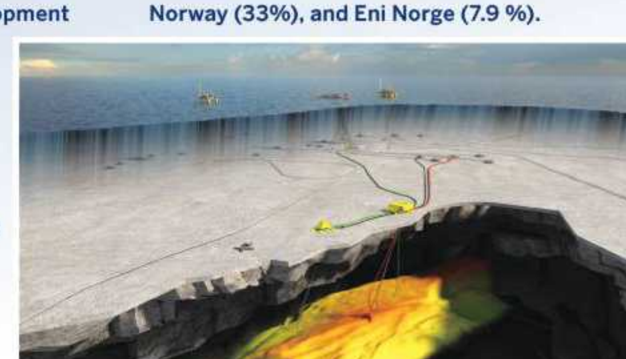
Tsentralno-Olginskaya-1 is the first well that will be drilled under the offshore area of the Laptev Sea. Khatangsky is in the Khatanga bay, in the North of the Krasnoyarsk region. The area spans 18,709sq km at 32m water depth.

"We carried out unprecedented geological exploration work within a very short period. We completed 21km of seismic studies that revealed the existence of 114 promising oil and gas-bearing structures. Preliminary estimates suggest that the Laptev Sea's total potential geological resources could come to 9.5 billion tonnes of oil equivalent," says Rosneft CEO Igor Sechin.

I Trestakk approved

Norwegian authorities approved Statoil's development plan for the Trestakk discovery in the Norwegian Sea. The development is now expected to cost US$641 million (NOK 5.5 billion), marking a near-50% decrease from original estmates. Trestakk, discovered in 1986, is on the Halten Bank about 20km south of the Åsgard field at 300m water depth. Its reservoir is at a depth of around 3900m.

Expected recoverable volumes at Trestakk are 76 MMboe, mainly oil. Tied into the Åsgard A production vessel, Trestakk is expected to come online in 2019. Statoil operates Trestakk with 59.1% stake. Partners are ExxonMobil E&P Norway (33%), and Eni Norge (7.9 %).



Global E&P Briefs

K Kosmos drills Yakaar

Kosmos Energy started the second phase of its multi-well exploration drilling program offshore Mauritania and Senegal.

The *Atwood Achiever* drillship is on location offshore Senegal in the Cayar Offshore Profond block and started drilling operations on the first exploration well in the program targeting the Yakaar prospect (formerly referred to as Teranga West).

The Yakaar prospect is approximately 40km west of the Teranga discovery.

L Eni finds Libyan gas

Italian giant Eni has discovered gas and condensate at the Gamma prospect, offshore Libya.

Gamma is in Contract Area D, 140km offshore from Tripoli. The discovery was made through well B1 16/3, which is 15km southwest of the Bouri field and 5km north of the Bahr Essalam field.

The well, drilled in 150m water depth, reached a total depth of 2981m (9780ft) and encountered gas and condensates in the Metlaoui Group of Eocene age.

Eni says that the well has the capacity to deliver over 7000 boe/d. Eni, through its subsidiary Eni North Africa BV, is operator of Contract Area D with a 100% working interest in the exploration phase.

N Masirah spuds Karamah off Oman

Masirah Oil spudded the Karamah-1 exploration well, with the Aban VII jackup in 23m water depth, in Block 50, offshore Oman, in late March.

The Karamah prospect has a target depth of about 3000m.

The well objective is to explore multiple target horizons of the Early Tertiary and Late Cretaceous formations.

O Qatar lifts North field moratorium

Qatar Petroleum has lifted a 12-year long self-imposed freeze on the North field, saying it plans to develop a new gas project in the southern sector of the field, commencing over the next few months.

Located in the Persian Gulf, the offshore North field is considered to be the largest single non-associated gas reservoir in the world, shared by Qatar and Iran. The moratorium was declared in order to study the reservoir's structure.

The field was discovered in 1971 and holds total recoverable gas of more than 900 Tscf, covering an area of about 9700sq km.

M Third time is the charm for BP

BP encountered a third gas find at the North Damietta Offshore Concession in the East Nile Delta, Egypt.

According to BP, 37m of net gas pay was found at the Qattameya Shallow-1 exploration well in high-quality Pliocene sandstones. Qattameya was drilled to 1961m total depth in 108m of water, 60km north of Damietta city, 30km southwest of Salamat and 35km to the west of Ha'py offshore facilities. BP said that it will study its options, which include a tieback to nearby infrastructure. BP has 100% equity in the discovery.

P Nido drills Galoc

Nido Petroleum started drilling at the Galoc-7 appraisal well, off The Philippines, using the *Deepsea Metro I* ultra-deepwater drillship.

The Galoc field is 70km west of Culion Island in the northwest Palawan basin, in Block C1 of Service Contract 14 at 320m water depth.

The reservoir depth is 2100–2200m with a 57m gross oil column consisting of early Miocene turbidite sandstone with 16% average reservoir porosity. It is produced using the *Rubicon Intrepid* floating production unit.

Q Husky to drill off China

Canada's Husky Energy has signed a production sharing contract for Block 16/25 in the Pearl River Mouth Basin, 150km southeast of Hong Kong.

Husky expects to drill two exploration wells on the shallow water block during 2018, in conjunction with two planned exploration wells at the nearby exploration Block 15/33.

Husky operates both blocks during the exploration phase, with a working interest of 100%.

R Phoenix South resource grows

Carnarvon Petroleum has increased its resource estimates by 32% at Quadrant Energy's Phoenix South discovery offshore Western Australia.

Upon further technical work done on the Phoenix South-2 discovery, Carnarvon has determined to increase the Phoenix South Caley resource estimates from the previously estimated 108 MMboe to 143 MMboe, due to the pressures encountered and the nature of the gas observed.

"The gross mean estimate is currently 489 Bcf recoverable gas and 57 MMbbl of associated condensate (being 143 MMboe, gross, Pmean) in a conventional anticline trapping structure," Carnarvon said.

The company says that further drilling is required to properly determine whether this case exists.

S NZ offers eight blocks

New Zealand has opened eight release areas, both on- and offshore, totaling more than 481,730sq km of exploration acreage.

The New Zealand Petroleum and Minerals Minister Judith Collins revealed five offshore, two onshore and one permit that stradles both on- and offshore acreage in the tender.

The offshore acreage, comprised of more than 475,000sq km, is in the Taranaki, Northland-Reinga, Pegasus - East Coast, Hawke Bay and Great South – Canterbury areas. The Taranki North release area holds acreage both on-and offshore.

Companies have until September 2017 to make bids. The ministry expects to grant permits in December 2017.

Contracts

Engie awards Gjøa contracts

Engie E&P Norge has contracted three front-end engineering and design (FEED) studies for modifications at the Gjøa platform in the North Sea.

Kongsberg Maritime has been awarded a contract for FEED studies in connection with the modification and upgrading of control and safety systems on Gjøa for the tie-in of Skarfjell. The work has started and will be completed in August 2017.

Saipem and Hereema Marine Contractors has been awarded contracts for the FEED studies related to offshore heavy lifting work. The scope covers two separate and parallel studies that will clarify the different options for safe and efficient lifting and installation of the Skarfjell-module on Gjøa. The work has started and will be completed in August 2017.

TechnipFMC gets Kaikias work

Shell chose TechnipFMC to provide the subsea production system on its Kaikias deepwater project in the US Gulf of Mexico.

TechnipFMC will manufacture, install and integrate the proprietary subsea production system and subsea umbilicals, risers and flowlines equipment designed to improve project economics by optimizing field production and minimizing lead times. This includes the first application of TechnipFMC's compact pipeline end manifold and horizontal connection system technologies with flexible jumpers in the deepwater Gulf of Mexico.

Kaikias, in the prolific Mars-Ursa basin, about 210km (130mi) from the Louisiana, will be developed through a subsea tieback to the nearby Shell-operated Ursa production hub.

SLB, Subsea 7 rack up Mad Dog 2 work

Schlumberger and Subsea 7, under the Subsea Production Systems (SPS) alliance with OneSubsea, have won a subsea production systems contract for BP's Mad Dog 2 deepwater development in the US Gulf of Mexico.

Subsea 7 also picked up a lump sum engineering, procurement, construction and installation scope for the subsea umbilicals, risers and flowlines and associated subsea architecture.

Subsea 7 estimates the value of the contract for Mad Dog between US$300-500 million.

The scope for the alliance includes subsea manifolds, trees, control system, single and multiphase meters, water analysis sensors, intervention tooling and test equipment for producer and water injection wells associated with the project.

Offshore installation activities are scheduled for 2019 and 2020. Subsea 7's contract includes the first substantial project in the US to use its Swagelining polymer lining technology.

HMC, AFG in Ekofisk decom

ConocoPhillips will choose Heerema Marine Contractors (HMC) and AF Gruppen (AFG) to remove and dispose of platforms connected to the Ekofisk field in the Norwegian North Sea.

The contract includes engineering, preparation, removal and disposal of four platforms, totaling about 36,000-tonne. The platforms are to be removed and disposed from 2017-2022.

Ekofisk, the first and one of the largest North Sea fields discovered, still provides significant Norwegian production.

Trendsetter scores Leviathan gig

Trendsetter Engineering has been awarded multiple contracts to design and manufacture subsea production equipment for Noble Energy's Leviathan Project, a large natural gas field development in the Eastern Mediterranean Sea off the coast of Israel.

Trendsetter's scopes of work include multiple clamp connection systems, subsea distribution equipment, MEG filter modules, 2in connection systems and subsea manifolds.

Equipment deliveries begin in late 2017 through late 2018.

Sparrow win Ichthys deal

Sparrows Group has won a three-year deal to deliver fixed crane maintenance and lifting and rigging services for the Inpex-operated Ichthys liquefied natural gas project in Australia.

The agreement includes maintenance, servicing and inspection of lifting equipment and cranes, the supply of lifting equipment, spare parts and materials; and technical and engineering support.

The journey from Tupi to Lula

Jerry Lee profiles the development of Brazil's giant Lula field, offshore Rio de Janeiro.

Lula, Brazil's first supergiant oil field, was described as "the second independence of Brazil" by the former Brazilian president Luiz Inácio Lula da Silva. Estimated to contain a total recoverable volume of 8.3 billion boe, the pre-salt carbonate reservoir is 250km off the southeast coast of Rio de Janeiro, beneath 2126m (6975ft) of water and 2791m (9156ft) of soil, rock and salt. Developing the field required many challenges to be overcome, some of which were included in a presentation covering the Lula Nordeste (NE) pilot project at the 2016 Offshore Technology Conference (OTC) in Houston.*

Originally known as Tupi, Petrobras made the ultra-deepwater discovery in 2006 from the 1-RJS-628 wildcat well drilled in block BS-M-11 in the Santos Basin, where they found 28°API oil that was both light (high gas to oil ratio) and sweet (low sulfur content). In 2010, Tupi was renamed Lula, after the former Brazilian president, and declared commercial in December that year.

Comprised of the Tupi and Iracema (a sub-structure of Tupi discovered in 2009) areas, Lula is part of the Santos Basin Pre-Salt Cluster (SBPSC), which currently produces 1 MMb/d, according to Petrobras.

The BS-M-11 consortium is developing Lula. Petrobras is the operator and has 65% interest; BG E&P Brasil, a Shell subsidiary, has 25% interest; Petrogal Brasil has the remaining 10% interest.

Development

Eager to tap into the Santos Basin's vast reserves, the consortium decided to fast-track Lula's development. However, when Lula was discovered, it was only the second discovery on the SBPSC. This meant that the consortium had to not only cope with the challenges of developing an ultra-deepwater field, but there would be no infrastructure in place and little information to aid them. The project's capital expenditure would be immense, so uncertainty and risks would need to be at a minimum.

According to the OTC presentation, Lula would be developed in phases, a strategy familiar to Petrobras, which would allow the learnings to be applied on future projects, progressively reducing risk. In the first phase, static and dynamic reservoir data would be collected through appraisal and reservoir data acquisition wells, drill stem tests (DSTs), extended well tests (EWTs) and pilots systems. Using this data, phase two would initially see definitive production systems put in place and later followed by new technologies to enhance production.

At Lula NE, one of the two Lula pilot projects, acquiring data and gaining production experience in the pre-salt area through different methods of secondary recovery were among the primary objectives. Secondary objectives included testing new equipment and technologies as well as an alternative subsea gathering system using uncoupled buoy supported risers.

Lula NE Pilot

The Lula NE pilot is in the northeast area of the field and was the second pilot installed on Lula. Exploratory drilling of the first well, 3-RJS-662A, was completed in 2009. A DST showed a high productivity index and no flow barriers. The well was followed up by a reservoir data acquisition well, 8-LL-1D-RJS, 4.2km away, which showed high injectivity and transmissibility between the two wells.

More information was still needed, and as part of the development plan, BW Offshore's floating production, storage and offloading (FPSO) unit *Cidade de São Vicente* was brought to 3-RJS-662A to perform an EWT. The EWT was conducted from April-November 2011 and produced approximately 2.8 MMbbl.

Later in the development project, 3-RJS-662A would be used as a gas injection well, and 3-RJS-662A would be used as a water-alternating-gas (WAG) injection well.

The FPSO *Cidade de São Vicente* was brought in to perform extended well tests on a Lula NE well in 2011. Photo from BW Offshore.

A large number of fluid samples were also taken from the field and studied to improve field modeling and simulations. And to reduce simulation time, for fast-tracking the field development, a large computer cluster was acquired. Although this was a costly investment, it provided great value to the project, helping to modify the development plans so that low and high GOR/CO_2 wells were better assembled preventing gas processing restrictions and more complex FPSOs.

On Lula NE, investment in information gathering was higher than average and was necessary in order to develop a robust development project. In addition to the fluid samples, these included, but aren't limited to, complete logging sets, cores, lateral rock samples, and daily pressure and temperature measurements. From this data, the consortium approved of the Lula NE plan, which consists of eight producers, five WAG injectors and a gas/ CO_2 injection well. Some producers would have intelligent completions, to help maximize plateau production, and two subsea WAG manifolds would be used to connect four of the five WAG injectors to the FPSO.

Early on in the project, the lack of proven subsea technology that could handle the project's demands was recognized. As a result, a buoy supported riser concept was developed as an alternative pre-salt subsea system. The concept would require two buoys, eight buoy foundations, 16 tethers, 15 steel catenary risers (one acting as a spare), for the production and injection lines, that would end at pipeline ends terminations, and riser anchoring piles. With this system in place, the wells would be connected to the buoys through the steel catenary risers, and the FPSO would be connected to the buoys using flexible jumpers.

The Lula NE FPSO, meeting the needs of a host of technical challenges, has been designed with the capacity to process 120,000 bo/d, 120,000 b/d of produced water, and 5 MMscm/d of gas. CO_2 would be removed for reinjection, and gas would be separated for fuel gas, reinjection, lift gas, or export via a gas pipeline.

The FPSO *Cidade de Paraty*, has been on production at Lula NE since June 2013 and has reached its plateau production in September 2014. The wells have shown good productivity and injectivity; the highest production from a single producer exceeded 35,000 b/d, while the highest injection rate exceeded 50,000 b/d at a single injector.

The Lula projects following Lula NE have since benefited from the static and dynamic information gathered there.

The FPSO *Cidade de Paraty* sails away from Brasfels Shipyard. Photo from SBM Offshore.

Elsewhere on Lula

Prior to the Lula NE pilot project, the Lula project came online in October 2010 via the FPSO *Cidade de Angra dos Reis*, which has the capacity to process 100,000 bo/d, 150 MMscf/d of gas, and inject 100,000 b/d of water. The Lula pilot area is being produced through five production wells, and five injections wells: one gas injector, two water injectors, and two WAG injectors.

In October 2014, production began from the Lula/Iracema Sul Area via the FPSO *Cidade de Mangaratiba*, which can process 150,000 bo/d and 280 MMscf/d of gas. The FPSO is connected to eight production wells and eight water injection wells.

Almost one year later, in July 2015, production from the Lula/Iracema Norte Area began five months ahead of schedule through the FPSO *Cidade de Itaguaí*, which can also process 150,000 bo/d, 280 MMscf/d of gas, and inject 264,000 b/d of water. The Lula/Iracema Norte Area produces to the FPSO through eight production wells, with the help of nine injection wells, and will export natural gas through a subsea gas pipeline.

Progress with the field development continued in 2016 with two more FPSOs coming online: *Cidade de Maricá* in February on Lula Alto, and *Cidade de Saquarema* in July on Lula Central. Both FPSOs are capable of processing 150,000 bo/d and 6 MMcm/d of gas. Plans for the development of Lula Alto includes 10 producing wells and seven injection wells, while Lula Central development plans include 18 wells split between producer and injector wells.

This year, Petrobras has plans to start production on Lula Sul and Lula Norte via the FPSOs *P-66* and *P-67*, respectively. Then in 2018, Lula Ext. Sol will be brought online with FPSO *P-68*. **OE**

**This article is adapted from De Moraes Cruz, R. O., Rosa, M. B., Branco, C. C. M., de Sant'Anna Pizarro, J. O., & de Souza Silva, C. T. (2016, May 2). Lula NE Pilot Project - An Ultra-Deep Success in the Brazilian Pre-Salt. Offshore Technology Conference. doi:10.4043/27297-MS*

SBM Offshore's twin FPSOs pass in Guanabara Bay as *Cidade de Maricá* departs from and *Cidade de Saquarema* arrives at Brasa shipyard, Niteroi, Rio. Photo from SBM Offshore.

ANALYSIS

In-Depth

E&P goes green

Elaine Maslin looks at efforts to breathe new life into old oil and gas platforms, such as refitting for renewable energy, while also cutting CO_2 emissions and cost.

Combined forces – the push to decarbonize and an industry with offshore facilities coming ever nearer to the ends of their lives – has provoked some innovative thinking.

On the one hand, renewable technologies could help to decarbonize offshore oil and gas production, while on the other, decommissioning could be an opportunity to breathe a second life into offshore facilities, geared towards a greener economy.

Such ideas – and combinations of them – were discussed at the Offshore Mediterranean Conference (OMC) in Ravenna, Italy, late March, with Eni often leading the charge.

"Things will never be the same as they were before," says Innocenzo Titone, conference chairman.

"In the transition (to a cleaner economy) the oil and gas industry has a role to play. No transition will be achieved without integration of renewables and fossil fuels, specifically gas." Such moves may be made compulsory in future legislation.

As part of the 2015 Paris Climate Conference (COP21) agreement, ratified last year, Italian major Eni committed to peddling renewables in addition to hydrocarbons. It's not a new goal – many oil firms, in fact, dove into renewables in the past only to let programs slide as oil prices rose. Donato Azzarone, vice president of energy solutions, renewables energies at Eni, points out that renewables have been considered in the exploration and production space for some time: solar-diesel power hybrid electrical submersible pumps have been used onshore Egypt, solar powered steamflood has been deployed, and wind turbines have been providing power on platforms.

DNV GL's Ben Oudman calls such an idea "late life greening." Another example of this is the Leman Echo facility in the southern North Sea, which used to be a gas processing platform. As the reservoir has dwindled, so has its use, but it is still a gas receiving facility. "NAM (a Dutch operator) decided to strip it down and install a large solar array," Oudman says. "It will be unmanned and all the energy for the gas transfer will be from solar power with diesel generation as a back-up," he says. This reduces CO_2, although this is mostly from cutting helicopter rides, it also boosts health and safety, as it is unmanned, and decarbonizes the existing activity, he says.

Eni CEO Claudio Descalzi says that Eni is weighing the use

An illustration of the Win Win (wind-powered water injection) project.
Image from DNV GL.

of renewables on oil and gas facilities. He points to how much power – from gas – is used to run offshore platforms and that this could come from renewables, instead of by burning gas or diesel. Higher rates of return on renewable power generation could also be achieved if combined with upstream, he says, not least because gas otherwise used for power generation could be sold instead.

"In the Mediterranean, we have 110 platforms, (some) installed 50-60 years ago. They are old, but we don't want to scrap them," he adds. "We want to transform their use, using solar, marine and wind energy. We are investing, in some cases, in pilots to test the use of all these different energies together. Use what we have and create new sources of energy."

Italian Economic Development Minister Ivan Scalfarotto also says that facilities off the Adriatic coast could be reused for wind and solar energy, or for monitoring the marine environment, seismic, tourism or wireless transmission.

The prize

DNV GL says that by taking various measures, oil and gas firms could reduce their CO_2 footprints cost effectively, on average, by 29% – offshore Norway at least, which already has a tax on CO_2 and therefore is perceived to be progressive in this space, said Liv Hovem, senior vice president Africa and Europe, DNV GL Oil & Gas at OMC. In greenfield projects, where opportunities to introduce new technologies – such as renewables, combined heat and power, carbon capture and storage and others – are easier, this could be 35%. With 75% of oil production in 2040 predicted to be from new fields, this could mean a huge CO_2 emission reductions in new fields globally, she said.

DNV GL has produced a tool to assess the opportunities, using what it calls a marginal abatement curve (MAC). This considers the cost per tonne of CO_2 of a measure and the overall CO_2 emission reduction. The firm assessed 28 different CO_2 reduction measures, from carbon capture and storage to alternative power and reducing flaring.

But, Hovem said that it is not just about adding new technologies, it's about how you operate a platform. "Power management and performance monitoring are promising quick win measures," she says. Reducing flaring, subsea processing and heat recovery are other shorter term wins. There's also an opportunity to use a hybrid system where turbines, which operate more efficiently at maximum load, could be complimented by battery technology, allowing a reduction in turbine capacity.

Win-win

One option is to use floating wind turbines to power subsea facilities, such as subsea water injection, specifically. DNV GL completed a feasibility study, with input from ExxonMobil, Eni and Statoil, on such a concept, based on a site in the North Sea. DNV GL targeted a 44,000 b/d concept, which would traditionally require a 3MW gas turbine on a platform. Replacing the 3MW gas turbine power would require a 6MW wind turbine, she says.

In DNV GL's concept, all the water injection equipment

Quick stats

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

New discoveries announced

Depth range	2014	2015	2016	2017
Shallow (<500m)	75	57	32	7
Deep (500-1500m)	32	20	12	0
Ultradeep (>1500m)	13	11	7	2
Total	120	88	51	9
January 2017	127	114	72	-
date comparison	-7	-26	-21	9

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	12	829	2495
Ultradeep	35	10,783	12,756
United States			
Shallow	5	27	71
Deep	19	890	1347
Ultradeep	16	2423	2180
West Africa			
Shallow	119	3789	16,239
Deep	26	2390	3650
Ultradeep	13	1761	2518
Total	245	22,892	41,256
(last month)	(265)	(23,959)	(45,070)

Greenfield reserves

2017-21

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Shallow	904	35,400	340,024
(last month)	(938)	35,785)	(344,070)
Deep	131	5755	97,156
(last month)	(136)	(6605)	(99,551)
Ultradeep	75	16,172	47,117
(last month)	(74)	(15,839)	(46,887)
Total	1110	57,327	484,297

Pipelines

(operational and 2017 onwards)

	(km)	(last month)
<8in.		
Operational/ installed	41,724	(41,584)
Planned/ possible	22,283	(22,436)
	64,007	(64,020)
8-16in.		
Operational/ installed	82,620	(82,548)
Planned/ possible	46,776	(47,396)
	129,396	(129,944)
>16in.		
Operational/ installed	95,171	(94,967)
Planned/ possible	44,677	(43,836)
	139,848	(138,803)

Production systems worldwide

(operational and 2017 onwards)

		(last month)
Floaters		
Operational	307	(309)
Construction/ Conversion	43	(42)
Planned/possible	292	(291)
	642	(642)
Fixed platforms		
Operational	9087	(9094)
Construction/ Conversion	79	(71)
Planned/possible	1299	(1302)
	10,465	(10,467)
Subsea wells		
Operational	5089	(5078)
Develop	321	(312)
Planned/possible	6361	(6361)
	11,771	(11,751)

Global offshore reserves (mmboe) onstream by water depth

	2015	2016	2017	2018	2019	2020	2021
Shallow	21,263.21	32,083.32	32,422.22	11,512.61	12,078.41	16,683.86	22,621.04
(last month)	(21,263.21)	(32,035.17)	(32,788.99)	(11,682.05)	(12,436.84)	(17,310.18)	(22,195.42)
Deep	972.99	1411.48	4324.15	3082.72	2480.71	5088.23	7906.17
(last month)	(972.99)	(1411.48)	(4786.07)	(2728.43)	(2567.19)	(5175.86)	(9046.09)
Ultradeep	2015.69	3075.34	1633.94	3962.03	3833.83	9609.94	5439.84
(last month)	(2023.19)	(3075.34)	(1671.44)	(3924.53)	(3693.78)	(9609.94)	(5206.35)
Total	24,251.89	36,570.14	38,380.31	18,557.36	18,392.95	31,382.03	35,967.05

Source: InfieldRigs 6 Apr 2017

Rig stats

Worldwide

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	95	60	35	63%
Jackup	403	222	181	55%
Semisub	118	63	55	53%
Tenders	27	15	12	55%
Total	643	360	283	55%

North America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	30	21	9	70%
Jackup	25	7	18	28%
Semisub	9	6	3	66%
Tenders	N/A	N/A	N/A	N/A
Total	64	34	30	53%

Asia Pacific

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	11	4	7	36%
Jackup	118	63	55	53%
Semisub	31	11	20	35%
Tenders	20	12	8	60%
Total	180	90	90	50%

Latin America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	23	18	5	78%
Jackup	51	24	27	47%
Semisub	25	18	7	72%
Tenders	2	1	1	50%
Total	101	61	40	60%

Northwest European Continental Shelf

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	0	1	0%
Jackup	50	32	18	64%
Semisub	39	22	17	56%
Tenders	N/A	N/A	N/A	N/A
Total	90	54	36	60%

Middle East & Caspian Sea

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	2	1	1	50%
Jackup	118	81	37	68%
Semisub	4	3	1	75%
Tenders	N/A	N/A	N/A	N/A
Total	124	85	39	68%

Sub-Saharan Africa

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	19	14	5	73%
Jackup	18	7	11	38%
Semisub	3	1	2	33%
Tenders	5	2	3	40%
Total	45	24	21	53%

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 6 Apr 2017

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

Ben Oudman.
Photo from DNV GL.

would be housed on a floating platform, which would also support the 6MW turbine. This would include a microgrid, to even out the power supply to control the water injection rate, as well as satellite communication, and four batteries for power storage, to be drawn down when production isn't high enough. The battery power would only be for keeping the onboard equipment on standby and communications systems running when the turbine isn't generating electricity.

According to analysis by DNV GL, if there are prolonged periods where the wind isn't strong enough to produce power, it wouldn't be damaging to have a period where water injection is inactive. The platform would also have a riser (for lifting water for re-injection), a water filtration system and a pump for injection.

Francesca Feller, senior consultant, DNV GL, points out that, from 2020, wind turbines will be rated 10MW (210m-diameter, 50MW annual production) and higher. Today, alongside the 6MW turbine, all other elements of such a system are available or being tested.

Economically, such a system could work, but it depends on the site and specific project demands, Feller says. DNV GL has run a simulation using real North Sea wind data and found it would be able to maintain injection above a minimum requirement. An indicative life cycle cost would see US$3/bbl saved over 20 years, she says. On top of that, 17,000-tonne of CO_2 emissions would be averted.

In a case where the injection is a longer distance from a platform facility, the benefit would be greater, she says. Retrofit applications, where an existing platform hasn't been fitted with injection facilities, could also be a positive case, she says. A possible phase two of the project will be to test the concept.

Weighing the options

Working for DNV GL in the Netherlands, Oudman says there's an opportunity to use some of the hundreds of facilities in the North Sea for renewables – or other purposes, such as aquaculture or even tourism (something perhaps more likely offshore Italy) – even when facilities are past their oil or gas producing lives. In fact, he suggests, the timing could be good to coincide with and enhance the renewable wind build out.

Oudman says that existing facilities could be reused for power-to-gas facilities – i.e. turning excess wind power into hydrogen or even synthetic methane. This would see wind power used, at times of low demand (where it is otherwise unused), to create hydrogen.

"There is a huge amount of decommissioning that is going to take place in the North Sea in coming decades: 600

platforms, 5000 wells, 10,000km of pipelines. This has an estimated cost of $32-42.6 billion (€30-40 billion). As a replacement for fossil fuel production, a huge amount of offshore wind will be installed in the same basin – 50-100GW. In parallel will be decommissioning in oil and gas and a build-up in renewables."

In the Dutch sector, there are 163 platforms (10 of which are oil facilities) and 2000km of pipelines, often in just 30m water depth. On average, facilities are 25 years old, Oudman says. "Just for the Dutch industry, the cost estimate for decommissioning is $5.3 billion (€5 billion) until 2050." Meanwhile, some 3.5GW of offshore wind capacity is due to be installed between now and 2023, at a cost of about $2.1-3.2 billion (€2-3 billion). "So there's (a combined) €8 billion ($8.5 billion) spending on decommissioning and build-up in renewables," Oudman says.

Currently, the Netherlands is focused on Round Two projects, but further rounds will be closer to where many of the offshore oil and gas facilities are.

"It is difficult to store electricity, so if you use it to make hydrogen it could also make synthetic methane; you could avoid the cost of putting electric cables to shore," Oudman says. "You just put in what you need with the cables, the rest is brought to land (as hydrogen) with offshore pipelines. There is significant cost to be saved if you can repurpose an asset, assuming it has enough life [left] for the job in the jacket and pipelines."

Oudman says that transporting gas is more efficient than transporting electricity. Comparing the BritNed interconnector and the Balgzand Bacton Line pipeline, which cost similar amounts to install, Oudman says the first, an electric system, costs $245/kW (€230/kW) per 100km while the second, a gas pipeline, has an equivalent $11/kW (€11/kW) per 100km. Put another way, he says replacing a 500km onshore transmission link with a pipeline with hydrogen would offer equal returns (synthetic methane would be cash negative, however). "If you can use hydrogen for transport and shipping, that's where you can find a positive business case," he says. DNV GL looked at a case study, using a 3.5GW wind farm. It assessed that of the 3.5GW some 400-600MW, or a sixth of the capacity, could be used to generate hydrogen or synthetic methane with a positive return.

He also says another possibility is producing ammonia using the excess wind power, bringing it ashore as a liquid. Transporting the hydrogen or ammonia by ship would also offer flexibility of where it is sold, he says.

Oudman also highlighted a project to create an offshore energy hub, which would involve creating artificial islands, supporting offshore wind – as a transmission hub and a platform – as well as fish farming, pumped hydro-storage, and power-to-gas. Dutch transmission firm TenneT and Danish national transmission firm Energinet have been looking at the North Sea Offshore Power Hub concept and signed a memorandum of understanding last year to investigate the concept. It would incorporate 458GW pumped hydro-storage, "vast power-to-gas potential" using existing infrastructure and a wind farm on a ring dyke forming the island, Oudman says. It would link all wind farms planned for 2030.

If this isn't feasible, facilities, the jackets at least, could be left in place as havens for marine life, for both current

Another angle of Win Win. Image from DNV GL.

inhabitants and future marine life. This is an option being taken by Engie and state participant EBN offshore the Netherlands (*OE*: December 2016). Two platforms will be left in place and monitored over 10 years as a trail type of rigs-to-reef project.

The bigger picture

There's also a bigger, ocean economy picture, points out professor Roberto Danovaro, of Marche Polytechnic University in Ancona, Italy. He told OMC, in light of moves by the Organisation for Economic Co-operation and Development to focus on a sustainable economy of oceans, and other efforts towards sustaining marine biodiversity: "Now is the time to look at these structures in a new perspective. We know decommissioning will happen globally. There are three main problems: the cost; the question whether it is absolutely needed to protect the marine environment; and are these structures useful to the marine environment."

Finding an alternative use could be an answer, he suggests. This could be using platforms as (marine) reserves, for CO_2 storage, aquaculture, etc. It may mean a case-by-case analysis of each platform, because each has a different habitat, which he admits would be complex. He proposes an ecosystem-based deepsea strategy, which is being developed under the Merces Project. (merces-project.eu)

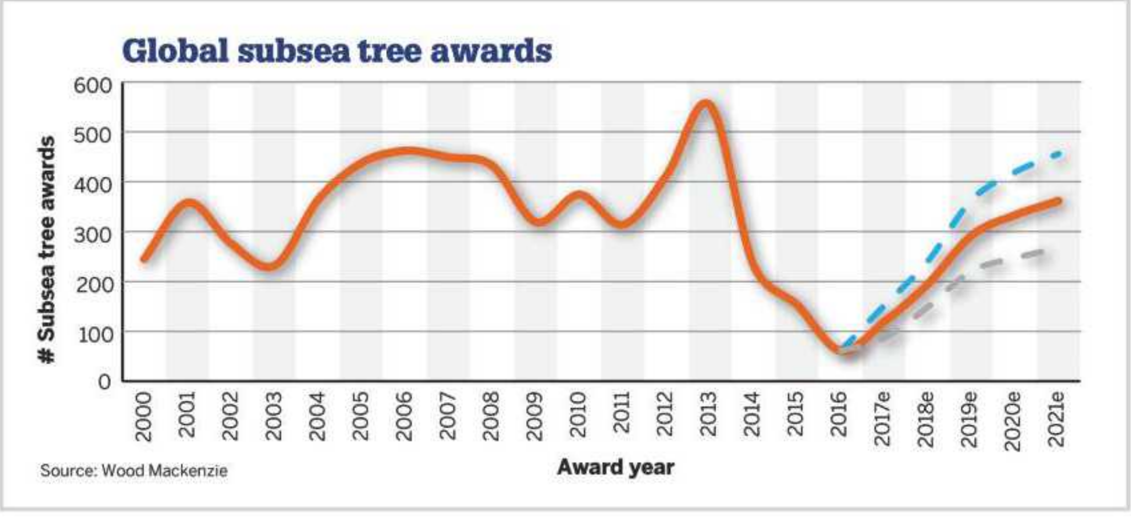
"Reuse is useful, but any strategy we use must be based on monitoring," he adds, something that industry could help with. **OE**

Global subsea demand poised for recovery

Wood Mackenzie's Caitlin Shaw provides perspective on the subsea market and how the industry will redefine a "good" year.

Wood Mackenzie's Upstream Supply Chain team has observed the global subsea market weathering three years of severely depressed subsea and deepwater demand activity due to cost concerns and a crash in the oil price. After years of collaboration, project re-assessment and cost discipline, 2017 is poised to start the next up cycle in subsea. Last year saw a record low level in subsea tree awards and 2017 could almost double that demand based on award opportunities in all major deepwater basins around the world.

While the profile of subsea projects going forward is likely to look different from what we have seen historically – smaller, more compact and efficient concepts – growth in 2017 is expected from the sub-80 subsea tree demand level of 2016. This is due in part to a higher expected oil price in 2017 than 2016, but has as much to do with the work that has been put into this current wave of developments in the pipeline. Operators have reduced the scope, changed the development scenario and standardized where possible to bring their project breakeven economics more in line with expected oil prices going forward.



Shell's Olympus and Mars platform in the Gulf of Mexico in 2013. Kaikias in the prolific Mars-Ursa basin 130mi offshore Louisiana. Photo from Shell.

Redefining "good"

The ever-present question of when demand will be "good" again cannot be ignored and recently the answer comes along the lines that "good" may have to be redefined based on a new chapter for the subsea industry. Wood Mackenzie's subsea tree award forecast does not portend a recovery to pre-2014 record levels for many reasons. The oil price just will not be what it once was and although that is disheartening to many, the industry is nothing if not innovative and will continue to adapt to this as they have in the past. Capacity has been reduced, if at no other level than head count, and continues to be right-sized as long as demand stays low. Even when backlogs build and the need for additional resources arrives, there will remain a lag in seasoned, highly efficient workers to fill in, which will add to lead times going forward. Good may not be a 500 subsea tree year – good may be closer to 250-300 within our forecast period.

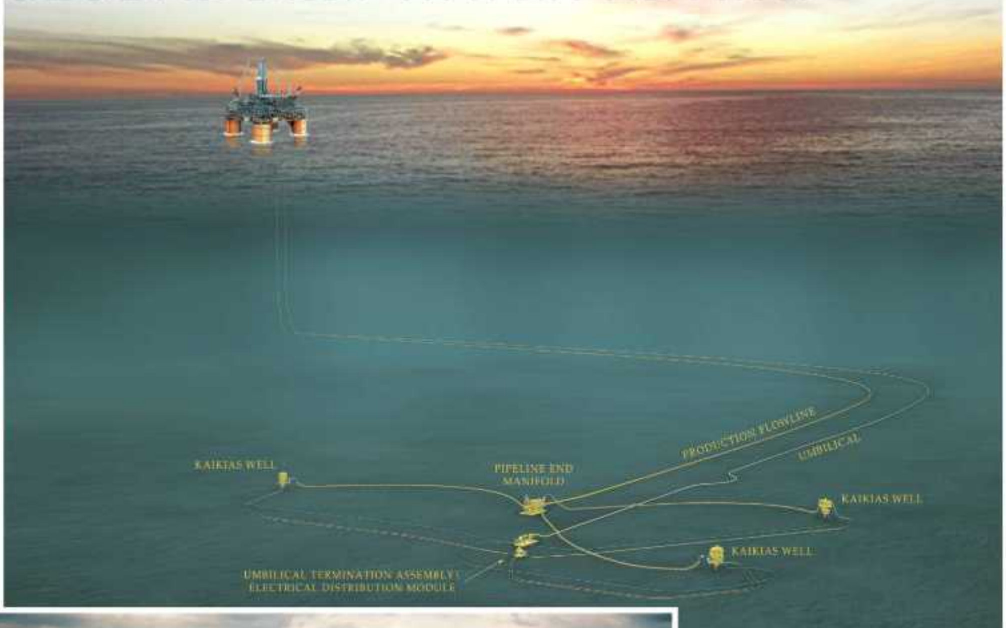
Working together to work through the downcycle

The current downcycle that the industry is working hard to transition out of, started materially affecting subsea demand in 2014 as operators became concerned enough with the cost of developing their subsea and deepwater fields that they severely halted project executions. There had been telltale signs of discontent among the operators with respect to development cost seen in re-bidding efforts for floating production systems (i.e. Chevron's Rosebank in 2013) and ongoing stalls in project execution of large, complex projects. The oil price drop at the end of 2014 exacerbated this trend and highlighted the dependency of most subsea and deepwater projects on a breakeven price north of US$70/bbl – a breakeven which was no longer sustainable.

The theme of the past two years in the offshore industry has been collaboration. The operators have been collaborating with the supply chain and working to bring them into the conversation earlier in a project's life cycle. The supply chain itself has been collaborating and consolidating to provide innovative solutions to the operators by creating efficiencies via avenues including enhanced vertical integration. The upper echelon of the subsea supply chain has seen the major OEMs pair off with the leaders in the marine construction market and work together to increase efficiencies throughout the entire life cycle of the project. This collaborative work has been focused, for the most part, on one main end goal – to reduce overall cost by increasing efficiencies and return on investment.

Subsea remains viable

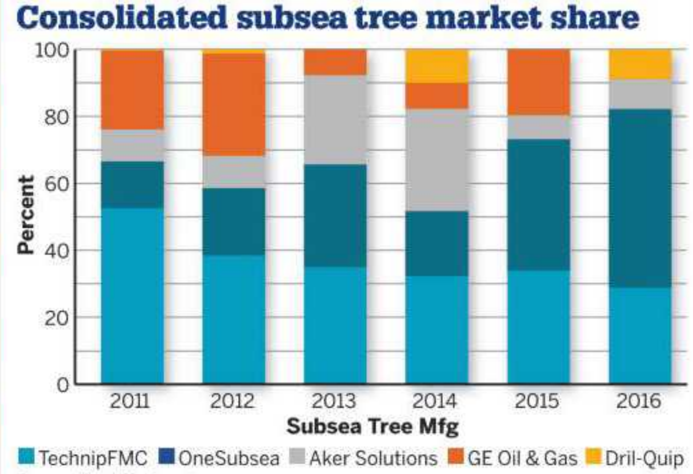
This joint work over the past 24 months to bring down development costs, increase efficiencies and reduce cycle time may be on the verge of being realized. Oil companies are working towards commercial solutions for executing their subsea developments in a lower oil price environment. Through efficient well concepts, right-sizing development scenarios and standardization, among other solutions, breakeven prices are now being discussed at $40-50/bbl instead of $70+/bbl. While the flood gates will not be opened just yet, the cautious optimism



An illustration of the Kaikias subsea infrastructure, a Gulf of Mexico project in which Shell recently announced a final investment decision. Image from Shell.

An illustration of the Mad Dog Phase 2 development in the Gulf of Mexico, which recently reached a final investment decision. Image from BP.

Consolidated subsea tree market share



Source: Wood Mackenzie

discussed around the reality of re-working global subsea fields to be economic under the current oil price outlook, increases confidence of a demand recovery in the coming years.

It is also important to keep in mind that not all subsea projects are created equal. Macro market conditions, commodity prices and geopolitical issues affect operators and projects differently and that is accounted for in the forecast outlook. We understand that natural gas projects for local supply represent a different momentum than those supplying into the global market. We also recognize that certain projects and certain operators are faster to adjust to the lower oil price and still prioritize execution of projects with an eye to longer-term oil price potentials.

The supplier landscape

In terms of subsea production systems, TechnipFMC and OneSubsea have been the market leaders over the past few decades. They have long-established relationships with some of the leading operators in deepwater around the world. GE Oil & Gas, Aker Solutions and Dril-Quip play critical roles in various market segments within the subsea supply chain. Along with full subsea production systems, Aker Solutions and GE Oil & Gas participate heavily in the subsea controls market with a lot of demand from projects where the equipment is allocated over more than one supplier as well as the aftermarket demand for replacement control units. Dril-Quip and GE Oil & Gas are the main providers of global subsea wellheads commonly providing this equipment into other suppliers' systems.

For operators with established frame agreements or preferred supplier relationships, some appear to be reaching beyond these traditional suppliers to look for additional ways of cutting cost. This trend could upset the near-term market share trend as competition remains tight while backlogs remain low. Whether this potential disruption would last long enough to statistically change supplier relationships is yet to be known, but the successful track record of TechnipFMC and OneSubsea would be difficult to permanently re-route.

Opportunities rising to the surface

While not the triple digit oil prices of years ago, the industry is getting more comfortable with a stable oil price between $50-60/bbl. Oil companies and the supply chain have been hard at work re-engineering how subsea is developed and executed and have had positive results in the form of lower publicized breakeven prices. While this will not get us back to pre-2014 subsea tree demand levels, it does provide strength behind an improving award scenario for 2017 and 2018. Projects are being re-worked, priorities are being re-evaluated and enabling technologies are being applied to reduce inefficiencies, reduce cycle time and bring down cost. While these solutions may not work for all projects in the near-term, it will mean something to the core of subsea demand and the operators and supply chain members involved. **OE**

Caitlin Shaw *is Wood Mackenzie's research director – Upstream Supply Chain. She graduated from Texas A&M University-Galveston in 2003 with a BS in marine biology. Prior to Wood Mackezie, Shaw was senior director of market research and the data division at Quest Offshore Resources.*

Deep dive

***OE* charts the top 10 deepest water projects currently in production and in development.**

Deepwater developments are serious business. And these 10 deepest developments are led by Anglo-Dutch supermajor Shell, and Brazilian national oil firm Petrobras, and focused on the US Gulf of Mexico and offshore Brazil. We let the projects speak for themselves here, with the help of data from Wood Mackenzie's Upstream Data Tool.

2919m

Stones (Shell)

The world's deepest standalone oil and gas development came onstream in September 2016. It utilizes the second floating production, storage and offloading (FPSO) unit to operate in the US Gulf of Mexico, preferred at such depths over a typical spar.

2809-2934m

Silvertip/Tobago (Shell)

These two small adjacent fields have been developed as subsea tiebacks – the world's deepest – to the Perdido hub in the Gulf of Mexico as smaller sister developments to Great White. Both fields are below 35 MMboe in recoverable reserves.

2692m

Chinook (Petrobras)

First oil was achieved in September 2012 from this Lower Tertiary field that was co-developed with the nearby Cascade (see below). Both fields utilize an FPSO, the very-first to be deployed in the Gulf of Mexico.

2482m

Cascade (Petrobras)

The smaller sister field to Chinook, described above. The two fields combined hold a relatively small 34 MMboe of commercially recoverable reserves.

2320m

Great White (Shell)

This field holds over 350 MMboe of reserves and came onstream in 2010 via a tieback to the Perdido hub. The world's deepest spar, it is moored in 2450m water depth in the US Gulf of Mexico, just 10km (6mi) from the international boundary with Mexican waters.

2307m

Coulomb (Shell)

This oil and gas field was developed as a subsea tieback to the BP-operated Na Kika floating production system. Production started in June 2004, and at that time was the deepest subsea completion in the US Gulf Of Mexico.

2249m

Hadrian (ExxonMobil)

Hadrian consists of two fields in the Gulf of Mexico: the oil-rich Hadrian North (KC 919) and gas-rich Hadrian South (KC 964). Hadrian South came online in March 2015, via a tieback to the Anadarko-operated Lucius spar. Final investment decision on Hadrian North has been delayed and is currently under re-evaluation.

2230m

Iara (Petrobras)

This Brazilian subsalt complex holds over 1.1 billion bo. Due onstream in 2019, it will be developed via three FPSOs. Total acquired a stake in the Iara area – plus other upstream, gas and power assets - for a combined US$2.2 billion in December 2016.

2230m

Lara Entorno (Petrobras)

First oil from this Brazilian project is also scheduled for 2019, and will peak at over 390,000 b/d.

2200m

Appomattox (Shell)

One of only a handful of deepwater projects to achieve sanction in 2015, first production is expected in 2019. The semisubmersible facility will then act as a hub for other nearby finds. First will likely be the Shell-operated Vicksburg, at a slightly deeper water depth of 2248m.

**Data from Wood Mackenzie's Upstream Data Tool.*

Ready to start

The Troll A platform.
Photo: Statoil/Øyvind Hagen.

Decommissioning in Western Europe is set to boom after numerous false starts, says Douglas Westwood's Ben Wilby.

Decommissioning has long been considered an area of huge potential within the oil and gas industry. The large amount of infrastructure to be removed gives companies that can complete decommissioning work, such as heavy lift operators, access to an emerging multi-billion dollar industry. Despite many previous predictions, large-scale decommissioning has yet to begin, with limited removals to date due to operators preferring to pay steady maintenance and operations costs each year, rather than the substantial costs required for decommissioning work. This approach has been bolstered by a strong oil price and enhanced recovery techniques that have kept fields such as Brent and Forties producing long after their initial design life, however, things are beginning to change.

Decommissioning activity has been brought forward due to the depressed oil prices over the last few years, which saw prices go from above US$110/bbl in 1H 2014 to a low of below $30/bbl in January 2016. This downturn led to a spate of abandonments globally, as fields became uncommercial. This affected mature regions with high opex, such as Western Europe, more severely; and UK fields, such as Dunlin and Athena, were among those abandoned earlier than expected.

Compared to last year, however, there is a more positive outlook for the future of the oil and gas industry, with oil prices recovering in the wake of OPEC's decision to cut production. This has shifted abandonment dates for many projects that were previously expected to begin decommissioning activity in 2018-2019 into the early parts of the next decade. Crucially, however, improvements in the oil price will only delay decommissioning, rather than stop it from moving forward, with many fields in the region at the end of their producing life regardless of oil price.

Large-scale oil and gas production in Western Europe started in the 1960s and many platforms are still in place. The average age of most platforms in Western Europe sits at over 25 years, driving high average opex costs in the region. While this has been somewhat stymied by the oil price crash and a subsequent drop in demand, this will not be the case indefinitely – with operating costs likely to rise in line with oil prices as supply chain pressures ease.

Total expenditure

Douglas Westwood (DW) estimates that from 2017-2040, the cost of decommissioning in Western Europe will reach $103 billion. This will be driven by activity in the UK and Norway, contributing a combined 81% of total spend. This will be split among several service lines, with well decommissioning activity having the highest expenditure, followed by topside removal.

Western Europe has had a large number of well installations, both surface and subsea, since first production in the 1960s. A high proportion of these will need to be removed over the forecast period and this will have a high associated cost. Well decommissioning is forecast to account for the majority of expenditure, representing 65% of the total market over the 2017-2040 period. This will be primarily driven by wells in Norway and the UK, which have the highest number of wells installed, including the vast majority of subsea wells in the region.

Topside and substructure removal is also expected to account for a large proportion of decommissioning expenditure in the region, totaling over $20 billion and representing 21% of total spend. Within this, there are a large number of extra-large platforms in the UK and Norway that will require extensive reverse engineering work. While there are potential cost savings to be made by using Allseas' new single lift vessel (SLV) *Pioneering Spirit*, which will allow the platforms to be removed in a single operation, bringing potential time and cost savings, there are a few issues outstanding. First, the *Pioneering Spirit* is the only SLV available, which will also be used for construction activities – leading to questions over availability. Secondly, the concept is still unproven and has only been used for one removal to date, the Yme platform in Norway (*OE*: September 2016). The vessel is due to see its second decommissioning workscope later this year with the removal of the Brent Delta topside. However, to enable a single life operation the platform required the installation of more steel to ensure that it could be lifted safely. Should other platforms also require this amount of preparation, the time and cost benefits will be lessened.

UK to dominate spend

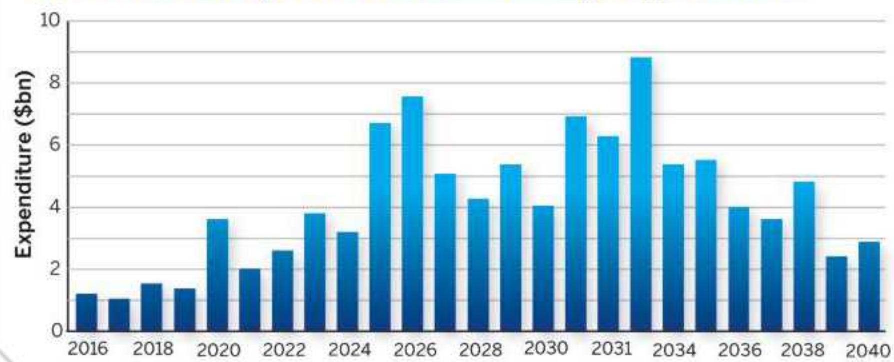
With the highest levels of installed infrastructure and an extremely mature basin, the UK will dominate both removals and expenditure over the forecast, accounting for 54% of decommissioning expenditure from 2017-2040.

In total, DW anticipates the removal of 290 platforms and over 3000 wells in the UK – over 2017-2040 – 44% and 54% of the total, respectively. This high level of removals, in addition to the weight of the platforms to be removed, will result in total UK expenditure of over $55 billion. The UK is likely to be at the forefront of decommissioning activity and, thus, it will likely become the leader in terms of establishing how large-scale decommissioning can be managed worldwide. Due to this, the country should be an area of focus for companies looking to capitalize on the need to remove infrastructure. Those companies that obtain a strong reputation in the UK will be able to transfer their knowledge and experience elsewhere, with operators elsewhere likely place a heavy reliance on those with strong track-records wherever possible.

Norway will see the second highest decommissioning spend over the forecast, totaling $28 billion, despite having a smaller number of installed platforms than both Italy and the Netherlands. This is due to the number of platforms that weigh over 5000-tonne – resulting in a higher number of removal days per platform. Due to large reservoirs, such as Troll and Åsgard,

Allseas' mega-vessel *Pioneering Spirit* gets into position to remove Yme's topsides in August 2016. Photo from Allseas.

Western Europe decommissioning expenditure



Source: Douglas-Westwood's Western Europe Decommissioning Market Forecast 2017-2040

Norway has the second largest active wellstock, with a high proportion being subsea. As a result, the cost requirements for well decommissioning in Norway are expected to amount to $20 billion alone, 72% of the total – a higher proportion than any other country. Unlike the UK, responsibility for decommissioning in Norway will be focused on one operator – Statoil. The company operates 69 of the 124 currently producing fields in the country while also holding stakes in others.

Italy and the Netherlands have very similar offshore sectors, categorized by stable weather conditions, allowing fields to be developed with smaller platforms (<1000-tonne). Both countries also have smaller reservoirs than Norway and the UK, meaning that the number of well removals in both countries are low in proportion to the number of platforms. Overall, DW expects expenditure in Italy to total $6 billion and the Netherlands to total $8 billion over the forecast period.

Summary

Overall, the ramping up of the decommissioning industry represents a significant opportunity for specialist companies tasked with removing the large tonnage installed and decommissioning the high wellstock built up in the North Sea over the last 50 years. Companies that can operate safely, efficiently, and establish strong, competitive reputations will be in an excellent position to capitalize, both within Western Europe and beyond.

For platform operators, responsible for undertaking decommissioning work, the current downturn represents a chance to be rid of operating assets that were only commercial at high oil prices, as well as abandoned platforms that are current liabilities, requiring extensive maintenance work for no material return. However, there will be huge costs involved to remove these assets, causing problems for many companies and the governments who will also assume much of the liability for these fields. **OE**

***Ben Wilby** is an analyst in Westwood Global Energy's Research team based in Faversham. Having joined in 2013, he primarily works on the continual updating of the SECTORS Database. He has authored numerous reports including the 'World Floating Production Market Forecast,' and the 'Western Europe Decommissioning Market Forecast.' Wilby graduated from the University of Chichester with a degree in history.*

Coming full circle

Decommissioning project team.
OE Staff photo.

Elaine Maslin reports on a new joint industry project, led by Intecsea, which aims to apply lessons learned to reduce decommissioning costs by building them into the design phase.

If there's one thing everyone knows about decommissioning, it's that it costs more than anyone wants to spend and most would rather not have to do it at all.

But, what if some of the cost of removing oil and gas infrastructure could be reduced by making the initial design more decommissioning friendly in the first place? A self-funded industry project is exploring the idea, initially focusing on subsea infrastructure.

The project's aim is to raise awareness about the functional requirements during decommissioning and the impact on project life cycle costs, as well as providing a tool to translate lessons learned into potential solutions, which could be implemented in future designs.

Stuart Martin, of Ardent, said that the project came about as a chance conversation with Alan Stokes, of Intecsea, and centered upon how their careers had come full circle; from design, installation and commissioning to decommissioning of assets on which they previously worked. "We both concluded that the costs associated with decommissioning could be mitigated by capturing lessons learned and utilizing these in the design phase," Martin says.

"We found several like-minded people and decided to create our own joint industry project – entirely self-sufficient and funded with shared stewardship of outputs. Subsea assets were chosen as our focus area given the make-up of the team," he says.

By capturing lessons learned and using these in the design phase (e.g. removing installation aids and then re-instituting them in the decommissioning phase), Stokes and others felt that the costs associated could be mitigated.

> **"Project teams are getting better at involving operations and maintenance teams in the design process."**
>
> **Alan Stokes**

"Project teams are getting better at involving operations and maintenance teams in the design process," Stokes says. "We're hoping that the decommissioning engineer is brought in as part of the design team."

As an example of where design could be more cognizant of decommissioning challenges, Stokes mentions the subsea manifolds that must be removed and taken onshore for dismantling. "Removal takes time and effort because the team does not know the weight of mud, etc., holding it down," Stokes says. "If they had a geotextile membrane underneath, they would have had more surety."

The industry has recognized the need to consider decommissioning since 1998, as operators have had to submit a decommissioning plan as part of their field development plan. But, how much that influences the design and in how much detail is not clear.

The Intecsea-led industry project – established in August 2016 with input from Ardent, BP, CNRI, DNV-GL, Eni, Jee, Proserv, Premier Oil, Woodside, and Xodus Group – decided to focus its efforts. Instead of looking at everything that could save money, the group first identified what the biggest cost drivers for subsea decommissioning are, drawing on information from Oil & Gas UK's annual Decommissioning Insight report.

Various elements of the subsea system were looked at and the likely costs involved during decommissioning outlined: owner cost (support costs, etc.), removal and onshore disposal, estimated. These were then put into a traffic light matrix (high-cost activities in red, medium as orange and low as green).

Within each area, details of the issues and possible solutions were then drawn up. Currently, there are 81 guidance notes and it is hoped this will increase, especially in areas where, so-far, less information was available.

The group has created a database, including a list of issues and mitigating actions that could be taken during the design process, both during detailed and concept design phases. Within each, there are considerations for the design engineer, e.g. around pipeline bundles, issues such as return facilities for flushing, having no shears greater than 36in, reducing complexity, the need to raise structures off the seabed for access by cutting and inspection tools.

For riser bases and manifolds, issues include complexity around flushing and isolation. The group has good information on rigid pipelines, removal and flushing and engineering down. Its data on wellheads is "getting there," but it would like more detail on manifolds and riser bases.

Proving value

Stokes is cognizant that while the suggestions for mitigation are all well and good, there needs to be careful consideration that these don't then increase complexity or cost, which could negate the point of doing it in the first place. For some operators, having a flushing loop or pigging loop is useful for life-of-field operations, which mean they're there for decommissioning. But, not all think the same.

Another key awareness is that a business case needs to be made. This in turn means that the cost of decommissioning has to be accounted for as part of the capex budgeting, which isn't something universally done – and certainly wasn't in the past.

"A question asked is 'why should we consider decommissioning during concept design,'" Stokes ponders. "We did a net present value (NPV) assessment on the Clyde field, including the cost of decommissioning. We re-ran it, to see if including decommissioning costs made a difference. If we can reduce the estimated cost of decommissioning, we can make our projects more attractive to senior management.

"On Clyde, just a 25% decommissioning cost reduction could increase NPV by 10%. What would you have to do to the capex in order to get that same 10% increase in NPV? You would need to halve the weight of the structure and there's no way you could do that. We're not going to see an easy win, but there's a target we can go for.

"We now have a database showing how much things cost and as a result we can show what a cost reduction will do to the NPV model."

Caroline Laurenson, consultant engineer at Xodus, says that adding in decommissioning considerations to the design can be difficult to rationalize, e.g. adding in extra valves and tie-ins, which could allow pipeline cleaning, because both have an additional capital cost and operational maintenance costs. Removing them could save cost, but then it means full depressurization may be needed to apply isolations, which then adds cost and complexity to the decommissioning operations.

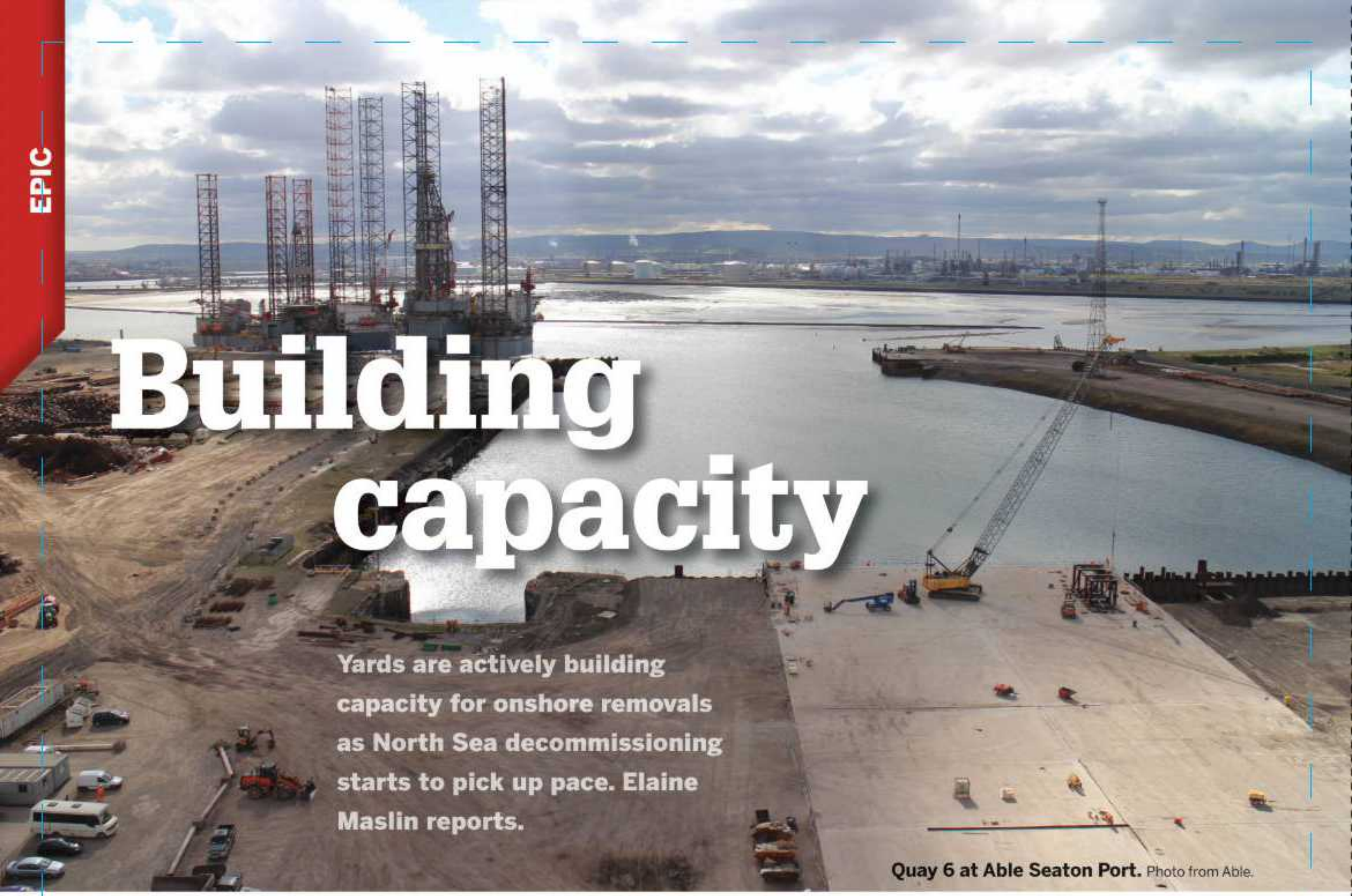
But, the guidelines are not just for the greenfield design engineers. It's also brownfield engineers that need to be cognizant of how their designs will impact decommissioning costs. "The industry needs to be aware of decommissioning throughout the life cycle," Stokes says.

You are not alone

There are other projects, which are leading in this direction and which could also help engineers in the design process, such as the SUT Salvage and Decommissioning Group (which is set to work with the group), and Wood Group's Sureflex JIP, which involves flexible pipe manufacturers looking at best practice design, installation and operations, and which is due to publish guidelines later this year. Xodus and the University of Dundee are also modeling skirted subsea structure removal from clay seabeds.

Some operators are also understood to have their own guidelines, but these are not necessarily shared and vary in detail, perhaps just offering guidelines such as lifting points that can be retained or flushing loops.

For the Intecsea-led group, the next task is developing the technical content and hosting environment of the database and making their guidelines available to subsea design engineers. OE



Building capacity

Yards are actively building capacity for onshore removals as North Sea decommissioning starts to pick up pace. Elaine Maslin reports.

Quay 6 at Able Seaton Port. Photo from Able.

Decommissioning isn't an activity usually associated with investment. The less spent the better, as far as oilfield operators are concerned.

However, what appears to be the tentative arrival of a sizable offshore decommissioning market has spurred many contractors into investment in onshore facilities for dismantling and disposal activities.

Even the Scottish government is seeing the opportunity, offering a US$6.29 million (£5 million) Decommissioning Challenge Fund (DCF) to support infrastructure upgrades and innovation in salvage and transport methods at Scotland's ports and harbors.

According to Wood Mackenzie, the total future decommissioning spend for the UK Continental Shelf alone is an estimated US$66 billion (£53 billion) in 2016 terms. In the short-term, some 140 fields are expected to cease production – in the UK alone – over the next five years.

Transport

Topsides will come ashore in a number of forms. One is via the *Pioneering Spirit* a single lift vessel, which carried out its first job last year, lifting out the 13,500-tonne Yme topsides offshore Norway and transporting them to a newly developed dismantling yard at Lutelandet, Norway.

Able UK at Hartlepool has invested in its quayside so that it's able to receive the 24,000-tonne Brent Delta topsides this year (See page 40), such is the step up in size that *Pioneering Spirit* offers.

There are also plenty of smaller facilities that could be lifted out in one go and taken to smaller shore facilities by a growing fleet of smaller vessels, however. And piece small work is also an option.

The 25,000-tonne Murchison topsides in the UK North Sea, for example, was removed in 26 lifts and five vessels transits by Heerema Marine Contractors from the UK North Sea field to AF Gruppen's facility at Vats, Norway.

Of the approximately 600 platforms in the Northwest Europe – including Norway, UK, Denmark, Netherlands, and Germany – about half have topsides weighing under 1600-tonne, according to an Oil & Gas UK database. The first offshore facilities to be decommissioned in Great Yarmouth, out of which the UK's oil and gas industry started, will be of this small type. These are due to arrive in Spring, under a contract to a partnership between Veolia and Peterson. While the facilities haven't been named, the partners said they will entail a number of production complex and satellite platforms from the southern gas basin, 40mi offshore Great Yarmouth.

The Great Yarmouth partnership, just like a growing number of others, is seeking to use this first contract as a springboard to becoming a "center of decommissioning excellence," i.e. winning more work. Some are entirely new facilities, like Lutelandet.

New sites

Once home to the construction of one of the largest North Sea facilities, Ninian Central in the 1970s, Kishorn's huge 160m-diameter drydock has been dormant for decades. Now, work has started to reinstate the facility on Scotland's west coast.

A contract was awarded in early January to Harris Pye, a Welsh marine engineering firm, to trial the hollow concrete dock gates (weighing 13,000-tonne each) and fabricate new gate seals and culvert tube covers, which will enable the dry dock to be pumped dry – a feat that will take four days.

The project is being led by Kishorn

Taking aim at Yme: *Pioneering Spirit.*
Photo from Allseas.

Port Ltd. (KPL), a joint venture between Ferguson Transport & Shipping and Leiths (Scotland). The yard will still need to gain a license for handling decommissioning projects and build shore-side facilities.

In Norway, a new player has emerged, Lutelandet Offshore. It is already working with Veolia to decommission the Yme platform for Talisman, delivered to its site by *Pioneering Spirit* last year.

The firm has been building a completely new site with a deepwater quay at Lutelandet, on the west coast of Norway. The firm, set up in 2009 to do decommissioning and inspection, repair and maintenance work, says the site, including offices and accommodation, will cover 346 acres (14 million sq m) with deepwater quays, a finger pier and dry dock.

It has a 150m minimum deepwater approach; all quays (stretching out 630m in two directions) are at least 21m deep, with potential for up to 40m.

DSM Demolition, a Birmingham-based firm that used to decommissioning steel structures onshore, has plans for a site in the Orkney Islands, north of mainland Scotland.

The firm was due to submit a planning application for its proposed facility at Lyness, on the east coast of the island of Hoy in 2016, and start operating in 2018 .

Late December, Aberdeen Harbour's plans to expand its facilities into Nigg Bay south of the existing harbor was sanctioned by the Harbour Board. The facilities will not just be for decommissioning, with the Harbour Board targeting a range of activities. However, this does include "up-scaled decommissioning activity."

The $434.9 million (£350 million) project is being built by Dragados UK, part of Spain's ACS Group, starting early this year, with completion scheduled for 2020. The facilities, in Nigg Bay, will include 1400m of new quay, with water depth of up to 10.5m, and will create an additional 125,000sq m of lay-down area.

Upgrades

Able UK, near Hartlepool, in northeast England, invested $35 million (£28 million) in a new quay with skid plates for heavy load-ins so that it could win the Brent field facilities decommissioning work.

The new quay - Quay 6 - at Able Seaton Port covers 60m x 120m with 45-tonne/sq m loading capacity, or 60,000-tonne in total, making it one of the heaviest load out quays in Europe. This was achieved through the installation of some 1242 piles, weighing almost 10,500-tonne, plus 4500-tonne of steel reinforcement and 40,000cu m of concrete. The Brent Delta facility is due to be landed here this month (May) and is expected to take 12 months to dismantle and remove.

Uniquely, the Seaton Port site is also home to the former BP North West Hutton living quarters, which were converted under a $1.2 million (£1 million) refurbishment project into modern office facilities, housed on self-propelled modular transporters, so it can be moved anywhere on site, according to project requirements.

Able acquired the facility as part of a contract to decommission the North West Hutton 20,000-tonne topsides and 10,000-tonne jacket, a project completed in 2011. The module support frame from North West Hutton is being used as a test lift structure by Allseas.

Dundee

Forth Ports Authority unveiled a $12.4 million (£10 million) investment to create a new quayside with "industry-leading" heavy-lift capability. The investment will see the development of the quayside at the east end of the port, connecting to the existing Prince Charles Wharf.

The quayside will offer heavy lift capability over its entire 200m length (80-tonne/sq m loading capability) with an ultra-heavy lift pad at one end. Coupled with a deepwater berth and 60 acres of land, the investment will enable the port to handle the largest cargoes used in the emerging North Sea industry sectors, says Forth Ports.

Southbay Civil Engineering started work on the site in February and this is expected to be completed by the end of 2017.

Forth Ports also has a partnership with Augean to offer decommissioning waste management at the port, with a new facility opening at the same time as the new quayside.

Montrose

Since 2012, Montrose, also south of Aberdeen, has invested $18.6 million (£15 million) in three heavy lift pads with a capacity of 15-tonne/sq m and it has also done major upgrades to quays on both the north and south sides of its harbor.

Lerwick

In 2016, Lerwick Harbour completed a $14.9 million (£12 million) project to extend and upgrade its quay at Dales Voe South, more than doubling the quay to 127m, with water depth up to 12.5m and 60-tonne/sq m load bearing capacity. An area behind the quay was also being leveled to create a new lay down area over 40,000sq m. Further plans for an ultra-deepwater quay have been on hold to see how and when the decommissioning industry develops.

At Lerwick's Greenhead Base, there have also been improvements, to handle load-in operations, with quayside strengthened for heavy lifts. Two new berths are also due to be constructed to create an additional 180m of quayside with 9m water depth, plus a 1000-tonne capacity heavy lift pad.

Norway

Norway already has a major player, in AF Gruppen, which last year took in the 26 Murchison topside modules, totaling 25,000-tonne, at its AF Decom Vats sites. The Murchison jacket it due to follow this year. AF Decom was also involved in the Ekofisk cessation project, where nine platforms were disposed.

Kvaerner Stord has also been involved in decommissioning projects, notably the Frigg field, in 2004-2010. The site is owned by Aker Solutions and shared with Scanmet in a cooperation arrangement.

There is also Lutelandet Offshore, mentioned earlier, and Stena Recycling in Stavanger. OE

EPIC

End of life or afterlife?

Susan Gourvenec offers a down under outlook for decommissioning offshore oil and gas facilities.

Australia's first offshore oil and gas facilities were constructed in the 1960s and the country is now facing the first wave of decommissioning projects.

A construction boom in the 1980s, and a more recent boom, which has seen the construction of multiple super projects, including Chevron's Gorgon and Inpex's Ichthys developments, means there is a sustained decommissioning challenge on the horizon.

As in other regions, Australia is questioning the rationale for complete removal of offshore oil and gas facilities at the end of field life and is looking to provide leadership across Australasia and Asia in decommissioning offshore oil and gas infrastructure.

Scale and cost

There are more than 100 offshore oil and gas platforms and subsea structures in Australia, including about 35 fixed platforms and 12 floating production facilities, many approaching the end of production life. Only a small number of facilities have been decommissioned to date, including the *Jabiru and Challis* floating production, storage and offloading (FPSO) developments.

Nearby, across Southeast Asia, there are more than 1700 offshore installations, nearly half of which are more than 20 years old and due to be retired. In Asia Pacific, more than 600 fields are expected to cease production in the next 10 years.

Australia has put a US$21 billion price tag on offshore decommissioning over the next 50 years, based on current policy and technology. Australia's predicted liability accounts for about 10% of the estimated total global decommissioning spending in that period, and can be compared with a UK estimate of nearly $60 billion by 2050.

Operating pipelines provide habitat for marine life. Photos from Woodside.

The scale of the decommissioning challenge is understood – less well understood are the best decommissioning options.

Options

▪ Complete removal and disposal onshore The current base case for offshore oil and gas infrastructure at the end of field life in Australia is – as elsewhere – complete removal and disposal onshore.

While complete removal of offshore infrastructure poses many challenges, a solution can be found for most engineering challenges with sufficient investment. An example is Allseas' *Pioneering Spirit* – the purpose built decommissioning vessel, built to remove (and install) topsides and jackets from the North Sea. It is 382m-long and 124m-wide and cost some $3 billion to build – although is forecast to save up to $12 billion in decommissioning costs in the North Sea.

But just because we can – should we?

There are challenges, risks and costs of removal and transport; challenges, risks and costs of disposal onshore, whether for landfill or recycling; and the destruction or disruption of ecosystems that have established around infrastructure over several decades of operation.

▪ In situ decommissioning There is much interest in Australia in the precedence of removal and relocation or disposal to another offshore location – most well-known is the US rigs-to-reefs program, through which more than 400 decommissioned structures have been converted to permanent reefs since 1986.

Removal, even for relocation, involves expense and risk and can damage the marine ecosystem that developed during the production life.

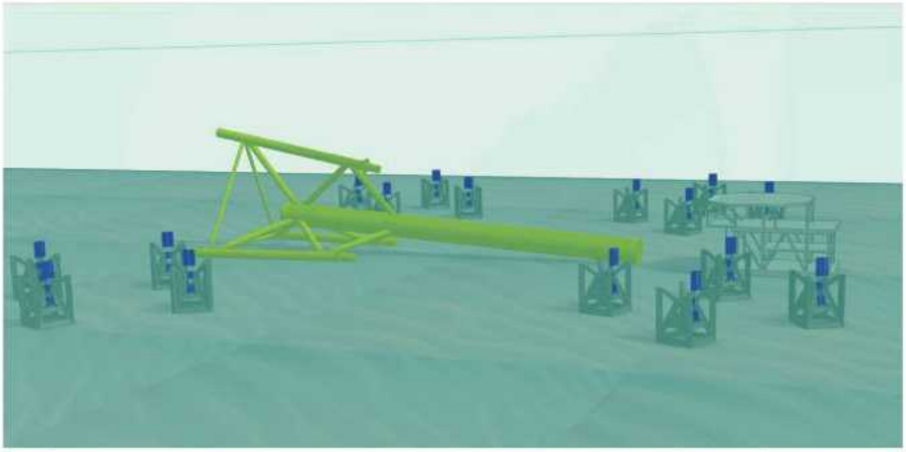
A version of the rigs-to-reefs approach is leaving part or all of the field architecture in situ – i.e. without relocation. This has the benefit of not needing to mobilize large vessels for removal, sea fastening and long-distance transport. Therefore, achieving a reduction in cost and risk, and leaving the established marine ecosystem intact.

If cost and risk of engineered removal are to be eliminated – the alternative must be demonstrated to be safe from an engineering and ecological perspective.

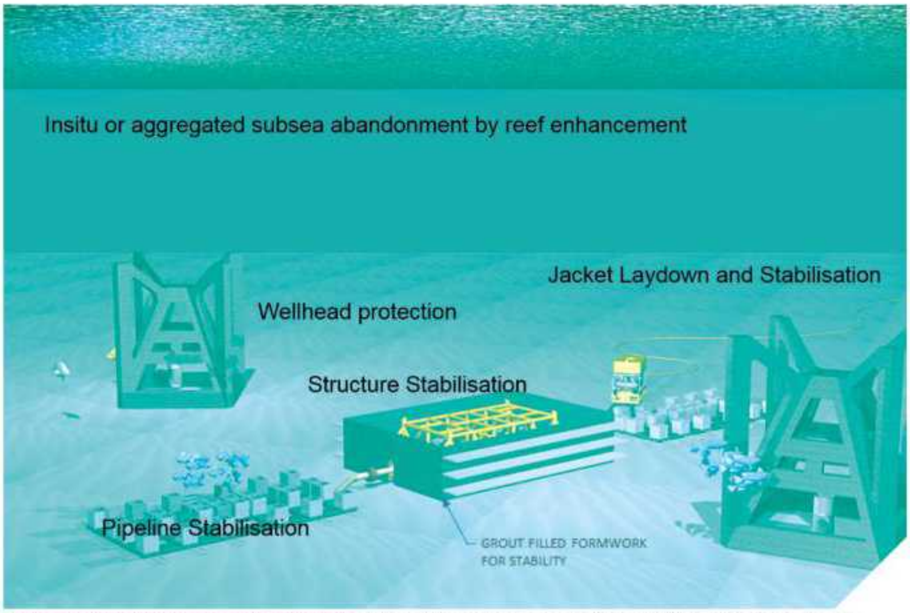
From an engineering perspective, the basis of design (BOD) for the afterlife of a structure, if left in situ, is quite different to the production life; tolerances on differential movements are less stringent due to reduced or absence of risk from loss of containment (once cleaned and flushed). The high-level BOD for the afterlife is perhaps limited to avoiding dispersal of the structure in large or small parts. Loading is less onerous in the afterlife due to the absence of operational loads and resistance can be increased relative to the design state due to marine growth, burial or embedment and increased seabed strength.

Viewed through the lens of removal – increased resistance adds to the challenge. Viewed through the lens of in situ decommissioning – increased resistance is beneficial.

Recent geotechnical research at the Centre for Offshore Foundation Systems at The University of Western Australia has shown the potential lifting force



Platform structure decommissioned in situ augmented with artificial reef modules.



Subsea structures decommissioned in situ augmented with artificial reef modules.
Images from Subcon.

to remove a shallow foundation from a muddy seabed at the end of production life can be up to nine times the foundation weight, without even considering marine growth. Considering this in terms of removal presents a significant challenge in terms of crane and vessel requirements. On the other hand, in terms of in situ decommissioning, it would make the structure more stable – and safer for the afterlife.

Geotechnical research of pipelines on sandy seabeds has shown that pipes can self-bury – which can make them either harder, and more ecologically disruptive to retrieve – or more stable if left in situ.

Undoubtedly, the notion of returning the seabed to its initial state is borne out of the best intentions, but after infrastructure has been part of the marine ecosystem for several decades, removing it might not be the best option.

From an ecological perspective, can it do more harm than good removing infrastructure? And, equally important, what are the risks associated with leaving the infrastructure in situ?

Marine science research from the Oceans Institute at The University of Western Australia has shown that offshore infrastructure on the Northwest Shelf supports diverse invertebrate habitats and fish life and benefits commercial fisheries. The warm tropical waters are particularly conducive to marine growth and various studies have demonstrated a range of marine biota on structures in Australian waters.

Trawling in areas offshore Australia decimated seabed habitat in the 1960s and 1970s, which has started to renew due to the hard standing provided by oil and gas infrastructure. Returning the seabed to the condition it was in before the oil and gas infrastructure was installed may be an ecological step backwards.

Similar experiences have been reported in the North Sea. Initiatives there, such as the INSITE (Influence of man-made Structures In the Ecosystem) [*OE*: February 2017] and LiNSI (Living North Sea Initiative) projects provide invaluable data to the required evidence base to inform decommissioning options.

An ocean laboratory case study for in situ decommissioning, such as that proposed in the Dutch sector of the North Sea through *Platforms Natuurlijk*, (*OE*: December 2016) would be a welcome addition to the evidence base for the Australian marine environment.

▪ **Augmentation** There is also the option of augmenting oil and gas infrastructure left in situ after decommissioning with engineered artificial reef modules to optimize benefits to marine life. Artificial reefs are widespread in Australia and Asia, and as such this is an area where Australia and Asia may provide leadership.

Challenges and opportunities

Australia faces some specific challenges, due to the geographical remoteness of the country and general sparsity of offshore infrastructure, which is spread around the vast coastline.

An emergent theme in Australia, as elsewhere, is the potential positive benefits of full or partial in situ decommissioning, and that cross sector transdisciplinary collaborative solutions may lead to win-win scenarios for all stakeholders and the marine environment.

With appropriate coordination and collaboration, it is possible that these efforts will transform the physical legacy of abandoned offshore oil and gas projects from a liability on the private and public purse, to an asset within the marine ecosystem creating a beneficial increase or concentration of the ocean ecosystem, benefiting a diverse range of stakeholders. **OE**

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Delta day arrives

Final preparations are being made for what will be the heaviest ever offshore lift and the first of the once prolific Brent field platforms removals using Allseas' mega-vessel, the *Pioneering Spirit*. Elaine Maslin reports.

Last year, Allseas' mega-vessel *Pioneering Spirit* vessel performed its first project, taking out the 13,500-tonne Yme platform topsides in a single lift offshore Norway. Early this month [May], it will sail to the Brent Delta facility, 186km off Aberdeen, to remove Shell's 24,500-tonne Brent Delta topsides, before then heading to the Black Sea to lay the TurkStream pipeline. As *OE* went to press, the firm also won a contract to lay the twin-pipeline Nord Stream 2 over 1200km through the Baltic Sea, in 2018-19, using the *Pioneering Spirit*, as well as Allseas' *Solitaire* and *Audacia* pipelay vessels.

In April, the vessel's final four lifting beams, installed after the Yme lift, were tested, with a 15,600-tonne cargo barge load, ready for the job, with final commissioning due to be completed ahead of a test lift in the Dutch North Sea, using a dummy platform. The vessel's pipelay stinger was also trial fitted in April, ready for its TurkStream job. Work will also start this year on the vessel's jacket lifting system, to be installed aft, as well as installing a new Huisman, 5000-tonne, tub-mounted crane.

For Allseas, the Brent Delta project will further validate some 30 years' work, proving and building its heavy lift vessel concept, which at 48,000-tonne topsides and 25,000-tonne jacket lifting capability, outstrips that of any other vessel in the market. The 382m-long, 124m-wide vessel, with a 122m-long, 59m-wide bow slot (and 1 million-tonne displacement at full draft), was built in South Korea by Daewoo Shipbuilding & Marine Engineering (2011-2014) at a cost of US$3 billion.

Fred Regtop, Captain of *Pioneering Spirit*, says that in August last year, the vessel, which can sail at 14 knots and has 95MW installed power, outperformed simulations for the Yme lift. Allseas' founder Edward Heerema says that in November 2016, the vessel then performed well when tasked with performing another test lift on a dummy platform installed in the Dutch North Sea, with 4.9m significant wave height and 7.9m maximum wave height.

For Shell, the Brent Delta topsides removal comes after 10 years' preparation work on the Brent field facilities, which has a further three platforms, also all due to have their topsides removed by Allseas in coming years.

Shell just completed a public consultation on its Brent Delta decommissioning plans, which resulted in some calls from environmentalists for more information. However, there have also been a lot of learnings through the project. For example, Shell thinks it can reduce the preparation scope required for the lift by 25% on the next project (Brent Bravo), including having less reinforcement work on the platform, but also by using concrete instead of installing new steel for the lifting points.

Brent Bravo provides different challenges, however, with an underwater obstruction on the legs meaning extra ballasting for the vessel to be able

to clear the site before sailing away. Charlie, the final facility that will be removed, will be the heaviest, at more than 30,000-tonne. While at the start, Allseas thought once one lift was done, the rest would be similar, the difference in platform design means this isn't quite the case, said Heerema at a briefing on the vessel in April.

However, Brent Delta was still the focus. Visiting the *Pioneering Spirit*, *OE* was told some 500 people were working and living aboard in order to get it ready for the job, as well as completing commissioning of the pipelay system, ready for its Turkstream pipeline project in the Black Sea immediately after the Brent Delta removal. Moored alongside was also Allseas' new acquisition, the newbuild support vessel *Volstad Oceanic*.

Brent Delta and two of the other three Brent topsides to be removed (Bravo and Alpha) are due to be taken to Able Seaton Port, Hartlepool, which underwent £28 million investment to be able to do the topsides dismantling work. Off Hartlepool, the topsides will be transferred onto stools on the *Iron Lady* barge, and towed onshore before being skidded on to Quay 6. Once there, the platform will effectively "disappear" within 12 months, says Neil Etherington, business development director at Able, with about 97% of it to be recycled.

While the Yme lift was performed just using *Pioneering Spirit*'s hydraulic system, due to the compressed air system being not quite ready, the Brent Delta removal will use the full system. Using compressed air allows for a faster lift off, having had 80% of the load already taken up through ballasting, Heerema says. The operation is done using the vessel's complex topsides lifting system, which involves coordinating eight sets of two lifting beams, each able to move independently both up and down but also aft, forward, to port and to bow, all in coordination with the vessel's DP system, to ensure the lifting arms can safety touch onto the platform being lifted without being impacted by vessel motion. Each pair will move into place in succession before the final lift.

Allseas has also been learning. After taking delivery of the vessel in Rotterdam, the firm added a sort of slot brace. This connects the two bows together during transit to stop any deflection caused by water pushing on their insides from potentially putting strain on the topsides being carried.

Following TurkStream, between 2018 and 2019 the vessel will install three platform topsides for Statoil's Johan Sverdrup Development project in Norwegian waters. We'll bring you more in next month's *OE*. **OE**

Allseas' *Pioneering Spirit* during pipelay mode with the stinger and stinger transition frame (STF) installed in the bow slot. In transit mode, the combination of both the stinger and STF increase the vessel's overall length to almost 450m.

Photo from Allseas.

Statistics show that dropped objects cause up to 10% of industrial fatalities, thousands of injuries that require medical treatment and a considerable number of lost time injury events. Photo from snapinadil/Shutterstock.

Danger from above

Chris Corcoran, of ABS, highlights the importance of further improving safety to reduce the number of dropped object incidents on offshore facilities.

The industry has made significant efforts to improve the offshore work environment, particularly over the past decade, but workers continue to sustain injuries, and many of these are caused by dropped objects. Statistics show that dropped objects cause up to 10% of industrial fatalities, thousands of injuries that require medical treatment and a considerable number of lost time injury events.

Safety in the offshore work environment has matured over the years, and many improvements have been made to personal protective equipment, work processes and safety training. A change in outlook has led to improvements in safety culture, with companies dedicating significant time and resources to improve safety and minimize injury to personnel, lost time incidents (LTIs) and asset damages. These advances protect workers' lives every day, but work remains to be done.

Improving safety

Data gathered from the UK Continental Shelf illustrate the wide range of incidents caused by dropped objects that can occur in offshore operations. Among the events recorded were objects dropped while executing derrick and well operations, issues resulting from crane and lifting events and episodes that involved equipment and tools falling from scaffolding.

It might seem such accidents would have been difficult to avert, but in fact, many could have been prevented.

The traditional approach to managing dropped objects has been to apply best practices for existing equipment. While this is a good first step, it does not go quite far enough in truly addressing the issue. What is needed is a standardized approach.

Without an industry standard, designs for mitigating the potential for dropped objects and the associated risks are developed by each company according to its own guidelines. This means the definition of the safety hazard varies from one manufacturer to another as does the degree of application of safety design specifications. Without a focus on equipment design standards for minimizing dropped objects or an industry body to consult on engineering processes, every company is on its own.

Developing guidance

As a classification society, ABS identifies areas where safety improvement is needed and works with industry to create a solution. Recognizing a need to supplement current best practice, ABS developed the industry's first standard provisions for dropped objects prevention, which promotes global safety initiatives and introduces a shift in equipment design considerations.

This guidance takes the current state of best practices to the international standard level and includes requirements for evaluating and certifying equipment designs. A life cycle process based on continuous monitoring for compliance forms the basis for an enhanced safety culture and creates a platform for focusing on designing and engineering equipment that is inherently "drops resistant," delivering an increased level of safety with related classification designations.

This guide marks the beginning of change.

As the number of approved equipment offerings grows, drops resistant like-for-like replacements will grow. In time, existing equipment will be replaced with drops resistant certified equipment, and eventually, drops resistant equipment will become the norm. When this transition is complete, the result will be a safer working environment.

By working together to find ways to mitigate risks to personnel, it is possible to improve worker safety.

The offshore industry is facing the challenge of adopting new technologies and operational practices and at the same time complying with increasingly complex international, national and local regulations. As the work environment evolves, it is critically important to make sure safety keeps pace. Developing much needed guidance is a way to pave the way for improved offshore safety. OE

Chris Corcoran is a senior staff advisor in the ABS Global Offshore division. He has served in various domestic and international roles in the ABS survey operations division involving development and application of classification and statutory compliance for offshore units, ships and fixed installations. Chris's career in the offshore and maritime industries spans 40 years, including 17 years with drilling contractors, where he managed global projects and technical operations support. He is a graduate of the University of Michigan and holds a Bachelor of Engineering Degree in Naval Architecture and Marine Engineering.


SAFETY PRODUCTS
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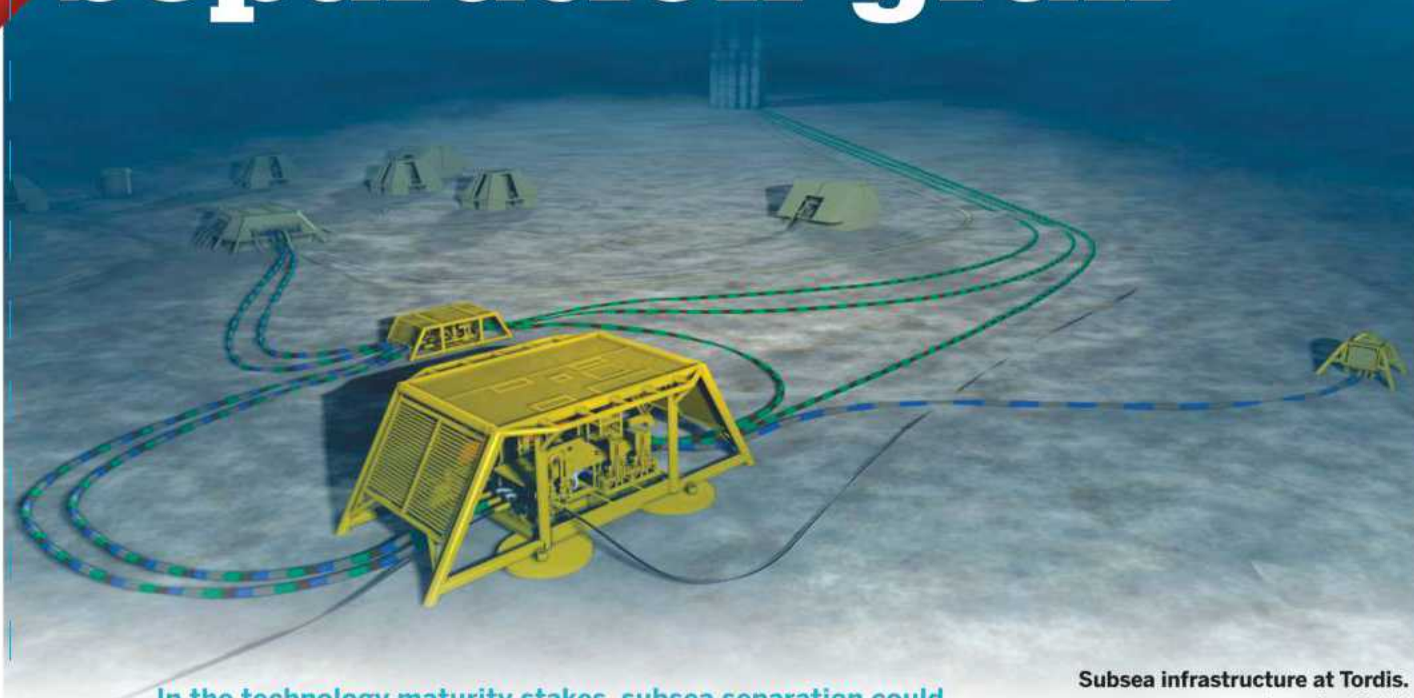
A holy separation grail



Subsea infrastructure at Tordis.
Image from Statoil.

In the technology maturity stakes, subsea separation could perhaps be described as one of the ugly sisters in the subsea processing world. But, perhaps Cinderella would be more appropriate. Elaine Maslin reports.

Subsea pumping has been around for decades. As of February, there were 24 subsea pumping systems in operation and a further five being manufactured, says Intecsea, with focus now on increasing system size. Subsea separation hasn't had quite so much luck. Despite having been around for decades, as of February, there were just six subsea separation systems operating, and only one more being manufactured. Despite the lack of widespread adoption to date, however, many are still working on separation technologies and once this technology is cracked it could have significant potential, not least in unlocking fields that are otherwise uneconomic.

Separation spans a wide breadth of field possibilities. Gas-liquids separation would help unlock deepwater, long step-out gas fields, and could prove beneficial if used with subsea compression systems, of which only two projects have been installed to date – Åsgard, a dry gas compression system, and the smaller Gullfaks wet gas compression system – both by Statoil, offshore Norway. A further four subsea compression systems are in the concept stage, says Intecsea. Oil-water separation, meanwhile, would be a boon for fields where water cut is high and topsides space and weight constrained.

Some companies are working on both. Saipem is developing its SpoolSep oil-water separation technology, and Multipipe, a gas-liquids separation technology, for example. Sulzer, through its Dutch businesses Ascom and Prolab, is working with ExxonMobil to provide a flexible subsea separation solution qualified for a range of applications to avoid the costly need to qualify technologies for each application (*OE*: May 2016), using electrostatic coalescence plus gravity-based separation.

FMC, now part of TechnipFMC, has long been a player in this space, alongside OneSubsea (legacy Framo), part of oilfield services group Schlumberger. GE Oil & Gas and Aker Solutions are also players.

Most recently, Aker Solutions has been working on a solution for mature North Sea fields where water cut is as high as 90-95%. Using a gravity separator, the system is designed to separate water to 500-1000ppm oil in water. Depending on the water quality requirement, a second stage could be added, potentially a compact floatation unit (CFU). These are typically used topside, but in this case, it would be marinized for subsea, says Marco Gabelloni, business development director, Aker Solutions. Gas is injected into the CFU, making bubbles, which trap oil droplets and separate them from the water – achieving 100-150ppm. A project to marinize a CFU will start this year. Additional stages can improve the water quality. Hydrocyclones, as used on Marlim, could also be used, Gabelloni says.

Aker Solutions is also working on a

deepwater separator, which would use pipe-in-pipe technology, a direction others, including Norwegian firm Seabed Separation (See page 46) and Saipem are going in.

Taking separation technologies into deeper waters offers greater challenges, however. Here, gravity separation – the traditional method used – becomes limited because of increased hydrostatic pressure and the associated wall thickness requirements. One option is a spherical system, which is able to withstand increased external pressure, but that means getting the internals to work, says Mac McKee, Intecsea's director of strategy and planning.

The holy grail, however, would be for subsea water treatment and subsea disposal, where subsea separated water no longer needs to be pumped topside to be treated before either being sent overboard or back down to a well for re-injection (which itself can cause issues around reservoir souring). It's also a stepping stone to the full subsea factory and would be an ideal combination with boosting or compression, depending on the application.

"There is a very fine line with what you can and cannot do with that water," McKee says. "Being able to deal with it subsea is a bit like the holy grail of subsea processing. Without it, some fields will be un-producible and in the end, one of the main drivers for the size and cost of some of the topside facilities is the water treatment and water handling systems on the host platform or vessel," McKee adds.

"Being able to eliminate those systems and combine subsea separation with subsea boosting (or subsea compression) would be revolutionary in terms of how you could redesign, or even eliminate, the offshore facility," he says. "But, to do that, you have to be able to separate out the water and treat it to a level regulatory agencies will accept and dispose of subsea without bringing it to the surface."

The challenges for water disposal, however, are not insignificant, from being able to achieve bulk filtration subsea to the current lack of guidance as to what's acceptable for subsea disposal, because it has not been done before.

One of the attractions for separation is it makes boosting technologies more efficient. Subsea boosting performs well, but it isn't the most efficient technology, especially multiphase, says Mika Tienhaara, head of upstream Americas, Sulzer Chemtech USA. With subsea separation, subsea processing could be more efficient.

So why has separation lagged? Probably due to inferior technology in the past. "At the same time, the design challenges [for separation] are immense when, deployed on the seafloor, you consider the start, or early versus peak production," Tienhaara says.

The number of concepts, and maybe the resulting fragmentation, hasn't helped, Gabelloni says. "Separation also hasn't proven itself as such a benefit, where boosting has. However, separation with boosting could offer larger benefits than boosting alone by combining the benefits," he says.

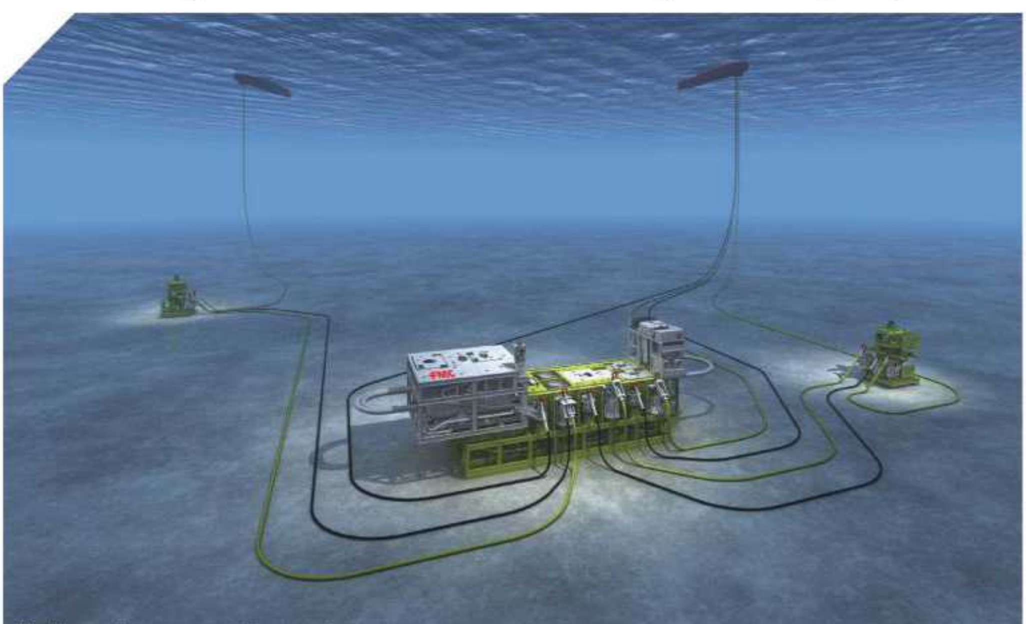
Cost has been a challenge also and this often relates to technology qualification. In the work with ExxonMobil, Sulzer has taken learnings from projects like Pazflor (gravity separation), Tordis and Marlim (long-pipe configuration gravity separation). "We took a systematic approach and while we didn't standardize, we at least have solutions for a variety of potential field applications, all available and ready to go ahead (i.e. pre-qualified)," Tienhaara says, that should reduce costs.

Sulzer and ExxonMobil's work notwithstanding, who will lead the charge in further subsea separation technology development and adoption is another challenge.

"Historically, the operators would come up with challenges and vendors would spend money to develop pumps, separators, and even compressors for the client," McKee says. "That worked on a few pilot projects and a few designs were put forward to be more or less 'off the shelf' products. But, then, fields got more difficult, more complicated, and you got to a point where you had to have the operator funding development and testing, and they also wanted to be involved in it, too, because they wanted to make sure it was fit for purpose. Now we are in a situation where neither side has the money to do that, to produce these more difficult fields and meet these challenges. It has to be a meeting in the middle, but I don't think we have really sorted that out yet."

But, Tienhaara says: "Availability and capability of [separation] technology is better today than five years ago. The subsea community should be ready and able to embrace subsea separation and at least assess what it could bring, and how it could impact field architecture. I expect more studies that will involve subsea separation, for liquids and relating to compression stations. It could lower the complexity of the solutions typically implemented."

McKee has a slightly different view. He says oil companies should now be screening all their subsea projects to see what benefit subsea separation would have. "Subsea separation is a must for subsea production systems to really achieve their potential and compete in this highly cost competitive market," he says. **OE**



Marlim subsea separation system. Image from FMC Technologies, now TechnipFMC.

Image from iStock.

Separation simple

Norway's Seabed Separation says simple is the best way to go by exploiting an understanding of the well stream. Elain Maslin reports.

Seabed Separation's technology is a dual pipe separator (DPS) system, using multiple inclined pipes, with piping inside, to separate water from oil. Removing water from the well stream subsea means (if it can be re-injected or disposed of out to sea) increased production, fewer topsides facilities requirements and less subsea infrastructure and chemical injection, as the water no longer needs to be brought to surface and treated.

Asle Hovda, Seabed Separation's CEO, says that by using many small separation pipes, instead of one large pressure vessel, you get over issues with water depth (and vessels so big they cannot be built or are impractical to handle).

The DPS can be flexible during field life – it could be used in series or parallel, and pipes can be added or removed. It would weigh less than a traditional gravity separator (by more than 75%, the firm estimates), cost less, and would reduce seafloor pumping requirements.

The idea is aimed at brownfield projects, to debottleneck topsides, or as an enabler for greenfield subsea projects. It could even be used as part of a so-called cold flow system, a concept popular around 2010.

The technology is based on an idea developed by Otto Skovholt in the late 1990s. In 2014, Skovholt conducted initial testing at the Institute for Energy Technology, outside Oslo, and received positive feedback from operators. Proventure, a Norwegian private equity firm, came onboard in 2015 and, together with business people in Trondheim, launched Seabed Separation (which now has support from Lundin, Aker BP (previously Det Norske) and public funding) to commercialize the concept.

In 2015-2016, a low-pressure full scale test pilot was designed and built and completed six weeks of testing at Sintef's Multiphase Lab, with better than expected results. In February 2017, building of a full scale, high-pressure (100 bar) pilot unit was completed. It is installed in Statoil's Porsgrunn (or P-Lab) test facility, south of Oslo, and will be used to verify the low-pressure test system, using real hydrocarbons and sea water. Testing, which was due to start on 18 April, will run into June and will help define the process operating envelope for as many different scenarios as they can throw at it.

"Our plan is to have the DPS unit available for commercial piloting mid-2018 for land operations," Hovda says. "Soon after that we will have a unit available for offshore operations in the North Sea."

The system isn't just pipes, of course. First, where there's gas, the free gas is stripped from the well stream. Then, the fluids go through an inlet arrangement, which slows down the fluids. Then, the fluids go into an inner closed end pipe. The internal pipe has outlets (perforations) through which the water drops out and down to an outlet at the bottom of the outer pipe, and the oil rises up and out through an outlet at the top of the outer pipe.

The inner pipe outlets would be arranged according to the application. By using pipe instead of a large separator, the water doesn't have as far to go to drop out, the firm says. As the heavier water resists rising up, the oil travels over the top of it faster, says Jon Sigurd Berntsen, the firm's chief technology officer. Sand could be flushed out through a dedicated sand flushing pipe. The pipes can be arranged in series or parallel, according to need for flow capacity and/or quality.

An indicative size topside facility is for 60,000 b/d (without gas) measuring 4 x 8m, 6 x 8m with a gas system. Its dry weight would be 11-tonne and operating weight 15-tonne (compared with 60-tonne dry weight for a standard topside separation vessel), with limited need for instrumentation and control, pumps or alarms, Hovda adds.

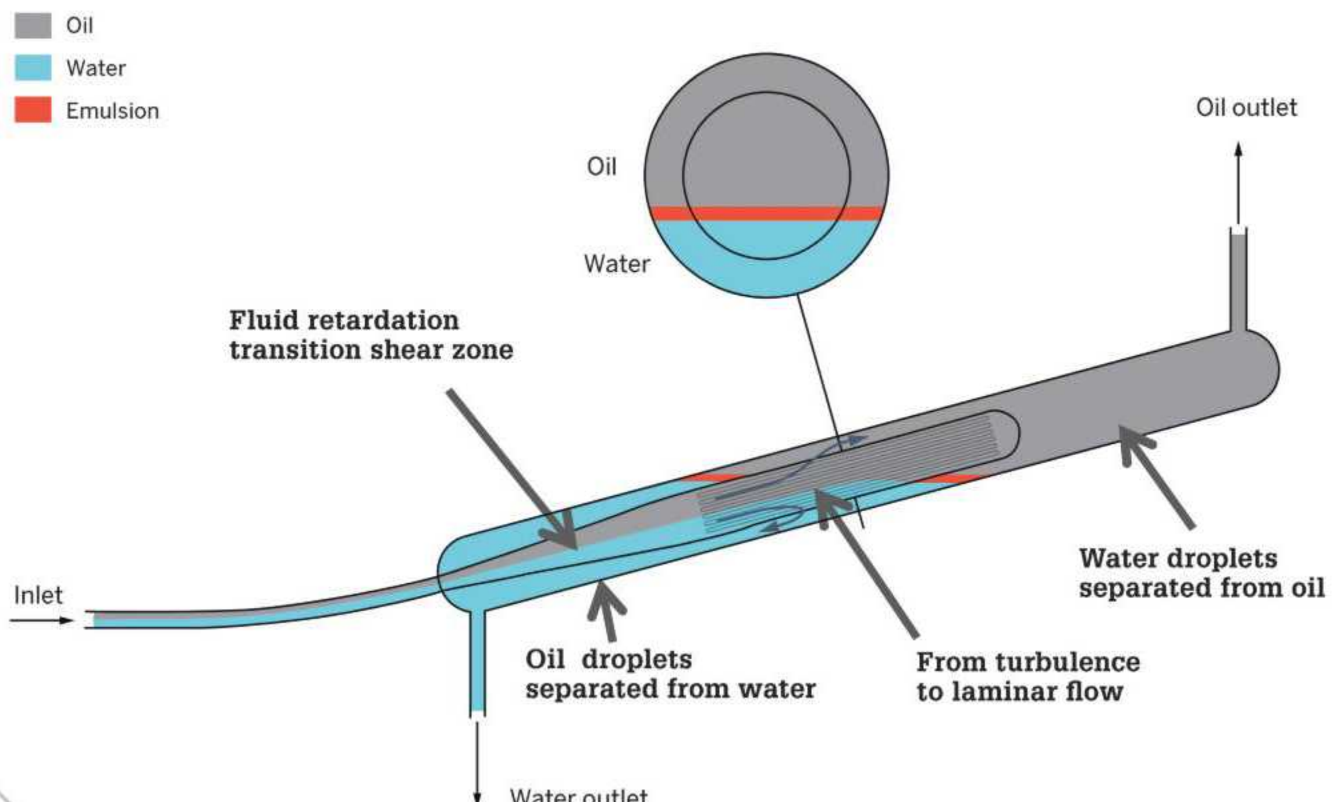
Berntsen, who has some 35 years' experience working with produced water, says part of the job has been to work with operators to understand what is happening in their pipelines and separation systems to develop a correct methodology.

The firm's goal is to achieve separated water clean enough to be discharged subsea – the Holy Grail. But, Berntsen admits, this will probably not be one step. But, because the water has been separated subsea, it no longer becomes a flow assurance issue, which means hydrate inhibitors wouldn't need to be used.

Berntsen says that it is actually easier to separate water closer to the wellhead because, in most cases, there the water is more "pristine," i.e. it hasn't started to form an emulsion with the oil and other components.

"This is nothing new, it's just applying knowledge and technology in the correct sequence, with no spinning," Berntsen says. OE

The dual pipe separator – how it works



Source: Seabed Separation

Let's get SubCool

Dehydration on the seafloor could help build a business case for stranded gas deposits. Elaine Maslin reports.

Australia's SubCool has developed a hybrid solution for stranded gas deposits. The concept would fully process the gas at the seafloor so that topsides facilities only need to deal with low pressure liquids, dramatically reducing topsides facilities weight, size and complexity.

For Richard Moore, SubCool's CEO, the technology is about creating a business case for deepwater gas fields that are otherwise uncommercial and stranded, particularly those in 175m+ water depth and 100km+ from shore, with 0.5Tcf+ of reserves.

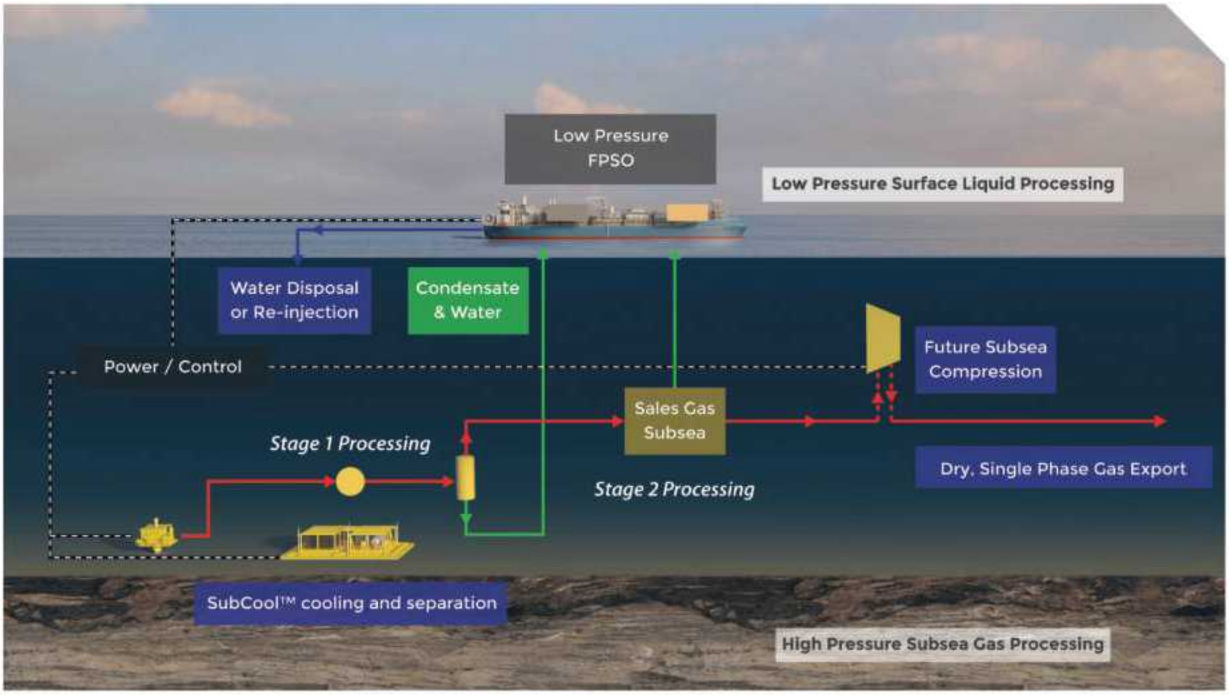
"The problem with deepwater gas is that the process facilities need to be mega-facilities," he says. This is because they have to be high-pressure gas systems, which has an impact on size and weight – and cost. High-pressure risers, high-pressure emergency shutdown valves, flare and utility systems for high-pressure, etc., are needed.

Floating liquefied natural gas (FLNG) facilities have been offered as an alternative, but, in Australia, four FLNG projects have been cancelled in 18 months, he says. "Capex and especially opex are high – it's complex." Subsea processing, meanwhile, has shown great potential, but is so far limited to shorter distances, he says. "Subsea projects are a great success for short distance projects. But for long distances, it's a problem."

When processing gas, you have to knock out the water and liquids and need low temperatures to do that, Moore says, and it makes sense to do that where it's cold – subsea. This would also mean hydrate inhibitors wouldn't need to be used to avoid flow assurance issues, which could be caused by leaving the water and liquids in the pipeline.

SubCool's subsea dehydration system would comprise first stage active subsea cooling (making use of the nearby cold seawater with a heat exchanger) and separation (with traditional or inline separators) to separate out the condensed liquids and water, followed by a dehydration process, called "Sales Gas Subsea" by SubCool, to enable dry single phase gas export. This cools the separated cooled gas to below ambient seawater temperature to condense the remaining condensable liquids and produce a single-phase dew-pointed gas. "The bulk of the dehydration is done by cooling the gas," he says. "What then comes to surface is lower pressure liquids, radically reducing the requirements of the topsides system." The surface unit would also provide power for the subsea facilities, and potentially could be unmanned.

Moore says the result could be a compact, low pressure surface unit for liquids processing and surface support, at 4000-tonne, instead of 24,000-tonne, and 20 bar instead of 200 bar. "Distance wouldn't be an issue and it would enable simpler, lower cost local subsea compression, as and when needed," he says. OE



SubCool's subsea dehydration system.
Image from SubCool.

E-luminating the deeps

Eelume has made a splash with its snake-like underwater robot, despite its lithe form not initially having been destined for a life subsea. Elaine Maslin sets out the detail.

This year a creature quite unlike any other seen before in the oil and gas industry will take some tentative steps towards full-fledged realization. Its makers believe it could herald a new era in subsea operations, towards the subsea resident robotics concept championed by others, but with a somewhat different shape.

Norwegian start-up Eelume's multi-articulated joint, snake-like subsea robot is being designed to be a subsea resident inspection, maintenance and repair (IMR) tool, able to transit multiple kilometers between subsea tiebacks and remain subsea for long periods.

There are a number of approaches in this area, mostly centered around designing a vehicle from scratch, such as Subsea 7's autonomous underwater vehicle (AUV) hybrid AIV (autonomous inspection vehicle), or by adapting currently available electric remotely operated vehicles (ROVs) (*OE*: October 2016).

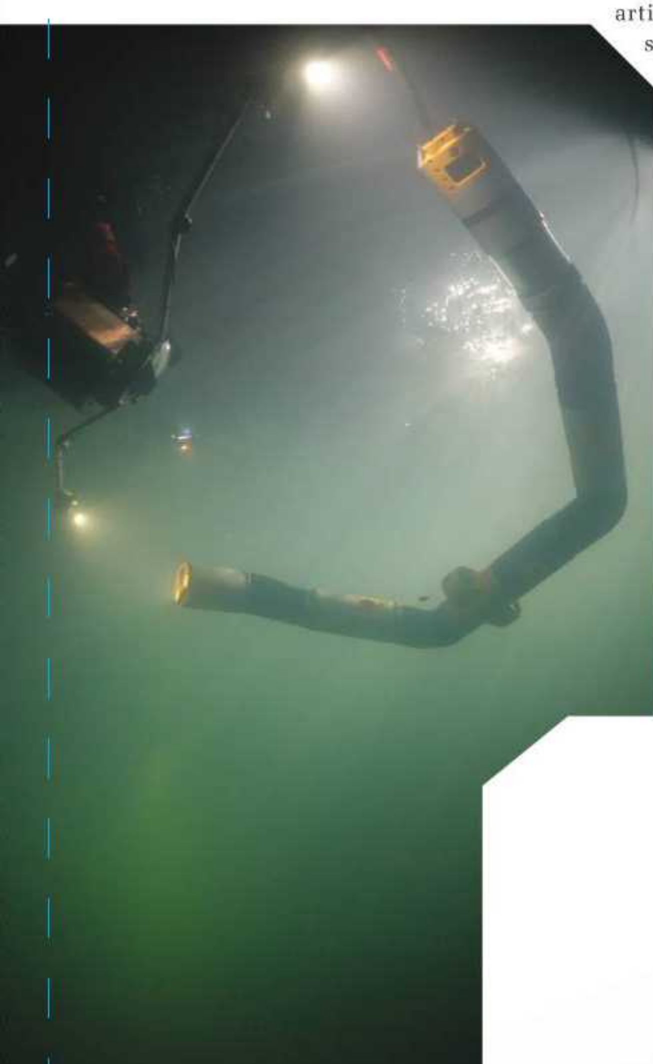
Having a resident subsea vehicle is seen as attractive because it would make the vehicle available for inspection, and potentially for 24/7 intervention and maintenance operations, without the need for a support vessel.

A robotic arm

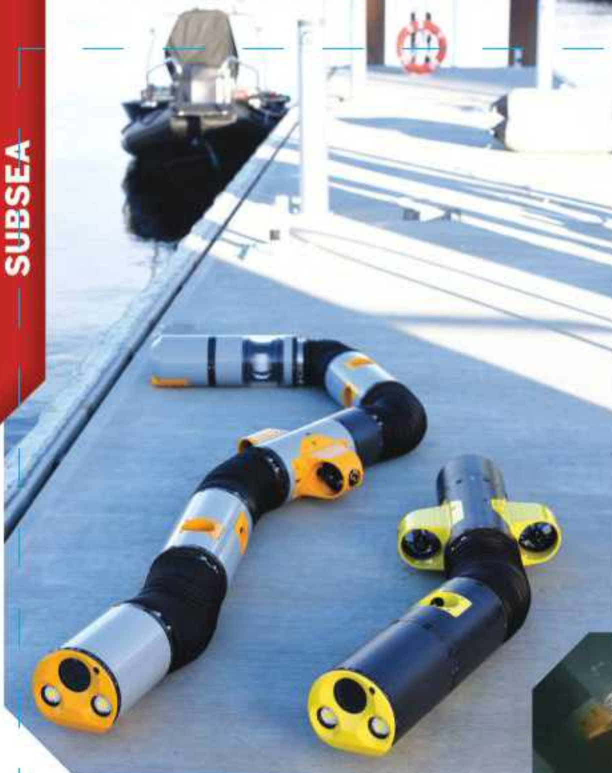
Eelume describes its unit, which would live in a subsea docking station, as a "self-propelled robotic arm" able to reach places conventional underwater vehicles cannot.

The vehicle's shape and ability to flex means it can form a U-shape, effectively making it dual functioning – i.e. it could hold on to something or have a manipulating arm on one end and a camera on the other. It's construction – multiple units, including its vertical tunnel thrusters and forward/back facing transit thrusters, as well as potential tools, connected with flexible joints – will also lend itself to a modular design, which can be interchanged, depending on its purpose, says Eelume CEO Arne Kjørsvik, who previously worked at Marine Cybernetics, which was acquired by DNV GL in 2014.

"We are quite sure this vehicle will [carry out] quite a lot of standard IMR solutions today," Kjørsvik says. "It is like a snake, but also like a manipulator



Eelume (a shortening of electric and luminaire, or light) trying out underwater life.
Photos from Eelume.



Top: Eelume and its predecessor on a Trondheim quayside. Bottom: Eelume trying out underwater life.

arm, which means you can put different tools on this arm to do different operations. It has easy access to constrained areas.

"But, we think the technology will also reshape the subsea business in the future. You might be able to construct subsea structures a bit lighter or easier as you don't need to prepare it for work with a work class ROV."

With tools like these, future subsea architectures could go one of two ways (or even both). One, where subsea facilities have power and communication links for the resident vehicle to dock into, helping to support the vehicle, but also making the architecture more complex. The other would be a separate power source and a communication link for the vehicle and in order to keep the subsea facilities simple.

Getting wet

An 18cm-diameter, 360cm-long, 70kg prototype, has been built and tested at 150m water depth in a fjord in Trondheim, Norway, traveling at up to 4-5 knots. This year, it will be superseded by a slighter wider diameter (20cm) unit, but not much longer (just under 4m is thought to be the maximum these underwater tools should grow). The firm hopes to put a faster vehicle into service by 2019.

Testing, to date, has been via a tether, for power and communications, but these are set to be phased out and batteries for power and acoustics or wireless for communications brought in, as the machine is developed, inevitably making it a little larger, but not too much, Kjørsvik says, and the power will be much less than that required by a work-class ROV, he adds.

Kongsberg will inevitably be involved with its positioning and navigation capabilities, developed for the likes of its Hugin and Munin AUVs. This summer, the latest prototype, still on a tether, will be trialed with tools and in deeper water, at 500m. Next year, the plan is for the vehicle to go wireless, without a tether.

Fighting fire

Eelume was formed in 2015 and is part owned by Norwegian maritime giant Kongsberg and NTNU (Norwegian University of Science and Technology). It has support from the Research Council of Norway and Innovation Norway, as well as Norwegian major Statoil. The company was spun-out from NTNU in Trondheim, but the technology itself has been under development since the early 2000s. Initially, the tool's intention was that it could be used by fire fighters in Trondheim, who had to deal with fires in the city's many wooden buildings. They had wanted a tool to hold a fire hose.

However, in 2014, someone had the idea to coat the unit in rubber and put it in water to see how it would swim. It turned out it could, and the idea to use it in the offshore industry was born. In 2016, Statoil signed a development contract with Eelume and the first wet-prototype was built not long after and tested in 150m water depth, carrying out inspection tasks and demonstrating its maneuverability.

Research work at NTNU has been behind the project, specifically around how to control a snake-like robot using NTNU-developed algorithms created to recreate how actual snakes move. Developments in battery technology, positioning systems, communication systems and subsea tooling technology, are also helping bring this technology to life, Kjørsvik says.

"The standard tools need to be recreated, they need to be a lot lighter than they are today," he says. "Most tools have been hydraulic; however, more and more are electrified, and that is an enabler for us."

Further development may see the materials that make up the unit change from aluminum and plastic to other lighter and stronger materials. "Today is about proving the concept of being a subsea resident," Kjørsvik says, however. "Communication, batteries and control system are the most important steps for us now. There are a range of different tools out there which we have to adapt, but that is an engineering job." **OE**

FURTHER **READING**

Video: Eelume debuts snake-like underwater robot:
http://bit.ly/2poydy7

Managing risers using data

Himanshu Maheshwari and Bulent Mercan, of 2H Offshore, discuss how a well-designed integrity monitoring program provides data for riser digital operations.

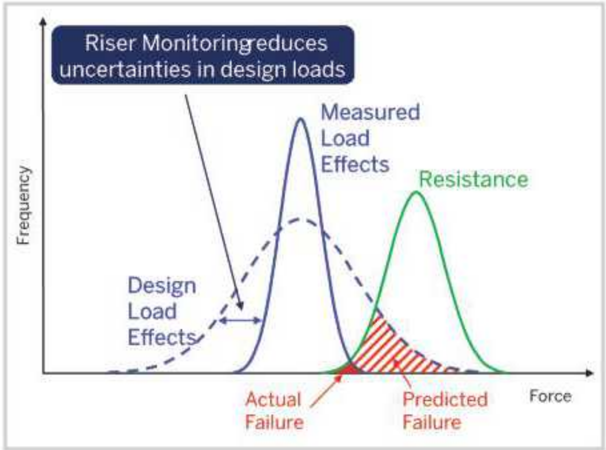


Fig 1: Large gap between predictive analysis and reality.
Images from 2H Offshore.

Machine learning, edge analytics, big data, cloud infrastructure, the internet of things (IoT). The offshore industry is starting to embrace digital technologies for drilling operations and condition-based maintenance (CBM). These technologies are of little use without data from subsea assets to drive them. A well-designed riser monitoring system will allow operations managers to access that data and harness these technologies to make knowledge-based operational decisions.

Deepwater drilling risers are often deployed in harsh offshore environments in water depths >1mi. In most cases, limited sensor data from the seabed and rig is used to help manage operations.

We are also pushing boundaries with deeper water depths, harsher environments, high-pressure, high-temperature (HPHT) reservoirs and drill floor automation, which makes riser operations increasingly challenging. Whatever the offshore conditions, developing a smart riser monitoring framework that reduces risk, increases safety and facilitates operational decision-making, requires careful consideration and planning in combination with data analytics and leading edge technologies.

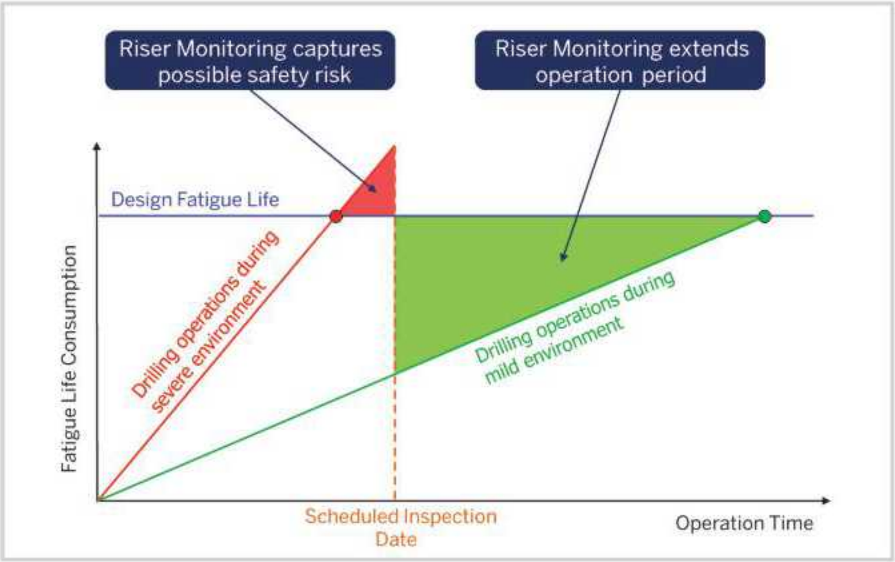


Fig 2: Condition-based riser maintenance.

Maximizing the value

Data driven decision-making is critical in today's market because the industry can no longer afford wastage on sub-optimal design tools. The drilling industry traditionally relies on numerical analysis tools to assess the structural integrity of riser components for fatigue and operating envelopes. The riser engineer provides the analysis results based on pertinent industry best practices and codes. These design provisions include high safety factors in order to account for the variability of the environment, soil, weld quality, material properties and hydrodynamic characteristics. This overly conservative approach with a safety factor can delivers results that are less than realistic (Figure 1), which could result in reduced operability.

Scheduled drilling riser joints inspection is another major expenditure for deepwater drillers. The high cost of logistics, inspection and re-certification of each joint affects the bottom line. CBM is accepted by regulatory and certification agencies as an alternate to the scheduled inspection. A strategic riser monitoring program backed by a robust data management process is an effective tool for CBM. The monitoring program effectively tracks the usage and loading on each riser joint to ensure against early failure and allows more accurate inspection frequencies as shown in Figure 2.

As the drilling industry settles into a "new normal," riser monitoring, data aggregation and digital data analytics offer significant opportunities for operators and drilling contractors to reduce costs and increase uptime.

Be clear on monitoring objectives

A monitoring system configured for CBM can vary greatly from one configured to increase operating windows, so it is important to specify monitoring objectives early in the project. Are you operating in high currents or high seastates? Is fatigue hot spot tracking required? Is there any need for a flex-joint limit assessment? Perhaps the concern is wellhead fatigue accumulations during high currents. With an understanding of what data needs to be collected, the system can be optimally designed and the most suitable sensors selected. Focusing on a cutting-edge sensor or platform instead of the key objective is a common but crucial mistake.

System engineering requires a detailed understanding of riser dynamics, instrumentation, and data analytics. There are a multitude of ways to configure a riser monitoring system and carry out the data analytics. Selecting the most appropriate approach depends on a number of factors, for example, environmental conditions, riser response, data acquisition access and data analytics considerations. Knowing which approach to use in what conditions is essential to achieving a reliable, low cost system.

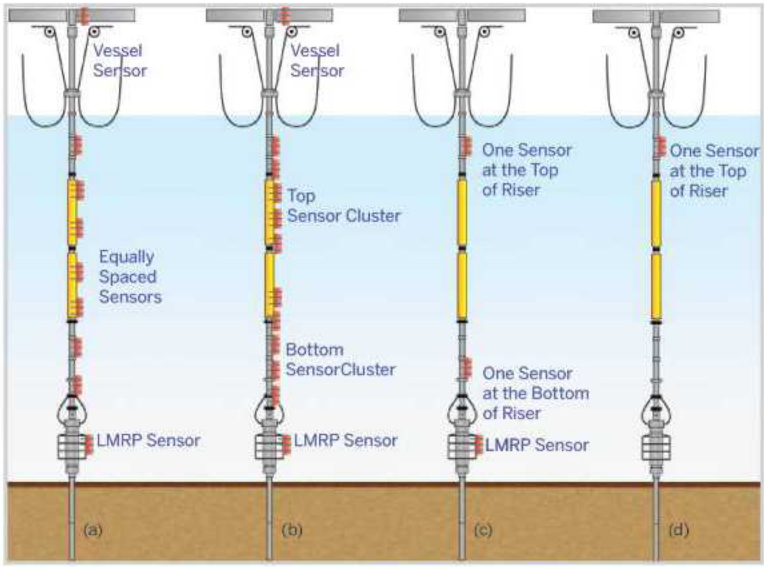


Fig 3: Reduced number of sensors with advanced field data analytics.

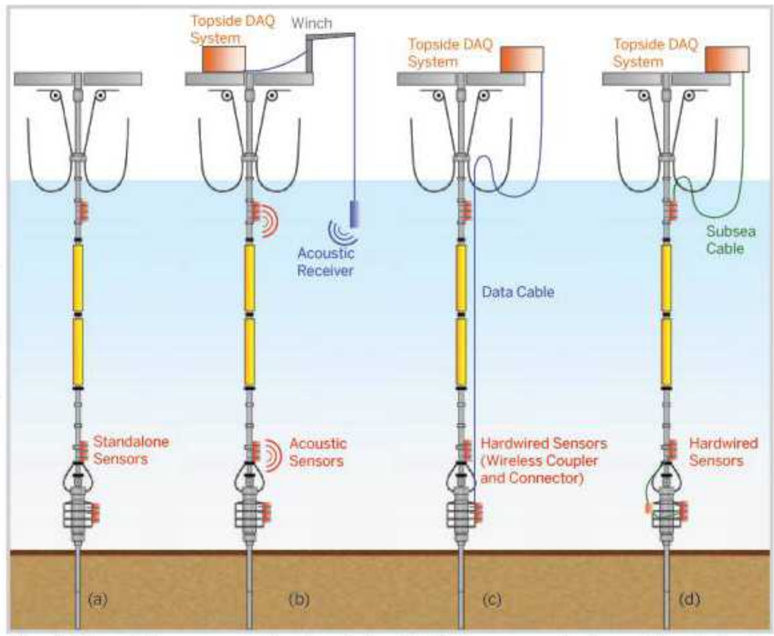


Fig 4: Standalone, acoustic, hardwired (wireless coupler), and hardwired configurations.

Selecting the system

Drilling riser response is typically monitored by high precision motion or strain sensors specially built for subsea. Motion sensors allow global response measurement, whereas strain sensors provide direct stress measurement at fatigue hot spots.

Sensors can be mounted equally spaced along the length of the riser, Figure 3 (a), but the cost of such a system would be very high due to the number of sensors needed.

Using fewer sensors in clusters at the top and bottom of the riser stack in the fatigue hot spots, Figure 3 (b), provides equivalent value in terms of data, but at less cost. Further savings can be achieved by reducing the number of loggers as shown in the configurations in Figure 3 (c) and (d) and using advanced data analytics.

Optimizing data transmission

Subsea data transmission requires expensive hardware. For a real-time riser monitoring system, data transmission is a major cost and schedule driver. Advanced planning goes a long way to assure a reliable system.

Standalone sensor packages with battery packs have been used as a cost-effective solution for riser monitoring as shown in Figure 4 (a). Standalone loggers deployed or retrieved by ROV have the least interference with drilling operations. They can be used to track fatigue and help with CBM. Standalone configurations are limited in providing operational support because recorded data is only available for analysis at the end of a monitoring campaign.

Acoustic sensors are better for near real-time monitoring and operational decision making as shown in Figure 4 (b). They have been extensively used in deepwater environments. Due to the small bandwidth, the acoustic communication systems can only achieve low data rates and suffer from low propagation speed, severe channel variation, and environmental interference. Acoustic data communication is more suitable for small data sets (e.g. motion spectra instead of time signals). Nano apps are used to process data on acoustic systems to reduce the size and frequency of transmission.

Hardwired systems offer real-time data access as shown in Figure 4 (c) and (d). A data cable can be installed along with a MUX line to integrate a number of sensors along the length of the riser. A wireless coupler is used for data access at each joint. As an alternate, short length cable near the top and bottom can be used to measure strategic locations and are extrapolated with analytics.

Applying advanced data analytics

Data processing tools can run on a sensor package or can analyze aggregated data on the rig for real-time assessment. Nano programs running on advanced sensor packages can greatly reduce the data transmission and power requirement leading to cost savings for acoustic systems. Triggers can be set to alert for events that require immediate attention. Real-time data aggregated on the rig is analyzed and published to provide operational guidance. The analytics can be as simple as trending, thresholding or spectral assessment. Careful attention should be paid to signal processing and analytical methods based on the sensor scheme, data transmission and riser response. Apps use various data analytics and transfer functions

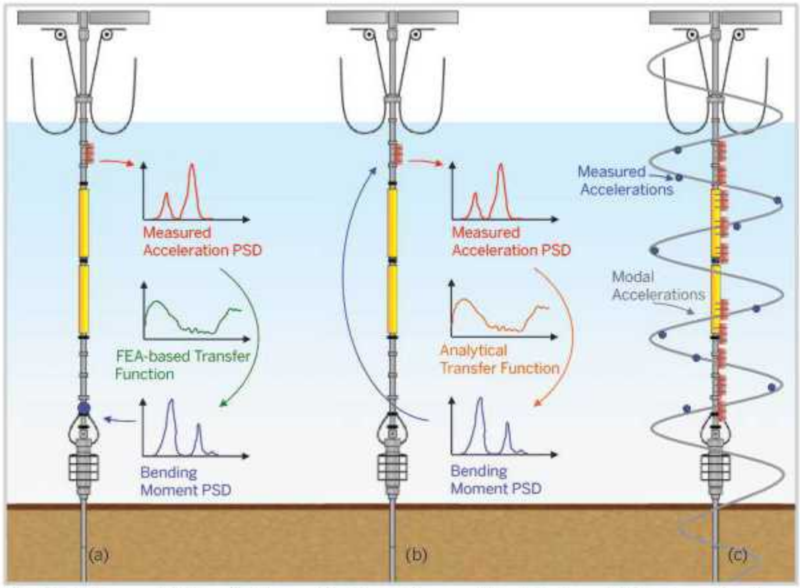


Fig 5: Data analytics; (a) transfer function method (b) analytical method and (c) mode matching method.

correlating measured data with riser response in demand.

Measured riser response at the sensor location can be correlated with responses at a distant riser location using transfer function methodology, as shown in Figure 5 (a). Finite element analysis (FEA) is performed to generate transfer functions for critical locations. This method is very cost effective as it requires data from a single sensor. However, the accuracy of the results will be compromised due to its FEA dependency.

The analytical method is independent of FEA and offers more accurate results. This method relies on analytically derived transfer functions correlating measured accelerations to curvatures at the sensor location, as shown in Figure 5 (b). Fatigue accumulations can be calculated at the sensor location.

The mode shape matching method is used to determine riser fatigue due to vortex induced vibrations. This method uses the modal amplitudes and frequencies fitting best into the measured riser response at various logger locations, Figure 5 (c). The result will require a number of sensors distributed along the riser in order to properly capture the riser excitation modes in the field.

Embracing digital operations

Digital operations help achieve dramatic improvements in productivity and efficiency by using data driven decision making from the rig floor to the command center. An example of riser digital operation system architecture is shown in Figure 6.

Typically, data from a number of sensors and devices including riser monitoring, environment, vessel motion, riser response tracking and in-between well joint inspections is stored on board the rig. A large number of operations fail to leverage from this data as it is stored in separate databases.

Edge analytics tools allow for data collection and analysis in which an automated analytical computation is performed on data at a sensor or on board rig database. Smart sensors and devices trigger raw or processed data transfer based on events to prioritize rig network resources and manage risks. Onboard data aggregation and real-time analytics will then provide insights into ongoing operations. A carefully designed user interface will deliver real-time feedback giving a realistic view of the operating envelopes, alerts and tracking of critical operations.

Rig personnel can access flex-joint angles, riser tension, rig offset, riser displacement/shape, environmental data, and fatigue damage rate tracking displayed along with their safe working limits. In addition, they can get real-time advisories for optimal tension and vessel offsets to stay within operating envelopes and reduce damage to the riser system.

At the command center, field data from multiple rigs are aggregated through cloud infrastructure for big data analytics. It includes a collection of field data recorded during operations at different water depths, environments and fields. Aggregated data sets can be used to develop more reliable predictive models with machine learning.

Machine learning is based on algorithms that can learn from data without relying on rules-based programming. Having access to input data and results facilitate training algorithms leading to improved predictions. Specialist apps can be used to calculate key parameters related to weld crack growth, wall thickness, sealability, corrosion and model calibration.

Riser monitoring systems should be designed with the combined understanding of end results, system response, data analytics and instrumentation. In turn, digital operations can uncover patterns from big data sets resulting in closing the gap between numerical analysis and reality; allowing increased uptime, providing smart stack-ups for fatigue management, delivering early warning for impending risks and facilitating CBM to optimize inspection frequency and extend asset life. **OE**

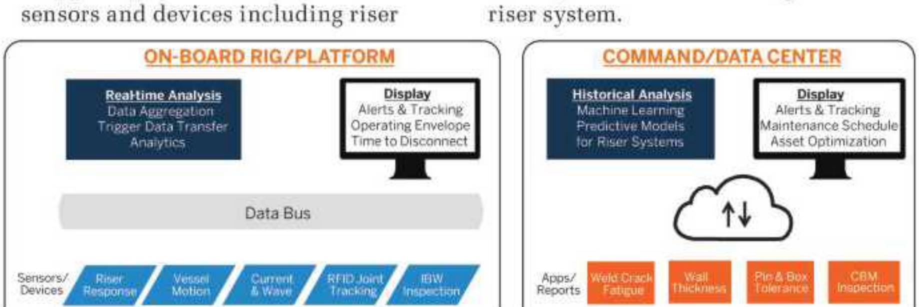


Fig 6: Riser digital operations.

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Bulent Mercan *is an engineering specialist at 2H Offshore. He has a PhD in civil engineering and over five years' experience in riser engineering, monitoring and data analytics.*

Digital twin for marine drilling risers

Greg Myers, of GE Oil & Gas, explains how the digital transformation of offshore assets enables a competitive advantage by reducing excessive inspection and maintenance costs and increasing uptime with real-time operational data.

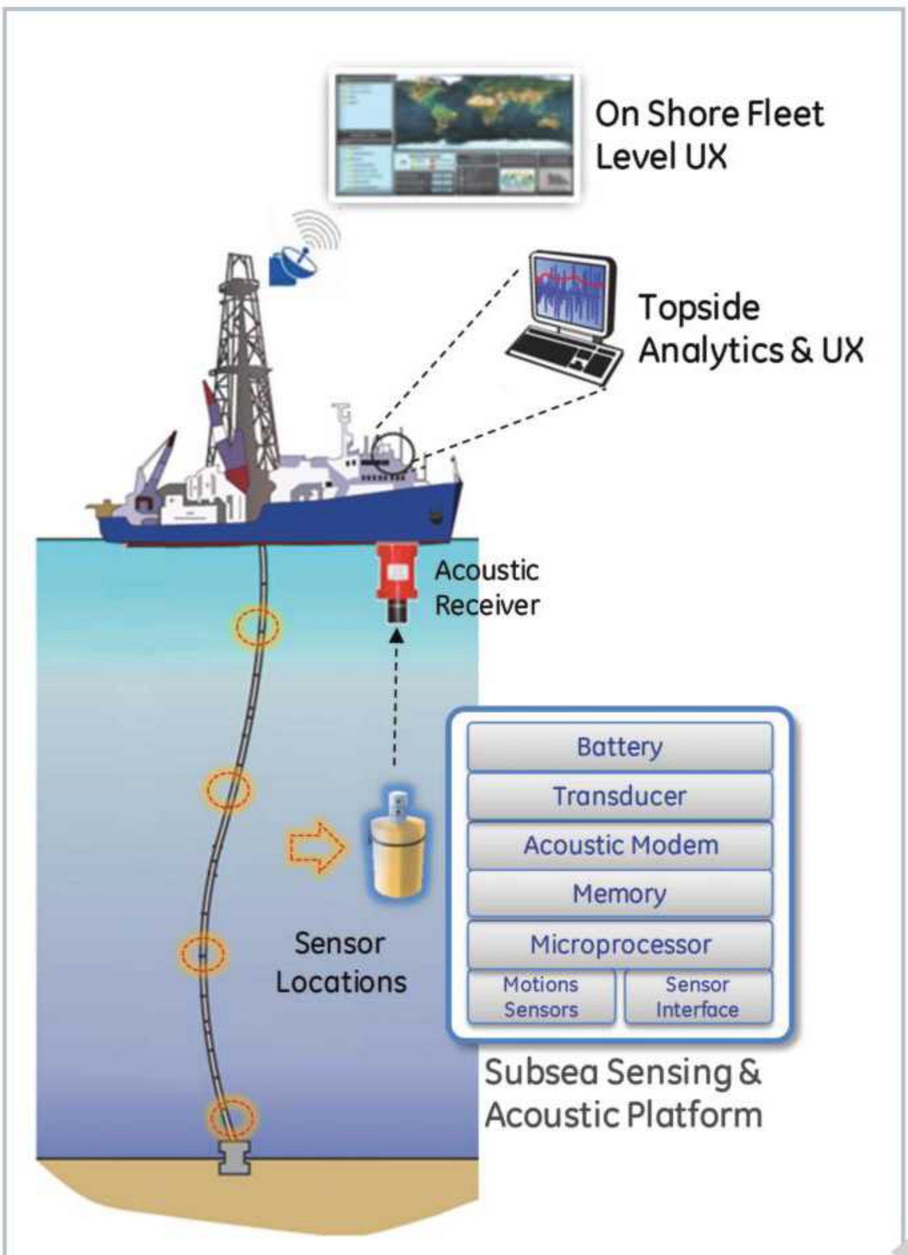

Fig. 1. System Overview for the marine riser digital twin. Images from GE Oil & Gas.

To compete in today's climate of energy price instability, operators and contractors can benefit from data-driven solutions to increase their operations visibility, optimize lifecycle management and reduce costs of maintaining offshore equipment. Drawing critical insights from operational data is a crucial first step.

The cost drivers of offshore drilling can include: (1) unplanned downtime associated with drilling in ultra-deepwater or harsh metocean conditions, such as strong loop currents, and (2) resources spent to transport and inspect riser joints onshore. These factors pose challenges on efficiently deploying and maintaining marine risers over their 20+ year lifespan, while meeting safety and regulatory needs. These factors can also cause riser curvature, hang-off deflections and high tensions at the blowout preventer and wellhead, which impart fatigue loading damage on the equipment.

Value from digital transformation

GE has addressed these challenges by creating a digital model of a physical asset, called a digital twin, which can then be optimized to drive enhanced business outcomes. In this instance, both a physical and a virtual model of a marine driller riser was created with the goal of reducing downtime or optimized inspection schedules of these critical assets, which can extend miles in length below the ocean's surface. The digital twin allows GE Oil & Gas to provide the driller with data-based diagnostics and insights into what is happening to the asset during a regular day or even during an extreme event, and then pick the most optimal way to run that asset. GE has already deployed thousands of digital twins in other applications such as aircraft engines, wind farms and power plants using Predix, the cloud-based

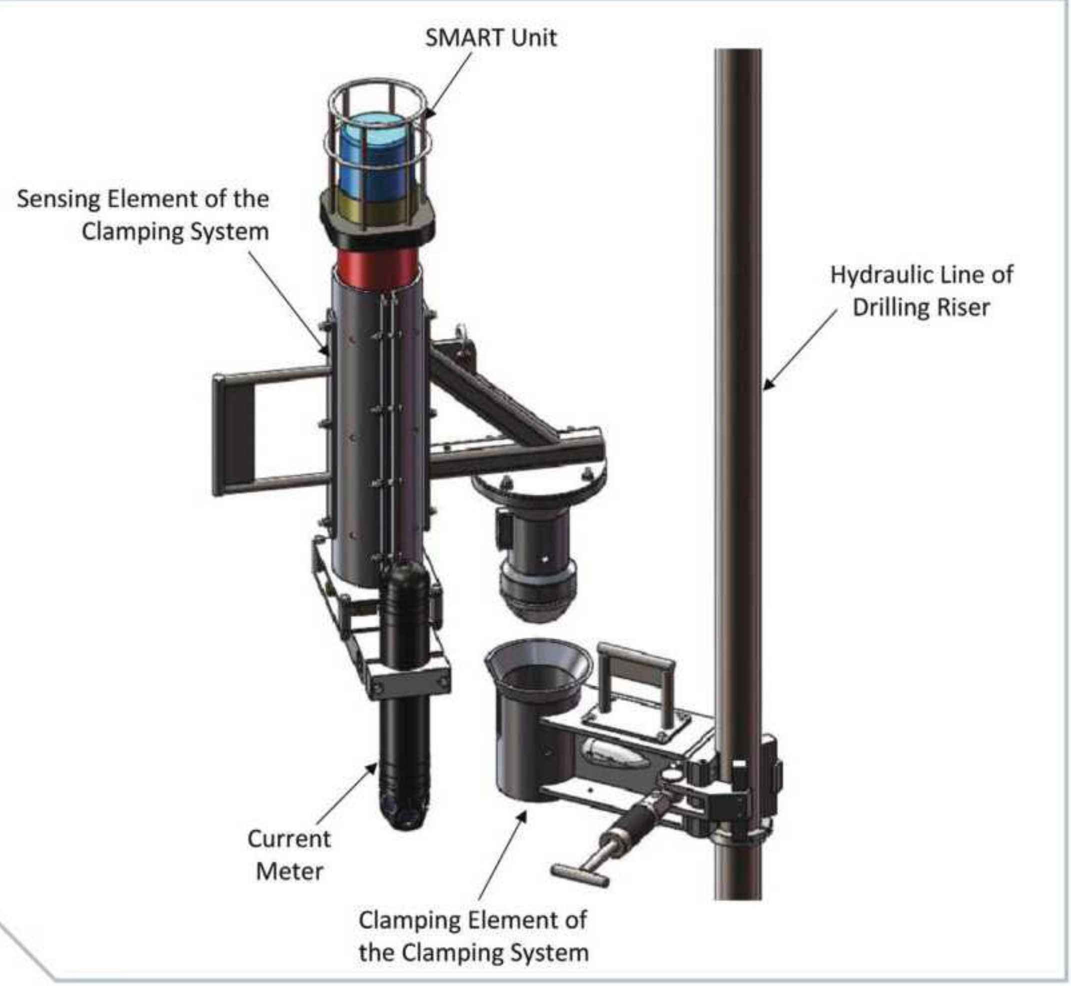

Figure 2. Illustration of the clamping system for deployment of the subsea sensing module.

operating system it developed for the Industrial Internet.

This marine riser digital twin will allow operators to maintain equipment in a more efficient manner. It can help reduce excessive maintenance and costs of the main tube for drilling contractors with a data-driven approach: a baseline database for drilling riser fatigue damage based on field operational data, in situ riser measurement data and environmental conditions. This "predictivity" allows transition from time-based to performance-based maintenance.

In addition, the system may take the guesswork out of decisions such as when to cease drilling activities due to strong currents or other adverse metocean conditions, or when it is safe to restart operations.

Anything that can provide significant reductions to unplanned downtime is critical. Working with RPSEA [Research Partnership to Secure Energy for America], NETL [National Energy Technology Laboratory] and GE customers, GE's concept was to give the drilling contractors and operators solutions to increase visibility into the health of their equipment below the surface. The system will help operations and engineering teams respond quickly to potential issues as they occur in real-time.

System approach to the marine riser digital twin

The digital twin provides near real-time condition monitoring and fatigue estimation of drilling risers (Figure 1). A modular approach was used for designing the subsea platform. The platform consists of an acoustic modem and transducer, rechargeable batteries, tri-axial accelerometers and gyroscopes, and a micro-processor for data acquisition and processing.

Unlike conventional techniques such as strain gauges for direct strain/stress measurement, the system measures the vibrations using accelerometers at select joints along the drilling riser. It transmits the vibration data and other sensor data, such as ocean currents, via acoustic telemetry in near real-time to a topside data acquisition system on the drilling vessel. Topside, advanced machine learning techniques, coupled with a physical asset model of the entire riser string, are used to calculate fatigue life estimates for all riser joints.

The digital twin, or machine learning model, is a virtual model of the riser that is continuously updated against the sensor measurements and metocean conditions. When this data is beyond the original training conditions, a model retraining is automatically triggered. This continuous learning and update of the digital twin model allows us to provide more precise calculation of the riser fatigue life and enable optimizing operations in near real-time. Visualization and alerts are provided by software, which ingests and performs advanced analytics on the field data enhance the operational decision-making for the drillers and operators.

A proof-of-concept of the digital twin was recently deployed in the Gulf of Mexico on a semisubmersible ultra-deepwater drilling rig for a nine-week test. Five subsea sensing modules were installed at key joints along the riser string by a remotely operated vehicle (ROV) controlled from the topside, with the lowest module located at a depth of 6200ft on the drilling riser string and

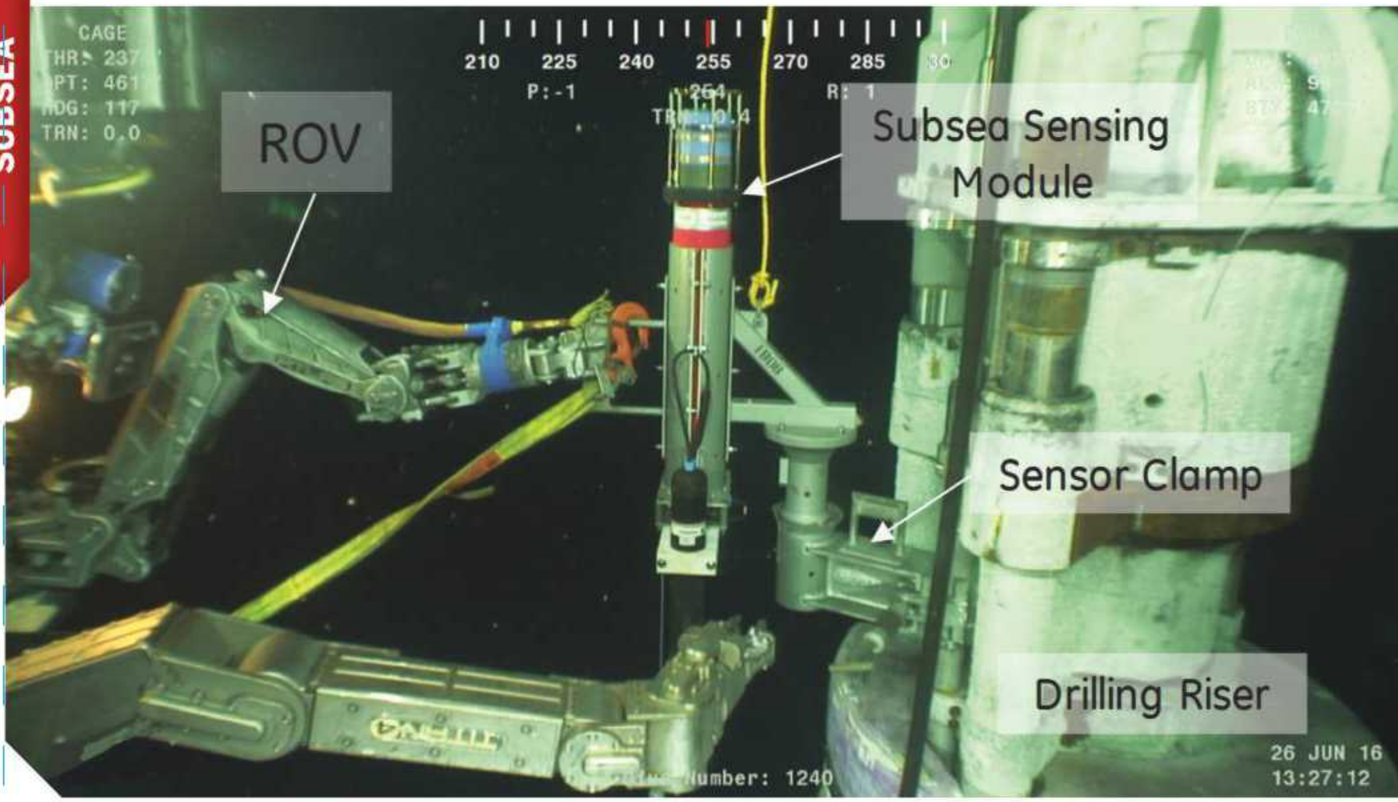

Figure 3. Deployment of the sensing element with the subsea sensing module to the clamping element by a ROV.

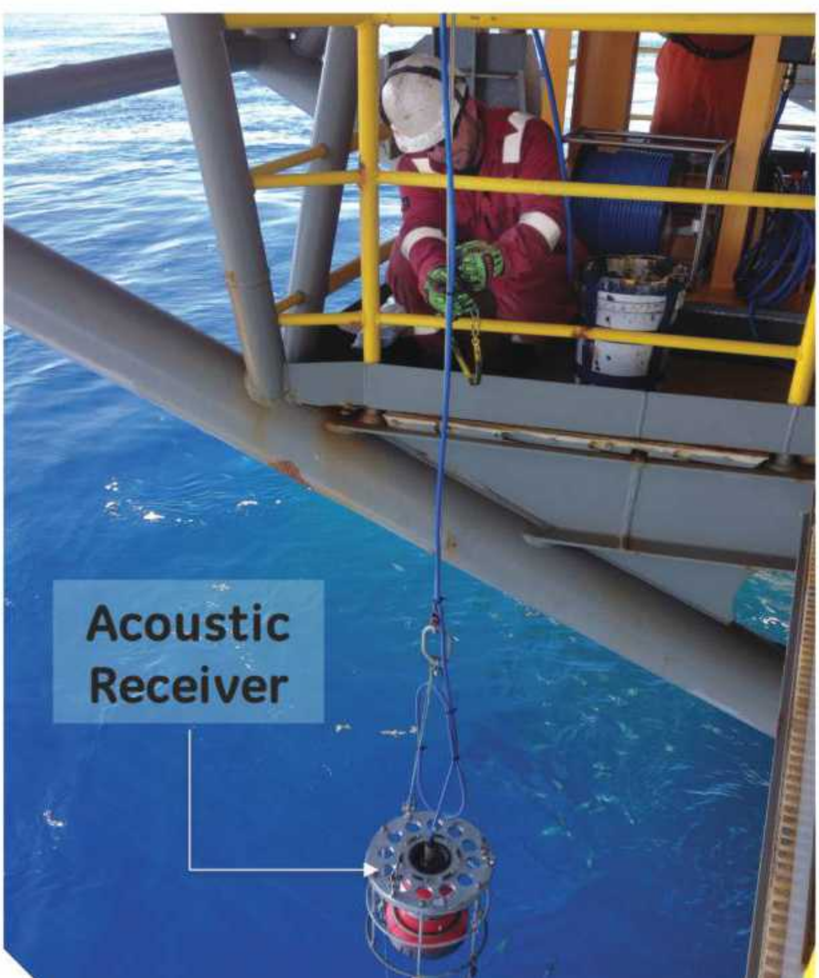

Figure 4. Topside acoustic receiver for data acquisition.

the remaining equally spaced from the sea surface, up to 350ft below sea level. The topside data acquisition system with the digital twin software collected processed sensor data every hour and analyzed the riser health and fatigue damage in real-time.

To deploy the subsea sensor module, a two-part clamping system was designed, which is riser agnostic and easily retrofittable onto existing risers. The system consists of two elements, as shown in Figure 2: 1) a clamping element which directly clamped onto an auxiliary line of a riser joint, and a bucket that contains the sensing element and has a rigid attachment to the riser; 2) a sensing element which inserts into the bucket to join the clamping element. This system allows the user to deploy and retrieve the sensor clamp and sensing element either manually or by ROV.

Figure 3 shows the docking of the subsea sensing module inside the sensing element into the bucket of the clamping element by a ROV, and Figure 4 shows the topside acoustic receiver for acoustic data acquisition on the drilling rig platform.

Novel aspects of the marine riser digital twin system from this field trial test include: (1) long-range deepwater communication for near real-time sensor data collection, and display of key riser health data and analysis of data to meaningful information, (2) advanced machine learning techniques for fatigue damage estimation, and (3) integrated system functionality of the marine riser digital twin system on a drilling riser, which is generic to the offshore drilling industry.

Next steps

As the marine riser digital twin advances toward a commercial product, it is envisioned that the entire twin deployment and running process will be handled by standard rig crew teams with no specialty human skill sets required to use the system as intended. When fully deployed, these advanced digital technologies will change the way we work and improve the integrity and performance of our assets. This is just the latest example of GE using software to improve subsea drilling. GE also has partnered with customers to optimize valve assemblies by adding cloud-based analytics running on GE's Predix digital platform, the operating system for the Industrial Internet.

The machine learning model – the virtual model of the riser is continuously updated against the sensor measurements and metocean conditions, and a model retraining is automatically trigger when the data is beyond the original training conditions. The continuous learning and update of the digital twin model allows us to provide more precise calculation of the riser fatigue life.

Special thanks to Sonardyne and Seanic Ocean Systems for their invaluable contributions to this program. OE

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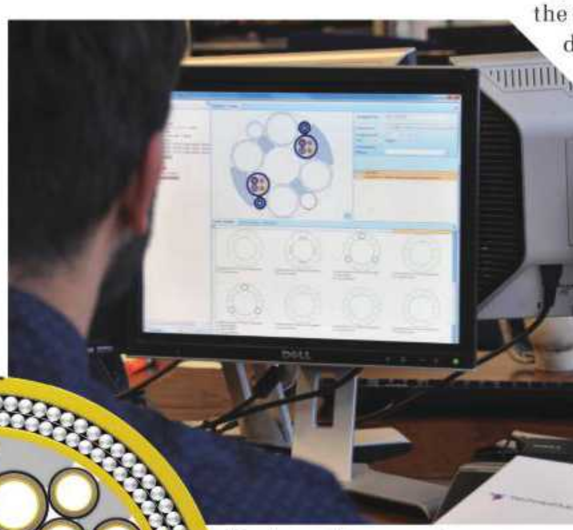
__Judith Guzzo__ is a senior research scientist at GE Global Research, focused in the Software Sciences & Analytics and Robotics domain. She has over 20 years of technical and project leadership experience in asset visibility technologies of complex systems with 9 issued US patents and over 15 peer-reviewed journal and conference proceedings.

__Shaopeng Liu__ is a lead scientist at the Software Science and Analytics division of the GE Global Research Center in Niskayuna, New York. Shaopeng has concentrated his focus on the research and development of cyber-physical system technologies and solutions for diverse industrial applications. Shaopeng received his Ph.D. degree in Mechanical Engineering from the University of Connecticut in 2012, and received M.S. and B.S. degrees in Mechanical Engineering from Tsinghua University, Beijing, China, in 2007 and 2004, respectively.

Improving umbilical design

Technip's Maurice Anderson discusses the benefits of using new software for designing umbilicals.



Design software and cross section design. Images from Technip.

The design of a subsea control umbilical is governed by international standards and requires detailed knowledge and experience of the materials, functional component capabilities and umbilical manufacturing processes. Such knowledge ensures successful delivery of a cost-effective and fit-for-purpose solution, which meets client expectations.

Dedicated engineering tools used to design umbilical components have successfully been employed on many clients' projects over the years, such as TubeCalc Pro and other independently verified third-party tools. These tools perform complex calculations, such as optimizing the wall thickness of a steel tube based upon international standards and client preferences. With a strong supply chain, market challenges to minimize costs and achieve commercially competitive solutions, minimizing tube wall thickness is a critical step in the design process. As the choice between seamless and seam welded tubes has recently expanded, TubeCalc Pro is able to account for differences between the two tube manufacturing techniques and quickly assesses the potential savings, while still ensuring a fit-for-purpose solution.

Although umbilical manufacturers have developed engineering design tools that enable efficient assessment of the functional component's performance, a key process is positioning the components together into the umbilical cross section design effectively. It is not uncommon for 1500 or more cross sections designs to be created each year. Traditionally, this relied heavily on the umbilical designer's expert skills and knowledge of material behaviors, umbilical assembly processes and in-service response to the intended environment to achieve a suitable design. The process involved manually drawing a cross section using CAD packages, from which key engineering parameters were extracted and entered into a database. The database provided a backbone from which cross section analysis tools could extract consistent input of data, such as performing tube stress and fatigue calculations.

Recognizing the inefficiencies and potential for human error during the data transfer, a bespoke umbilical cross section design tool has now been created. Rather than manually drawing the cross section by hand, the tool allows the umbilical designer to enter pre-approved functional components into a template driven cross section design. Each template can be easily tailored towards a particular manufacturing process, service application or a particular client preference, allowing the umbilical designer to rapidly create the cross section design. The position of the functional components is then automatically placed and intermediate fillers created where necessary, meaning an umbilical cross section can be created in a fraction of the time. To ensure quality and manufacturability, the tool automatically assesses the design against in-house design rules, so that a risk profile for the design can be mapped against previous experience and any potential engineering concessions can be clearly identified, enabling a more efficient sign-off and approval process.

Once the design has been completed, the key engineering data is automatically extracted into the database. A formal cross section design drawing can be automatically created along with the accompanying cross section datasheet populated with routinely calculated mechanical properties. The tool also synchronize with the existing engineering analysis tools, to repeatedly generate design reports using a standard format. Clients not only benefit from quicker response times to cross section design requests, but the standard reporting format will enable easier review due to the familiar format and confidence in the results given the tool has been verified by an independent third party.

Other than the speed of initial cross section design, inevitable design changes, as the subsea field architecture matures, can be efficiently implemented. For example, if an additional functional component is required, or a tube dimension increases, they can be easily swapped out and positional changes of the remaining components will automatically adjust. All intermediate filler designs, armor packages and outer sheath dimensions are also instantly updated. Design evolution is systematically recorded when the database is updated, ensuring a very clear quality audit trail.

Through the development of this suite of integrated engineering design and analysis software tools, umbilical designs for future projects will be created quicker, more accurately and ensure the most cost effective, fit-for-purpose solution. **OE**

Flexible to the core

JDR's latest tool. Photo from JDR.

Northeast England has a heritage when it comes to the shipping and offshore industries. Elaine Maslin reports on how JDR and GE Wellstream are keeping the tradition alive.

Handling multiple strands of wire to make wire rope is a well-honed skill on the Tyne in northeast England. Companies have been doing it here for centuries – one of the companies bought to form British Ropes in 1924 was Thomas and William Smith, from Newcastle upon Tyne, itself founded in 1782.

At that time, Newcastle was one of Europe's biggest industrial centers. While industry isn't quite at the same scale as what it once was on the Tyne, the skills remain (as do some of the companies, including Bridon, formed from British Ropes) and the companies that are using them are putting them to good use – in the offshore industry.

The carcass line at GE Wellstream. Photo from GE Wellstream.

JDR, in Hartlepool, not far south of Newcastle, has recently installed a new horizontal layup machine (HLM) for steel tube umbilicals. It's the largest of its type in the UK and the largest HLM in the world.

The firm has been making significant in-roads into the renewables industry, including introducing 66kV cables, and has its sights set on the emerging floating wind farm market, as well as continued work in oil and gas.

Meanwhile, GE Oil & Gas' Wellstream business, on Walker Riverside, is completing work on its new composite umbilical manufacturing line and has research projects well underway at its still relatively young innovation center there. DUCO, part of TechnipFMC, meanwhile, installed a new vertical helix assembling machine to manufacture steel tube umbilicals back in 2014.

JDR's Hartlepool facility. Photo from JDR.

JDR

Despite a downturn in oil and gas, JDR has been growing its capacity and capability. The firm started the first product run off its new 40m-long HLM last August. The impressive unit is able to wind 17 functional layers (up to 4000-tonne of component can be loaded at a time) into a steel tube dynamic, static or deepwater umbilical, at up to 6.5m/min.

Its first job was flying leads, under a contract with GE, for ONGC's Vashishta and S1 project, in the KG Basin, 30-35km off eastern India, in 250-700m water depth. JDR is supplying 12 steel tube flying leads and associated hardware.

The new HLM adds to JDR's existing capacity, which includes a vertical lay machine, two armoring machines, and two large storage carousels. The firm supplied 500km of product last year – compared to 200-300km in the past – and sees that number growing. Much of it will be wind farm work, including its newly qualified 66kV cables.

66kV

66kV cable is one of the firm's recent advances. It does not need a lead barrier, as other higher voltage cables do, which helps to reduce product weight, making transport and installation easier, and eliminate fatigue issues associated with lead. Increasing power cable voltage from the established 33kV to 66kV will also help accommodate the larger wind turbines increasingly being installed, as well as future subsea factory needs.

The technology was qualified last year and the first application will be on Vattenfall's European Offshore Wind Deployment Centre (EOWDC), off, Aberdeen under a contract with VBMS, part of Boskalis. JDR will supply 20km of 66kV inter-array and export cables, plus associated accessories, for the 11, 8.4MW turbine test and demonstration facility, due to start up in 2018.

Mid-April, JDR won its first commercial 66kV array cable project with VBMS to supply intra-array cables for ScottishPower Renewables' East Anglia One (EA1) offshore wind farm. JDR will design and manufacture 155km of array cables including end terminations, plus a cable management system at each offshore wind turbine generator, to allow for a 66kV topside connection to the switchgear cables.

The 714 MW EA1, with up to 102 wind turbines, will be the first of four projects in the East Anglia Zone. The offshore wind farm will consist of up to 102 wind turbines and will be located 43km off the Suffolk Coast in the southern North Sea. The wind farm is expected to power 500,000 homes when fully operational in 2020. JDR's delivery is scheduled for Q1 2019.

Other recent wind farm wins include a contract to supply power cables for the 1.2 GW Hornsea Project One, 120km offshore Yorkshire, England, and a subcontract from Siem Offshore Contractors to supply 180km of subsea power cables for the 84-turbine, 588MW Beatrice offshore wind farm in the Outer Moray Firth, off Scotland.

Meanwhile, JDR has been given preferred supplier status by US Wind, for the full cable package on its 750MW Maryland development project. Expected to be the largest offshore wind farm to date in the US, the Maryland project will include a maximum of 187 turbines in up to 30m water depth, 24km off the coast. A final investment decision is expected in 2018. JDR will supply and install 196km of inter-array cable, 180km of export cable and cable accessories. Delivery and installation is due in 2019-2020.

JDR is also making in-roads into floating offshore wind, which Peter Worrall, technical services director, JDR, says might be new to many, but involves principles the firm uses on floating production systems, where flexible connections are needed. The firm has won a European floating wind farm front-end engineering contract and is 66kV cable supplier on it, but Worrall was unable to say more at this stage.

AC/DC

The firm is also looking into AC power transport. Worrall says that using AC over DC for power transport can be beneficial, where it's possible. While DC is required for longer distances, using AC for shorter distances eliminates the need for converter stations on each end. This could mean optimizing designs so that it is accepted that a wind farm doesn't generate maximum power at all times, so that some losses in the power export can be accepted. "It's finding the goldilocks position," so that AC can be used, Worrall says.

Oil and gas

For subsea oil and gas infrastructure, JDR is looking to down rate the 66kV cable to a 45kv cable, for lower, shorter distance power demand, and use the 66kV cable for up to 100km step outs with power requirements.

But, it is also producing umbilicals, particularly in the Middle East and India, recently, and has tenders ongoing elsewhere. Cameron, on behalf of ONGC, awarded JDR a steel tube umbilical contract for 11 wells at the Western Offshore project. The Indian project includes the Mumbai High, Bassein and Satellite, and Neelam and Heera assets,


GE's composite flexible pipe. Photo from GE Wellstream.

mostly in 100m water depth. JDR will supply 11 umbilicals, with a total 53km length, as well as subsea terminations and accessories, with delivery in Q4 2017. Worrall says that JDR is also doing more front-end engineering work these days, looking at local studies, but also global analysis work to see how systems can be optimized.

GE Oil & Gas

GE Oil & Gas has been expanding and plans to add composite flexibles to its capabilities at its Walker Riverside facility in Newcastle this year.

The site has been producing flexible pipe since 1997. It has the capability to produce 2-16in flexible pipe, including four 12in dynamic, high-pressure, high-temperature risers for Shell's floating LNG Prelude project offshore Australia last year.

This year, it is introducing hybrid composites to its stable, reducing product weight by replacing a metallic pressure resistance layer with a carbon fiber layer.

With the opening of its Newcastle Innovation Center in 2015, complementing its Rio Innovation Center focusing on more deepwater and sour service applications, the firm is also focusing on new developments, such as the T-profile or anti-FLIP carcass.

FLIP stands for flow induced pulsations, a phenomenon known as singing risers. "This is when dry gas flows at high speed over corrugations in the inner bore and produces an acoustic resonance," says Rusty Justiss, general manager at Newcastle. "We are working on a pipe, with another layer [the

T-profile, which sits between the carcass corrugations], to create virtually smooth bore." The challenge is to get a smooth bore while not impacting the mechanical properties of the pipe, including its weight.

The center is also testing different polymers to destruction and working on ways to further improve pipe – from using fiber optics inside the pipe for monitoring (including measuring temperature and leak detection) to developing an ROV-deployable version of GE's MAPS-FR flexible riser inspection technology, which is based on magnetic stress measurement, and detects any tensile wire breakage.

The center is also home to testing facilities that can put pipe through -20°C to 130°C cycles, including bending.

The more visible action is in the firm's production facility where a new composite machine will soon join the multiprocess production process required to build up all the layers required for flexible pipe.

Recent projects at the site include Shell's aforementioned Prelude project and its Gannett development, as well as Eni's East Hub project.

GE's flexible pipe starts with an internal carcass, made from flat steel strips, which are formed and interlocked to create a tube with a set bending radius and collapse resistance, to the outer layers, which may include insulation.

Layers include a barrier, around the central carcass, made from a type of polymer, which is extruded onto the carcass, to provide pressure containment. There is also the Flexlock layer, which provides pressure resistance. This is pre-formed at 4-12mm thick, depending on the requirements, and wound on to bobbins before being wound on to the barrier layer.

With its new composite line, carbon fiber can now be added to the pipe, instead of the Flexlock layer, using a laser consolidation process. Replacing the tension resistance layer with a composite reduces the weight of the product while keeping more broadly it's established properties, Justiss says.

Flexible pipe also has a minimum of two tensile armor layers, with each pair wound on in opposite directions. The armor machines simultaneously wind multiple wires, each with a helical twist put into it, to make it lay properly. Anti-wear tape, made from a glass – or aramid fiber tapes if needed – is then added to prevent "bird-caging," a phenomenon which could see the armor layers spring out into a cage if put under compression along the length of the pipe. Further layers could also be added, such as an insulation layer, if required, before the end fittings are added and the product is loaded out on reels or direct to vessel from storage carousels.

The benefit of the composite layer is a 30% reduction in pipe weight, Justiss says, which means more product can be stored on a single reel and installation vessels will be able to be lighter with smaller tensioners for handling.

The number of buoyancy clamps or tethers used infield could also be reduced, GE says. The firm also says total installed cost would be reduced by 20-25%.

The 10in pipes GE is looking to produce this way would be able to handle up to 15,000psi fluids beyond 3000m water depth, with up to 150°C capability. The first will be manufactured this year, and the 10in pipe put through qualification. **OE**

Biopolymer containers on Heidrun's deck.
Photo from Statoil.

Sticky business

Offshore enhanced oil recovery pilots in the North Sea are paving the way towards helping to get more heavy oil out of the ground. Elaine Maslin reports.

Using polymerized water to flood fields and increase recovery rates is an established technology onshore. But, to date, polymer use for enhanced oil recovery (EOR) offshore has been limited to a handful of projects.

Since 2003, CNOOC has been using polymer from platforms on its heavy oil fields in Bohai Bay, offshore China. France's Total was first to take polymers on a floating production, storage and offloading (FPSO) vessel deep offshore with its polymer EOR pilot on the Camelia field offshore Angola in 2010-11, with a skid-mounted injection pilot on the deck of the *Dalia* FPSO.

Since 2010, Chevron has been trialing polymer EOR on its Captain heavy oil field and, more recently, Statoil has been putting the technology to test on its Heidrun field, with plans for further pilots on other fields in coming years.

While there are challenges associated with the technology, there's a large prize in getting it right, particularly for heavy or viscous oil.

Ruben Schulkes, project manager for polymer flooding technology development, Statoil, says that the Norwegian major has one of the largest portfolios of offshore heavy oil, including the Peregrino field offshore Brazil, the Mariner field in the UK (first oil due in 2018), and Grane, offshore Norway.

Heavy oil production recovery rates are often low (less than 20% is not unusual), compared to the average 50% or up to 70% on Norway's more usual lighter oil fields, Schulkes says. A breakthrough in increasing the recovery rate of this treacly stuff could be significant. Statoil's Mariner field, for example, is estimated to contain 250 MMbbl – a 5% increase in recovery would be significant.

Currently, waterflood is used to sweep heavy oil fields, but alone it isn't hugely effective because of a fingering effect caused by the water finding paths of least resistance through the reservoir and then sticking to them. This creates "water motorways," leaving behind swathes of unswept reservoir. This happens because of the difference in viscosity between the oil and the water. For example, in the Mariner field the oil viscosity ranges between 67-506 centipoise (cP) oil, while water is 0.5-1cP (500cP is typical for syrup). Adding polymer to the water increases the water's viscosity enabling it to more effectively sweep the reservoir.

But, what also makes polymer EOR

interesting is that in combination with increasing recovery rates, it reduces water cut, Schulkes says. Statoil has clear ambitions to reduce the amount of CO_2/bbl of oil produced and reducing the amount of produced water is a step towards reaching this ambition, he says.

Offshore challenges

Using this technology offshore isn't so easy. To get the polymer into the water, it has to be water soluble, Schulkes says. There are two types of water soluble polymer, biological and synthetic. The latter is already easily available in the large volumes needed, but, in Norway, synthetic polymer is classified a red chemical since the biodegradability is slower than acceptance criteria require. In the UK, it's classed as yellow chemical, due to different rules. The classification as a red chemical in Norway implies that produced water containing even tiny traces of synthetic polymer cannot be release into the sea and has to be reinjected.

Biological polymer, meanwhile, is made by fungi and meets all the criteria to be a green chemical, including in Norway. It's also more resistant to shear, meaning that a polymer molecule will not be drawn to pieces while entering the reservoir. A reduction in the length of the polymer reduces the viscosity of the polymer/water mixture and, therefore, the effectiveness. But, it's not widely available in large quantities. And, because it's biological, it can get eaten by bacteria in the reservoir, also reducing its viscosity. Closer well spacing onshore also makes polymer flood easier – it can be sent where it is needed faster, so less of it and lower injection rates are needed. Offshore, the well spacing is larger, which means that a larger reservoir volume has to be dealt with. This, in turn, requires higher pump rates, to get the polymer where it's needed, leading to the shear degradation mentioned above. In addition, in an offshore setting, the polymers will be in the reservoir for a longer time, implying that thermal degradation of the polymer may become an issue that will also reduce its viscosity, Schulkes says.

There's also a logistical question – to ship the polymer as powder and mix it onboard or to ship as an emulsion. "No one has done this full field offshore before," Schulkes says. "There is uncertainty at what point it is worthwhile to start polymer flooding. In principle, it would be beneficial to start polymer from the start, to stop the water motorways occurring. But it's not a mature technology. So, it is going to be a brownfield technology."

Captain

Chevron's Captain EOR project in the UK North Sea is the most advanced polymerized water injection project in the basin. It has been and is still a long-term project, but its full implementation could see significant volumes recovered from the field and subsequently others.

Statoil's Heidrun field. Photo from Statoil, by Øyvind Hagen.

Chevron has been working on the project for 10 years. Earlier this year, it started its fourth pilot project on the field to further refine its future polymer EOR plans for Captain. The plan looks likely to be a staged roll-out, starting with up to six long-reach horizontal injection well, using synthetic polymer, followed by full-field expansion.

Discovered in 1977, in Block 13/22a, the billion-barrel Captain field achieved first production in March 1997 thanks to technology developments in horizontal drilling and downhole pumps. Production peaked at 100,000 b/d and is now around 26,500 b/d.

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

Its reservoir conditions – pressure, temperature, type of rock and oil properties – make it an attractive candidate for polymerized water injection.

"If we can introduce polymerized water, we can exploit the mobility ratios between the oil and the polymer," says Richard Hinkley, general manager of Projects and Future Growth at Chevron Upstream Europe. "Instead of coning, we are bull heading a bank [of polymerized water] towards the producing wells." This will also help reduce the water cut produced and, rather than extending field life, it could mean recovery is maximized earlier instead.

The timing is important, Hinkley says. "There is a tradeoff between not leaving it too late or not going too early when you still have an effective waterflood," he says. "We are producing around 26,500 b/d. Now is the time to focus on optimizing recovery and implementing EOR."

To assess the potential for polymer EOR and develop its approach, Chevron started with a screening process, then lab trials, before going on to complete three pilot projects. Each pilot has targeted specific uncertainties, Hinkley says. The first, an injector-producer pair, in 2010, ran for 30 months and was to see if the polymer enhanced recovery process worked at Captain.

The second, an injector producing to four wells, drilled in 2013, and running for 18 months, was to see if polymer

Chevron's Captain WPP. Photo from Chevron.

worked on a typical producer-injector configuration for what the asset needed. The third pilot, started in 2016, and running for six months, was back to an injector-producer pair, and was to enhance understanding of the logistics and supply chain requirements involved in polymer EOR. Building upon this, in Q1 2017, Chevron started injection on a fourth well, which is ongoing and will further expand the learnings from earlier pilots. "As we are going, we are fine-tuning the polymer and learning. Each pilot informs the next phase and helps us progress," Hinkley says.

Richard Hinkley

Designer polymer

Crucial to the work has been designing a polymer for the specific conditions at Captain. As well as developing the right polymer, Chevron is also keen to develop a strong supply chain for polymer.

"One of the key lessons is that it takes a lot longer than you think," Hinkley says. "There are no short-cuts. We have been 10 years from initial screening and as a result we are on pilot number four. We have demonstrated the polymer works. We have had to fine tune the polymer for the specific reservoir conditions at Captain. Now we are at the point where we are looking at long-term staging the development, going from a pilot to six wells in the platform area [Area A] of the field. We are looking to make a decision to go with that this year. If that is a success, we would like to go to full field expansion."

Polymer injection facilities were installed as part of the original development, but some brownfield work will be needed to accommodate the six-well project. This will include bulk provision of the polymer and modification work on the Captain wellhead protector platform (WPP), including new polymer mixing equipment to expand processing capacity.

A full field expansion would require a bridge-linked platform. Chevron had issued an invitation to tender for a new facility to hold the polymer injection equipment, but this was then put aside in favor of the staged approach.

Chevron's learnings from the project to date, along with lessons learned from others, are to be included in a project led by the Oil and Gas Authority to create a "starter-pack" for those looking to try polymer EOR. "This will help others understand if EOR is suitable for their reservoirs and what expectation they can have towards implementation," Hinkley says, adding that Chevron's experience and lessons learned will also be incorporated.

Up for the challenge

Meanwhile, Statoil has also been putting polymers to the test – synthetic and biopolymers – through a series of pilots.

Statoil ran its first pilot polymer EOR project, using biopolymer supplied by partner Wintershall, part of Germany's BASF, on the Heidrun field, in the Norwegian Sea, offshore Norway in Q3 2016. The field has been producing since 1995, from a floating tension leg platform with a concrete hull. A single well was used, for injection and back production.

Several EOR tests have been performed over the past years (single well tests of synthetic polymer and low saline water injection). The single well test of biopolymer consisted of injecting biopolymer, biocide and water tracer and producing this back after 39 days shut-in.

"From analysis of samples taken during injection and back production, we were able to conclude on degradation of the biopolymer, the injectivity development and on the impact polymerized water has on topside water treatment facility," Schulkes says.

One of the main aims at Heidrun was to test if there would be no biodegradation – due to bacteria eating the biopolymer – in the near well area and to see how much biocide would have to

be injected to achieve this. It was also set up to test if there was shear degradation in the injection phase and to see what impact back production of the polymer would have on the production system, particularly the water processing system.

"We found there was no biodegradation of the polymer in the near well zone," Schulkes says. "That was a significant result and means the amount of biocide injected was sufficient to protect the polymer. The test also verified we didn't get a significant amount of shear degradation during injection and the results also showed we had good injectivity into the reservoir."

The sampling work helped understand what type of bacteria are in the reservoir, which would be important for future projects, as this determines what biocide is used. But, this would be something that would need managing over time, as bacteria can adapt to their environment, which could mean having to change out biocides periodically, Schulkes suggests.

The project was also a useful exercise in terms of experience for Statoil in handling polymer, i.e. the logistics involved, Schulkes says. Nevertheless, Statoil isn't looking to carry out more polymer injection on Heidrun. Instead, it is planning another pilot on the Peregrino heavy oil field in the Campos Basin offshore Brazil.

Polymerizing Peregrino

Peregrino, 85km offshore Rio de Janerio, contains some 300-600 MMbo recoverable. Production started in 2011, via two fixed platforms and a floating production vessel. At 14° API gravity, it is the second heaviest oil to be produced in Brazil.

Statoil is planning to test synthetic polymer on Peregrino, with a two-well – injector-producer – pilot. "The business case for this field is more obvious," Schulkes says. The pilot is due to start later this year and is expected to run for a year. The aim here is to prove polymer can be injected and sustain sufficient viscosity when it is injected. "Synthetic polymer is more easily shear degraded than biopolymer," Schulkes says. "We will use the pilot to prove that the technology works for polymer flooding in viscous reservoirs."

The biggest issue is the number of uncertainties around using this technology, which Statoil hopes the Peregrino pilot will help to reduce. "With successful results from Peregrino, we will re-evaluate the business case for polymer flooding on Peregrino and we will also be able to be more certain about the upside for Mariner (in the UK North Sea)," he says. A pilot on Mariner could start around 2021. It very much depends on the Peregrino pilot and the oil price as this is not a cheap technology, Schulkes says.

A polymer EOR trial is also being considered for Johan Sverdrup, in the Norwegian North Sea, although it's a less obvious candidate for this technology because it has a lighter oil. Despite this, a two-well pilot within three years of production start-up was included in the agreed plan for development and operation for the field. "One of the challenges at Johan Sverdrup is the recovery rate is already estimated at 70%, without polymer flooding, because the oil has a relatively low viscosity and the reservoir properties are good," Schulkes says.

"Each pilot gives you a more robust business case, but given that each reservoir is different we would still be taking a step-by-step approach," he adds. OE

A cavitron mixer (a mixing unit for polymer and water). Photo from Statoil.

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The North Sea gets steamy – piloting steam flooding in the North Sea.
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The pressure is on

Quietly, but surely, high-pressure, high-temperature expertise is being developed on the UK Continental Shelf. Elaine Maslin sets out the detail.

Action on Alder. Photos from Airborne.

An Airborne Oil and Gas 6in TCP flowline.

The North Sea's latest high-pressure, high-temperature (HPHT) development to come onstream was Chevron's Alder field – a project that saw a field discovered in 1975 finally brought online 41 years later (November 2016), thanks to a string of new technology developments.

It joins Total's Elgin Franklin HPHT development in the central North Sea, which was challenged with pressures up to 15,500psi and temperatures up to 350°F (176°C) (*OE*: August 2014). The discoveries were made in 1991 and 1986, respectively, and took 15 years and US$24.1 million (£20 million) of research investment to bring online. Next to come onstream will be Maersk Oil's Culzean development (*OE*: December 2015), with first oil expected in 2019.

The pressures and temperatures are high – a household pressure cooker works at a maximum 15psi and 250°F (121°C). A standard coal plant steam working pressure is about 2460psi. Alder is 12,500psi and with temperatures up to 302°F (150°C). Culzean is higher yet, at 348°F (176°C) and around 13,500psi.

The 2005 Jackdaw discovery saw even bigger numbers, at 17,250psi reservoir pressure and temperatures at 385°F (196°C) at its base (*OE*: August 2014). Operator BG Group, now part of Shell, had to qualify new equipment to carry out a 2012 drill stem test on Jackdaw.

Despite the difficulty and cost of these wells, HPHT exploration continues. Total started drilling its Sween HPHT exploration/appraisal well in the northern North Sea earlier this year. It has potential gross mean gas reserves of 107 MMboe, with upside potential of over 200 MMboe, according to farm-out documents.

Meanwhile, the UK business of CNOOC-owned Nexen Petroleum is planning two North Sea HPHT exploration wells, starting with Craster, west of Shetland, this year, followed by Glengorm. Drilling was due to start on Craster, using a semisubmersible and a Plexus HPHT wellhead system, in June-July 2017. Glengorm will be drilled in the central North Sea using a heavy duty jackup.

Alder

Chevron has said Alder had seven technology firsts to get it to first production. The field, discovered in 1975, is about 160km from the Scottish coastline in Block 15.29a, in 150m water depth. The development is a single subsea well drilled using the *Blackford Dolphin* semisubmersible drilling rig and tied back, via a 28km pipeline, to the existing Britannia platform.

The project has a planned design capacity of 110 MMcf/d of natural gas and 14,000 b/d of condensate. Produced fluids are processed on a new dedicated 800-ton topsides process module, built by OGN in Newcastle (recently acquired by Smulders) and installed on the Britannia bridge-linked platform.

Chevron assessed the field numerous times, but it wasn't until 2009 that it saw that technology to unlock it could be available, as well as having capacity on the Britannia host facility. Key technologies used to unlock the field included Chevron's first vertical monobore subsea tree system; a subsea high integrity pressure protection system (HIPPS); and a specially designed corrosion monitoring system to measure the real-time condition of the production pipeline. It also used vacuum insulated tubing and a reeled 10in/16in pipe-in-pipe system.

A subsea cooling loop was also developed to cool the production from 150°C to 115°C as it enters the subsea pipeline. But, then to keep the production warm, to prevent hydrate formation, a pipe-in-pipe system is used for the 28km tieback to Britannia.

Technip had the contract for the detailed engineering, procurement, installation and commissioning of the subsea system. OneSubsea supplied the two HPHT vertical, subsea monobore trees and wellheads. Aker Solutions supplied the subsea control system, including the topsides hydraulic and electrical components.

Another technology first was provided by Airborne Oil & Gas, headquartered in Ijmuiden (Port of Amsterdam). The firm supplied a 12,400psi, 126m-long, 1in internal diameter, 0-20°C operating temperature methanol injection spool for permanent service on Alder. To date, thermoplastic composite pipe (TCP) has been established for use in temporary applications, such as downlines or injection lines, but not permanent service.

Airborne's TCP is made from carbon fiber or glass fiber and polymer tape meld-fused together, with a coating.

The Alder jumper was made from made from e-glass and polyethylene. It has a 1m minimum bend radius and a 15-year design life.

One of the main benefits of using a TCP jumper was that it was lightweight – just 1kg/m in water – enabling remotely operated vehicle manipulation subsea, said Jessica Lyon, subsea engineer, Chevron Energy Technology Company, at Subsea Expo earlier this year.

Martin van Onna, chief commercial officer, Airborne Oil & Gas, told Subsea Expo that TCP also has a high collapse rate, and high internal pressure rating and fatigue capabilities.

Testing

Proving the pipe was fit for service was a challenge, because there wasn't a dedicated standard for TCP, he said. Airborne used the standard for composite materials and a recommended practice for qualification of new technology and then chose the highest safety class, leading to the highest safety factors. "Stress, strength, strain, stiffness, were tested through the product life cycle, from manufacturing to transport and maintenance," van Onna says. Burst and collapse testing was to 2400 bar. "We have proven that we understand the performance of the pipe and we are able to qualify it," he says.

The pipe was installed September 2016 using Subsea 7's *Deep Arctic*. Flowline Specialists were used for handling the pipe, as they had previous experience handling Airborne's TCP.

A subsea carousel was used to limit the free span and give the divers maximum control of the product. Flowline Specialists also supplied under rollers with delivery reel and turn table for the carousel.

The pipe was laid from the tree to the manifold using the carousel, hung from the vessel's crane, freely rotating for the diver's handling ease. The jumper was installed in 13 hours. Following hook-up, a leak test was carried out, and since field start-up on 1 November, the jumper has been used a number of times.

"TCP is already established as a temporary solution, but we have now shown it is viable for permanent solution," van Onna says. "We hope Alder will be the first of many. We will see it used for jumpers and larger flowlines, and risers in years to come."

The technology was originally developed for coiled tubing to handle rapid gas decompression. OE

Faster fit

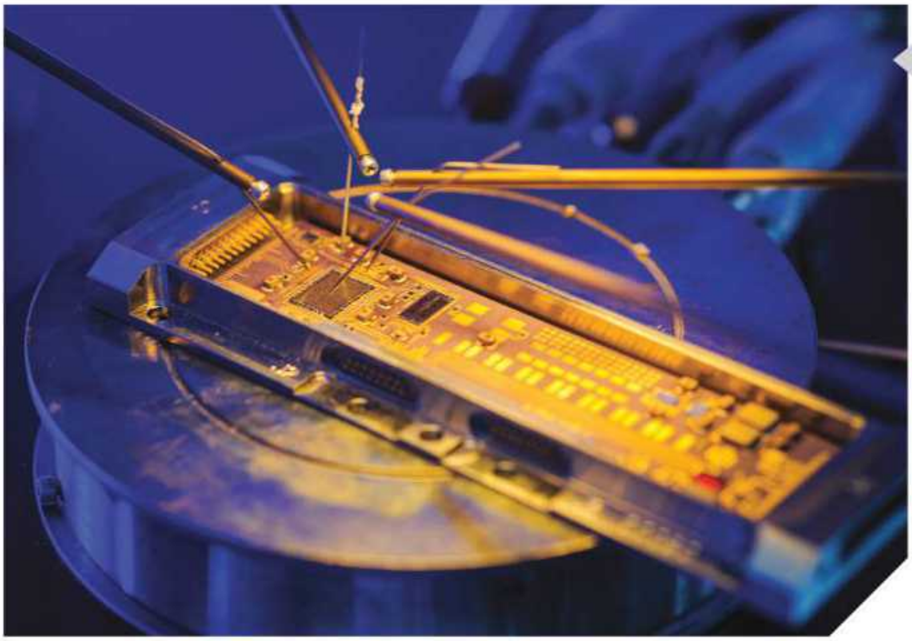
Airborne Oil & Gas's technology development is not just about the pipe itself and what it can withstand, it's also about logistics. Airborne has developed the end fittings for its pipe in such a way that they can be fitted fast. It is clamped on, the liner reamed, wedges applied and a sleeve pulled over them, clamping it in place, all in about 2-3 hours.

This means long lengths of pipe can be supplied and specific lengths cut off as and when needed, with in-field terminations carried out during installation. This has the added benefit of making the pipe a component, not a final product, which creates less havoc when it comes to local content laws.

"They can reel off the length they need, cut it off and terminate it and install quicker," says Martin van Onna, chief commercial officer at Airborne. "You can use half the length and at lower cost than jumpers." Furthermore, "termination can be offshore and we have done it offshore," he says, which means that J-tubes can be smaller, as they don't need to also accommodate the wider end fitting. ▪

High-temperature target

Jerry Lee examines how Schlumberger's PowerDrive ICE ultraHT RSS enabled Pemex to drill a high temperature well in Mexico's shallow Sureste Basin.

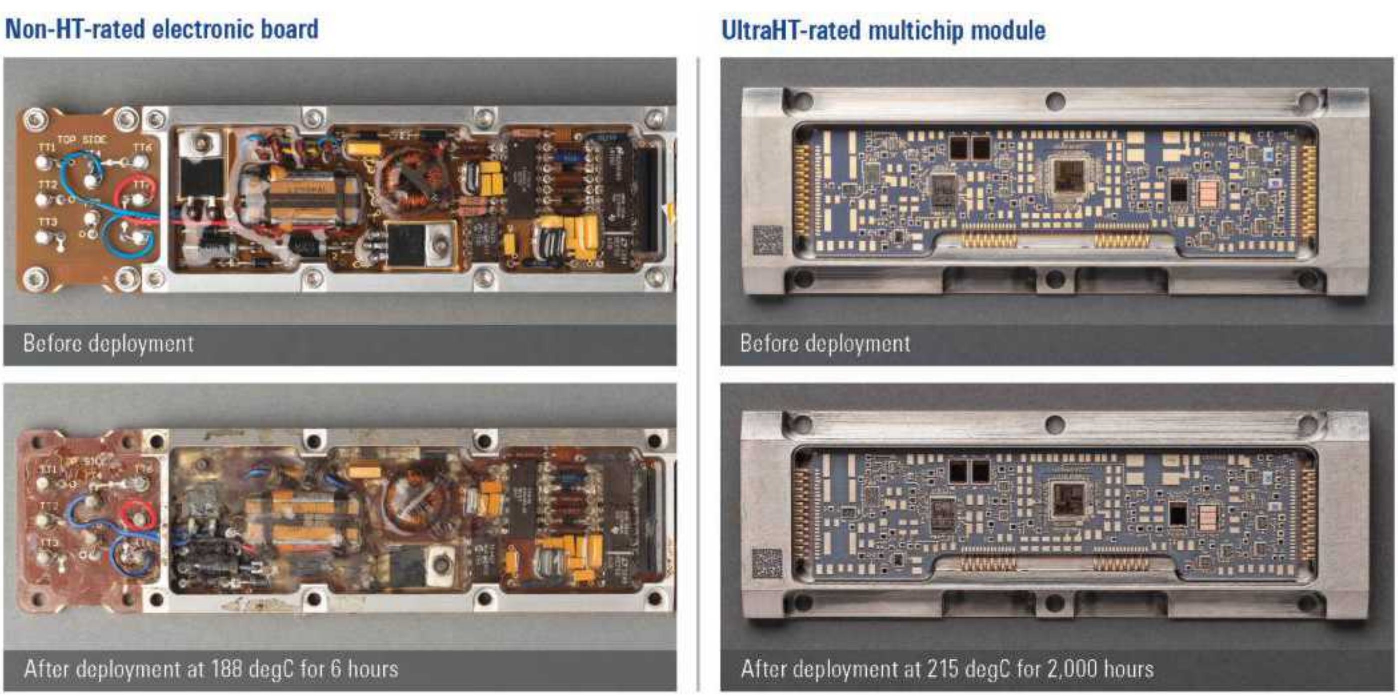


The proprietary electronics in the PowerDrive ICE and TeleScope ICE services have been verified to 200°C (392°F) and 2 million shocks for 35,000 hours. Images from Schlumberger.

Exploring for hydrocarbons offshore Mexico, Pemex planned to drill an exploratory well targeting a high-pressure, high-temperature (HPHT) reservoir in the shallow waters of the Sureste Basin. To reach their reservoir objective, Pemex engineers developed a well plan that required a complex J-shaped profile with a curve that inclined to 25° in the 8.5in hole section.

To achieve this profile, Pemex required a rotary steerable system (RSS) with precise inclination control to drill the curve. Challenging the well plan further, this system also needed the ability to operate in heavy weight mud and in a high-temperature (HT) environment – 338°F above the 8.5in section and expected to exceed 356°F, which is above the 350°F rating of most HT-rated RSSs.

To drill this HT exploration well, Pemex required a RSS-rated above 350°F in order to reliably control the direction of the drillbit while operating



Left: The non-HT-rated electronic board failed after being exposed to 188°C (370°F) for approximately 6 hours. Right: The ultraHT-rated multichip module, however, has full functionality after being tested to 215°C (419°F) for 2000 hours.

in a HT environment. If a RSS rated below 350°F were selected instead, the risk of an electrical component failing under HT conditions increases and would result in the loss of directional control. With Pemex's well plan demanding a sharp inclination to reach the objective, this could be problematic.

Pemex found their solution in Schlumberger's PowerDrive ICE ultraHT RSS, which is a fully rotating system with ruggedized electronics that expands the RSS's operating window to 392°F and 30,000psi. As a result, Pemex had the ability to reliably maintain control of the direction of the drillbit while operating in the HPHT environment. Furthermore, the PowerDrive ICE ultraHT RSS used metal-to-metal seals, enabling the system to function in heavy weight mud, which was called for in the well plan.

In addition to having the ability to control the direction of the drill bit, the driller needs to know where the well is being drilled and in what direction. Traditionally, this is done by running a wireline with logging tools to survey the well, which would determine where the well has been drilled and orientation of the well. Each survey then would require pipe to be tripped multiple times and for sections of the well to be drilled in order for the survey to see if the well is on target or if corrections need to be made, all while rig time accumulates.

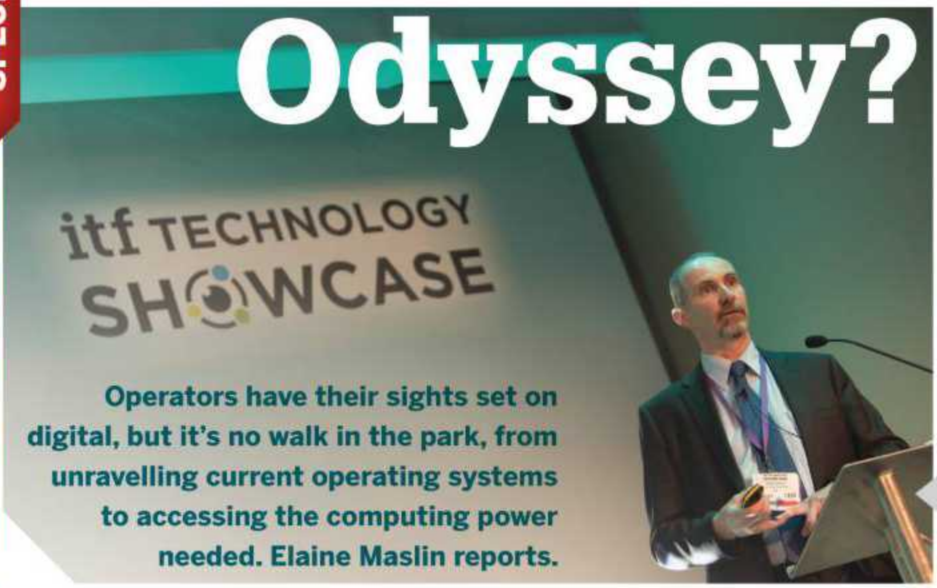
However, with the precise inclination control needed to follow the complex well profile, real-time directional data delivery was required. As a result, Pemex equipped the bottomhole assembly (BHA) with Schlumberger's arcVISION array resistivity compensated service and TeleScope service. The arcVISION service provided the driller with gamma ray, inclination and annular pressure-while-drilling data, and TeleScope provided high-speed telemetry-while-drilling. With these two services, the real-time directional data, needed for the driller to follow the complex will profile, was provided.

Using this BHA, which included a SHARC bit from Schlumberger's Smith Bits, Pemex drilled the 8.5in hole section of the well, building the inclination of the curve from 17.5° to 26.3°. A tangent to the curve was then drilled and maintained till the end of the run, resulting in a dogleg severity of 2.94°/30m. For 304 hours, the PowerDrive ICE ultraHT RSS operated reliably in temperatures ranging from 338°F to 358°F and in mud weights up to 17ppg.

The combination of the arcVISION and TeleScope services with the PowerDrive ICE ultraHT RSS enabled the precise inclination control the driller needed to drill the curve in a HT environment, make corrections on-the-fly, and outperform the directional plan.

Due to the success the system achieved, Pemex would see the PowerDrive ICE ultraHT RSS used as the standard for the exploration wells that followed and targeted the HT reservoir. OE

2020: A Digital Odyssey?



Greg Hickey. Photo from ITF.

Operators have their sights set on digital, but it's no walk in the park, from unravelling current operating systems to accessing the computing power needed. Elaine Maslin reports.

Going digital isn't just about adding digital technology to the same old plant. It's far more than that and offers not just gains, but an entire paradigm shift in the way industry operates. However, new forms of computing, such as artificial intelligence or cognitive computing, may be needed to achieve this.

So says Greg Hickey, a project manager for BP, currently in the firm's Upstream Technology group working as the business architect for the firm's strategic technology program in Digital Operations.

It sounds like a mouthful. It's also a significant challenge. Hickey told the ITF Technology Showcase in Aberdeen earlier this year that BP wants to digitize its business by 2020.

"This will mean having a common digital platform, standardizing ways of working, digitally empowering people, having organizational model alignment, and using new technology and innovation," Hickey says. There will be a one-stop desktop for every engineer in the business within two years, he says. There they'll be able to access facility data (in real-time) – relevant to their job function.

Hickey describes integrated knowledge management, which can help engineers take the right actions, using data from across whole operations business. Workflows will be standardized and unplanned downtime driven out, with 24/7 working across continents with centralized operating models will make use of scarce skills. All this will be underpinned by cloud computation and predictive analytics, Hickey says.

We can "convert unplanned into planned interventions and reduce costs," he says. "If we add digital technology onto the same old plant, it adds a few percents of improvement and efficiency in the same geography, but has limited impact on the bottom line. Digitizing the whole business can add 2-4%, operating digitally, efficiently, and safer with less downtime and opening up the possibility of a paradigm shift in the way we operate."

Part of the drive for this transformation is the current economic environment. "We are in a new operating environment with tight margins and lean operating organizations," Hickey says. "We see oil prices at US$50-60 long-term. We need to be more efficient and transform our business to operate in this environment."

But, the oil and gas industry has lagged in this area, and quite often this means it has a large complex puzzle to unravel, due to a plethora of "point solutions."

Indeed, the challenges include data and systems integration, Hickey says. "Replacing and integrating point solutions, creating and standardizing workflows," he says, and managing the organization and structures.

BP is working with GE Oil & Gas as a strategic partner as part of its transformation, specifically, with GE's Predix system. But it still faces challenges.

The first is enabling predictive analytics, which can be expensive and slow to develop. "There are not enough data scientists in the world to address what we want to address," he says. The cost could be prohibitive. But, there could be solutions in the world of artificial intelligence and cognitive computing which could close the gap, Hickey says.

A second challenge is how to automate deployment and configuration of updates needed over the lifetime of a facility. "Currently it is very manual. How do we do these so that the cost and speed of delivery is such that we can keep up as industry changes?" These are questions Hickey would like answers to. OE

Saipem moves toward digital

Italian contractor Saipem has taken steps to adopt the 21st century digital world. Under an agreement, Saipem and Japan's NTT DATA will collaborate on wearable devices, the Internet of Things, cyber security, and virtual and augmented reality. In 2016, NTT DATA and Saipem-Innovation Factory collaborated on the "Digital Site" project at Saipem's Arbatax yard in Sardinia, where the use of innovative devices for the health and safety of workers, among which NTTS DATA's Hitoe smart shirt, was experimented.

Meanwhile, Saipem is also working with Siemens on subsea controls systems. The two firms signed a joint development agreement aimed at qualifying and promoting an open standard subsea control systems for Saipem's subsea bus architecture, based on Siemens Subsea DigiGrid. Saipem says this could create the first control system in the market promoting a modularized and standardized subsea system through open framework architecture. The combined system will be capable of controlling an all-electric configuration, ideally suited for long-distance subsea tiebacks, avoiding hydraulic umbilical cables and using distributed architectures with high performing control units to support technology applications including seawater treatment and separation. ▪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Teaching machines to speak drilling

Maana's Jeff Dalgliesh discusses a recent project with Chevron aimed at training a machine to understand how drillers describe problems encountered during operations.

Typically, when people think of Intelligent Machines they think of algorithms that monitor equipment sensors and alert people when a problem is suspected in the operations. However, there is another set of use cases that is beginning to emerge in the industry where Intelligent Machines are being used to understand what people are talking about and use this understanding to assist in making operational decisions.

An example of this was presented at SPE Intelligent Energy in Aberdeen, last year, by Maana, a technology company based in Palo Alto, California, and Chevron. "Natural Language Processing Techniques on Oil and Gas Drilling Data" set out how Maana and Chevron trained a machine to understand how drillers describe problems they encountered in operations. This enables well planning engineers to get a better understanding of potential risks associated with drilling a well by seeing how often a problem happened in the past.

For simplicity, let's say an average well might take about 30 days to drill and on average the driller may make eight comments each day describing the operations and problems they encountered. This equates to about 240 comments per well. A company such as Chevron has more than 100,000 wells worldwide, which represents 24 million comments. Training a machine to read all 24 million comments and classify each comment into a problem type would allow a well planning engineer to get a better understanding of the frequency of a certain type of problem. If a person took five seconds to read and classify each of the 24 million comments, it would take about three years and nine months – non-stop. A properly trained algorithm could do this in a few minutes.

Here is an example of a typical comment describing a drilling operation where the driller encountered the pipe being stuck in the hole:

PIPE STUCK WHILE ROTATING 10in OFF BTM. LOST PUMP PRESS AND GAINED STGROKES WHILE JARRING ON PIPE. MIX & PUMP 100BBLS DFE1310 WHILE JARRING ON PIPE. SPOT IN PLACE AT 2400HRS. JAR PIPE FREE 3MINS. AFTER SPOT WAS IN PLACE. PULL 12STDS. PUMP 30BBLS TO CLEAR SPOT OUT OF DP. PUMP SLUG. POOH

There is a lot of jargon and technical terminology in the comment. This jargon and technical language provides a lot of clues as to what the driller is talking about. Maana uses natural language processing algorithms to take these clues and build statistical language models to classify the comment into a problem type.

A challenge when training natural language understanding algorithms for the oil and gas industry based on comments is identifying when the author is describing an actual problem that happened or when they are describing a Health, Safety and Environment (HSE) meeting on the rig where they are training to respond to the problem. For example, our first pass of the natural language understanding algorithm identified a lot of kicks on the rig based on the comments, when we dug deeper a huge majority of these comments were the HSE stand up meeting where the crew was reviewing well control emergency procedures.

Using Intelligent Machines to mine the vast amounts of unstructured text in organizations unlocks deeper understanding of operations so operators can make more informed decisions for future operations. In a world where people and Intelligent Machines coexist in operations, being able to understand each other is an important element to designing our technology systems of the future. Combining machine learning techniques, knowledge models and state-of-the-art information processing techniques can help organizations navigate the transformation to a human-guided machine-assisted future. **OE**

__Jeff Dalgliesh__ is Maana's Oil and Gas Specialist, working with clients to apply machine learning and artificial intelligence techniques. Prior to Maana, Dalgleish worked for Chevron for 18 years most recently as drilling and completions technology manager and previously was the drilling and completions technology architect, both at the Chevron Engineering Technology Co. He holds a BSc in Computer Science from University of British Colombia in Canada.

Getting a grip on data

Photos from iStock.

Most workers don't make anything real anymore – they make data. Daniel Brown, of Common Data Access, ponders whether the oil and gas industry can figure out how to turn data into profit.

Data is the catalyst of the modern world. For the newest companies – Uber, AirBnB – that's all they have. They don't own plant and machinery. They just take one person's data, transform it, and sell the result to you for profit. For the past 10 years, other industries have been trying to learn from the same playbook. How to maximize the speed with which data moves through their organizations. How to design every step of the work to avoid waste, and extract the maximum value for them, and their shareholders.

These businesses also analyze their data in the whole, rather than piece by piece, and in doing so are learning about how their companies actually work, what their customers actually buy (rather than say they want), and are dealing far more effectively with statistical risks, such as fraud and credit control. Ten years ago, all this was new. Today, for a business of any size, it is part of daily life. As Ford's ex-CEO, Alan Mulally often said: "Facts and data set you free."

Until the oil price crash, none of this mattered much in our industry. Margins were healthy, and technology investments were all about science and engineering solutions for new, harder to develop prospects, rather than business process investments in operational efficiency. While the world was riding the analytics wave, oil and gas was doing well enough to not need to pay attention.

Today, every dollar counts. Every marginal dollar saved in lifting costs is critical in staving off cessation of production. Advances in oilfield technology deliver ever more economical solutions to the engineering challenges posed by aging infrastructure. But, it is the transformed business practices you get by being smart about data that offer savings in every other part of the exploration and production value chain – from prospect identification, all the way through to keeping a lid on decommissioning costs.

Good data management and good business process are two sides of the same coin. Do data well, and workers have the information they need at their fingertips for their piece of the work – and pass that data on to the next person in the line, so they have the same. Good data organizations take care of their "sources of truth," and don't waste time finding things they should already have, or shuffling things around in spreadsheets because what they're given isn't quite right.

Data preparation tools like Alteryx and KNIME, together with data visualization tools like Qlik, D3, and Tableau are eradicating spreadsheets from the workplace for essentially every routine task, and eliminating huge amounts of wasteful effort, all for a more reliable and consistent result, and way shorter cycle times.

Data engineering tools are also making headway. For 40 years, reporting to government of oilfield activities took place in paper form – so archives of those reports tend to be scanned images of the paper, rather than crisp, modern digital documents ready for analysis. Thanks to advances in image and character recognition tools, these scanned images can now be routinely read and analyzed, unlocking the knowledge of decades of exploration and development activity for modern day explorers to benefit from (*OE:* February 2017).

The next data wave?

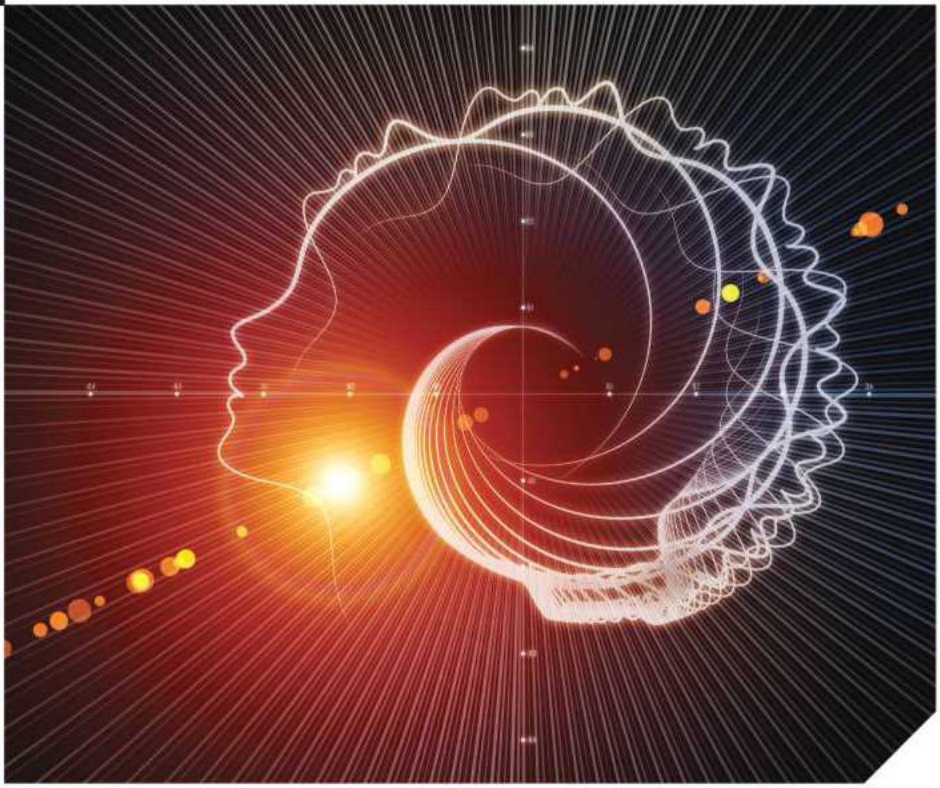
So, will oil and gas be riding the next wave in the data science revolution? Machine learning has now reached the peak of Gartner's "hype cycle" for new technologies. Can this bring the same benefits to oil and gas that it must in other industries?

Machine learning at its core is a collection of pattern matching algorithms that are just very, very, very fast. The technology has been around for decades, but it is only with recent changes in computer architecture – particularly the use of powerful graphics chips for the calculations involved – that it has become affordable for everyone to use.

Machine learning systems can be trained to spot patterns in any kind of data, from images and movies to real-time data from plant and machinery. Once trained, they can work at a speed, scale, and reliability that humans will never match.

Hand-crafted learning systems have been in use in oil and gas for years to help humans avoid particularly expensive, or dangerous mistakes. BP's Well Advisor system, co-developed with Kongsberg (*OE:* September 2016), is credited with essentially eliminating cases of stuck pipe; and critical rotating equipment such as gas turbines are routinely monitored by their manufacturers to optimize maintenance schedules, and avoid outages.

More general learning systems are now starting to make a difference in other areas. As part of Common Data Access' (CDA) 2016 Data Challenge, Schlumberger presented a geological model building workflow that, starting from raw log curves and cuttings information, compressed nine weeks of petrophysical labor into nine hours of computer time. That's quite a saving.



In data we trust?

While current machine learning techniques are good at the jobs they're trained to do, they are not yet the perfect digital assistant for today's subsurface professional. They are only as good as the data they're trained on (and training can take months to complete); and once trained, they still can't explain why they make the decisions they make. The computer can't yet explain how it can identify a cat in a photograph. It's not the ears, the tail, and the fur that makes the cat – just some fast mathematics that outputs a probability, with no insight into the "why."

For learning systems that we can truly trust, an explanation is needed. If a computer is to pick prospects from an automated analysis of seismic trace data, it would be helpful to know why one prospect is more worthy of investigation than other. What kind of trap is it? Are there geological indicators to suggest a seal rock may be present?

Thankfully, this next wave of machine learning is of huge interest to the rest of industry as well. From shopping habits to autonomous vehicles, enormous investments are being made to address these, and the other challenges, and oil and gas can benefit from the results – if we work together to get after them.

CDA is industry's custodian of the UK's offshore subsurface data. We have the data part of data science covered. But we need help to cover the rest. Data science is a team sport – and it is only when data, business, and technology are well matched that we can make real progress. **OE**

Daniel Brown has been working in and around data and information for over 20 years – in the physical sciences, for one of the original internet search engines, and for BP, leading their global data services organization. Today, Daniel looks after the project portfolio of CDA, the world's largest repository of UK subsurface well and seismic data, and is leading their work to build industry capability in data analytics.

The robot race

The Argos Challengers. Photo by Laurent Pascal from Total.

A competition to develop an offshore autonomous robot has helped iron out some of the issues that will need resolving to take this technology offshore. Elaine Maslin reports.

While we're not quite at the so-called Singularity, when super-intelligent computers outrun their human masters' ability to control them, the introduction of robots into the offshore oil and gas industry is looking like an ever more realistic prospect.

Be it for assessing inside confined spaces (which require a shut-in for humans to enter), operating in hazardous areas or to simply reduce manning levels, robotics has become high on the agenda for many operators.

Total has just completed its Argos (Autonomous Robot for Gas and Oil Sites) Challenge, in Lacq, France, which saw five teams pitch their robotic creations against a string of tasks on a mock-platform site. It was the third and final round of the competition, which has been getting progressively harder.

Total's aim was for a robot, able to detect and control leaks, weighing less than 100kg, which can move between floors, and on different types of flooring, from grating and corrugated iron to cement and wet slippery surfaces, under its own power. It should have remote control functionality, be ATEX/IECEx compliant with a technology readiness level 5, and be a fully autonomous robot.

However, the competition, run with the French National Research Agency (ANR), has helped Total better understand the solutions it needs, including that it could be better to have multiple simpler robots, working together, than a single multi-tasking unit, says Kris Kydd, head of prospective lab robotics at the R&D department of Total Exploration and Production, based in Pau, France. Kydd was speaking at the ITF Technology Showcase in Aberdeen earlier this year.

"Argos was a way to kick off robotics [in Total]. For us this is just the beginning," he says. "Now we are looking at robotic non-destructive testing and aerial unmanned vehicle (AUV) applications and shifting towards unmanned if we can prove autonomous functionality, to increase remote monitoring and automation." The end result could be that platforms are designed differently, to accommodate robots, including AUVs and even rail systems, he suggests.

Five teams have been taking part: Air-K, Argonauts, Foxiris, LIO and Vikings, from Japan, Austria, Spain and Portugal, Switzerland, and France, respectively. The Vikings Team won second round and all five took part in the final round of the challenge, over five days, in March.

As well as being ATEX/IECEx compliant, the robots had to prove they could carry out rounds and perform one-off tasks autonomously, but also enable an operator to be able to step in and switch to remote control mode at any time.

The robot would also be expected to operate at the site of an incident, such as a hydrocarbon leak, and in potentially hazardous and harsh environments, ranging from -50°C to +50°C, hygrometry of up to 100% and sea spray, heavy rain and up to 100km/hr winds.

Robots in the running. Photo by Benjamin Valette, from Total.

For the third round, instead of trying to put additional functionality into the robots, ranging from tracked to four-legged machines, Total decided to spend more time proving the existing functionality, including going up and down stairs and the autonomous functionality. The aim is to be able to "hit a button" and the robot will complete a mission autonomously.

Obstacle negotiation, included in the second round, was repeated, with the addition of a human presence – in which case the robot needs to detect there's a human and go into standby mode. The site was also changed, so that it wouldn't match the model with which the robot was programmed.

Communication loss was also tested – as was waterproofing as the teams had to operate in heavy rain on the first day and the ability to move up a long ramp (something some of the teams hadn't anticipated). For one robot, false readings of heat spots were recorded (it had spotted the sun).

The next step will see a US$539,000 (€500,000) bonus awarded to the winner and an industrial pilot launched on a Total production site.

Kydd says that there have been two key lessons to date. The first is the communication. Wi-Fi was used on the test site, measuring 15m x 15m, with a remote cabin 10m away. "Already we can identify black spots," he says. "So, we need to shift to 4G LTE. Wi-Fi is not robust enough."


Foxiris in action.
Photo by Benjamin Valette, from Total.

The second lesson is that robots don't like to multi-task, he says. "We maybe wanted too much too soon. It is difficult to achieve in a single platform. We're now shifting to more task specific robots, to take the complexity away, having smaller, simpler robots communicating together."

Total is not alone in promoting offshore robotics. The Petrobot robotic challenge (*OE*: April 2016), involving Shell, Chevron and GE Inspection Robotics, looked to reduce the need for manual entry into pressure vessels has led to the forming of the Sprint Robotics Collaborative, based in the Netherlands.

A more subsea-oriented robotics challenge is Shell's Xprize. It has set a challenge for teams to survey 500sq km of ocean bottom in 24 hours. Round 1 of the competition will see teams map 20% of that area and identify various features within 16 hours. We're set to tell you more about this in the next issue.

Shell has also been developing Sensabot, for the North Caspian Operating Co. consortium, for use on unmanned islands of the H_2S-rich Kashagan development, for faster, more efficient 24-hour response and inspections. **OE**

FURTHER **READING**

The winner of Total's Argos challenge will be announced later this month. Check back with OE on 12 May.
www.oedigital.com/component/k2/item/15055

Gulf of Mexico

Thunder (Horse) rolls

Audrey Leon profiles the Thunder Horse field, speaking with project manager Steve Raymer about the BP-operated field's most recent expansion project, which came in 11 months ahead of schedule and $150 million under budget.

This year is set to be an exciting one for BP. The firm is looking to bring seven pro jets online in 2017. One project, the Thunder Horse South Expansion (THSX) in the deepwater Gulf of Mexico (GoM), was originally slated for start up in late 2017, but it had the good fortune to come online earlier than scheduled, due to good planning and execution.

The THSX project is expected to boost production at the Thunder Horse facility by an estimated 50,000 gross boe/d.

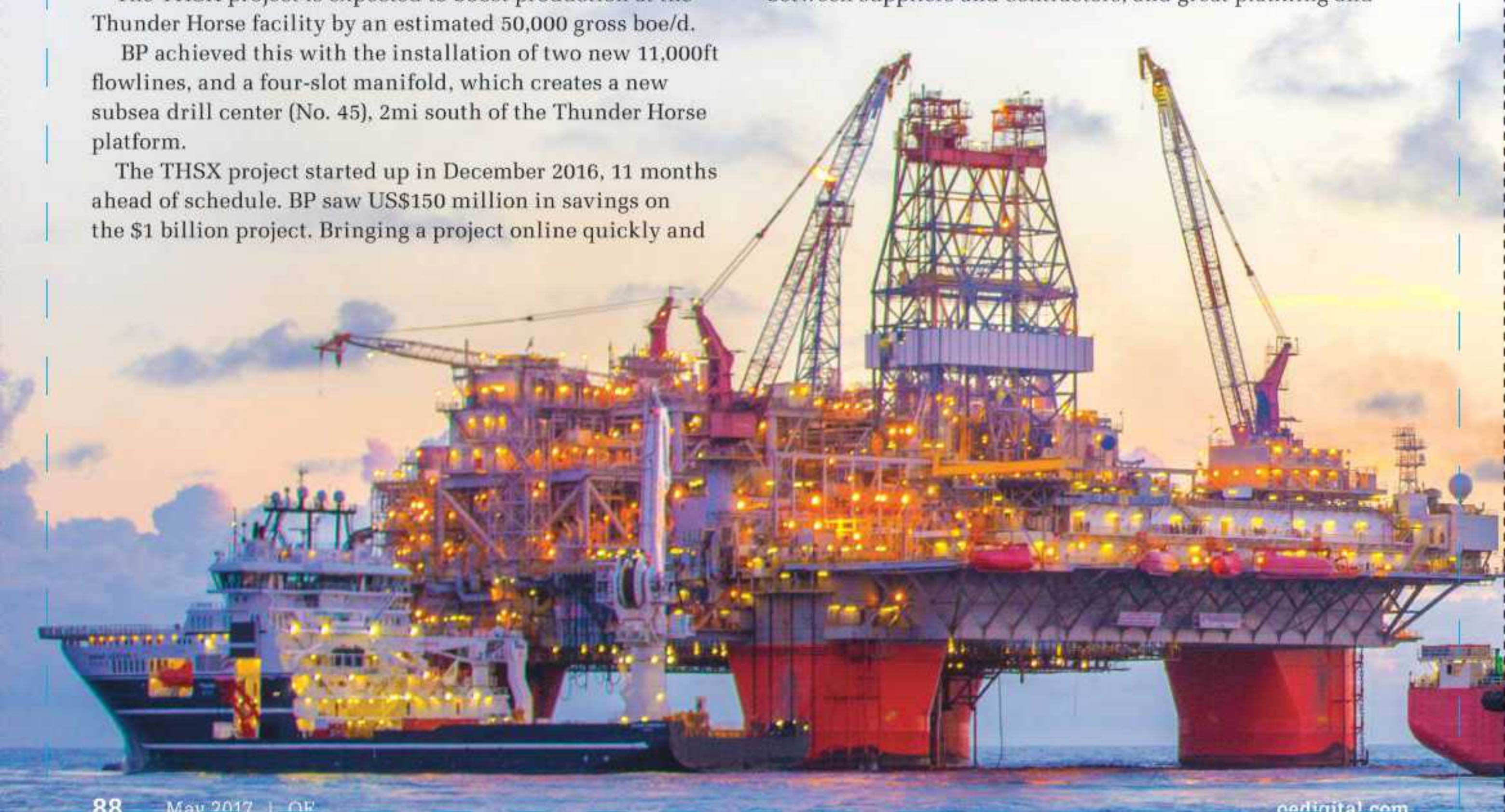
BP achieved this with the installation of two new 11,000ft flowlines, and a four-slot manifold, which creates a new subsea drill center (No. 45), 2mi south of the Thunder Horse platform.

The THSX project started up in December 2016, 11 months ahead of schedule. BP saw US$150 million in savings on the $1 billion project. Bringing a project online quickly and cost-effectively is quite a boon in today's low oil price environment. These kinds of numbers are positives that plenty of oil and gas firms will want to replicate.

BP acknowledged the success the firm has had at previous GoM projects, such as its Kepler field, which ties back to BP's Na Kika platform.

"We are also making significant progress in exploration by shortening our cycle time from discovery to production on some of our latest discoveries," said CFO Brian Gilvary in BP's 3Q 2016 analyst call. "Our Nooros discovery in Egypt was on production two months after discovery and Kepler-3 came online within 11 months of discovery, which is faster than typical GoM developments of this scale."

The main drivers for bringing THSX online ahead of schedule and under budget were standardization, cooperation between suppliers and contractors, and great planning and



coordination on execution efforts, says Steve Raymer, THSX project manager, BP.

The field

While Thunder Horse is one of BP's largest fields in the GoM, it hasn't been the easiest to develop. This is owed to its complex geology and mother nature's whim.

Discovered in July 1999, BP did not bring the field into production until 2008, three years after its initial target, due to issues stemming from a direct hit by Hurricane Dennis (2005).

BP operates Thunder Horse (75%) along with co-owner ExxonMobil (25%). The field sits inside Mississippi Canyon blocks 778/822 in the Boarshead basin, 150mi southeast of New Orleans in water depths ranging from 5800-6500ft.

Thunder Horse consists of two adjacent fields (North and South) with reservoirs in the Upper Miocene turbidite sandstones. In BP's fact sheet on the field, the company calls the wells required to access the reservoirs, "some of the most challenging and deepest in the Gulf."

The development consists of subsea wells producing to a permanently moored, floating semisubmersible production, drilling and quarters (PDQ) facility. The PDQ, which is BP's largest facility in the GoM, is taut-wire moored in 6300ft water depth. It has 250,000 bo/d and 200 MMcf/d of natural gas processing capacity, and accommodation for nearly 300, BP said. Oil and gas is exported through the Mardi Gras Transportation System.

BP awarded FMC Technologies a frame agreement in 2001 to provide the field's subsea production system, which is designed for 350°F and 15,000psi and operated via an electro-hydraulic controls system. The field has 5in x 2in conventional subsea trees and manifolds. Round-trip pigging capability is incorporated into the manifold architecture, FMC (now part of TechnipFMC) says.

Loading Pipeline End Termination (PLET) system onto Technip's *Deep Blue* vessel. Photos from BP.

Geology

According to a 2010 OTC paper on Thunder Horse, some two-thirds of the oil in place is in the South with one-third in the North. North and South share a common aquifer in the syncline separating the two regions, says Arnold et. al.

The paper describes Thunder Horse South as a large 4-way dip closure that begins at approximately 20,000ft true vertical depth subsea (TVDSS) and persists to 30,000ft TVDSS. Arnold et al said that half of the closure lies below a thick salt canopy.

Helix Energy Solutions' *Grand Canyon II* (left of Thunder Horse) and Technip's *Deep Blue* ultra-deepwater pipelay vessel (right) during in field SIMOPS.

Gulf of Mexico

Arnold et. al describe Thunder Horse North as a large 3-way dip closure against a near vertical salt stock. The paper says that there is a high degree of lateral stratigraphic and structural segmentation. The closure lies below the salt canopy, which also results in poor imaging (similar to Thunder Horse South).

Multiple stacked reservoirs are found in Miocene age sandstones on both the North and South fields, the paper states, which are grouped as Pink, Brown, and Peach stratigraphic intervals.

"Not all of those are developed at every drill center in the North or South," Raymer says. "By and large, the North is Pink and Brown, and the South is Brown and Peach."

Raymer says that the sections grouped as Pink, Brown and Peach denote different reservoir sections, depths, pressures and hydrocarbon composition. "They have different properties that result in different production," he says. "They can all mix together and produce together. Part of the beauty and part of the challenge is developing those three different reservoir sections."

Field improvements

Since start up in 2008, BP has steadily worked to improve production from the field. In May 2016, the supermajor started up a water injection project on the North field, with the goal of extending production life and recovering an additional 65 MMboe.

Aimed at Thunder Horse's North Pink geology, the water injection will boost overall recovery within that section of the field, Raymer says.

"It's always been in Thunder Horse's long-term plan to have water injection as part of the overall development concept to deliver full recovery from the field," he adds. "We are seeing a good response from the project and we're very happy with it."

Expansion

Raymer says that when the Thunder Horse field was initially developed, BP knew to provide for future expansion.

"When we first sanctioned Thunder Horse, we knew it would be a massive field," he says. "We put the infrastructure in to initially develop a good chunk of that. And, while we did that, we also recognized that we didn't have perfect understanding of the reservoir."

Raymer says that, as time has gone by, and BP drilled more wells in the South, the firm increased its knowledge about not only the size of the reservoir, but how best to develop it.

"It became clear that the most economical way for us to [develop it] was to add another drill center and expand an area of the field that we called South Expansion, to tie into the existing infrastructure, using the expansion capability that we built in initially," he says.

Part of what made the THSX project so successful is the use of standardized components and working with contractors who had previously provided equipment on the field.

Raymer says that for THSX, BP wanted to use what Thunder Horse already had. "We had an existing subsea tree design," he says. "All we had to do was call FMC Technologies and order a few more. We had existing subsea equipment, the same manifold design. We did not redesign anything from scratch where we had the opportunity to use something that we already had."

The project came together quickly. Raymer says BP ordered its first long-lead equipment in August 2014, taking delivery of most of that equipment around August/September 2016. "We installed

At Technip's 60 acres (24 ha) spoolbase facility, south of Mobile, Alabama, sections of pipe, 10in (25cm) in diameter, and more than 1in thick, were welded together to form the two 11,000ft (3350m) flowlines, which were then spooled onto a reel on the *Deep Blue*'s deck.

the majority of that equipment toward the back end of 2016 and we brought production on in December."

In 2015, Technip, prior to its merger with FMC Technologies – another supplier on the project – was tasked with design, engineering, fabrication, installation and pre-commissioning of the new production pipeline systems on THSX. The project scope included: project management and engineering; coating, fabrication, installation and permanent anchoring of two rigid, 3.25km production flowlines, each with four pipeline end terminations; pre-commissioning and testing. Technip's ultra-deepwater pipelay and subsea construction vessel, *Deep Blue*, handled offshore installation work.

Deep Blue unspooled and lowered the two new flowlines to the seabed over a period of eight days, with the help of Helix's *Grand Canyon II*, to connect the existing drill center below the Thunder Horse platform with the new drill center, according to BP Magazine.


The ROV control room aboard the Thunder Horse platform.

Grand Canyon II assisted with the pull-in operations as well as pre-commissioning work for the flowlines once they were installed on the seabed.

BP also used the subsea construction vessel, *Siem Stingray*, to install the rest of the subsea equipment including production manifolds and jumpers.

Overcoming challenges

One major hurdle that plagues most large-scale developments is the scheduling of simultaneous activities. Raymer said that the THSX project came together because of good communication and well-coordinated project execution.

"There was a high amount of SIMOPS (simultaneous operations) going on in the field while we were doing our construction," Raymer says. "The Thunder Horse asset itself was drilling a well as well as producing. We had [Transocean's] *DD3 [Development Driller III]* drilling our first South Expansion well at drill center 45 – where we were putting all the expansion equipment."

Raymer adds that while those operations were going on, Technip was in the process of laying the flowlines with *Deep Blue*.

"Just in that time frame alone in summer 2016, we had three extremely valuable assets working together in close proximity, and we were able to complete all that construction work without disruption to the ongoing production and drilling activities that were occurring simultaneously," Raymer says. "While it certainly was a big challenge, it was also our greatest success as a project to be able to deliver that work safely, without incident and without any disruption to operations."

Planning played a big role as well in executing the project's SIMOPS.

"We did an enormous amount of upfront work," Raymer says. "We employed some 3D modeling techniques to explicitly map out and model the paths that the flowline installation vessel would need to take. We did similar 3D models showing any required offsets or movements that the drilling rigs might need to do while operating.

"Once we had all that technical information, then, the bulk of the work from that point is communication, and regular engagement sessions with the leadership and the operations managers of each of the different assets coming together, and being very clear on the roles and responsibilities on the execution plans and on the scope of work, and the timing that we were all going to follow to orchestrate the execution of all this activity.

"That coordination was a major driver towards us being able to deliver the project 11 months ahead of schedule," Raymer says, adding: "Being able to do all those things simultaneously (flowline, subsea equipment construction and installation at the same time as drilling and completions of the wells), made the execution extremely efficient versus having to do all those things one at a time, in a series."

Of course, another potential challenge, like with any offshore project in the GoM, is mapping out a window to execute work before the worst of Hurricane season. BP is famous for its severe weather assessment team, which boasts a team of meteorologists who keep tabs on GoM storm conditions.

For the THSX project, BP ran into a spot of good luck due to a relatively mild 2016 hurricane season.

"We specifically aimed for and targeted a window of opportunity that was right before the start of hurricane season," Raymer says of the THSX project. "We were able to get this flowline installation done in the late July/beginning of August time frame. And that was before the active part of hurricane season, allowing us to minimize that risk.

"If there had been a storm that had come through, during that time, we had contingency plans in place to be able to postpone and re-assemble post-event as necessary. But, fortunately, that wasn't the case for us."

What's next?

Raymer says that BP expects to see an increase of 50,000 boe/d at the field. "We have two of our four wells online, at this point, with the third currently being drilled (by the *West Vela*)," he says. "The fourth is in line to be done after that."

BP expects full production to be achieved at THSX in 2019. **OE**

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Gulf of Mexico

Mexico's big opportunity

Audrey Leon chats with Statoil's Helge Hove Haldorsen about the positive results emerging from Mexico's energy reform, how it compares to Statoil's own experience as a state-owned operation, and its overall strategy in the Mexican Gulf.

OE: Statoil has held an office in Mexico since 2001, can you tell me your thoughts on Mexico pre- and post- the energy reform? What was it like to come into the country and establish operations, and what is it like in this new environment working within the country? Is there a noticeable difference?

Helge Hove Haldorsen
Images from Statoil

Helge Hove Haldorsen (HHH): The Mexican energy reform took courage and collaboration, just like exploration and production (E&P), and I believe the appropriate name for it is: Mexico's Big Opportunity! Just a few years into the reform, it already has had a massive impact on the oil and gas industry in Mexico. Especially considering the ~50% reduction in the oil price seen since 2014, what has been achieved since Mexico hung up its "Open for E&P business" sign has been nothing short of impressive.

So far, Mexican authorities have successfully completed four transparent and competitive bid rounds; a total of 55 areas have been bid out to the industry leading to 39 awards; 49 new E&P companies have been established in Mexico – of which 25 are new Mexican independents, and 12 producing fields are now being operated by other companies than the national oil company Pemex.

In this period, Pemex has also farmed down and handed over operatorship of its Trion deepwater discovery, and also took part in its first open and competitive bid round in the recent deepwater tender. All of this has taken place in just a couple of years, which speaks to the impressive work-rate and commitment of the Mexican government to this new Mexican energy model.

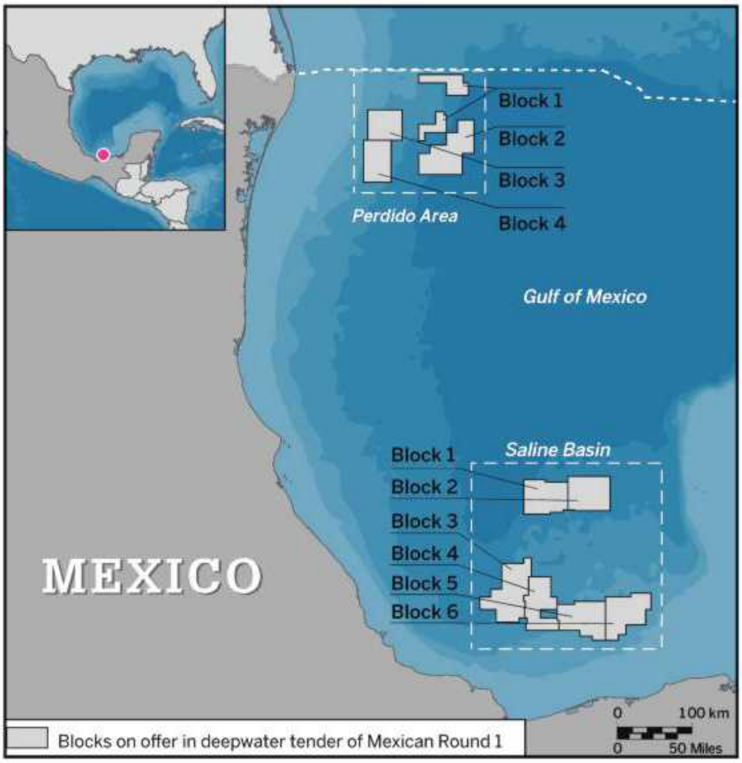
And, this is only the results of the so-called Mexican Round 1. Round 2 has already been announced, and we're looking forward to consecutive tenders throughout the year for new opportunities in shallow water, onshore and in deepwater areas. The recently updated Mexican five-year plan outlines more opportunities in the years to come, which helps provide the overview and predictability that is so important to industry. Mexican authorities – spearheaded by Energy Secretary Joaquin Coldwell, CNH President Juan Carlos Zepeda and others – have done a remarkable job thus far.

Let me also mention AMEXHI, the new Mexican upstream association with some 50 members including Pemex. This has become an important member of the new E&P ecosystem in Mexico interacting with the authorities and institutions on important policy and regulatory matters – sharing global best practices in both technical and policy matters.

OE: Statoil (in consortium with BP and Total) picked up two blocks (1 and 3) in the Saline Basin during Mexico's deep-water round in December 2016, and Statoil has participated in previous shallow water rounds. Could you discuss why it was important for Statoil to participate from the very

beginning – some companies including majors have been absent from the rounds so far.

HHH: Statoil's interest in Mexico has always been driven by the opportunities that we see, and our bid round participation so far has been driven more by the subsurface than any strategic wish per se to enter early. It was the subsurface potential that we saw that drove our participation in the shallow water tenders of Round 1, and it was again the prospective potential – albeit with the increased risk and uncertainty of this frontier area – that led us to participate in the deepwater tender together with our strong partners BP and Total.



At the same time, there may of course also be benefits to companies entering Mexico early. They may get a head start in terms of developing the necessary subsurface understanding, regional knowledge and commercial grounding to succeed. But ultimately, our interest in Mexico is driven by – as much as it is dependent on – material opportunities and globally competitive terms and conditions.

OE: What is your strategy for Mexico, including your current acreage?

HHH: Statoil entered Mexico in 2001, and has a long-term perspective in the country. We're committed to reviewing opportunities that fit Statoil's strategy and competency areas, assuming globally competitive terms and conditions. Of course, as one of the world's largest offshore operators, our interest is primarily offshore. We've also built up a sizable onshore business in the US over the last decade, so we are not entirely discounting onshore opportunities in Mexico either.

The key for all upcoming opportunities in Mexico, however, is that they are able to compete for capital against other opportunities in Statoil's global portfolio. And since we have been able to reduce the breakeven price for our next-generation and non-sanctioned portfolio from over US$70 to now less than $30, future opportunities in Mexico really need to be very good to compete!

OE: Related to the previous question, which offshore areas (either shallow or deep water) are considered to be the most exciting areas for exploration?

HHH: Mexico has a significant yet to find potential offshore, particularly in the more frontier deepwater areas. Most of the Mexican deepwater is either underexplored or not explored at all, which of course from an exploration perspective is very exciting. So, we are very pleased about our two recently awarded blocks in the deepwater Saline Basin of Mexico, together with our partners BP and Total.

These are significant, frontier areas, with considerable subsurface uncertainty but with play-opening potential. There is a lot of running room here, so we are optimistic about our chances, but a lot of work still remains to be done to further mature and prove up this acreage.

On the whole, shallow water areas in Mexico are considered to be more mature, given that this is where the majority of Mexico's offshore exploration and production has taken place over the years, so the remaining exploration potential here is most likely also less prospective. Having said that, the Sureste is a very prolific basin, and there will most likely also be "hidden or overlooked gems" in this area as well.

OE: What does the current upstream E&P scene look like in Mexico in your view? What is your perspective on current activity off Mexico?

HHH: It is very exciting to see so many new players coming into Mexico, especially the fact that you now have 25 new Mexican E&P companies in the country. No one would have thought that 2-3 years ago.

From Statoil's perspective, this can only be good for Mexico. More companies participating will mean more eyes looking at the seismic, more ideas about where the oil flows, and ultimately more wells and discoveries.

I am also of the opinion that this new Mexican energy model will ultimately also be very good for Pemex, which Pemex CEO Jose Antonio Gonzalez Anaya also said at CERAWeek in March. If we draw a comparison with Statoil's experience in Norway, I think it will be clear that having multiple E&P companies can actually be to the benefit of the national oil company. In this way, through partnerships and collaboration, we were able to learn from some of the best, and by also having to compete with the same companies it forced us to continuously improve. I believe it has been a key part to Statoil's success.

So with Pemex already being one of the largest producers worldwide, I think they have every reason to benefit from the influx of ideas and investments that the new Mexican energy model brings. Indeed, Pemex is already benefiting – just look at the interest and the investments they got with Trion, and now they are looking at farming down several other fields and discoveries as well.

OE: What are some of the challenges Statoil sees in the Mexico market (workforce, technology, etc.), and what are

Gulf of Mexico

Statoil, Total and BP attended formal signing with SENER's Joaquin Coldwell and CNH's Juan Carlos Zepeda on 10 March. Image from CNH.

some ways the company has worked to resolve them?

HHH: I think it is important to remember that while the Mexican market is new to many of the recent upstream entrants, the oil and gas industry has been flourishing in the country for about 100 years.

Mexico already has a strong and competent oil and gas supplier industry, and a very well developed economy in many other areas as well. And if you look beyond E&P, Mexico also has very competitive and technologically advanced automotive and aerospace industries – with people, knowledge and competencies that can be further leveraged for the benefit of the oil and gas industry going forward as well.

As the industry moves into newer and less familiar areas in Mexico, such as deepwater and unconventionals, it will be key for companies such as ours that we work with our local counterparts and suppliers to transfer and strengthen skills also in these areas. Working to establish links between suppliers, universities and research institutes both in Mexico and abroad will also be important in this regard.

OE: What is the long-term outlook for Mexico's oil and gas industry from your perspective?

HHH: From Statoil's perspective, the long-term outlook for oil and gas in Mexico looks very good. The energy reform, and the new Mexican energy model which it triggered, has given Mexico a great opportunity.

Indeed, the International Energy Agency (IEA), in a recent publication addressing the outlook for energy in Mexico to 2040 with and without the energy reform, concludes that the Mexican nation and the Mexican people can look forward to material benefits from the reform if it is executed in a manner that provides the predictability and investor security needed to attract the required risk capital and activity level.

But, there is a sense of urgency here. To deliver on this potential there is a need to increase and incentivize activity. Only through exploration activity and by drilling wells will the significant yet to find potential in Mexico ever be proved up. And it is only by increasing activity that people will start seeing the true benefits – employment, investment and revenues – of oil and gas and the new Mexican energy model. And indeed, if you give any credence to the recent estimates of "peak oil demand," it is a strategic objective for Mexico to monetize its hydrocarbons while they are still needed.

According to an assessment by AMEXHI, the upstream oil and gas association in Mexico, as many as 20-30 wildcat wells are needed each year to deliver the increased production estimated in the IEA report.

So while Mexico is off to a great start, even more needs to be done to incentivize early activity (e.g. by adjusting the bid formula to give increased weight to the work program). Only in this way will Mexico be able to deliver on its potential and deliver the full and true benefits to citizens and industry alike.

OE: Is there anything else that you would like to add?

HHH: I would like to reiterate my belief that the energy reform is 'Mexico's Big Opportunity.' In the IEA report mentioned earlier, two scenarios are compared: A 2015-2040 journey for Mexico without the energy reform implemented and another scenario with full energy reform implementation. When the two forward scenarios are compared, it is clear that full energy reform implementation delivers many key long-term benefits to Mexico and the Mexican people: Oil production in 2040 is more than a million barrels per day higher, the cumulative GDP during 2015-40 is about a trillion dollars higher, oil revenues are ~$600 billion higher and investments are almost $300 billion higher. If the energy reform were not implemented, Mexican authorities would have had to compensate for the lack of income with higher taxes and lower state and federal budgets. 'It takes a village' to deliver 'Mexico's Big Opportunity.'

The Mexican authorities have so far been very good

Gulf of Mexico

'neighbors' promulgating an open dialogue with the players in the E&P industry. This collaboration has already secured many win-wins as global best E&P practices have been brought to Mexico.

The following two areas require special and continued attention:

- **The Bid Formula:** In the current bid formula, extra royalty is given a weight factor of nine compared to extra work program offered (and the extra work program is capped at two wells). This set-up makes it possible to win a block by bidding high extra royalty and zero wells.

This is hardly in Mexico's interest as the extra royalty is only seen if a discovery is made starting with the first oil production 5-10 years from now offshore. In real estate, they say that three things are important: location-location-location. What Mexico needs now is: activity-activity-activity!

Every exploration well is a 'snowball' of activity in the Mexican oil states and if a commercial discovery is made, the 'snowball' grows big in a hurry when it comes to activity: employment, investments, all the way to production and income. Mexico should perhaps start defining success through the number of offshore wild cats drilled per year with 20/year as the goal as noted above.

Nothing can deliver 'Mexico's Vision In The Gulf' more than activity-activity-activity. The most important 'lever' to pull to achieve this is the terms and conditions offered by Mexico compared to other countries. What if Mexico, by design, decided to offer the best terms in the world? 'Economic Gravity' would then attract even more risk capital to Mexico leading to more activity and more discoveries quicker.

- **Contract Administration:** Contract administration could be much more efficient with the introduction of electronic signature and data transfer.

There is too much paper and copying and signing. The carrot is that costs are lowered and Mexico becomes more competitive and business friendly. **OE**

Helge Hove Haldorsen *is Director General Statoil Mexico in Mexico City. Haldorsen previously served as Vice President Strategy & Portfolio Statoil North America in Houston. Prior to joining Statoil, Haldorsen worked for Norsk Hydro in various senior roles. Haldorsen earned an MS in Petroleum Engineering from the Norwegian Institute of Technology in Trondheim and a PhD in Reservoir Engineering from The University of Texas. He also served as SPE President in 2015.*

Gulf of Mexico

Churning around?

Prospects are looking up in the US Gulf of Mexico as operators make final investment decisions. EIC's Jake Gillian outlines activity in the area.

The US Gulf of Mexico (GoM) has seen somewhat of a slowdown in activity ever since the oil industry recession began in November 2014. There does, however, finally seem to be some light at the end of the tunnel with project investment set to take a significant jump as we close out 2017 and move into 2018 (See capex investment chart).

Signs that the tide is turning are best exemplified by final investment decisions (FIDs) coming for both BP's Mad Dog II project, and Shell's Kaikias subsea tieback in February 2017. BHP Billiton (a 23.9% shareholder) committed to invest US$2.2 billion into the Mad Dog II project, while Shell took steps to secure investment for the development of the Kaikias deepwater field: the first Shell project approval for 18 months.

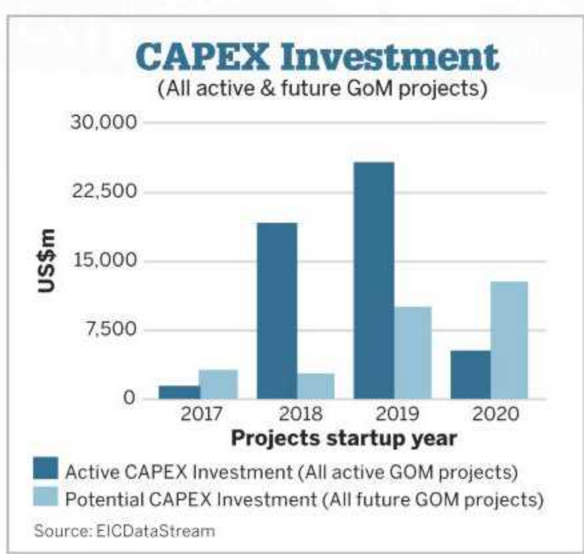
Project activity

The Mad Dog II project, operated by BP (60.5%) with partners BHP Billiton (23.9%) and Chevron (15.6%), aims to deliver up to 140,000 b/d through a total of 14 subsea wells by 2021. Project costs have recently been cut to $9 billion (down from $20 billion) through standardizing design, lower steel prices, and the renegotiation of contracts, and as a result BP gave the project the greenlight in December 2016. Following BHP Billiton's FID, Chevron also took the decision to proceed with the project in early March 2017. Samsung Heavy Industries has recently (January 2017) been awarded the $1.3 billion contract to build the semisubmersible production unit.

There are also significant opportunities developing at Shell's Vito offshore oil field project. Recently, Shell narrowed the shortlist for the semisubmersible production facility down to Hyundai Heavy Industries, Samsung Heavy Industries, and Daewoo Shipbuilding & Marine Engineering. Kiewit, and COOEC are shortlisted for topsides only. Contract awards are expected in late 2017.

Encouragingly, the North Platte offshore oil discovery, operated by Cobalt (60%) and partnered with Total (40%) encountered 198m of net oil pay in January. Cobalt is seeking a production unit capable of producing between 80,000 and 100,000 bo/d of oil. Cobalt has not chosen to proceed with a traditional multi-stage tender process and instead has opted to partially fund a design competition, expected to be underway as early as Q2 2017.

Appraisal drilling at Anadarko's Shenandoah-6 well reached total depth in February 2017 and sidetrack work was started. SBM Offshore is currently proceeding with front-end engineering and design work (funded by Anadarko) for the facilities semisubmersible platform while Wood Group is proceeding with topsides and subsea components. There is currently no firm date for an FID, and Anadarko has previously cited the low price of oil as the main reason that investment was not forthcoming. However, with the price of oil stabilizing, Anadarko upping their share in the discovery to 33%, and continuous appraisal work being undertaken, there may be an FID soon.



Source: EICDataStream

The outlook

The outlook for the GoM is definitely bright, especially when considering the projected level of investment in 2018 and 2019 into major project start-ups. Additionally, with the increasing utilization of subsea tiebacks, breakeven costs are being lowered. Shell, for example, is expecting breakeven costs of below $40/bbl on its Kaikias subsea tieback through utilizing infrastructure already in place at the Shell-operated Ursa production hub.

Furthermore, President Donald Trump's plan to open up 73 million acres of coastline for offshore drilling as a way to drive the US toward energy independence reinforces the optimistic outlook for the region's future. **OE**

__Jake Gillan__ works on the EIC's project tracking database, EICDataStream, for North and Central America as well as monitoring market trends, project and business opportunities beneficial to the EIC membership. He has a BA in History from Plymouth University in the UK and has worked for UK valve supplier, PJ Valves.

A panel discussion at UTC 2016. Photo from UTC Bergen.

Simply electrifying

Ahead of the Underwater Technology Conference (UTC) in Bergen this June, Elaine Maslin spoke with program chairman Nils Arne Sølvik and Statoil's Chief Engineer Subsea Technology & Operations, Rune Mode Ramberg, about some of the topics likely to come up.

While there are signs oil and gas investment might be on the rise, the subsea industry still faces multiple challenges – not least retaining its focus on simplification and cost reduction, facing growing emissions reduction targets and ensuring that there's a sustainable business going forward.

One answer to all of these challenges could be technology. Subsea production, all-electric and remote operations could help reduce costs and carbon emissions. On the other hand, business and contracting models need to change to achieve and sustain the cost reductions and simplification the industry has been striving toward.

"When the oil price comes back up and projects start to get sanctioned, will we then go back to the normal oil industry capacity frenzy and cost escalation," asks Nils Arne Sølvik, chair UTC 2017 program committee/president, OneSubsea processing systems. "What do we do now to avoid that? One of the things we are focusing on is all-electric, which could be, I think, an important cost reduction technology. We just need to make sure that when interest picks up that we stay focused on benefiting from these technologies, otherwise we will go backwards and we will be back on the cost wagon."

Rune Mode Ramberg, chief engineer subsea technology and operations, Statoil, who is also on the UTC program committee, adds: "The current challenge is a lot about simplifying the system. Going all-electric is a way to remove hydraulics and simplify the system."

This push, as well as a growing emphasis on CO_2 reduction, reducing chemical leakages, enabling flexible systems, and all-electric becoming more competitive, is driving momentum in this space. He says there will be much more development and much more installation of all-electric in a couple of years.

All-electric also feeds into the digitalization space, enabling more information to be sourced from the seafloor.

"The first parts of the system are already out there working," Ramberg says. "Electric actuators are available and in operation. Åsgard subsea compression is an electric system." Statoil is planning a DCFO (direct current fiber-optic) combined cable for power and controls for its Johan Castberg floating production development (*OE:* August 2016), providing power to valves and communication. "DCFO technology is an important step going forward, in digital and electrification. I believe in simplicity, I believe simple solutions will survive," Ramberg says. The next step is high voltage power distribution, he adds.

Johan Castberg floating production vessel. Image from Statoil.

Subsea field remote operation is another strong topic at UTC. Statoil is playing in this space, too. The firm has an e-ROV concept that envisions a remotely operated vehicle (ROV) stationed in the field and operated from shore, with fiber-optic communications and power from control system power. This would remove the need for ROV support vessels. Initial trials of such a system have been ongoing and this summer Oceaneering is contracted to provide an ROV for the e-ROV project as part of a trial. With this kind of future in mind, Statoil is starting to design projects with fiber infrastructure already installed, Ramberg says.

But, the future of the industry is not just about technology. Could contracting models shift from procurement practices that drive price and capacity heat to more performance-based contracts, asks Sølvik.

"The traditional set-up is high-quality, installed and delivered on time," he says. "The contractor has a focus on executing project delivery and hardware and then lets the operator run it. If it is a performance-based structure, the contractor knows they have to live with what they deliver. If they don't deliver high-quality, there is risk to their reputation and the next job and you hit the value stream and cash flow.

"Instead, the end client could look at how much oil we get out and then pay for the production. Or maybe the focus could be on performance, in terms of availability requirements," Sølvik says. Indeed, in the offshore renewables market, contractors have increasingly been taking equity stakes in projects, as well as acting as lead contractors, aligning the project's performance with their own goals. TechnipFMC's SVP in Norway has noted that the company is considering doing something similar in the oil business. Indeed, floating production system providers already also work on production-based contracts. The airline industry has also been through such a change, going from having their own huge internal engineering teams, to their jet engines now being owned and maintained by the likes of GE, points out Sølvik. "We might need such a shift as well. Contractors will have to take greater responsibility," he says.

"If we shift to take responsibility for supplier-led solutions – the performance of it – then we make more in depth decisions about what kind of hardware we deliver and be able to optimize and analyze it, for maintenance in a life of field scenario and in a very efficient way," Sølvik says.

They'll also have to digitize, he says. "When you tie a change in business model in with digitalization and surveillance, condition-based monitoring, production optimization, production management... you will need to have a platform to achieve these things. You need a digital twin. We need digital responsibility of all our kit."

Pressure on the industry will also come in the form of carbon emissions reductions, Sølvik says. "It is going to grow in force." To achieve climate targets set by the 2015 Paris agreement, CO_2 emissions need to go down dramatically, impacting sales and how firms operate.

"That will have an impact on oil consumption, but gas will still need to grow," Sølvik says. "And the focus on gas is important for us, and means using technology that can reduce emissions. I think subsea has a major role to play in that picture. The efficiency budget for a platform-based development with old fashioned artificial lift methods is much worse than a complete subsea tieback to infrastructure or to shore. Using modern artificial lift methods – boosting, compression, downhole boosting – that's much more efficient than a traditional water injection system or gas-lift system. Those are also topics that will be important."

Ramberg says communication is also important, across companies – oil companies and the supply chain – to find a "win-win" situation. Subsea is also a part of a bigger system and how the entire value chain fits together needs to be understand more, he says.

"It's a very interesting program this year, especially focusing on electric," he adds. "It's really bringing a lot of new ideas to the table and not just traditional subsea hardware. This is time for electricians to go to a subsea forum as well." **OE**

OTC Spotlight Awards highlights innovation

This year's OTC Spotlight on New Technology winners showcase innovation in drilling, completions, production, and subsea operations. Congratulations to all the 2017 winners.

This year, The Offshore Technology Conference (OTC) selected 17 technologies to receive its 2017 Spotlight on New Technology Award. The awards will be presented in the NRG Center Rotunda Lobby on 1 May in Houston. The recipients were selected based on four criteria: New and innovative: less than two years old; original and groundbreaking; proven: through full-scale application or successful prototype testing; Broad interest: broad appeal for the industry; and significant Impact: provides significant benefits beyond existing technologies. For a third year, OTC recognizes innovations developed by small businesses. This year's recipient of the Spotlight on Small Business Award went to two firms, Fuglesangs Subsea, producer of the Omnirise Minibooster; and WiSub, producer of the Torden High Power Pinless Subsea Connector.

Dril-Quip, producer of BigBore-IIe Wellhead System

The BigBore-IIe is a fully qualified wellhead system consisting of a DXe connection profile, integral high-capacity hanger lock-down, superior system fatigue, and high-capacity running tools. The BigBore-IIe provides significant drilling cost savings by reducing the number of trips into the well, elimination of drilling/production lock-down equipment, and allows for reduction of casing strings.

www.dril-quip.com

Dril-Quip, producer of DXe Wellhead Connector

Dril-Quip's DXe Wellhead Connector, suitable for HPHT (high-pressure, high-temperature) and severe cyclic load environments, has a highly engineered locking profile and gasket design providing high structural capacity and high fatigue-resistance resulting in longer service life. The technology of this critical connection is validated beyond API-16A-PR2/API-TR7 requirements with both structural and fatigue physical testing. **www.dril-quip.com**

Fuglesangs Subsea, producer of Omnirise Minibooster

The Omnirise Minibooster is the world's first barrierfluid-less and seal-less pump intended for permanent subsea applications down to 3000m. The system includes a unique subsea electric variable speed drive, and was successfully qualified as part of NOVs' Active Subsea Cooler system in partnership with Statoil, Shell, Chevron, Total and GE.

www.fsubsea.com

Halliburton, producer of EcoStar

The Halliburton EcoStar valve is the world's first electric downhole safety valve (e-DHSV). The EcoStar e-DHSV eliminates hydraulic fluid to enable a fully electric completion system with zero risk of exposing electronics to produced wellbore fluids while retaining the same failsafe mechanism as today's conventional safety valves. **www.halliburton.com**

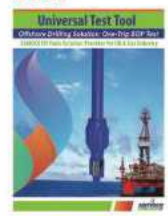
Halliburton, producer of HCS AdvantageOne offshore cementing system

The HCS AdvantageOne Offshore Cementing System addresses the

complexities of deepwater with the versatility for use in all offshore environments. This intuitive system enables remote operations, has an integrated liquid additive system for precise slurry blending, and predictive maintenance capabilities with shore-based monitoring to help preempt equipment-related non-productive time.

www.halliburton.com

Samoco Oil Tools, producer of OneTrip Universal BOP Testing Tool



In collaboration with Shell Offshore Engineering, Samoco Oil Tools has engineered, manufactured and tested OneTrip, a revolutionary blowout preventer (BOP) testing tool. Samoco's OneTrip can conduct required BOP tests in one trip, eliminating the need for multiple trips along the stack and reducing a rig's idle time by a minimum of 50%.

www.samocooiltools.com

SBM Offshore, producer of Stones FPSO Turret Mooring System

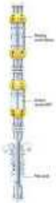
The Stones floating production, storage and offloading (FPSO) unit's Turret Mooring System (TMS) incorporates a series of enabling technologies to become the deepest mooring system of any floating production unit, and the first disconnectable TMS to support steel risers. These new technologies will facilitate future developments in ultra-deepwater, and HPHT reservoirs.

www.sbmoffshore.com

Schlumberger, producer of Managed Pressure Drilling Integrated Solution

The Schlumberger Managed Pressure Drilling (MPD) Integrated Solution is the industry's first complete, all-OEM, reservoir-to-flare-stack deepwater MPD

Solutions

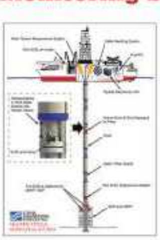


system. When MPD design, engineering, manufacturing, system integration, well engineering, and on site well delivery services are delivered from one platform and from a single supplier, operators minimize rig footprint while maximizing drilling efficiency and versatility.
www.slb.com

Schlumberger, producer of OptiDrill Real-Time Drilling Intelligence Service

The OptiDrill Real-Time Drilling Intelligence Service enables continuous real-time condition monitoring by integrating a comprehensive set of drilling dynamics and mechanical information. The service mitigates drilling risk and improves performance by providing actionable information to continuously identify hazardous drilling dynamics events and trends, and recommending safe operating parameters.
www.slb.com

Stress Engineering Services, producer of RealTime Fatigue Monitoring System

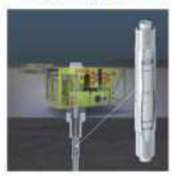


The RealTime Fatigue Monitoring System (RFMS) was developed to provide fatigue damage of drilling riser, and wellhead systems. The wellhead is the last pressure containing barrier between the well and environment. Managing the loads ensures that system integrity is not compromised, and protects the environment from hydrocarbon discharge.
www.stress.com

Sulzer, producer of Compact Mass Transfer and Inline Separation Technology (cMIST)

ExxonMobil Upstream Research Co.'s new Compact Mass transfer and Inline Separation Technology (cMIST) replaces conventional TEG towers and associated separator vessels to meet pipeline dewpoint specifications. cMIST achieves this goal with significant reductions in weight, footprint and cost. cMIST for dehydration is licensed to Sulzer for onshore and offshore applications.
www.sulzer.com

Techni, producer of BAMSE



BAMSE (B-Annulus Monitoring System) is a pressure and temperature sensor for installation in the B-annulus of oil and gas wells. The BAMSE system uses no active electronics in the inaccessible B-annulus and is designed for life-of-well reliability.
www.techni.no

TechnipFMC, producer of 20k HPHT Subsea Choke

TechnipFMC 20k HPHT Subsea Choke is designed to withstand life-of-field fatigue in HPHT oil and gas production environments without the need for hydraulic fluids. It meets, or exceeds, API 17TR8. Its plug-and-cage design leverages proprietary HPHT sealing technologies and TechnipFMC's G2i electric actuator, providing increased controllability over traditional hydraulic actuation technology.
www.technipfmc.com

Weatherford, producer of AutoFrac RFID-Enabled Stimulation System

The AutoFrac system enables efficient stimulation in open-hole sections of extended-reach offshore wells where traditional technologies have often failed to provide adequate reliability. The system enables remote operation of lower completion tools and provides several options for tool communication that do not rely on control lines or mechanical actuation.
www.weatherford.com

West Drilling Products, producer of Continuous Drilling and Circulation Unit

The Continuous Drilling & Circulation Unit (CDU) – is the heart of the CMR Technology, offering the world's first continuous drilling operation, and is also the world's first fully robotized circulation unit. The CDU substantially (up to 50 %) reduces the overall time of drilling operations because it eliminates down-hole problems associated with differential sticking and pressure fluctuations and reduces safety risk by removing all personnel from the rig floor during the drilling operation.
www.westgroup.no

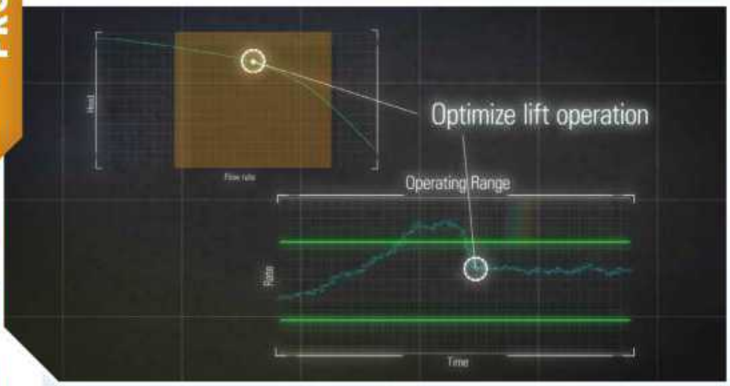
Wild Well Control, producer of DeepRange Plug & Abandonment Tool

Wild Well's DeepRange intervention tool delivers a groundbreaking plug and abandonment (P&A) solution in a riserless package. The robust remotely operated vehicle-driven technology offers a minimally invasive solution that maintains wellbore integrity while providing a cost-effective yet high-quality option that will change the way subsea P&A operations are done for years to come.
www.wildwell.com

WiSub, producer of Torden High Power Pinless Subsea Connector

The Torden High Power Pinless Subsea Connector is WiSub's next-generation product developed in collaboration with NOV to increase connection reliability between the BOP and LMRP (lower marine riser package). This innovation is further standardizing autonomous underwater vehicle and remotely operated vehicle connections, combining patented high-speed data transfer with highly-compact resonant power transfer. Torden delivers improved mating tolerances and reliability.
www.wisub.com

Solutions



Schlumberger launches Lift IQ

Schlumberger has introduced the Lift IQ production life cycle management service, which offers monitoring, diagnostics and optimization of artificial lift systems in real time. This new service securely collects, transmits, evaluates and interprets data to improve production efficiency, extend equipment run life and reduce operating costs.

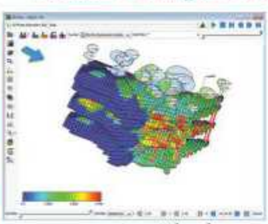
The Lift IQ service comprises four service tiers including visualization, real-time surveillance and diagnostics, well optimization and field optimization.

"As operators focus on ways to reduce their costs, one consideration is whether they are getting the full value of their artificial lift equipment," said David Paterson, president, Artificial Lift Solutions, Schlumberger. "With the Lift IQ service, we can use real-time data to improve equipment run life and uptime as well as to adjust drawdown for maximum field recovery for the productive life of the well."

From Artificial Lift Surveillance Centers (ALSC) around the world, experienced service engineers monitor equipment alarms and events to identify probable causes and quickly report remedial actions for rapid implementation. Data are gathered through satellite or cellular connections with three convenient storage options of on-premise, in-country or global. In conjunction, engineers at the 24/7 ALSC provide in-depth analysis to proactively manage commissioning and restarts as well as avoid shutdowns typically caused by high gas and low flow conditions.

www.slb.com/liftiq

Emerson releases Roxar Tempest 8.0



Emerson Automation Solutions released Roxar Tempest 8.0, a reservoir management software suite. The latest version features additional history-matching capabilities; enhanced field productivity thanks to greater simulation performance; and an integrated workflow from geosciences to production.

Describing the new software, Kjetil Fagervik, vice president of product development and marketing of Roxar Software at Emerson Automation Solutions: "We added even greater value throughout the reservoir lifecycle by providing a technology platform that combines engineering and geology and ensures that the very best uncertainty and risk analysis information is available for those vital field development decisions."

Roxar Tempest, which runs on Windows and Linux and operates alongside Emerson's reservoir modeling solution, Roxar RMS, is an integrated software suite that provides a single, consistent interface and is used in hundreds of installations worldwide. Tempest modules include fluid analysis and an economic evaluation tool that provides cash flow analysis derived from simulation results. All modules can be deployed as an integrated suite with a common interface, or separately within 3rd party simulation workflows.

www.emerson.com

Synthesis simplifies integration

Specialist subsea manufacturer L&N Scotland is offering a solution, the Synthesis system, for the current constraints faced by subsea operators during product integration stages.

Conventional methods for obtaining a complete subsea system have commonly required operators to procure all component parts through multiple suppliers and purchase orders. Synthesis, however offers a fully commissioned package complete with a pre-manufactured and "ready-to-fit" kit of parts, through a single purchase order.

Synthesis compromises of a full turnkey support package complete with all small-bored tubing lines staged in reverse fitment order, along with all line and assembly sequence documentation for installation.

www.lnscotland.com

GATE acquires eelReel

The eelReel tool is an extended reach solution to clean plugged flowlines and pipelines. With an established track record of resolving a multitude of blockages comprised of hydrates, scale, paraffin, and asphaltenes, the eelReel Tool is a solution for remediation of pipeline blockages and production restoration. The coil tubing deployed tool has an extended reach close to 5mi, can traverse 5D bends, and is deepwater-certified with patented technology delivering plug remediation.

GATE said that it acquired the eelReel tool to support its portfolio of turnkey blockage remediation and pipeline/flowline maintenance services to the energy industry. BlueFin, a GATE Energy company, will deliver the field execution services of the tool in conjunction with their proprietary chemicals, gel pigging technologies, mechanical cleaning and pigging tools for early intervention, all supported by pumping and filtration on each job. GATE's flow engineering services (integrity management, production chemistry and flow assurance) will provide advanced modeling and evaluation for each job. **www.gate.energy**

Managing the pressure

AFGlobal sheds light on its launch of a key RGH component for deepwater MPD operations.

The venerable rotating control device (RCD) that has long been the enabling component of managed pressure drilling (MPD) operations has a purpose-built replacement with an innovative new design that eliminates wear and maintenance prone rotating components. AFGlobal's Active Control Device (ACD) provides the prerequisite seal and diversion of annular wellbore returns using a novel, non-rotating device enabled by an actively pressurized, co-molded element.

The new device eliminates the bearings and rotating components that are a regular source of maintenance and failure in standard RCDs. Instead, its active pressure sealing system hydraulically applies closing pressure to maintain consistent wellbore sealing integrity over time as the sealing sleeve is worn.

RCD elimination

While the basic design for RCDs has evolved from early diversion devices used in air drilling, the ACD is designed specifically for MPD. It is API 16RCD-qualified to isolate and seal off the top of the riser to divert mudflow during MPD operations. The ACD is installed subsea in the marine drilling riser below the rig riser tension ring and slip joint. Configured as part of a riser gas handling system (RGH), the device enables MPD operations on floating drilling rigs equipped with any generation of riser.

The ACD's non-rotating, hydraulically controlled sealing sleeve that surrounds the drill pipe features a unique co-molded element manufactured with an enhanced urethane matrix reinforced with a durable polytetrafluoroethylene (PTFE) inner shell. As the sealing sleeve wears, pressure is actively applied to force the element against the drill pipe to maintain a consistent seal. With standard RCDs, the passive rotating elastomer seal is degraded with use, resulting in a performance decline requiring regular replacement. The rotating system also includes a bearing assembly that must also be maintained.

Active sealing

Active pressure sealing is a significant advance over RCD operations that degrade the performance of a passive rotating elastomer seal, says AFGlobal. The device varies hydraulic pressure on the seal to compensate for wear and accommodate passage of wear inducing tool joints. In addition, active pressure is a positive wear indicator to inform maintenance and assure MPD operations. Service life and performance is further enhanced by the greater durability of the co-molded element and lubrication of the seal with clean drilling mud.

MPD integration

The ACD is a component of AFGlobal's RGH system, which is an integral part of the drilling riser. The RGH is used to address safety issues that occur when formation gas breaks out of solution in the riser. It is also the basis for establishing an MPD-ready rig configured for the addition of manifolds, instrumentation, control systems, and other MPD equipment. The component-based RGH system easily accommodates MPD service company equipment in addition to AFGlobal MPD systems owned by the drilling contractor or operator. OE

For deepwater, subsea applications, the Active Control Device offers a significant departure from conventional RCDs with a purpose-built, non-rotating, hydraulically controlled sealing sleeve around the drill pipe. Photo from AFGlobal.

Demanding work

Jerry Lee reports on the development of Weatherford's latest advancement in underreamer technology, the RipTide RFID.

While drillbits have evolved to keep up with the demands of drilling challenging wells, most underreamer technology used to enlarge the well has not. A new version of Weatherford's RipTide RFID (radio-frequency identification) drilling reamer aims to narrow the gap.

Drilling while simultaneously enlarging hole sections can be an effective technique to save rig time; however, when modern drillbits are paired with an antiquated underreamer design, operators may not see optimum performance. While modern drillbits can handle the more abrasive formations of today's deepwater campaigns, the same can't be said for most underreamers, which suffer from excessive vibration and premature dulling in these extreme environments. To address the issue, Weatherford developed the ReamSync borehole enlargement performance system, which includes dull-grading analysis, cutter modeling, and the use of new PDCs with high thermal stability. The company then collaborated with cutter manufacturer US Synthetic to create a premium version of the RipTide drilling reamer featuring a new cutting structure and Deep Diamond PDC (polycrystalline diamond compact) cutters for challenging deepwater applications.

The key to ensuring underreamer performance is keeping the cutters sharp. When the drillstring rotates, tool vibration, thermal variations, and the abrasiveness of the formation cause the cutters to dull and impair reamer performance. To mitigate these issues, US Synthetic recommended its Deep Diamond PDC cutters for this application. Using a proprietary reattachment material in conjunction with US Synthetics' patented manufacturing process, the Deep Diamond cutters have been developed to have thermal stability that is comparable to deep-leach performance, and substantial abrasion resistance, which is key to maintaining a smooth borehole.

"As a result of our collaboration with Weatherford, we learned about the RipTide reamer's ability to minimize vibration and stabilize the reaming environment, and saw an ideal opportunity to apply our Deep Diamond technology," says Rick Frost, international sales director/product management, US Synthetic.

Using the right cutters is only part of the solution. The other is putting them in the right place.

The original RipTide reamer uses triple cutter blocks that are plural set, which means each block is identical and cuts the same area. For extremely abrasive formations, however, Weatherford favors a single set design. In a single set design, the blocks are slightly offset, which enables each cutter to work evenly, in concert with each other, while distributing the work rate, which reduces vibration, says Eddie Valverde, drilling services business development manager – Western Hemisphere, Weatherford.

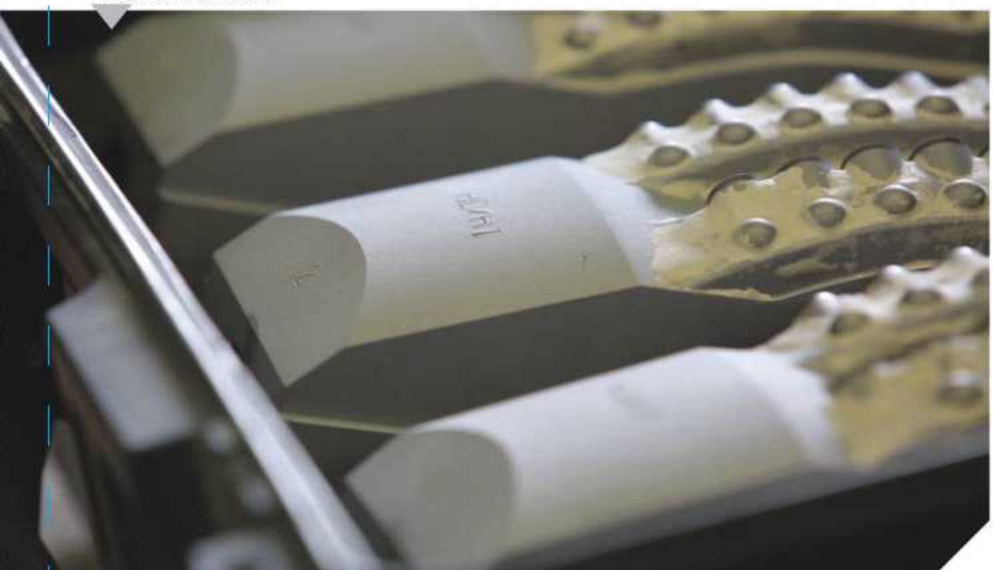
"In a 360° rotation, the cutters are all working evenly and removing the same amount of formation," Valverde says. "The change from a plural set to a single set enabled us to drill a smoother borehole, with decreased vibration and, after adopting the new cutters from US Synthetic, it allowed us to drill through some very abrasive formations without dulling the cutting structure."

With better cutter placement and improved abrasion resistance, the marriage of these two technologies created a more stable environment with less vibration, leading to better underreamer performance.

This new version of the RipTide RFID drilling reamer has been run in the Gulf of Mexico on two occasions for hole sections that kicked off after the salt layer and transitioned from the Miocene section (sandstone to shaly) into the very abrasive Wilcox sand.

"We have seen more than 75% improvement in the dull grading, which means we've had zero-dull grading on these two runs. Coupled with that, we were able to meet the client's rate-of-penetration objectives, and we were able to finish the entire section in one run," Valverde says. "Ensuring that the RipTide can make it down with zero-dull grading is very important. That gives the client confidence that the borehole is large enough to run casing and cement it properly." OE

The premium cutter blocks on the RipTide drilling reamer are designed as a single set to evenly distribute the work, ensuring a smooth, concentric underreamed hole.
Photo from Weatherford.



Activity

SNC-Lavalin weighs Atkins takeover

SNC-Lavalin CEO Neil Bruce

In early April, Montreal-based engineering and construction firm SNC-Lavalin expressed interest in acquiring UK-based engineering firm Atkins Global for cash consideration of £2.08 billion (US$2.6 billion).

The Canadian company said that an offer would be subject to a number of pre-conditions, and the recommendation of of Atkins Global's board. SNC-Lavalin has until May [this month] to make a firm intention to make an offer, according to the UK's Takeover Code.

Atkins released a statement in April confirming SNC-Lavalin's interest, saying that it has received an indicative offer from SNC-Lavalin at an offer price of 2,080 pence in cash for each Atkins share for the entire issued and to be issued share capital of Atkins.

"The Board of Atkins has indicated to SNC-Lavalin that the possible offer would deliver value to Atkins shareholders at a level that the board would be prepared to recommend, subject to reaching agreement on the other terms and conditions of the offer," Atkins said in statement.

In 2014, SNC-Lavalin purchased Jersey-based oil and gas services company Kentz for £1.2 billion. ▪

Borr takes Transocean jackups

Borr Drilling, a Norwegian newcomer with ties to Seadrill, moved to acquire Transocean's entire jackup fleet, including newbuilds, in a US$1.35 billion deal. Borr Drilling signed a letter of intent in late March with Transocean to buy 15 high-specification jackup rigs, consisting of 10 rigs in Transocean's fleet and five newbuilds under construction at Keppel FELS.

Borr Drilling is new to the industry, but has significant ties to top management at London-headquartered Seadrill. Borr's CEO Rune Magnus Lundetrae previously served as Seadrill's CFO from 2012-2015. Borr's COO Svend Anton Maier worked at Seadrill from 2007-2016, before that he was at Transocean and Ross Offshore. Seadrill's former president and CEO Fredrik Halvorsen sits on Borr Drilling's board of directors, as well as Tor Olav Trøim, Seadrill's former vice president and board member from 2004-2014.

Inpex sells Indonesian subsidiary

PT Medco Daya Sentosa, a subsidiary of Medco Energi Internasional, will acquire Inpex's wholly owned subsidiary, Inpex Natuna. By purchasing Inpex's subsidiary, Medco picks up an additional 35% non-operating interest in South Natuna Sea Block B production sharing contract (PSC).

Medco Energi previously acquired 40% operating interest in the South Natuna Sea Block B in November 2016. With the acquisition, the company will soon hold 75% interest in the block. South Natuna Sea Block B is 1200km north of Jakarta, Indonesia in the Natuna Sea in water depths of 50-55m. Before the acquisition. Chevron holds the remaining 25% interest in the PSC.

GE, Noble Corp. form DigitalRig partnership

GE and Noble Corp. have entered a partnership to collaborate on the Digital Rig solution. GE will deploy its latest marine asset performance management (APM) system, powered by Predix, on four of Noble's drilling rigs.

GE's marine APM solution combines "digital twin" data models and advanced analytics to detect off-standard behavior—often a sign of potential failure or performance degradation—of target assets on the rigs. As the system continues to learn, this ability to predict the future condition of rig-wide assets will also enable a shift from planned to predictive maintenance.

Exxon sells Norwegian business

Supermajor ExxonMobil has sold its operated upstream business on the Norwegian Continental Shelf (NCS) to newcomer Point Resources, which now enters the market as a mid-sized Norwegian exploration and production (E&P) player. The price of the deal was not disclosed.

Exxon is selling its operated stake in the producing Balder field (100%), Ringhorne (100%), and Ringhorne Øst (77%) fields; the partially developed Forseti field (100%); the Jotun Unit, where production ceased in 2016 (90%); and adjoining exploration areas that contain several undrilled prospects. The deal also includes the Jotun A floating production facility.

The deal will see the transfer of ExxonMobil's 300 offshore and onshore E&P staff in Norway; and the company's office building in Sandnes, near Stavanger. Point Resources will also receive field assets such as platforms and floating production storage and offloading vessels.

James Fisher acquires Insight Marine Projects

James Fisher Marine Services (JFMS) has acquired the operations and assets of Insight Marine Projects Ltd., a specialist survey company headquartered in Cornwall, UK, which will be rebranded this year to form the subsea surveying division of marine projects at JFMS.

The purchase will see the addition of hydrographic/geophysical survey and construction support to JFMS's existing offering to the renewables, oil and gas and civil engineering markets around the world.

"Being part of JFMS means that Insight is now able to undertake larger and more complex surveying projects for customers around the world," says Alex Richards, managing director of Insight.

Aker completes Reinertsen acquisition

Aker Solutions completed its US$25 million acquisition of oil services provider Reinertsen. The agreement to buy Reinertsen's Norwegian oil and gas services business, was announced in late March, and has been cleared by Norway's competition authority.

The acquisition agreement excludes Reinertsen's liabilities as of 19 December 2016, when the company went into debt negotiation proceedings.

Reinertsen, the third-largest maintenance and modifications supplier offshore Norway, has its main offices in Trondheim and Bergen, where Aker Solutions also has a solid presence. The company's order backlog contains key maintenance and modifications contracts with Statoil, including a minimum six-year framework agreement awarded in December 2015.

SLB opens production technologies facility

Schlumberger opened a new purpose-built Production Technologies Center of Excellence, in late March, aimed at solving customers' global challenges related to oil and gas production chemistry, particularly those encountered in deepwater, heavy oil and other extreme environments.

The center features nine laboratories that combine Schlumberger's process systems, production software and advanced chemistry. Forty research scientists are dedicated exclusively to product development and formulation activities that maintain asset integrity, address flow assurance challenges and remedy production issues, such as deposit formation and naturally occurring gases.

"This center brings under one roof, our capabilities in chemical research, production chemicals formulation and performance testing for our global operations," said Guy Arrington, president, M-I SWACO, Schlumberger.

Eni adds computing capacity

Eni started up its new HPC3 (high performance computing), in early April, in the Green Data Center in Ferrera Erbognone, Italy, enabling full support of all activities in the exploration and production sector.

Together with the existing HPC2 system, HPC3 will provide Eni with a sustained 5.8 PetaFLOPS, and 8.4 PetaFLOPS of peak computing capacity.

The new cluster continues along Eni's high performance computing philosophy based on hybrid architectures, by using top end GP-GPUs as computational accelerators. HPC3 is an intermediate step towards the next evolution, the HPC4, expected at the beginning of 2018. With HPC4 Eni's target is to overcome the barrier of 10 PetaFLOPS of computing power.

"The start-up of the new HPC3 supercomputer and the next comer HPC4 will enable Eni to deploy the most advanced and sophisticated proprietary codes developed by our research for [exploration and production] activities," said Claudio Descalzi, CEO, Eni. "These technologies will provide Eni with unprecedented accuracy and resolution in seismic imaging, geological modelling and reservoir dynamic simulation, allowing us to further accelerate overall cycle times in the upstream process and to sustain [exploration and production] performances."

Aqualis expands to Taiwan

Marine and offshore engineering consultancy Aqualis Offshore opened a new office in Taiwan to support local offshore wind and oil and gas

MacGregor opens VR showroom

MacGregor, part of Cargotec, opened a new facility in Arendal, Norway, which houses a training academy for customers. It specializes in advanced simulation training and has a purpose-built virtual reality (VR) showroom.

The academy provides a risk-free environment where the users learn how to make real-time, complex maneuvers.

"Customers can offer their crew fully-immersive training programs, which are so much better than previous offerings," said Jan Finckenhagen, training manager, advanced offshore solutions. "This will reduce the likelihood of causing injury to personnel or damage to equipment because they have already tried and tested it."

The VR showroom is divided into two zones comprising an authentic operating chair for offshore crane simulations and a zone where participants can walk around the simulated ship familiarizing themselves with the safe operation of the equipment.

All simulation training for MacGregor offshore cranes, offshore mooring and loading systems, as well as deck machinery and steering gear is now located in Arendal. MacGregor expects to train between 70 and 100 people at its new academy every year. ▪

COMPANIES

Activity

Siemens opens Gulf Coast service center

Among the senior executives at the facility ribbon cutting ceremony was Judy Marks, CEO for Siemens USA and executive vice president for new equipment solutions at the Dresser-Rand business, and Tim Holt, CEO for Siemens power generation services division.

Siemens has opened its new service center in Geismar, Louisiana, near Baton Rouge, to serve the region's oil and gas industry, and related markets. The facility features the latest technology and 28,000sq ft of shop floor space to repair and rebuild critical equipment such as centrifugal and reciprocating compressors, steam turbines, expanders, pumps, and rotary compressors.

"When our customers' assets require physical services, we invest in our people and in modern facilities like this one to ensure we have the right expertise and the right resources available to help create differentiating value for our customer," said Tim Holt, CEO of Siemens Power Generation Services Division. "And, we put them both close to our customers because we know that's the difference between mere service and excellence." ▪

developments in early April.

The company says that the purpose of the office is to promote its marine and engineering services locally, and to support the development of sister company Offshore Wind Consultants' offshore wind energy projects in Taiwan.

"Taiwan has a rapidly growing offshore wind sector as well as certain requirements for offshore engineering and marine survey services," says Phil Lenox, director – Asia Pacific, Aqualis Offshore. "Aqualis Offshore and Offshore Wind Consultants provide senior competence for the offshore sectors, so we believe that our experience can be utilized well in Taiwan."

ITF, OGIC offer innovation funding

The UK's Industry Technology Facilitator (ITF) and Oil & Gas Innovation Centre (OGIC) have joined forces to fund and support the development of innovations which could reduce costs, raise production efficiency, and

PGS names *Ramform Hyperion*

With the launch of the *Ramform Hyperion* seismic acquisition vessel, PGS has concluded it newbuild program with a naming ceremony at the Mitsubishi Heavy Industries Shipbuilding Co. yard in Nagasaki, Japan, in late March.

The Ramform design was created by Roar Ramde in the early 1990s. The first vessel of the Ramform Titan-class came in 2013 with the delivery of *Ramform Titan*, which was followed by *Ramform Atlas* in 2014 and *Ramform Tethys* in 2016.

"The four Ramform Titan-class vessels and the two Ramform S-class vessels constitute our core fleet of ultra-high-end Ramforms," says Per Arild Reksnes, executive vice president operations, PGS. "These vessels can tow more streamers than any other vessel as well as tow extremely wide streamer spreads. Hence, surveys can be tailor made to meet our customers' needs, be it the highest possible data quality or the most efficient coverage of a large exploration area."

PGS says that its Ramform Titan-class design merges advanced maritime technology with the imaging capabilities of the GeoStreamer seismic acquisition technology. The 70m broad stern allows ample space for 24 streamer reels: 16 reels aligned abreast and 8 reels further forward, with capacity for 12km streamers on each reel. ▪

improve safety and environmental performance.

OGIC has made US$1.2 million (£1 million) available to support companies with projects that require research and development to be undertaken at a Scottish university. OGIC can fund up to 70% of these costs and ITF can potentially "top-up" financial support if an innovative project engages the interest of its members.

Applications are invited for all types of innovation, from developers of any size or country, that will benefit the oil and gas industry.

Editorial Index

What's next

Coming up in OE June

- **Feature – Offshore Technology Outlook**
- EPIC – Transport & Installation
- Subsea – Subsea Technologies
- Production – Efficiency
- Drilling & Completions – Drilling Efficiency
- Regional Overview – Mediterranean/North Africa

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Underwater Technology Conference (UTC)
Bergen, Norway
20-22 June

The Trestakk development will be featured in June's Subsea section. Image from Statoil.

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